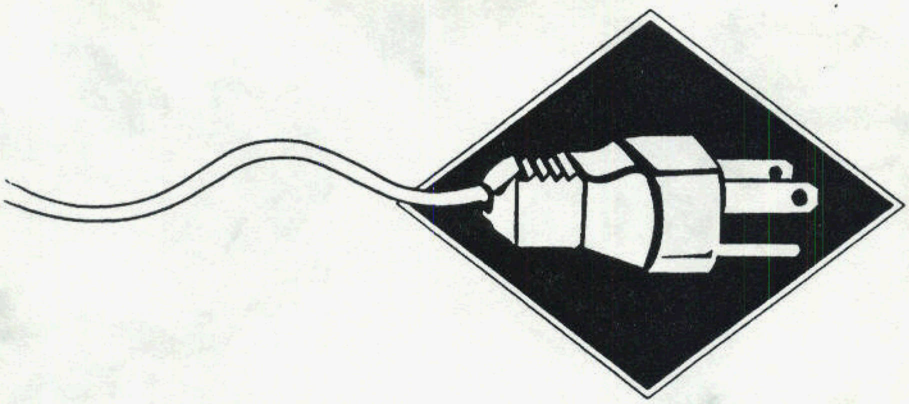

Review of

Electric Service Quality and Reliability

December 1997

By Authority of
The State of Florida for
The Public Service Commission
Division of Research and Regulatory Review
Bureau of Regulatory Review

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1.0 Executive Summary

1.1 Objectives

A review of distribution service quality and reliability of Florida's four major electric companies was requested by the Division of Electric and Gas in January 1997. The Bureau of Regulatory Review sent out initiation letters in March 1997 to Florida Power & Light Company (FPL), Florida Power Corporation (FPC), Gulf Power Company (GPC), and Tampa Electric Company (TEC). Field work was conducted between August 1997 and October 1997. The objectives for the review were to:

- Determine whether service quality provided by Florida Power & Light Company, Florida Power Corporation, Gulf Power Company, or Tampa Electric Company had declined over the period 1992 through 1997.

- Document the efforts of the companies to promote and maintain distribution service quality and reliability.

- Analyze service quality information gathered by the Florida Public Service Commission (FPSC) through both customer complaints and the annual distribution reliability reports filed with the FPSC.

1.2 Scope

The scope of this review included an investigation of the quality of service provided to electric service end-users by the distribution organizations of Florida Power & Light Company, Florida Power Corporation, Gulf Power Company, and Tampa Electric Company. The specific time period was restricted to the years 1992 through 1997 in most cases, although some older data was examined for perspective. Staff considered both the documented results of utility activities and descriptions of planned or partially-implemented activities that were considered relevant to distribution service quality. In determining whether service quality had declined over the study period, staff focused on the following information sources:

- FPSC customer inquiries/infractions
- Reliability data filed with the FPSC
- Internally-monitored reliability indicator data
- Customer satisfaction survey results
- Customer inquiries to the utilities
- Customer property damage claims

1.3 Methodology

This review was based upon information gathered through document requests and interrogatories, interviews with distribution department personnel, examination of company policies and procedures, and analysis of quantitative service quality indicators monitored by the company and the FPSC. Particular attention was paid to utility staffing reductions, workforce reorganizations, budget reductions, and changes in utility practices that may have affected service quality in the past or may affect it in the future.

1.4 Overall Opinion

Although the four utilities experienced varying distribution service quality trends and results, this review underscores the importance of effective service quality monitoring. Indicators must be monitored to detect emerging problems before they grow into large ones. In a future competitive arena in which retail wheeling provides a choice of electric service generation suppliers to customers, the quality of service issues will be of critical importance to the generation suppliers, as well as to customers. Awareness among all electric service providers of customer expectations, in residential and commercial/industrial customers alike, will become even more important than it has been in the era of service territory monopolies.

The indicators monitored by the Florida Public Service Commission must provide commissioners and staff with a multi-dimensional insight into service quality issues. A complete understanding of the status of service quality cannot be gained by examining one or two indicators. The information currently required by Rule 25-6.0455 should be expanded to provide a more comprehensive assessment of service quality and reliability performance.

The data examined in this review indicates that a reduction in distribution service quality occurred at both Florida Power & Light Company and Florida Power Corporation over the period studied. By late 1996 or early 1997, both companies had recognized the need for extensive efforts aimed at improvement. Both companies have targeted areas where rapid improvement can be made, as well as areas where more extensive work and time will be required to show results. Therefore, in some measures or indicators, positive results could be observed during 1998. In other areas, results may lag two or three years behind the corrective actions.

Over this period, the FPSC should maintain a continuing monitoring effort to keep abreast of changes and developments affecting service quality for all companies addressed in this review. This effort may involve one or more follow-up reviews to determine the success of efforts to resolve problems discussed in this report.

Chapter 7 presents in detail the conclusions drawn by the Bureau of Regulatory Review from this review. It also includes recommended actions for monitoring the efforts of Florida Power & Light Company and Florida Power Corporation to improve distribution reliability and service quality.

2.0 Background and Perspective

2.1 Significance of Service Quality

Distribution service quality can be divided into two components: system reliability and power quality. Customers expect that whenever they flip the switch, their utility's electric distribution system can be relied on to provide power, and that the quality characteristics of the power supplied will meet the customer's needs. Therefore, problems arise when power is not provided (for example, an interruption) or when the quality of the power provided does not meet the customer's needs (for example, low-voltage conditions). If service quality is viewed as a continuum, service interruptions of various lengths (including momentary interruptions) are at one end. Service interruptions, also commonly referred to as "outages," are of course the most recognizable service quality problem to customers. At the other end are electrical noise, transients, voltage swells and sags, and harmonic distortion. Somewhere in the middle of the continuum are under and over voltages, over currents and low power factors.

Service quality is an important factor in the efforts of electric utilities to retain customers in the face of competition. Customer interest in and need for high overall system reliability is on the increase for all customer classes. Almost every large industrial customer now uses computers and other sensitive electronic equipment. In the United States, there are presently no standards defining the length of power interruptions that electronic equipment should be able to tolerate. The result is that, as customers use increasing amounts of electronic equipment, they become more intolerant of blinks, dips or voltage sags. Naturally, customers want the highest service quality with the lowest cost.

Maximizing system reliability requires a utility to minimize the following contributing factors:

- Number of long interruptions
- Number of short interruptions
- Number of customers interrupted
- Duration of interruption (time)

Most distribution systems are built in a radial fashion, fanning out from the substations. Disturbances at any point on the system may cause an interruption of service to all customers electrically downstream from the disturbance. Lightning, tree contact, animal contact, and equipment failures are all possible causes for service interruptions. Momentary interruptions, usually defined as those under one minute in duration, are created when a circuit breaker in the distribution system trips and automatically resets. These trips may be caused by occurrences such as lightning strikes or tree branches coming in contact with power lines. Animals, such as squirrels on power lines, can cause short circuits resulting in momentary power interruptions.

The main objective of any method for determining system reliability is to improve system performance by pinpointing equipment or system components with lower than normal reliability and to identify needed system improvements.

2.1.1 Emergence of Electric Competition

The beginning of a competitive electric industry has already emerged in the wholesale market and may penetrate the retail market in the not too distant future. Competition at the retail level will be among independent power producers, power marketers, and other electric utilities, in addition to increased competition with natural gas utilities. Several states have already opened their electric lines to allow retail wheeling.

Electric utilities nationwide are positioning themselves for the advent of retail wheeling. With retail wheeling, customers are able to select their generation supplier, much as customers select their long distance telephone company. The electricity from the customer's choice of generation supplier is wheeled over the utility's transmission and local distribution lines to the customer's meter for consumption. Therefore, even in an era of retail competition where a customer has a choice of generation suppliers, the exact same local distribution system will still provide that customer's power through its power lines.

The changing electric power industry will obviously affect public utility regulation. Regulators will be under increased pressure to shift risks to utilities, allow utilities to earn higher rates of return, and give utilities increased flexibility in their pricing, operations, and planning decisions. Utilities are currently preparing for competition by reducing their costs, restructuring, and in some states, seeking the approval of their state commission for less tightly-controlled and more performance-based regulation.

The Florida Commission recognizes that competition and the talk of competition in the electric industry is increasing. Florida ratepayers do not pay high electric rates compared to their counterparts in New England and California, where retail competition has been ordered by state regulatory commissions. In Florida, the primary impetus of competition, at both the wholesale and retail level, is the unexpectedly low price of natural gas, coupled with the new highly efficient gas-fired combined-cycle generating units technology. These events are making the electric industry a declining cost industry at the generating level.

Electricity can be generated from new technology combined-cycle generating units at approximately $30 to $35 per 1,000 kWh. The cost for electricity from existing coal and nuclear generating units is generally $45 to $50 per 1,000 kWh. The residential bill in Florida is typically between $75 and $85 per 1,000 kWh. The difference between the generation level cost and the cost to consumers is due to transmission, distribution, and administrative costs to deliver electricity from the power plant to the customer.

As the electric industry continues to position itself for the introduction of competition, there are concerns regarding the quality and price of service to the small captive or core retail customer who may not have the options and flexibility available to the larger customer. Some of these concerns include downsizing and the associated cost cutting measures, shifting of cost allocations between customers, diversification, mergers, and the increasing business risk for the electric utilities.

2.1.2 Performance-Based Regulation

Performance-based regulation (PBR) has been in use in various forms for many years. Under a broad definition, utilities may be offered rewards and/or penalties as incentives to minimize costs, to lower rates, or to improve some other aspect of performance. Incentive regulation has been used extensively in both the telephone and railroad industry. While its use in the electric and natural gas industry is less extensive, it has been rapidly growing. In 1992, FERC passed a comprehensive policy statement which approved incentive rate making for natural gas pipelines, oil pipelines, and electric utilities. PBR is a variation of incentive regulation which focuses on various aspects of the regulated industry's performance characteristics. PBR mechanisms are used to set some sort of threshold performance level. Most PBR mechanisms create incentives to minimize cost through price or revenue caps, with incentives for maintaining reliability and customer service. Basically PBR sets rates or revenues in advance, and the company is rewarded directly for any cost-efficiency achieved, retaining some or all of the savings for the benefit of the shareholders.

Through performance-based regulation, regulators seek to encourage economic efficiency, further competition, enhance the environment, and improve services. As of July 1997, only six utilities have had PBRs for any significant length of time: Central Maine Power Company, Rochester Gas & Electric Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Company, Consolidated Edison, and San Diego Gas and Electric Company. The experience thus far has been varied.

Inappropriate incentives to reduce cost could result in unacceptable declines in service quality. Many PBR approaches consist of two or more mechanisms, one of which might typically cover service quality. Because of growing competition and likely service unbundling, it may well be necessary to have one PBR mechanism governing transmission and distribution service and another governing generation service.

A report, prepared by Synapse Energy Economic, Inc., for the National Association of Regulatory Utility Commissioners, on *Performance-Based Regulation in a Restructured Electric Environment* identified several PBR indices to consider with respect to service quality:

- Customer complaints to the utility
- Outage frequency
- Outage duration
- Major outage recovery
- Momentary outage frequency
- Employee safety

A three-year historical average may serve as a potential performance benchmark. When three years of historical data are not available, a benchmark might be developed based on experience in other states, or by state-wide or national averages. Peter Navarro, an associate professor of economics at the California School of Management, University of California-Irvine, recommends using a quality control mechanism that penalizes the utility for reductions in employee safety, customer service, or reliability.

By way of example, the Colorado Utilities Commission has a Quality of Service plan with the Public Service Company of Colorado which assesses monetary penalties for declining service quality. Benchmarks are established for three performance measures: (1) customer complaints, (2) telephone response time by the utility's call center, and (3) electric service unavailability. If performance falls below established benchmarks, specified penalties will be assessed regardless of the company's earning level. Maximum penalties for failing to meet the benchmarks are: $3 million for service unavailability, $1 million for customer complaints, and $1 million for telephone response time. Penalties are divided among the company's customers and are credited directly to the customer bill in June of each year. More details concerning the Colorado plan can be found in Appendix 2, which describes electric service quality monitoring activities in other states as well.

2.1.3 Customer Awareness/Technological Changes

Power quality includes characteristics such as voltage stability, spikes, transients, flickers, sags, and surges, as well as harmonic distortion and noise. The quality of service supplied is of increasing importance to both residential and business customers as they place increasing reliance on digital equipment that is relatively sensitive to power quality. Residential customers see gaps in power quality when their VCRs and digital clocks require resetting. Business customers see gaps in power quality as expensive downtime for computers and automated equipment.

In Florida, the three main causes of reliability problems are lightning, tree limbs, and animals. Direct and nearby lightning strikes to an overhead distribution line are significant events that create incredible stresses on line conductors, insulators, and protective equipment. Utilities must work to minimize potential damages to equipment and the public and to restore the line's integrity as soon as possible. This is accomplished through the use of lightning arresters and protective devices installed throughout the utility's distribution system.

Some responsibility for protecting against property damage lies with the customer. To reduce the effects from voltage irregularities or lightning strikes, customers can purchase and install surge protectors on all sensitive electronic equipment. Neither utilities nor customers can prevent 100% of all lightning-related damage, particularly in Florida. However, hardware and electric supply stores and some Florida electric utilities offer protection devices which plug directly into the circuit box or electric meter and may protect the home from damage caused by voltage fluctuations.

Customers can also prevent the frustration and damage caused by momentary power interruptions. When purchasing new solid state electronics, customers should buy items which are equipped with battery back-up. When purchasing an air conditioner, customers should purchase one with a time delay relay. In the event of a momentary interruption, the relay will prevent restarting the unit for three to five minutes, which minimizes the possibility of damage to the compressor. Additionally, uninterruptible power supply (UPS) units can be purchased from computer supply stores to protect home computers from momentary interruptions.

Tree limbs or other obstacles should not normally come in contact with power lines or come any closer to them than the clearance distance specified by the National Electric Safety Code (NESC). A successful tree-trimming program, along with a successful preventive maintenance program, should prevent many tree-related interruptions. Trees coming in contact with overhead power lines will cause service interruptions. Customers can assist the utility in reducing tree-related interruptions by ensuring that trees on their property are not allowed to grow into contact with utility power lines. Customers should avoid planting trees near transformers or underneath power lines. If a tree is touching a power line, customers should not attempt to trim the tree, but should contact the utility to schedule a line clearing crew to perform this potentially dangerous work.

Frequently, utility efforts to protect service reliability by trimming trees come into conflict with local tree-protection ordinances or individual customers' concerns and property rights. In these cases, the proper balance between safety, reliability, conservation, and aesthetics must be sought and achieved among the parties involved. Customers concerned about trees they planted and nurtured have a right to be heard, but they must also understand the utility's responsibility to ensure the safety and reliability of service not only to that customer, but also to the surrounding community. Customer education regarding company policies and procedures can reduce such conflicts.

2.2 Service Quality Measurement Methods and Issues

The forms of regulation used may be changing, but the need to assure high quality electrical service has not changed. Especially in the early years of PBR, close monitoring and evaluation are essential to ensure quality is maintained, rates are not increased unnecessarily by quality standards that are too high or by rewards that are too easily achieved, and that reasonable customer desires and expectations are met.

Any inter-utility company comparison should be performed with great caution, since data definitions and the ability to capture data detail can vary widely. No two distribution systems are alike in age, condition, or design. Similarly, reliability and service quality are sensitive to weather conditions, population density, and other variables which vary from one service territory to the next. Therefore, satisfactory performance is best defined with respect to the history of a particular utility and its performance over time.

2.2.1 Traditional Industry Measures

Distribution system reliability is defined and measured by electric utilities using a variety of performance indices. Using these performance indices, the utility can determine the projected impact of planned additions or modifications on system reliability. The Institute of Electrical and Electronic Engineers (IEEE) is codifying a group of reliability indices that measure frequency and duration of service interruptions in various ways. A 1995 IEEE survey found that 63 percent or more of utilities used each of the following, in order of popularity:

- System Average Interruption Duration Index (**SAIDI**) is also known as "Service Unavailability" or "Customer Minutes of Interruption." This index measures the average length of interruptions, usually in total minutes, experienced by all customers served on the system over a period of time, usually a year. SAIDI is calculated by dividing *total customer hours of interruption* by *total customers served.* An upward trend in SAIDI is normally perceived as a reduction in reliability.

- Customer Average Interruption Duration Index (**CAIDI**) measures the average time duration, usually in minutes, before service was restored to customers experiencing an interruption. CAIDI is calculated by dividing *customer hours of interruption* by the *number of customer interruptions*. An upward trend in CAIDI is normally perceived as a decrease in reliability.

- System Average Interruption Frequency Index (**SAIFI**) measures the average number of interruptions of all customers served by the system over a period of time, usually a year. This index is a reflection of reliability as it relates to system design. SAIFI is calculated by dividing *customer interruptions* by *customers served.* An upward trend in SAIFI is generally perceived as a reduction in reliability.

- Average Service Availability Index (**ASAI**) measures the percentage of time a customer has power in a given time period. This measure is equal to 100% minus the percent of interruption time accounted for by SAIDI.

Mathematically, SAIDI is the product of the interruption frequency component, SAIFI, times the interruption duration component, CAIDI. Assuming an average interruption duration of 50 minutes and an average system frequency of interruption of 2 times per year, the system service unavailability value would be 100 minutes per year. The calculation of SAIDI can be further fine-tuned as needed. For example, it can be calculated for a specific portion of the service territory to either include or exclude the effects of named tropical storms or to include or exclude pre-arranged outages for planned maintenance or system expansion.

These indices may provide a common system for evaluation of distribution system reliability. However, utilities use a variety of different indices to evaluate the reliability of their system. The variety of methods used to evaluate system reliability has been increasing in direct proportion to the increased availability of prepackaged software for reliability calculations and increased performance of personal computers. The main objectives of any method of system reliability are to improve system performance by pinpointing equipment or line sections with lower than normal reliability and to evaluate potential system improvement.

Other indices include:

- Momentary Average Interruption Frequency Index (MAIFI) measures the average frequency among all customers of momentary interruptions, usually defined as interruptions of less than one minute in duration.

- Customer Total Average Interruption Duration Index counts an interrupted customer once regardless of the number of interruptions and so measures the interruption outage duration per customer interrupted.

- The Average System Interruption Frequency Index measures interruption frequency taking into account the size of loads interrupted.

- Customer Experiencing Multiple Sustained Interruptions and Momentary Interruptions Events reports the percentage of customers suffering more than a specified number of events.

The utility industry has not agreed on precise standards for reporting system, feeder, or equipment reliability. The lack of conformity sometimes prohibits a direct comparison of reliability information as reported by different utilities. For example, two utilities may both calculate what they refer to as "SAIDI," but one company may exclude the effects of hurricanes, while the other company may include hurricane-related interruptions in its calculations, exaggerating the difference in reliability between the two utilities. No attempt has been made to adjust the data provided in this report to ensure consistency of methodology. Therefore, direct company-to-company comparison of the data provided in this report is discouraged.

2.2.2 FPSC Distribution Service Reliability Reports

In an attempt to gather uniform information on service reliability, the Commission requires each utility to file a Distribution Service Reliability Report (Rule 25-6.0455) with the Commission by March 1 of each year. This report has been required since 1993, although TEC, GPC, and FPL voluntarily provided 1992 reports as well. Each report covers the preceding calendar year and includes the following information:

- The utility's total number of service interruptions (N) categorized by cause.

- The average length of service interruptions experienced (L-Bar).

- The utility's three percent of feeders with the highest number of feeder breaker interruptions, identified by number, substation, and general location. Additionally:
    - Number of customers in each service class served by the feeder
    - Number of service interruptions (N)
    - Average length of service interruption (L-Bar)

Utilities are required to categorize each interruption as one or more of the following causes:

- Lightning
- Tree or limb contacting line
- Animal
- Line downed by vehicle
- Dig-in
- Substation outage
- Line transformer failure
- Salt spray on insulator
- Corrosion
- Other
- Unknown

To avoid skewing the data as a result of events beyond the control of the utility, the FPSC's definition of a service interruption excludes those caused by momentaries, circuit breaker operations, hurricanes, tornados, ice on lines, planned load management, or electrical disturbances. Reliability measures for the past four years can be found in report section 3.2.2, for Florida Power & Light; 4.2.2 for Florida Power Corporation; 5.2.2 for Gulf Power Company and 6.2.2 for Tampa Electric Company.

Florida electric utilities are required by Rule 25-6.044 (3) to make all reasonable efforts to prevent interruptions of service, and, when such interruptions occur, should attempt to restore service within the shortest time practical, consistent with safety. When utilities interrupt service for prolonged periods for the purpose of working on the system, the rule states that it should be done at a time which, when at all practical, will cause the least inconvenience to customers. Scheduled interruptions should be preceded by adequate notice to affected customers.

Exhibits GEN-1 and GEN-2 display the trends in numbers of interruptions experienced by each of the utilities examined in this review as reported in the Distribution Service Reliability Reports over the period 1992 through 1996. Exhibit GEN-1 shows the trend in actual total interruptions, while Exhibit GEN-2 equalizes for the size differences between these companies by presenting the interruption data on a per 1,000 customer basis.

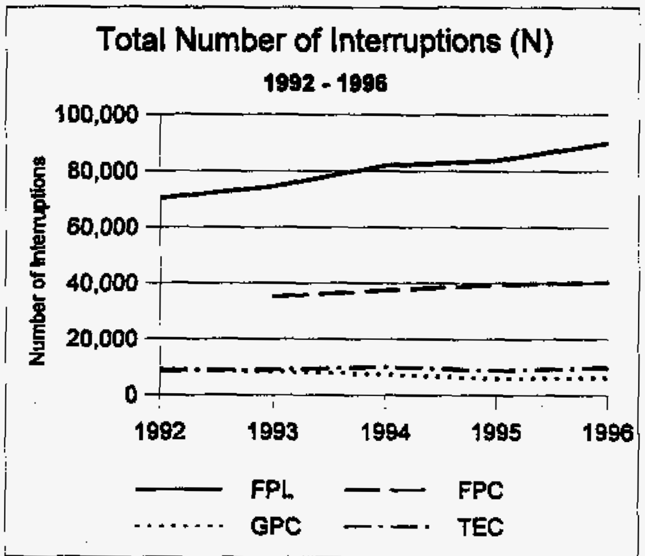


EXHIBIT GEN-1 *Source: FPSC Reliability Reports.*

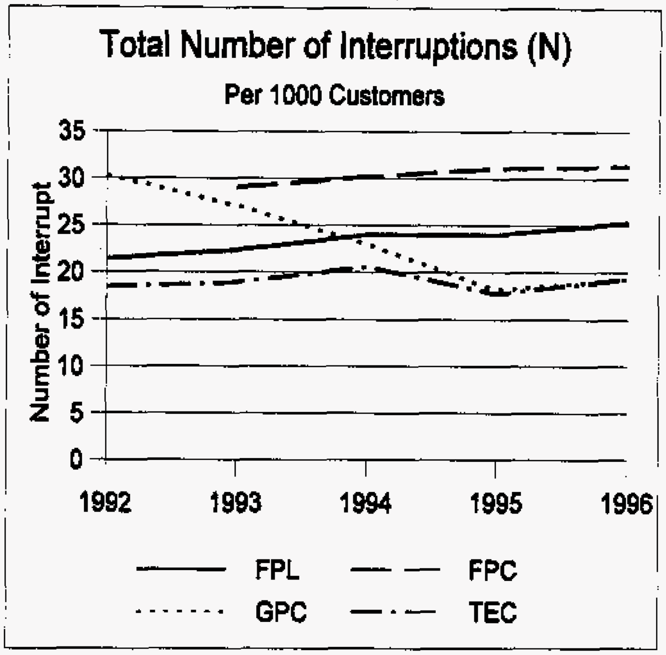


EXHIBIT GEN-2 *Source: FPSC Reliability Reports, Statistics of The Florida Electric Utility Industry.*

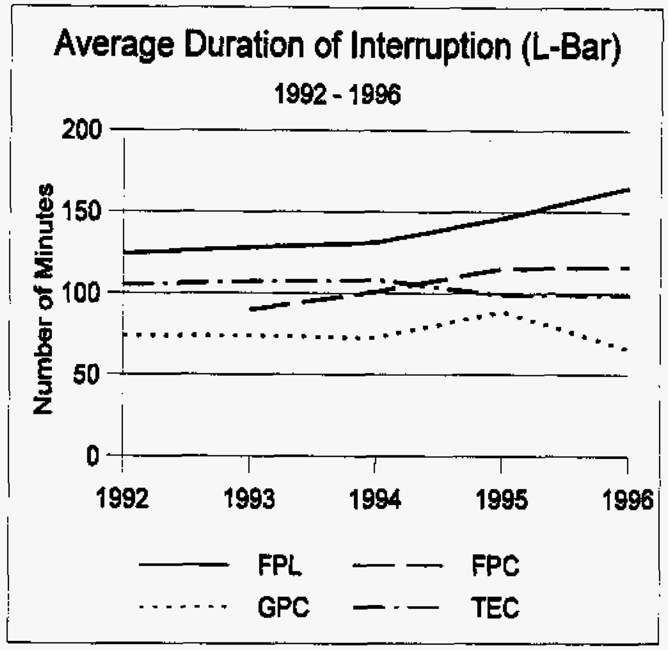


EXHIBIT GEN-3 *Source: FPSC Reliability Reports.*

Exhibit GEN-3 displays the trend in average duration of interruptions (L-Bar) over the 1992 through 1996 period. The calculation of L-Bar provides a simple average of all interruptions, but does not provide a "weighting" to adjust for the number of customers interrupted.

2.2.3 FPSC Consumer Inquiries and Complaints

A second mechanism used by the FPSC staff to monitor electric service quality is customer inquiries received. The FPSC Division of Consumer Affairs is the primary contact for customer inquiries lodged with the Commission. Upon receiving a customer inquiry, the Consumer Affairs representative qualifies the customer to assure that the utility company has been first contacted by the customer. If the company has not yet been contacted by the customer to solve the inquiry, the customer is referred to the company for resolution. If the inquiry has not satisfactorily been resolved by the company, Consumer Affairs will document the customer's inquiry.

After inquiries are received and logged, the Consumer Affairs representative contacts the company to requests an investigation and a description of company actions taken to resolve the inquiry. At the time the case is closed, Consumer Affairs makes a determination as to whether the company has committed an infraction. Infractions occur when a utility has violated FPSC rules, a company tariff, or a company policy. If there is no infraction, the inquiry is categorized by type of complaint. Consumer Affairs records the number and category of customer inquiries for each company and reports the results monthly to FPSC Commissioners and staff through its Complaint Tracking System. These reports help identify and trend continuing company billing and service problems which may require staff attention.

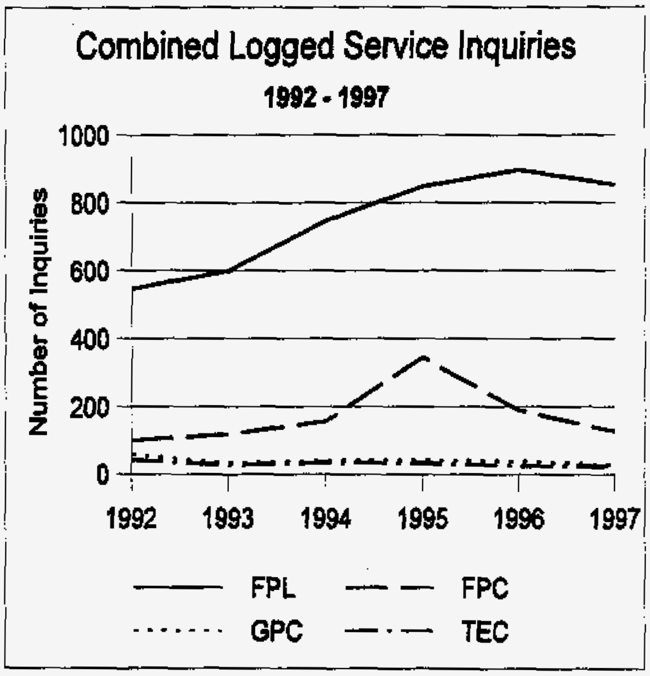


EXHIBIT GEN-4 *Source: FPSC Division of Consumer Affairs.*

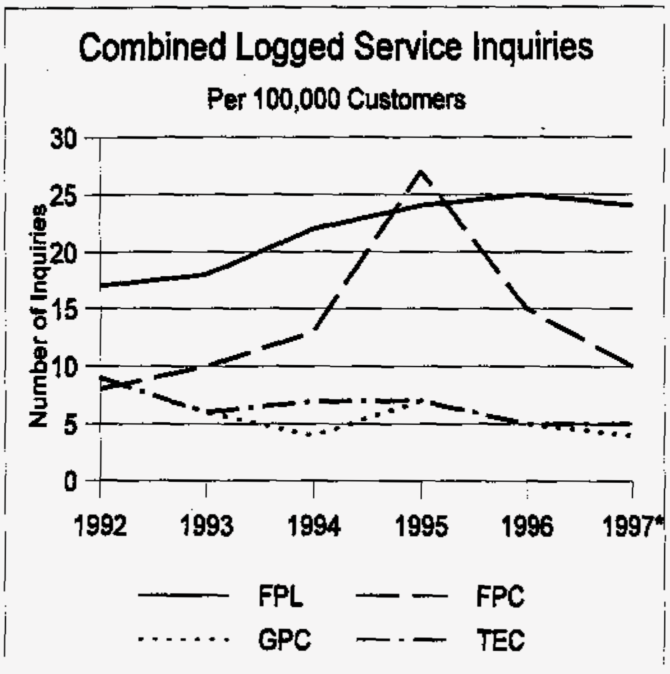


EXHIBIT GEN-5 *Source: FPSC Division of Consumer Affairs Statistics of the Florida Electric Utility Industry.*

** 1996 Number of Customers used as proxy for 1997.*

Exhibits GEN-4 and GEN-5 respectively show the total number of electric service-quality inquiries and service-quality inquiries per 100,000 customers received by the Commission between the years 1992 and 1997. A detailed analysis of all service-related customer inquiries for each company can be found in report section 3.2.1 for Florida Power & Light; 4.2.1 for Florida Power Corporation; 5.2.1 for Gulf Power Company, and 6.2.1 for Tampa Electric Company.

2.2.4 General Utility Information

Exhibit GEN-6 provides general information relating to each of the four utilities included in this review. FPL is, by far, the largest utility in the state with over 27,650 square miles of service territory and 3.6 million customers. FPC is the second largest utility with over 20,000 square miles and 1.29 million customers. TEC has a more compact service territory with 2,000 square miles, but has over a half million customers. GPC's service territory, on the other hand, is more spread out with 7,400 square miles, but only 330,565 customers.

1996 General Statistics Comparison				
Utility	**Florida Power & Light**	**Florida Power Corporation**	**Tampa Electric Company**	**Gulf Power Company**
Operating Territory (square miles)	27,650	20,000	2,000	7,400
Generating Capacity (megawatt)	16,369	7,341	3,650	2,134
Substations	476	353	180	115
Substation Capacity (kva)	102,087,240	41,522,275	16,235,857	9,274,019
Customers	3,551,000	1,292,075	513,100	330,565
Total Employees	10,170	4,629	2,798	1,384
Union Employees	3,828	2,035	1,432	625
Operating Revenues	$ 5,986,000,000	$ 2,393,592,542	$ 1,112,000,000	$ 634,364,807
Residential Customer Revenues	$ 3,324,000,000	$ 1,299,108,653	$ 539,700,000	$ 285,498,429
Commercial Customer Revenues	$ 2,116,000,000	$ 537,248,202	$321,300,000	$ 164,181,324
Industrial Customer Revenues	$ 203,000,000	$ 206,764,971	$ 102,900,000	$ 78,994,161
O & M Expenses	$ 3,258,000,000	$ 1,493,438,213	$ 940,300,000	$ 394,079,735
O&M Expenses Per Customer	$917.00	$1,155.84	$1,858.56	$1,192.14
Number of Customers Per Employee	349	279	183	239
Number of Customers Per Union Employee	928	635	358	529

EXHIBIT GEN-6

Source: 1996 Annual Report FERC Form 1 or 10-K.

2.2.5 Regulatory Activity in Other States

Competitive pressures in the electric industry, especially in the generation of electric power, have forced state and federal regulators to take a hard look at the issue of restructuring. There is considerable debate on how restructuring will affect rates, the reliability of the electric system, environmental and social goals, and utility recovery of previous investments. Some states, including California, New York, New Hampshire, and Rhode Island, have already have adopted legislation to allow competition in the retail electric market. The FPSC published a report in October 1997 which identifies specific restructuring activities that are occurring in other states. The report is entitled "*States' Electric Restructuring Activities: An Initial Progress Report.*"

Appendix 2 identifies which states are particularly concerned about electric service quality and have adopted rules for monitoring purposes. The rules typically require that an annual report be filed with the Commission which identifies the number of interruptions as well as reliability indices such as SAIDI, SAIFI, and CAIDI. Some states require the utilities to conduct and document detailed inspections of distribution facilities. Some of the activities of interest include:

- California has explicitly identified and defined assumptions to be used when calculating indices to assure uniformity and consistency.
- California requires utilities to conduct inspections of distribution facilities.
- California has established tree-trimming standards.
- Colorado has implemented a Quality of Service Plan with the Public Service Company of Colorado. The plan assesses penalties for failure to achieve benchmarks in customer complaints, telephone response, and electric service unavailability.
- Illinois requires annual reports assessing the programs the utilities use to provide reliable service. Illinois will evaluate whether to require service standards in the year 2000.
- Iowa requires utilities to file a program for inspection and maintenance of electrical supply lines.
- New York requires utilities to calculate SAIFI and CAIDI for each operating area. The Commission identifies a lower threshold of adequate service, below which further review, analysis, and corrective action may be required.
- Oregon requires utilities to calculate SAIDI, SAIFI, and MAIFI. Oregon also requires the utilities to set threshold levels for statewide operations, operating areas, and each circuit.

3.0 Florida Power & Light Company

3.1 FPL Company Profile

As Florida's largest electric utility, Florida Power & Light Company (FPL) serves about half the state's population. The operating utility is by far the largest subsidiary of the parent corporation, FPL Group, which also operates ESI Energy (domestic independent power projects), FPL Group International (global power projects), and Turner Foods Corporation (Florida citrus). FPL also owns and operates subsidiaries including FPL Energy Services, Inc., and FPL Energy Services II, Inc., which provide or market energy services, conservation services, or financing for these projects. Operating revenues for FPL totaled nearly six billion dollars in 1996, up from five and one half billion in 1995. FPL's employees totaled just over 10,000 at the end of 1996, about 38 percent of whom are members of the International Brotherhood of Electrical Workers.

FPL's service territory covers an area of 27,650 square miles, covering the lower half of the Florida Peninsula, the entire Atlantic Coast except Duval County, and the Gulf Coast south of Tampa Bay. Providing reliable electric service to its large and stretched-out service area presents challenges that would not exist in a more compact, contiguous region. FPL serves outlying areas of extremely low density, such as the Everglades, as well as the high-density Miami/Fort Lauderdale metroplex. Other cities served include St. Augustine, Daytona Beach, Melbourne, Stuart, West Palm Beach, Naples, Fort Myers, Sarasota, and Bradenton. In addition to its geographic diversity, FPL serves a culturally diverse customer base including large numbers of Spanish-speaking customers, as well as concentrations of retired senior citizens, and seasonal residents, posing unique customer service challenges.

Customer accounts served totaled 3.6 million during 1996, an increase of 2.9 percent above 1995 levels. The compounded annual growth rate for kWh sales and customers, was 3.7 percent and 2.0 percent, respectively, over the period 1994 through 1996. This growth was fairly equally spread across the residential, commercial, and industrial customer categories.

Segmented by type, 88.8 percent were residential customers, accounting for just over half of 1996 energy sales. Commercial customers comprised 10.7 percent of the total, but purchased over 38 percent of FPL's total energy production. Industrial customers made up less than .5 percent of the customer base, while accounting for five percent of energy purchases.

Total FPL generating capacity stood at 16,369 total megawatts at the end of 1996, of which 82 percent was fossil-fuel burning (largely oil and gas), and 18 percent nuclear-powered. FPL's 34 base-load generating units include 28 steam turbines and 6 combined-cycle units. FPL owns and operates 476 distribution and transmission substations with a total capacity of 102 million kilovolt-amperes. FPL has nearly 45,000 pole miles of overhead lines and nearly 20,000 miles of underground and submarine cable.

3.2 FPSC Service Quality Indicators

The two key indicators of distribution service quality monitored by the staff of the Florida Public Service Commission are customer inquiries and complaints, and the annual Distribution Service Reliability Report filed by the four large investor-owned electric utilities. Customer inquiries and complaints are handled by the FPSC Division of Consumer Affairs. The Reliability Report is monitored by the Division of Electric and Gas. This section examines and compares FPL's record in both areas over the study period of 1992 through 1997.

3.2.1 FPSC Customer Inquiries and Complaints

Over the years 1992 though 1997, the FPSC has experienced a sharp increase in the number of service-related customer inquiries received from FPL customers. This occurred after a period of declining or stable numbers of inquiries from 1985 through 1991. Exhibit FPL-1 displays the trend in service-related inquiries (such as those related to extended or momentary service interruptions, and voltage problems) and excludes billing-related calls. In 1992, a total of 545 such inquiries were received. By 1995, this number had grown to 847, and in 1996 the total was 897. Through September of 1997, this number stood at 640, which would imply an annualized 1997 total of 853. Although a variety of causes such as increasing customer expectations may have been at work, the increased volume of customer concerns expressed to the FPSC about service quality issues implies that customers perceived a significant decline in service quality by FPL over this period.

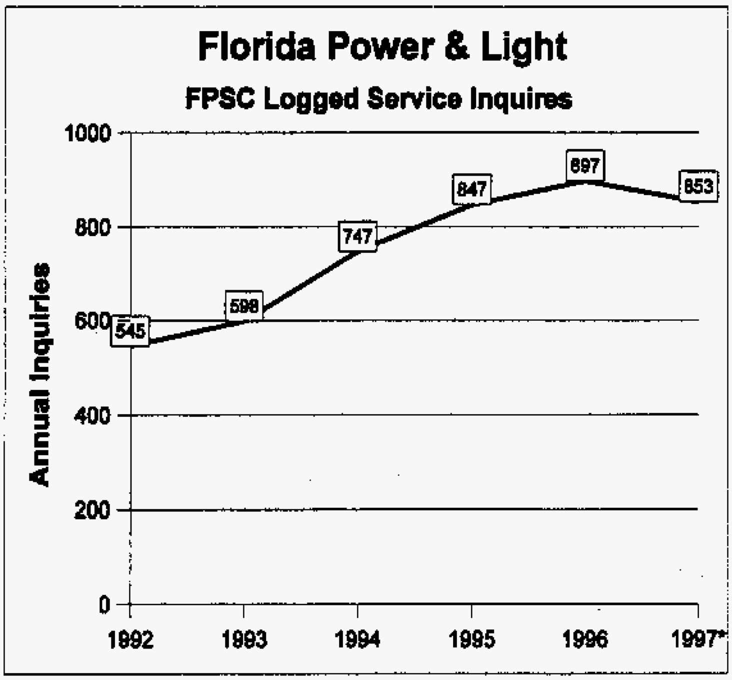


EXHIBIT FPL-1 *Source: FPSC Consumer Activity Reports 1992-1997.*

**Annualized based on data through September 1997.*

Four distribution quality-related categories rated among the top eleven: service outages, frequent outages, voltage and surge problems, and momentary interruptions. Together, these four categories accounted for 159 (29 percent) of the 545 total 1992 inquiries. By 1995, the combined categories of frequent outages, service outages, voltage and surge problems, and momentary interruptions accounted for 316 (37 percent) of the 847 total. The category of frequent outages now was the second most common type of inquiry in 1995, with 158.

Appendix 3 provides information from a sample of service-related FPL customer inquiries received by the FPSC during 1996 and 1997. Among the 118 customer inquiries determined to have constituted an infraction, the leading cause was violations of FPSC rules and tariffs relating to street lighting. The second leading cause was FPL's failure to restore the site of a repair to its former condition, particularly leaving a ground strap, or temporary service connection, in place for an extended period. However, as can be seen in Appendix 3, many of these inquiries deal with the frequency and length of interruptions being experienced. Although many such complaints do not constitute an infraction of current rules or company policies, they still represent unsatisfactory service quality and considerable inconvenience to customers. The need for updating FPSC rules relating to infractions is discussed in Chapter 7 of this report, which presents conclusions from the review.

3.2.2 FPSC Distribution Service Reliability Report

FPL's annual Distribution Service Reliability Report results from 1992 through 1996 indicate substantial declines in all three areas currently measured annually by the FPSC: total number of interruptions (N), average interruption duration (L-Bar), and the 3% of feeders most prone to interruptions. Partial 1997 results show a continuation of the increasing trend in number of interruptions. As shown in Exhibit FPL-2, FPL has experienced a steady increase in number of interruptions over the period 1992 through 1996. Interruptions increased from 70,284 in 1992 to 89,959 in 1996, an overall increase of 28 percent or about seven percent annually. Through November 1997, FPL customers had experienced 89,761 interruptions. FPL projects an annual 1997 total of 95,380--an increase of 6 percent over 1996, and a jump of 36 percent from 1992.

Exhibit FPL-3 shows the most frequent causes of interruptions for the years 1992 through 1997. In each year, the top five causes were: unknown (repairman was unable to detect a specific cause), lightning, other (other than one of the reporting categories specified by Rule 25-6.0455), tree-related, and animal. The fact that the leading cause was "unknown" underscores the transient nature of most interruptions and the difficulty and uncertainty inherent in reconstructing a cause after the fact. FPL believes, however, that a significant portion of the "unknown cause" interruptions are tree-related.

Florida Power & Light
Total Interruptions by Category
1992-1996

Cause	1992		1993		1994		1995		1996		1997*	
	Total	%	Total	%	Total	%	Total	%	Total	%	Total	%
Animal	6,321	9	6,575	9	6,558	8	7,439	9	7,401	8	7,016	9
Corrosion	1,706	2	1,960	3	2,508	3	1,881	2	1,357	2	975	1
Dig-In	915	1	1,037	1	933	0	824	1	796	0	565	1
Lightning	10,245	15	13,568	18	14,491	18	10,287	12	11,008	12	14,467	19
Salt Spray	203	0	250	0	347	0	343	0	496	1	296	0
Substation	190	0	193	0	183	0	197	0	223	0	200	0
Transformer	866	1	602	1	213	0	849	1	231	0	152	0
Tree	9,649	14	7,550	10	9,428	11	10,553	13	11,347	13	8,980	12
Unknown	29,584	42	32,706	44	37,335	46	42,119	50	46,341	52	36,549	47
Vehicle	1,089	2	1,198	2	1,190	1	1,192	2	1,073	1	830	1
Other	9,516	14	8,913	12	8,840	11	8,218	10	9,686	11	7,315	10
Total	**70,284**	**100**	**74,552**	**100**	**82,026**	**100**	**83,902**	**100**	**89,959**	**100**	**77,345**	**100**

EXHIBIT FPL-2

Source: FPSC Reliability Reports 1992-1996, FPL Response to Document Request 4-12.
**As of September 1997.*

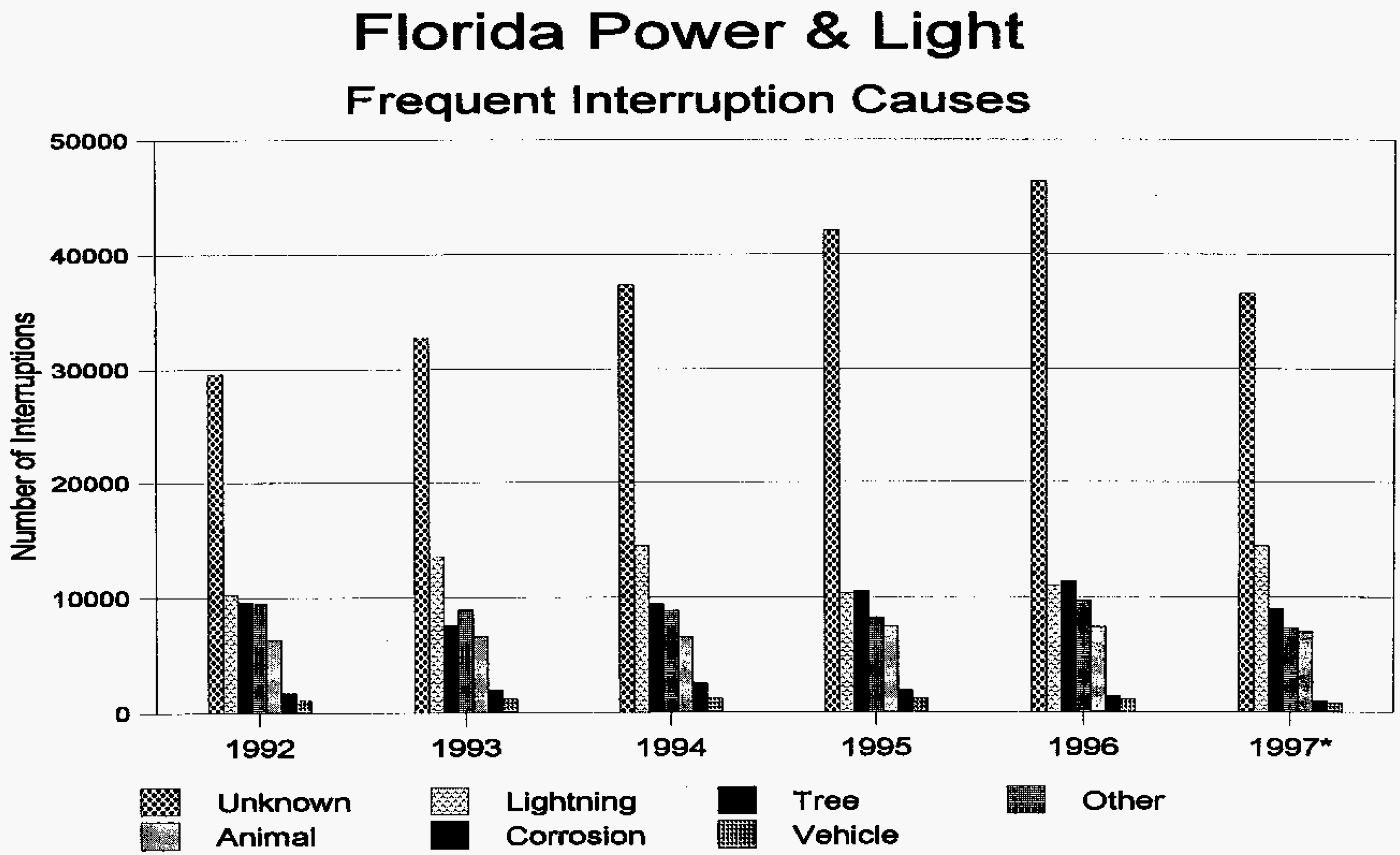


EXHIBIT FPL-3

Source: FPSC Reliability Reports 1992-1996, FPL response to Document Request 4-12.

**As of September 1997.*

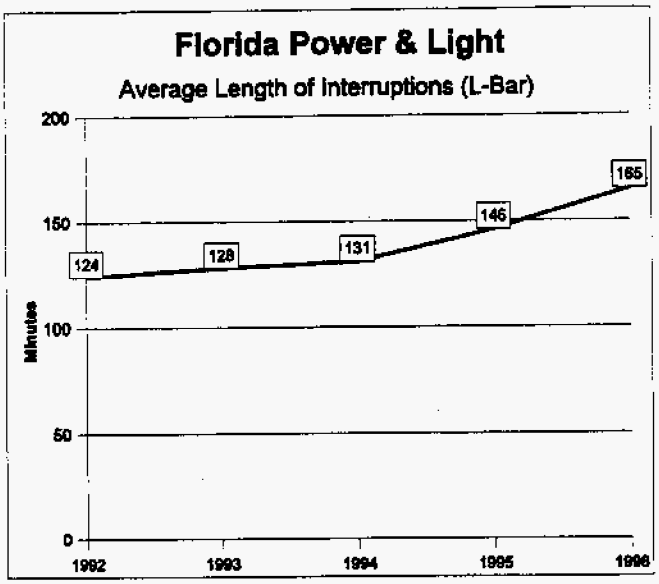


EXHIBIT FPL-4 *Source: FPSC Distribution Reliability Reports 1992-1996.*

During the period 1992 through 1996, FPL's average length of interruptions (L-Bar) grew by 33 percent. As shown on Exhibit FPL-4, the 1992 average of 124 minutes grew to 146 in 1995 and then 165 in 1996. This equates to an average annual increase in duration of interruptions of 8.5 percent.

The FPSC Distribution Service Reliability report requires the utility to identify the distribution feeder lines with the highest numbers of interruptions. FPL's three percent "worst-performing feeder" lists over the 1992 through 1996 period show patterns of feeders repeatedly making the list. Two feeders have appeared on the list in four of the five years it has been filed, while eleven other feeders have been on the list three times. Forty-three more feeders have made the list twice. Some feeders, especially longer circuits, may continue to be problematic even despite remedial efforts. However, these "repeat offenders" represent identified trouble areas being experienced for two or more years without being fully resolved. As a result, during 1997 identifying and addressing the problems of poor-performing feeders has been a major focus by FPL, as discussed in section 3.5 of this report.

3.3 Company Service Quality Indicators

While the FPSC measures of customer inquiry activity and the Distribution Service Reliability Reports provide indicators of service quality, FPL has its own methods of monitoring performance. These indices help the company identify trends and areas in need of improvement.

3.3.1 Internal Service Quality Indicators

A variety of distribution service quality indicators or indices are used by FPL to monitor its Distribution Business Unit's operations, primarily on a monthly basis. Although company-wide results are discussed below, many of these indicators are also calculated and examined for smaller service areas. Consistent with the indications of trends in customer inquiries to the FPSC and the annual Reliability Reports filed with the Commission, FPL's internally-tracked indicators denote a substantial decline in distribution service reliability over the period 1992 through 1997.

Service Unavailability

The primary indicator of overall system distribution service quality tracked by FPL today is the service unavailability index. Exhibit FPL-5 graphically displays service unavailability data

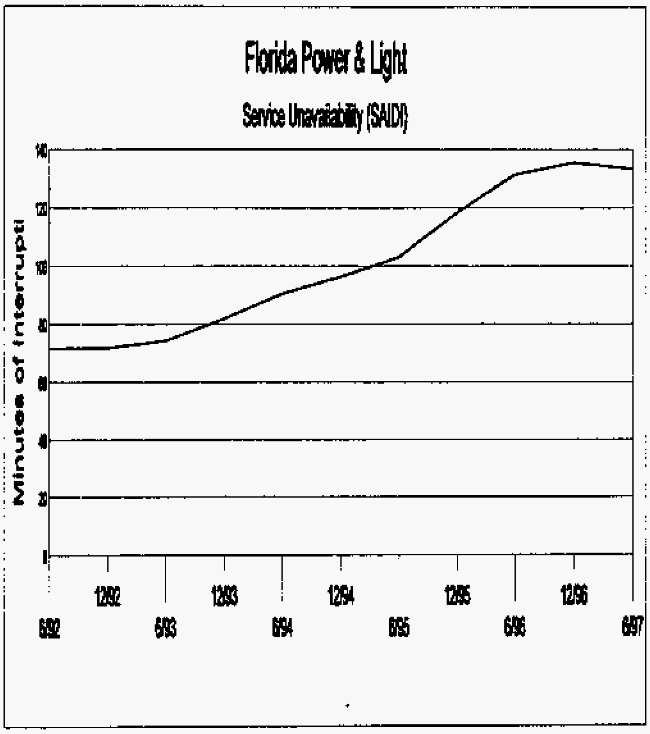


EXHIBIT FPL-5 *Source: FPL Response to Document Request 2-9.*

for FPL for the period from June 1992 through June 1997. Within this five-year period, the average FPL-served customer experienced a nearly 100 percent increase in total annual interruption time as measured by service unavailability. An analysis of individual service unavailability results for FPL's 15 geographical service areas indicated this increase was experienced throughout FPL's service territory, rather than being isolated to just a few areas.

The service unavailability index, also abbreviated "SU," indicates the system-wide annual number of minutes of service interruption experienced by the average customer served by FPL. SU is equivalent to System Average Interruption Duration Index (SAIDI) discussed in section 2.2.1 of the report, which is widely used throughout the electric industry. Although it is similar in some ways to the FPSC Reliability Report's "L-Bar" indicator of average interruption duration, SU (SAIDI) also reflects the impact of the vast majority of customers who actually experience zero or very few minutes of interruptions. Therefore SU (SAIDI) provides an overall, weighted-average picture of total system interruption time, while L-Bar shows the average length of all interruptions without regard for the number of customers affected.

Exhibits FPL-6 and FPL-7 separately display the two components of service unavailability: average interruption duration and frequency of interruption. As described in section 2.2.1, the duration component is frequently referred to as Customer Average Interruption Duration Index (CAIDI). This measure shows the average length of an interruption for the customers who experienced an interruption. As shown on Exhibit FPL-6, FPL's outage duration dropped in late 1992, then

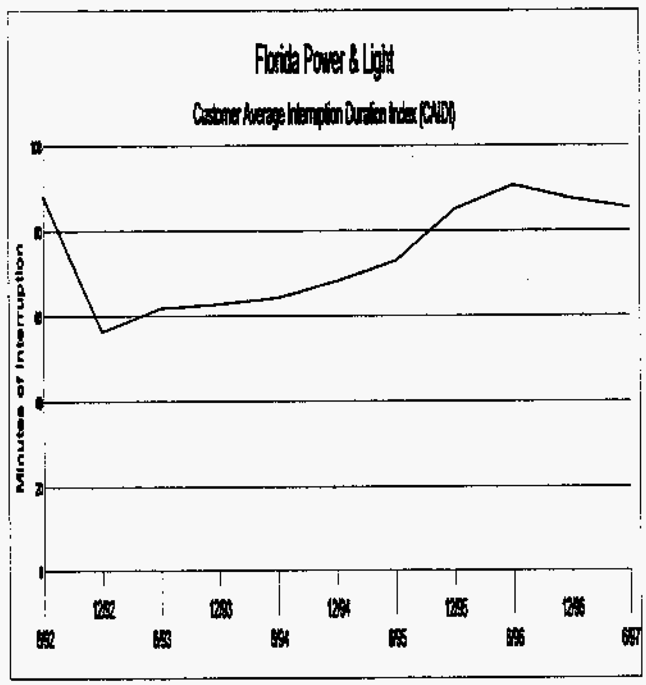


EXHIBIT FPL-6 *Source: FPL Response to Document Request 2-9.*

increased steadily through mid-1996. By mid-1997, CAIDI had stabilized and declined slightly from its 1996 peak. Specifically, the average increased to about 1.4 interruptions per year in 1994, and as of mid-1997, the average was just under 1.6 interruptions annually.

Other Measurements and Indicators

Although SU (and its components) serve as FPL's primary system reliability index, numerous other indicators have been used to monitor distribution reliability in specific applications. Some of these other measurements and indicators, such as interruptions per mile, have been tracked at least since 1993, while others have been added or deleted over the years to target a specific area of focus or problems. FPL indicates that the management reports containing the specific indicators used as far back as 1992 had not been retained, but states that the company monitored average service restoration time during that year.

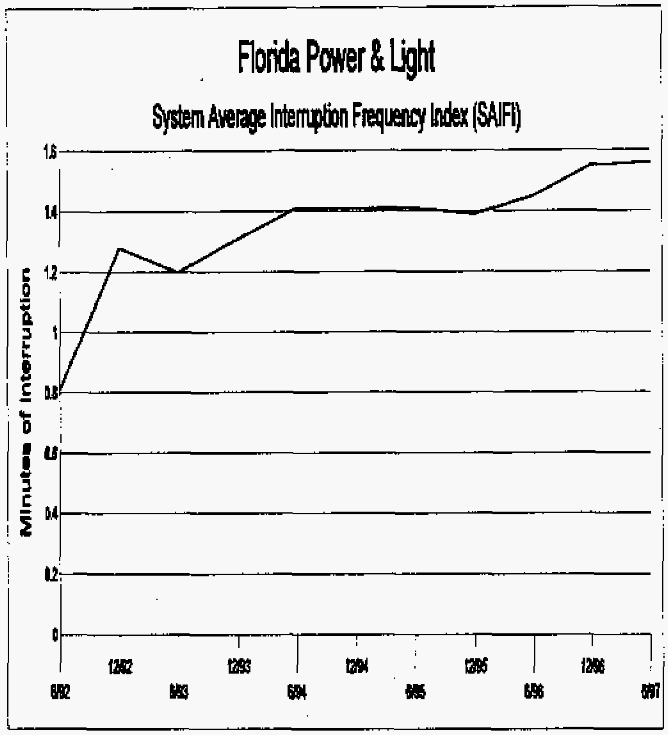


EXHIBIT FPL-7 *Source: FPL Response to Document Request 2-9.*

Interruptions per mile, calculated on a 12 months-ending basis, has been an internal FPL reliability indicator since 1993. FPL sets targets for interruptions per mile and tracks them against actual results on a total company basis. During the period 1993 through mid-1997, the number of interruptions per mile was stable, trending slightly downward. This is possibly due to the fact that increases in interruption length and frequency indicated by CAIDI and SAIFI above are largely offset by growth in the number of miles in FPL's distribution system.

Since 1994, FPL has tracked the number of transformers experiencing high numbers of interruptions within a 12-month period. This indicator of interruption frequency can identify troublesome distribution system components or sections, providing useful input for maintenance planning. FPL has sustained a high rate of growth in the number of devices (in most cases transformers) experiencing 10 or more interruptions per year. For example, in 1994, only 759 devices reached this failure level. In 1995, the number jumped 25 percent to 948. During 1996 alone, the number increased 175 percent to a total of 2,612.

Various indicators have been used over the years to provide a measure of the problem of customers receiving poor service. During 1994 and 1995, FPL tracked the number of long-duration interruptions (those over 11.7 hours in length) on a year-to-date basis. During 1994, there were 168 such outages, while in 1995, this number grew to 259. In 1996, FPL tracked the percentage of customers with over four hours of total interruption duration in a 12-month period and determined that as of December 1996, about 16 percent of customers experienced this level of poor service. In 1997, FPL discontinued the use of this indicator, instead measuring the number of customers encountering more than ten interruptions in twelve months.

3.3.2 Utility-Handled Inquiries and Complaints

Customer inquiries to FPL are received through the Customer Service Department's Phone Centers. These inquiries may involve customers calling with a question, a request, a problem, or a complaint. Inquiries can run the gamut from a question about a customer's account balance and due date, to a request for new service connection, or a complaint about frequent momentary interruptions. The common thread is a customer's need for action from the utility.

Examining the subject-matter breakdown of these inquiries can provide insight into the topics of interest to customers and possible problem areas. As shown in Exhibit FPL-8, nearly 12 million total incoming calls were handled in 1996. The number of total incoming inquiries handled by FPL Customer Service Phone Centers increased by about 25 percent from 1993 to 1997.

Over the same period, incoming inquiries relating to trouble reports or outages increased by 119 percent, as shown in Exhibit FPL-9. With inquiries regarding trouble reports and outages growing at over four times the rate of total inquiries including billing and all other topics, it is clear that problems affecting service quality were increasingly an issue of concern to FPL's customers over the study period.

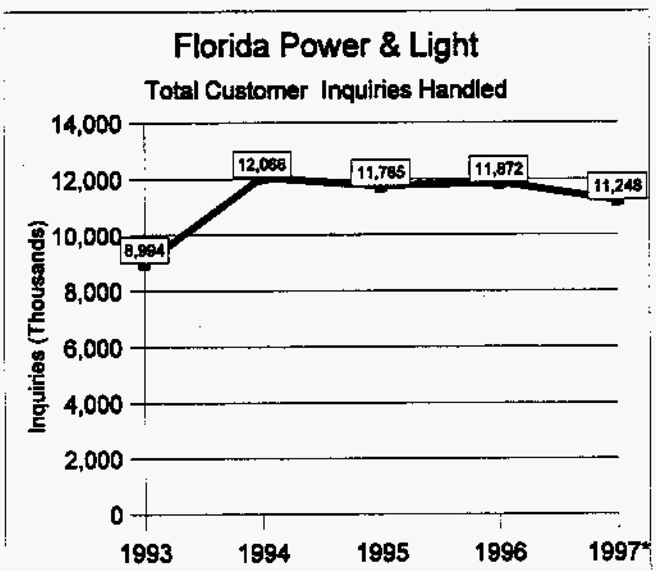


EXHIBIT FPL-8 *Source: FPL Response to Document Request 4-23.*

**Projected based on data through September 1997.*

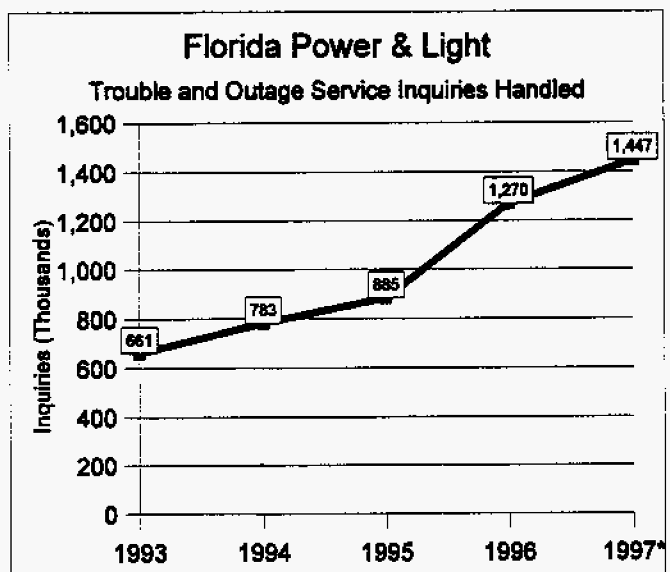


EXHIBIT FPL-9 *Source: FPL Response to Document Request 4-23.*

**Projected based on data through September 1997.*

Customer complaints that require escalation within FPL for handling are referred to as "executive complaints." These are usually instances where a dissatisfied customer has asked to speak with a manager or has specifically addressed letters to company officers. The company response, through the appropriate FPL representative, is handled much like the resolution of FPSC complaints and is tracked for record-keeping purposes. During 1997, FPL began to categorize executive complaints to provide future ability to analyze trends in types. Through September 1997, executive complaints totaled 580. Of these, 362 (62%) were assigned to the Distribution Business Unit for handling. Just over half of the 362 distribution complaints were related to outages, interruptions, and voltage problems.

Prior to 1996, customer complaints were sent directly to the field by FPL Customer Service staff for review and resolution by field operations personnel, who were usually untrained in complaint resolution. FPL noted that, in some cases, either follow-up on complaints was ineffective, or complaints were lost in the shuffle by field forces who were busy performing their primary operational duties.

In 1995, FPL consolidated handling of distribution-related complaints within the Distribution Business Unit. This change made complaint resolution an operational function, as opposed to a staff function. In 1997, the Distribution Business Unit further expanded the complaint handling function to include customer interface activities for determining customer relations needs specific to distribution activities, as further described in section 3.5.

3.3.3 Customer Satisfaction Surveys

Customer survey information has been used by FPL to monitor customers' perceptions of service quality and to identify changes in customer satisfaction. FPL has, in recent years, contracted with a handful of external third party customer survey firms to measure customer perception of service quality. FPL has used the same contractor to perform its basic customer satisfaction surveys from 1992 to date, providing continuity in methodology and interpretation. In addition, special-purpose surveys have been commissioned or purchased from other contractors or vendors.

FPL management utilizes these surveys, in conjunction with internal indicators such as those described in subsections 3.3.1 and 3.3.2, to identify areas in need of improvement. For example, in selecting the internal indicators used to track customer service discussed in section 3.3.1, the dividing lines used to denote acceptable and unacceptable interruption length and duration are provided by FPL customers themselves in satisfaction surveys.

Residential Customers

FPL's 1992 through 1996 survey results conducted among residential customers who had experienced a recent service interruption exhibited downward trends in all categories: overall quality, quick restoration of service, accuracy of estimated restoration time, and quick arrival time. The 1994 through 1996 surveys for the first time showed more customers rating outages as "very or extremely inconvenient" than those who said the outages they experienced were "not at all" or "not too inconvenient." Over this period, in some categories residential customers rating FPL "poor" or just "fair" now accounted for a quarter to a third of the customers surveyed.

The 1993 through 1996 surveys taken among the general residential customer population showed steady or slightly increasing satisfaction regarding the categories of momentary interruptions, restoration, and power quality. However, the 1996 survey also showed slight decreases in satisfaction with major interruptions and overall quality of FPL services. As noted in section 2.1.3, in recent years, residential customers have become more aware of power quality variations, specifically momentary power interruptions (those lasting less than one minute). This has resulted from increased use of personal computers, VCRs, and other appliances with digital clocks, which now provide extremely sensitive monitors of momentary interruptions. This has magnified the challenge of satisfying residential customers.

Commercial/Industrial Customers

The 1993 through 1996 surveys of commercial/industrial customers showed even more pronounced declines in customer satisfaction with FPL. In 1996, satisfaction levels dropped to their lowest point since 1992 in the categories of momentary interruptions, major interruptions, and power quality (spikes, surges, and dips), with fewer than one-half of commercial/industrial customers rating themselves as satisfied. Commercial/industrial customers also grew less satisfied with the quality of restoration efforts and FPL's ability to meet their voltage requirements. According to survey results, momentary interruptions ranked as the top priority for most commercial/industrial customers, followed by major interruptions, restoration, and power quality.

Comparing customers' own stated expectations to their actual experience reveals that in 1996, 24 percent of FPL's total commercial/industrial customers experienced at least the number of momentaries that they considered to constitute "a major inconvenience." An additional 33 percent experienced what they specified in surveys to be a "minor inconvenience" level of momentaries.

Overall, FPL's survey results indicate that customers' expectations regarding service quality have increased. For example, in 1995 more than half of large commercial/industrial customers considered one to four interruptions exceeding one minute in length to be a major inconvenience. In 1997, approximately two-thirds of these customers considered the one to four range of interruptions to be a major inconvenience.

3.3.4 Customer Damage Claims

FPL damage claims are separated into two types: public claims and company claims. Company damage claims are a result of others damaging or destroying FPL property, equipment, or assets. Public damage claims are a result of public property being damaged by FPL employees, equipment, or facilities. Understandably, a large percentage of public damage claims involve the Distribution Business Unit since it provides the system's point of interface with customers.

Exhibit FPL-10 shows the number of public property damage claims processed and dollars paid for claims during the period 1992 through September 1997. As shown in the exhibit, the number of customer claims increased steadily during the period 1993 through 1997.

The total dollars FPL paid in damage claims trended downward for the period 1992 through 1997, dropping by over 40 percent from 1992 to 1996. The percentage of claims paid versus claims filed has declined sharply from 43.7 percent in 1992 and 51.4 percent in 1993, to just 21.6 percent in 1996.

In making a ruling on a customer claim, FPL investigators apply a three-point liability rule, seeking to answer three questions: Was FPL negligent? Was the customer negligent? Was the customer's damage directly caused by FPL's negligence?

To answer the question of negligence, four elements must be determined to be present: FPL owed a duty to the customer, FPL violated that duty, there was a causal connection between FPL's failure and the harm or damage, and the customer incurred an actual loss. The investigator gathers information in the case file to document the answers to these key questions. This information gathering effort includes reviewing Trouble Call Management System data, completing a "Statement of Claimant" form, interviewing the customers and neighbors or employees, inspection and photography of the scene, inspecting damage and noting condition, make and model of equipment, and obtaining documentation of repairs or estimates.

Florida Power & Light
Public Claims 1992-1997

Year	Claims Filed	Claims Paid	Percent Paid	Dollars Paid
1992	6,593	2,881	43.7%	$1,320,377
1993	6,096	3,131	51.4%	1,540,188
1994	6,915	2,520	36.4%	1,114,556
1995	7,443	2,196	29.5%	922,054
1996	8,160	1,764	21.6%	734,719
1997*	5,862	1,385	23.6%	762,433
TOTAL	41,069	13,877	33.8%	$6,394,327

EXHIBIT FPL-10 *Source: FPL Response to Document Request 1-22.*

* *As of September 1997.*

Customer property damage claims can be reduced by customers' own efforts to protect their property from the effects of power surges. Customer education efforts play a key role in informing customers of what they can do to protect themselves and the limits of utility responsibility. FPL has used its monthly *Energy News* billing inserts for this purpose, including a May 1996 article on momentary power interruptions, how they occur, and how customers can minimize their effects. The February 1997 issue contained an article describing surges and surge protection devices. In addition, FPL has produced a pamphlet detailing information regarding momentary power outages that is provided to customers who report frequent occurrences of momentaries.

When Distribution Claims receives notification of a property damage inquiry, the customer is contacted within three to five days by telephone, written correspondence, or a site visit from one of 17 Claims Specialists located throughout the state. Customers are informed that the Claims Specialist will conduct an investigation into the facts surrounding the claim. Information regarding the claim is secured through telephone contact, a site visit if necessary, receipt of customer receipts for payment, and through verification against company records. A Statement of Claimant form may also be sent to the customer to collect information regarding the complaint and secure additional supporting documentation.

The Claims Specialists investigate claims to determine liability. They also conduct public employee damage awareness presentations at company service centers. All public damage claims are to be processed by the Claims Specialist and closed within 90 days of their entry into the Claims Tracking System, or the claim is reported to management as an exception. The Claims Supervisor regularly audits the files of the Claims Specialist to assess performance and assure the accuracy of claims records.

In October 1995, the company damage claims process was transferred to the Distribution Business Unit, under the Director of Distribution Support Services. The Distribution Claims Supervisor reports directly to the Manager of Engineering Services and oversees a staff of approximately 23 claims processors and specialists. In January 1997, the Customer Service and Distribution Business Units agreed that accountability for claims should reside with the Distribution Business Unit. In February 1997, public damage claims were also shifted to the Distribution Business Unit, which consolidated the responsibility for company-wide damage claims.

3.4 Distribution Organization and Service Quality Activities

The delivery of power to end-use customers is the responsibility of FPL's Distribution Business Unit. Therefore, this organization plays the major role in electric service quality since it is responsible for both the maintenance and repair of the portion of FPL's system that actually brings power to customers.

FLORIDA POWER AND LIGHT
ENERGY DISTRIBUTION
APRIL 1997 ORGANIZATIONAL CHART

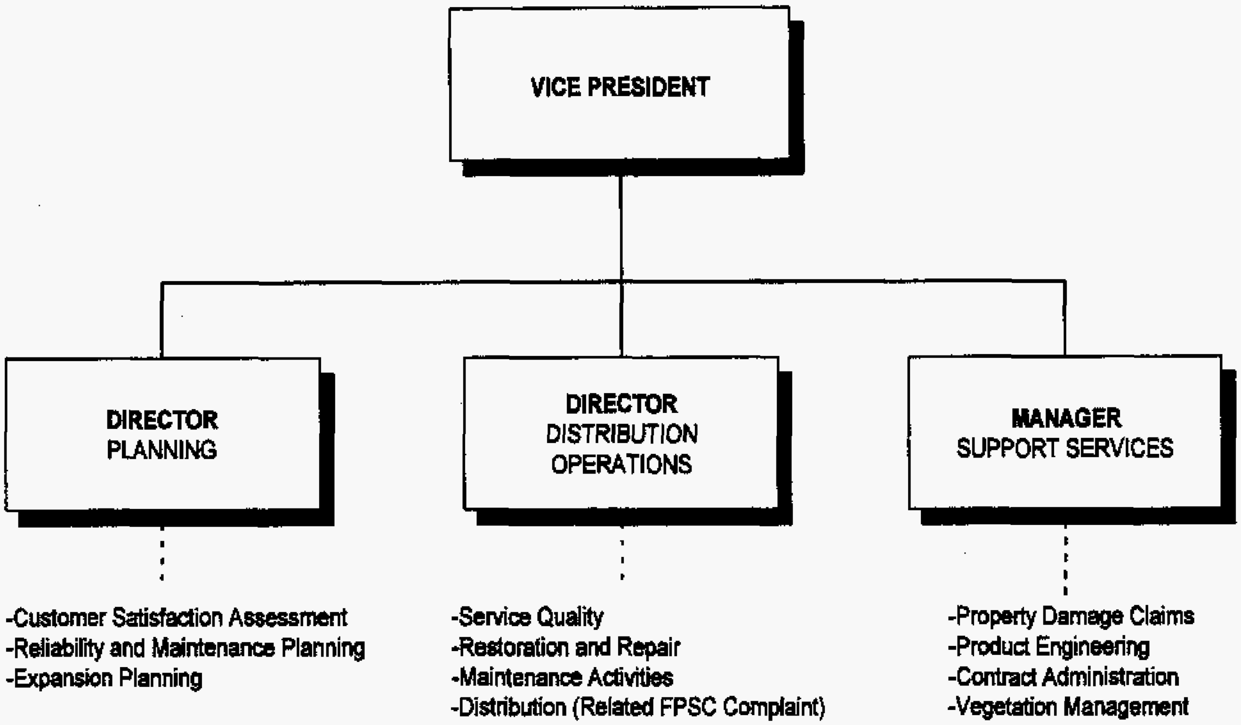


EXHIBIT FPL-11

Source: FPL Response to Document Request 1 Questions 1, 5, 13 and 19.

3.4.1 Structure, Staffing, and Functions

The overall downward trend in distribution service quality indicators described in sections 3.2 and 3.3 has prompted FPL to make extensive changes in its Distribution Business Unit leadership, beginning in early 1997 with the naming of a new vice-president. Upon assuming his position, the vice-president called for a complete re-examination of results, practices, activities, priorities, and organizations. Efforts to reassess the Business Unit's activities have continued throughout 1997 and have resulted in significant changes in personnel, procedures, and organizational structures. Many of these recent changes are discussed in detail in section 3.5.

FPL's Vice President of Distribution and six directors are responsible for the Distribution Business Unit. As shown in Exhibit FPL-11, the directors responsible for the distribution functions of planning, support services, and operations are most relevant to this service quality review.

The Director of Planning is responsible for maintaining network reliability through developing and implementing an overall reliability and maintenance plan. This process involves planning for the upkeep and expansion of the company's distribution system. In planning for system reliability, the Director of Planning makes use of the company's internal service reliability indicators and customer satisfaction surveys in prioritizing both capital expenditures and operations and maintenance expenditures.

The Director of Operations is responsible for the distribution field forces and their activities. Upon assuming his position during early 1997, the Director of Distribution Operations assessed his organization and made changes to respond to the sub-par performance as described in sections 3.2 and 3.3. According to FPL, the intent of this change was to bring a system-wide perspective to the deployment of maintenance workers, repair crews, and other resources to ensure that the most important distribution needs receive proper prioritization. Distribution maintenance activities, particularly preventive maintenance measures, are described in detail in sections 3.4.2 through 3.4.5. Repair activities, including the restoration of power to customers after interruptions, are described in section 3.4.6.

The Director of Support Services oversees a variety of support responsibilities that do not directly involve providing electricity to customers, but which support distribution operations. This support includes four activities that substantially impact electric service quality: vegetation management, contract administration, customer damage claims, and product engineering. Vegetation management (also called "line-clearing" and "tree-trimming") is vital to preventing tree-caused outages due to interference with distribution lines. FPL's vegetation management process is described separately in section 3.4.3 of the report. Also separately addressed, in section 3.3.4, is FPL's handling of customer damage claims, including those from damage to customer property caused or alleged to be caused by the company's plant or equipment.

3.4.2 Maintenance Planning

The Distribution Business Unit's Director of Planning is responsible for ensuring FPL's distribution infrastructure can adequately serve the customer load. Planning for the maintenance of the existing distribution system and its future expansion is a key component for providing an adequate infrastructure. FPL's Planning and Reliability group is headed by the Director of Planning and consists of 15 Planning Engineers throughout FPL's four geographical areas (North, South, East, West), a Reliability Analyst, a Senior Reliability Planner, and a Planning and Reliability Manager.

Total FPL operations and maintenance spending without fuel dropped in 1993, 1994, and 1995, then increased in 1996, as shown in Exhibit FPL-12. However, during the same period, distribution O&M spending declined steadily, as shown in Exhibit FPL-13. From 1993 to 1996 distribution O&M spending dropped by over 20%. The extent of these cost reductions appears to have been detrimental to service quality.

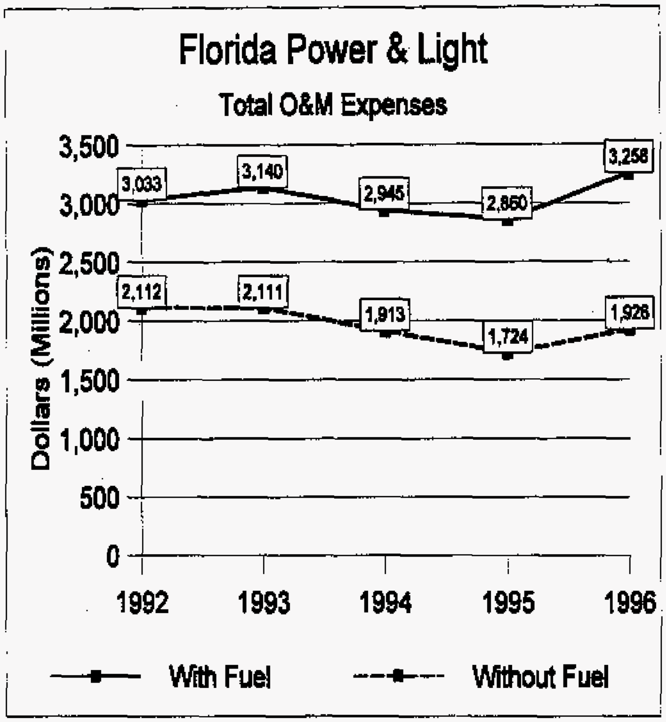


EXHIBIT FPL-12 *Source: FPL FERC Form 1, 1992-1996.*

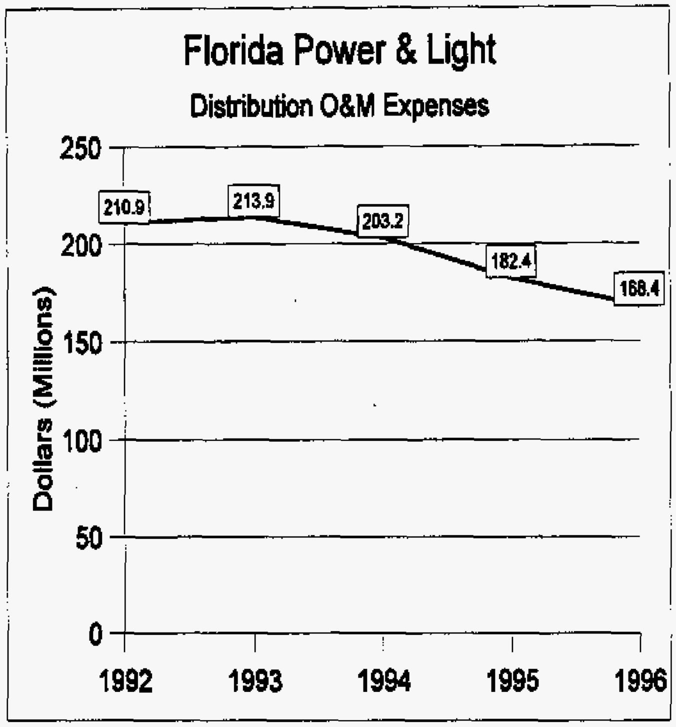


EXHIBIT FPL-13 *Source: FPL FERC Form 1, 1992-1996.*

Through 1996, FPL performed distribution maintenance planning on an annual basis, through prioritization of key maintenance projects in conjunction with the annual budgeting process. For example, the 1997 and 1996 annual distribution maintenance plans are summarized in Exhibits FPL-14 and FPL-15.

In 1997, the new Distribution Business Unit leadership instituted the concept of a longer term distribution maintenance plan. This new planning effort, known as "Reliability 2000," resulted in a more forward-looking plan that coordinated company-wide resource allocations for a three-year period. The *Reliability 2000 Plan* is discussed in more detail in section 3.5.4, where Exhibit FPL-28 highlights the plan's specific reliability programs being used by FPL to remedy identified distribution service quality and reliability problems.

Florida Power & Light
1997 Distribution Maintenance Activity Prioritization

Activity Name	Purpose	Planned	
		Capital	Operations and Maintenance
Distribution Automation	Decrease feeder interruption restoration duration by repairing 400 existing and adding 150 new automated switches.	$4,561,886	$ 808,533
Reliability Performance Index Program	Performs facilities surveys on 46 feeders serving top 50 high load factor customers.	160,171	254,269
Padmount Switch Program	Refurbish remaining 345 of 608 EEI-manufactured cabinets.	812,151	61,024
Feeder Coordinator/Sectionalizing-Per Plan	Install disconnect switches, OCRs, and fuse switches.	670,572	102,084
Critical Equipment Submersible Transformers	Replace 20 submersible transformers on Miami Beach.	25,344	127,133
Critical Equipment Revault Program (Miami Beach)	Water seal 25 manholes on Miami Beach.	202,750	101,707
Critical Equipment Switch Cabinets (Miami Beach)	Replace nine custom-made padmount switch cabinets.	182,475	20,341
Critical Equipment Oil Fuse Cut Outs	Replace oil fuse cutout with fuse links.	608,251	152,560
Critical Equipment Cathodic Protection	Replace anodes on manhole and duct systems in Miami Beach, Hallandale, Dania, and Ft. Lauderdale.	0	1,044,697
Critical Equipment General	Replace various critical equipment found during routine work.	458,240	514,085

Florida Power & Light
1997 Distribution Maintenance Activity Prioritization

Activity Name	Purpose	Planned	
		Capital	Operations and Maintenance
Emergency Backup Switch Program	Inspect 2554 throwover vaults and execute necessary repairs or replacements.	225,216	442,016
Oil-Filled Switch Program	Rebuild remaining 19 of 44 sidewalk throwover vaults of Miami Beach.	1,216,503	261,277
Miami Network Program	Upgrade and maintain downtown Miami network and removal of abandoned cable from critical ducts.	709,626	711,946
Multiple Interruptions - Policy	Investigate and execute necessary follow up work upon 4 interruptions to the same device in a 12 month period.	1,713,203	507,713
Load Balancing	Maintain feeder phase balance to acceptable levels.	263,896	26,623
Vegetation Management	Removal of vegetation from feeder circuits that are worst performers from vegetation-related interruptions.	0	13,496,069
Capacitor Bank	Inspect and execute necessary repairs to existing capacitor banks.	553,308	183,361
UV-21 Cable Policy	Inject or replace direct-buried primary cable upon first known cable failure and complete rebuild of Royal Palm Yacht Club underground system.	8,630,943	292,208
Small Wire	Replace unprotected small feeder conductor.	2,128,881	406,826
Wiredown Policy	Investigate and execute follow up work upon 2 wiredowns to same conductor within 2 years.	743,923	203,690
Padmount Security Inspection Program	Inspect remaining 123,640 of 184,513 padmounted transformers and repair or replace as necessary.	0	2,497,691
Environmental Policy	Correction of leaking electrical equipment found during normal work.	295,347	128,404
Totals		**$ 24,162,686**	**$ 22,344,257**

EXHIBIT FPL-14

Source: FPL Response to Document Request 1-7.

Florida Power & Light
1996 Distribution Maintenance Activity Prioritization

Activity Name	Planned	
	Capital	Operations and Maintenance
Vegetation Management	$ 0	$ 17,812,000
Substation Pull-Off Replacement Program	343,658	23,336
Padmount Switch Program	879,424	936,145
Reliability Performance Index Program	183,215	648,490
Distribution Automation	128,440	261,038
Service Center Discretion	55,227	39,230
Feeder Coordinator/Sectionalizing-Per Plan	704,105	86,194
Small Wire	3,279,251	765,141
Critical Equipment	1,267,395	1,200,892
Oil Truck	0	149,856
Oil Filled Switch Program	479,189	171,520
Miami Network Program	278,536	85,552
Multiple Interruptions-Policy	1,216,469	585,332
Load Balancing	120,492	11,790
VAR Management-Maintenance	558,315	198,075
UV-21 Cable Policy	7,449,863	671,277
Wiredown Policy	451,067	140,141
Padmount Security Inspection Program	0	0
Padmount Security Inspection Follow-up	291,282	379,145
Environmental Policy	221,648	105,135
TOTAL	**$ 17,907,576**	**$ 24,270,289**

EXHIBIT FPL-15

Source: FPL Response to Document Request 1-7.

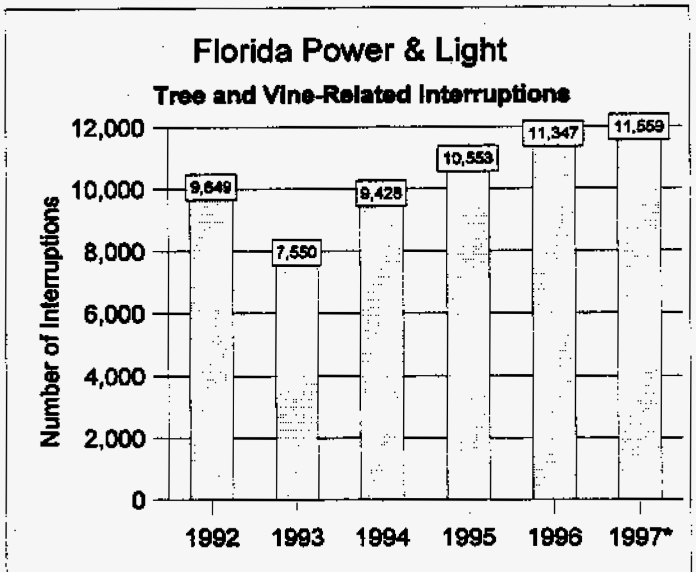


EXHIBIT FPL-16 *Source: FPL Response to Document Request 3-10.*

**Annualized based on data through June 1997.*

3.4.3 Tree Trimming

A key area of activity targeted by FPL during 1997 has been tree-trimming, usually referred to as "line clearing" within FPL. As a result of the Distribution Business Unit's 1997 self-assessment, funding for FPL's tree-trimming operations was increased by $6.4 million during 1997, or 21 percent above 1996 actual expenditures. According to FPL, this additional funding has been used to support the "worst feeder" tactical teams described in section 3.5.2, and has allowed a 12 percent increase in the number of feeder miles cut during 1997 beyond the original plan.

Exhibits FPL-16 and FPL-17 depict both tree and vine-related outages and tree-trimming budgets and expenditures for the years 1992 through 1997. As shown in Exhibit FPL-16, after a decline of 22 percent from 1992 to 1993, the number of tree-related interruptions steadily increased from 1994 through 1996. Year-to-date interruption figures indicate that 1997 levels may slightly exceed 1996 interruptions. A comparison of Exhibits FPL-16 and FPL-17 show that the 1993 decline in interruptions may have prompted a 33 percent reduction in 1994 tree-trimming expenditures versus 1993 levels. According to FPL, efforts during this period were successful in increasing contractor productivity, negotiating improved contractor rates, and increasing the tree removal rate to 25 percent. Despite these efforts, the number of tree and vine-related interruptions increased from 7,550 in 1993 to 11,347 in 1996. The impact of the 1997 and future tree-trimming budget increases will not be immediately apparent, but could begin to be seen during 1998.

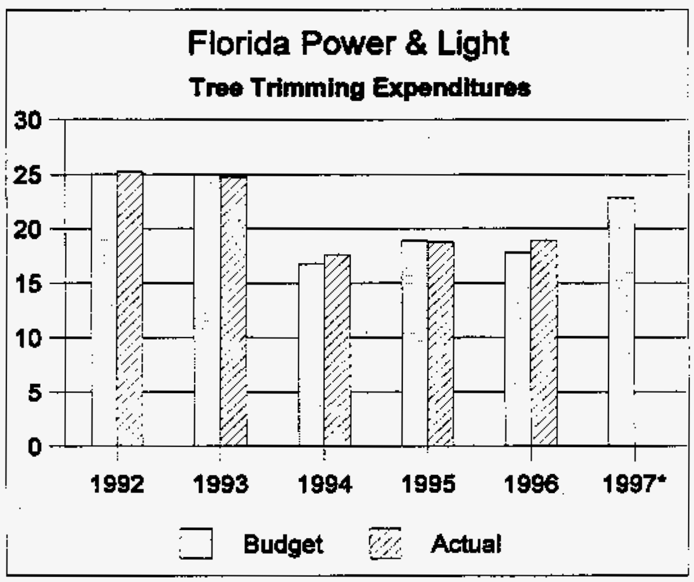


EXHIBIT FPL-17 *Source: FPL Response to Document Request 3-9.*

**Annualized based on data through June 1997.*

FPL's tree trimming operations are under the direction of the Vegetation Management Manager within Distribution Support Services. The manager is responsible for oversight and evaluation of all line-clearing activities which include tree trimming, tree removal, and vine control (cutting and spraying). Presently, the manager has three supervisors and ten utility arborists under her direction whose primary responsibilities include administration of contracts, evaluation of contractor work completed reports, and field evaluation of contractor performance.

All of FPL's line clearing activities are performed by outside contractors who abide by the procedures outlined in the Certified Arborist Manual published by the International Society of Arboriculture (ISA). Presently, the company is contracting through 1999 with Asplundh, which performs one hundred percent of the company's line clearing operations. Asplundh is paid on the basis of the amount of brush, branches and vines removed, with verification of work completed provided through weekly unannounced field audits by FPL arborists. In addition to verifying reported amounts cut, the inspections address quality of work, compliance with cutting guidelines, customer contact efforts, quality of supervision, and quality of documentation.

Through an additional $13 million in tree trimming expenditures beyond its originally planned 1997 levels included in the *Reliability 2000 Plan,* FPL expects to implement an overall three-year trim cycle for all laterals and feeders between 1998 and 2000. This plan was approved by FPL executive management in November 1997. FPL is also in the process of implementing a "variable" maintenance cycle that takes into account areas that may require more or less frequent attention than specified by a three year cycle. Tree trimming under the variable cycle will be prioritized based on most current performance information, time of last maintenance, and scheduled by electric circuits. FPL is currently constructing a database to track the completion of tree-trimming by circuit.

Customer education efforts in the area of tree trimming have included articles in *Energy News*, the monthly customer billing insert in each of the years 1995 through 1997. Customers are urged to report trees growing into distribution wires and to avoid trimming near wires. Recent efforts have focussed upon making customers aware of the possibility of trees and shrubs eventually interfering with lines before planting by placing the "right tree" in the "right place."

3.4.4 Substation Maintenance

As a vital component of the distribution system, the proper maintenance of substations is key to overall system reliability. Even the temporary loss of a substation can affect thousands of customers and require rerouting of portions of the system load.

Over the period 1992 through 1996, the number of total distribution substation outages was relatively stable, as shown in Exhibit FPL-18. Through the first seven months of 1997, 174 substation outages had occurred, which projects to a year-end total of 298, or 12 percent higher than the 1996 total of 267. Of the 1997 total, 77 were breaker operations, while only 102 breaker-related outages were recorded during all of 1996.

Florida Power & Light Total Substation Outages by Category 1992 - 1997*						
CAUSE	1992	1993	1994	1995	1996	1997*
Breaker	99	113	103	114	102	77
Regulator	64	77	63	68	63	45
Animal	43	45	22	27	26	28
Other Substation Equipment	38	25	29	32	26	4
Human Element	12	12	10	15	7	3
Transformer	5	11	6	12	10	2
Unknown	5	10	2	2	3	2
Foreign Interference	4	0	4	1	4	5
System Related	3	0	2	3	0	1
Environment	1	10	8	6	26	6
TOTAL	274	303	249	280	267	174

EXHIBIT FPL-18

Source: FPL Response to Document Request 3-5.

** Through July 1997.*

Maintenance of FPL's distribution substations is the responsibility of the Substation Department of the Power Delivery Business Unit, which also maintains FPL's transmission substations. A complete reorganization of this business unit, including significant manpower reductions, was carried out in 1994. Total bargaining unit employees decreased from 483 in 1993, to 391 in 1994, and as of mid-1997 stood at about 340. Despite the staff reductions, substation outages actually declined sharply from 303 in 1993 to 249 in 1994, as shown in Exhibit FPL-18.

Exhibit FPL-19 displays 1992 through 1997 total maintenance expenditures for FPL's distribution substations. These expenditures declined in 1993 and 1994, then increased steadily through 1997. Maintenance activities, including inspections of each distribution substation every other month, are coordinated within each of five geographical service areas. These inspections are performed by electrician specialists, covering specified checkpoints including: station perimeter security, station grounding, bushing connections, battery condition, and counter

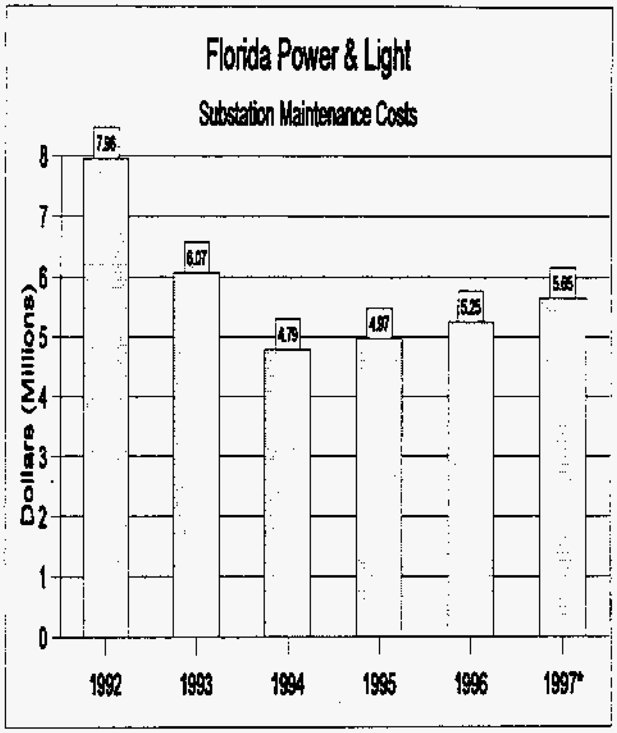


EXHIBIT FPL-19 *Source: FPL Response to Document Request 1-8.*

**Projected by FPL.*

readings. Exceptions observed are recorded via a pen-based tablet computer system, which has been in use since 1994. No change has been made in inspection frequency since that date.

To prevent transformer-caused outages, FPL reports that its current practice requires a dissolved gas-in-oil physical properties test be performed annually on every substation transformer. From 1992 through 1996, these tests were performed only on autotransformers, generator main transformers, and 230 kilovolt distribution power transformers. In addition, transformers are also tested after a valid transformer relay operation, and the transformer is not returned to service unless results are normal. If test results indicate the presence of dissolved gasses or moisture, the oil is filtered and processed. When results exceed Institute of Electrical and Electronic Engineers guidelines, the transformer is taken out of service and inspected to determine the cause of gas production.

3.4.5 Plant and Equipment Inspection

Currently, aging or defective plant and equipment in need of replacement is identified by FPL through the course of normal repair and maintenance activities and through investigating reported problems. Distribution Operations also has the capability to identify possible trouble areas and trends through input received from numerous internal sources. These include its analysis of Early Warning Reports (subsection 3.5.2), customer complaints (subsection 3.5.2), and Distribution Support Services' analysis of customer property damage claims (subsection 3.3.4.)

In addition, the maintenance planning process (subsection 3.4.2) identifies and prioritizes major projects involving plant refurbishment and replacement. The *Reliability 2000 Plan* includes initiatives to review conductor replacement and system design standards and to assess distribution components such as transformers, cable, and lightning and grounding protection over the period 1998 through 2000.

Wood Pole Inspection and Treatment

Pole-caused interruptions are only a minor problem according to FPL. Over the period 1992 through September 1997, they accounted for just 309 interruptions, or .06 percent of FPL's total. From approximately 1984 through 1994, FPL utilized a contractor to perform inspection and treatment of creosote wood poles. Poles were injected with a fumigant to prevent termite and other pest infestation. FPL discontinued this program once a 100 percent treatment coverage had been completed after concluding that second treatments of creosote poles did not significantly impact the service life. Since the end of the creosote pole treatment program, FPL's maintenance practices specify "all deteriorated poles identified via normal work should be evaluated for reinforcement and if not applicable then replaced. Pull poles initiated by customer request/complaints."

Pole replacements numbered 906 with total expenditures of $2.14 million in 1995, and 1,042 poles for a total of $1.82 million in 1996. Through August 1997, 708 poles had been replaced at a cost of $1.09 million, which would annualize to $1.64 million at year's end.

Line Patrol and Inspection

Until 1995, FPL performed routine patrol/inspection based upon available resources and workload. The problems identified by this activity generated work tickets which were routed to the responsible area manager. In late 1995, this practice was discontinued when FPL determined that the company received "minimal benefits derived from these patrols" versus those discovered and addressed by service center employees through normal daily activities.

FPL's *Reliability 2000 Plan* calls for efforts to identify and replace lines and other system components over the 1998 through 2000 period. The plan is discussed in section 3.5.4.

Cable Injection and Replacement

Due to the difficulty of locating and repairing underground cable failures, repeated problems trigger special handling as directed by FPL's distribution system standards. For example, when "underground direct buried primary cable has a failure for the first time, it is repaired. If it fails a second time, a decision is made to either inject or replace the cable." Injection of cable with a silicone compound can be used, depending upon the number of splices, to prevent failures due to intrusion of moisture and gasses. A comparison of the 1987 and 1996 standards for replacement of various types of cable showed no changes in the specified number of dielectric failures required before the problem cable is replaced.

Cable injection totals have varied since 1992, when 534,045 feet were injected, to lows of 160,730 in 1994 and 3,050 in 1995 while a new "flow-through" splice was developed and implemented to allow more effective injection of the silicone material. In 1996, cable footage injected totaled 554,606, and through September 1997, injection was on a pace to exceed 500,000 feet of cable for the year.

Over the years 1992 through 1997, FPL replaced approximately 68 million feet of distribution wire and cable. As shown in Exhibit FPL-20, the replacement of deteriorated cable and wire steadily decreased over the period 1992 through 1996, with the exception of 1993, when Hurricane Andrew caused replacement of large amounts of overhead wire. However, cable and wire replacement efforts through portions of 1997 would project to levels exceeding the 1996

Florida Power & Light Cable and Wire Removed From Service 1992-1997*						
	1992	1993	1994	1995	1996	1997*
Feet of Wire and Cable Removed (000 ft)	10,684 ft	28,899 ft (includes Andrew)	8,477 ft	7,348 ft	6,598 ft	6,918 ft
Annual Total Removal Cost ($000)	$11,400	$17,980 (includes Andrew)	$8,769	$8,736	$8,540	$10,196

EXHIBIT FPL-20 *Source: FPL Responses to Document Requests 4-7 & 5-1.*

**Annualized based upon partial 1997 data.*

totals for footage removed and expenditures. The *Reliability 2000 Plan* addresses cable performance assessment and plans for replacement for 1998 through 2000.

Transformer Replacement

Through the course of performing repairs or reassessing load additions, FPL Distribution Operations identifies the need for replacement of transformers on an ongoing basis. Replacement can result from lightning damage or simply the addition of load from new construction. The new *Reliability 2000 Plan* will address assessment of distribution components such as transformers, and future replacement and maintenance expenditures.

As shown in Exhibit FPL-21, the number of transformer replacements of all types, for either preventive or corrective purposes, declined steadily over the period 1992 through 1995, then increased in 1996. Through July 1997, transformer changeouts and associated spending had increased to well above 1996 levels. These partial results imply a projected total of over 20,000 changeouts by year-end.

Florida Power & Light Transformer Replacement 1992-1997*						
	1992	1993	1994	1995	1996	1997*
Transformers Replaced	22,309	22,187 (excludes Andrew)	19,316	16,108	16,989	20,403
Total Install Cost ($000)	$30,313	$31,095 (excludes Andrew)	$26,252	$22,144	$24,384	$33,778

EXHIBIT FPL-21 *Source: FPL Responses to Document Requests 4-8 & 5-2.*

**Annualized based upon data through 9/97*

3.4.6 Restoration/Repair

The key functions of restoring interruptions to service and repair of the distribution system are overseen by the Director or Distribution Operations, as indicated on Exhibit FPL-22. Statewide accountability for reliability and restoration operations belongs to the Restoration/Reliability Manager, and his two Restoration Managers. These three key positions are responsible for minimizing the duration of interruptions, and coordinating activities with the Area Managers in deploying field forces and other resources. The Restoration/Reliability Manager and Restoration Managers are also responsible for FPL's consolidated Dispatch Centers, which provide the communication link within FPL's operations and to the customers affected.

The Restoration/Reliability organization provides first response to calls between customer information, system information, and field crew information for service restoration and repairs through its Line Specialist Rotators, or "trouble men" as they are commonly known. At the scene, the trouble man will assess the situation and make repairs such as replacing a blown fuse or removing a branch obstructing lines. If additional forces or equipment is needed, the trouble report may be referred to a maintenance/construction crew from one of FPL's 15 areas.

Since 1988, FPL has consolidated its distribution service centers and restructured its operations several times. Over this period, FPL regrouped and consolidated its distribution service centers, reducing their total number from 60 in 1988, to 58 in 1991, 51 in 1993, 42 in 1995, and 37 in 1996. These consolidations were anticipated to take advantage of productivity enhancing measures such as the use of remote computer terminals in service vehicles, improved computer-based dispatching capability, and the increased use of home dispatch of service vehicles by distribution personnel.

Each Service Center is under the direction of an Area Manager and serves as the base of operations for the support staff and construction/maintenance crews under his direction, as well as the Restoration/Reliability organization's trouble men. Also, two and three man crews, with their larger trucks and heavy equipment, who work out of the service center. They are used to assist trouble men in answering trouble calls when the workload is heavy and additional forces or equipment are needed, such as in the aftermath of a severe thunderstorm.

Customers calling in to report a service problem may either speak directly with a Customer Service Representative or, by responding to various telephone prompts, may respond via FPL's automated Voice Recognition Unit through their touch-tone telephone keypad. In either case, the information is entered into the Trouble Call Management System, which creates a work order commonly referred to as a "trouble ticket." Depending upon geographical location, the trouble tickets are routed to one of four Dispatch Centers. The Trouble Call Management System analyzes the trouble tickets, grouping those that may be related, and they are dispatched to field forces for investigation and resolution. The Trouble Call Management System stores data

FLORIDA POWER AND LIGHT
DISTRIBUTION OPERATIONS
APRIL 1997 ORGANIZATIONAL CHART

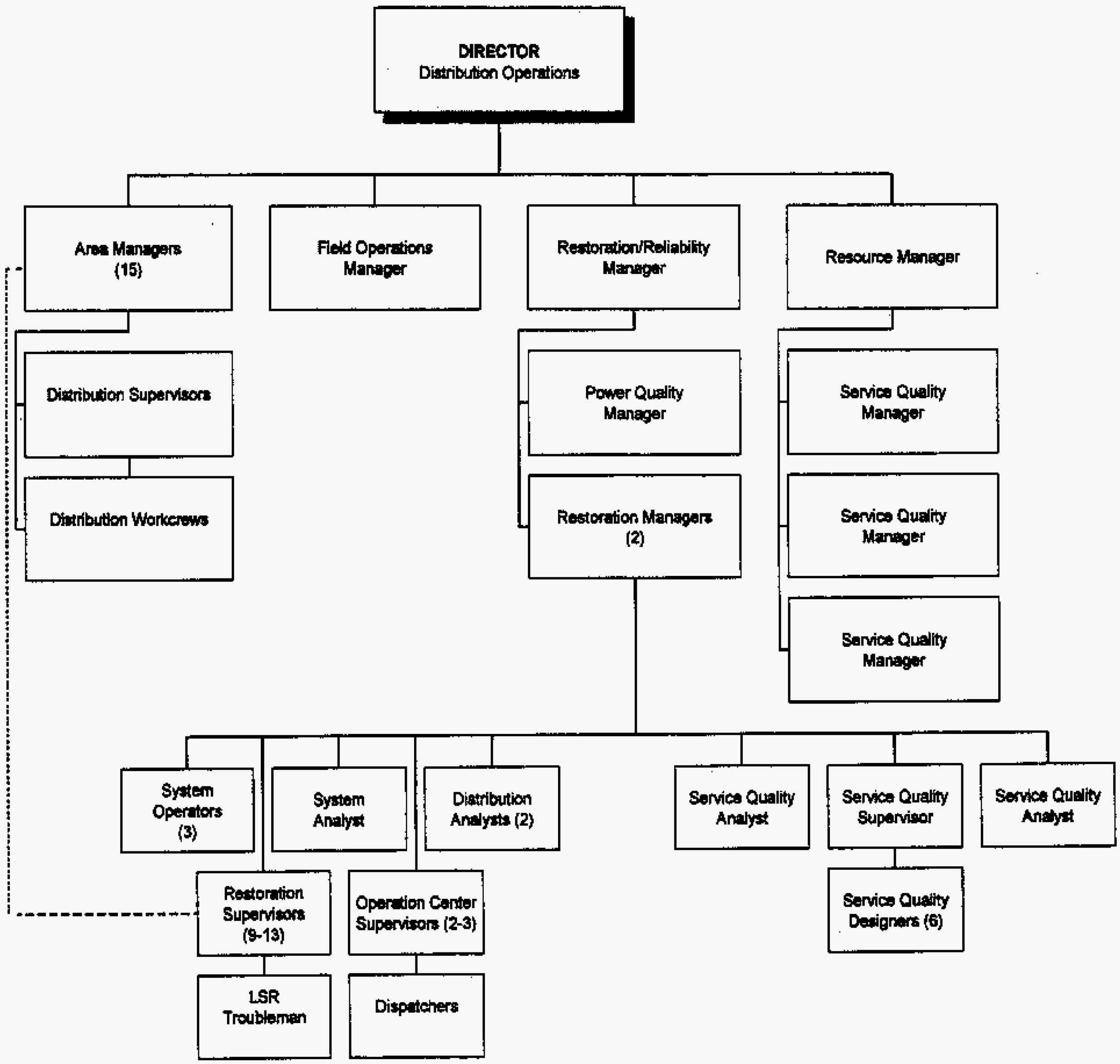


EXHIBIT FPL-22

Source: FPL Document Requests 1, Questions 1,5,13, and 19.

including the type of problem reported, the time reported, the dispatch time, the type of repair or maintenance work completed, and the time the service was restored.

The total volume of trouble tickets handled can provide a measure of repair workload and frequency of problems experienced by customers. The number of trouble tickets created and investigated by FPL has increased in recent years, as shown in Exhibit FPL-23. After decreasing from a high point in 1993, caused in part by the effects of Hurricane Andrew, the number of trouble tickets held steady in 1994 and 1995. Then, trouble tickets increased by 7.7% in 1996, and based upon the 1997 count through September, could grow another 8.9% for the year.

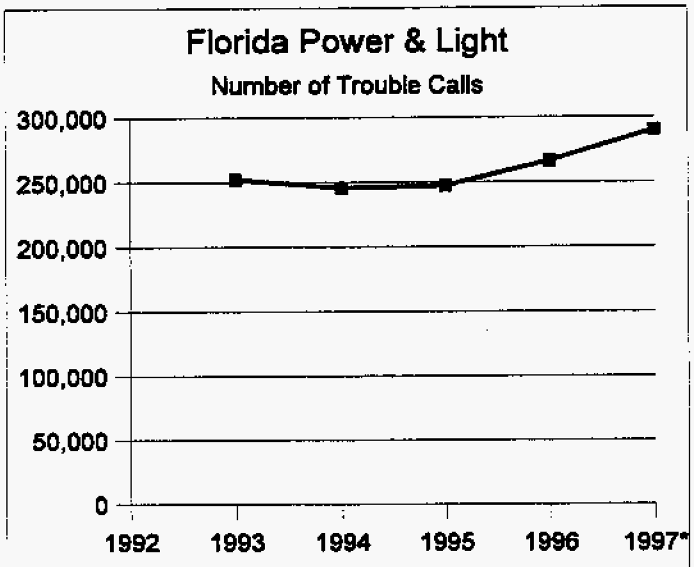


EXHIBIT FPL-23 *Source: FPL Response to Document Request 5-6.*

***Annualized based upon data through September 1997.*

The Dispatch Centers handle trouble reports received from customers by Customer Service Representatives at FPL's Customer Service Phone Centers. Prior to 1988, FPL operated thirteen Dispatch Centers statewide. In 1988, eight of these locations were consolidated to the Daytona center. In 1992, the Ft. Myers and Sarasota centers were consolidated, as were the Miami and Ft. Lauderdale centers in 1994. The current four Dispatch Center locations are Sarasota, Miami, West Palm Beach, and Daytona.

Trouble Call Management System data can be used for analysis of distribution reliability and restoration performance. Exhibit FPL-24 displays data indicating an increasing trend in arrival minutes for FPL Restoration/Reliability personnel responding to trouble calls. Trouble calls are stratified according to the prioritization codes which indicate the severity of the customer's reported problem. Arrival minutes improved from 1993 to 1994 in all categories dropping from 61 minutes on average to 57 minutes. During 1995, arrival minutes increased to 70, and in 1996 reached 80 minutes on average. Through September 1997, there was little change from 1996 levels. Overall, arrival minutes increased by about a third from 1993 through 1997.

FPL states that repair, maintenance, or restoration work prioritization is based upon safety considerations and numbers of customers affected. Preferential treatment to neighborhoods or geographical areas is not given according to the company, despite the widely-reported case of FPL executives being notified of outages and repair efforts in Palm Beach County's Lost Tree Village where they reside. Management states that this is the only such instance of priority notification

Florida Power & Light Average Trouble Call Investigator Arrival Minutes 1993-1997					
Priority Code	1993	1994	1995	1996	1997*
1	55	39	44	46	45
2	69	56	66	72	72
3	58	56	69	80	81
4	67	66	85	97	99
Overall Average	61	57	70	80	81

* Through September 1997

Priority Code 1: Feeder interruptions, and/or any potentially hazardous condition (injury, fire, pole/wire down).

Priority Code 2: Customer reporting problem recurring same day after problem initially reported, treated and resolved.

Priority Code 3: All other troubles involving a single no-current or partial no-current condition.

Priority Code 4: All other troubles involving no loss of service.

EXHIBIT FPL-24 *Source: FPL Responses to Document Requests 1-18 & 5-5.*

of interruptions, and that it was a response to inquiries by residents made to FPL executives regarding power outages. FPL notes that Lost Tree Village has experienced a high rate of underground cable failures due to the advanced age of its cable. According to FPL, no priority was given for restoration efforts in this neighborhood beyond standard considerations.

Corporate-wide staffing reductions at FPL reduced the number of restoration and maintenance trouble men and crew members in recent years, as shown in Exhibit FPL-25. These employees numbered 894 in 1995 and 762 in mid-1997. FPL indicated that the information for specific job category breakdown before 1995 was not retained and is not available. Over the period 1992 through 1997, the total reduction in Distribution bargaining unit employees was 25.7 percent.

In support of the *Reliability 2000 Plan*, FPL's revised 1998 staffing plan calls for 891 union restoration and maintenance employees, also as shown in Exhibit FPL-25. Some construction forces are being shifted to restoration and maintenance activities to accomplish the planned effort.

Florida Power & Light Staffing Comparison of Distribution Bargaining Unit Employees 1992 (Actual) - 1998 (Planned)										
Job Category	1992 Actual	1993 Actual	1994 Actual	1995 Actual	1996 Actual	7/97 Actual	1998 Plan	1998 Rev. Plan	1992-1998 Revised Change (%)	1995-1998 Revised Change (%)
Restoration & Maintenance	NA	NA	NA	894	769	762	762	891	NA	(.3%)
Construction	NA	NA	NA	725	776	783	686	531	NA	(26.8%)
Other Support	NA	NA	NA	482	476	476	446	472	NA	(2.1%)
Total*	2,550	2,363	2,247	2,101	2,021	2,021	1,894	1,894	(25.7%)	(9.9%)

EXHIBIT FPL-25

Source: FPL Response to Document Request 3, Item 6.

** Excludes overtime FTE.*

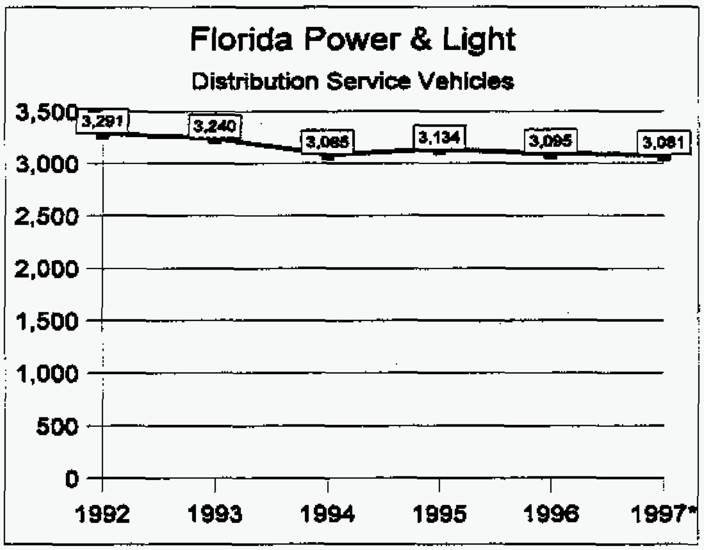


EXHIBIT FPL-26 *Source: FPL Response to Document Request 3-8.*

**As of August 1997.*

Over the 1992 though 1997 period, FPL's number of Distribution fleet vehicles, including repair and maintenance vehicles, declined, but at a lower rate than total bargaining unit employees. As shown in Exhibit FPL-26, in 1992 the fleet numbered 3,291 vehicles, and in mid-1997, stood at 3,081. This represents a total decrease of 6 percent over the five year period.

3.5 Recent Trends and Changes

During late 1996, FPL management recognized that there were indications of a decline in service reliability and responded by restructuring the Distribution Business Unit during the first quarter of 1997. The new Vice-President of Distribution commissioned an internal review to identify where and how to begin correcting observed problems. This effort continued through 1997 and included the re-examination of structure, processes, practices, and budget allocations. As of the writing of this report in late 1997, the repercussions of this effort were not yet fully determined.

3.5.1 Distribution Environmental Assessment

This internal review of the Distribution Business Unit, known as the *Distribution Environmental Assessment*, provided an examination of FPL's strengths and weaknesses regarding distribution service quality in a March 1997 report. FPL evaluated customer survey information, internal company measurements and benchmark data comparing FPL to other utilities. Indicators examined included average minutes of service unavailability (system-wide), outages per mile of lines, distribution expenditures per customer (capital and O&M), and customer satisfaction. Overall, the Environmental Assessment indicated that FPL had successfully driven down distribution operations and maintenance costs, but had not maintained the desired level of service quality and reliability. The report notes that in one comparative benchmark study of customer expectations, FPL ranked below the national and southeastern U.S. averages in all reliability scores. Yet another comparative study of service unavailability by the North American Electric Reliability Council showed that FPL ranked below the top quartile, but above the national average.

The results of the Distribution Environmental Assessment led to the identification of key improvement areas for the FPL Distribution Business Unit. Although these improvements have been relatively quickly identified and implemented, there will be some lag effect in achieving the desired results in service quality and customer satisfaction.

The Executive Summary of the Distribution Environmental Assessment included the following findings:

Benchmarking

- Distribution O&M cost is among the top quartile of low cost utilities in the nation.
- Service unavailability has risen steadily since '92 with a leveling off in '96 and remains in the second quartile of comparable utilities.
- Distribution focused on the restoration component . . . while customers rank priority of reliability component as 1) Momentaries 2) Major Interruptions 3) Restoration 4) Power Quality.

Customer Expectations

- The majority of service quality survey results continue a downward satisfaction trend since 1994 . . . significant changes in customers' accepted tolerance ranges indicate customers have raised their expectations.
- Per the national benchmark for large commercial/industrial customers, FPL is in a poor comparative position on reliability to other regional utilities.

In response to these findings, the Environmental Assessment included the following recommendations:

- Renew emphasis on customer satisfaction, establish customer service expectations for the workforce. Initiate strategy, utilizing surveys, to reverse customer perceptions.
- Evaluate current reliability strategies affecting customer satisfaction while maintaining competitive cost position.
- Evaluate work processes to improve productivity/efficiency.
- Position organization for future re-regulation, preparing for performance based ratemaking and markets with new products and services.
- Utilize diverse group of departments/individuals to develop future strategies.
- Develop Environmental Assessment Action Plan.
- Develop plan to build employee skill base for future environmental assessments.
- Refocus on quality improvement tools and techniques.

3.5.2 Tactical Teams

Based upon the Environmental Assessment, FPL formed four task teams to address four key areas. One team is studying FPL's distribution feeders most prone to interruptions, while a second team is studying the feeders most prone to momentaries. A third task team is examining the process of customer "service recovery" (meaning recovering a dissatisfied customer's confidence in FPL), while a fourth team addresses the need to increase the quality of communication between FPL and commercial/industrial customers.

The two teams addressing problem feeders are comprised of FPL employees from diverse disciplines and functions. The teams have identified and targeted 22 feeders with high numbers of interruptions, and 36 feeders with high numbers of momentaries. Inspections were performed to identify problems and diagnose their causes. This effort identified the major causes as tree-trimming conditions, needed wire upgrades, and insufficient lightening protection. Based upon this analysis, plans for corrective action and other countermeasures have been identified. According to the company, all corrective actions for the feeders will be implemented by the end of 1997. Tree trimming has also been accomplished for each of these feeders.

FPL plans to continue this effort, addressing and rehabilitating more of the worst performing feeders. The Task Team's findings have been considered in budgeting for the 1998 through 2000 workload in the *Reliability 2000 Plan.*

Exhibit FPL-27 shows early results of the two momentary teams' efforts. During 1997, significant reductions in numbers of both interruptions and momentaries have been achieved. According to FPL, additional poor performing feeders will be addressed once the initial effort has been fully analyzed and a workable approach is developed for wider implementation. The results of these tactical teams will also be used as input in maintenance planning and activities.

Florida Power & Light
Feeder Tactical Teams
Momentaries and Interruptions
Preliminary Results

Monthly Momentary Comparison on 36 Feeders												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1996	471	164	261	122	244	420	256	342	273	220	204	227
1997	83	51	70	105	137	194	269	215	98	NA	NA	NA
Monthly Interruption Comparison on 22 Feeders												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1996	13	9	14	9	13	13	9	7	19	13	33	25
1997	0	3	6	6	9	11	14	13	5	NA	NA	NA

EXHIBIT FPL-27 *Source: FPL Response to Document Request 4-2R.*

3.5.3 Distribution Operations Realignment

During 1997, FPL has assessed the need for organizational and procedural changes within the organizations involved in distribution field operations. As a result of this review, the following four problem areas were identified and targeted to address increasing customer dissatisfaction:

- Increased Service Unavailability minutes
- Increased Momentary Power Interruptions
- Unclear accountability for reliability within the organization
- Customer Service response to complaints separated from operations

Several organizational changes were made within the Distribution Operations group to address these concerns. Displayed in Exhibit FPL-22, the positions of Restoration/Reliability

Manager, Resource Manager and several positions reporting to each were added in the first few months of 1997.

Reliability Manager

A key element in responding to the observed lack of accountability for reliability was the creation of the Restoration/Reliability Manager position. This position provides a single point of accountability for reliability issues. In contrast, prior organizational structure divided this responsibility among four managers, each responsible for a geographical zone of FPL's service territory. Through the Restoration/Reliability Manager, and the two Restoration Managers reporting to him, FPL intends to facilitate a highly flexible, seamless, boundary-less approach to the restoration process. Acting as "traffic controllers" for the entire FPL service territory, it is expected that they will be able to deploy the 1400-man repair/maintenance/construction workforce to provide more reliable service.

Field Operations Manager

Reporting to the Operations Director, the position of Field Operations Manager was created in early 1997 to examine practices and determine how they could be standardized or improved to reduce trouble response time and restoration time. For example, during 1997, a high number of FPSC complaints were received involving "ground straps" left in place for several weeks. Ground straps are temporary service connections used to temporarily bypass faults in underground cable until repairs can be made. The Field Operations Manager studied and revised FPL's practices for tracking and removing ground straps within 21 days of initial installation in order to reduce customer dissatisfaction and complaints.

Resource Manager

The Resource Manager position was created to provide a company-wide perspective to distribution operations resource deployment to ensure that resources are deployed where they are needed. The Resource Manager works with the Reliability/Restoration Manager and Area Service Center Managers to even out gaps in the workforce through adjustments to scheduling and deployment across territory "boundaries," particularly when heavy workload exceeds or threatens to exceed available manpower.

Also reporting to the Resource Manager, a Customer Service Coordinator was brought in during 1997 to provide an operations level involvement in responding to customer complaints received directly by FPL and through the FPSC Division of Consumer Affairs. The coordinator and her staff of four analysts employ their knowledge of distribution operations to resolve customer problems, interfacing with field forces to investigate, and resolve customers' problems. The Coordinator prepares weekly and monthly reports analyzing customer complaints and FPL's efforts to resolve them. This provides distribution management with an earlier awareness of trends in types and locations of customer problems. She also provides feedback about the problems to distribution field forces and the Field Operations Manager about the causes of problems her group has handled.

Two additional managers form the new Service Quality Group, which also reports to the Resource Manager. The Service Quality Data Manager collects, analyzes, and ensures the integrity of data measuring FPL's reliability and service quality indicators. Data is compiled by the Service Quality Group for use by distributions operations personnel, such as the Early Warning Reports, which were instituted in mid-1997. These daily reports provided to distribution managers identify system components experiencing multiple failures within a specified time period as an early warning for the need for service or replacement.

The Service Quality Group's Reliability Project Performance Manager participates in the problem-solving processes, such as the tactical teams described above, and ensures effective implementation of the corrective measures that grow out of these problem-solving efforts. This position is intended to provide a sustained focus on attaining the desired improvement in service unavailability and momentary interruptions.

3.5.4 Reliability 2000 Plan

FPL's longer-term approach to its decline in reliability and service quality has been the creation of the *Reliability 2000 Plan*. The company's immediate response during 1997 included the implementation of new management structures and approaches, the formation of tactical teams, and the implementation of their findings. The *Reliability 2000 Plan*, formally approved by FPL executive management in November 1997, addresses the needed improvements identified in the March 1997 *Environmental Assessment*. As shown on Exhibit FPL-28, specific reliability programs have been identified to address the various problems, providing increased expenditures of $11 million in 1998, $17 million in 1999, and $11 million in 2000. In addition, the plan dedicates additional budget money to ongoing infrastructure improvements and customer programs. In total, the plan adds $84 million in spending beyond 1997 levels over the period 1998 through 2000.

According to FPL, the plan is a comprehensive assessment and work plan identifying reliability goals and priorities through the year 2000. FPL notes that the plan will target service interruptions, momentary interruptions, and service restoration time through initiatives including reviews of company practices involving tree trimming, conductor (line) replacement, system design standards, and the service restoration process. FPL indicates the plan will include an assessment of distribution components such as transformers, cable performance, and lightning and grounding protection.

During October 1997, following the completion of field work for this review, FPL again made changes to the distribution field operations organizational structure depicted in Exhibits FPL-11 and FPL-22. Consequently, staff has not analyzed nor described these changes in detail within this report. These recent organizational changes are intended to facilitate the

Florida Power And Light
Reliability 2000 Plan
1998-2000 Reliability Programs
($000)

Reliability Programs	1997	1998	1999*	2000*	Strategy And Comments
Restoration Initiatives	$ 1,300	$ 4,145	$1,540	$ 560	Includes 1998 addition of 7 Line Specialist Rotators (Trouble men).
Distribution Automation	742	390	5,390	1,390	1998: Repair and relocate 50 automated switches, 1999 & 2000: Maintenance on existing automated and new installations.
Feeder Telemetry	2,000	1,414	4,500	4,500	1998: Install feeder telemetry on 130 feeders in Dade. 1999: Complete Dade & Broward, start Palm Beach. 2000: Complete remaining feeders.
Worst Performing Feeders-Changed To Outlier Feeder For 1998	1,541	2,175	0	0	Interim program, through 1998 to improve 50 poor performing feeders. Note: $7.3 million in 1999 and 2000 to address feeders/laterals experiencing multiple interruptions.
Lateral Outliers	N/A	760	0	0	Interim program, through 1998 to improve 150 poor performing laterals. Note: $7.3 million in 1999 and 2000 to address feeders/laterals experiencing multiple interruptions.
Vegetation Management	23,000	25,000	29,500	29,500	Increased funding for next 3-5 years to regain control of growth affecting FPL facilities. First 3 year cycle begins in 1999.
Lightning Protection-Program	N/A	1,050	To be deter-mined	To be deter-mined	Correct lightning protection on 37 feeders system wide. Work with Distribution Engineering to evaluate standards.
Cable Replacement-Feeder	420	5,077	4,828	4,378	Replace failing feeder cable after the fourth failure. Replace worst 38 miles of critical cable (failed 4 or more times).
Program Totals	**$29,003**	**$40,011**	**$45,758**	**$40,32/8**	
Increase Over 1997 Spending	**—**	**$11,008**	**$16,755**	**$11,325**	

EXHIBIT FPL-28

Source: FPL Responses to Document Requests 2-1 & 5-6.

**Actual Results achieved as a result of 1997/1998 efforts could impact projected expenditures for 1999 and 2000.*

implementation of the *Reliability 2000 Plan* by enhancing the attention given to the plan's specific programs and initiatives. This October 1997 organizational structure is depicted in Exhibit FPL-29.

The results of the Reliability 2000 effort will obviously be critical to reversing the downward trend of many of the measures of distribution service quality discussed in this report. Ultimately, this process will require a period of years to show its full effect, although some results can be observed in the interim, perhaps within 1998.

3.6 Conclusions

By virtually every measure examined, FPL distribution service quality has declined over the period 1992 through 1996. Though it is difficult to identify precisely where and how, it appears that FPL's reductions to operations and maintenance costs over the period studied have also reduced distribution service quality. In early 1997, FPL began to take extensive actions to reverse this decline, including a strategic plan that sharply contrasts the cost-cutting approach employed during this decade. Through the newly-approved *Reliability 2000 Plan*, FPL has allocated an additional $84 million dollars to improve its distribution network over the next three years. In 1998, FPL plans $34 million in distribution spending beyond 1997 levels, followed by an additional $28 million in 1999, and $22 million more in 2000.

FPL's response has also included management changes and restructuring in the Distribution Business Unit, identification, and assessment of weaknesses. These efforts have yielded some promising preliminary results. A need to change the territorial mentality in the service restoration function was recognized, in order to more appropriately utilize the field workforce, which was reduced significantly in recent years. Changes have been made to give additional attention to customers' needs and expectations. Substantial increases in tree-trimming budgets have already been made in 1997 and will continue for three more years to reduce this key problem.

Although substantial progress may be made in some areas within a year, the total process is likely to require a period of at least two to three years for all results to be seen. The results of these efforts can be measured by the existing company indicators and through monitoring by the FPSC. To effectively monitor this progress, the FPSC needs to enhance the existing service quality information captured through the annual Reliability Report filed by FPL. To ensure that progress is made and that plans for improvement (particularly those outlined in the *Reliability 2000 Plan*) are carried out, a follow-up review based upon 1998 results will be necessary.

FLORIDA POWER AND LIGHT COMPANY
DISTRIBUTION OPERATIONS
OCTOBER 1997 ORGANIZATIONAL CHART

- **VICE PRESIDENT** Distribution Business Unit
  - **SAFETY/TRAINING/ METHODS** GENERAL MANAGER
    - Training Manager
    - Development And Methods Manager
    - Safety Manager
  - **COST AND PERFORMANCE** DIRECTOR
    - Cost Manager
    - Financial Manager
    - Senior Analyst
    - Senior Manager
    - Senior Manager
    - Rotation
  - **SUPPORT SERVICES** DIRECTOR
    - Engineer/Service Manager
    - ERC/MTC Manager
    - Environmental Manager
    - CRS Manager
    - Materials Management Manager
    - URD Construction Director
    - Logistics Manager
    - Distribution Inventory Services Manager
    - PD Inventory Services Manager
    - Logistics Support Manager
  - **OPERATIONS SUPPORT** DIRECTOR
    - Reliability Manager
    - Restoration Manager
    - Construction Manager
    - Support Manager
    - Customer Comm. Manager
  - **DISTRIBUTION PLANNING** MANAGER
    - Regulation Strategy Manager
    - Business Proc. Manager
    - Planning Manager
    - New Business Manager
  - **FLEET SERVICES** DIRECTOR
    - South Manager
    - Northeast Manager
    - West Manager
    - Plant Manager Legislative Coordinator
    - Maintenance Manager
    - Technical Operations Manager
  - **URBAN OPERATIONS** DIRECTOR
    - Area Managers (8)
    - Trouble/Dispatch Office Manager (Central/South Fla.)
  - **SUBURBAN OPERATIONS** DIRECTOR
    - Area Managers (8)
    - Trouble/Dispatch Office Manager (North)
    - Trouble/Dispatch Office Manager (West)

EXHIBIT FPL 29

Source: FPL Revised Response to Document Request 1-1, 5, 13, and 19.

4.0 Florida Power Corporation

4.1 Company Profile

Florida Power Corporation (FPC), a subsidiary of Florida Progress Corporation, is the second largest investor-owned electric utility in the state of Florida with 4,629 employees and 1996 operating revenues just under $2.4 billion.

In anticipation of competition, in July 1996, FPC reorganized its operations into the following three strategic business units:

- Energy Supply
- Energy Solutions
- Energy Delivery

Energy Supply is FPC's power generation group responsible for overseeing the company's fossil fuel (coal, oil, and natural gas) and nuclear operations. Specific responsibilities include construction of new power plants, power generation, and maintaining maximum efficiency of power.

Energy Solutions is the customer services arm focused on sales and marketing and finding new ways to use emerging technology to develop new products and services. The Energy Solutions group is responsible for credit and billing functions as well as measuring customer satisfaction and guiding FPC in making improvements in customer service.

Energy Delivery, the primary focus of this review, oversees FPC's transmission and distribution lines as well as system operations and planning. Responsibilities include construction, maintenance, and power restoration of the company's transmission and distribution network.

The company currently serves 1.3 million customers in 32 of Florida's 67 counties, covering an area of about 20,000 square miles, primarily in central and north Florida. FPC's service territory includes areas around Orlando, the cities of St. Petersburg and Clearwater, and rural North Florida localities. In sum, through 13 baseload generating units, FPC has a total electric generating capacity of 7,341 megawatts of power with 4,600 miles of transmission lines and 23,914 miles of distribution lines.

Over the period 1986 to 1996, FPC's total customer base grew at an annual rate of 3.2 percent; however, in recent years the company has experienced a lower customer growth rate. From 1993 to 1996, the average annual rate of growth in customers was 2.1 percent and from 1995 to 1996, customers grew at just 1.6 percent.

Segmented by type, 88.3 percent of FPC's accounts were residential, accounting for 56 percent of total energy sales in 1996. Non-residential accounts (commercial, industrial, public street highway lighting, and public authorities) comprised 11.7 percent of the total, but purchased 37 percent FPC's total energy production.

4.2 FPSC Service Quality Indicators

The two key indicators of service reliability monitored by the FPSC are customer inquiries received by the Division of Consumer Affairs and the annual reliability reports filed by electric utilities. This section examines and compares current year indicators to prior years and provides an assessment of the collected information.

4.2.1 FPSC Customer Inquiries and Complaints

Direct questions or concerns to FPC that are not resolved to the customer's satisfaction may result in the customer filing a complaint with the FPSC. Beginning in 1996, customer complaints received were categorized as either a service or billing inquiry.

A review of service-related inquiries logged against FPC for each of the years 1992 through 1997 is depicted in Exhibit FPC-1. FPC attributes the sharp increase in inquiries from 1994 to 1995 to deployment and roll-out issues related to a new customer service computer system that were corrected by year end 1995. According to FPC, the new system extended the time it took customers to contact FPC's Customer Service Center. Since customers were unable to reach FPC in an acceptable time frame, they contacted the FPSC regarding reliability, customer service, and billing issues.

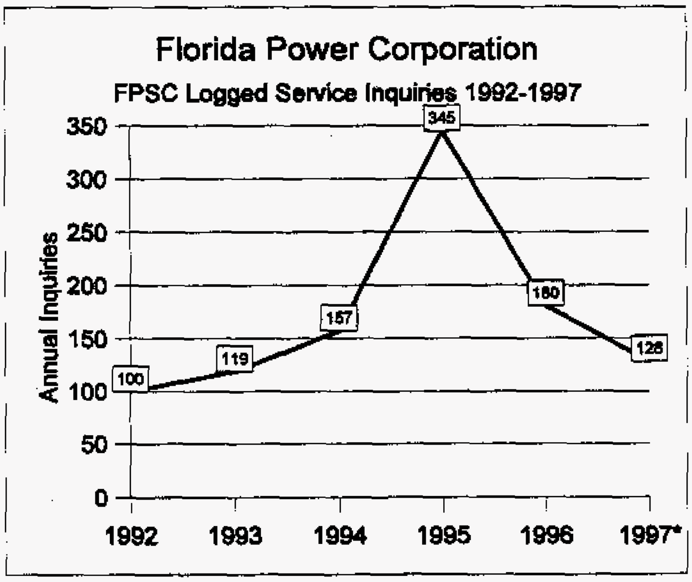


EXHIBIT FPC-1 *Source: FPSC Consumer Activity Reports, 1992-Sept. 1997.*

**Projected based on 96 inquiries received as of 9/30/97.*

In 1995, the highest numbers of service-related inquiries were attributed to frequent outages (67), service outages (33), and tree trimming (28). From 1995 to 1996, the number of service inquiries dropped 48 percent, with the highest numbers attributed to outages (65) and questions concerning rules and tariffs (34). As of September 30, 1997, the Division of Consumer Affairs had received 96 inquiries, with the most frequent number of calls (24) relating to outages.

Appendix 3 provides a sample of service-related FPSC customer inquiries received from FPC customers during 1996 and 1997. Many of these inquiries deal with high frequency and long duration of interruptions being experienced. Although many such inquiries do not constitute an infraction of rules and tariffs, they still represent unsatisfactory service quality and considerable inconvenience to customers.

Beginning in 1996, closed inquiries in violation of a company policy, tariff, or FPSC rules are designated as infractions. In 1996, FPC had 20 service infractions and through September 1997, the company had seven. Of the 20 infractions in 1996, most frequent causes of infractions were improper service disconnects, street and outdoor lighting outages, delay in connecting the customer's initial service, and errors in the customer's service application record. Sixteen of the 20 infractions were from urban customers, while four were rural. Five of the seven infractions in 1997 matched the leading causes of 1996 inquiries.

4.2.2 FPSC Distribution Service Reliability Report

The FPSC's annual distribution service reliability report requires each utility to provide: their annual number of service interruptions (N), sorted by cause, the average length of all interruptions (L-Bar), and the top three percent of the utility's feeders with the highest number of interruptions.

A review of FPC's number of service interruptions, categorized by cause for the years 1992 through November 30, 1997 is provided in Exhibit FPC-2. It should be noted that Rule 25-6.0455 requires that all prearranged outages and outages due to transmission, relay, generation, and customer problems to be excluded from the annual report. FPC's results indicate that the total number of interruptions have steadily increased since 1992. Interruptions, on average, increased five percent annually or 20 percent overall, from 33,570 in 1992 to 40,382 in 1996. Through November 1997, FPC reported 39,914 interruptions, which projects to an annualized 1997 total of 43,543--an increase of 7.8 percent over 1996 and 30 percent from 1992.

Exhibit FPC-3 takes Exhibit FPC-2 a step further by showing the most frequent causes of interruptions for the years 1992 through September 1997. The top three causes in each year were: other (outside the reporting categories specified by Rule 25-6.0455), tree, and animal. Several causes that make up the category of "other" include connector failures, defective equipment, human error, storm/wind, and underground primary cable.

Exhibit FPC-4 depicts FPC's average length of interruptions using the L-Bar minutes provided in the annual reports. It should be noted that L-Bar averages the lengths of all interruptions equally without considering the number of customers affected by each interruption. Over the period 1993 through 1996, the average length of interruptions grew 29 percent from 90 minutes in 1993 to 116 minutes in 1996. This equates to an average annual increase of nine percent. L-Bar reported through November 1997 was 112 minutes.

Florida Power Corporation
Total Interruptions by Category
1993-1997

Cause	1992		1993		1994		1995		1996		1997*	
	Total	%	Total	%	Total	%	Total	%	Total	%	Total	%
Animal	4,342	13	4,694	13	4,158	11	4,494	11	5,863	15	7,614	19
Corrosion	0	0	0	0	0	0	0	0	0	0	0	0
Dig-In	422	1	349	1	385	1	376	1	358	0	483	1
Lightning	3,540	11	3,093	9	3,949	11	2,778	7	3,658	9	4,001	10
Salt Spray	0	0	0	0	0	0	0	0	0	0	0	0
Substation	69	0	99	0	66	0	90	0	51	0	63	0
Transformer	2,579	8	2,779	8	2,799	7	3,123	8	3,605	9	2,630	7
Tree	4,286	13	4,429	13	5,421	14	6,844	17	7,295	18	5,723	14
Unknown	2,755	8	2,912	8	2,816	7	4,143	10	3,985	10	4,188	10
Vehicle	430	1	461	1	443	2	457	1	383	1	300	1
Other	15,147	45	16,406	47	17,549	47	17,201	43	15,184	38	14,912	37
Total	**33,570**	**100%**	**35,222**	**100%**	**37,586**	**100%**	**39,506**	**100%**	**40,382**	**100%**	**39,914**	**100%**

EXHIBIT FPC-2

Source: FPSC Reliability Reports 1993-1996.

**Through November 30, 1997*

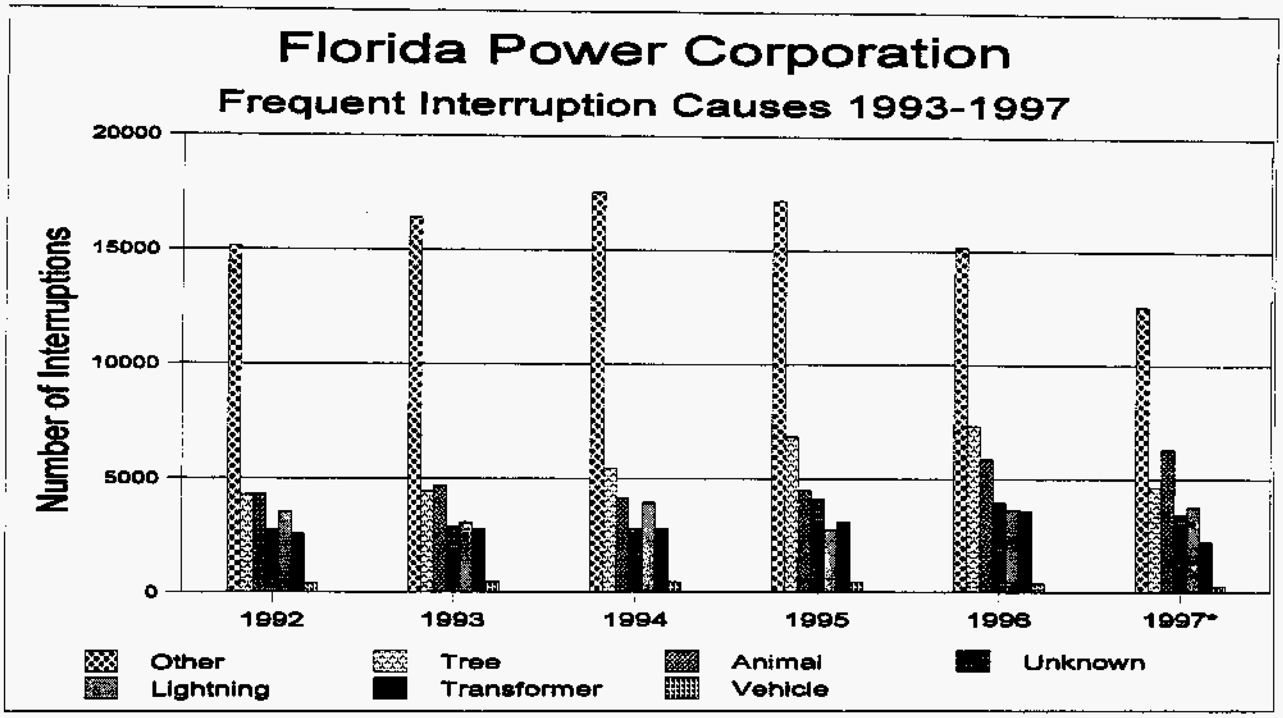


EXHIBIT FPC-3

Source: FPSC Reliability Reports 1993-1996.
FPC Response to Document Request 3-2.

**Through November 30, 1997.*

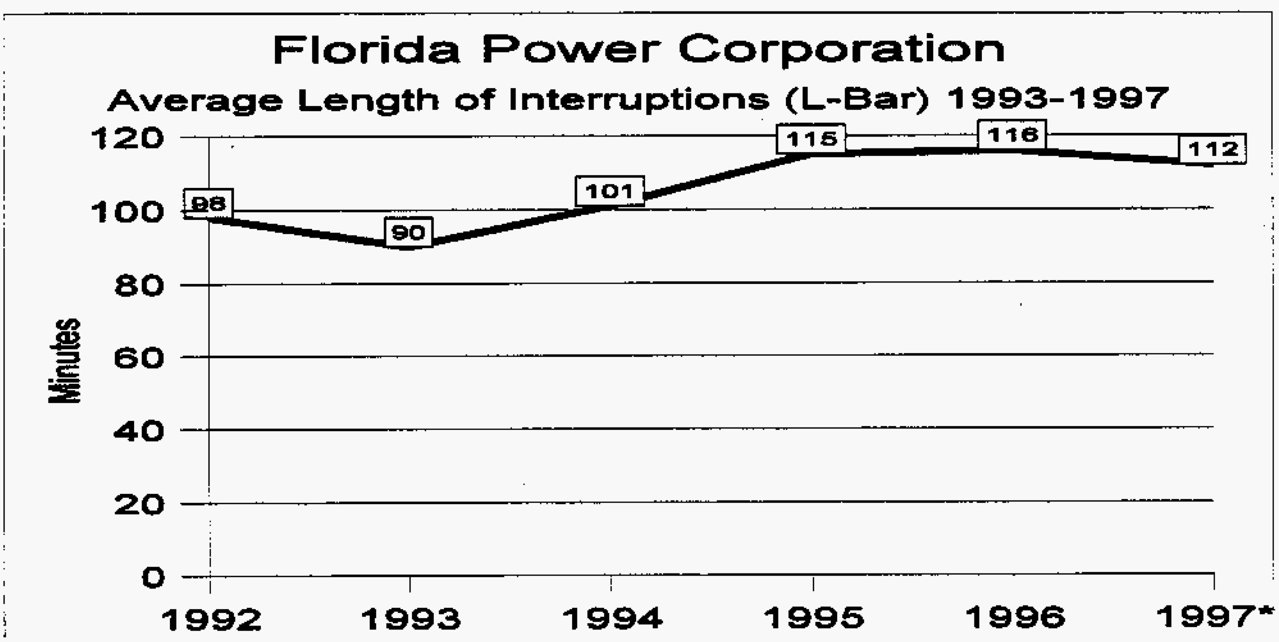


EXHIBIT FPC-4

Source: FPSC Reliability Reports, 1993-1997.
FPC Response to Document Request 3-2.

**Through November 30, 1997.*

An examination of FPC's three percent "worst performing feeder" lists (an average of 27 per list) shows some patterns of feeders repeatedly making the list. Over the period 1993 to 1996, one feeder appeared on the list for all four years, while two feeders appeared on the list for three years. Ten feeders made the list twice. These "repeat offenders" represent identified trouble areas being experienced for two or more years without being fully resolved. To a certain extent, some feeders such as long rural circuits may continue to be problematic. FPC's efforts to combat its worst performing feeders is discussed further in sections 4.4.3 and 4.4.5.

4.3 Company Service Quality Indicators

A variety of internal measurements throughout the company are available for use in monitoring distribution operations. Several key measurements, including internal reliability indicators, utility-handled customer inquiries and complaints, customer satisfaction surveys and customer claims are discussed below.

4.3.1 Internal Reliability Indicators

Prior to FPC's recent reorganization and formation of the Energy Delivery Business Unit, the company's operations were divided into three geographical regions (Suncoast, Central Florida and North Florida). Although the company's organization is no longer separated in this manner, reliability statistics are still kept separately by region in order to monitor performance and compare historical data.

This section summarizes FPC's system performance using the three primary service reliability indices which reflect the quality of electric service to the customer; SAIDI, CAIDI, and SAIFI. These three indices, as well as a variety of secondary indicators, are tracked internally by FPC.

System Average Interruption Duration Index

The primary indicator of overall system distribution service reliability tracked by FPC is the CMI/C index, also known throughout the electric industry as SAIDI (System Average Interruption Duration Index). CMI/C measures the average duration of an interruption for all customers served. CMI/C is determined by dividing the sum of all customer minutes of interruption by the average number of customers served. In calculating CMI/C, FPC includes planned interruptions and excludes any interruptions that were over 24 hours and affected at least 10 percent of FPC's customer base. Under this exclusion, which would apply for example to a hurricane, FPC would be so highly mobilized for service restoration that normal outage reporting procedures would be suspended and customers would reasonably expect service to be out for an extended period of time.

Exhibit FPC-5 graphically depicts FPC's CMI/C data over the period 1992 through 1996. Since 1992, CMI/C increased by 65 percent, indicating that FPC's customers' total annual interruption time increased, on average, by 63 minutes. According to FPC, contributors to the

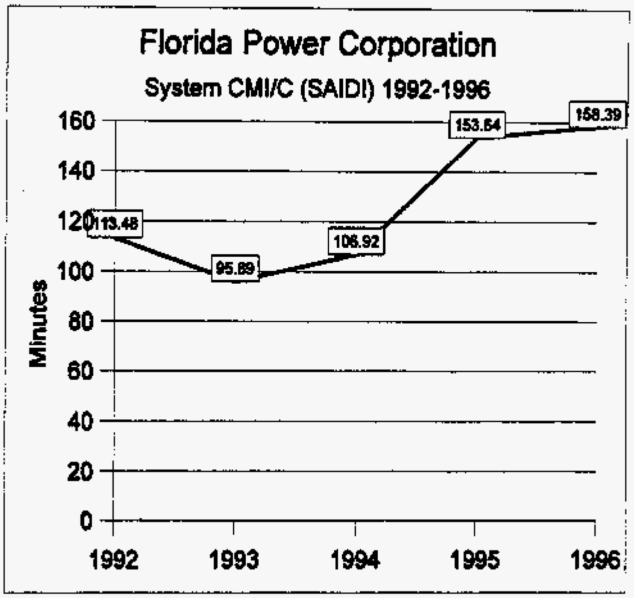


EXHIBIT FPC-5 *Source: FPC Response to Document Request 1-3.*

increase in CMI/C over this period were tree-related interruptions, defective equipment, underground primary cable, less than effective direction of maintenance resources, and increased severe weather during 1995 and 1996.

In 1996, CMI/C reached its peak over the five year period. Several factors, including those already listed, contributed to the deterioration in reliability. Two specific events during 1996 influenced the reliability results for the year. First, an overload on the company's system tripped relays on the company's system on March 25, 1996. The overload was caused by a combination of several FPC generating units being down for maintenance at the time the Orlando Utilities Commission exercised previously arranged purchase power agreements. Second, on October 7, 1996 tropical storm Josephine caused a large number of interruptions in FPC's service territory, particularly in the company's Suncoast Region. The storm did not make a direct hit on FPC territory and therefore its impact was not excluded under the company's guidelines.

As of November 1997, FPC's system CMI/C was reported at 134 minutes. In 1997, the company set a goal to improve CMI/C to 145 minutes or eight percent under its 1996 total of 158 minutes, as shown in Exhibit FPC-6. In addition to 1997, FPC has set CMI/C goals for each of the years 1998 through 2000. FPC is striving for an average annual improvement of 14 percent over the period 1997 to 2000.

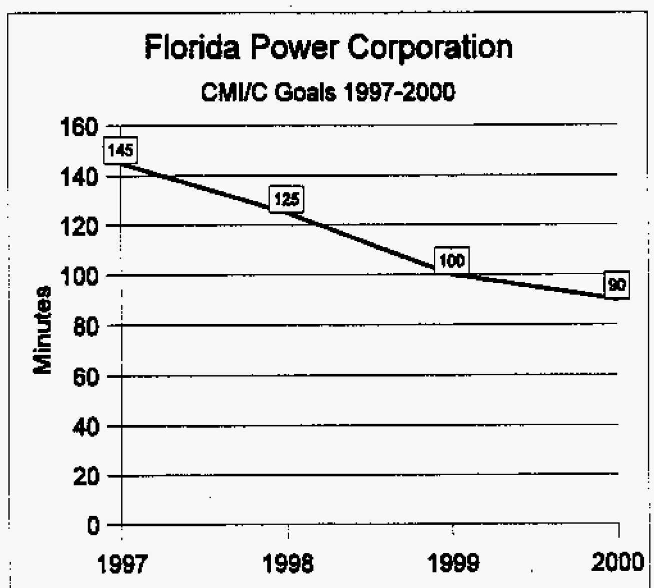


EXHIBIT FPC-6 *Source: FPC Energy Delivery Reliability Orientation August 15, 1997.*

Customer Average Interruption Duration Index

A component of CMI/C is the average outage duration for customers interrupted, otherwise known as CAIDI (Customer Average Interruption Duration Index) in the electric industry. CAIDI is determined by dividing the sum of all customer minutes of interruption by the number of customer interruptions. CAIDI is FPC's primary internal indicator for measuring response

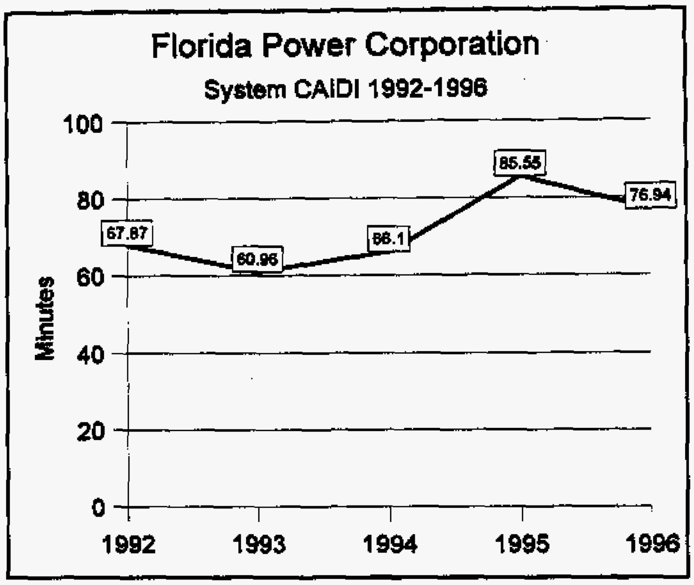


EXHIBIT FPC-7 *Source: FPC Response to Document Request 1-3.*

time--the time elapsed from when a customer reports an interruption until their service is restored.

Exhibit FPC-7 presents FPC's system CAIDI indices for the period 1992 through 1996. As can be seen, CAIDI increased from 61 minutes in 1993 to about 86 minutes in 1995, representing a 45 percent increase in average outage duration. In other words, FPC's customers who encountered an interruption in 1995, were without service 25 minutes longer, on average, when compared to 1993 outage duration figures.

The primary contributor to the increase in CAIDI in 1995 was decreased response availability in FPC's sparsely populated Northern region, which includes such towns as Monticello, Perry, Apalachicola, Wildwood, Ocala, Crystal River, and Inverness. Additionally, in the same year, FPC's Northern region was peripherally affected by Hurricanes Opal and Allison. The company's average outage duration for its Northern Region was 143 minutes for the year, up 44 minutes over the 99 minutes reported in 1994. However, excluding minutes attributed to the two hurricanes during the year, CAIDI for FPC's North Region was 118 minutes.

FPC's CAIDI indices for 1996 were down when compared to 1995. As of November 1997, FPC reported 76 minutes for system CAIDI--which equates to the December 1996 level.

System Average Interruption Frequency Index

The remaining component of CMI/C is the average frequency of outages, or SAIFI (System Average Interruption Frequency Index). It is determined by dividing the total number of customer interruptions by the average number of "all" customers served. In other words, this index indicates the number of times per year that the "average" customer can expect to be out of service.

Exhibit FPC-8 depicts FPC's system SAIFI numbers for each of the years 1992 through 1996. In 1996, the index was 2.06, indicating that, on average, a customer was interrupted 2.06 times. As can be seen, system SAIFI has increased since 1993, further indicating that FPC has experienced a decline in reliability. However, as of November 1997, SAIFI has declined to 1.77. Similar to the results indicated by CAIDI, the primary driver behind the increase in SAIFI is FPC's Northern Region. From 1993 to 1996, the number of interruptions per customer in FPC's Northern Region, on average, increased from 1.83 to 3.06 times.

Other Indicators

Although CMI/C is FPC's primary index, the company also tracks a variety of secondary measurements to monitor system performance. Indices tracked since at least 1992 are as follows:

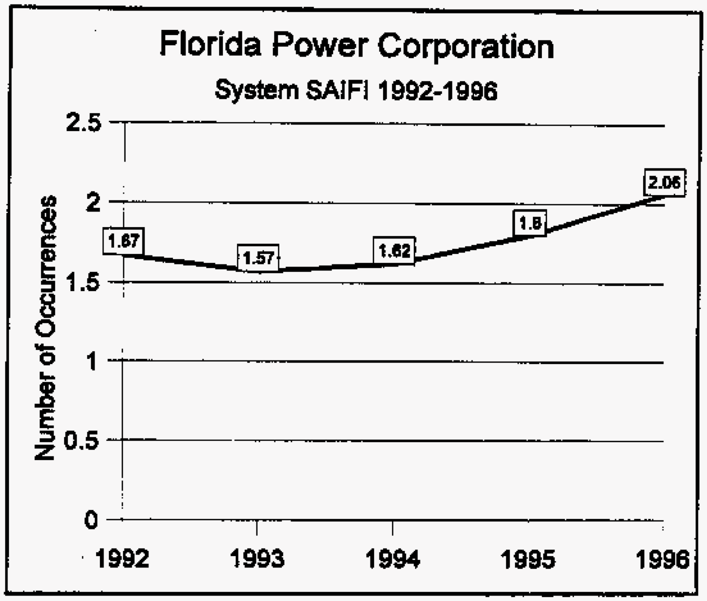


EXHIBIT FPC-8

Source: FPC Response to Document Request 1-3.

- Average number of customers whose service is interrupted by each interruption (ACPI).
- Multiple interruptions to the same customer (CAIFI).
- Percentage of customers having more than five interruptions.
- Percentage of customer minutes of interruption greater than two hours.
- Percentage of time during a given year that an average customer was in service (ASAI).

The Average Customer Per Interruption (ACPI) indicator is defined as the average number of customers whose service is interrupted by each interruption. FPC's system total ACPI for 1996 was 61, meaning that an average of 61 customers was affected per interruption. Since 1993, FPC's ACPI index has increased, on average, by 10 percent per year. As of November 1997, ACPI declined to 54.

The Customer Average Interruption Frequency Index (CAIFI) measures interruptions to the same customer. FPC's CAIFI for 1996 was 2.35. From 1992 to 1995, customers who were interrupted experienced, on average, 2.23 interruptions per year.

FPC also tracks the percentage of its multiple interruption customers who experienced a total of five or more in a year. Over the period 1994 through September 1997, 2.7 percent of customers were interrupted more than five times a year.

Another indicator monitored by FPC is the percentage of customer minutes of interruption greater than two hours. For each of the years 1994 through September 1997, the percentages equated to 41, 54, 50, and 46 percent, respectively.

FPC's Average Service Availability Index (ASAI) is the percent of time that customers were in service for a given year. ASAI is determined by dividing the customer hours of service by the customer hours of service possible. This index has been referred to for several years in the utility industry as the "Reliability Index." FPC's ASAI, on average, is about 99.97 percent per year.

4.3.2 Utility-Handled Inquires and Complaints

FPC's Customer Solutions organization tracks FPSC inquiries and courtesy calls, and beginning 1996, the department began tracking internal "executive" office letters and calls directed to upper management. In 1996, the company received 501 executive calls and 68 letters. From January through September 1997, FPC received 439 executive calls and 88 letters directed to executive offices. Of the total received in 1997, 42 calls and 10 letters pertained to outages, 22 calls and one letter pertained to tree trimming, and 23 calls and four letters pertained to property damage.

In June 1996, FPC implemented a Voice Response Unit which provides automated services for customer calls by prompting the customer to use touch tone service to provide information on the problem they are experiencing. The Voice Response Unit has the capability of categorizing and offering three types of automated services; power outages, bill inquiry, and credit extensions. Since its inception, the Voice Response Unit has processed an average of over 24,000 calls a month.

Exhibit FPC-9 provides a monthly breakdown from June 1996 to September 1997 of the total processed calls into these three categories. In comparison to last year's summer months, June through September, the total number of calls processed by the Voice Response Unit increased 69 percent. The highest number of calls processed to date occurred in July 1997, with 42,009. Almost half of these calls (20,793) were related to outages. This 20,793 is more than three times the average rate of monthly outage calls (6,687) since June 1996. It should be noted that in March 1997, FPC added the capability for its Voice Response Unit to provide estimated restoration times, possibly resulting in increased customer calls. Additionally, the increase in calls may partially be attributable to customers increased acceptance and awareness of using the Voice Response Unit system. If a customer's call cannot be handled automatically, it is routed out of the Voice Response Unit to the first available customer service representative. The service representatives are accountable for keeping records of their interactions with customers and may, using their best judgement, code the call by type. These "wrap-up" codes have been maintained since implementation of the Voice Response Unit, and they allow FPC to track the type of calls the service representatives are handling.

Since June 1996, the service representatives have handled over 272,000 calls a month. Of the 272,000 calls, an average of over 23,000 (8.5 percent) are coded as "power outages." A review of monthly data received through September 1996, shows that the highest number of "power outage" calls were recorded in July 1997, with 44,410. In comparison to July 1996, outage calls increased by 61 percent, up from 27,510. Similarly, an average of approximately 4,000 calls (one percent of total) a month are coded as "service problems." The numbers of

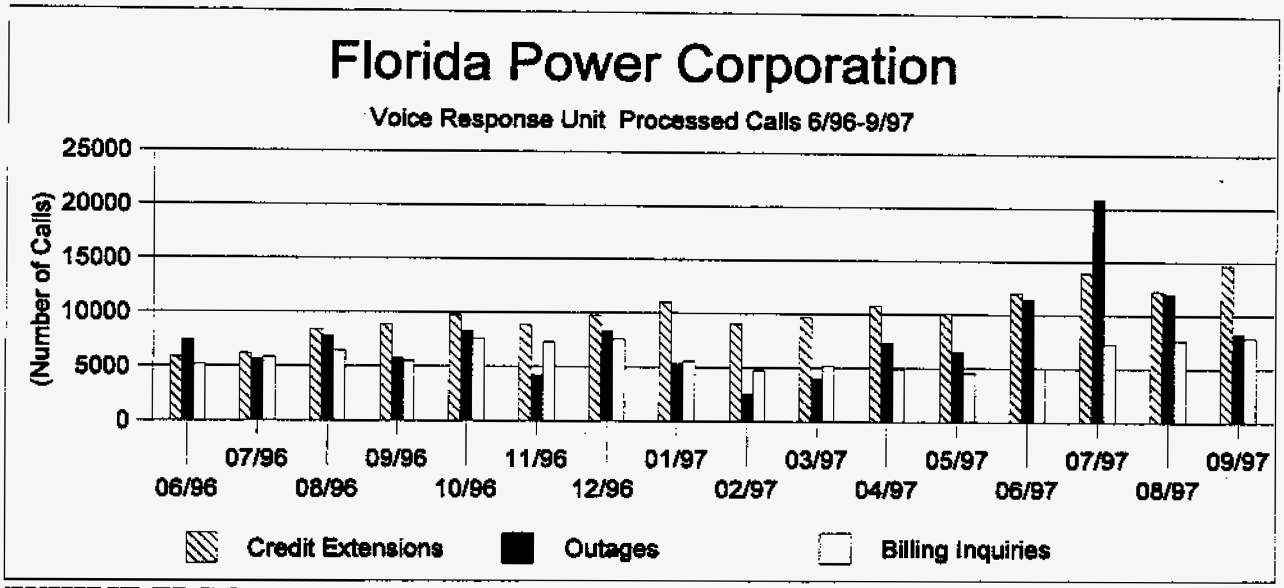


EXHIBIT FPC-9 *Source: FPC Response to Document Request 3-18.*

monthly "service problem" calls remained fairly consistent since June 1996, with the highest number of calls (5,877) received in October 1996.

4.3.3 Customer Satisfaction Surveys

Since its inception in 1987, FPC's Residential Customer Opinion Survey (COS) has been providing the company with regular measures of residential customer opinions, beliefs, attitudes, and evaluations of their relationship with FPC. The COS was conducted on a quarterly basis from 1987 to 1991, then semi-annually beginning in 1992. Because only minor variations were observed in the COS results throughout 1991 and 1992, the decision was made to conduct the COS on an annual basis in 1993. Information collected from the COS is used by FPC to establish strategic goals concerning the overall position of the company in customers' minds, and to develop operational objectives with regard to enhancing FPC's relationship with customers. Results are also reported to energy distribution on a monthly basis. In the event that results change significantly from previous reporting periods, corrective actions can be taken.

On average, about 600 telephone interviews are conducted annually with a random sampling of residential customers, stratified by region. This sample size allows for an error rate of plus or minus four percent. Overall, from 1992 through 1996, the COS surveys gave FPC positive ratings in the area of service reliability. The 1996 survey results do, however, indicate that FPC's residential customers are less satisfied with FPC's ability to keep down momentary interruptions (less than 10 seconds) than its ability to reduce the number and duration of power outages lasting five minutes or longer. This further supports the notion that customers, as a whole, are becoming less tolerant of momentary interruptions.

In addition to the residential COS, opinion surveys were conducted for all of FPC's small, medium, and large commercial and industrial customers in 1992, 1993, and again in 1996. A total of 1,352 telephone interviews were conducted over the three year period, for an average of 450 interviews per survey. Survey results indicate that commercial and industrial customers are satisfied with overall "power quality" and "service reliability;" however, the 1996 satisfaction percentages have moderately declined since 1992 and 1993. Specifically, the 1992 and 1993 power quality results indicate an 88 and 86 percent overall satisfaction rate, while the 1996 power quality results declined to 82 percent. Similarly, the 1996 service reliability satisfaction results dipped from 93 percent in 1993 to 88 percent.

Beginning November 1996, FPC made efforts to conduct monthly surveys of customers who had recent interaction with the company (e.g., called the phone center, used a business office, participated in a conservation program) in order to examine customer-related issues of particular concern. The comprehensive survey, identified as FASTRACK, includes a sample of residential customers, as well as commercial customers with an average monthly usage of less than 70,000 kWh. In January 1997, respondents were asked about the reliability of their electric service and Florida Power's ability to keep down the number of momentary interruptions. In addition, customers who called in specifically to report an outage were asked about their level of satisfaction with the restoration of their electric service.

The January FASTRACK results indicate that almost nine in ten customers are satisfied with FPC's ability to keep down the number of power outages lasting five minutes or longer. Two-thirds are very satisfied. Only six percent of all FASTRACK customers are dissatisfied with FPC's performance in this area. Similarly, 85 percent are satisfied with the company's ability to keep down the number of momentary interruptions (10 seconds or less), with 63 percent very satisfied and only seven percent dissatisfied.

4.3.4 Customer Damage Claims

Customers may request compensation for damaged property resulting from FPC's system. Damage may result from lightning, equipment failure, employee error, voltage fluctuations, and power surges. FPC does not proactively inform customers of their rights to file a claim against the company. However, FPC servicemen are instructed to direct customers to the company's Claims Department when the customer indicates they may have suffered a property damage loss. Additionally, FPC periodically uses bill stuffers, pamphlets, and television and radio public service announcements to educate customers on how to protect against damage from lightning, power surges, etc. In addition, FPC will conduct a grounding inspection to ensure a customer's home is properly grounded. For six dollars a month, FPC offers and installs meter-based surge protectors. Exhibit FPC-10 depicts the total dollars paid-out for all types of claims filed against FPC and the portion of the total specific to "general property damage" for the period 1992 to 1996. The remaining types of claims filed against the company are categorized as automobile bodily injury, automobile property damage, and general bodily injury. The company's average annual pay-out on general property damage claims over the period shown was approximately $820,000. The total amount of general property damage claims paid over the five year period was $4.1 million dollars, less than half of the $8.5 million paid by FPC for all types of claims filed. As of August 31, 1997, FPC paid-out $544,690 in general property damage claims.

Exhibit FPC-11 presents the total number of claims filed over the same period and the portion of the total that is general property damage claims. general property damage claims are by far the most numerous of total claims filed, even though they represent less than half of the total claims paid annually, on average. The total number of general property damage claims filed annually is about 95 percent of total claims filed. From 1992 to 1996, the number of general property damage claims filed has increased by 49 percent, growing at an average of slightly over 10 percent a year. Of the total number of general property damage claims shown for each of the years, FPC is paying, on average, just under 50 percent of the claims filed. Taking Exhibit FPC-11 a step further, Exhibit FPC-12 sorts the total number of general property damage claims filed annually into nine cause categories tracked by the company and the total dollars associated with each cause. With the exception of the "Miscellaneous" category, the leading cause category of general property damage claims filed each year is attributed to "open neutrals," averaging 800 claims a year. From 1992 through August 1997, the greatest percentage increase in number of claims filed occurred in the categories of "Cut in Error/Cut for Nonpayment" and "Environmental/Tree Trimming," at 106 and 89 percent, respectively. Conversely, the greatest percentage decrease in claims filed over the same period occurred in the categories of "Transformers" and "Underground," which improved by 32 and 30 percent, respectively.

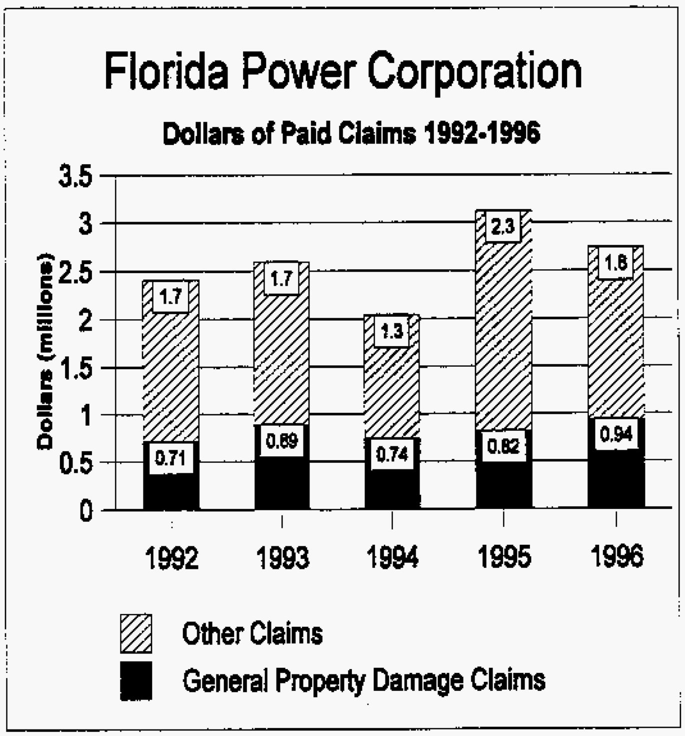


EXHIBIT FPC-10 *Source: FPC Response to Document Requests 1-22, 3-21, 3-22.*

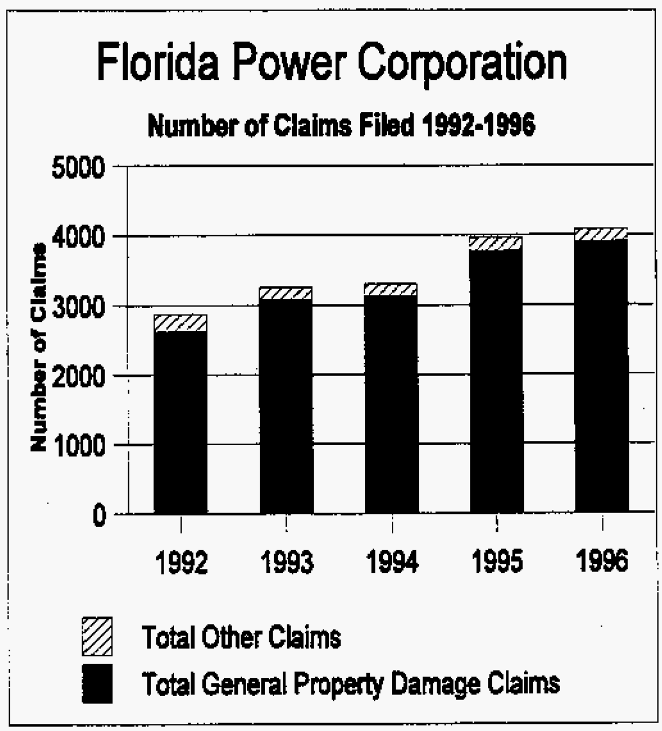


EXHIBIT FPC-11 *Source: FPC Response to Document Requests 1-22, 3-21, 3-22.*

Florida Power Corporation
General Property Damage Claims by Cause
1992-1997

Cause	1992		1993		1994		1995		1996		1997*	
	Claims Filed	Dollars Paid ($000)	Claims Filed	Dollars Paid ($000)	Claims Filed	Dollars Paid ($000)	Claims Filed	Dollars Paid ($000)	Claims Filed	Dollars Paid ($000)	Claims Filed	Dollars Paid ($000)
Open Neutral	748	$264	886	$353	796	$239	879	$332	897	$340	594	$232
Transformer	202	$78	206	$79	182	$37	238	$83	262	$57	137	$48
Interruptions	219	$9	170	$12	224	$21	283	$17	342	$41	359	$27
Weather	140	$7	324	$38	96	$3	299	$25	174	$4	202	$3
Single Phase	57	$2	59	$8	54	$1	36	$2	68	$12	41	$9
Underground	295	$50	248	$49	238	$57	238	$64	163	$64	206	$50
Cut in Error/ Cut Nonpay	79	$16	57	$10	149	$14	190	$19	193	$33	163	$12
Environmental /Tree Trim	75	$63	41	$16	53	$20	77	$20	106	$91	142	$22
Miscellaneous	1,052	$223	1,090	$322	1,329	$347	1,530	$255	1,697	$297	1058	$143
Total	**2,867**	**$714**	**3,081**	**$888**	**3,121**	**$740**	**3,770**	**$817**	**3,902**	**$940**	**2,902**	**$545**

EXHIBIT FPC-12

Source: FPC Response to Document Request 3-23.

**Through August 31, 1997.*

In terms of total dollars paid for general property damage claims, "open neutral" claims represent the greatest proportion, averaging over $293,000 or 38 percent of the annual totals. The "Miscellaneous" category averages 34 percent of total dollars paid out each year, followed by the categories of "Underground" at eight percent and "Environmental/Tree Trimming" at five percent.

It is the responsibility of FPC's Claims Department to investigate claims filed against FPC. The Department is headed by a director who has three claims agents and two support positions reporting directly to him. The claims agents are geographically based and are responsible for investigating claims, determining liability, and providing assistance in any claims litigation. The organizational arrangement of the Department has remained relatively the same since 1982.

The process of handling a claim begins when a customer contacts a FPC customer service representative about a potential claim. The service representative notifies a claims agent, who in turn must return a call to the customer within 24 hours or the next business day. The agent will obtain specific details regarding the claim from the customer and will confirm liability via examination of the field report prepared by one of the operating centers' linemen. If the claim involves repairs to damaged property (e.g., computer), the customer may elect to choose their own vendor or one of FPC's qualified vendors to repair or estimate damages. During the course of reporting and investigating a claim, the customer is not required to submit any company forms, but must provide written documentation of the loss and any service repair invoices if applicable. The claims agent provides the documentation to validate the claim and can authorize payment up to $2,500.

4.4 Distribution Organization and Service Quality Activities

The delivery of power to end-use customers is the responsibility of FPC's Energy Delivery Business Unit. As a result, this organization plays the major role in electric service quality since it is responsible for both the maintenance and repair of the portion of FPC's system that actually brings power to customers.

4.4.1 Structure Staffing and Functions

As part of the company's new Energy Delivery business unit, FPC is currently restructuring and consolidating its distribution organization. During mid to late 1997, FPC began the process of extensive realignment of its distribution management and staff, as well as extensive redefining of job functions. According to FPC, the realignment was done as part of efforts to prepare for competition with the intent of improving power quality and service reliability.

FLORIDA POWER CORPORATION
ENERGY DISTRIBUTION
1997 ORGANIZATIONAL CHART

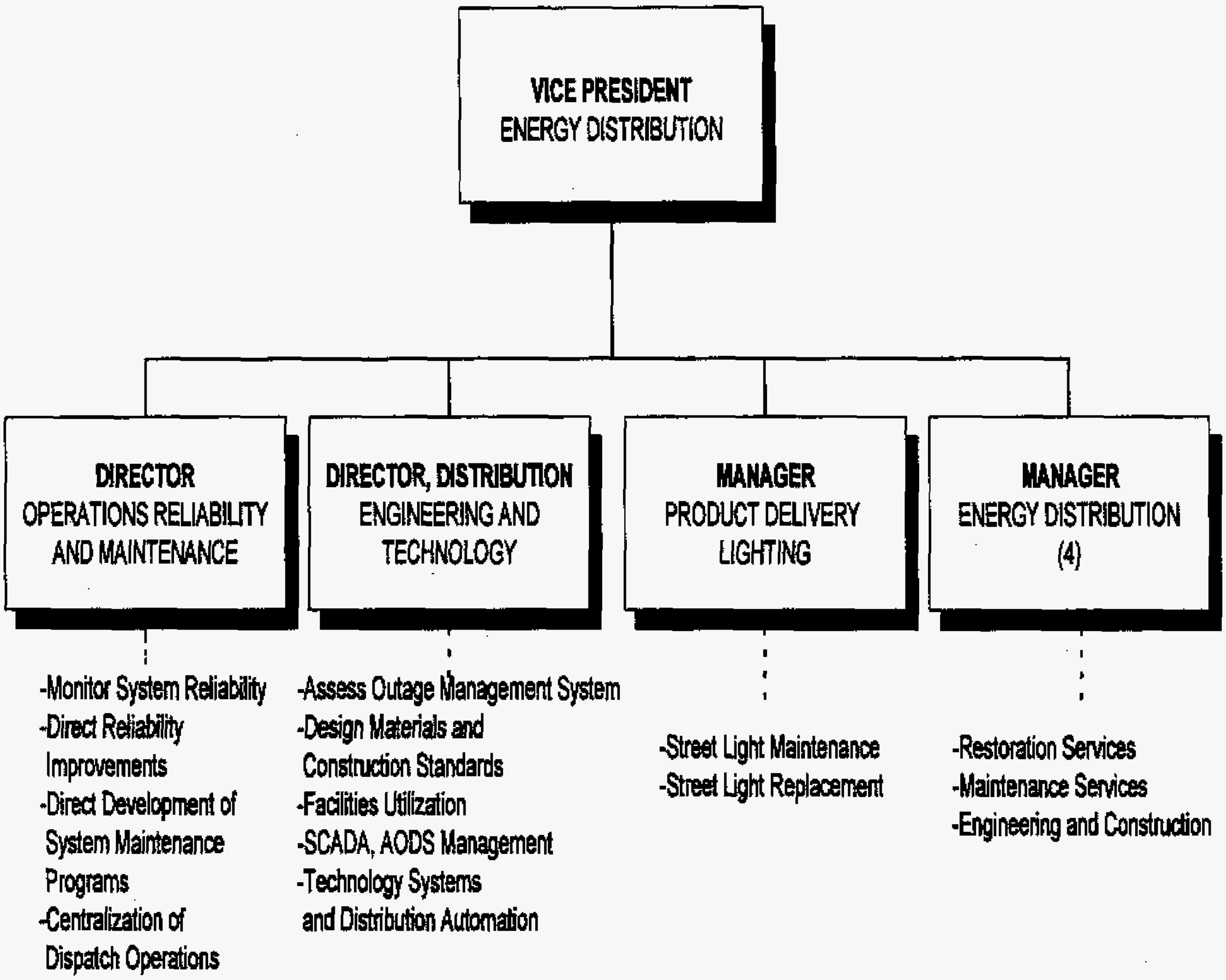


EXHIBIT FPC-13

Source: FPC Response to Document Request 3-5.

Exhibit FPC-13 displays FPC's present distribution organizational structure highlighting 2 upper-management positions directly responsible for ensuring reliability and service quality provided by the company's distribution network. As shown, the department is headed by the Vice President of Energy Distribution with two directors and five managers reporting directly to him.

The Director of Distribution Engineering and Technology is responsible for developing, designing, and implementing various information systems and standards which measure and monitor the distribution network's performance. For example, the director is currently assessing an outage management system in order to improve outage management and response times.

The Director of Operations, Reliability and Maintenance is a position created in 1997 that is specifically responsible for monitoring reliability from a corporate-wide perspective. The position will utilize and apply the company's service reliability indicators described in section 4.3.1. In monitoring system reliability, the director will be responsible for developing and directing the company's overall reliability and maintenance plans. FPC presently has two separate groups under the director's supervision, System Maintenance and System Reliability. The company anticipates developing a third group, Systems Operations, in 1998. Each group is headed by a manager as shown on Exhibit FPC-14.

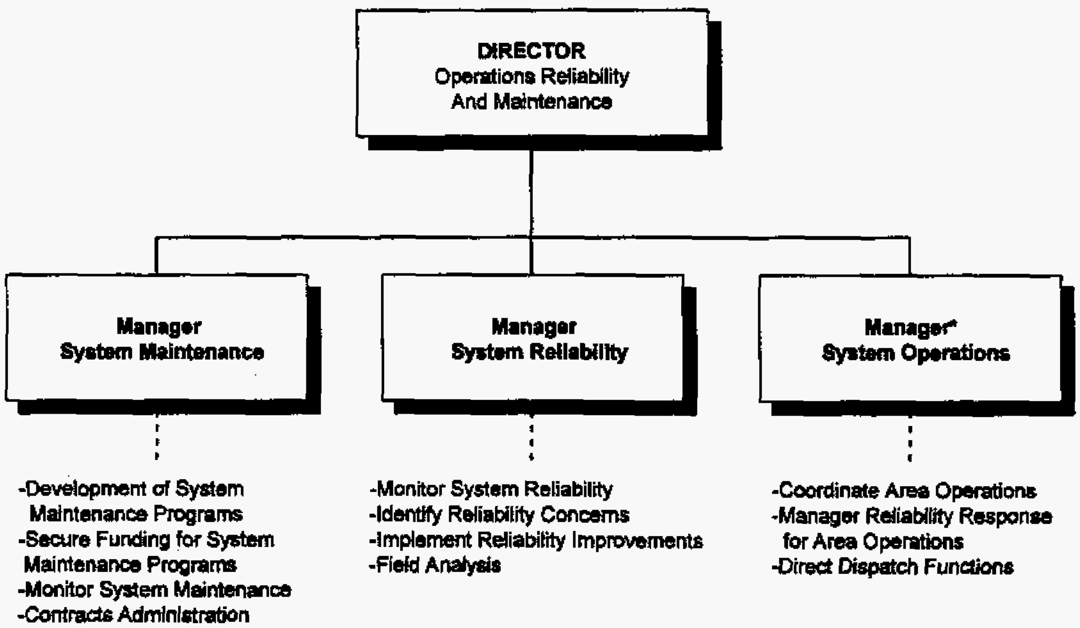
The System Maintenance group is responsible for developing, administering, and implementing system maintenance plans and programs (e.g., tree trimming, lightning protection, and line and pole inspections). The System Reliability group is primarily responsible for monitoring system operations (e.g., worst feeders, breaker operations) and providing the System Maintenance group with potential maintenance programs. System Operations will be responsible for overseeing coordination of FPC's dispatch operations and leveraging operating area resources and response times.

Of the five managers reporting directly to the Vice President of Energy Distribution, the Manager of Product Delivery-Lighting is a new position created to specifically monitor new installations and operational reliability of street lights. The remaining four Energy Distribution Managers are separated geographically and are responsible for overseeing the distribution operations for each of their respective areas, including maintenance and restoration.

With the exception of some programs that have recently been consolidated and implemented company-wide (i.e., tree-trimming, pole inspections), maintenance and restoration activities are presently identified and carried out at the company's local operating center levels. Exhibit FPC-15 is presented to highlight the key positions responsible for FPC's maintenance and restoration operations.

Another critical aspect to service reliability is preventive maintenance of substations. In the case of FPC, employees within the Bulk Power organization, under the Energy Delivery umbrella, are responsible for constructing and maintaining the company's 353 transmission and

**FLORIDA POWER CORPORATION
RELIABILITY AND MAINTENANCE
1997 ORGANIZATIONAL CHART**



**To be hired in 1998.*

EXHIBIT FPC-14

Source: FPC Response to Document Request 3-5.

FLORIDA POWER CORPORATION
ENERGY DISTRIBUTION
MAINTENANCE & RESTORATION OPERATIONS
1997 ORGANIZATIONAL CHART

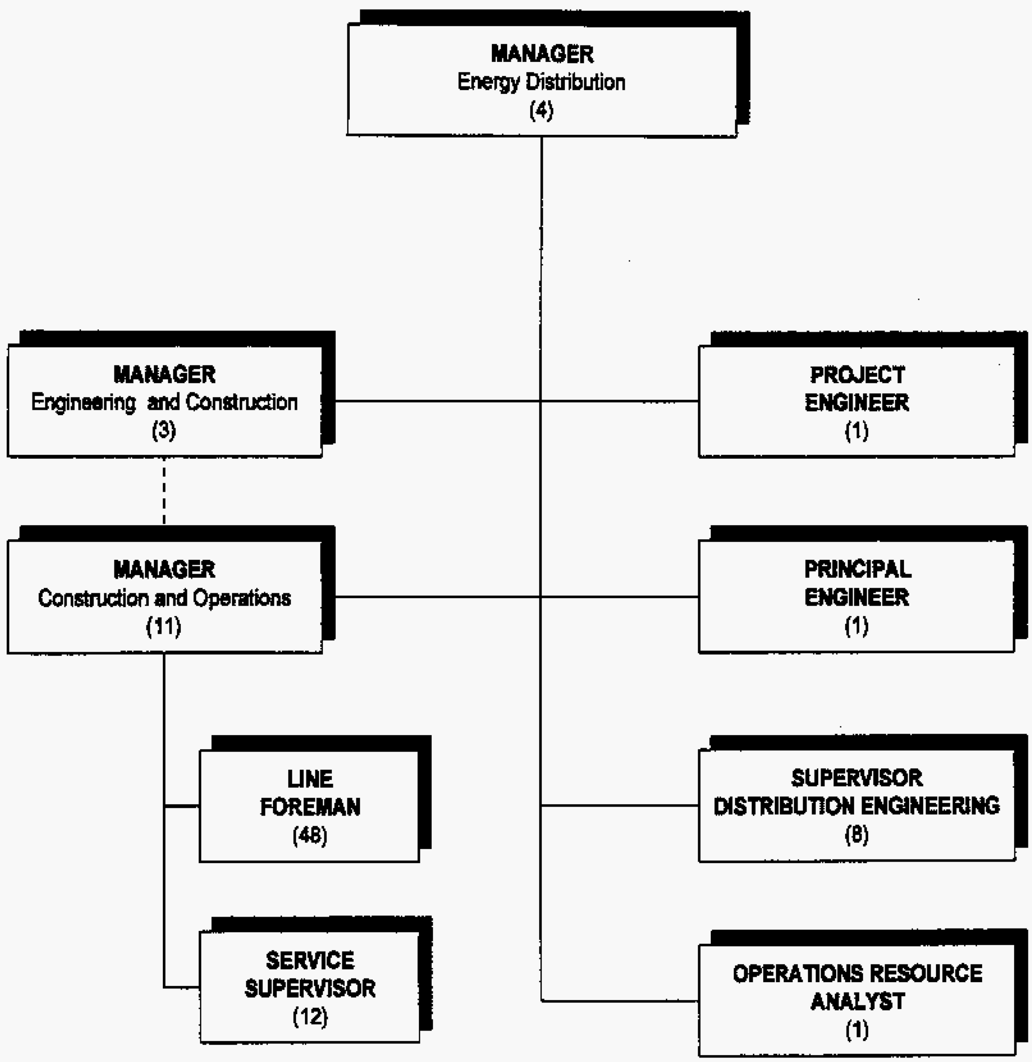


EXHIBIT FPC-15

Source: FPC Response to Document Request 3-5.

FLORIDA POWER CORPORATION
BULK POWER DELIVERY
SUBSTATION MAINTENANCE
1997 ORGANIZATIONAL CHART

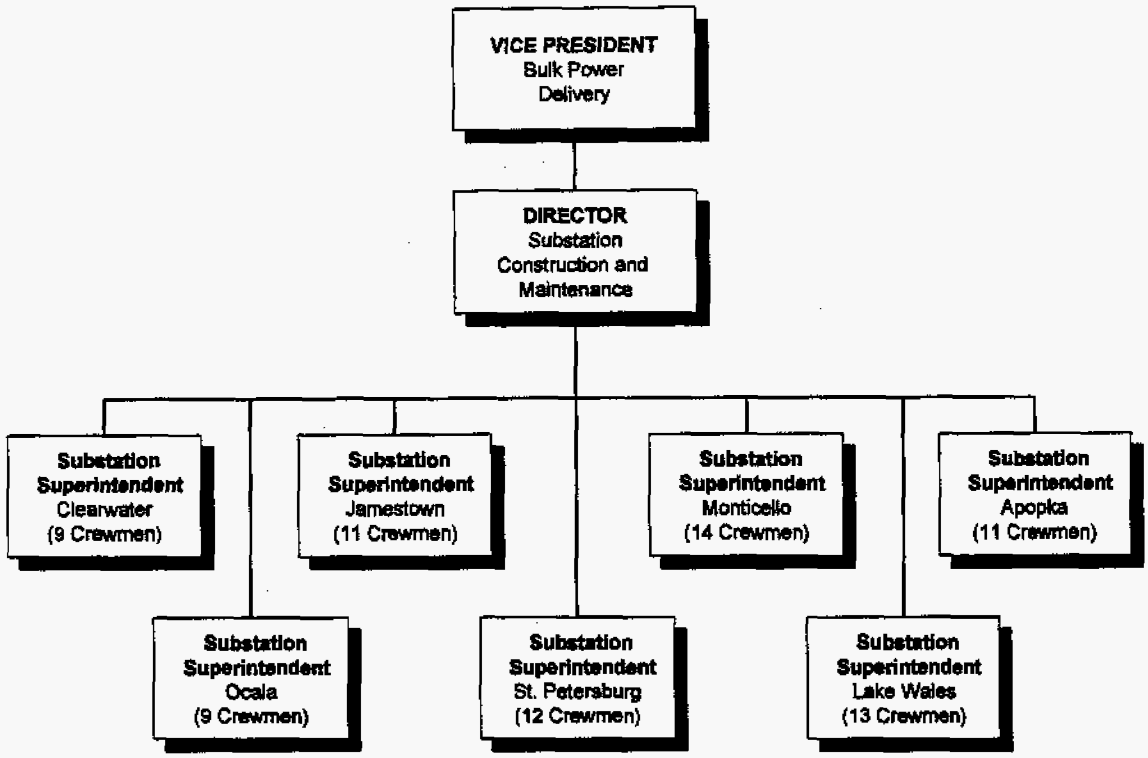


EXHIBIT FPC-16

Source: FPC Response to Document Request 2-11.

average, has a crew of ten bargaining unit employees who carry-out the daily work activities as described further in section 4.4.4. Over the period 1993 through 1997, the total number of bargaining unit employees responsible for maintenance has been reduced by eight percent from 68 to 62.

4.4.2 Maintenance Planning

As the question of electric industry restructuring remains to be answered, an important issue is the attention utilities are presently giving to preventive maintenance of their distribution facilities. In preparation for competition, utilities are tempted to reduce operations and maintenance (O&M) expenditures on their facilities in order to remain cost-competitive. However, utilities must also balance the need to maintain levels of service reliability while keeping these costs down to retain customers in an era of competition.

In FPC's case, total O&M expenses excluding fuel decreased in 1995 and 1996, while the distribution portion of total O&M expenses have remained fairly constant. Exhibit FPC-17 shows FPC's total O&M expenses with and without fuel over the period 1992 through 1996.

Exhibit FPC-18 depicts the company's distribution portion of total O&M over the same period. Distribution O&M increased five percent from $50.3 million to $53 million, at an annual average rate of 1.4 percent.

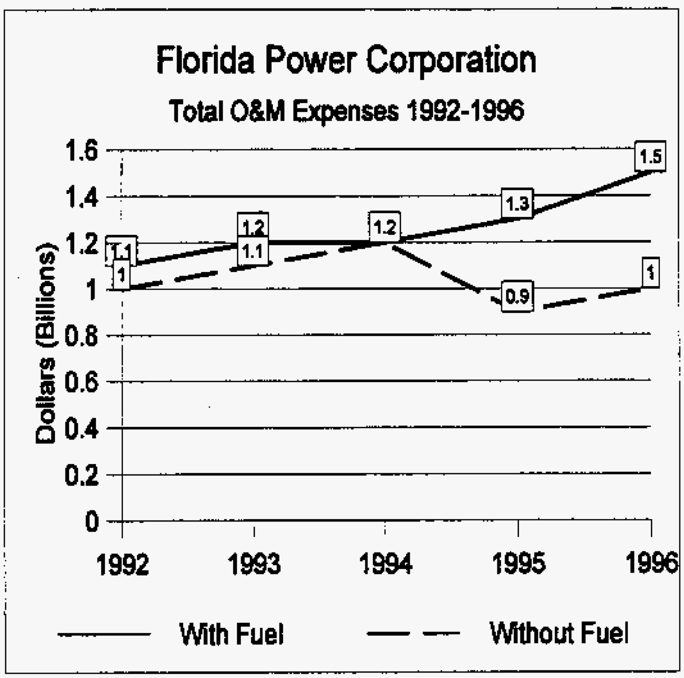


EXHIBIT FPC-17 *Source: FPC FERC Form 1 Annual Reports, 1992-1996.*

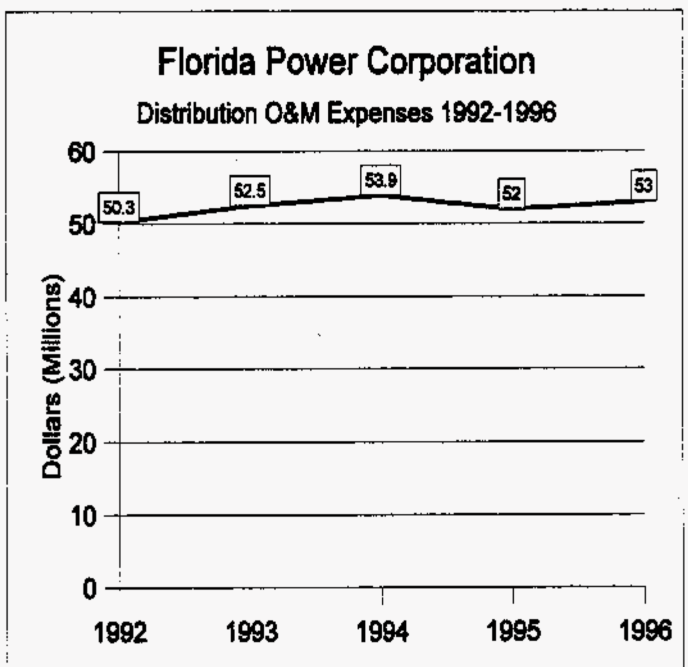


EXHIBIT FPC-18 *Source: FPC FERC Form 1 Annual Reports, 1992-1996.*

Presently, FPC does not prepare a formal annual maintenance plan for its distribution facilities. For the most part, routine maintenance activities are identified by FPC engineering, construction, and service personnel observing the need for maintenance or replacement of equipment during the course of their daily assignments. These activities are done primarily on an as needed basis and are budgeted based on historical data showing the volume and costs of work for the different types of activities identified. Funds are allocated from FPC's corporate annual O&M budget to each of the operating center levels to handle their respective maintenance activities. FPC does, however, use somewhat of a more proactive approach to planning maintenance for certain types of critical equipment (e.g., large three phase transformers, capacitor banks, and IS-1 switches). For example, capacitors are inspected twice a year by operating personnel to assure that this equipment is in service. These activities are rolled into the corporate O&M budget as well.

As part of FPC's efforts to focus on service reliability, Energy Delivery has recognized the need to prepare a formal maintenance plan that takes a programmatic approach to preventive maintenance. With the creation of the System Maintenance group under the new Director of Operations, Reliability, and Maintenance, the company will be less reactive and more proactive regarding maintaining its distribution network. This planning process may still take a period of one to two years before it is fully implemented.

In the meantime, FPC has realized that immediate benefits need to be achieved by strengthening specific maintenance activities. These activities include tree trimming, plant and equipment inspections, substation maintenance and restoration, and repair services.

4.4.3 Tree Trimming

Of the preventive maintenance programs FPC has been working to implement, the company has made tree trimming its highest priority. Tree trimming historically has been funded and controlled at each of the local operating centers, but as part of FPC's recent restructuring, tree trimming operations have been centralized under the direction of the Manager of Distribution Operations and System Maintenance. As part of FPC's reorganization, it is anticipated that FPC's tree trimming operations will fall within the responsibilities of the System Maintenance group.

Exhibit FPC-19 depicts the number of tree-related interruptions from 1992 through September, 1997. Exhibit FPC-20 depicts FPC's corresponding budgeted and actual tree trimming expenditures for the period 1992 to 1997. A comparison shows FPC's reduction in funds from $9.7 million in 1992 to $8.1 million in 1996, resulting in a 78 percent increase in tree-related interruptions over the same period. Although actual expenditures increased, it apparently was not enough to reverse the trend of increased interruptions. The company has since increased its 1997 budget to $12.2 million, an increase of $1.5 million over 1996 expenditures by year end, representing a 15 percent improvement over 1996. For the 12 months ending November 30, 1997, FPC reported 5,992 tree-related interruptions.

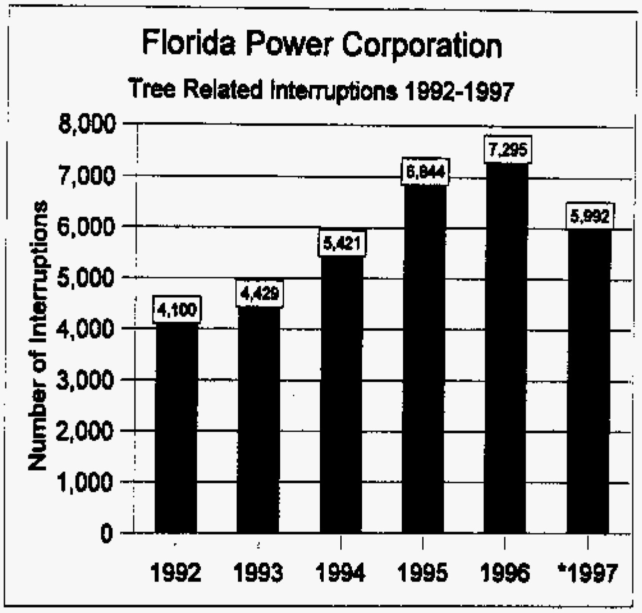


EXHIBIT FPC-19 *Source: FPSC Service Reliability Reports 1993-1997.*

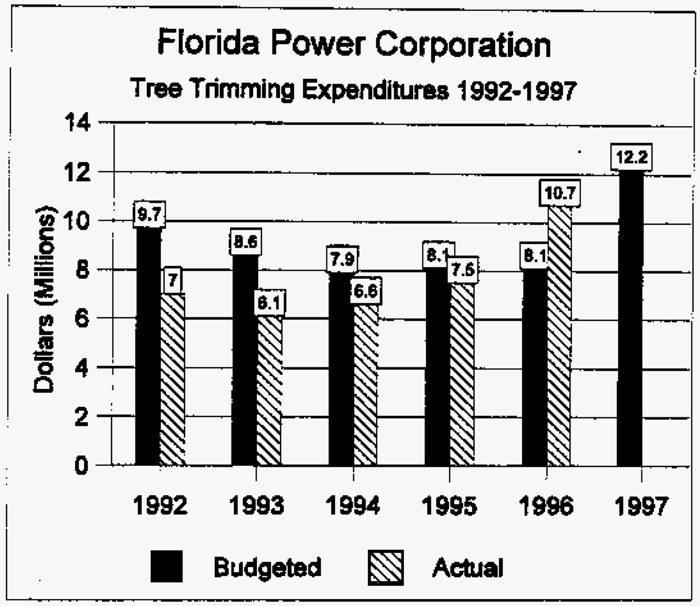


EXHIBIT FPC-20 *Source: FPC Response to Document Request 2-4.*

**12 months ending November 30, 1997.*

During 1996, a "partnership" was developed with FPC's tree trimming vendor, Farrens, in that FPC will allow the vendor a fairly wide degree of discretion in deploying its resources and preventing tree-related outages. FPC entered into a six-year contract with Farrens to perform one hundred percent of the company's tree-trimming operations. The contractor will maintain FPC's distribution lines on a three-year trim cycle.

As part of the new contract, FPC moved from time-and-material pricing to price-per-foot unit pricing. FPC will no longer be billed for hours worked and materials used, but will be billed based on the measured footage of trees cut. Tree removal is measured by walking underneath the length of the tree canopy to be cut using a measuring wheel. The price per foot varies according to whether the removal requires a bucket, climbing, or is performed from the ground.

Additionally, under the new contract, FPC will target the company's worst performing feeders first. The contract calls for systematic coverage of entire feeders (beginning to end) until trimming is complete and provides for penalties if FPC pulls maintenance crews off their normal work to handle trouble tickets or "hot-spots". Upon completion of a feeder, Farrens guarantees the work against any tree-related interruptions that occur on that feeder thereafter for three years. If the lines do not stay clear over the three year period, the contractor will go back to the feeder and trim the trees causing problems at their own expense. As of the third quarter 1997, roughly 14 months into the new contract, there have been no tree-related outages on completed circuits due to improperly trimmed trees. Per FPC's contract with the vendor, the company is committed to sustain the funding level to ensure a three-year trim cycle.

According to FPC, trees may be trimmed around service drops during the routine maintenance cycle. Typically, only those lines that pose an immediate threat to the service drop, or which may pose a threat before the next scheduled maintenance trimming cycle, should be trimmed. Customers who request limb or tree removal around service drops which do not pose a threat to the service drop should be advised that FPC will arrange to disconnect the service drop to allow a private tree trimming contractor to remove the limb or tree safely.

The quality of the contractor's tree-trimming work is monitored by the volume of trees trimmed. Based on a statistical survey, FPC determined the annual target volume of trees that needed to be trimmed (starting with the worst feeders) and set aside funds to get FPC's distribution system on a three year trim-cycle. The actual volume of trees trimmed is tracked to determine if the contractor is keeping up with the three year trim-cycle. At the end of the first year, Farrens completed exactly one-third of the cycle.

Similar to FPC's educational efforts to protect customers from storms and power outages, FPC periodically uses bill stuffers and pamphlets to educate customers on tree trimming and preventing tree-related interruptions. Examples include landscaping and pruning guides, and pamphlets answering questions how and when trees will be trimmed. In addition, FPC employs a Corporate Forester who is responsible for interacting with customers and providing presentations to city and county governments.

4.4.4 Substation Maintenance

Another vital facet of service reliability is maintenance of substations. The key to proper monitoring of substations is to embark on a program of proactive or predictive maintenance, while holding down costs and improving service reliability at the same time.

Exhibit FPC-21 reflects FPC's total substation maintenance expenditures for each of the years 1992 through March 1997. The exhibit separates total costs associated with transmission and distribution substation maintenance in accordance with FERC Accounts 570 and 592. The accounts include the cost of labor, materials used, and expenses incurred in maintaining the stations. From 1992 to 1996, total costs increased 29 percent

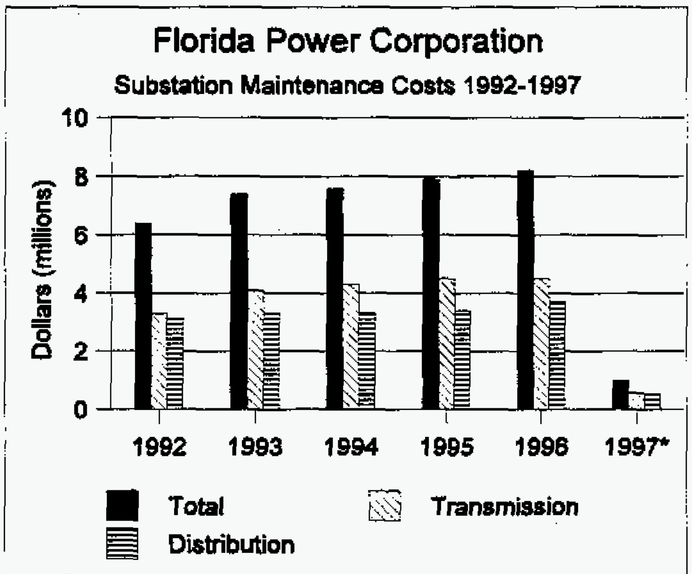


EXHIBIT FPC-21

Source: FPC Response to Document Request 3-13.

**Through March 1997.*

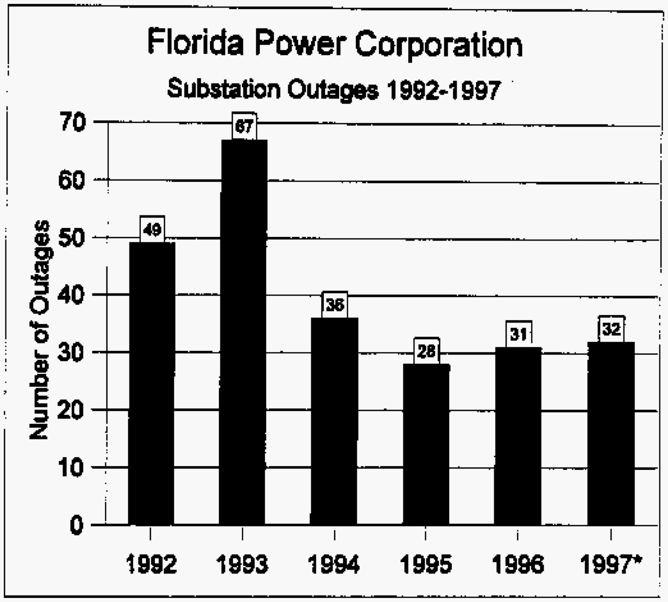


EXHIBIT FPC-22 *Source: FPC Response to Document Request 2-8.*

**Through August 31, 1997.*

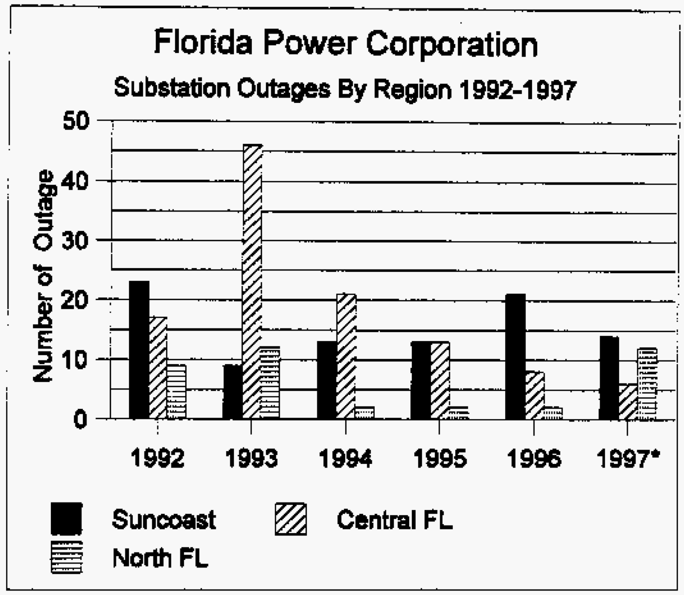


EXHIBIT FPC-23 *Source: FPC Response to Document Request 2-8.*

**Through August 31, 1997.*

from $6.4 million to $8.2 million. The increase in costs is primarily attributed to higher labor, transportation, and material costs (averaging about five percent annually). Additionally, FPC added twenty-five new substations over the five year period, which would tend to push up the cost of maintenance expenses.

Exhibit FPC-22 to reflects the number of substation outages, over the period 1992 through 1997, resulting in customer interruptions. Exhibit FPC-23 further breaks down these outages geographically by FPC's three regions. As shown on Exhibit FPC-22, the largest number of substation outages (67) occurred in 1993, with the majority (46) of outages occurring in FPC's Central Florida region (as can be seen on Exhibit FPC-23). Since 1993, the total number of outages have remained fairly consistent. The six leading causes of outages over the five year period were defective equipment, unknown, lightning, non-preventable breaker malfunctions, human error, and animals.

Maintenance of both FPC's transmission and distribution substations falls under the responsibility of the company's Bulk Power organization, as previously mentioned. According to FPC's Substation Inspection procedures, all of FPC 353 substations are inspected each month, which includes examination of transformers, circuit breakers, regulators, power fuses, insulators and switches, oil and gas leaks and perimeter security. The monthly inspection data is fed into

FPC's Substation Maintenance Management Information System (SMMIS) which tracks equipment installed, date installed, location, and next scheduled maintenance.

4.4.5 Plant/Equipment Inspection

Additional preventive maintenance programs have been accelerated as a result of FPC's restructuring and focus on improving service reliability. The company's efforts in these areas are discussed separately below.

- Pole Maintenance
- Lightning Protection
- Underground Cable
- Line Inspection

Pole Maintenance

In 1996, FPC launched a pole maintenance program which involves re-inspection on the company's older poles (both penta and creosote treated). FPC spent over $7.3 million on the inspection and repair or replacement of facilities since starting this program. The inspection is carried out by Osmose, an FPC contractor. Osmose is currently inspecting and treating poles in need of preservative injections and is also bracing the poles, when necessary, to extend their life. Poles in need of replacement are handled by FPC. Targeted completion of the program is mid 1999. FPC is currently replacing about 6,000 poles per year, which amounts to about 10 to 12 percent of the total poles inspected.

Lightning Protection

In 1996, in an effort to combat lightning-related outages, FPC committed to increasing transformer protection. Direct lightning damage to transformers costs FPC around $3 million a year. FPC began installing "under oil arresters" (arrester is located inside transformer) rather than using pole lightning arresters for new and replacement installations. Additionally, FPC's underground transformers normally are not protected with arresters except at the end of the underground feeds. As of October 1996, all installations of new padmount transformers were equipped with under oil arresters, significantly improving underground protection.

Approximately 8,000 of the new pole transformers and 3,500 new padmount transformers were installed. After one year, less than 10 of the new units needed repairs as a result of failed arresters. It should be noted that under oil arresters can not be applied in all applications. They can only be used in a single-phase or three-phase Y-Y transformer connections, which accounts for 85% of installations.

Underground Cable

Also in 1996, FPC performed an extensive review of its underground cable replacement procedures. The review examined the cost effectiveness of underground cable as well as the key drivers of cable failures. Results of the review determined that it would be more feasible to evaluate alternative methods of restoring as opposed to replacing cable. FPC estimated that restoration of underground cable would be about half the cost of replacement. As a result, FPC instituted two cable restoration pilot programs. The first, "cable injection" is refurbishment of cable that is presently in service and involves displacing gases or moisture in the cable with a non-conductive silicone-based substance. The second program calls for increased surge (lightning) protection. The protection would be provided on the new padmount installations which come with "super" surge protection built internal to the transformer with the under oil arresters. FPC estimated total costs of both programs to be approximately $350,000.

Line Inspection

In early 1997 FPC launched a detailed line inspection of its poorly performing feeders, beginning with the feeders serviced by the company's Jamestown and Apopka operating centers. The approach is a proactive effort taken by FPC to reduce CMI/C and the number of interruptions. The inspection is being performed, for the most part, by one unit of 10 to 12 linemen taking about three weeks to complete a typical feeder. FPC estimated costs per feeder to be $40,000 to $50,000. The inspections include a detailed pole-by-pole patrol and top-of-the-pole visual examination of all facilities, correcting any problems found.

As of June 1997, FPC's Apopka Center completed the refurbishing of ten feeders and the Jamestown Operating Center finished 20. Comparing the first six months of 1997 to the first six months of 1996, Apopka noticed a 72 percent decrease in CMI and Jamestown noticed a 43 percent decrease in CMI for the targeted feeders.

Examples of repairs to date on the completed feeders include poles replaced, transformer change-outs, squirrel guards installed, 600 amp switches replaced, lightning arresters added or changed-out, insulators changed-out, reclosers installed, cross arms replaced, and ground rods set. It is FPC's intention to "roll-up" the line inspection program into the System Maintenance group's responsibilities under the Director of Operations, Reliability & Maintenance. The work order system used by FPC does not routinely provide data regarding the miles of wire and number of distribution system components replaced.

4.4.6 Restoration and Repair

As previously mentioned, FPC's restoration and repair services are carried out at each of the operating levels. In 1994, FPC consolidated its area operations, which primarily consisted of moving construction and maintenance crews from one locale to another. Company-wide, FPC reduced the number of its operating centers from 36 to 25. However, in nearly all cases the troublemen who provide first response on interruptions were not relocated. The greatest impact occurred in FPC's North Region, where the centers were reduced from 18 to 11-- particularly the centers surrounding FPC's Ocala and Crystal River areas (from 10 centers to three). Operating centers in FPC's Central Region were reduced from 13 to nine. None of the five centers in the Suncoast Region were consolidated. It should be noted that FPC is currently reassessing its consolidation of its operating centers and the impact on reliability--primarily focusing on its Northern Region.

Along with consolidation of its operating centers in 1994, FPC consolidated and reduced staffing associated with each of the centers. The hardest-hit personnel category was middle-management. According to FPC, management was downsized by 23 percent. The total number of bargaining unit employees, (i.e., meter readers, reconnect & disconnect fleet services, substation crews, line servicemen and troublemen) was reduced from 1,140 in 1993 to 1,044 in 1995 (8.4 percent). Line servicemen and troublemen alone were reduced by 69 employees which represented a six percent reduction.

Exhibit FPC-24 shows staffing levels of FPC's bargaining unit employees, sorted by regions, over the period 1993 through September 1997. The 8.4 percent reduction is reflected when comparing the first quarter 1993 totals to the first quarter 1995 totals. Over the five year period shown, FPC reduced its bargaining unit workforce by 3.7 percent, from 1,140 employees to 1,097. The largest cutback over this period occurred in FPC's North Region, from 205 employees to 187 (8.8 percent).

Florida Power Corporation
Bargaining Unit Staffing Levels
1993-1997

Region	1st Qtr 1993	1st Qtr 1994	1st Qtr 1995	1st Qtr 1996	Sept. 1997	Percent Change 1993-1994	Percent Change 1994-1995	Percent Change 1995-1996	Percent Change 1996-1997	Percent Change 1993-1997
Suncoast	374	369	347	361	372	-1.3%	-6.0%	4.0%	3.1%	-.53%
North Florida	205	195	180	177	187	-4.9%	-7.7%	-1.7%	5.7%	-8.8%
Central Florida	561	538	517	526	538	-4.1%	-3.9%	1.7%	2.3%	-4.10%
Total	1140	1102	1044	1064	1097	-3.3%	-5.3%	1.9%	3.1%	-3.7%

EXHIBIT FPC-24 *Source: FPC Response to Document Request 2-6.*

The trend in FPC's distribution vehicles supporting these field forces, is reflected in Exhibit FPC-25. The data shown includes service (e.g., bucket and construction) trucks and vehicles used by line crews, foremen, meter readers and reconnect and disconnect personnel. From 1992 through 1997, the total number of vehicles was reduced ten percent, from 908 to 817. The largest reduction (6.5 percent) occurred over the period 1994 to 1995, which parallels the years FPC downsized its workforces and consolidated its operating centers. Exhibit FPC-25 also separates the total vehicles into each of FPC's three geographic regions. Over the six year period shown, total vehicles for FPC's Central, Suncoast and North regions were reduced 11 percent, ten percent and eight percent, respectively.

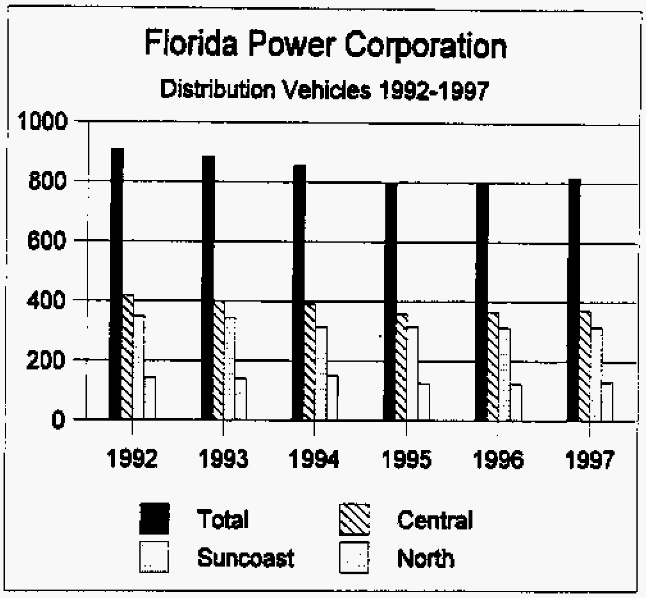


EXHIBIT FPC-25 *Source: FPC Response to Document Request 4-1.*

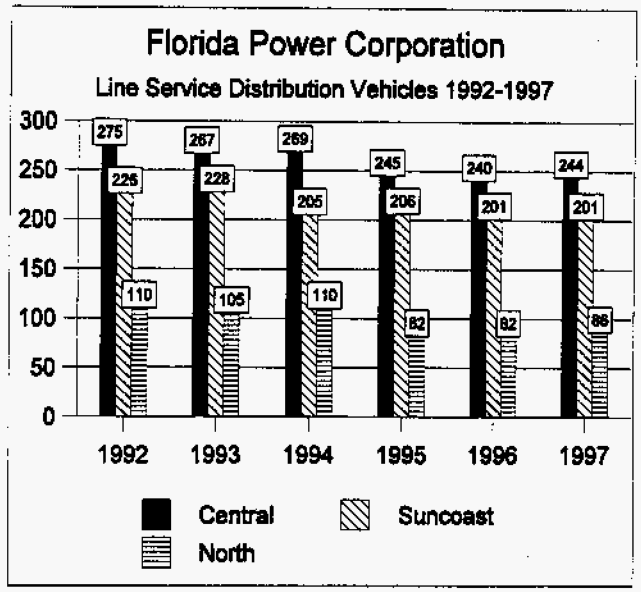


EXHIBIT FPC-26 *Source: FPC Response to Document Request 4-1.*

Exhibit FPC-26 breaks down Exhibit FPC-25 further by presenting the trend in FPC's line service vehicles, separated by region. From 1992 to 1997, total line service vehicles for FPC's Central, and Suncoast regions were reduced 11 percent. Line vehicles in FPC's North Region were cutback by 22 percent, from 110 to 86. This was largely due to a 30 percent reduction in FPC's Ocala operating center, from 75 to 53 over the same period. According to FPC, included in the 75 vehicle count were 12 "miscellaneous other trucks" (e.g., support vehicles, flat-bed trucks, stake body trucks, and cranes). By 1995, the number of these was down to zero. This was due to the transfer of accountability for Transmission Maintenance from Distribution to Transmission Construction. These vehicles were transferred to another department along with the work resources and did not constitute a true reduction.

With concern for declining levels of service, in early 1996, FPC created a "virtual" call center by consolidating its call answering functions from four regional locations into two fully linked call centers. Improvements were made to the telephone network which included a new 800 number and increased lines for all of FPC's northern area customers. According to FPC, these improvements allowed more customers to report outages sooner, therefore increasing the average duration of outages reported. The new network provides for emergency backup and rerouting of calls should a primary line fail. Additionally, FPC implemented several new technologies in the call centers including the Voice Response Unit capabilities mentioned in section 4.3.2. The Voice Response Unit provides automated services, including reporting of outages.

FPC's service restoration process is highlighted in Exhibit FPC-27. The process begins when a customer reports an outage to a customer service representative or by way of the Voice

FLORIDA POWER CORPORATION
OUTAGE HANDLING PROCESS
1997

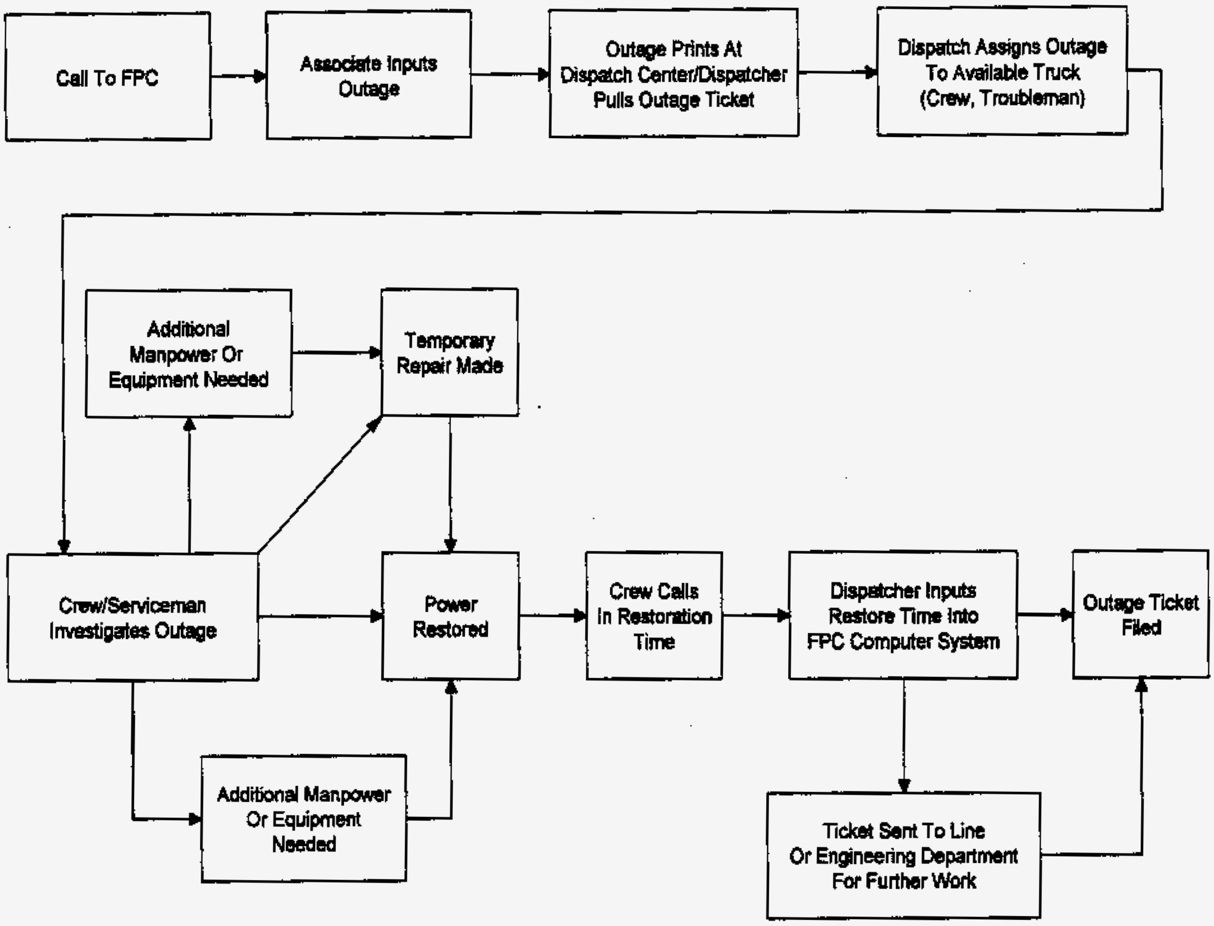


EXHIBIT FPC-27

Source: FPC Response to Document Request 1-16.

Response Unit. Upon receipt of an outage call, a trouble ticket is automatically printed at one of FPC's six dispatch centers closest to the outage. A dispatch operator assigns the trouble ticket to an available troubleman within close proximity of the call. The process in FPC's Northern Region is slightly different in that a contracted firm monitors the Voice Response Unit outage calls and faxes the trouble tickets to the call center closest to the outage.

FPC's policy requires troublemen to live within 40 minutes of the operating center where they are based. Additionally, troublemen are authorized to bring home company trucks to allow for quicker response times. The first line of defense in the majority of FPC's outage calls are the company's troublemen. During off-shift hours and weekends the company can dispatch off-duty troublemen and service crews from their home to assist in the restoration process.

4.5 Recent Trends and Changes

As previously mentioned, the company's operations were divided into three geographical regions (Suncoast, Central Florida and North Florida). Each region was headed by a Vice President who had numerous responsibilities including overseeing customer services, system planning and transmission and distribution operations. In 1996, FPC recognized that each regional Vice President, because of their vast area of responsibilities, could not specifically focus on targeted segments of the utility's business. As a result, FPC saw the need to realign its operations into the three strategic business units previously identified in section 4.1. The business units are intended to integrate work processes and reduce the tendency of having three separate regions operating as stand alone organizations.

Under the Energy Delivery business unit, the new Vice President of Energy Distribution has directed his staff to implement specific programs which focus primarily on service reliability. These programs include plans to reduce outage duration, improve the company's worst performing circuits, and maximize the effectiveness of the company's tree trimming program. Specific examples of recent actions taken by FPC to improve reliability are presented in Exhibit FPC-28. Although these actions were relatively quickly identified and implemented, FPC expects some lag effect in achieving the desired service reliability measurements.

4.6 Conclusions

FPC's distribution reliability and service quality, measured by both FPSC and company indicators, declined notably over study period 1992 through 1996, and has shown some improvement in 1997. Beginning in 1996, FPC began to take extensive actions to reverse this decline. These actions have included management changes, restructuring in the company's Energy Delivery Business Unit, identification and assessment of weaknesses, and actions to improve reliability. To ensure that improvement in distribution service quality is made, a follow-up review based on 1998 results will be necessary.

Although FPC's system indices (SAIDI, CAIDI, SAIFI) for 1997 have improved over 1996 results, recent activities implemented by FPC may lead to further improved reliability in future years. For example, FPC reported a 72 and 43 percent decrease in CMI/C for line inspection activities surrounding the Jamestown and Apopka areas. Additionally the company has not experienced any tree-related outages on completed circuits due to improperly trimmed trees since August 1996. As these programs and other initiatives are put in place company-wide, FPC's system indices may begin to show signs of improvement. Also, with the creation of the Director of Operations, Reliability and Maintenance position, the company will be less reactive and more proactive regarding maintaining its distribution network.

Florida Power Corporation 1996-1997 Planned Actions Taken To Improve Reliability
■ Improved the response availability of line department personnel by setting and enforcing higher call out expectations.
■ Assured the maximum number of employees are available during the storm season by scheduling line crews on five eight-hour days rather than four ten-hour days, and scheduling the latest hours practical within the contractual guidelines.
■ Delegated the decision to call for additional resources from other regions or work centers to the construction and operation managers and first line supervisors.
■ Reemphasized the practice of calling operations engineers at the onset of storms to assist in restoration activity.
■ Began to utilize available personnel for material hauling during storm situations (i.e., substation, meter readers, R&D, stores).
■ Initiated management meetings with all supervisors and employees to emphasize the need for efficient and timely restoration of outages.
■ Assured the timely repair of underground residential distribution primary cables to prevent extended outages arising from loop feeds left on a radial feed.
■ Added contract resources to the existing workforce during storm months.
■ Patrolled and repaired 50 of the worst performing circuits system wide.
■ Implementing a system-wide program to patrol all feeders not planned to be trimmed until 1998 and 1999, and clear identified problems likely to cause large outages.
■ Adding two Senior Engineering Representatives to monitor, investigate and correct reliability problems.
■ Replacing lightly loaded three phase reclosures with hydraulic single phase units.
■ Replacing heavily loaded three phase reclosures with electronically controlled single phase units.
■ Adding shift supervisors in dispatch centers to assure appropriate management of restoration activities, performance of personnel, and reduction of long duration outages.
■ Adding fault indication on selected circuits to speed restoration efforts.
■ Piloting an automated detection system-wide called Outage Sentry.

EXHIBIT FPC-28 *Source: FPC Response to Document Request 2-12.*

5.0 Gulf Power Company

5.1 Company Profile

Gulf Power Company (GPC) is a wholly-owned subsidiary of the Southern Company, headquartered in Atlanta, Georgia. The Southern Company is a diversified holding company, acting as parent of GPC and four other regional operating electric utilities, located in the Southeastern United States. Headquartered in Pensacola, GPC is the fourth largest investor owned electric utility in Florida. GPC serves approximately 330,500 customers in a ten county 7,400 square mile operating territory, located in the panhandle of Northwest Florida, with an employee base of 1,384.

The GPC customer base is the smallest of the four major investor-owned electric utilities in Florida. Unlike many other electric utilities, GPC's customer base consists mainly of residential and small commercial customers located in small towns and communities, from Panama City in the East to Pensacola in the West. GPC's customer base has grown by 9.6 percent during the period 1992-1996, averaging 2.4 percent annually. The customer base consists of 87 percent residential customers and 13 percent of commercial/industrial customers.

GPC's 287,752 customer residential sector is both the largest consumer of power and the largest revenue producer. In 1996, this sector represented 47 percent of all GPC power consumption and 54 percent of its annual sales. The 42,380 customer commercial sector represents GPC's second largest sector in size, consumption, and annual revenues. In 1996, the commercial sector represented 32 percent of GPC power consumption and 31 percent of its sales revenues.

5.2 FPSC Service Quality Indicators

Two mechanisms currently used by FPSC staff to monitor electric utility service quality are FPSC customer inquiries received and annual FPSC Distribution Service Reliability Reports submitted by each company. Customer inquiries are researched and investigated to determine whether the company has violated a FPSC rule, approved tariff, or a company policy. The number and type of repeat offenses by a company indicate where serious problems may exist.

Annual Distribution Service Reliability Reports provide information regarding the number and type of interruptions experienced annually by utility customers. This information profiles the causes of interruptions, which can be used to develop strategies for reducing specific types of interruptions and to reduce the number and length of interruptions. In addition, utilities are required to identify the three percent poorest performing feeders with the highest number of interruptions. These two monitoring mechanisms provide FPSC staff with useful trend information for identifying continuing electric service quality and reliability problem areas.

5.2.1 FPSC Customer Inquiries and Complaints

Commission records for the period 1992-1997 indicate that a total of 242 inquiries were filed against the company. Of the 242 inquiries received, 112 (46%) were service-related complaints and 130 (54%) were billing-related. During this period, GPC averaged 48 Commission inquiries annually from GPC customers.

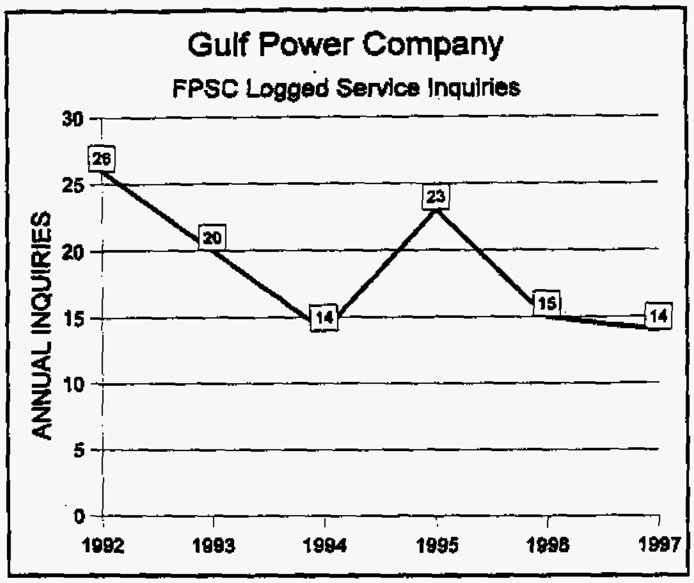


EXHIBIT GPC-1 *Source: FPSC Consumer Activity Reports 1992 - September 1997.*

Service-related Commission inquiries address customer difficulties with service reliability and quality. Exhibit GPC-1 graphically shows the number of service-related Commission inquiries logged annually by GPC customers during the period January 1992 through September 1997. As shown, GPC service-related Commission inquiries dropped sharply from 1992 to 1994, rose in 1995, dropped again in 1996, and remained at about the same level in 1997.

Since 1996, GPC customers have made 68 total inquiries, of which 29 (43%) were service-related and 39 (57%) were billing-related. Of the service-related inquiries logged, none were found to have violated a company tariff, policy, or Commission rule, which would classify the complaint as an infraction. As of September 1997, GPC service-related inquiries are equal to the lowest level for the period of 1992-1997. GPC has had no service-related infractions since 1995, when 21 company infractions were related to service.

5.2.2 FPSC Distribution Service Reliability Report

Reliability reports submitted by GPC include interruption categories different from those set forth in Commission rules. GPC reports twelve categories including: tree, wind, lightning, vehicle, animal, deterioration, contamination, overload, loose connection, vandalism, dig-ins, and other. These categories differ from FPSC rule requirements in reporting the categories of wind, deterioration, contamination, overload, loose connection, and vandalism. Exhibit GPC-2 shows the number and type of outages reported by GPC during the period 1992 through August 1997. The number of reported GPC interruptions ranged between a high of 9,130 outages in 1992 to a low of 6,413 outages in 1996. Based on the 4,668 outages reported through August 1997, GPC annualized outages for 1997 will total 7,002. The 589 outage increase is 9.2% over 1996, but 2,128 outages (23.3%) lower than the 1992 level.

Gulf Power Company
Total Interruptions by Category 1992-1997

CAUSE	1992		1993		1994		1995		1996		1997*	
	Total	%	Total	%	Total	%	Total	%	Total	%	Total	%
Animal	3,092	34	3,223	38	2,874	39	1,685	29	2,091	33	1,617	35
Contamination	169	2	134	2	134	2	104	2	116	2	52	1
Deterioration	1,112	12	896	11	789	10	718	12	687	11	385	8
Dig-In	91	1	137	2	123	2	72	1	81	1	26	1
Lightning	1,386	15	1,493	18	1,063	14	1,170	20	1,211	19	1,316	28
Loose Connection	101	1	66	0	85	1	74	1	56	1	21	1
Overload	129	1	146	2	111	2	137	2	213	3	79	2
Tree	1,166	13	822	10	825	11	789	13	654	10	300	6
Vandalism	11	0	11	0	5	0	4	0	9	0	4	0
Vehicle	256	3	189	2	189	3	184	3	146	2	153	3
Wind	196	2	205	2	155	2	146	3	167	3	66	1
Other	1,421	16	1,109	13	996	14	815	14	982	15	649	14
Total	**9,130**	**100%**	**8,431**	**100%**	**7,349**	**100%**	**5,898**	**100%**	**6,413**	**100%**	**4,668**	**100%**

EXHIBIT GPC-2

Source: FPSC Reliability Reports 1992-1997.

** Data through August 1997*

Exhibit GPC-3 shows the GPC annual average outage length (L-Bar) for all interruptions, during the period 1992-1996. The L-Bar measurement computes the average number of minutes for the total of all outages reported during the year. The GPC L-Bar average ranged from 74.3 minutes in 1992 to 65.6 minutes in 1996. As shown by the exhibit, the highest L-Bar level was experienced in 1995, during a year in which GPC experienced two named storms.

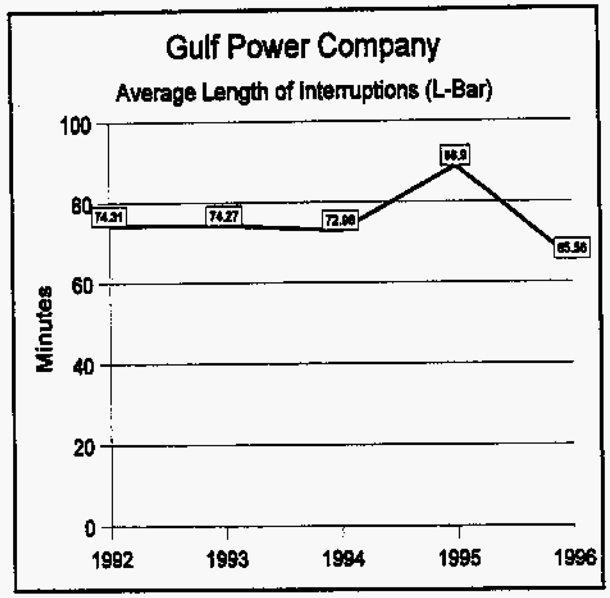


EXHIBIT GPC-3 *Source: GPC Reliability Reports 1992-1996.*

Exhibit GPC-4 shows the most frequent interruption causes from GPC Reliability reports, for the period 1992 through August 1997. Reliability reports indicate that the greatest number of interruptions is caused by animals. The number of animal-caused outages dropped in 1994 and 1995, but began upward again in 1996. However, 1996 animal-caused interruptions were still well below the 1992-1994 levels. Through August 1997, animal-caused outages had dropped again and were lower than the 1995 level. However, annualized 1997 animal outages could reach 2,425 outages, which would be the largest number of animal outages since 1994.

Lightning-caused interruptions were the second largest category of outages, but were considerably lower than animal outages. Lightning interruptions hit their lowest level in 1994 and increased slowly upward in 1995 and 1996. Based on the 1,316 lightning outages experienced through August 1997, annualized lightning caused outages for 1997 could reach 1,974 outages. This would represent the largest number of outages during the period 1992-1997 and would be an increase of 658 outages (54%) over the 1996 level.

Other category interruptions were third largest in number. This category dropped considerably in 1992-1995 and rose slightly in 1996. Tree-related interruptions which were the fourth largest cause of outages for the period and continued to drop from 1992-1996. Deterioration was the fifth largest cause category and was similar to tree interruptions in both the level of outages and the decrease in interruptions from 1992-1996. Vehicle and wind interruptions were the smallest cause categories and remained very small in number throughout the period 1992-1996.

5.3 Company Service Quality Indicators

While the FPSC uses customer complaints and reliability reports to monitor company service quality and reliability, the utilities have their own methods of monitoring performance in

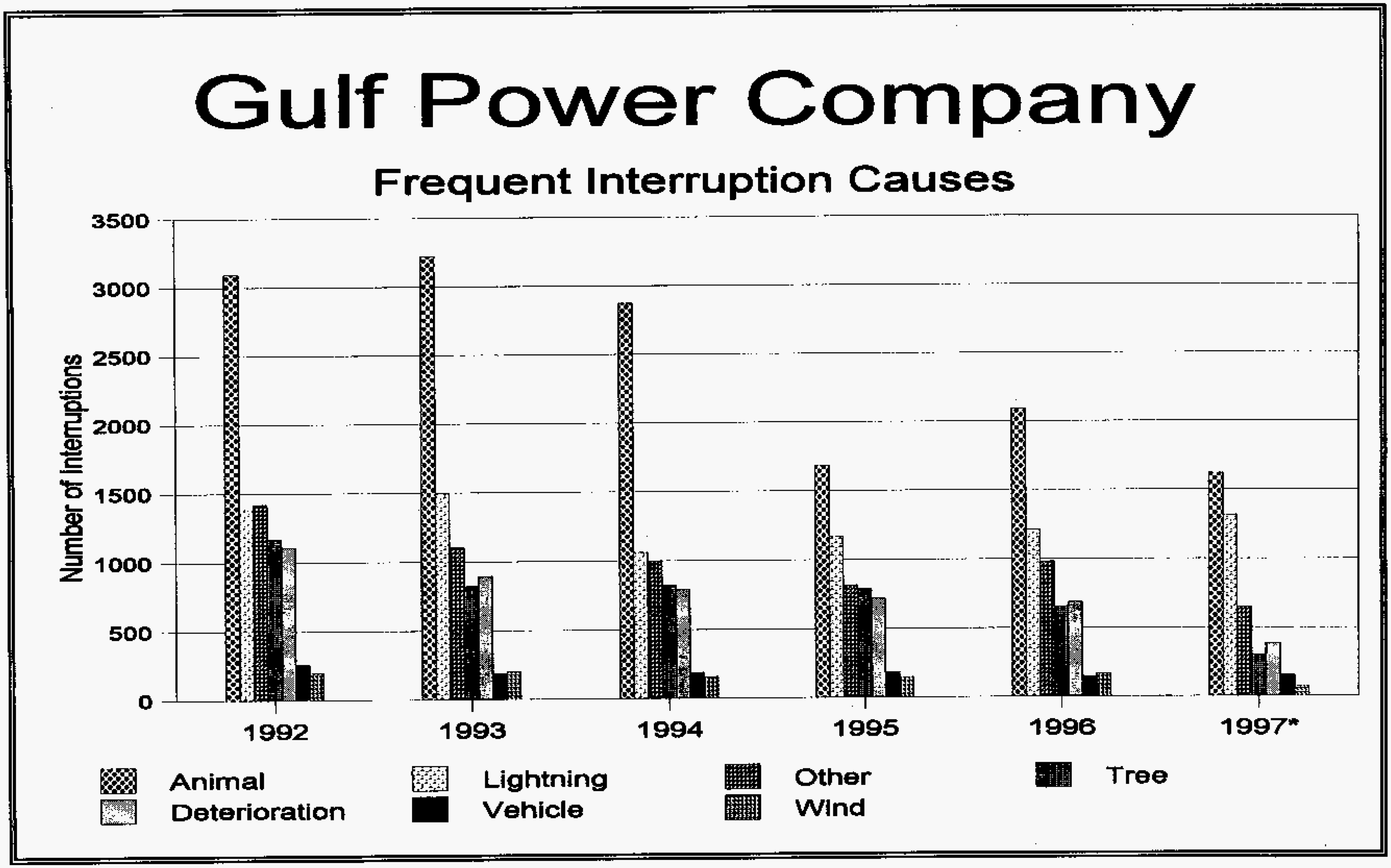


EXHIBIT GPC-4

Source: FPSC Reliability Reports 1992-1996, GPC Response to Document Request 4-1E.

**Through August 1997.*

these two areas. Internal indices and measurements help the utility identify areas where service reliability and quality defects exist. Trending these indices shows performance over time, which resulted from company efforts to improve service quality and reliability.

GPC representatives state that management also emphasizes company performance in four target categories, through employee incentive bonuses. Based on overall company performance in return on equity (ROE), FPSC complaint levels, customer satisfaction survey results, and the six year Customer Minutes of Interruption (CMI), GPC management makes available annual performance bonuses to its employees.

5.3.1 Internal Reliability Indicators

GPC uses a series of ten measurement indices, captured in the Distribution Trouble Report, to track company performance. These indices are reported for the current month, current period (12 months), previous period (previous 12 months), and for a six year average period (6 year annual). Indices are reported separately for both overhead and underground outages. The ten indices reported by the Distribution Trouble Report are:

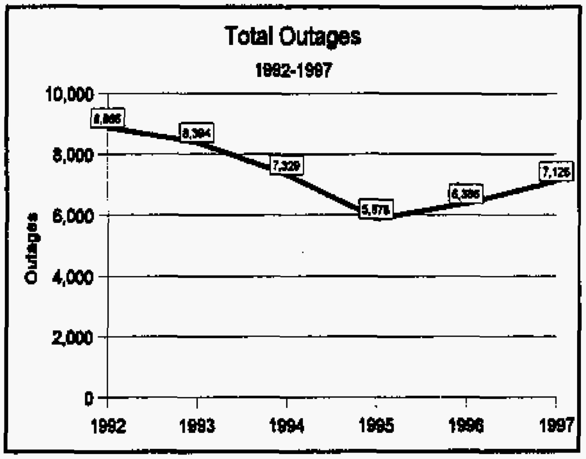
- Total Outages
- Outages Per 100 Miles
- Number of Customers Interrupted
- Percent of Customers Interrupted Monthly
- Total Interruption Time (minutes)
- Reliability Index
- Tree Outages Per 100 Miles
- Dig-in Outages Per 100 Miles
- Average Interruption Time (minutes) Per Customer Interrupted (CAIDI)
- Average Interruption Time (minutes) Per Customer Served (SAIDI)

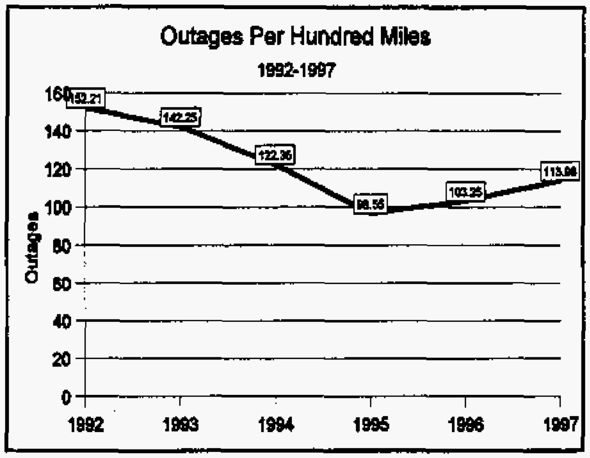
GPC excludes certain information from its measurements to reduce the effects of planned maintenance and certain catastrophic events. Named storms, tornadoes, planned outages, dropped feeders by supervisory control due to emergency conditions, and interruptions less than one minute in duration are excluded from GPC Distribution Trouble Report results.

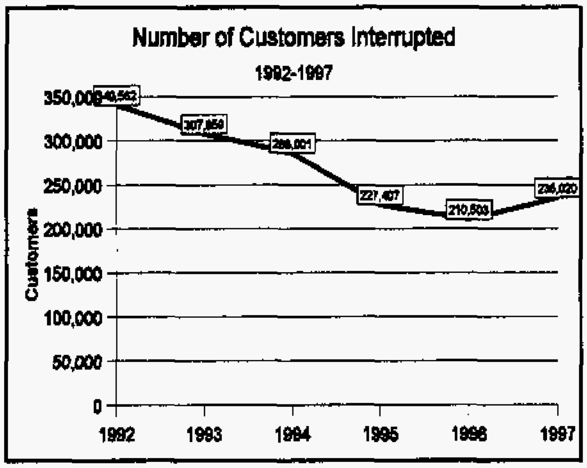
According to GPC representatives, performance measurements for the last ten years have focused on reducing outages through improving the ten Distribution Trouble Report indices. Exhibit GPC-5 shows annual measurements for six of these indices during the period January 1992 through September 1997. As shown by the exhibit, GPC indices have trended downward for the period, except for slight increases in 1997. In all cases, measurement levels were improved over those experienced prior to 1993.

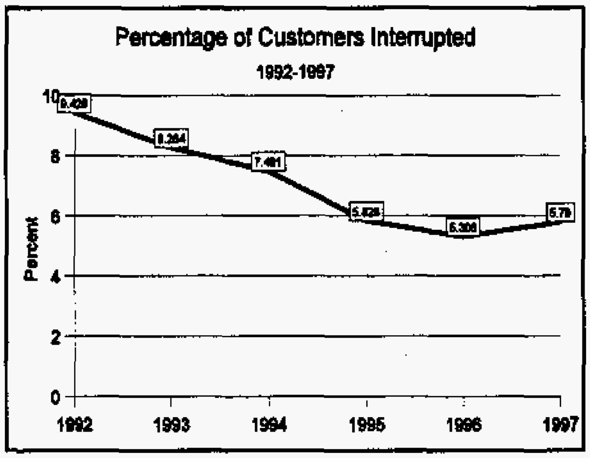
The GPC Average Interruption Time Per Customer Interrupted, also known as the Customer Average Interruption Duration Index (CAIDI), trended upward from the 1994 level,

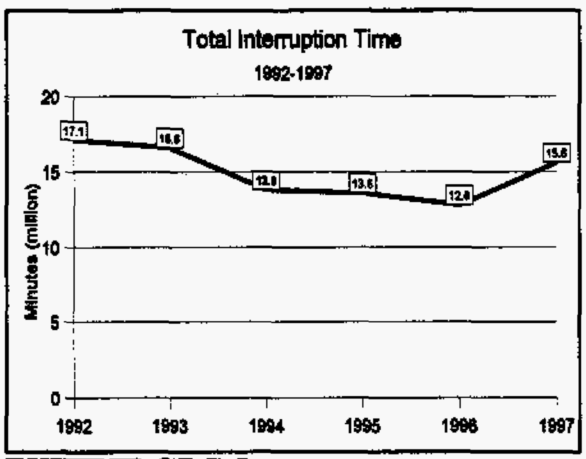
GULF POWER COMPANY
Distribution Trouble Report Measurements
1992 - September 1997











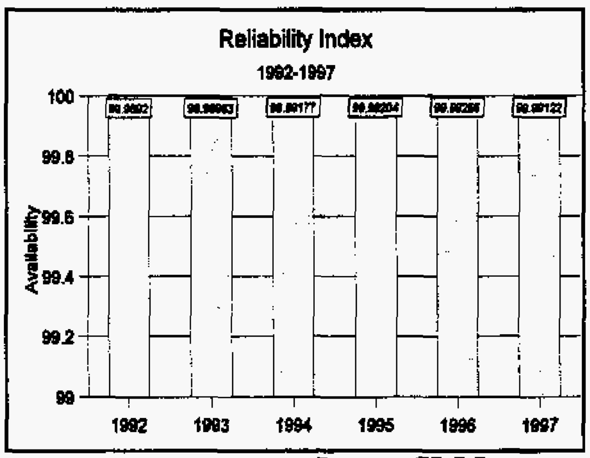


EXHIBIT GPC-5

Source: GPC Responses to Document Requests 1-7 and 3-9.

through September 1997. As shown in Exhibit GPC-6, the CAIDI index rose from 48.1 in 1994 to 66.3 in September 1997.

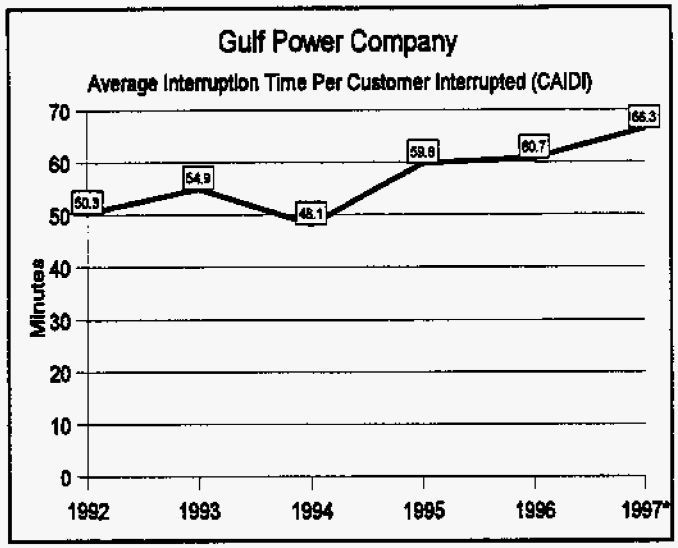


EXHIBIT GPC-6 *Source: GPC Response to Document Requests 1-7 and 3-9.*

**Annualized based on 12 months ending September 1997.*

An increase in the CAIDI index often signals increased company response/restoration intervals for customers affected by the outages. However, GPC representatives state that this is not the case with the increase in CAIDI during the period 1994-1997. According to company document responses, "The current Average Interruption Time shows that outages happen in areas where less customers are affected. This does not indicate that longer response/restoration times are occurring. They do indicate that the corrections made over the last few years affected more customers per outage." This response indicates fewer customers are affected by an outage and the CAIDI interval increased because of the reduction in the number of customers affected by an outage, rather than response/restoration intervals of customers with outages.

GPC representatives state that the primary indicator to track GPC customer service quality is the six year average of Customer Minutes of Interruption Per Customer Served, referred to as CMI. Customer Minutes of Interruption Per Customer Served is also known as the System Average Interruption Duration Index (SAIDI). Exhibit GPC-7 shows annual SAIDI for the period 1992 through September 1997. As shown in the exhibit, the GPC SAIDI index dropped during 1994-1996 and rose slightly through September 1997. However, the increase in 1997 is only slight and represents improvement over the SAIDI levels prior to 1994.

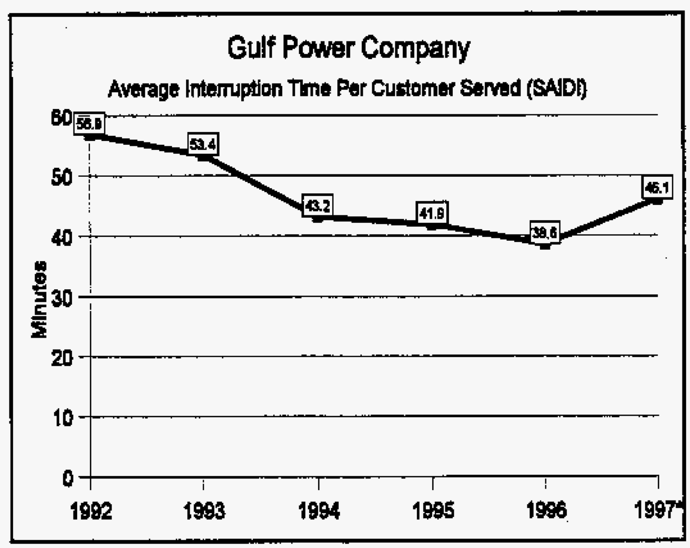


EXHIBIT GPC-7 *Source: GPC Response to Document Request 5-8.*

**Annualized based on 12 months ending September 1997.*

CAIDI and SAIDI indices monitor the average duration of outages, while other indices measure the frequency of interruptions. The Customer Average Interruption Frequency Index (CAIFI) and

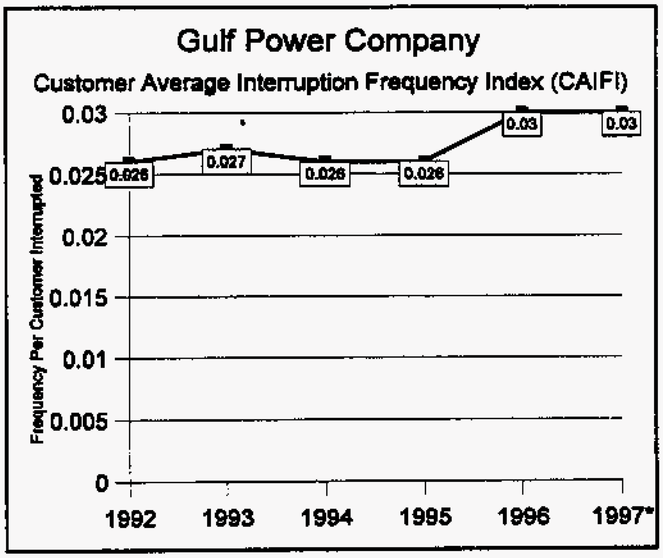


EXHIBIT GPC-8 *Source: GPC Response to Document Request 5-8.*

***Annualized based on 12 months ending September 1997.**

the System Average Interruption Frequency Index (SAIFI) measure the frequency of outages experienced by customers with outages, and as an average, across all GPC customers served.

CAIFI looks specifically at the frequency of outages for customers having experienced an outage. Exhibit GPC-8 shows CAIFI for the period 1992 through September 1997. As shown by the exhibit, the customer average frequency of outages increased slightly during 1996 and 1997.

SAIFI measures the frequency of total customer interruptions relative to the total number of customers served. Exhibit GPC-9 shows SAIFI declined for the period 1992 through 1996 and increased slightly through August 1997. These two frequency indicators are important to assessing GPC distribution quality and reliability, but are not the only indicators reviewed by GPC management.

GPC management relies upon all ten Distribution Trouble Report indicators to signal service quality and reliability defects and believes that continued emphasis on improving these indices will favorably impact and reflect on the overall service quality and reliability provided to GPC customers.

Other GPC Internal Indicators

In addition to the service reliability and quality indices monitored in the Distribution Trouble Report, GPC uses other indices to provide Power Delivery staff and management further insight into other types and frequency of service interruptions. These indices report average service availability, frequency of momentary outages, repeat customer momentary outages, customer repeat sustained and momentary interruptions and other important reliability and quality measurements including:

- *Average Service Availability Index* (ASAI) reports the customer hours service is available relative to the customer hours of service demand.

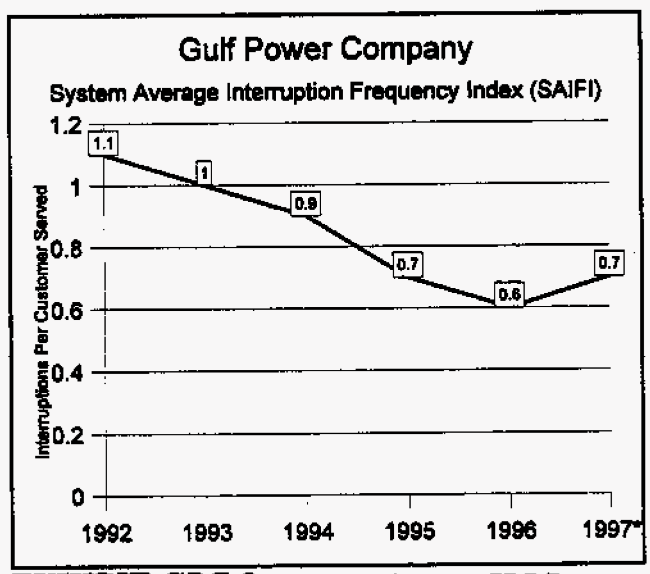


EXHIBIT GPC-9 *Source: GPC Response to Document Request 5-8.*

**Annualized based on 12 months ending September 1997.*

- *Average System Interruption Frequency Index* (ASIFI) examines connected kilovolt amperes interrupted relevant to total connected kilovolt amperes served.

- *Average System Interruption Duration Index* (ASIDI) measures the connected kilovolt amperes minutes interrupted relative to the total connected kilovolt amperes served.

- *Momentary Average Interruptions Event Frequency Index* (MAIFI) reports the total number of customer momentary interruption events relative to the total number of customers served.

- *Customers Experiencing Multiple Interruptions Index* (CEMI) measures the total number of customers experiencing more than a certain number of sustained outages relative to the total number of customers served.

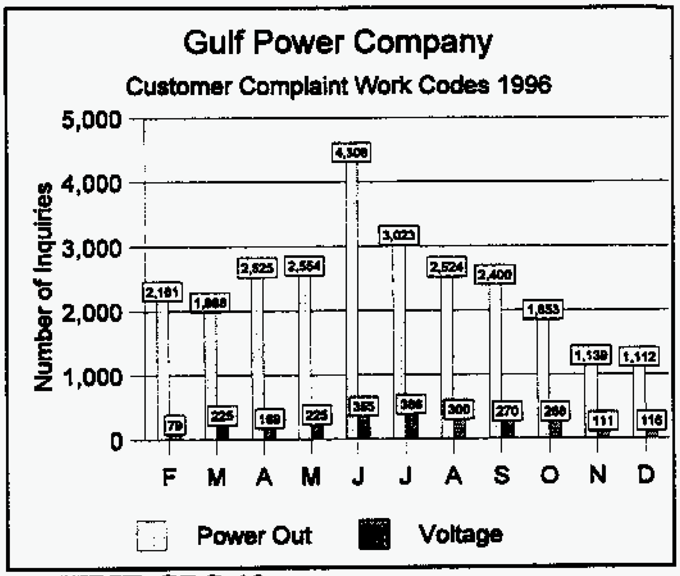
- *Customers Experiencing Multiple Sustained Interruptions and Momentary Interruptions Events* (CEMSMI) examines the total number of customers experiencing more than a certain number of interruptions relative to the total number of customers served.

5.3.2 Utility-Handled Inquiries and Complaints

GPC receives customer inquiries and complaints at three different levels, including the Customer Service Center level, executive management level, and FPSC level. Almost all GPC customer inquiries and complaints company-wide are handled through the Customer Service Center, located in Pensacola. The Customer Service Center handles telephone requests for new service, billing adjustments, payment plans, disconnect/reconnect services, and repair services. Customer Service Center Representatives staffing the call center classify customer calls and enter a code manually into the Customer Information System to categorize the type of call and work performed with each customer call.

The Customer Service Center coding process does not include every call received through the call center, nor does the process attempt to measure customer complaint levels. However, work code data does provide insight into Customer Service Center level customer inquiries and complaints relating to power outages, outdoor lighting, and voltage problems. The code data consists of six primary categories and a total of 29 codes to further categorize the work type. Primary categories include General Billing, Collection, Orders, Outages, High Bills, and Miscellaneous Services.

Outage codes indicate when a Customer Service Center Representative worked with a customer regarding some sort of electrical outage. Generally, these efforts are in reporting a customer electrical outage or in handling a customer complaint about outages previously experienced. The three outage code categories tracked by the GPC Customer Information System are Power Out, Outdoor Light Not Working, and Voltage Problems.



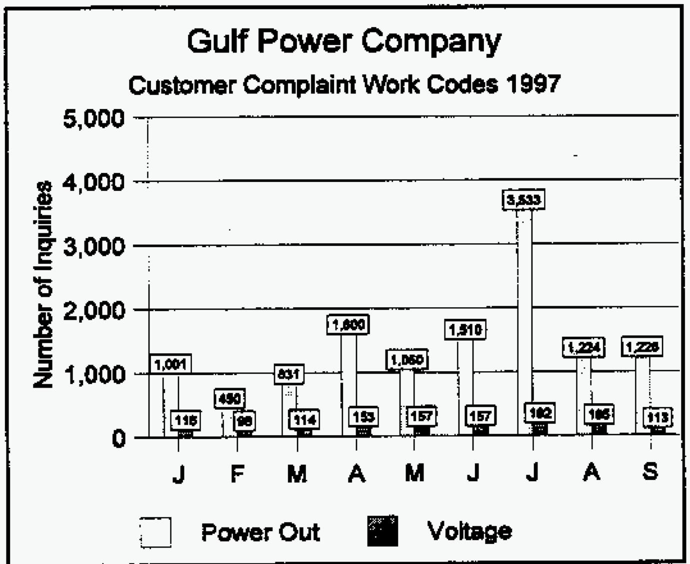


EXHIBIT GPC-10

Source: GPC Responses to Document Requests 2-26 and 3-16.

Exhibit GPC-10 presents a graphic representation of the total work code entries for two of the three categories from February 1996 to September 1997. As shown in the exhibit, the highest work activity is in the Power Out category. Voltage work codes show very low activity. The Power Out work code, for both 1996 and 1997, show increased activity in the summer months. This is expected because summer months generally have the highest system use, highest storm damage, and highest lightning periods. The exhibit also shows a marked decline in the overall number of outage-related work code entries and in the peak summer months activity during 1997. While the work codes are not all inclusive and are not specifically designed to track customer complaints, they offer insight into the level of work performed by Customer Service Center Representatives in handling customer problems regarding service outages.

Beyond Customer Service Center level customer inquiries and complaints are executive management and FPSC complaints. These two categories are reported and coordinated by the Accounting Clerk, Senior, at GPC. Executive complaints are those called or written directly to executive management members for assistance and problem resolution. According to company representatives, GPC had only two executive level complaints in over six years.

5.3.3 Customer Satisfaction Surveys

Market Sector Surveys

Historically, GPC has used customer satisfaction surveys directed at specific market sectors such as Residential, Commercial/Industrial, Active Customers, and Key Accounts. GPC management utilizes these surveys, in conjunction with their own internal measurements, to identify and make improvements in electric quality and customer service.

Exhibit GPC-11 shows GPC's annual results of market sector satisfaction surveys for the period 1992-1996. Overall, GPC customer satisfaction survey results have shown improvement. Although the results seem low, GPC management believes continued improvement is the most important measure. Residential scores increased from a low score of 54.1 in 1992, to a 73.5 score in 1996. Commercial and Industrial scores increased from a low of 52.0 and 51.9 respectively, in 1992, to a combined score of 52.65 in 1996.

GPC customer satisfaction survey efforts first started in the late 1980's. GPC began by conducting their own customer surveys until the early 1990's. Southern Company then began a system-wide approach for administering the surveys. In 1992, Southern Company contracted for a Gallup Survey to establish a benchmark for its companies system-wide. Since that time, a combination of survey approaches have been used to identify customer perception and satisfaction.

Each market sector customer satisfaction survey conducted from 1992-1995 included customer questions related to service reliability, service quality, length of outages, and frequency of momentary outages experienced by customers. It is interesting to note that, as early as 1992, GPC surveys were identifying customer perception of service quality and reliability.

In 1995, satisfaction surveys were modified to include active account questions within the survey population, rather than surveying active customers separately. In addition, customer satisfaction survey questions related to service reliability, service quality, length of outages, and momentary outages were restructured and reduced in number. This change was primarily due to the Voice of the Customer Research project, which showed that customers concerns were not in those areas at that time. In 1996, GPC combined its commercial and industrial segment surveys into a single business survey. Beginning in 1997, regular market sector surveys will be discontinued in favor of the annual benchmark study, which will include market sector analysis.

Southern Company administers customer satisfaction survey programs through independent survey contractors representing GPC and the other Southern Companies. The Marketing department acts as local administrator of the customer satisfaction survey effort, and survey cost allocations come from Marketing budget dollars. Company involvement in survey program design and content is conducted through a Customer Satisfaction Council in each company. This council consists of Marketing, Customer Service, Power Delivery, Engineering, and executive level management representatives.

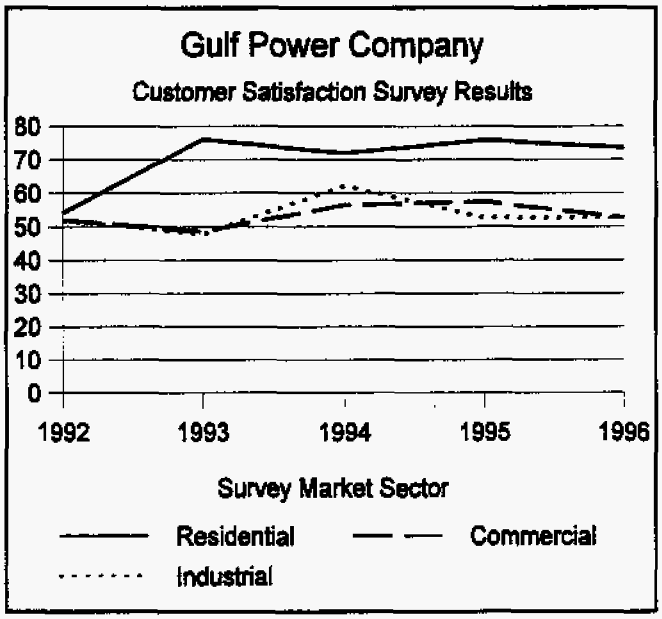


EXHIBIT GPC-11 *Source: GPC Response to Document Request 1-27.*

Each of the company groups provides feedback to the Southern Company Customer Satisfaction Working Group. This group is responsible for decisions regarding question emphasis and format changes to the system-wide surveys.

Benchmark Surveys

In 1992, the Southern Company contracted with the Gallup Survey group for the first of its benchmark surveys. These surveys compared Southern system companies with each other and with other companies known for having superior quality and reliable service. The 1992 benchmark effort was the first comparison of Southern Company and GPC customer perceptions of service quality and reliability to those of customers of other similar utilities.

Voice of the Customer Research

In 1994, Southern Company conducted the Voice of The Customer Research project to research customer concerns and perceptions throughout the Southern system and within individual companies. The project, completed by an outside survey contractor, also assisted in the design, wording and selection of future surveys and questions. The project was completed in two phases. The Voice of The Customer for Residential and Small Business was completed in June 1994 and the Voice of The Customer for Key Accounts was completed in February 1995.

The project results provided important insight into measuring customer perceptions and identified key performance attributes associated with customer satisfaction. For instance, the Residential and Small Business results identified clean, uninterrupted power as one of the top ten attributes desired. However, small business rated Southern system performance higher in this category than did residential customers. Industrial customers, from the Key Accounts Voice of The Customer study, rated clean, uninterrupted power as the number one attribute desired and rated this attribute as a strength of the Southern system. Surveys conducted after 1994 included information, attributes, and customer word descriptions uncovered during the Voice of The Customer research project. The purpose was to create survey questions addressing the customer concerns that the research had identified.

1996 Benchmark Survey

In 1996, GPC completed its regular market sector surveys in parallel with a benchmark survey. The benchmark survey, conducted in the fall of 1996 and issued in February 1997, was conducted to identify "drivers of loyalty" to support management planning. The study examined loyalty drivers for overall satisfaction, price, product/service quality, and customer retention. The study compared Southern Company and each individual system company against 16 other electric utilities throughout the United States. Survey questions addressed customer issues that were identified in the Voice of The Customer research project. The survey was designed to benchmark residential, moderate-sized commercial, and large energy user responses.

[redacted]

[redacted]

[redacted]

[redacted]

Gulf Power has filed a request for confidential classification of the above information, pursuant to Rule 25-22.006, Florida Administrative Code. The request is pending.

1997 Benchmark Survey

In early 1997, a working group of marketing representatives from each of the Southern companies joined with Southern Electric Services to develop a benchmark effort of 16 competitive companies having operating territories physically connected to the Southern system. The study was to be coompleted in late 1997 by an outside survey contractor. It will provide Southern companies a blind benchmark study of their own company compared to other competitors surrounding them in the Southeast. The benchmark study breaks customers studied into categories of large customers, using 1 megawatt or more, customers using 99 kilowatts down to 50 kilowatts, general business

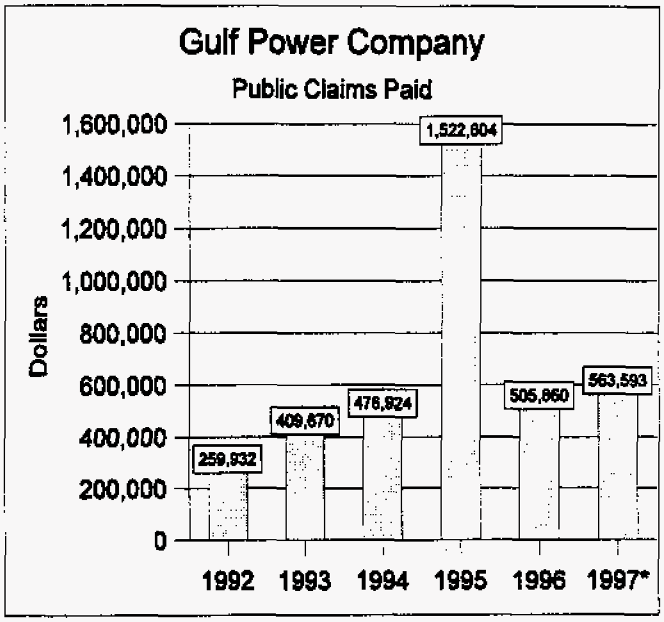


EXHIBIT GPC-12 *Source: GPC Responses to Document Requests 1-22, 2-16 and 4-1.*
**Through September 1997.*

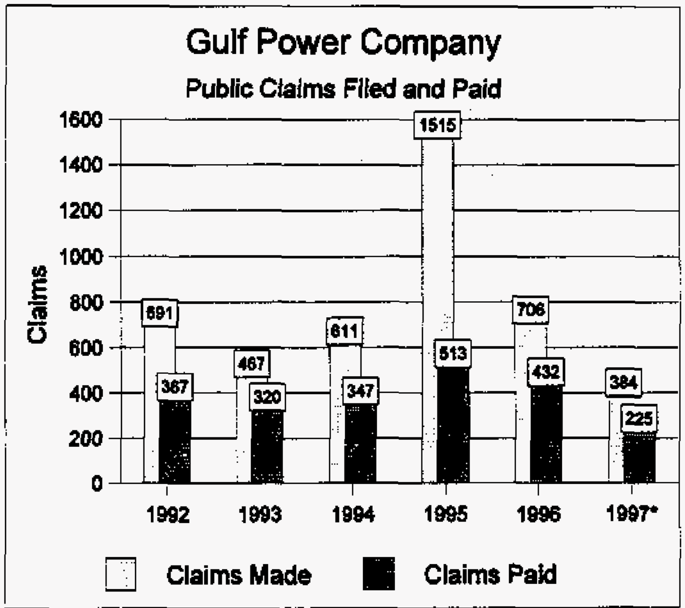


EXHIBIT GPC-13 *Source: GPC Response to Document Request 1-22.*
**Through September 1997.*

customers, and residential customers. GPC and the Southern Company will be moving away from the traditional customer satisfaction survey to the benchmark method for all future efforts. Results of the 1997 Benchmark survey were not available at the time this report was published.

5.3.4 Customer Damage Claims

The GPC damage claims process involves the use of field Claims Coordinators to process customer damage claims within a geographic area. The Claims Coordinators report to the Power Delivery Manager in each of the three divisions, who has responsibility for customer claims less than $5,000 with no attorney involvement, no liability, and no extenuating or questionable issues. Customer claims greater than $5,000 with legal involvement, with potential company liability, with questionable issues, or with the potential for fraud are referred to the Claims Administrator.

Exhibit GPC-12 shows the public damage claims dollars paid by GPC during the period 1992 through September 1997. According to company representatives, the rise in 1995 public claims was related to storm damages from two named storms experienced that year. As shown in the exhibit, 1997 public claims increased slightly over the 1996 level, but are not significantly higher than the 1994 claims level. Exhibit GPC-13 shows the number of customer damage claims made and the number of claims paid by GPC for the period 1992 through September 1997. GPC paid about 50.4% of the customer damage claims filed during the period.

The GPC Claims Administrator is also the Employee Relations & Risk Management Manager. In fact, none of the individuals involved in the GPC claims process are involved with claims on a full time basis. GPC also provides no formal claims processing training for Claims

Coordinators. Only informal training with the job incumbent, or on-the-job experience, is provided to assist coordinators in performing their duties and responsibilities.

Claims Coordinators maintain contact with District Managers regarding complaints located within their geographical area of responsibility, begin preliminary research and investigation of the customer's claim, and identify any questionable issues that prevent the claim from being paid. The coordinator also negotiates the amount of claim to be paid to the customer, based on the current depreciated value of the property or equipment damaged. Coordinators handle as many as 500 to 600 claims calls per year, but not all claims result in a GPC payout.

Typically, GPC damage claims include property restoration and resurfacing claims, storm damages, minor structural damage to houses, and power surges affecting appliances, stereo equipment, VCRs, and TVs. Damage claims paid at the Power Delivery Manager and District Manager level are reported to the Claims Administrator, and all paid claims are tracked on the computer mainframe. The Settlement and Suits report and the Injuries and Damages report are used to track the number, type, and costs of GPC damage claims. Recently, a Southern Company system-wide claims program called Risk Management Information System was implemented to track public and company claims.

5.4 Distribution Organization And Service Quality Activities

The GPC Distribution organization is part of the Power Delivery Management team, providing staff and operational assistance in the areas of planning, budgeting, engineering, tree trimming, technical service support, and the coordination of line construction contractors with district level supervisors. The Distribution Manager and staff have direct reporting responsibility for certain field personnel including contractors implementing daily distribution activities and engineering representatives designing large, specialized projects for the districts. Daily construction and maintenance is conducted through the Power Delivery Manager organization. The combined efforts of the Power Delivery team are directed toward improving GPC's overall service quality and reliability.

This section provides an overview of the GPC Power Delivery and Distribution organizational structure, staffing levels, and responsibilities for construction and maintenance of the distribution system.

5.4.1 Structure, Staffing and Functions

Prior to 1994, the Power Delivery organization reported through the Vice President Customer Services and Division Operations. During this time, distribution functioned as a staff organization, reporting to the Power Delivery General Manager. The distribution staff organization had little daily involvement in divisional operations under this organizational structure. Operational duties for distribution were conducted through two Division General

GPC CUSTOMER SERVICE AND DIVISION OPERATIONS PRIOR TO 1994

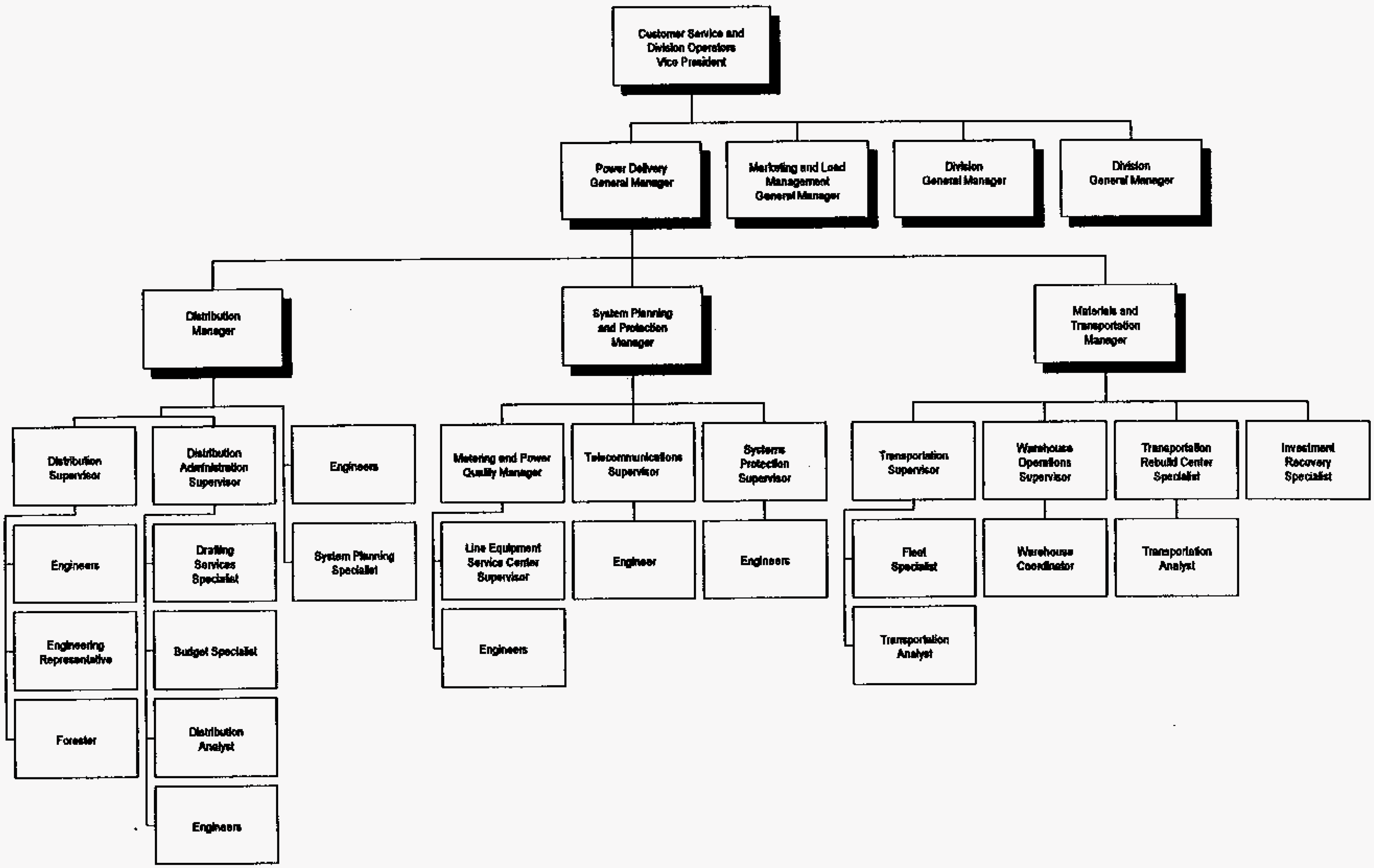


EXHIBIT GPC-14

Source: GPC Response to Document Request 2-5.

GPC POWER DELIVERY
ORGANIZATIONAL CHART
AS OF AUGUST 1996

VICE PRESIDENT
Power Delivery and
Customer Operations

GENERAL MANAGER
Power Delivery

Customer
Operations

Power Delivery Manager Pensacola
- -Engineering/Construction Distribution
- -Engineering/Construction Transmission/Substation
- -Technical Services Support
- -Engineering Services Coordination
- -Line Construction
- -Maintenance
- -Restoration/Repair
- -Winch Truck Operator
- -Meter Verification
- -Warehousing for Maintenance and Transmission

Power Delivery Manager Fort Walton
- -Engineering/Construction Distribution
- -Technical Services Support
- -Engineering Services Coordination
- -Line Construction
- -Maintenance
- -Restoration/Repair
- -Winch Truck Operator
- -Meter Verification
- -Warehousing for Maintenance/ Transmission

Power Delivery Manager Panama City
- -Engineering/Construction Distribution
- -Engineering/Construction Tranmission/Substation
- -Technical Services Support
- -Engineering Services Coordination
- -Line Construction
- -Maintenance
- -Restoration/Repair
- -Winch Truck Operator
- -Meter Verification
- -Warehouse for Maintenance/ Transmission

Distribution Manager
- -Distribution Planning
- -Distribution Engineering
- -Line Clearing
- -Technical Service Support
- -Line Equipment Repair
- -Line Construction Contractors
- -Line Construction Coordination With Districts

Metering\ Engineering Systems Manager
- -Engineering Metering Systems Power Quality
- -Drafting
- -Meter Repair

System Proctection Manager
- -Engineering System Protection Special Projects
- -Distribution Control Center Trouble Tickets Recording Analysis Dispatch

Protection Services Administrator
- -Emergency Management Center
- -Cable/Telephone Contracts

EXHIBIT GPC-15

Source: GPC Response to Document Request 1-13.

Managers, within three geographical divisions, Western, Central, and Eastern. Exhibit GPC-14 shows the GPC organizational structure for Power Delivery prior to 1994.

In 1994, GPC consolidated executive management into four primary business units and brought power delivery and distribution functions under the Vice President Power Delivery and Customer Operations. These organizational changes moved power delivery operations and distribution staff under the General Manager Power Delivery. In effect, this change brought the GPC distribution organization into a closer relationship with power delivery daily operations. Exhibit GPC-15 shows the current organization, staff, and operational functions reporting to the General Manager Power Delivery.

Power Delivery

The Power Delivery organization is responsible for construction and maintenance of GPC's network of substations, overhead distribution lines, and underground distribution facilities. These facilities include a myriad of substations, poles, cable, cross arm assemblies, insulators, transformers, switches, fuses, reclosers, grounding equipment, and metering devices.

Power Delivery staff functions include Distribution, Metering/Engineering Systems, System Protection, and Protection Services. The Metering and Engineering Systems Manager and staff provide computer systems support, mapping support, metering support, and customer Power Quality technical support. The Power Quality technical group responsibilities are directed at solving GPC commercial and large industrial customer power problems.

The System Protection Manager and staff provide electric system protection for generation, transmission, substation, and distribution equipment and are responsible for the centralized Distribution Control Center (DCC) for trouble call reporting. The Project Services Administrator and staff are responsible for environmental, safety, and regulatory matters, as well as the company's emergency management program.

Power Delivery daily operations, including distribution construction and maintenance, are handled by three Power Delivery Managers. The three Power Delivery Managers, located in Pensacola, Ft. Walton, and Panama City, have management oversight and responsibility of daily operations within one of three geographical territories. The geographical territory responsibilities are assigned similar to the previous Western, Central, and Eastern Division boundaries.

Distribution

The Distribution Manager and staff provide both operational and staff assistance in support of the Power Delivery Manager's distribution responsibilities. The major areas of responsibility include:

- Distribution Planning
- Distribution Engineering
- Line Clearing

- Technical Services Support
- Line Equipment Servicing

Distribution Planning supports the planning effort by completing distribution load studies and manpower studies, which aids in budget analysis. Distribution Engineering supports the Power Delivery field forces by providing engineering for major capital construction and maintenance projects company-wide. Underground Residential Distribution Engineering Representatives coordinate projects with GPC underground contractors, directional boring contractors, and facility locating contractors. The Line Clearing Supervisor is responsible for all transmission, substation, and distribution system vegetation management, including planning, budgeting, and coordinating tree-trimming contractor efforts throughout the company. The Line Equipment Service Center Supervisor oversees the repair and recondition of distribution line equipment removed from service with remaining useful life.

In 1992, GPC examined work force costs for distribution construction and maintenance through a quality improvement task force. The purpose of the task force was to determine the optimum size for distribution line/service crew productivity and to identify types of contractor work which could be completed by company crews after productivity improvements were made.

The results of the study suggested that GPC could downsize distribution construction crew size from three person crews to two person crews and reduce maintenance crew size from a two person crew to a one person trouble crew. Apprentice personnel were eliminated from the crews, and additional trucks were added to expand the number of crews. During the period 1992-1995, GPC changed the size of work crews to smaller, more productive crews located closer to their geographic work areas. This change reduced crew drive time and provided greater flexibility in locating resources where they were needed throughout the company.

To accommodate the reduced crew sizes, GPC downsized service trucks, but increased the total number of vehicles used in distribution construction/maintenance and substation maintenance. Distribution construction/maintenance increased from 65 vehicles in 1990 to a high of 99 vehicles in 1996. Substation maintenance increased the number of vehicles used from one in 1990 to 18 in 1996. The total number of distribution vehicles varied from a high of 186 vehicles in 1994 to a low of 132 in 1997. Exhibit GPC-16 shows the total number of GPC distribution vehicles for the period of 1990-1997.

Overall, the number of distribution vehicles has decreased since 1995. Engineering/Supervision vehicles decreased from 75 in 1990 to 13 in 1997. Construction/maintenance vehicles increased from 65 in 1990 to 99 in 1996 and dropped to 87 in 1997. Substation maintenance vehicles increased from one in 1990 to 17 in 1997. Metering and Transformer repair increased from ten vehicles in 1990 to 15 in 1997.

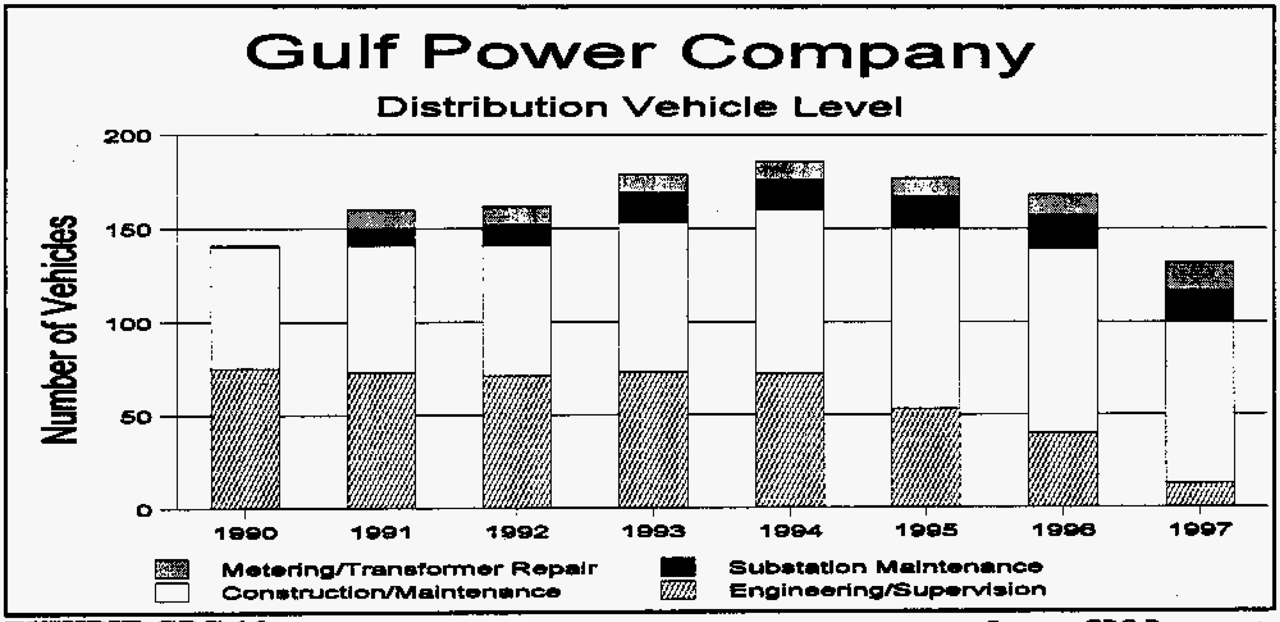


EXHIBIT GPC-16

Source: GPC Response to Document Request 2-9.

The reduction of Engineering/Supervision cars offset increases made to Construction/Maintenance and Substation maintenance vehicle levels. The number of cars used by GPC Engineering/Supervision reduced from 41 in 1990 to zero in 1997. Construction/Maintenance line bucket trucks were reduced, partially as a result of smaller crews, from 24 in 1990 to only one in 1997. On the other hand, the number of material handling bucket trucks increased from 21 in 1990 to 59 in 1996, then decreased again to 54 in 1997. Also partially as a result of smaller crew sizes, substation maintenance increased the number of trucks with service beds from zero in 1990 to 15 in 1997. In an effort to further create work force management efficiencies, GPC also staggered crew work schedules and began using company employees to complete work previously done by contractors. These changes brought about the reduction of 82 full time equivalent positions, which eliminated most of the contractor force used by GPC.

GPC Distribution staffing levels were downsized from 416 employees in 1992 to 368 employees in 1997. This represents a reduction of 48 employees (11.5%), during the period of 1992-1997. Overall, the number of GPC employees company-wide was reduced from approximately 1605 full and part-time employees in 1992 to 1384 employees in 1996. This represents a reduction of 221 employees (13.8%), during the period. Total distribution staffing reductions for the period remained slightly less than that of the company.

Exhibit GPC-17 graphs the distribution staffing levels from 1992-1997 divided into Management, Non-Management, and Bargaining Unit categories. The two categories losing the most employees during the period are Management, with 24 fewer employees (-48%) and the Bargaining Unit with 32 fewer employees (-11.8%). The non-management category increased from 94 employees in 1992 to 102 (8.5%) employees in 1997. These reductions in the number of employees reflect GPC efforts since 1992 to re-engineer processes, restructure organizationally, re-assess staffing levels, consolidate operations functionally, introduce technology to gain productivity and cost efficiencies, and strategically position the company for the upcoming competitive environment.

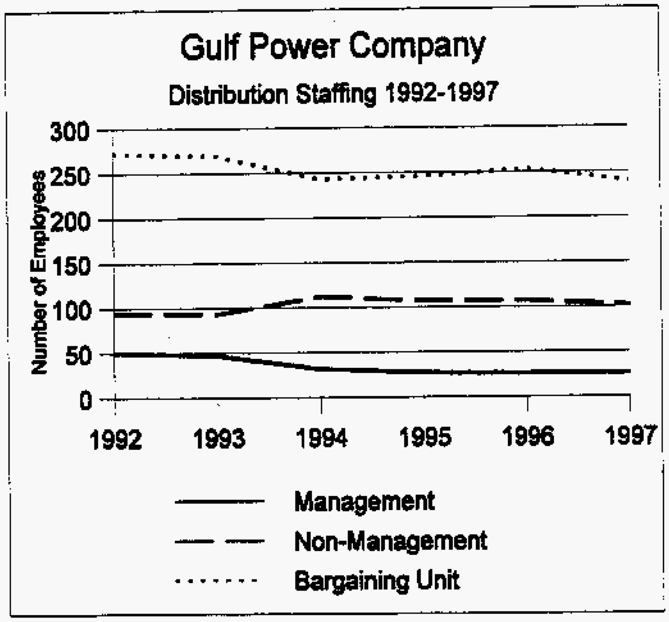


EXHIBIT GPC-17 *Source: GPC Response to Document Request 2-19 and 3-9.*

5.4.2 Maintenance Planning

Planning distribution line and equipment maintenance is the responsibility of the Distribution Manager staff organization, with input from the Power Delivery Manager organization in each of the three geographical territories. Engineering and Construction (E&C) Supervisors, reporting to the Power Delivery Managers, are responsible for crews completing maintenance activities within assigned local geographical areas. Currently, GPC has four E&C Supervisors reporting to the Power Delivery Manager in Pensacola, three reporting to the manager in Ft. Walton, and three reporting to the manager in Panama City.

During the period of 1992-1996, GPC overall operations and maintenance (O&M) expenses ranged between $351 and $394 million dollars (12%) over the period. O&M costs, adjusted to exclude fuel, showed an increase from $168 million to $210 million (25%) for the period. Exhibit GPC-18 graphs the increase of GPC O&M expenses with and without fuel.

GPC distribution O&M expenses rose from $18.5 million in 1992 to $23.3 million in 1996, an increase of $4.8 million (26%). Exhibit GPC-19 graphs GPC distribution O&M dollars for the period. GPC distribution maintenance expenses continued to increase from $12 million in 1993 to $14.9 million (24%) in 1996. GPC distribution operating expenses remained level at around seven million from 1992 to 1994, increased to nine million in 1995, and dropped again to $8.3 million in 1996.

In 1992, GPC established three Total Quality Management (TQM) teams to address methods for reducing system outages and improving system quality and reliability. A Momentary Outage Reduction Team (MORT), Sustained Outage Reduction Team (SORT), and Transmission Outage Reduction Team (TORT) were established to identify causes for customer outages and evaluate methods for improving service.

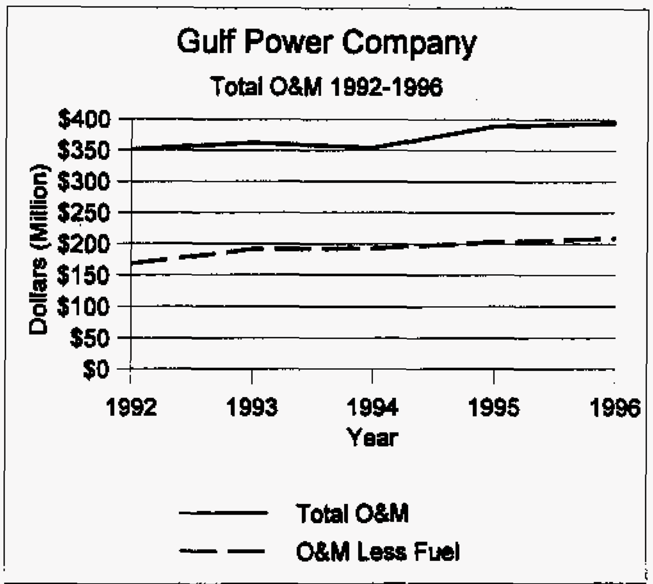


EXHIBIT GPC-18 *Source: FERC Form 1, 1992-1996.*

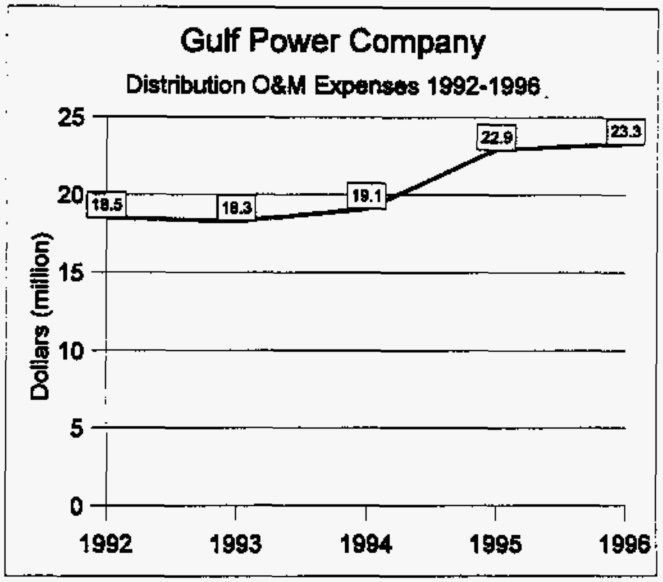


EXHIBIT GPC-19 *Source: FERC Form 1 1992-1996.*

MORT was established to reduce outages of a momentary nature which affected GPC customer service. The team identified lightning, animals, and trees as the major causes of momentary outages and made two primary recommendations: 1) to improve grounding and bonding on transformer banks and 2) to shorten the interval for reclosers at the substation to reduce the number of momentary outages. The MORT team recommendations were approved by GPC executive management and completed by September 1993. GPC also began placing animal guards on transformers where an animal outage previously occurred.

SORT was established to reduce distribution sustained outages to GPC customers. This TQM team identified the need to improve GPC grounding practices and concentrated on the distribution "worst feeders" in each division. Team recommendations were to 1) revise affected engineering and line/service practices to upgrade necessary grounding specifications and, 2) improve grounding for the worst feeders in each division. The SORT team recommendations were approved by GPC executive management and completed by July 1993.

TORT was established to reduce transmission outages affecting GPC customers. The TQM team identified the transmission "worst five lines" and compared them with the next five worst lines. The first five lines were scheduled for repair in 1994, and the next five lines were scheduled for completion in 1995. Additionally, transmission revised its bulletin for transmission line inspections, modified daily operating reports to reflect worst lines, and improved the data collection process. The TQM team recommendations were approved by GPC management. The assessment of lines was completed by October, 1993. The first five lines were improved by the end of 1994, and the second five lines were completed by the end of 1995. However, the GPC transmission "worst lines" improvement program was not extended beyond 1995.

In addition to MORT, SORT, and TORT, GPC conducted other TQM studies during the 1992 time frame to improve service quality, increase company productivity, and reduce costs. Other programs begun to improve GPC service quality included projects to reduce the amount of small wire outages and tree-trimming projects to reduce tree-related outages.

As a result of the TQM studies, ongoing distribution maintenance programs were established to further reduce the level of outages and improve GPC service quality and reliability. These ongoing maintenance programs are funded based on the input of district level managers, Engineering and Construction Supervisors, Engineering Supervisors, Power Delivery Managers, and Distribution Staff.

Emphasis on these ongoing programs can differ from year to year, based on budget constraints, construction needs, and the number of problem areas needing immediate attention. Budget dollars are distributed, based on the number and priority of projects, to meet the ongoing needs of the company and its customers. The ongoing programs and activities included annually within the distribution maintenance budget include:

- **Ground Pole Inspections** - contracted to an outside vendor for pole inspection and treatment.

- **Pole Replacement Program** - conducted by GPC to replace or reinforce rejected poles identified by the outside vendor.

- **Deteriorated Conductor Program** - completed by GPC forces to replace old deteriorated copper wire and aluminum copper stranded primary conductor wire.

- **Pole Relocation and Clearance Corrections** - to provide proper distribution facility clearances where possible hazardous situations exist.

- **Group Relamping Street Lights** - based on historical replacement of lamps.

- **URD Cable Injection/Replacement Program** - for the injection of aged and faulty underground primary cable.

- **Padmount Transformer Painting** - for the maintenance of padmounted transformers, switchgear and primary feed-through cabinets located in corrosive areas deemed by each District Engineering Department.

- **Transformer Vault Improvements** - to upgrade ground mounted transformer installations.

- **Inspection of Submarine Cable Crossings** - to include annual inspection of cable for possible deterioration.

- **Local Distribution Network** - to replace deteriorated equipment and maintain network transformers and protectors through inspections and the LESC rebuild facility.

- **Distribution Line Clearance** - to maintain adequate tree and vegetation clearance from company lines for public safety and to maintain a sustainable competitive cost per mile.

- **OCR Maintenance Program** - to conduct oil covered recloser maintenance on a seven year cycle.

GPC management finds these ongoing maintenance programs to be effective in reducing outages, but allows for the addition of other maintenance programs on an as needed basis. Those additional programs, upon completion, would be discontinued in favor of the established ongoing maintenance programs.

5.4.3 Tree Trimming

Prior to 1995, GPC's tree trimming responsibilities were carried out by the Division Managers. Each Division Manager placed emphasis and budget dollars into vegetation management, based on the district needs they were responsible for. GPC corporate staff advised and provided support to the Division level program efforts.

In 1995, GPC vegetation control efforts were consolidated under the Line Clearing Supervisor, reporting to the Distribution Manager. Since that time, GPC's emphasis on tree trimming and vegetation management has been more consistent, and budget dollars have been reduced. This is evidenced in the annual Line Clearing budget shown in Exhibit GPC-20. Budget information includes both Transmission and Distribution line clearing expenditures for the period 1990-1997. Actual expenditures ranged from a low of $3,078,885 in 1990 to a high of $3,966,305 in 1995. Expenditures were at their highest levels during 1993-1995, under the previous division organizational structure. Since the 1995 consolidation of tree trimming responsibilities under the Line Clearing

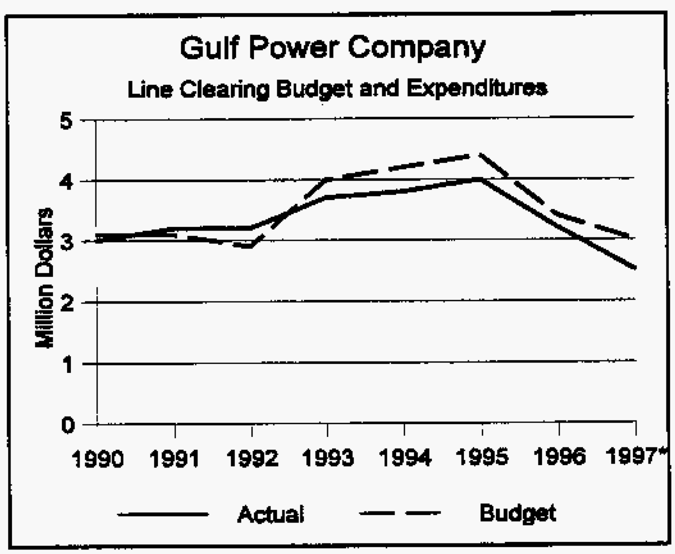


EXHIBIT GPC-20 *Source: GPC Responses to Document Requests 2-12 and 4-2.*
**GPC year-end projection.*

Supervisor, actual expenditures have been reduced by $733,492. The average annual tree-trimming expenditure level for the period 1990-1997 was $3,325,769.

The Line Clearing Supervisor is responsible for developing and implementing tree trimming, tree removal, and vine eradication programs throughout GPC. This is accomplished through the Line Clearing Supervisor's coordination of tree trimming contractor efforts company-wide. The Line Clearing Supervisor also is responsible for company special projects related to forestry. For example, the conversion of GPC's sod farm operation to a tree farm required the coordination and involvement of the Line Clearing Supervisor.

Gulf's Distribution Line Clearing performance measurements include:

- Tree trimming costs per mile
- Six year average for tree caused outages
- Customer satisfaction survey results
- Number of outages per 100 miles
- Tree outages per 100 miles

Exhibit GPC-21 shows that GPC's maintenance tree trim costs per mile dropped considerably in 1996 and remained steady through September 1997. In the past, GPC re-bid the tree trim contract and experienced very low rates for the contract. However, due to the low prices, contractors could not maintain quality work crews. This problem negatively affected both the contractor work quality and crew availability levels.

In late 1995, GPC's tree trimming cost per mile was at $2,795 per mile. As a result of vendor re-negotiations in late 1995, GPC established a tree trim cost per mile benchmark of $2,000. The vendor must meet the benchmark, or pay a sliding scale monetary penalty up to $100,000. By late 1996, the vendor decreased costs per mile below the benchmark, maintained quality workers, improved crew availability levels, and exceeded the agreed upon contract specifications. The GPC Line Clearing contract was again re-negotiated in 1997 with the current tree trim contractor.

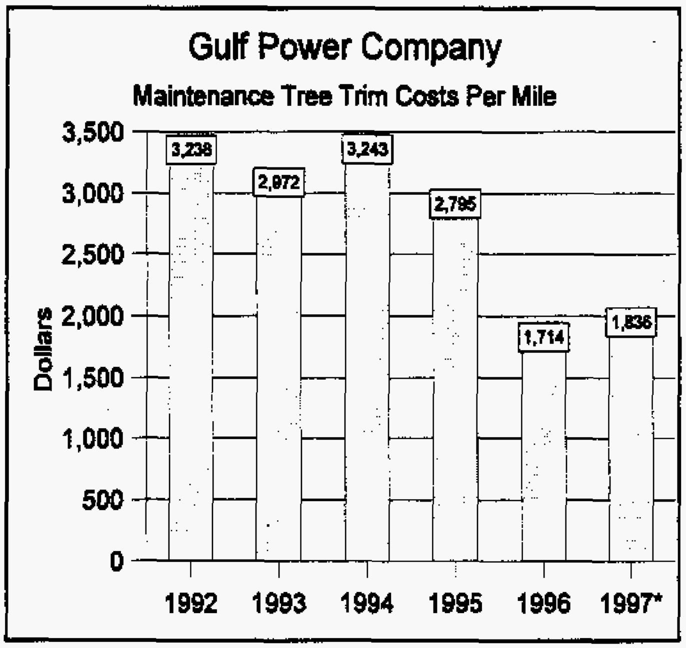


EXHIBIT GPC-21 *Source: GPC Responses to Document Requests-31 and 4-1.*

**Through September 1997.*

The GPC six-year average for tree-caused outages shows a decrease from 18.9 outages in 1992 to 14.6 outages through

September 1997. This index shows continued improvement over a six-year period and is evidence of GPC's long term emphasis on reduced tree-caused outages.

Although one of the Distribution Line Clearing measurements is customer satisfaction survey results, none of the customer satisfaction survey questions directly address and measure customer satisfaction related to tree trimming. However, customer survey responses relating to the reliability and quality of GPC's service are impacted by tree trimming activities. Overall, GPC Customer Satisfaction results have shown improvement for the period of 1992 through September 1997.

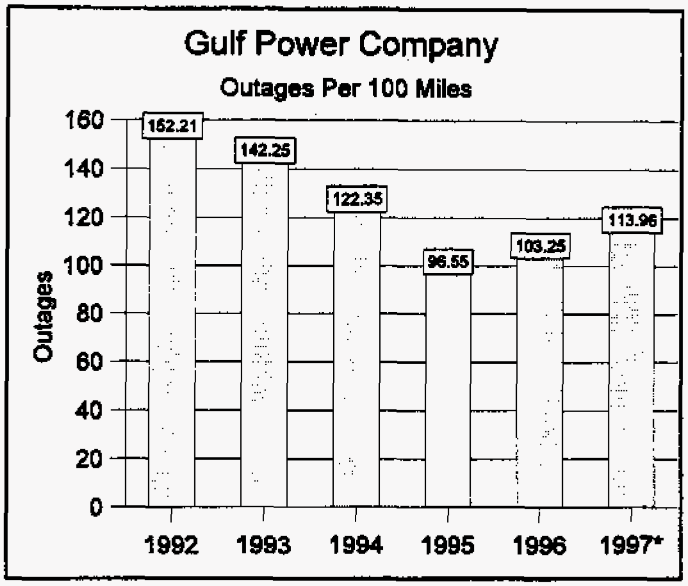


EXHIBIT GPC-22 *Source: GPC Responses to Document Requests 1-7 and 3-9*

**Through September 1997.*

Exhibit GPC-22 graphs the number of GPC outages per hundred miles for the period of 1992 through September 1997. This index allows GPC to compare the level of outages experienced across the entire 7,400 square mile operating service territory, considering both rural and urban customer outages. As shown by the exhibit, GPC outages per hundred miles decreased from 1992 through 1995. Since 1995, outages have increased slightly, from 96.55 in 1995 to the September 1997 level of 113.96. While the level of outages per 100 miles has increased in recent years, it remains lower than those experienced from 1992-1994.

The Tree Outages Per Hundred Miles index averages tree-related outages over the 7,400 square mile GPC system operations. This index is another system wide measurement, providing additional insight into the number of tree-related outages. As shown in Exhibit GPC-23, GPC tree outages per hundred miles dropped from 22.35 in 1992 to 15.77 in 1993. The decrease came at the same time GPC began the TQM MORT, SORT, and TORT teams. Since 1993, tree outages per hundred miles remained at the same level through 1996. By the end of September 1997, tree outages per hundred miles were at the lowest level for the period of 1992 to 1997.

GPC methodology for identifying circuits with the greatest tree trimming needs is based upon customer calls, engineering concerns, and the Distribution Trouble Report outage report. When a customer experiences more than three outages, an engineering assistant drives to the circuit identified, observes the problem areas, and determines what is needed to correct the problem. A project is then developed by the engineer and input to the budget. The Line Clearing Supervisor budget request includes these projects, with estimates of additional spot trim work, and dollars for completing a trim cycle of three to four years. Upon budget approval, the Line Clearing Supervisor and staff coordinate and oversee contractor crews and projects. The quality of work performed by the contractor is monitored by the Engineering Representative with the contractor supervisor after each circuit is completed.

The Distribution Line Clearing System is the data base containing project and cost information. According to company representatives, this system is outdated and will be replaced by the Tree Reverse Invoice Management System on a Southern system basis. The Tree Reverse Invoice Management System will download time sheet and cost data to Accounts Payable and automate the entire tree-trimming process. The Tree Reverse Invoice Management System will also provide cost per circuit, activity type, and other detailed cost information to support productivity and performance measurement for the line clearing function.

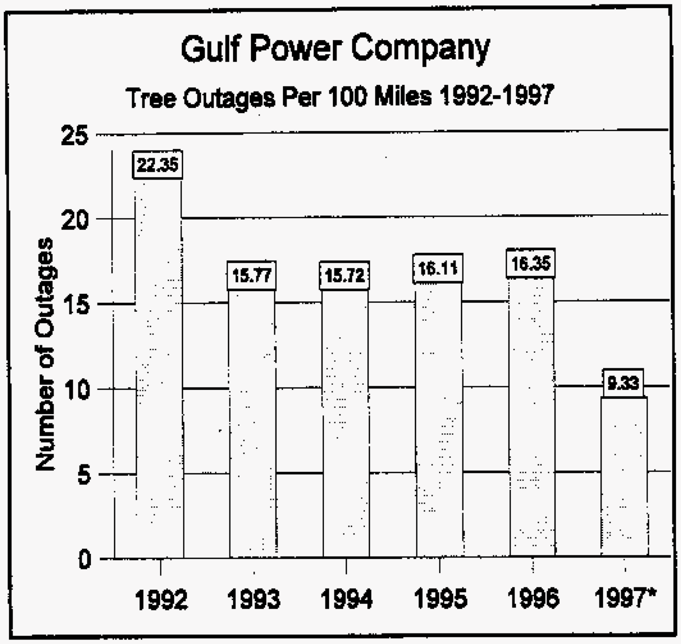


EXHIBIT GPC-23 *Source: GPC Response to Document Requests 1-7 and 3-9.*

**Through September 1997.*

5.4.4 Substation Maintenance

GPC operates a total of 115 substations, including four generating plant substations, 14 transmission substations, and 97 distribution substations. Distribution substation maintenance is the responsibility of the Engineering and Construction Supervisor Substation and Transmission within assigned geographical areas. Two Engineering and Construction Supervisors and their crews are responsible for completion of substation maintenance work company-wide. One supervisor reports to the Power Delivery manager in Pensacola, and the other reports to the Power Delivery Manager in Panama City.

The Engineering and Construction Supervisor Substation and Transmission in Panama City is also responsible for Ft. Walton area substation maintenance. These two groups also complete substation work for other Southern companies, as work levels and management priority allows. According to GPC representatives, geographical boundaries have been torn down in Transmission/Substation Maintenance and Construction. While there are assigned geographical areas for each of the Engineering and Construction Supervisors for Substation and Transmission, both can relocate crews to other areas within GPC and the Southern system.

As shown in Exhibit GPC-24, GPC substation maintenance expenses ranged between $1.1 million in 1992 to a high of $3.4 million in 1996. Based on expense levels through August, maintenance expenses are projected to be $2.6 million for 1997. This represents a reduction of $.8 million (24%) in substation maintenance expenses for 1997.

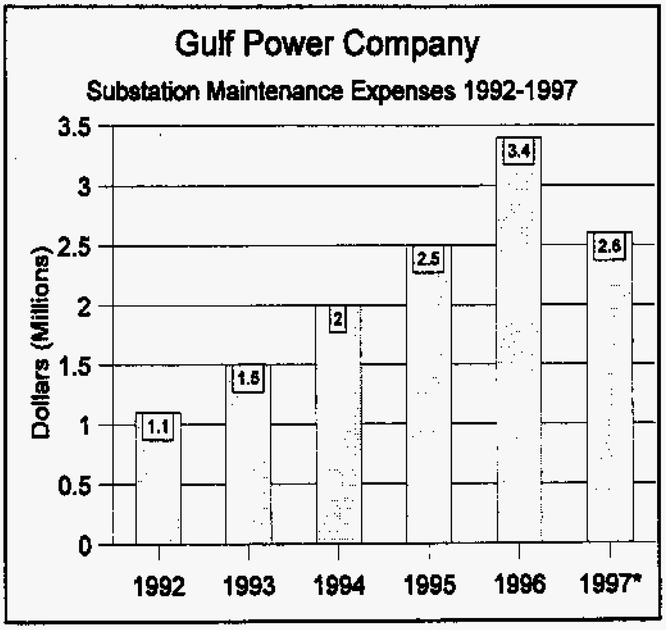


EXHIBIT GPC-24 *Source: GPC Responses to Document Requests 1-8 and 3-9.*

**Annualized projection based on August 1997 levels.*

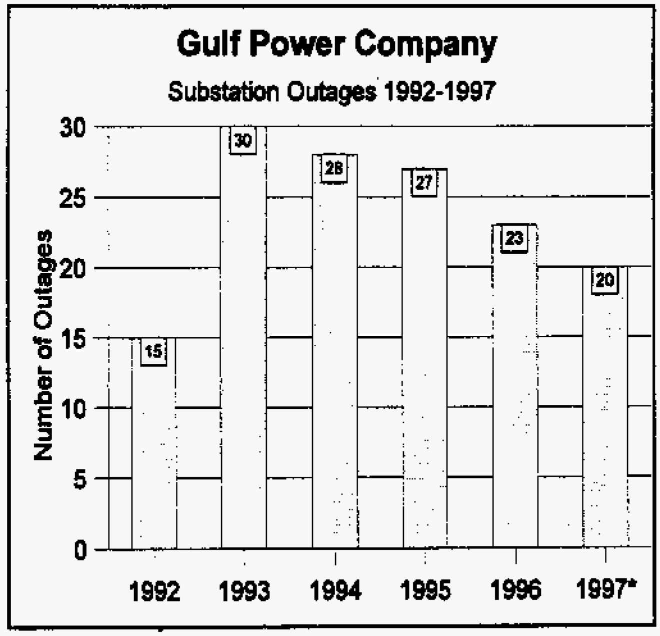


EXHIBIT GPC-25 *Source: GPC Responses to Document Requests 2-18 and 4-1.*

**Through September 1997.*

Exhibit GPC-25 shows the number of GPC substation outages experienced during the period 1992 through September 1997. As shown in the exhibit, substation outages doubled from 15 in 1992 to 30 in 1993 and slowly reduced to a total of 20 outages in 1997. Most GPC substation outages are caused by thunderstorms, lightning, and animals. Outages caused by substation maintenance were reduced from a high of nine in 1994, to zero outages in 1997.

In 1990-1991 the Southern Company began an effort to standardize substation maintenance procedures and a change from preventive maintenance to predictive diagnostic maintenance. In 1994, Southern Company issued standard Substation Maintenance Instructions and Specifications for Southern System electric utilities, including GPC. The two volumes of instructions and specifications provided standard Southern System maintenance intervals, testing techniques, and maintenance criteria for substation equipment.

Also in 1994, Southern Company began implementing the Substation/Transmission Operations and Maintenance Procedure (STOMP) system throughout the Southern system of electric utilities. STOMP provides an annual prioritized listing of maintenance testing activities for GPC substations. These activities are prioritized for work by predictive failure software. When substation crews complete the maintenance and testing, the results are input to STOMP.

The system uses test information to predict devices most likely to fail and prioritizes maintenance accordingly. STOMP contains a data base of device test results, predicts potential failures, and schedules substation maintenance prior to the occurrence of a predictive failure.

STOMP was not fully operational in all Southern companies until late 1996. Therefore, GPC has only been documenting predictive substation maintenance results since January, 1997.

GPC distribution maintenance is not currently included in STOMP for predictive maintenance scheduling. However, according to company representatives, distribution maintenance will be incorporated into STOMP, or another form of predictive maintenance scheduling, in the near future.

5.4.5 Plant/Equipment Inspection

Plant and equipment inspections are the responsibility of the Power Delivery Manager organization in each geographical area. Inspections are completed by the Engineering and Construction Supervisor field forces, and documented reports of the inspections are retained by the supervisor. Distribution Bulletin 10, titled *Distribution System Inspection and Maintenance Program*, outlines the steps necessary to inspect and maintain GPC distribution plant. The procedure also provides direction for proper record keeping of maintenance activities completed, in compliance with FPSC Rule 25-6.036 requiring such inspection programs for each electric utility under the jurisdiction of the Commission.

These inspections are completed in a five-year cycle for overhead, underground and submarine distribution plant and equipment. Transformer Load Management maps are to be used and marked to indicate inspections made, deficiencies identified. and the disposition of any deficiencies. The person performing the inspection is responsible for recording their name, and date they completed the inspection upon the Transformer Load Management map.

According to the procedure, records are to be retained so that the latest inspection and correction results are available for every location on the system. A progress report of Transformer Load Management or feeder areas completed is to be sent to the Distribution Department by the end of January each year. The Distribution Manager is responsible for updating the procedure, developing inspection checklists, coordinating with districts to complete and record the inspections, and for evaluating work methods to improve reliability. Power Delivery Managers are responsible for ensuring inspection of the facilities, making system corrections, keeping records complete, and making sure reports are made in the proper manner and time frame.

In addition to Distribution Bulletin 10, GPC requires field inspection of customers reporting more than three outages. GPC's Distribution Trouble Report system records the number of customer outages experienced each month and reports customers with more than three recurring outages. In these cases, a company employee completes an inspection and identifies the potential cause and corrective actions to resolve the customer problem.

Distribution Inspections

GPC document request responses indicate the only records of distribution inspections, prior to 1995, were ground-line pole and padmount painting inspections. The total number of inspections completed during the period 1992-1995 is unknown. According to company information, as the result of experiencing two hurricanes during the year, GPC completed an extensive inspection of distribution lines and equipment during the fall of 1995. GPC elected to downsize the 1996 and 1997 distribution equipment inspections and allocate resources elsewhere because of the extensive post hurricane inspection effort. GPC plans to continue annual ground-line pole, padmounted painting inspections, and regular distribution inspections during 1998.

Data compiled from field inspections is generally reported to the Engineering and Construction Supervisor and to Technical Services Distribution staff personnel. This data is used by Technical Services staff to develop projects aimed at correcting problem areas and to update budget requirements. Minor improvements are completed by line crews at the time field inspections are made. Larger projects are reported for later correction and are included in the budget.

Substation Inspections

During the period of 1992-1995, GPC substation maintenance records show mainly breaker maintenance, painting information, and Doble test results. GPC document responses indicate that regulator maintenance reports were not input to automated records because of the large number of units and the lack of available manpower in corporate offices to record the data. Regulator counter readings were downloaded from quarterly substation inspection reports to document inspections completed. Regulator test sheets are kept in division and district files to document the results of testing efforts.

Prior to 1997, GPC substations were routinely inspected within the cycle inspection program. According to GPC document responses, 1997 was the first time divisions were responsible for input of substation maintenance information and for creating maintenance work orders. It was also the first full year of substation maintenance testing under STOMP. Substation test results are not yet fully entered into the system.

GPC representatives expect that all substation maintenance activity should be entered and tracked through STOMP by the end of 1998. The move to predictive maintenance is expected to greatly reduce the need to complete future substation preventive maintenance inspections. Instead, STOMP will predict when devices will fail and schedule replacement of the device prior to a failure occurring.

5.4.6 Restoration and Repair

Prior to 1994, GPC restoration and repair operations were wholly located in each of the three Divisions, under the responsibility of the Division Manager. Each repair center dispatched crews to repair customer outages within the districts located in its division. In 1994, GPC consolidated the trouble reporting and dispatch function into one Distribution Control Center (DCC), located in Pensacola. The DCC is managed by the Distribution Control Room Supervisor, who reports to the System Protection Manager. The System Protection Manager reports to the Power Delivery General Manager.

The GPC trouble reporting function currently resides within two different reporting organizations, Customer Service and Power Delivery. However, these two organizations report to the same vice president and operate as teams to complete the restoration and repair function. GPC customers may report trouble calls via an Interactive Voice Response unit or by transfer to a Customer Service Representative. If the customer reports the trouble through the Interactive Voice Response, a trouble ticket is automatically generated in the DCC, under the responsibility of the Power Delivery organization. If a trouble ticket is required and generated by the Customer Service Representative, it is transmitted to the DCC, including the Customer Service Representative's last name as an identifier.

The DCC then dispatches the trouble ticket to the work center closest to the problem, and service personnel complete the necessary work to restore the customer's service. Upon completion of the repair work, once the customer's service is again energized, GPC service personnel notify the DCC of the trouble ticket completion. The completion time is manually entered into SERVLOG, a computer data base for capturing and accessing trouble ticket completion information. If the trouble ticket involves a customer outage, the information is entered into the Distribution Outage Report system. Exhibit GPC-26 is a flow chart of the repair reporting and restoration process.

In 1993, Southern Company began a system-wide approach to automating trouble call reporting and analysis. Alabama Power and GPC were selected as pilot companies for a new automated trouble call system. However, until mid-1995, the GPC trouble ticket process was completed and reported manually. The trouble ticket information was manually entered into SERVLOG and report data was extracted from the Distribution Trouble Report system.

In the second quarter of 1995, GPC began using the new Trouble Call Management System. The transformer line number information was downloaded to the Trouble Call Management System from the Transformer Load Management System and cross-referenced with customer account information to automatically identify customers affected by outages. The Transformer Load Management System supplies the number of meters associated with each transformer. Distribution linemen or servicemen are responsible for identifying the number of customers affected by an outage. The number of customers affected from the transformer to the substation is identified by the DCC.

Currently, the Trouble Call Management System does not automatically time and calculate the reported outage length, the number of customers affected, the location, or the type of outage. Instead, the system operator manually enters the time repair work is completed. Actual field counts, field estimates, feeder count information, and average customers per transformer information is used to estimate the number of customers affected by an outage. For small outages the actual field count is used. For larger outages, the other methods mentioned are used.

Today, the Trouble Call Management System allows DCC operators to identify and locate distribution system repair problems, but is not currently equipped to predict an outage type. All

GULF POWER COMPANY
DISTRIBUTION CONTROL CENTER
TROUBLE TICKET PROCESS

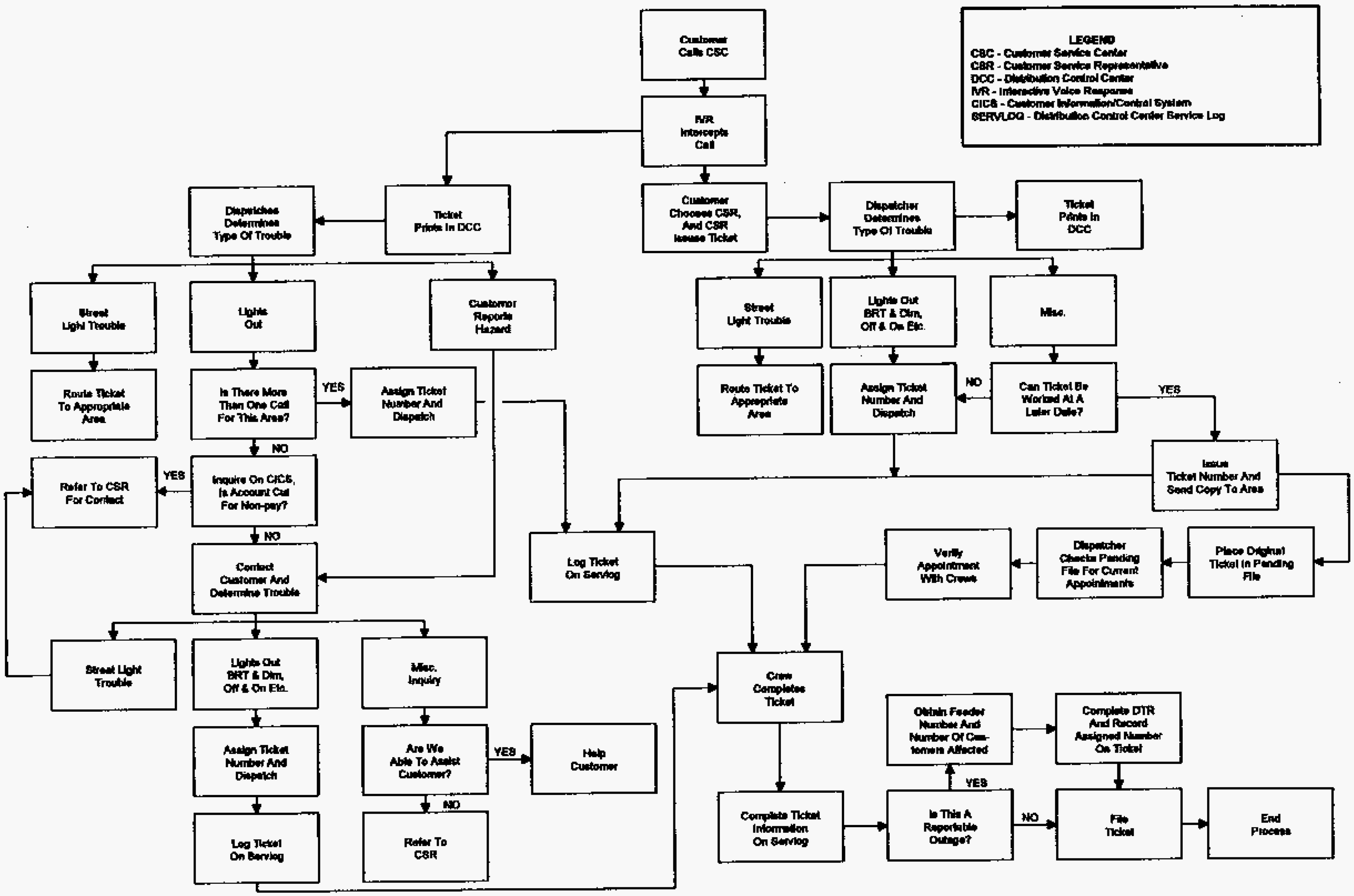


EXHIBIT GPC-26

Source: GPC Response to Document Request 1-16.

areas of the system are not energized at this time, and all features are not currently being used. However, GPC representatives believe that the system will be fully operational, and all features will be useful, by the end of 1997. Company representatives also believe that two Trouble Call Management System software release versions, scheduled for December 1997 and June 1998, will provide replacement of the current Distribution Trouble Report system or allow an interface between the two systems, to extract and record data for trending and analysis. Otherwise, the historical data now in the Distribution Trouble Report would have to be retained in that system, and two systems would require data processing support.

Repair process performance is reflected in the length of time it takes to repair and re-energize customer service. The Average Interruption Time Per Customer Interruption (CAIDI), monitored in the Distribution Trouble Report, indicates the average time GPC customers affected by an outage were out of service. If this index increases, it indicates the company is taking longer to correct repair problems. If the condition persists, customers will begin complaining about the company's service response time. If the index is reduced, it reflects more prompt response and repair service for the customer. Quicker response and repair efforts generally are expected to improve customer perception of company service.

5.5 Recent Trends and Changes

In recent years, GPC and the Southern Company have continued to make additional changes, promising to provide continuing quality and reliability improvements to GPC service. Some of these programs have been previously mentioned in other sections of this report, but bear mentioning in this section for their future benefits to GPC service quality and reliability.

In 1996, GPC began or improved the following programs to further reduce outages, improve crew efficiency and improve service order completion efficiency:

- **Smaller Work Crews** of two-man maintenance crews and one-man trouble crews to improve crew efficiency and coverage.
- **Staggered Work Schedules** to gain efficiencies in manpower and crew usage through better scheduling of different work crews.
- **Placement of New Development Underground Cable in Conduit** to reduce underground outages in new residential development areas.
- **Implementation of STOMP** to predict when substation device outages will occur and prioritize maintenance to replace devices before actual failure.
- **Identification of Underground Cables With Greater Than Three Outages** to target these cables for replacement or injection.

In 1997, GPC began implementing these additional programs:

- **Exempt Staffing Study** to re-evaluate position responsibilities, priority of duties, outsourcing or alternative methods to complete duties and responsibilities, and determine necessary staffing levels for the future.

- **Initial Phase of Automated Resource Management System (ARMS)** which will provide computerized service orders and mapping/location information to GPC service vehicles for more efficient order completion.
- **EMS 2000** to improve GPC automated management of the electric system and diagnostics for the system.

These GPC and Southern Company initiatives and programs are directed at positioning their companies as the preferred provider of electric service in the future competitive environment.

5.6 Conclusions

GPC's TQM efforts in the early 1990's, and ongoing company improvement efforts, have reduced outages and improved system quality and reliability. Since 1992, GPC and the Southern Company have consistently made the following changes and efforts to better serve their customers and prepare for impending electric utility competition:

- Studied and implemented programs to improve the quality and reliability of service

- Standardized on system-wide equipment use

- Refined and updated methods and procedures

- Increased company and employee productivity

- Reduced costs for providing services

- Improved computer systems and their utilization

- Re-engineered GPC's organization and processes

Almost every GPC index used to track service reliability and quality has improved during the period 1992-1997. GPC and Southern Company ongoing efforts to re-engineer processes, standardize equipment and maintenance practices system-wide, and increase employee productivity, have contributed to fewer outages and improved service quality during the period. In addition, these efforts have kept customer service and Commission complaints at low levels.

Overall, GPC internal indices, internal complaint tracking mechanisms, external surveys, and Commission complaint results indicate that GPC customers are reasonably satisfied with the quality and reliability of service provided by GPC during the period 1992-1997.

6.0 Tampa Electric Company

6.1 Company Profile

Tampa Electric Company (TEC) is the third largest investor-owned electric utility in the state of Florida with 1996 operating revenues of $1.1 billion. TEC is a subsidiary of TECO Energy, Inc., a diversified energy-related holding company. The company operates solely within the state and is engaged in the generation, purchase, transmission, distribution and sale of electric energy.

On December 31, 1996, TEC had five generating plants and four gas-turbine peaking units with a total net winter generating capability of 3,650 megawatts. About 98 percent of the company's generation for 1996 was from its coal-fired units. Approximately the same level is expected for 1997.

Electric power is transmitted and delivered via 180 substations (49 transmission and 136 distribution), having an aggregate transformer capacity of 16,235,857 kilo-volt amperes. The transmission system consists of approximately 1,208 pole miles of high voltage transmission lines, and the distribution system consists of 6,866 pole miles of overhead lines and 2,538 trench miles of underground lines. As of December 31, 1996, there were approximately 513,200 meters in service. TEC had 2,798 employees as of December 31, 1996, of which 1,142 were represented by the International Brotherhood of Electrical Workers.

TEC's retail territory encompasses an area of about 2,000 square miles in west central Florida, including substantially all of Hillsborough county and parts of Polk, Pasco, and Pinellas Counties representing a total population of approximately one million. The principal communities served by TEC are Tampa, Winter Haven, Plant City, and Dade City.

To more efficiently and effectively manage its operations, TEC has divided its service territory geographically into eight divisions managed by seven operations centers. The operations centers act almost as a "mini-company" providing engineering and construction services, as well as acting as staging areas, and points of resupply for maintenance vehicles. The eight divisions are Tampa, Mulberry, Brandon, Plant City, Winter Haen, Ruskin, Auburndale, and Dade City.

As of December 31, 1996, TEC served a total of 513,200 customers. Of the year-end total customers, 451,900 (88 percent) were residential, 56,200 (11 percent) were commercial, and the remaining 5,100 (1 percent) consisted of industrial and other customers.

For the ten-year period 1986 to 1996, TEC's total customer base grew at an annual rate of 2.1 percent. The trend in customer growth over the past five years has been slightly lower, however, at 1.9 percent per year. From 1995 to 1996, TEC's total customer base increased 2.23 percent from 501,900 to 513,200.

During 1996, residential customers accounted for 44.2 percent of TEC's retail sales, while commercial customers represented 32.3 percent. Industrial customers comprised only 0.11 percent of TEC's actual year-end customer base for 1996, but accounted for 15.4 percent of total retail megawatt-hour sales. All other customer types claimed the remaining 8.1 percent of 1996 retail sales.

6.2 FPSC Service Quality Indicators

The FPSC currently uses two mechanisms to monitor electric utility service quality: analysis of customer complaints and inquiries received by the Division of Consumer Affairs and monitoring of Distribution Service Reliability Reports (reliability reports). These two monitoring mechanisms provide FPSC staff with useful information for identifying continuing electric service quality and reliability problem areas.

6.2.1 FPSC Customer Inquiries and Complaints

Exhibit TEC-1 depicts total logged service-related inquiries for the years 1992 through projected year end 1997. As shown, inquiries logged with the FPSC regarding TEC have decreased over the period analyzed, declining a total of 44.2 percent from 43 logged inquiries in 1992, to 24 for projected year end 1997. This reflects an average annual decrease in logged service inquiries over the period of 11 percent. The primary subject of an inquiry for the period analyzed was typically regarding high bills and questions regarding rules and tariffs

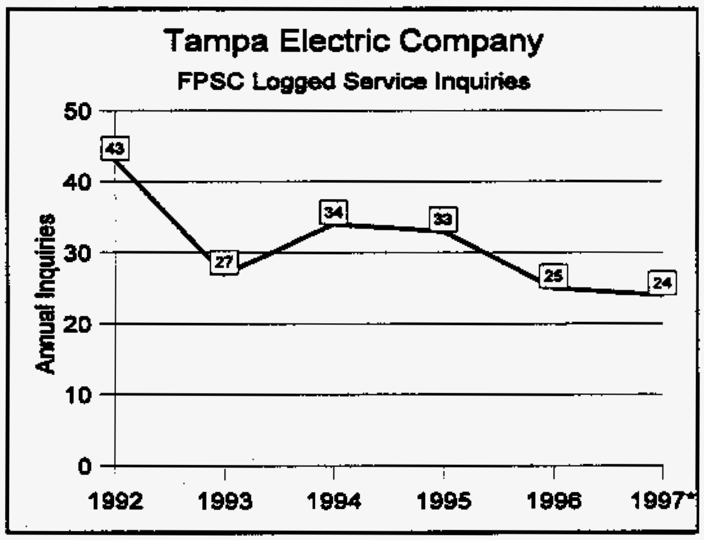


EXHIBIT TEC-1 *Source: FPSC Consumer Activity Report 1992-1997.*

** Actual data through September 1997.*

6.2.2 FPSC Distribution Service Reliability Reports

As shown in Exhibit TEC-2, total interruptions experienced by TEC have remained relatively stable for the period 1992 through 1996, increasing at an average rate of 3.2 percent per year. The company experienced its greatest number of interruptions in 1994 with 10,023, representing an increase of 995 interruptions, or 11 percent, over the previous year. The greatest one-year increase occurred between 1995 and 1996 when the number of interruptions increased 11.32 percent from 8,788 to 9,783.

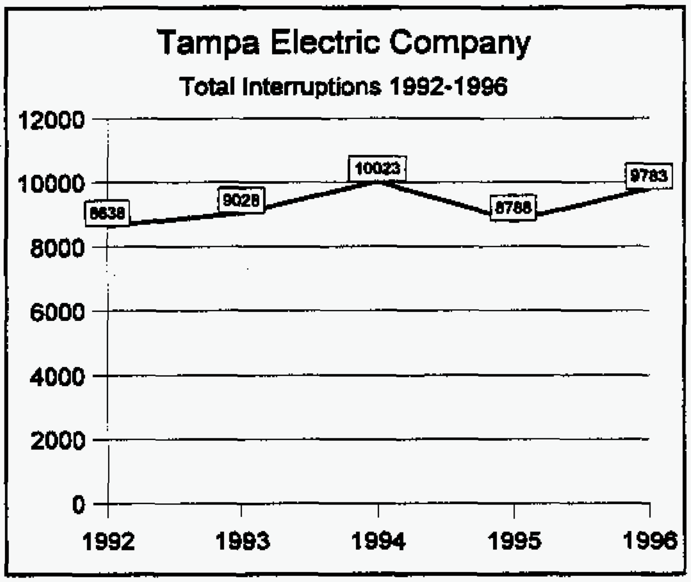


EXHIBIT TEC-2 *Source: Distribution Service Reliability Reports.*

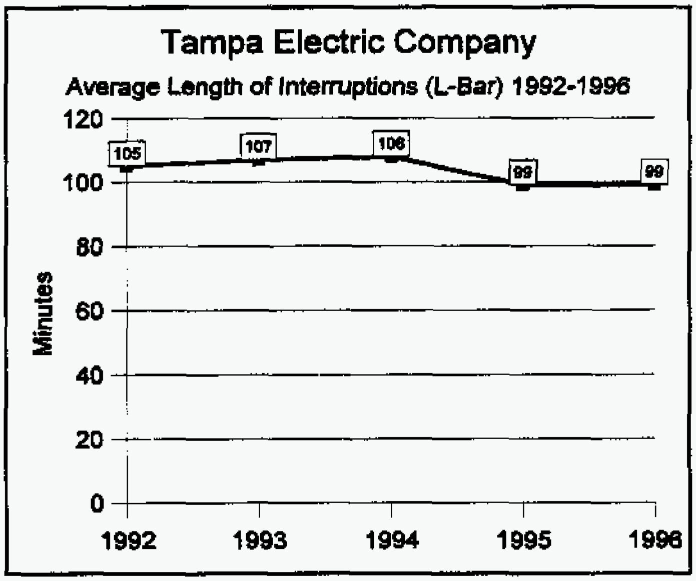


EXHIBIT TEC-3 *Source: Distribution Service Reliability Reports.*

The average length of interruptions shown in Exhibit TEC-3 have also remained relatively constant, ranging from 105 minutes in 1992, to 99 minutes in 1996. The longest interruption for the period was an average of 108 minutes, occurring in 1994. In 1995 and 1996, L-Bar declined to 99 minutes.

This average length of interruption, also known as "L-Bar," is a measure of the average time to restore an interruption from the moment it is reported. This particular measurement equally averages all interruptions, regardless of the number of customers experiencing the interruptions.

Exhibits TEC-4 and TEC-5, illustrate some of the most common causes of service interruptions experienced by TEC during the period reliability reports have been filed by the company. According to TEC, the leading known cause of service interruptions is due to weather/lightning, accounting for an average of 36.1 percent of total interruptions for the 1992-1996 period. The categories of "Unknown" and "Other," respectively, represent the second and third largest categories of service interruptions, representing 16.4 and 16.3 percent of total service interruptions for the four-year period.

Tampa Electric Company
Total Interruptions by Category
1992 Through 1996

CAUSE	1992		1993		1994		1995		1996		1997*	
	Total	%	Total	%	Total	%	Total	%	Total	%	Total	%
Animal	1,400	16	1,228	14	1,154	13	1,400	16	1,771	18	2,747	22
Corrosion	204	3	5	0	83	1	30	1	39	0	39	0
Dig-In	23	0	24	0	16	0	46	1	41	1	44	0
Lightning	3,013	35	3,429	38	4,573	46	2,577	29	3,144	32	4,417	36
Salt Spray	0	0	0	0	0	0	0	0	0	0	0	0
Substation	94	1	37	0	33	0	26	0	36	0	55	0
Transformer	355	4	329	3	274	3	307	3	431	5	339	3
Tree	596	7	606	7	531	5	960	11	805	8	844	7
Unknown	1,368	16	1,586	18	1,757	18	1,505	17	1,366	14	1,681	14
Vehicle	281	3	294	3	297	3	295	3	319	3	329	3
Other	1,304	15	1,490	17	1,305	13	1,642	19	1,831	19	1,833	15
Total	**8,638**	**100**	**9,028**	**100**	**10,023**	**100**	**8,788**	**100**	**9,783**	**100**	**12,328**	**100**

EXHIBIT TEC-4

Source: FPSC Reliability Reports 1992-1996, and TEC Monthly ED Outage Summary and Reliability Report.

**Projected year based on actual amounts at September 30, 1997.*

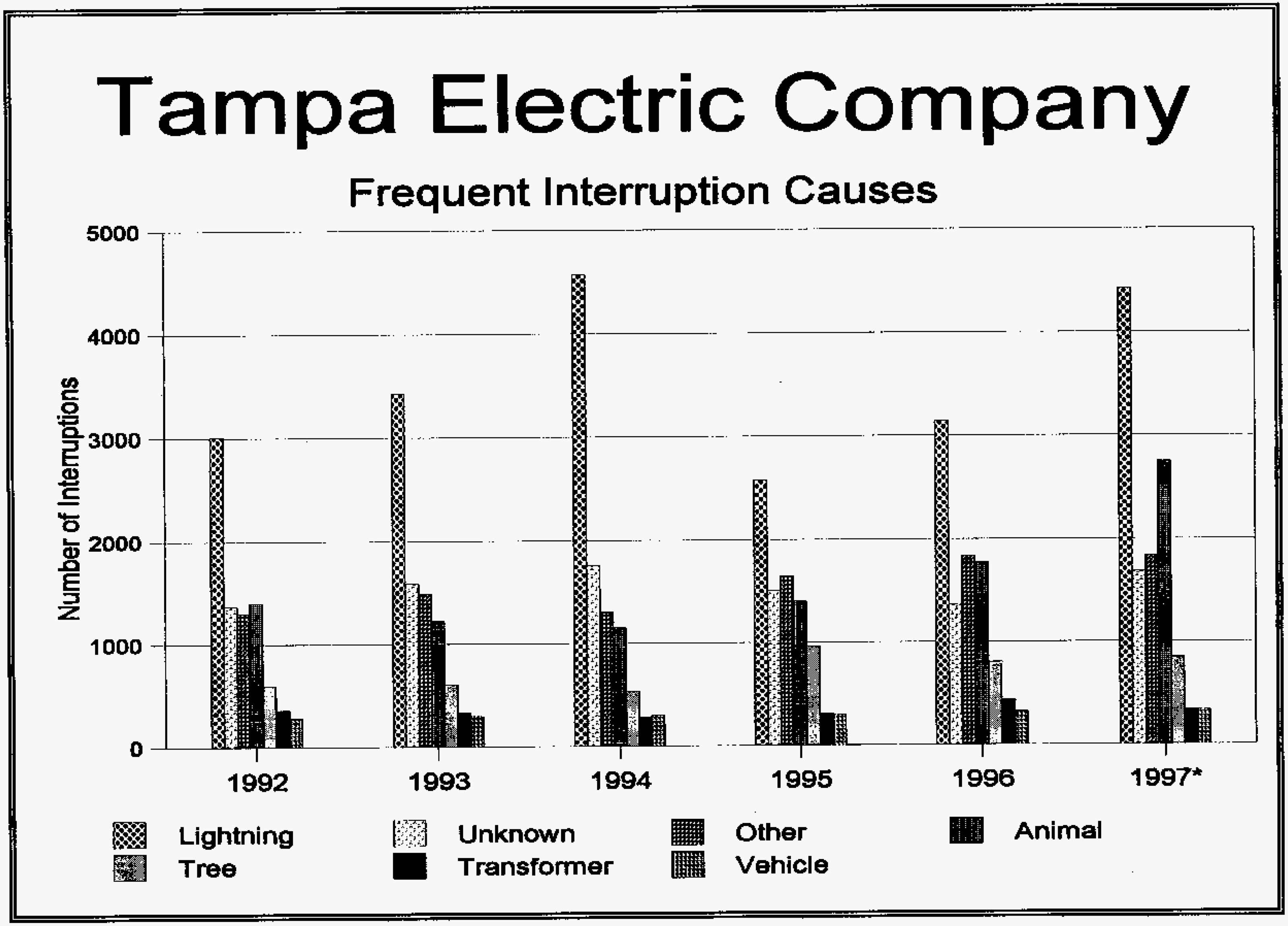


EXHIBIT TEC-5 *Source: FPSC Reliability Reports 1992-1996, and TEC Monthly ED Outage Summary and Reliability Report*

* *Projected year based on actual amounts at September 30, 1997*

Although Commission Rules require that interruption data be separated by overhead and underground, TEC does not make this separation when filing its annual reliability report. According to TEC, such a separation would be difficult to do, and because of a lack of standard in reporting by all utilities, would not be useful as a comparative tool if the separation was made. As a result, an analysis of interruptions by overhead and underground could not be made.

Further hampering the analysis was the large number of interruptions included in the categories of "Other and "Unknown" previously described. TEC states that these categories are frequently used because not every interruption will clearly fit one of the designated categories, and many times it cannot be readily determined what the cause of the outage actually is.

6.3 Company Service Quality Indicators

Tampa Electric constantly monitors the performance of operations in order to gauge the quality of service provided to its customers. Analytical measurements of service reliability are one factor in the measurement of over-all service quality. Typical methods employed in this effort are calculation and monitoring of internal reliability indicators. These indicators measure key performance relationships and provide an objective look at how the company is performing currently and over time.

In addition to analytical measurements, service quality and reliability can be assessed by customers' perceptions of quality. To aide in measuring its customers' perception of service quality, TEC gathers and analyzes data through customer complaints handled by the utility, the use of customer satisfaction surveys, and analysis of damage claims filed against the utility by customers.

6.3.1 Internal Reliability Indicators

TEC uses several internal reliability indicators to measure system performance including planning, design and operations. The most used reliability indicators for these purposes are the System Average Interruption Duration Index (SAIDI), the Customer Average Interruption Duration Index (CAIDI), and the System Average Interruption Frequency Index (SAIFI).

To make the reliability data as useful as possible, TEC not only calculates these reliability indicators in total, but also breaks them down by each of the seven service areas. This gives the company the ability to analyze outages and related causes and response times by area.

To make these indices represent normal operations of the utility, TEC will exclude certain events from their calculation. For example, planned system outages are excluded from reliability index calculations. Interruptions of service less than one minute in length and the effects of named tropical storms and hurricanes are also excluded from the calculations.

TEC not only uses these indicators to measure and analyze performance, but also uses them as an incentive component as part of employee pay. The company uses a complex calculation, a component of which includes these performance indices, in determining its contribution to its employee stock ownership plan (ESOP). Although only one part of the calculation, this does provide financial incentive for improving system performance.

System Average Interruption Duration Index (SAIDI)

This index is generally considered to be a reflection of operating performance and indicates the total minutes of interruption time the average customer will experience in a year. SAIDI is calculated by dividing total customer minutes of interruption by total customers served. An upward trend in SAIDI is normally perceived as a reduction in reliability, whereas a downward trend is perceived as an increase in reliability. Factors having a direct influence on this index include the severity of the storm season, and the number of customers impacted by component interruptions due to system design. All interruptions have an incremental impact on this index. As the duration of an interruption increases or the number of customers involved in an outage increases, the impact on this index also increases.

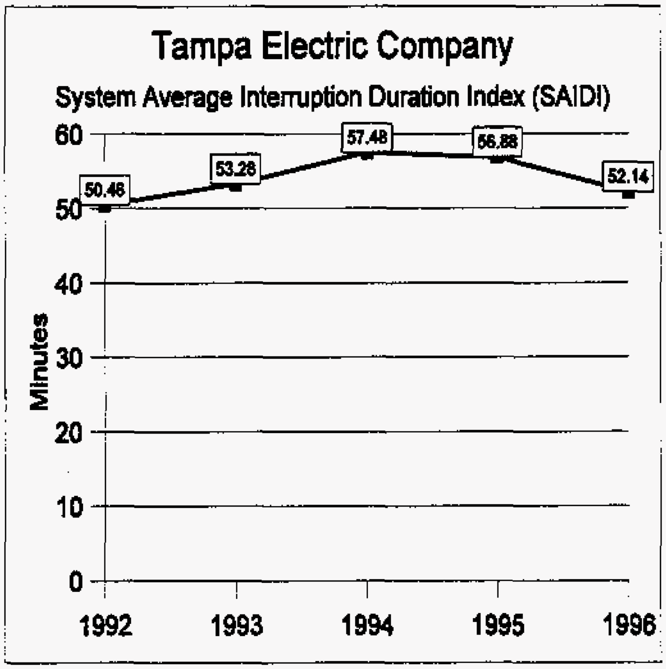


EXHIBIT TEC-6 *Source: TEC response to Document Request 2-1.*

As shown in Exhibit TEC-6, Tampa Electric's SAIDI has remained relatively stable from 1992 through 1996. In 1992 the index was at 50.46 minutes, and though it increased to its maximum for the period of 57.48 in 1994, it decreased to 56.88 in 1995, and 52.14 in 1996.

Customer Average Interruption Duration Index (CAIDI)

This index indicates the average amount of time a customer who experienced an interruption will be out of service and is generally considered to be a reflection of operating performance. CAIDI is calculated by dividing customer minutes of interruption by the number of customer interruptions. Like SAIDI, a decline in CAIDI over time is normally perceived as an improvement in reliability, with an increase over time perceived as a decrease in reliability. The number of customers affected by a given interruption can have a significant effect on this index.

This index is most affected by interruptions involving large numbers of customers. Thus, an overall increase in major interruptions with short durations gives the false impression of improving this index. Conversely, light storm season activity that results in numerous small interruptions in comparison to major interruptions, is reflected in an increase in CAIDI, which may be interpreted as a decrease in operating efficiency.

Exhibit TEC-7 depicts the relatively steady increase in CAIDI beginning in 1993 after an initial drop between 1992 and 1993 of 6.9 percent. The index rose a total of 15.6 percent from its 1993 low, to 46.62 minutes in 1996, representing an average annual growth rate of 5 percent over the three-year period (1.8 percent measured from 1992).

System Average Interruption Frequency Index (SAIFI)

This index is normally considered a reflection of reliability as it relates to system design. SAIFI indicates the number of times per year that the average customer can expect to be out of service. SAIFI is calculated by dividing the number of customer interruptions by customers served. An upward trend in SAIFI is generally perceived as a reduction in reliability. According to TEC, the major factor influencing this index is the severity of the storm season.

SAIFI is most affected by outages involving large numbers of customers. Years where a severe storm season is combined with a large number of major disturbances reflect the worst frequency indices.

The company's SAIFI increased steadily from 1992 to 1994, as indicated in Exhibit TEC-8, and from 1994 through 1996 displayed a similar decrease. For the four-year period, TEC customers experienced, on average, 1.297 interruptions per year. This is compared to 1996 when the average number of interruptions were at their lowest at 1.235 per year, and 1994 when interruptions were at their highest level of 1.425 per year.

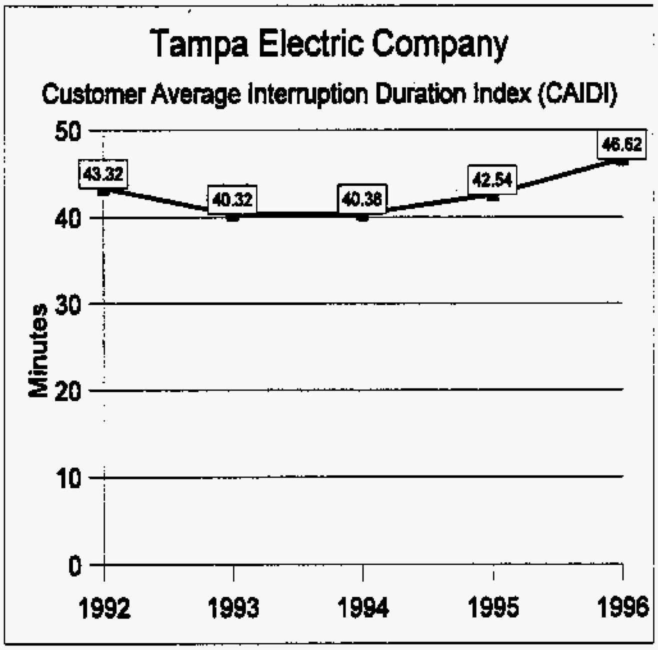


EXHIBIT TEC-7 *Source: TEC Response to Document Request 2-1*

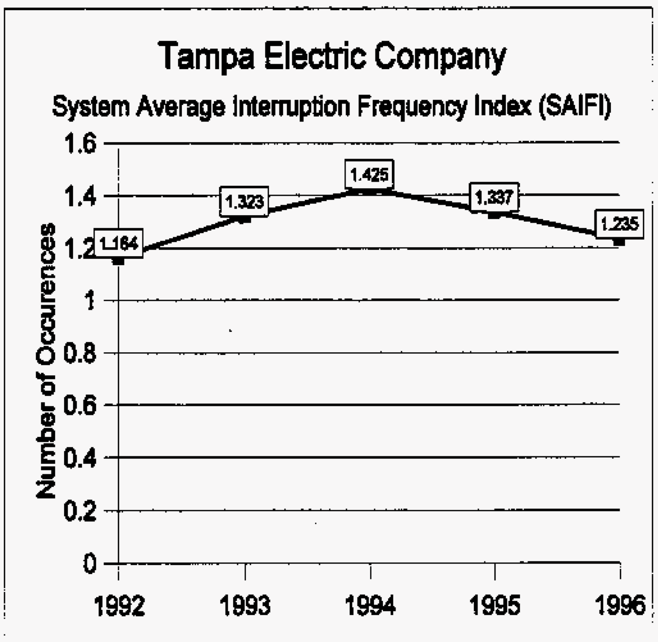


EXHIBIT TEC-8 *Source: TEC Response to Document Request 2-1.*

Other Measurements and Indicators

In addition to the reliability indices discussed above, TEC also tracks and uses several other indices and measurements to monitor system performance. For the period 1992 through 1997 to date, TEC has tracked the following:

- *Average Customers Per Interruption (ACPI)* - This index tracks the average number of customers that are interrupted each time there is an interruption.

- *Average Service Availability Index (ASAI)* - Referred to in the industry as the "index of reliability," it is the percentage of time during a given year that the average customer was in service. This index is the graphical inverse of the SAIDI index.

- *Average Hours per Interruption (AHI)* - Average interruption duration for a particular distribution system component.

- *Customer Interruptions (CI)* - The number of interruptions of one minute or longer to customers. For example, if a component serving two customers failed four times, the component would contribute 2x4=8 to the CI.

- *Customer-Hours of Interruption (CHI)* - Customer interruptions multiplied by the hours of duration of that interruption.

6.3.2 Utility-Handled Inquiries and Complaints

For the period 1992 through 1996, TEC recorded an average of 119,500 customer contacts (phone, walk-in, and mail) per year reporting trouble alone, with 95,000 contacts as of August 31, 1997. The majority of contacts by customers come in the form of telephone calls. Annually, TEC receives about 1.5 million calls from customers that range from requests for company brochures, to calls reporting trouble, to calls requesting credit arrangements.

Exhibit TEC-9 graphically depicts total calls by customers received by TEC over the period 1992 through projected 1997. As is shown, customer calls of all types were at their lowest level for 1992 at 963,926 before increasing 69.5 percent to 1,634,405 calls in 1995. Beginning in 1995, total calls by customers received at the company leveled out through projected 1997, averaging 1,516,431 calls per year.

Calls received by TEC to report trouble--a component part of total calls received--have experienced an inconsistent pattern in movement as shown in Exhibit TEC-10. These calls consist of all calls placed to the company to report trouble and, in many cases, include multiple calls to report the same trouble.

Analysis of customer complaints made directly to the utility is one method available to determine customers' perceptions of service quality. The number and types of complaints received from customers during a given time period can give the utility insight into quality of

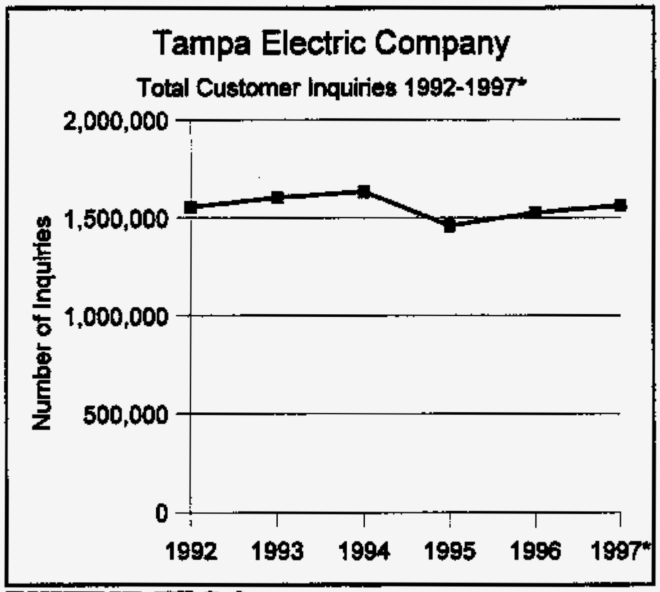


EXHIBIT TEC-9 *Source: TEC Response to Document Request 2-18.*

** Projected year based on August 31, 1997 data.*

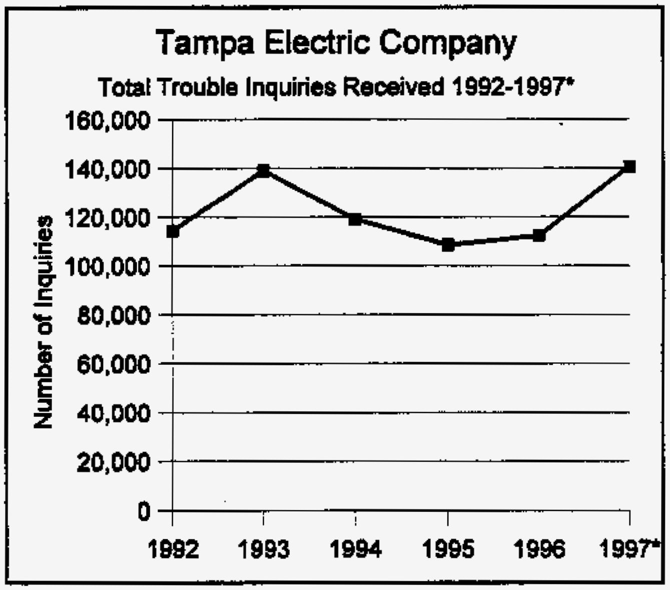


EXHIBIT TEC-10 *Source: TEC Response to Document Request 2-18.*

** Projected year based on August 31, 1997 data.*

service provided to customers. Comparing the level of complaints received to previous periods can tell the utility how well it is doing to address customer concerns and can show the utility where to focus more attention to correct lingering problems.

Typically to file a complaint, a customer will contact TEC directly - usually by phone, however, customers may contact the company by walk-in or by mail. When contacted directly, a customer representative will speak with the customer and obtain pertinent information regarding the complaint. The customer representative will then code the customer's account identifying the nature of the contact (high bill, request energy audit, outage complaint, voltage problems, etc.).

The customer representative will try to help the customer with their complaint to the extent possible and will transfer the call if necessary (for instance, in the case of a billing problem). If the customer's complaint is regarding a service problem, the representative will generate and send a trouble ticket, being sure to provide any relevant explanation of the complaint. The customer representative is then required to provide the customer with their name and phone number and advise the customer that a TEC representative will contact them by the end of the next business day. After the trouble ticket is entered into the system, it is processed and worked in the usual way. Once completed, the customer is to be contacted to verify that the problem has been corrected. The customer is also to be advised to contact TEC if a subsequent problem occurs.

6.3.3 Customer Satisfaction Surveys

Results of customer satisfaction surveys indicate that on average, TEC's customers are satisfied with the quality of electric service they are receiving. Approximately 94.0 percent of the customers responding to the surveys administered from 1992 through 1995 indicated they were either "satisfied" or "very satisfied" with the quality of electric service they were receiving. The highest dissatisfaction rate of customers responding to the surveys was six percent. When asked about the effect of interruptions, most customers (an average of 77.5 percent) stated short outages of less than one minute had the least impact on them, whereas an occasional long outage of approximately 50 minutes was more of an inconvenience.

TEC began using customer satisfaction surveys in 1988 when the company hired an outside contractor to conduct telephone surveys. The following year, TEC began issuing a mail survey in which 2,000 of its customers were randomly selected and sent a copy. In 1997, the sample size was increased to 4,000 customers to increase the reliability of the survey to the range of plus or minus two to three percent.

The objectives of each survey can vary also; one may be comprehensive in nature, gathering customer perceptions on the company's image, to determining the effect of voltage fluctuations, while another may focus on how many momentary interruptions are considered an inconvenience by the customer. The objective of this effort is to identify perceived dissatisfaction by the customer, and develop ways to address and reverse such dissatisfaction. The results of the customer satisfaction surveys are also included as a component in the calculation of TEC's contribution to the "Success Sharing" program, a part of the employees' compensation.

TEC's customer satisfaction surveys are conducted quarterly by staff within the Energy Services and Planning Delivery Business Unit who are experienced and qualified in research techniques. Personnel from Energy Delivery requesting the survey will work with the Research personnel in designing and developing the survey to be used--in some cases, a previous survey will be acceptable.

6.3.4 Customer Damage Claims

Exhibit TEC-11 depicts the total dollars paid-out for all types of customer property damage claims filed against TEC for the period 1992 through projected 1997. Tampa Electric was unable to break-down property damage by damage caused by power related sources, versus property damage due to incidents such as auto accidents. TEC's average claims paid over the period shown was $640. The total amount of claims paid over the period was $4.6 million, compared to $6.5 million in claims filed for the period. As of September 30, 1997, TEC paid-out a total of $291,536 in property damage claims, with actual claims incurred of $322,503. Exhibit TEC-12 graphically compares the Average Claim Incurred and Average Claim Paid for the period.

Tampa Electric Company Claims 1992-1997*						
Year	No. Claims Filed	Claims Incurred	Claims Paid	Claims Outstanding	Average Claim incurred	Average Claim Paid
1992	1,239	$1,081,873	$1,028,504	$53,368	$873	$830
1993	1,193	$721,399	$658,958	$62,441	$605	$552
1994	1,243	$817,957	$622,002	$195,955	$658	$500
1995	1,189	$2,642,345	$1,480,238	$1,162,108	$2,222	$1,245
1996	1,255	$768,587	$484,314	$284,273	$612	$386
1997*	1,171	$430,004	$388,715	$41,289	$367	$332

EXHIBIT TEC-11 *Source: TEC Response to Document Request 2-19 and 4-17.*

* *Projected year 1997, based on actual amounts at September 30, 1997*

No proactive attempt is made to inform customers of their right to file a damage claim with TEC. The only unsolicited notification given appears on the back of the customer's monthly bill where a brief statement asks the customer to contact TEC if they have any questions or complaints. Phone numbers and addresses are provided for reference, including the FPSC's toll-free complaint number.

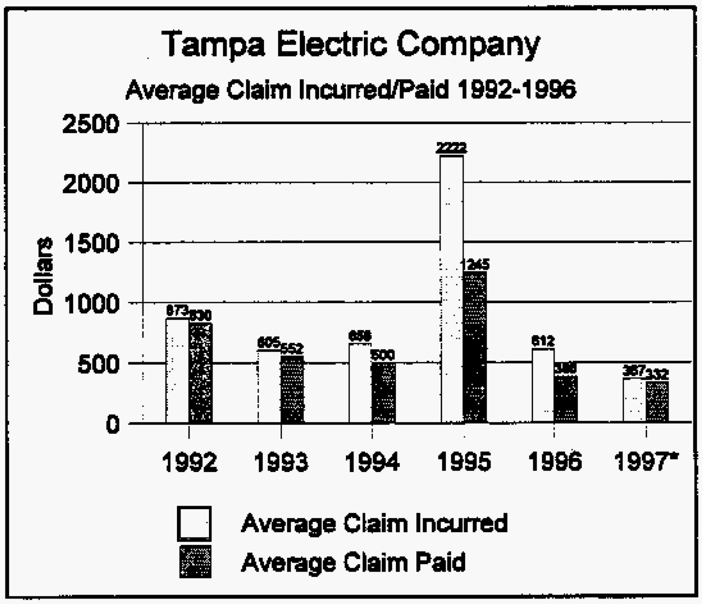


EXHIBIT TEC-12 *Source: TEC Response to Document Request 2-19 and 4-17.*

* *Projected Year based on actual amounts at September 30, 1997.*

One method to help reduce the claims related to energy delivery is to educate customers about the hazards of lightning and other power fluctuations. To this end, Tampa Electric employs several forms of media to inform customers on how to protect their homes and property against lightning strikes and power surges. Media employed in this effort includes press releases, advertisements in newspapers and on radio and television, commercial news letters, and even the Internet.

As depicted in Exhibit TEC-13,

the process for resolving a damage claim begins with the customer contacting TEC to make a complaint. As described in the process for handling customer inquiries, a customer service representative will take down all pertinent information from the customer and enter it onto a customer inquiry form.

Once completed, the customer inquiry form is sent to TEC's Risk Management Department. The Risk Management organization is comprised of a director, supervisor, and manager, each with a staff of five, and a senior administrative specialist who report directly to the vice president of Risk Management.

Once in receipt of the customer inquiry form, Risk Management will conduct an investigation through TEC's Trouble Analysis System (discussed in more detail in section 6.4.6). The purpose of the investigation is to verify that there was some type of trouble reported or indicated at the location and time where the damage claimed to have occurred. According to TEC, no distribution trouble can affect a customer and not be recorded on the Trouble Analysis System.

If the investigation determines the location did experience trouble during the time in question, the claim is further investigated. Issues looked at during this phase include: is TEC liable for the cause of damage; and, could the trouble reported have caused the damage claimed. Once all elements of the claim have been looked at, TEC will decide to pay the claim or not.

The process is straight forward from this point: if TEC determines they should pay, the amount is determined, payment is made, and the case is closed. If the decision is that the company should not pay, the customer is informed of that decision. There is no appeal process; the case is closed.

TAMPA ELECTRIC COMPANY
DAMAGE CLAIM PROCESS
AS OF AUGUST 1997

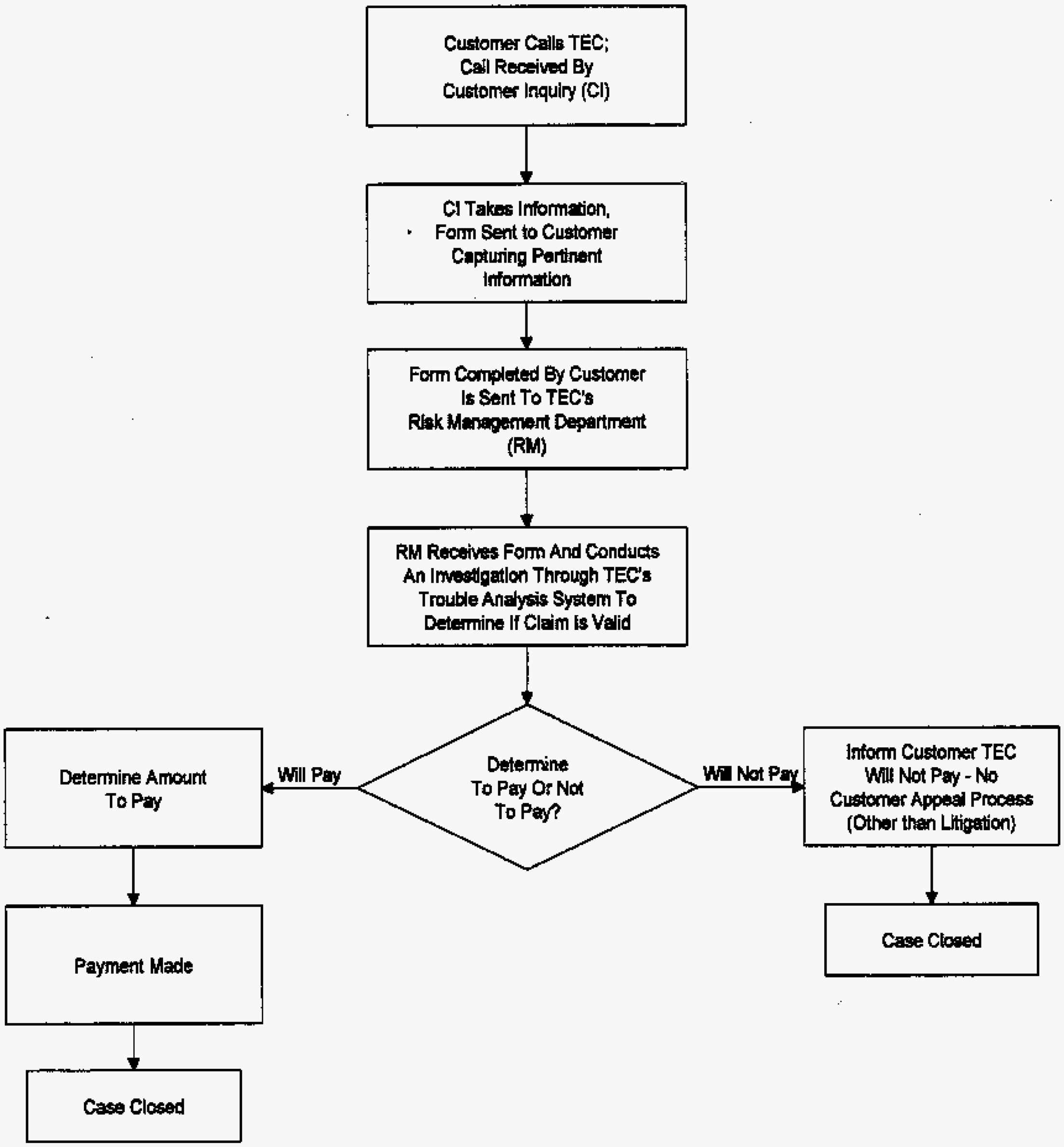


EXHIBIT TEC-13

Source: TEC Document Requests 1, Questions 1,5,13, and 19

6.4 Distribution Organization and Service Quality Activities

Tampa Electric's Energy Delivery organization is the group directly responsible for developing, operating and maintaining the company's electric power distribution systems. Some of the responsibilities include construction and maintenance of transmission and distribution lines and substations and related maintenance, Energy Delivery system planning, and substation operations. This group also tracks and reports statistics on quality of service, including service reliability reports to the FPSC, as well as industry recognized reliability indices used for internal purposes.

6.4.1 Structure, Staffing and Functions

Exhibit TEC-14 depicts TEC's present distribution organizational structure, highlighting the upper-management positions directly responsible for ensuring the reliability of the company's distribution network. As shown, the department is headed by the Vice President of Energy Delivery with three directors and one manager reporting directly to him.

The Director, Energy Delivery Systems is responsible for the processes that keep the electric current flowing through the system. These processes include switching, dispatching of trouble men and servicemen, line clearing activities (tree-trimming), and repair and maintenance activities. Responsibility for collecting and reporting data on system reliability is another responsibility of the Director of Energy Delivery Systems.

The Director of Energy Delivery Engineering and Construction is responsible for all phases in the planning and construction of transmission and distribution lines and related substations. Substation operations and electric meter operations are also under the control of this director.

The Director of Energy Delivery Operations is responsible for directing the planning, design, engineering, marketing interface, performance analysis, system security, and support services for the electrical system from the power plant to the customer's meter. In addition, this position is responsible for directing the construction, operation, maintenance, and testing of all substation and metering facilities.

Energy Delivery's current three director organization has been in place since December 1, 1995, when it changed from the previous structure consisting of a director at each of the seven service centers. Part of this change was to facilitate communication and allow the directors to better prioritize the allocation of resources to where they are most needed.

In December 1995, TEC's Operations Centers changed their organization from being managed by a general manager to a manager. The only exception was for the Plant City center. Because that center is responsible for two divisions, it remains headed by a general manager. According to TEC, its Energy Department has been in the process of refining the organization for several years. The objective is to eliminate layers of management, streamline processes, cut

TAMPA ELECTRIC COMPANY
ENERGY DELIVERY
DIRECTOR LEVEL ORGANIZATION
1997

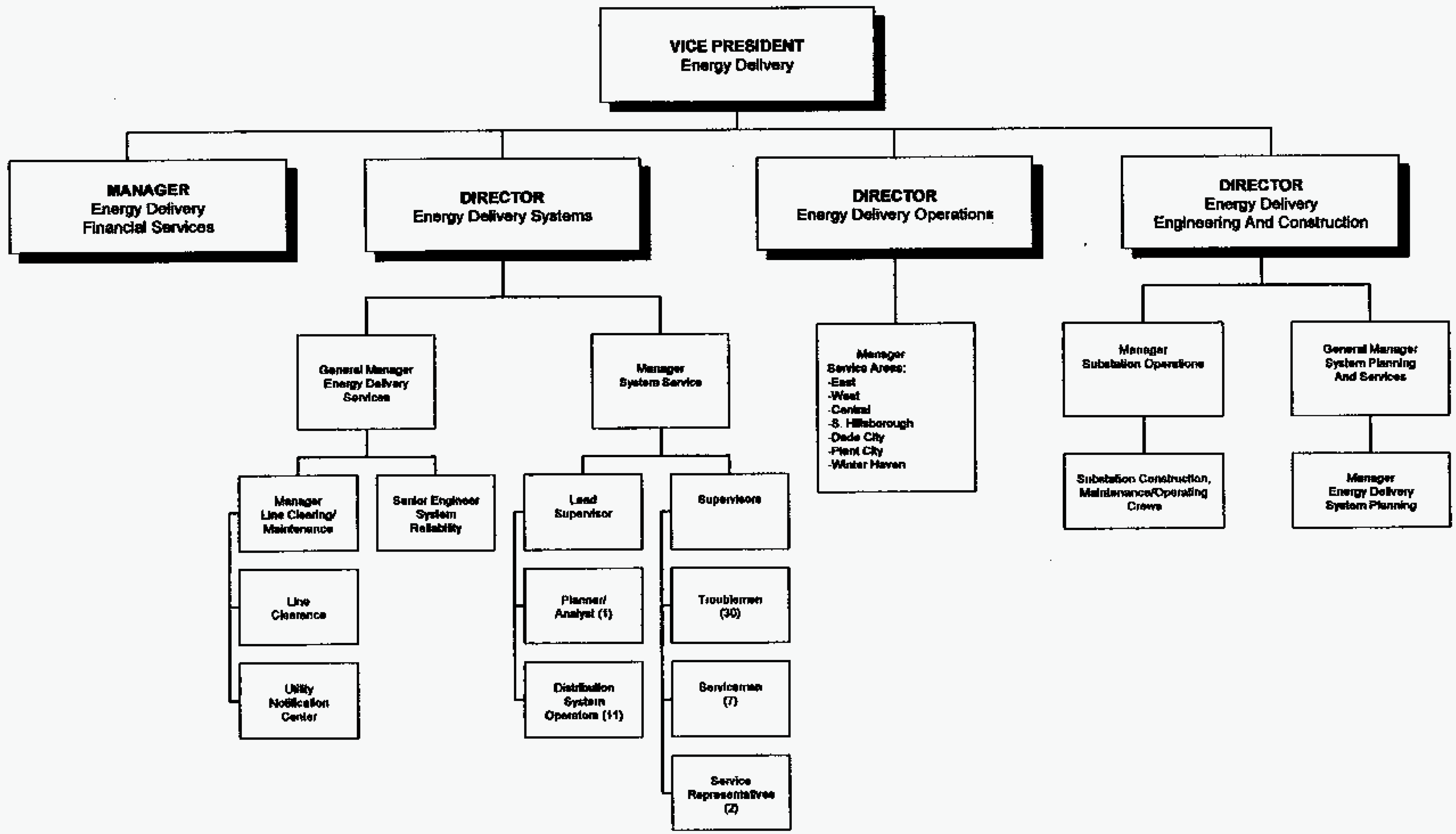


EXHIBIT TEC-14

Source: TEC Response to Document Request 1, Item 5.

costs, improve efficiency, and make the organization more responsive to their customers, according to TEC. The change from general managers to managers in service areas is part of that ongoing process.

6.4.2 Maintenance Planning

The necessity for adequate maintenance planning is evident when looking at the significance of Operating and Maintenance (O&M) expenses over time. Exhibits TEC-15 and TEC-16 point out this significance as they illustrate both the magnitude and trend in total O&M expenses and a component, Distribution O&M expense for the period 1992 through 1996. As Exhibit TEC-15 indicates, total O&M expenses increased relatively steadily over the period, increasing a total of 9.4 percent in 1996 over 1992 at an average annual rate of 2.3 percent. In comparison, Distribution O&M expense increased at an annual rate of 2.9 percent for the two-

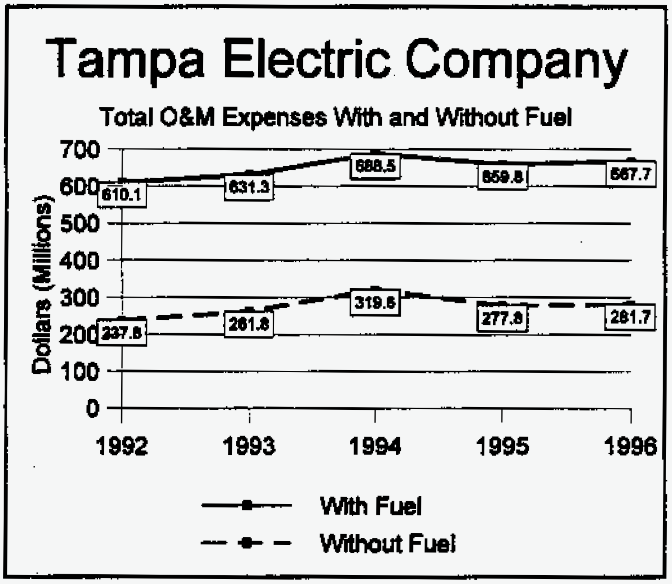


EXHIBIT TEC-15 *Source: TEC FERC Form 1, Annual Reports 1992-1996.*

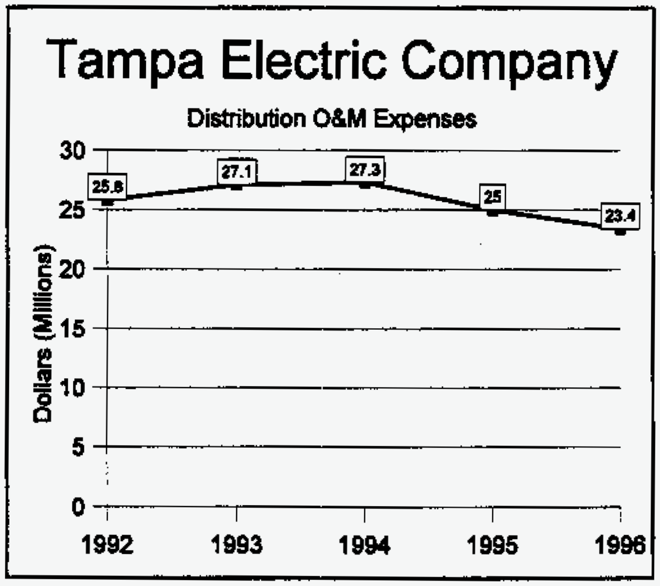


EXHIBIT TEC-16 *Source: TEC FERC Form 1, Annual Reports 1992-1996.*

year period 1992 through 1994, then declined at a rate of 7.4 percent per year from 1994 through 1996. In total, 1996 Distribution O&M was reduced approximately $2.4 million, or 9.3 percent, from 1992 levels. As the dollar amounts alone indicate, maintenance planning is essential for the proper functioning of the maintenance process.

TEC's current maintenance planning process began in 1995, with the goal of centralizing the maintenance planning function, while combining the coordination of this effort with the other transmission and distribution planning activities. The maintenance planning process, as it currently exists, is closely tied to the budgeting process. The end product of this process can be seen in Exhibits TEC-17 and TEC-18 which present, in summary form, the 1997 and 1998 maintenance plans.

The maintenance planning process is divided into three major processes:

- Identification of corrective and preventative maintenance projects.
- Prioritizing and approval of maintenance projects.
- Monthly comparison of approved maintenance projects with budget to determine additional projects to complete.

Maintenance projects are broken into two categories--preventive and corrective. Preventive maintenance is generally routine repairs made on equipment that is still in good operating condition with the goal being to extend the life and reliability of that equipment. This type of maintenance can be more easily planned and budgeted because the related equipment is still in good operating condition. Corrective maintenance, on the other hand, is much more difficult to plan and budget. Equipment associated with corrective maintenance has been discovered to have failed which, based on the significance of the part, may require immediate attention.

These preventive and corrective maintenance activities are identified at the operating levels and are typically the result of TEC engineering, construction and service personnel observing the need of maintenance or replacement of equipment during the course of their daily assignments. When one of these maintenance items is discovered, it is noted in memo form and submitted to the relevant service center at the end of the day. The memo is forwarded to the planner assigned to that service center. Corrective maintenance items are then scheduled for completion, while preventive maintenance items are prioritized and completed as the budget allows.

A steering team made up of planners and managers of TEC's operating and engineering areas assign a priority (from 1 to 4 based on the significance of the item) to each maintenance item associated with their individual areas. The list of projects is then regrouped by that priority and approved for completion by the team.

The final list of ranked preventive maintenance activities is used to guide and determine which activities are completed first. Monthly, the remaining projects are compared to the remaining budget to determine which, if any, additional projects can be completed.

TEC's substation operations has gone a step further by formalizing the maintenance planning process. The component parts of substation operations subject to the maintenance process are identified. For each, the types of maintenance the equipment is subjected to is identified (preventive and/or corrective). Maintenance cycle parameters are indicated for equipment subject to preventive maintenance.

Tampa Electric Company
1997 Preventive Maintenance Plan

Priority	Description	Budget *	Priority	Description	Budget *
1	Transmission and Distribution Metering (Testing)	$2,176,784	25	Distribution line transformer switchgear retrofit	$85,000
2	Transmission line and pole inspection	$110,000	26	Substation automated maintenance program pilot	$20,000
3	Distribution pole inspection/replacement	$702,587	27	Replace OZ & FLO breakers	$210,152
4	Substation transformer inspection/testing	$512,220	28	Substation transformers-install LTC oil filters	$77,800
5	T&D breaker maintenance	$756,597	29	T&D substation maintenance	$124,827
6	Replace 2-230kV BZO breakers	$227,950	30	Distribution line patrol (OH/UG)	$328,014
7	T&D line clearing and herbicide	$6,345,757	31	Distribution capacitor patrol/maintenance	$50,249
8	T&D substation maintenance-Equipment Maintenance	$223,938	32	Substation grounding-inspection & maintenance	$43,230
9	T&D monthly metering	$218,968	33	Protection and Coordination	$143,297
10	T&D substation maintenance-Inspection & testing	$764,106	34	Transmission line & pole R/W maintenance	$263,552
11	Transmission line & pole inspection-structure replacement	$1,238,000	35	Distribution OCR/reg. (SCADA)	$207,926
12	Transmission and Distribution Metering (Testing)	$396,424	36	Distribution line transformers-animal guards	$60,079
13	Substation transformer cooler and fan replacement	$219,600	37	Padmounted 3 phase transformer planned painting	$99,430
14	Transmission static wire	$250,000	38	Substation arrestor inspection	$11,000
15	T&D EMS/RTU inspection and testing	$131,952	39	Transmission tower guards	$37,500
16	Distribution line transformers/switchgear inspection/testing	$181,200	40	Distribution circuit grounds and arresters	$196,800
17	Distribution line transformers/switchgear painting-customer call-in	$247,500	41	Distribution network-retrofits	$227,804
18	Replace epoxy bushings	$110,777	42	Distribution capacitor radio controllers	$71,000
19	T&D EMS/RTU-replace obsolete	$133,000	43	T&D underground cable-replace takeoff	$49,800
20	Distribution network inspection & testing	$52,046	44	Transmission line and pole inspection	$10,700
21	Relamping	$516,600	45	Distribution line transformer switchgear	$18,090
22	Distribution line & station regulators	$4,379	46	Hathaway relay changeouts	$13,500
23	Transmission underground cable	$25,596	47	Carrier and tone relay changeouts	$150,000
24	Distribution line transformer switchgear inspect	$2,454		Total Preventive Maintenance (Proposed O&M and Capital)	$18,048,185

EXHIBIT TEC-17 ** Amounts include both O&M and Capital budgeted amounts.* *Source: TEC Response to Document Request 2, Item 3.*

1998 Preventive Maintenance Plan

Priority	Description	Budget *	Priority	Description	Budget *
1	Transmission & Distribution Metering	$1,667,302	29	Distribution line transformer switch gear	$185,680
2	Transmission line and pole inspection	$154,500	30	Substation painting/refurbishing	$67,000
3	Substation inspections	$247,832	31	Relamping	$503,179
4	Distribution pole inspections	$810,000	32	Substation CB replacements-69kV (5)	$200,000
5	Substation transformer maintenance	$488,212	33	Substation CB replacements-15kV	$172,577
6	T&D breaker maintenance	$614,783	34	Substation maintenance application	$30,000
7	Mulberry substation rebuild	$914,800	35	Substation PCB equipment removal	$94,845
8	T&D substation maintenance	$1,157,123	36	Substation transformer-(install LTC oil filters)	$67,130
9	Replace 2-230kV BZO breakers	$329,200	37	Distribution OCR	$147,656
10	Transmission switch maintenance 5yr cycle	$60,900	38	Distribution circuit grounds and arresters	$196,800
11	T&D line clearing/herbicide	$5,908,379	39	Substation grounding (inspect and repair)	$48,400
12	Obsolete protection and control equipment	$446,700	40	Substation arrestor inspection/replacement	$79,850
13	Transformer oil reclamation	$53,193	41	Animal guards	$140,000
14	Distribution UG cable replacements	$90,000	42	Protection and Coordination	$50,242
15	Transmission line & pole inspection	$2,089,036	43	CSP transformer replacement	$20,000
16	Transmission & Distribution metering	$427,285	44	Transmission line and pole (R/W maintenance)	$259,352
17	Transmission static wire	$250,000	45	Distribution regulators-(SCADA)	$60,270
18	Transmission 230kV dampers	$30,000	46	Transmission tower grounds	$37,500
19	T&D EMS/RTU (inspection & testing)	$131,952	47	Distribution network (energy control & SCADA retrofit)	$230,705
20	Distribution line transformers/switchgear	$12,300	48	Distribution static removals	$70,000
21	Stinger cover/tree wire installation	$55,000	49	Distribution GOAB replacement	$20,000
22	Strain guy installations	$110,000	50	Hathaway relay changeouts	$13,500
23	Distribution line transformers/switchgear	$78,165	51	Carrier & tone relay changeouts	$192,000
24	Maritime substation painting/refurbishing	$70,000	52	Adaptive trip ind installations	$50,000
25	T&D EMS/RTU (replace obsolete)	$133,000	53	Pole reconfiguration	$50,000
26	Distribution network (inspection & testing)	$52,046	54	Distribution line transformers/switchgear painting	$91,019
27	Distribution line patrol (OH and UG)	$208,943			
28	Transmission UG cable	$40,000		Total Preventive Maintenance (Proposed O&M and Capital)	$19,899,691

EXHIBIT TEC-18 ** Amounts include both O&M and Capital budgeted amounts.* *Source: TEC Response to DOCUMENT REQUEST-2, Item 3*

TEC states that, in order to reduce their maintenance expenses, they have extended the maintenance cycles of equipment past that recommended by the manufacturer. According to the company, various maintenance cycles were studied by highly experienced people within TEC to develop cycle extensions that could be safely implemented. This concept of "Reliability Centered Maintenance" that is based on extending the maintenance cycle of equipment where prudent--given factors such as age, activity, and overall reliability--both lowers maintenance expense and provides for reliable operation of the system, according to Tampa Electric.

6.4.3 Tree Trimming

Vegetation control encompasses the removal and clearing of all plant matter from transmission and distribution lines. Although tree trimming is the largest component of this process, removal of vines and other vegetative material is also included here.

Interruptions due to trees remained relatively steady from 1992 through 1994 and at an average of 578 per year. Tree-related interruptions increased sharply in 1995 and 1996, rising 66.2 percent and 39.3 percent, respectively, over the 1992 to 1994 average as shown in Exhibit TEC-19 With a projected total of 844 tree-related interruptions, a similar increase in 1997 of 46 percent is also anticipated.

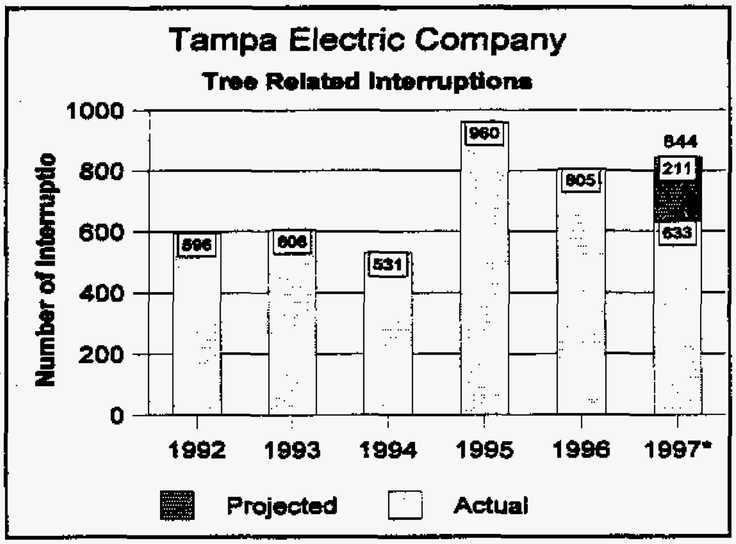


EXHIBIT TEC-19 *Source: FPSC Service Reliability Reports 1993-1997.*

** Projected 1997 based on September 30, 1997 actual of 633.*

TEC directly attributes these increases in "reported" tree related interruptions to two causes: the installation of Mobile Data Terminals in its trouble trucks, and educating trouble men on the importance of accurately reporting the causes of outages. The combination of new technologies and the awareness of the critical nature of reporting the correct causes of outages resulted in the increase of reported tree related outages according to TEC. As further evidence of this cause and effect relationship, TEC points to a corresponding decline in the category of "unknown" outages in 1995 and 1996. The relationships between all reported causes of outages for the period are depicted in Exhibits TEC-4 and TEC-5 in section 6.2.2.

Vegetation control (tree trimming) is the responsibility of the Manager, Line Clearance and System Maintenance, within Energy Delivery Systems. TEC's tree trimming function was centralized and placed under the control of a senior supervisor in the Fall of 1986. Previously, the tree trimming function was divided among the seven service areas, with each of the areas competing for budget money. TEC found that this "geographic" method of tree trimming was sufficient as long as no group got behind due to time or funding. However, the current "circuit" method of tree trimming does not rely as heavily on budgeting dollars to the precise geographic area needed, increasing TEC's flexibility to apply funding where most needed.

By 1996, TEC had gradually moved from a four-year tree trimming cycle to a two-year cycle. The impetus for this change was the results of a 1983 study on the subject which showed the benefit of a two-year versus a four-year tree trimming cycle. TEC contends that its two-year cycle necessary is to keep-up with vegetation growth in order to reduce momentary outages. In its 1992 rate case, TEC requested O&M expenses to fund the two-year cycle, arguing that the two-year cycle and related O&M expense requested recognized the significance of improving service reliability to its customers. The Commission disagreed and only allowed funds for the continuance of TEC's four-year cycle.

Despite the Commission's disallowance of specific O&M expenses to fund a two-year tree trimming cycle, TEC has maintained that pace. It has done so by shifting O&M dollars from other areas into its tree trimming program.

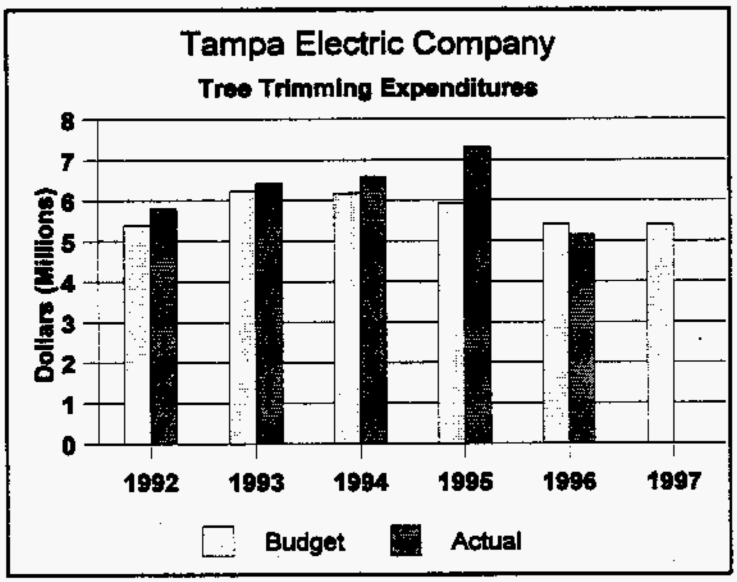


EXHIBIT TEC-20 *Source: TEC Response to Document Request 2-14.*

Exhibit TEC-20 depicts TEC budgeted versus actual line clearing expenses for 1992 through 1996, with projected amounts for 1997. The company experienced a significant increase in line clearing expenses in 1995. Expenses for that year were 23.2 percent over budget and were 10.9 percent higher than the previous year's actual amounts. According to TEC, in 1995 the company continued the practice established in prior years of allocating any surplus O&M dollars to tree trimming in order to establish a two-year trimming cycle. 1995 was the final year needed to establish the two-year cycle accounting for the increase in actual expenditures over budgeted amounts.

According to TEC, the 8.9 percent drop in budgeted and 29.6 percent decline in actual line clearing expenses for 1996 was the result of the increased spending activities in 1995. Because the system had been throughly trimmed, TEC says it was able in 1996 to focus on service and secondary cables, primarily targeting trees with limbs actually contacting the cables.

TEC says it believed these changes in the scope of line clearing were safely made in 1996 without sacrificing service reliability, which resulted in the indicated savings.

Tree trimming is conducted exclusively by contractors at TEC. Currently, TEC employs three contractors--Asplundh, Farrens, and Davy--who work on a continuous basis performing regularly scheduled, as well as "hot-spot," tree trimming.

In 1991, TEC developed the "Contractor Performance Appraisal System" to evaluate the performance of the tree trimming contractors. Under this system, contractors are appraised on time standards, and quality of work, reporting accuracy, management support, customer interaction, and other things. All of these evaluation criteria go into a total performance rating. Failure to meet the evaluation criteria can result in removal from TEC's bid list to termination of the current contract.

The vendor's performance rating is also used to set billing rates for the work. TEC has established a hierarchy of rates that are awarded based on vendor performance as measured by Contractor Performance Appraisal System. Tampa Electric reports that since going to this performance/productivity-based method of contracting in May 1991, its tree trimming costs to date have been reduced a total of $19 million, or about 40 percent.

According to TEC, during the tree trimming process all practical efforts are made to trim the trees in such a way that they remain esthetically pleasing and healthy, while at the same time providing a lasting benefit. To accomplish this, all cutting is made to National Arborist's Association Standards. Constraints on trimming are further increased by the ordinances of various governmental bodies through which TEC's transmission and distribution lines run. These efforts have to be balanced against the goal of clearing power lines within the National Electric Safety council's (NESC) guidelines which sets safety standards for trimming trees from power lines.

From time to time, customers will call TEC to request tree trimming or vine removal from drops or other distribution lines serving them. In these cases, the service in question is inspected and, if found to need clearing, is put on a prioritized list to be cut. Responsibility for trimming growth from service drops varies from utility to utility; however, Tampa Electric states it claims responsibility for lines from the power plant to their customer's meter, thus assuming responsibility for clearing the drop of vegetation.

To help decrease time customers are out of service due to tree-related reasons and to speed the response time to address "hot spots," TEC has piloted the use of Mobile Data Terminals in some of its tree trimming vendors' service vehicles. Mobile Data Terminals are small computers linked to the Trouble Analysis System via radio transmission and are very similar to the terminals now installed in police and other emergency vehicles. This allows a contractor to be directly dispatched to trouble spot to perform whatever tree removal or trimming work that needs to be done. The company states it has been pleased with the reduction in response times and increase in productivity associated with the contractors' use of Mobile Data Terminals and is considering expanding the program over the next two years.

Efforts to educate and inform customers about the tree trimming program and activities are facilitated by an annual brochure mailing included in the customers billing. Additionally, tree trimming crews are provided with educational material designed to inform customers about the need to trim trees and the standards used to trim them. These materials are provided to customers as needed to address any concerns they may have regarding tree trimming activities on, or near their property.

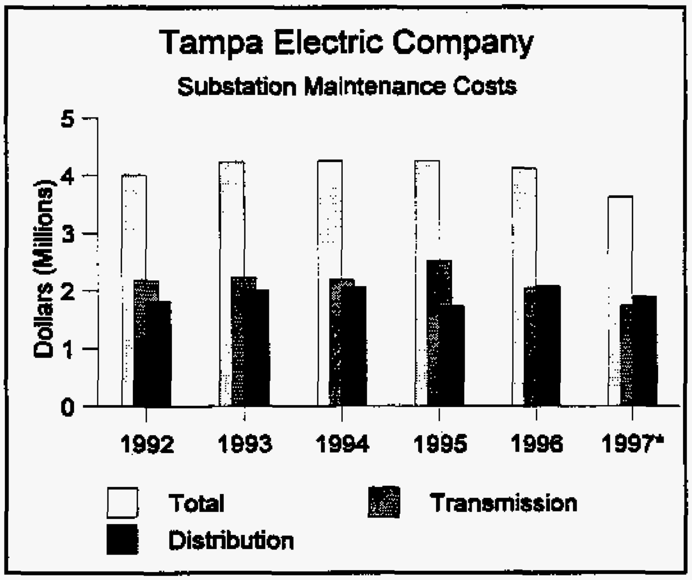


EXHIBIT TEC-21 *Source: TEC Response to Document Request 1-8.*

** Projected Year 1997*

6.4.4 Substation Maintenance

Tampa Electric transmits and distributes electric power through a total of 185 transmission and distribution substations as of September 30, 1997. Historic and projected operation and maintenance costs for TEC's transmission and distribution substations are depicted in Exhibit TEC-21. In 1996, TEC allocated \$1.8 million and actually spent \$2.1 million of its total \$4 million O&M budget in the area of distribution substation maintenance.

Exhibit TEC-22 provides a snapshot of the substation outages and causes of those outages for the period 1992 through August 1997. Substation outages for the period have remained relatively stable, averaging 31 outages per year. In 1995, the number of outages was unusually low at 13. Although measured as of August, 1997 outages have exceeded the five year average at 38 outages for the year. The five leading causes of substation outages for the period measured are:

- Foreign Interference (animals, public, etc.)
- Failure of Substation Equipment
- Circuit Breaker Operations
- Defective Power Equipment
- Relay and Controls

A complete analysis of substation staffing is provided in Exhibit TEC-23. As the exhibit indicates, Tampa Electric's substation workforce has remained relatively constant over the 1992

Tampa Electric Company Substation Outages by Cause 1992 Through Projected 1997							
Cause	**1992**	**1993**	**1994**	**1995**	**1996**	**1997***	**Total Outages**
Foreign Interference(Animals, Public, etc)	2	10	2	5	5	16	40
Breaker	11	8	0	1	3	0	23
Fault in Cable	3	0	0	0	0	1	4
Relay/Controls	13	2	0	0	1	0	16
Switch	4	2	0	0	0	0	6
Substation Equipment	0	9	17	1	1	1	29
Human Element	0	2	1	0	1	7	11
Weather	0	4	3	1	0	7	15
Defective Power Equipment	0	0	0	0	11	13	24
Deterioration of Component	0	0	0	0	2	3	5
Other	6	9	6	5	5	6	37
Total	39	46	29	13	29	54	210

EXHIBIT TEC-22 *Source: TEC Response to Document Request 2-7.*

** Projected year based on actual amount at August 31, 1997.*

to 1997 period. The company says it is able to accomplish the same amount of productivity over time with this constant level of workers through:

- *Working Smarter* - focusing a defined work-force on critical areas to improve quality and reliability.

- *Extending the Maintenance Cycle* - lowering costs and allowing a consistent level of work force to cover an expanding system.

Tampa Electric Company Substation Operation Employees						
	1992	1993	1994	1995	1996	1997*
Inspections						
Supervisor	1	1	1	1	1	1
Electricians	7	8	8	8	9	9
Substation Maintenance						
Supervisor	2	2	2	2	2	1
Electricians	19	16	18	16	18	18
Maintenance Spec.	0	0	0	0	0	1
Planner	1	1	1	1	1	1
Shop Personnel						
Supervisor	1	1	1	1	1	1
Electricians	9	10	9	6	4	4
Utility Helper	0	0	0	0	0	1
TOTALS	40	39	40	35	36	37

EXHIBIT TEC-23

Source: TEC Response to Document Request 3-15.

* *As of August 30, 1997.*

- *Increasing the Construction Cycle* - freeing people to work on maintenance.
- *Use of Technology Such as Computers and Database Operations* - in effect multiplying the impact of the current work-force.

Each of TEC's 180 substations are inspected on a routine basis once a month. During this inspection, a formal inspection sheet is completed and kept on file. The inspection sheet covers every major component of the substation. Items checked on transformers and circuit breakers include bushings, leads, wiring, condition of the control cabinet, and any oil leaks are noted. Substation grounds are also checked during the monthly inspections. Station grounding is checked, gates and fences are checked to be in good condition and properly secured. Any debris found within the grounds is examined to determine if it came from a failed piece of equipment, indicating a potential repair. Anything found to be abnormal is written-up in a formal memo and given to the substation planner to schedule corrective work.

Substation maintenance is conducted on both a routine, preventive basis, as well as on a corrective basis. Preventive maintenance is generally scheduled well in advance and is provided for in Substation Operations "formalized" maintenance program mentioned earlier in section 6.4.2. Some of the preventive maintenance activities include:

- Scheduled maintenance on transformers which includes diagnostic testing, testing of oil, and testing cooling fans.

- Scheduled maintenance on transmission and distribution breakers, includes diagnostic testing, oil filtration, and other internal and external checks.

Substations with high animal-related outages are enhanced with animal guard features. Such devices are basically enhanced insulation that will hopefully prevent an animal climbing on the substation equipment from completing a circuit and causing a breaker operation. Because of the cost involved, TEC says it plans to place these devices only on substations shown to have an animal problem and does not plan to retro-fit all substations or place animal protection devices on new construction as part of their design.

Corrective maintenance is conducted on a prioritized basis as the need arises. Such maintenance is usually identified as the result of routine monthly substation inspections, or in the case of a substation outage. The item requiring maintenance is identified and forwarded to a planner who will schedule the necessary crews to do the work. Typical corrective maintenance items include:

- Repair of oil leaks during substation inspections.

- Bushing replacements found during transformer and circuit breaker diagnostic testing.

- Circuit breaker maintenance due to mis-operations or slow operation.

6.4.5 Plant/Equipment Inspection

Tree trimming makes up a large portion of TEC's preventive maintenance programs. But other maintenance programs crucial to service reliability include:

- Pole Inspection
- Line Inspection
- Lightning Protection
- Underground Cable Inspection
- Substation Maintenance

Pole Inspection

Wood poles are another element to be considered in providing reliable service to customers. TEC has approximately 320 thousand distribution poles in service, with nearly 311 thousand being wood with the balance equally distributed between concrete and composite poles. Constantly exposed to the elements, these poles may become damaged by a variety of causes including rot, termites, weather, woodpeckers, and from being struck by automobiles. Severely damaged poles may fail, causing power outages to customers, as well as presenting a safety hazard.

To discover poles in need of repair or replacement, TEC employs a formal inspection process. According to TEC, the company inspects approximately 10 percent of the poles in their system each year that are at least 10 years old and have a treatment other than copper chromium arsenate (CCA). In a process that is designed to ensure the system is covered uniformly, a proportional share of the annual sample is allocated to each service area. It is then the responsibility of each service area to determine the specific geographic area to inspect. During this cycle, poles are subjected to various tests to determine their fitness for service. These tests include: visual inspection, tapping the pole and listening for hollowing, drilling into the pole to check for rot, and digging around the pole to look for subsurface rot.

As a result of these tests, poles are determined to either be fit as they are or require repair or replacement. Repairs to poles can be made either by removing rot and retreating the affected area or by bracing the pole to strengthen it until being eventually replaced. Exhibit TEC-24 shows the results of TEC's pole inspections for the period 1992 through 1996, with projected results for 1997. Prior to 1995, TEC had contracted with an independent company who was responsible for both inspecting and repairing/bracing wood poles. TEC has since replaced the original vendor with two others to perform this task.

Tampa Electric Company
Distribution Pole Inspection Results

Year	1992	1993	1994	1995	1996	1997*
Inspected	14,987	15,337	9,300	15,266	16,759	15,000
Rejected	4,355	4,233	2,674	1,271	932	832
Reinforced	1,064	970	641	244	0	0
Replaced	3,082	3,023	1,936	767	932	1,098
Treated	4,146	3,993	2,577	1,011	0	0

EXHIBIT TEC-24 *Source: TEC Response to Document Request 2-25.*

** Poles inspected based on projected year 1997. Projected results based on actual amounts at August 31, 1997.*

Poles are "rejected" if their ground line circumference is less than 50 percent of their original circumference or are not sound above ground. Poles are a "reinforceable" if they have 50-80 percent of ground line remaining and decay does not extend more than 4.5 feet above ground line. Also, the pole must have at least a two inch shell thickness of sound wood at 15 inches above the ground line. Poles defined as "rejects" and some "reinforceable" poles are replaced. Treated poles are those that have been treated with preservatives following a ground line excavation.

Line Inspection

Distribution line inspections are another critical element in the maintenance process. To provide reliable service, these lines must be continuously checked for conditions that may lead to an eventual loss of service. To this end, distribution lines are patrolled on a schedule along with pole inspections. This patrol is done by TEC's System Service personnel and also by Field Engineering personnel.

There are two types of line inspection that must be made concurrently to adequately monitor distribution lines for reliability. The first is a *physical* inspection which involves the physical and visual inspection of the lines. The second method is an *analytical* inspection which involves determining the line's capability of handling loads as it is currently configured.

TEC has several methods to accomplish both types of categories of line inspection. Physical inspection is accomplished through circuit patrols. Through these, circuits are visually inspected throughout the year for broken cross arms, bad lightning arresters, broken insulators and for trees that have grown into the circuit. TEC also employs a method of inspection called "Thermovision" where an infrared camera is used to identify heating--an indicator of damage--on lines, connections, splices and switches. To enhance this physical inspection process, TEC has implemented its Adopt-A-Circuit Program.

The Adopt-A-Circuit Program is an annual activity in which an individual or a team is assigned to patrol and monitor a specific distribution circuit throughout the year. The purpose of the program is to improve service quality and circuit reliability by focusing attention on distribution circuitry with below average performance histories. The program was started approximately three years ago and includes scheduled and unscheduled circuit patrols. Program participants are asked to recommend construction and maintenance projects to improve the performance of their assigned distribution circuits. Improvement activities may include feeder design, reconfiguration, line clearance, grounding, animal protection, equipment replacement or repair, or insulation enhancement. According to TEC, the program has helped in identifying field conditions often associated with momentary circuit interruptions and has helped to improve average customer interruption time.

The second type of line inspection, analytical inspection, is accomplished in a variety of ways such as through contingency analysis, and analysis of circuit breaker logs and DCI Sentry Monitors. Reports are generated monthly and sent to each service area Operations Engineer for their review and action. A Circuit Performance Review is also conducted on all circuits on a five-year basis, and that report, too, is given to the Operations Engineers for their review and action.

TEC conducts a *contingency analysis* where each year the distribution planner reviews the loads on all distribution circuits and what impact switching operations will have on those circuits during a multi-year period. If load or voltage problems are seen, the planner determines the best solution and decides when to implement any changes.

Operations of circuit breakers and oil-covered recloser's (OCR) are recorded daily. These logs are reviewed on a monthly basis to identify any problems and patterns that should be addressed. The various circuits also have DCI Sentry Monitors installed to determine if the circuit is experiencing any recurring voltage or outage problems.

To augment the overall reliability of TEC's distribution lines, the company developed its *Worst Performing Circuit Team.* This team was organized by the Energy Delivery Management Team to support a 1997 department goal to improve service reliability by targeting TEC's worst performing circuits. The teams activities have included: the development of a methodology for ranking TEC's worst performing circuits; identifying feeders to be included in the current Adopt-a-circuit program; presentations to promote the improvement of system insulation; and the collection and distribution of outage information.

Line inspections can identify wire that is in need of replacement due to deterioration. TEC reports no change-outs were made from 1992-1995, but 18.03 miles were changed in 1996, and 4.96 miles were changed in 1997 at a cost of $274,000 and $130,000 respectively. According to TEC, the static wire change-out has all been the replacement of 3/8" High Strength (HS) with its current standard, 3/8" Extra High Strength (EHS) wire.

Lightning Protection

Virtually all equipment on an electric distribution system is susceptible to, and does sustain, lightning damage. Tampa Electric estimates its average annual cost due solely to lightning at $447,538. This estimate only includes lightning damage that caused a customer outage, and does not include overhead costs associated with responding to these outages, according to TEC. According to TEC, the most frequently damaged distribution equipment includes transformers, poles and wire, overhead arresters such as surge arresters and insulators, and underground cable accessories (i.e., terminators, elbows, and bushings and take-offs).

There are two basic lightning protection schemes for distribution facilities, the shield wire design and the arrester design. TEC utilizes the arrester design, and arresters with ground wires. Just a few of the features of TEC's lightning protection design includes:

- Surge arresters located at least every quarter mile on wood poles and every eighth mile on concrete poles and on all equipment poles.

- Circuit breaker recloser sequence to decrease potential for equipment damage.

- Surge arresters installed in auto-switch gear.

- Developed a program to install meter-based surge arresters.

Underground Cable Inspection

To maintain the reliability of its underground distribution system, TEC conducts line patrols similar to that for above-ground equipment. The underground system is on a five-year inspection cycle in which the components are visually inspected for damage or potential problems.

The inspection generally consists of the above-ground components, such as pad-mounted transformers, being opened and examined. The lineman will open the transformer cabinet and examine the contents, looking for any problems. The exterior portion is similarly inspected, and any corrective measures needing to be taken are written-up in memo form and submitted to the appropriate planner for work to be scheduled.

The major causes of underground cable failure include lightning, moisture in the cable, and dig-in's (when someone accidentally severs a cable by digging in to it). The summer lightning season sees the most occurrences of underground cable failures. Lightning entering underground distribution cables from above-ground sources such as transformers accounts for most of the sub-surface distribution failures each year.

Repairing and replacing underground cable can be a difficult and time consuming job. The method in which the underground cable has been laid plays a large part in how difficult that job will be. There are generally two methods in which to place underground cable: the direct bury method, and the conduit method.

With the direct bury method, cable is placed directly in the trench that has been dug and then covered. This method is simple, and less expensive than the conduit method, but a draw-back is that to repair or replace the cable, it must be completely dug-up. The conduit method places a pipe (the conduit) in the ground in which the distribution cable is run. This method is more expensive to install because of the extra material and labor required; however, to repair or replace the cable, it can be pulled out of the conduit and a new or repaired section can be replaced, decreasing the interruption time. According to TEC, over 95 percent of their underground distribution system is conduit based.

6.4.6 Restoration and Repair

Exhibit TEC-25 shows TEC's Energy Distribution bargaining unit employee staffing levels for the period 1992 to August 1997. Over that period, the company has reduced its bargaining unit workforce by 16.4 percent from 225 in 1992 to 188 at August 31, 1997. According to TEC, most of this reduction has been accomplished through attrition, allowing the company to avoid lay-off's. One strategy Tampa Electric employs to help avoid unwanted lay-offs is to keep its company workforce levels below the minimum levels of its constantly fluctuating workload. The gap in permanent workforce to workload is then filled by contract workforces. The company says it does not anticipate a need for further workforce reductions in the foreseeable future.

Tampa Electric Company Energy Distribution Bargaining Unit Staffing Levels						
Service Area	1992	1993	1994	1995	1996	1997*
Eastern	67	70	64	63	60	55
Central	37	37	36	36	32	32
Western	49	49	43	39	41	40
SHA	19	19	18	14	14	13
WHA	24	25	25	24	23	22
PCA	24	25	22	20	20	20
DCA	5	6	6	6	6	6
Total	225	231	214	202	196	188

EXHIBIT TEC-25 *Source: TEC Response to Document Request 2-8.*

** As of August 31, 1997.*

With its workforce operating with fewer people, efficient and effective deployment of human resources becomes a critical issue in maintaining quality of service and assuring outage times are as brief as possible. In order to adequately cover restoration and repair of the system during periods when, traditionally, workers were out of service (such as in the evenings during the summer storm season and on weekends), TEC was gone to a "non-traditional" work schedule. What this means is that now troublemen and crews operate on shifts around the clock and on weekends, which assures there is a crew on duty to respond to a trouble call once it is received. In support of this effort, Service Area personnel are cross-trained as troublemen. This allows the total complement of troublemen to be maintained when a full-time trouble man is out of service due to vacation, illness, or other reason.

Exhibit TEC-26 depicts the trend in distribution vehicles used by TEC's field forces in accomplishing their work. For the period 1992 through August 1997, total Light, Medium, and Heavy vehicles were reduced by 83 units (9.7 percent). As the exhibit indicates, this reduction took place largely during the period 1994 through 1996. During this period, total vehicles declined by 82 units with heavy vehicles experiencing a total reduction of 32 units and a 44 unit reduction in light vehicles.

TEC attributes the decline in vehicles over the entire period 1992 through August 1997 to a combination of factors. Such factors include overall reduction in staffing levels, management of O&M vehicle budgets to lower costs, and transferring vehicles and equipment to other TECO Energy operating companies.

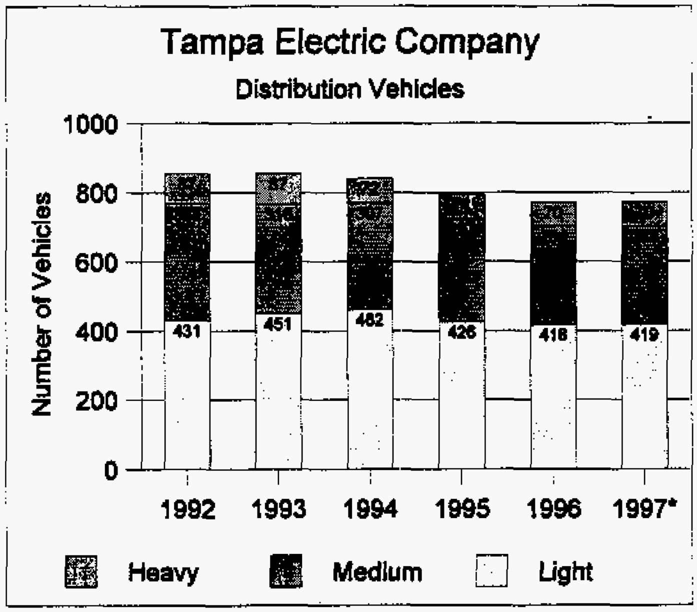


EXHIBIT TEC-26 *Source: TEC Response to Document Request 2-13.*

**As of August 31, 1997.*

Light vehicles are chiefly made up of light trucks, vans, and utility vehicles and are typically used by supervisors to inspect work being done and by customer service positions to conduct work such as meter reading and electric service cut-off. Light vehicles are also used to transport parts and supplies to the various job sites, and are used in various security applications.

Medium vehicles are generally larger trucks with side mounted tool boxes or flat beds and are used to maintain the buildings and grounds or areas like substations. These vehicles are also used to haul parts and supplies that are too large for light vehicles to job sites.

Heavy vehicles are large trucks used primarily for distribution work. The equipment is used for pole setting and transformer hauling and installation and includes aerial "bucket" trucks and trucks equipped to dig holes for distribution poles.

Trouble calls made by customers are the primary source of trouble tickets generated that trouble men must respond to. As shown in Exhibit TEC-27, in a typical year TEC trouble men will respond to over 40,000 trouble tickets.

Exhibit TEC-28 depicts the trouble reporting process which typically begins with the customer calling TEC to inform the company of a service problem. A customer service representative will obtain the pertinent facts from the customer regarding the nature of the

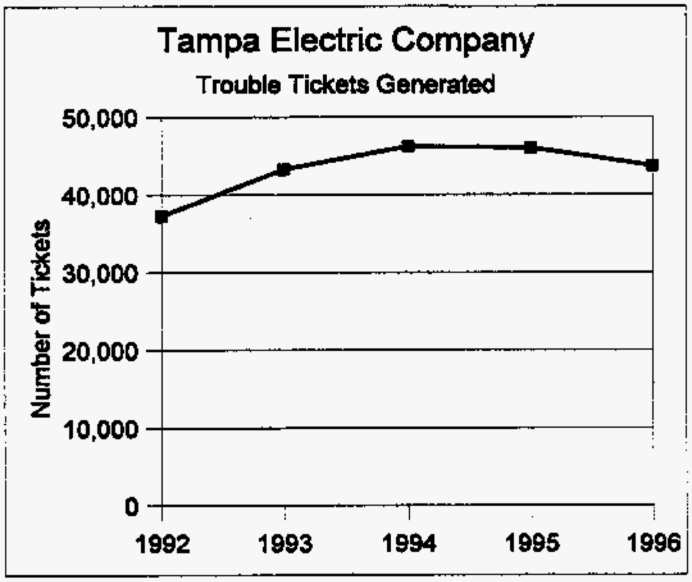


EXHIBIT TEC-27

Source: TEC Response to Document Request 2-1.

problem and the service location involved. The customer service representative will perform a preliminary analysis at this point and, if possible, may offer a solution over the phone, such as to have the customer check their circuit breakers if only a part of their residence or business is not receiving service.

If a solution cannot be offered over the phone, the trouble is entered into TEC's Trouble Analysis System. The Trouble Analysis System is a relational database that draws information from a variety of interrelated computer systems within TEC, such as the Customer Information System (containing customer account information) and for use in recording and analyzing various trouble occurring throughout the company as a whole. The Trouble Analysis System is used in a variety of applications from responding to customer inquiries to investigating damage claims and, in this case, recording system trouble. Once entered into the system, the Trouble Analysis System will generate a trouble ticket for the location. The trouble ticket contains all the information regarding the reported trouble and is used by the distribution system operators to assign a trouble man to investigate the problem.

Trouble tickets are displayed to the distribution system operators via computer screen for further analysis. The dispatchers will compare and analyze the trouble tickets in order to determine a pattern in service disruptions being reported. The purpose of this analysis is to help the dispatcher determine the magnitude of the service problem in order to prioritize the dispatching trouble men. For example, multiple calls from an area indicating a transformer or feeder may be out of service would be accorded a higher priority than a single residence reporting an outage. Similarly, a school or hospital reporting an outage may be given a higher priority than a feeder experiencing an outage.

Trouble men receive these trouble tickets directly to their vehicles by way of Mobile Data Terminals. With the new Mobile Data Terminals installed in their service vehicles, both trouble men and crews can be dispatched directly from their homes, thus avoiding the necessity to travel to a service center to be dispatched, saving considerable time. The Mobile Data Terminals are also used to dispatch trouble for work such as street light repair and meter work. Trouble tickets are worked in order of priority as determined by the trouble man. To help the trouble man in determining what priority to give a trouble ticket, each ticket is coded by the Distribution System Operator, indicating the scope of the problem.

TAMPA ELECTRIC COMPANY
TROUBLE REPORTING PROCESS
AS OF AUGUST 1997

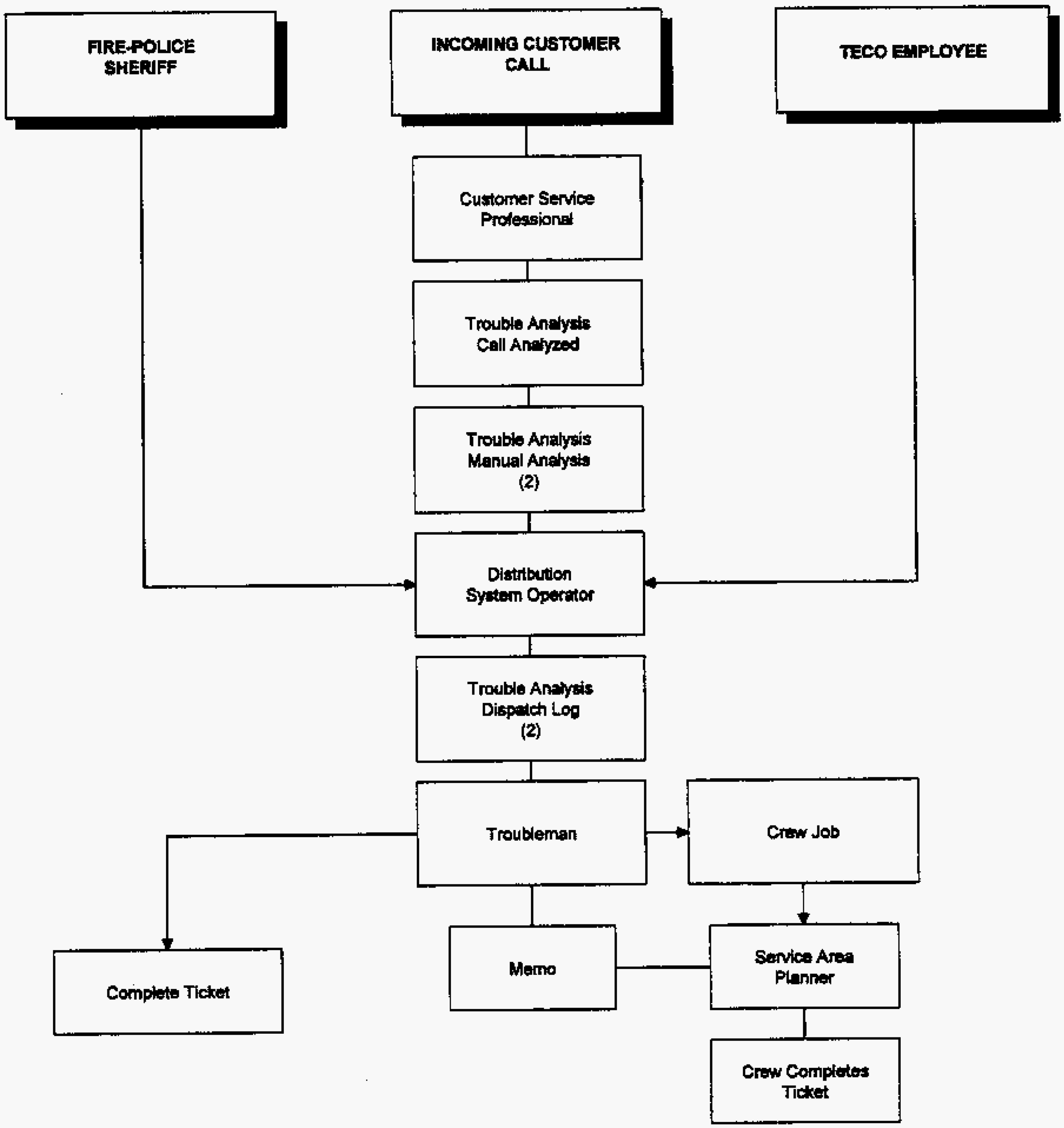


EXHIBIT TEC-28

Source: TEC Document Requests 1, Questions 1,5,13, and 19

For example, a trouble man may have three trouble tickets assigned to him, each being displayed on his Mobile Data Terminal. One ticket may be coded to indicate the customer is experiencing a "partial outage", the second may be coded to indicate "all power out", while the third, also coded as "all out," is upgraded to indicate multiple calls from the same area - an indication that the outage is wide-spread. In this example, the trouble man would probably take the call in order of the "all out" up-graded call first, next would be the "all out" single residence, and third would be the "partial outage."

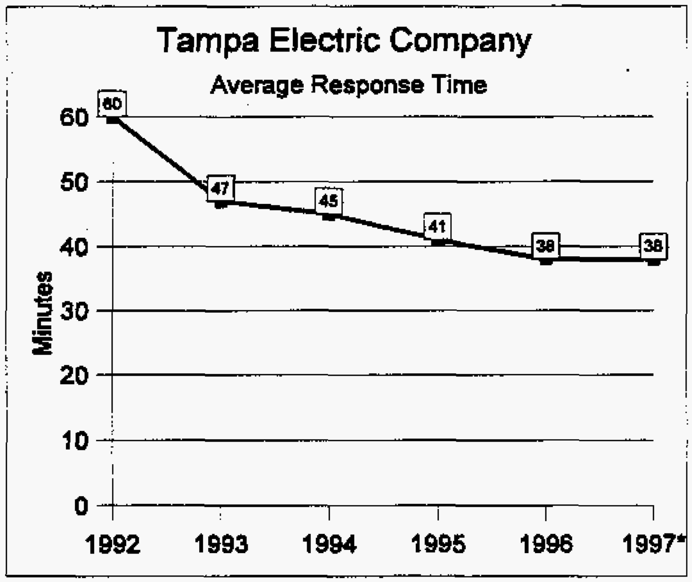


EXHIBIT TEC-29 *Source: TEC Response to Document Request 4-3.*

**As of September 31, 1997.*

Although the trouble men are generally responsible for prioritizing the calls to which they respond, the Distribution System Operators have the authority to direct the order in which trouble tickets are addressed. This is usually done only in critical situations such as during storm repairs or in special circumstances, an example would be giving priority to a customer with special need.

During the course of the day, the status of each trouble ticket can be monitored by the Distribution System Operators through the Mobile Data Terminals. This aids the Distribution System Operator in assigning work and allows the efficiency of trouble men and work crews to be measured.

The Mobile Data Terminals system also has limited capability to analyze equipment needs on some repair jobs. For instance, when requesting a work crew, a trouble man will enter a request for the part that is to be replaced, say, a transformer. Once the request is entered, the Mobile Data Terminals system will compare the load history for the location with the size of the transformer being requested. The system may then display a recommendation to use a larger or smaller sized transformer based on that location's load history. The trouble man may accept the recommendation or reject it, based on their knowledge of the location.

Once on site of a trouble call, the trouble man will make contact with the customer and try to correct the problem if possible. If the repair is too large or too complicated for one trouble man to complete, he will make arrangements for a crew to be assigned to address the problem. This is done by inputting the information into the Mobile Data Terminals regarding the problem, requesting a crew, and estimating the crew size needed. This information is then transmitted to the service area and is given to a planner for scheduling. Before TEC began using Mobile Data Terminals, the trouble man would have to travel back to the service area they were dispatched from, manually write up a report, and request a work crew.

Response times have decreased, as shown in Exhibit TEC-29, from 60 minutes in 1992 to a low of 38 minutes in 1996. This reduction in response time may be attributable to the installation of the Mobile Data Terminals in restoration and repair vehicles.

6.5 Recent Trends and Changes

During the past year, TEC has implemented several changes that have helped the company become more responsive and effective in the area of service quality. These changes, coupled with overall trends being established and followed by the company, can be categorized as organizational, process, or technological in nature. The following paragraphs briefly describe the more significant trends and changes observed.

Organizational Trends and Changes

Recently, TEC moved the system reliability function from being a part of the System Planning group to become the System Reliability group within the Engineering Services Department, which is responsible for implementation of the Maintenance Planning plan. This move puts the System Reliability group in the same location and in direct contact with the System Operations and System Service departments. According to TEC, this allows better communications between System Reliability and the individuals responsible for inputting the data for outages.

Process Trends and Changes

TEC has implemented several process changes during the past year that directly enhance system reliability and overall quality of service:

- 1997 - Made system reliability a part of the company-wide Employee Stock Ownership Plan (ESOP) goals.

- 1997 - A "Best Practices Cable Installation Team" was formed to determine the best methods for installing underground cable with the objective of reducing damage during installation.

- 1997 - Began producing a daily DCI-Sentry monitoring device report to provide data on power quality and interruptions for specific customers and/or circuits.

- 1997 - Development of the "Adopt-a-Circuit program.

- 1997 - Installed animal protection in 35 substations.

- Use of Mobile Data Terminal allow for home dispatch of trouble men and crews, saving time.

- Mobil Data Terminals were installed in some tree-trimming contractors' vehicles to allow dispatching to "hot spots," thus saving time.

- Development of the "Worst Performing Feeder Team."

- Recently, TEC has implemented a specific Maintenance Planning Process that allows the company to address all aspects of reliability within the Energy Delivery organization and gives the System Reliability group direct input into areas--such as animal outages--to the plan.

Technological Trends and Changes

Recent trends and changes in technology have aided Tampa Electric in responding to reported trouble quickly, and have allowed the company to better analyze reported problems to discover their causes. Examples of such technology are:

- *Mobile Data Terminals* - Eliminates almost all paper and allowing direct input of outage causes by the individual responsible for responding to the outage.

- *CAD TAII* - A system that incorporates TEC's current computer aided drafting (CAD) system with its Trouble Analysis system. Linked together, TEC can generate a graphical representation on a computer monitor of all outages presently on the distribution system. This allows quick location, identification and analysis of reported trouble.

- *DCI-Sentry* - A system which, when installed at a customers location, calls in via modem whenever an outage, under voltage, or over voltage occurs. TEC states they have placed an order for an advanced version of this system that will directly tie-in to its customer information system and generate trouble tickets when there is a continuing outage situation at the customer's location.

- *Electronically Controlled Reclosers* - Allows for single phase operations, thus affecting fewer customers, remote control from the System Service office, and tracking of fault phases.

- *Radio Controlled Capacitor Installations* - Allows a computer system to determine when and if a capacitor bank is required on the line, and able to determine when the capacitor unit may be in need of service.

- *Substation Automation* - Among other information, supplies the phase and magnitude of all faults on the system, thereby allowing for determination of fault locations.

6.6 Conclusions

Taken together, the various measures of service quality and reliability do not indicate any significant problem occurring presently with TEC. Both FPSC's and Tampa Electric's methods of measuring and analyzing performance and customer satisfaction seem to indicate the company is performing adequately. Industry standards for measuring performance (SAIDI, CAIDI, and SAIFI) do not indicate reliability problems with the company. Customer inquiries made with the FPSC about TEC remain low, and results of self-administered customer surveys indicate overall satisfaction with the company.

TEC may benefit from a service territory that is more compact than other Florida investor-owned utilities. Such a benefit allows the company to respond more quickly to restore service interruptions by its repair crews not having to travel as far as others may have to. Response times have also been decreased through the installation of Mobile Data Terminals in restoration and repair crew vehicles, allowing home dispatch of crews and eliminating the need of the crew to travel to the service center to sign-in when coming on duty. Mobile Data Terminals have also allowed the trouble man or repair crew to view all trouble tickets dispatched to them, providing the flexibility to prioritize work based on level of urgency and location.

Some areas TEC may improve on include separating overhead and underground outages on FPSC reliability reports as required by Rule 25-6.044. As discussed in section 6.2.2, the company currently does not make this required separation, making it impossible to analyze the data with regard to overhead and underground distribution.

Another opportunity for improvement rests in the area of results from customer satisfaction surveys. Currently, results of surveys are presented to management in compiled form only, with limited analysis consisting of tabulations and cross-tabulations of data being provided (no conclusions or recommendations regarding the data are made). Although this allows management complete *flexibility* in interpreting the data, *consistency* in interpreting the data is jeopardized. A standard analysis and interpretation of the data should be designed to establish patterns, over time, that might be useful in identifying trends in customer perceptions. This would serve to augment the independent analysis of the compiled data by the reader.

7.0 Conclusions

7.1 Enhancement of Reliability Reporting Mechanisms

This review of distribution service quality and reliability indicates that a significant decline in distribution reliability can occur within a relatively short span of time. Therefore, the Bureau of Regulatory Review recommends that the Commission's current reliability reporting mechanisms be enhanced to provide greater ability to detect and prevent future recurrences.

By expanding the current requirements of the annual Distribution Service Reliability Report, as specified in FPSC Rule 25-6.0455, a more complete and well-rounded assessment of distribution reliability and service quality could be obtained. These additional reporting requirements could include the system average interruption duration index (SAIDI), the customer average interruption duration index (CAIDI), and the system average interruption frequency index (SAIFI). The widespread use of these indicators throughout the electric industry and all of the companies in this review establishes that these indices are credible measures of reliability and service quality.

Additionally, due to increased customer awareness of, and interest in, momentary interruptions, the reliability report should also provide consistently-calculated measures of Momentary Average Interruption Frequency index (MAIFI). To the extent any limitations of a particular utility's distribution data systems prevent the capture of momentary interruption data, the Commission staff should begin discussing with the company how and when this limitation can be overcome.

In addition to expanding the annual Distribution Reliability Report, the Commission should specify the precise method of calculation for each index and the inputs used. The handling of effects of named tropical storms and planned outages should also be standardized.

7.2 Improvement Goals and Action Plans

To insure the prompt and thorough resolution of the reliability and service quality problems, two companies, Florida Power & Light Company (Chapter 3) and Florida Power Corporation (Chapter 4), should be required to develop specific performance goals for 1998 through 2000. The goals should be developed at a minimum for objective measures such as number of interruptions and L-Bar. Additionally, the Commission should have the utilities develop benchmarks for SAIDI, CAIDI, and SAIFI and at least one indicator of multiple service problems, such as percentage of customers experiencing more than a target number of interruptions per year.

In addition to the company established goals, the Commission should request that the utilities file a report which identifies the steps the company intends to take to achieve the specified goal. This report will be for informational purposes only, for use in the event a future review is needed.

Appropriately, both Florida Power & Light and Florida Power Corporation have already made efforts to address service quality and reliability problems and have allocated extensive resources to obtain improvement during 1998 and beyond. Still, due to the long-term nature of some of these corrective measures, the Commission staff will need an objective basis for accountability and for gauging the rate of progress achieved. These performance goals and action plans can provide this basis for evaluation.

7.3 Follow-up Review of Improvement Results

After 1998, one or more follow-up reviews should be performed to assess the actions taken by the companies and the results of these actions. This review could determine whether improvement goals were met and planned actions were implemented. The review may also gather information on additional problems identified or additional plans and programs developed to improve distribution reliability and service quality.

7.4 Service Quality and Reliability Standards

If follow-up reviews conducted by the FPSC in 1999 determine that the improvement goals have not been met by Florida Power & Light Company or Florida Power Corporation, and/or that the companies' efforts have been inadequate, the Division of Electric and Gas should pursue the establishment and enforcement of electric service quality standards. Separate standards should be established for each utility. In the mean time, commission staff should research and study the concept of developing both system reliability standards and individual customer related standards.

All four electric utilities should be encouraged to establish a company policy which identifies specific numerical distribution service quality and reliability standards for customers. The standards should address the number and duration of outages, as well as the number of momentary interruptions a customer should expect in a year as reasonable. Establishment of these standards on a voluntary basis will mitigate the need for Commission created standards in the future.

7.5 Assessment of Adequacy of FPSC Rules

It is further recommended that a thorough reassessment be performed to determine whether current FPSC rules adequately address service quality and reliability problems experienced by ratepayers. Regulatory, societal, and technological changes have created a need for the FPSC to update its rules regarding electric service quality and reliability. For example, FPSC rules do not specifically define continuity of service or address the number of short interruptions (momentaries), the number of long interruptions, and the duration of interruptions that constitute adequate service quality.

Numerous customer complaints are currently being received that do not constitute infractions under current rules, but still represent considerable inconvenience to customers. Without clearer guidelines of what customers should expect in terms of service quality and an incentive in the form of infractions being observed, these problems may not receive adequate attention from the companies.

7.6 Customer Education

Significant reductions in customer inconvenience and property damage could be achieved through heightened efforts by both the FPSC Division of Consumer Affairs and the electric utilities to educate customers about tree trimming, uninterruptible power sources, and surge protection devices. Through the use of public service announcements and educational materials, customers could be made aware of the damage protection provided by the utility, the limits of that protection, and the customer's responsibilities and options in this area.

7.7 Customer Property Damage Claims Monitoring

The Commission may consider requiring the utilities to file an informal quarterly report during 1998 which identifies each customer property damage claim filed with the four utilities. Further, the report should identify whether the claim was paid, paid in part, or denied. If the claim was denied or denied in part, a reason for denial should be identified. After 1998, Commission staff will ascertain whether further action is needed.

APPENDIX 1

Glossary of Terms

ACPI - Average Customer Per Interruption - Measure of magnitude of an interruption in number of customers effected.

AHI - Average Hours Per Interruption - Measure of average interruption duration for a particular distribution system component.

ARMS - Automated Resource Management System

Arresters - or Surge Arrester - Device which protects lines and equipment against voltage surges caused by lightning, equipment switching or abnormal system conditions. The surge arrester is connected from the line to ground to provide a conducting path. This limits the voltage on lines or equipment and dissipates excess energy harmlessly.

ASAI - Average Service Availability Index - Measure of the customer hours service is available relative to the customer hours of service demand.

ASIDI - Average System Interruption Duration Index - Measures of the connected kilovolt amperes minutes interrupted relative to the total connected kilovolt amperes served.

ASIFI - Average System Interruption Duration Index - Measure of the connected kilovolt amperes interrupted related to the total connected kilovolt amperes served.

CAF - FPSC Division of Consumer Affairs, the portion of FPSC staff involved in receiving and investigating customer inquiries and complaints.

CAIDI - Customer Average Interruption Duration Index - Measure of the average duration of interruptions experienced by the customers interrupted.

Capacitor - An electrical device that maintains or increases voltage in power lines and improves the efficiency of the electrical system by reducing inductive losses that produce wasted energy.

CEMI - Customers Experiencing Multiple Interruptions Index - Measure of the total number of customers experiencing more than a certain number of sustained outages relative to the total number of customers served.

CEMSMI - Customers Experiencing Multiple Sustained Interruptions and Momentary Interruptions Events - Measure which examines the total number of customers experiencing more than a certain number of interruptions relative to the total number of customers served.

CHI - Customer Hours of Interruption - Customer interruptions multiplied by the hours of duration of that interruption.

CI - Customer Interruptions - The number of interruptions of one minute or longer to customers.

CI - Commercial/Industrial customer class

CMI/C - Total customer minutes of interruption divided by number of customers, this measures the average duration of outages for the total number of customers served. Conceptually equivalent to SAIDI and SU.

CMI - Customer Minutes of Interruption

COS - Customer Opinion Survey

CSCRs - Customer Service Center Representatives

CSR - Customer Service Representative

DCC - Distribution Control Center

DCI Sentry Monitors - A system installed at a customer's location, which calls in via modem whenever an interruption, under-voltage, or over-voltage condition occurs.

Distribution Feeder Line - A distribution feeder is the main circuit or trunk line from which taps carry electricity to residential and commercial customers.

DTR - Distribution Trouble Report

ESOP - Employee Stock Ownership Plan

E & C - Engineering and Construction

ED - Energy Delivery

Feeder - An electric circuit with limited capacity extending from the main distribution line feeder, usually supplying a small number of customers. (Often used interchangeably with "circuit".)

FPC - Florida Power Corporation

FPL - Florida Power & Light Company

FPSC - Florida Public Service Commission

GPC - Gulf Power Company

Harmonic Distortion - A power quality problem caused by customer load and wiring characteristics, resulting in irregular currents or voltages. Harmonic distortion can affect computers, audio and other types of equipment.

Hot Spots - Areas of heat being emitted that may indicate sites of electrical faults within distribution components.

IEEE - Institute of Electrical and Electronic Engineers

Inquiries/Infractions - Inquiries are customer calls received by the FPSC Division of Consumer Affairs, whichmay be deemed to constitute an infraction of FPSC rules or tariffs, or of a company policy.

Interruption - Interruption of electric service to a customer, usually of one minute or more in duration. Usually excludes Momentary Interruptions, defined below.

kWh - Kilowatt hour - A common unit of electric energy consumption, and the basic unit of electric energy. It equals the total energy developed by the power of one kilowatt (kW) supplied to or taken from an electric current steadily for one hour. In other words, 1,000 watts consumed for one hour equals a single kilowatt hour.

kva - Kilovolt-amperes - A unit of electrical force equal to 1,000 volt-amperes. The kilovolt-ampere is the practical unit of apparent power.

L-BAR - Average length of all service interruptions experienced, this measure is not weighted for the number of customers effected by an interruption.

Line Transformer - A garbage can-sized cylindrical object generally attached to power poles that steps down primary distribution voltage to secondary distribution voltage for delivery to individual customers.

MAIFI - Momentary Average Interruption Frequency Index - Measure of the total number of customer momentary interruption events relative to the total number of customers served.

Momentary Interruption - Interruption of service to a customer of less than one minute in duration. Usually represents loss of power for a fraction of a second caused by transient conditions, such as tree limbs or animals contacting with components of the distribution system. Momentaries can cause air conditioners to quickly shut off then back on, and many digital clocks to reset to 12:00,

MORT - Momentary Outage Reduction Team

N - Number of Interruptions, as reported in the Distribution Service Reliability Report to the FPSC.

NESC - National Electric Safety Code, The American National Standard which covers basic provisions for safeguarding people from hazards arising from the installation, operation or maintenance of 1) conductors and equipment in electric supply stations, and 2) overhead and underground electric supply and communications lines.

NRRI - National Regulatory Research Institute

OCR - Oil-Covered Reclosers

O & M - Operations and Maintenance

Outage - In a strict sense regarding electric distribution, the condition of a piece of equipment being out of service, which may not result in service interruption to customers, for example through the use of circuit breakers and switching. Term is also used more loosely as interchangeable with interruption of service.

Padmount Transformers - Transformers located on the ground on concrete pads and protected by steel cabinets. Used in conjunction with underground distribution systems.

PBR - Performance Based Regulation

Retail Wheeling - The use of one utility system's transmission facilities to transmit power to and from another system. Wheeling service allows a utility to transfer its power to another utility through an intermediate utility system. For this use, the intermediate system receives a wheeling charge, usually calculated as a flat mill-per-kilowatt-hour fee.

RMIS - Risk Management Information System

SAIDI - System Average Interruption Duration Index - Measure of the average duration of interruptions for the total number of customers served by the system. Conceptually equivalent to CMI/C and SU.

SAIFI - System Average Interruption Frequency Index - Measure of the average frequency of interruptions for the customers served by the system.

SORT - Sustained Outage Reduction Team

STOMP - Substation/Transmission Operations and Maintenance Procedure

Substation - An assemblage of equipment designed for switching, changing or regulating the voltage of electricity. This definition does not include service equipment, line transformers, line -

transformer installations, or minor distribution or transmission equipment. High electrical voltages from 69,000 to 765,000 volts are required to move electricity through transmission lines across great distances. Electric motors and appliances are not designed to use electricity at these high voltages, so voltage reductions must take place at a substation near a community served or along the transmission line serving a very large customer.

SU - Service Unavailability - Measure in minutes of the average duration of unavailability of service (i.e., interruptions) for the total number of customers served by the system. Conceptually equivalent to CMI/C and SAIDI.

TCMS - Trouble Call Management System

TORT - Transmission Outage Reduction Team

Transformer - An electromagnetic device that increases the voltage of electricity as it leaves the power plant so it can travel long distances or lowers the voltage of electricity for distribution.

Transients - A transient is any short-lived disturbance in the voltage of power supplied by a utility to its customers. The disturbance can be a spike or surge, or a sag or dip. Such transients may be caused by lightning striking a power line, routine switching of utility circuits, animals or other foreign objects touching a line, or improper use of end-use equipment. Normally, a transient provides only a momentary blinking of lights, and only a momentary interruption in the function of equipment or appliances. However, delicate office and data-processing equipment is often sensitive to transients, so that the presence of a transient can result in lost data, or even damage to equipment.

Trouble Ticket - Generic term referring to a trouble call received from a customer, and the resulting work order to resolve the problem. Trouble tickets may or may not involve an interruption of service.

URD - Underground Rural Distribution

Under oil arresters - Lightning arrestors which are submerged inside a container of non-conductive liquid to reduce arcing that occurs when lightning arrestors are blown by a lightning discharge.

UPS - Uninterruptible Power Supply - A system that runs on a battery that is continually charged by electricity. When a power interruption occurs, the battery continues to feed energy to the device to which it is connected and temporarily replaces the power normally provided by another source.

VRU - Voice Recognition Unit or Voice Response Unit - A computer-assisted telephone answering system that guides the customer in obtaining or reporting information such as reporting service interruptions.

Voltage Dips or Sags - A brief period of under-voltage that can be caused by start-up of on-site customer equipment, faults on a power system, large load changes in a utility service area or utility equipment malfunction. Dips lasting half a cycle or longer can cause computer memory loss.

Voltage Surge or Swells - A sudden dramatic increase in the voltage of electricity. Surges can be caused by lightning or abnormal system conditions and are potentially damaging to electronic devices. Spikes are similar but last for a shorter period of time.

APPENDIX 2

Electric Service Quality Monitoring Activities in Other States

Below is detailed information on 13 states that have reporting or monitoring requirements relating to electric service quality. Included is information from Arkansas, California, Illinois, Iowa, Kentucky, Michigan, Mississippi, Montana, New Hampshire, New York, Oregon, Rhode Island and Texas. The majority of these service requirements have only been implemented in recent years as a prelude to competition. The date the rules regarding service quality were adopted follows the name of each state.

Arkansas *(1994)*

Record Requirements
Arkansas electric utilities are required to maintain accurate records of trouble reports for at least two years. The report should include the identification of the person reporting the trouble, geographic area of the trouble, time and date of the initial report, description of the trouble, description of the trouble found by the utility, action take to clear the trouble, and date and time the trouble was cleared.

Additionally each electric utility must maintain records for two years of all detected or documented service outages. Each record shall include, date, time, location, cause, extent, and duration. Records of substations operations must also be maintained for two years.

Operations
Arkansas PSC has very specific service connection requirements for both when distribution facilities are available and when they are not. The requirements include deadlines for service connection expected service dates, and written proposal requirement. The Commission also requires each electric utility to receive trouble reports and make repairs on a 24-hour basis.

Maintenance
Arkansas electric utilities are required to restore service within 24 hours after an outage is reported. Additionally each utility is required to adopt a program of maintenance and inspection on its electric plant to determine the need for replacement and repair. Frequency of inspections are based on the utility's experience. Tree trimming is also addressed in the Arkansas electric rules.

California *(1997)*

Reporting and Recording Requirements
California Electric utilities are required to submit information on (a) system reliability using uniform methods for assessing data on the frequency and duration of system disturbance, (b) circuits that persistently perform poorly, and (c) accident or incidents affecting reliability.

The indices used for reporting system reliability are: SAIDI, SAIFI, and MAIFI. The commission has also explicitly identified and defined assumption to be used in calculating indices to assure uniformity and consistency of data such as, definition of: sustained and momentary outages, planned outages excludable major events, outage recording start and stop times, and circuit tracking level. The report filed with the commission each year must also include information about any group of customers commonly served by a circuit (no smaller than the facilities below the level of the last step down transformer in the area) that experienced more than one five-minute or more outage per month on a rolling annual average basis, after exclusion of major events. Each utility must also report the 10 largest outage events, and indicate whether any of them were excluded from the reported indices. For each major event excluded from the reliability indices, the utility must report the total number of customer affected, the number of customers without service at periodic intervals, the longest customer interruption, and the number of people used to restore service.

Utilities are also required to report accidents within two hour of the utility's determination that the accident is reportable. Reportable incidents are those (a) resulting in a fatality or personal injury rising to the level on in-patient hospitalization and involving utility own facilities or (b) are of significant public attention or media coverage and involve utility owned facilities. Incident involving estimated property damage of the utility or other estimated in excess of $20,000 that are allegedly attributed to utility owned facilities are to be reported within 60 day to the Commission.

Distribution Inspections

In March 1997, California developed standards requiring each utility to conduct inspections of its distribution facilities to assure high quality and safe operations. Each utility is required to submit a report to the commission annually which details the number of facilities by type which have been inspected during the pervious period, problem identified, date of corrective action and identity of the person performing the corrective work, facilities scheduled for inspection, but not inspected, and a date by which they will be inspected. Three types of inspections are required: patrol, detail, and intrusive.

A **Patrol** inspection (simple visual inspection to identify obvious structural problems and hazards) of overhead, underground, and pad-mounted transformers, switching/protective devices, regulators/capacitors, overhead conductors, street lighting, and wood poles must be done yearly in urban areas with a population of more than 1,000/square mile, and every other year in rural areas. A **Detailed** inspection (opening up of structures and equipment to carefully observe their condition and record it in a central location) of urban and rural overhead and pad-mounted transformers, switching/protective devices, regulators/capacitors, and conductors must be done every five years, and detailed inspection of underground equipment every three years. An **Intrusive** inspection (using sophisticated diagnostic tools such as analyzing samples) must be made every 10 years for wood poles over 15 years old if not previously inspected, or every 20 years if poles have passed a previous intrusive inspection.

Tree Trimming Standards

In January 1997, the California Commission adopted standards for tree trimming. For typical electric lines running though most residential areas, trees and branches must be kept at least 18 inches from overhead lines, depending on the line voltage, the potential for arcing, and the possibility of line contact. For higher voltage lines, greater distances are required. The guidelines suggest creating at least a four-foot minimum radial distance around 2,400 to 72,000 volt conductors, 6 feet around 72,000 to 110,000 volt conductor, 10 feet around 110,000 to 300,000 volt conductors, and 15 feet around conductors carrying more than 300,000 volts at the time vegetation is trimmed. Under the rules, utilities must maintain clearance between electric lines and vegetation that is visible from the ground, sufficient for persons working around lines to keep themselves and their tools away from danger.

Colorado (1997)

The Colorado Utilities Commission has a Quality of Service Plan (QSP) with Public Service Company of Colorado, which is the state largest electric utility. The plan is designed to maintain Public Service Company of Colorado (PSCo) existing or historical levels of service by discouraging cost saving at the expense of service levels. This is accomplished by assessing monetary penalties to encourage the Company to invest in quality service.

Under the plan, benchmarks are established for each of the following performance measures: (1) customer complaints received by the Colorado Public Utilities Commission; (2) telephone response by the PSCo Customer Inquiry Center; and (3) electric service unavailability. The QSP shall be in effect for five years and is separate from the company's Performance-Based Regulatory Plan. If the company's performance falls below the established benchmarks, penalties will be assessed regardless of the company's earning level.

Reporting Requirements

By April 1 of each year, the company will file with the Commission a report detailing PSCo actual performance as compared with the benchmark established for each measure. The report will be accompanied by supporting documentation related to the results achieved along with any penalty calculations. The report is verified by staff and then submitted to the Commissioners.

Penalty Disbursement

Any penalties will be credited to the electric customers bill during the July billing cycle. The maximum total penalty in the first year is $5 million (allocations: customer complaint $1 million, telephone response $1 million and electric service unavailability $3 million) The total penalty can increase $2 million annually based on performance in the previous year.

Benchmarks

Customer Complaints benchmark is 0.8 complaints per 1000 customer. These are contacts to the CPUC External Affairs section by PSCo customers that are classified as either objections, not in compliance, or in compliance. Information contacts are not included.

The telephone response measure assesses the response time to customer call. The answer time is measured from the instant the customer selects the option from the mechanized menu to speak to a customer service representative to the time the call is responded to by a CSR. The benchmark is 70% of call answered within 45 seconds.

The service quality measure will assess the duration and frequency of electric distribution system service interruption that PSCo electric customer experience on a performance year basis. For the first two years, SAIDI will be utilized for this measure. Beginning in the third year, CAIDI and SAIFI will be utilized. The SAIDI benchmark is 86 minutes for the total Colorado electric distribution system for the first performance year. In the second year, the SAIDI benchmark is 86 minutes and no single regional SAIDI shall exceed 150% of the system SAIDI benchmark. In the third performance year, the CAIDI and system SAIFI benchmarks will be set in November 1998 and will be equivalent to the System SAIDI benchmark where system CAIDI times system SAIFI equals system SAIDI. No single regional CAIDI shall exceed 150% of the system CAIDI benchmark

Illinois *(1996)*

Record Requirements

The Illinois Commerce Commission requires utilities to keep records which show a history of electric service interruptions experienced by each customer at the customer's current location. For each interruption, the company must collect information on interruption date, time, duration, cause, area circuit numbers, number of customers interrupted, and the account number and address of each customer affected.

Commission Notice

A utility must notify the commission when any single event (e.g. storm, tornado, equipment malfunction, etc) causes interruptions for 10,000 or more of the utility's customers for three hours or more. After such interruptions have continued for three hours, the utility must notify the Commission with the following: reasonable estimate of the number of customer interrupted, starting date and time, interruption duration, location, cause, expected restoration time, and company contact.

Annual Reports

Annually in June, each utility must file an annual report which includes a general assessment of electric service reliability. The assessment must include a review of programs the utility uses to provide reliable service, the cost of programs, description of new programs, and changes to existing program which the utility is considering. Additionally the report must include a:

- Table showing the achieved level of reliability indices for each operating area of the utility. Reliability indices required include SAIFI, CAIDI and CAIFI.

- List of the worst performing circuits for each operating area of the utility

- Statement of the operating and maintenance history of circuit designated as worst performing circuits, along with a description of any action taken or planned to improve such circuits to include schedule and cost.

- Discussion of the status of actions which the utility indicated in previous annual reports that it would take to improve electric service reliability

- Name, address and telephone number of company contact

In the year 2000, Illinois utilities are also required to submit an additional report to the Commission. The report will include two lists. One list will show the 0.1 percent of the utility's customers or 100 customer, whichever is smaller with the largest number of interruptions during the prior year. The list will include the number of interruptions, circuit number, and customer names and/or account numbers. The second list will include the 0.1 percent of the utility's customers or 100 customers, whichever is smaller with the largest number of interruption duration hours during the prior year.

Cause Categories

The categories to be used for record keeping and reporting are defined by the Illinois Commerce Commission as follows:

Interruption Cause Categories	**Interruption Code Description**
Utility/Contractor Personnel-Errors	Unclassified Error
	Switching Error
	Accident by Utility
	Testing Error
	Dig-In by Utility
	Accident by Utility Contractor
	Dig-In by Utility Contractor
Customer	Overload
	Customer Equipment
Public	Foreign Object
	Fire
	Vandalism
	Accident by Others
	Dig-In by Others

Weather Related	Lightning Wind Ice Sub-Zero Cold Flooding
Interruption Cause Categories	**Interruption Code Description**
Animal Related	Wildlife
Tree Related	Tree Contact Limb Broken
Overhead Equipment Related	Contamination Malfunction Broken Fuse Link
Underground Equipment Related	Underground Failure Contamination Malfunction
Scheduled	Initiated by Utility for Maintenance or Repair
Station Equipment Related	Contamination Malfunction
Unknown	Unknown
Other	None/Other

Reliability Review

Once all utilities have filed the third annual report, the commission may elect to initiate a proceeding to decide whether to adopt electric service reliability standards. In deciding whether to adopt standards, the commission will consider:

- Reports filed with the commission
- Nature and cost of program utilities' has designed to maintain and improve electric service reliability
- Nature and cost of the utilities interruption data record keeping and reporting capabilities

- Information developed from surveys designed to learn whether customer believe that utilities should improve the level of electric service reliability and if so whether customer are willing to pay rates which reflect the associated costs

- Testimony on the subject of electric service reliability submitted in Commission proceedings

The commission may also initiate an investigation of a utility to determine whether the utility provides electric service consistent with the commission's reliability policy. Based upon the results of the investigation, the commission may order the utility to take such corrective action as the commission deems necessary to improve electric service reliability

Iowa *(1994)*

The Iowa Utilities Board (IUB) has an electrical safety code which purpose is to promote safe and adequate service to the public. It also provides standards for uniform and reasonable practices by utilities and establishes a basis for determining the basis for such demands that may be made by the public. The code defines the electric safety code as compliance with NESC with some specific modification unique to their state. Additionally, the code requires each electric utility to file with the IUB a written program for inspecting and maintaining its electrical supply lines and substations (excluding generating stations) in order to determine replacement and repair. If the plan is revised or altered throughout the year, revision must also be filed.

Inspection and Maintenance Plans

As a part on an annual report each utility must file a certification of compliance with the inspection plan or a detailed statement of noncompliance. The inspection plan must include:

- Listing of all counties which have electric supply lines in Iowa

- Schedule for periodic inspection (Inspection cannot exceed 10 years for any given line or piece of equipment. Lines operated at 34.5 KV or above shall be inspected at least annually for damage and to determine the condition of line insulators.)

- Plan must include a complete listing of all categories of items to be checked during an inspection and shall provide for the inspection of all supply lines and substations within the adopted inspection period

- Instructions or standards which inspection can use to determine is a facility is in acceptable condition

The utilities must keep record in order to demonstrate compliance with its inspection program. Corrective action must be taken promptly.

Accident Reports

All accidents to employees or other persons involving contact with energized electrical supply facilities which result in a fatality, admission to a hospital, $10,000 in damage to the property of the utility and others, or any accident consider significant by the utility must be report to the IUB as soon as practical.

Kentucky

The Kentucky PSC requires all utilities to construct and maintain their plant and facilities in accordance with good engineering practices. Standards of accepted engineering practices are specified by rule as compliance with the applicable provisions of the following publication NESC, NEC, American Nation Standards Code for Electricity Metering and the USA Standard Requirement for Instrument Transformer. Additionally, utilities are required by rule to make all reasonable efforts to prevent interruptions of service and when such instances occur, to restore service with the shortest possible delay. When service is necessarily interrupted to work on equipment, it should be done when practical and notification should be given to customer which may be seriously affected.

Record Requirements

Utilities are to keep a records of: starting and shutting down principle units of power station equipment and feeder for major divisions; indications of sufficient switchboard instruments to show voltage and quantity of the load; all interruptions to service affecting the entire distribution system of any single community or important division of a community; and date and time of interruption, date and time of service restoration, and when known, cause of interruption

Inspection Procedures

The Kentucky PSC requires each utility to adopt inspection procedures to assure safe and adequate operations of its facilities and compliance with commission rules and regulations. The procedures are filed with the commission for review. Utilities are required to make systematic and inspections as follows:

- *Continuously*-Production facilities

- *Not to exceed every 6 months*-
  - Unmanned production facilities
  - Substation and electric lines where primary voltage is 69 KV or greater
  - Underground network transformers and network protectors in vaults located in buildings or under sidewalks

- *Not to exceed every year*-
  - Production facilities on standby status
  - Substations with primary voltage of 15 to 68 KV

- *Not to exceed two years-*
    - Electric lines operating at voltages of less than 69 KV including insulator, conductors and supporting facilities.

Voltage and Frequency

Each utility is required by rule to adopt a standard nominal voltage(s) as required by its distribution system for its entire constant voltage service. The voltage shall be stated in every rate schedule and terms and conditions of service. Voltage at the customer service entrance:

- *For Lighting* -variation in voltage between 5pm and 11pm shall not be more that 5% plus or minus the nominal voltage adopted. Total variation in voltage from minimum cannot exceed 6% of the nominal voltage

- *For Power* -voltage variation shall not at any time exceed 10% plus or minus the nominal voltage adopted.

Some variations from the voltages specified are allowed if the service is supplied directly from a transmission line, if it is an emergency service, if it is an extended area where customers are widely scattered, or if the business done does not justify close voltage regulation.

Each utility supplying alternating current shall adopt a standards frequency of 60 hertz which should also be stated in the utility's rate schedule.

Michigan *(1996)*

Michigan requires utilities to keep records of sustained interruptions of service to customers and to make an analysis of the records. The records should include: cause, date and time, and duration. Planned interruptions should be scheduled at a time that will not cause unreasonable inconvenience to customers and shall be preceded by adequate notice. Each utility is also require to notify the commission of any major interruptions of service to its customers. Additionally, utilities are required to adopt a program of maintaining adequate line clearance through industry-recognized guidelines. A line clearance program shall recognize the NESC standards and shall include tree trimming.

Mississippi *(1994)*

Mississippi uses customer service reliability as one of three performance indicators in setting rates on a semi-annual basis. Customer service reliability measures the reliability of the utility's service to electric customers and is based on the average amount of time a customer is without power during any twelve month period. The numerator of the reliability index is the total amount of customer time for all interruptions during the evaluation period based on the summation of individual interruptions of varying length and affecting different numbers of customers. The denominator is the number of customers at the end of the evaluation period times the total hours available to serve. *Excluded are major disasters, scheduled outages, outages to replace individual meters or service drops, breaker and recloser operation which do not lock out and outdoor lighting.* Based on the utility's performance a score on each of the three indicator is determined and then weighted and used as an input in the formula for calculating rates.

Montana *(1997)*

Montana had *drafted* service standards for energy utilities. The standards require utilities to make regular periodic measurements to determine the level of service for each standards included in their rules. The standards will address:

- Utility business offices and toll free calling
- Customer Service Hook-up
- Utility rate information
- Utility billing
- Customer complaints and appeals
- Customer non-emergency service requests
- Utility response commitments
- Customer trouble reports
- Utility service disruption
- Utility planned outages
- Utility system reliability

New Hampshire *(1997)*

The New Hampshire Public Utilities Commission issued an order in September 1997 approving measures designed to maintain the reliability of electric utilities. The decision was the culmination of a staff investigation on tree trimming practices conducted last year. The agreement established among other things:

- Specific tree trimming cycles-specified number of years for each company.

- Method for notifying landowners regarding spraying.

- Funding for comprehensive engineering analysis and implementation of line protection devices by year 2000.

- The reporting of momentary interruptions on an annual basis.

- Specified budgets for specific reliability projects.

- Standardization of reliability performance measures beginning third quarter of 1997 *Measures used by Public Service of New Hampshire include: SAIFI, CAIDI, SAIDI and CII.*

New York *(1997)*

In late 1996, the New York Department of Public Service modified its standards on Reliability and Quality of Electric Service staff recommended eliminating the requirement that utilities analyze five percent of their worst feeder circuits as prescribed by the Commission. The reason is that the companies now have all their own circuit review programs, which was not the case prior to the adoption of the standards. Staff recommend replacing the existing requirement with a requirement that utilities file details of their own program to analyze five percent of their own worst circuits each year, along with program documentation.

Service Reliability and Power Quality Objectives

Utilities are require to meet specific service levels established by the NY PSC, and report details of its electric service reliability program to the Commission in March of each year. Advanced notice of interruptions is required and records must be kept of instance where the utility concluded that it is not reasonable or practicable to provide advance notice. Utilities are also required to report details of its power quality program to the Commission in March of each year.

Operating Area Reliability Performance Levels

Each utility is required to calculate SAIFI and CAIDI indices for each operating area at the end of each calendar year. The NY rules establish a lower threshold of adequate service below which further review, analysis and corrective action may be required. When a utilities calculation for SAIFI and CAIDI for an operating area falls below the minimum level the utility must prepare a report for the Commission which analyses interruption patterns, trends as well as operating and maintenance history of the affected area, describes the problem causing unacceptable performance, and the action the utility is taking to resolve them.

Service Level Value Establishment

The Commission will periodically establish actual numerical values for SAIFI and CAIDI Objectives and Minimum level to be assigned to each operating area of each electric utility. Among the factors used to guide the establishment of SAIFI and CAIDI values will be a comparison of actual multi-year SAIFI and CAIDI indices, trends among the indices, the average, high and low values of multi year indices, demographics, physiographic and load characteristics of an operating area and relative performance of an operating area in relation to other operating area within a given utility's franchise area

Individual Circuit Reliability Performance Level

Each company is responsible for developing and maintain a program for analyzing its wort-performing circuits during the course of each year. The companies shall analyze a minimum of five percent of its circuits as part of it circuit review program each year.

Annual Report
In March of each year each utility must file a report which includes:

- An overall assessment of the reliability performance corporate-wide, and, in each of the company's operating areas, in relation to the Objective and Minimum Levels for interruption frequency and duration, as set by the Commission.

- A description of the program the company has in place for analyzing worst-performing circuits and a summary of the results of the program for the subject year. Copies of monthly, quarterly, or annual circuit analysis reports used by the company can be used to fulfill this requirement.

- A description of the company's current reliability programs noting changes that were made from the previous year.

- A status report on the company's power quality programs, including data on the number of power quality complaints received during the year and the number of power quality investigations conducted during the year.

- A listing of circuit performance, by operating area, based on SAIFI and CAIDI performance for the calendar year.

Oregon *(1997)*

The Oregon PUC recently (8/97) adopted new rules on electric service reliability. The previous rules were too general and needed to be updated to be current with emerging trends in the electric industry and customer expectations. The new rules cover such areas as continuity of service, interruption records, reliability calculations, threshold levels, annual reports, and major event filing.

Interruption Records
Oregon electric utilities are required to keep records of each interruption of services that affects one or more customers. Each record shall contain the following:

- Operating area, substation and circuit involved
- Date and time of interruption
- Date of time service was restored
- Duration of interruption
- Number of metering points affected
- Cause of interruption
- Weather conditions at time of interruption
- Whether the interruption was planned or unplanned
- Protection device that made the interruption

- Component involved *(e.g., transmission line, substation. overhead primary main, underground primary main, transformer, etc.)*

For interruptions where customers are not simultaneously restored, utilities shall keep records that document that the step-restoration operations. For major events where the utility cannot obtain accurate data, the utility shall make reasonable estimates. Utilities are required to retain this interruption information for 10 years.

Reliability Calculations

Oregon electric utilities are required to calculate at year-end SAIDI, SAIFI, and MAIFI, with and without major events, on a system-wide basis, for each operating area, and for each circuit.

Threshold levels for SAIDI, SAIFI, and MAIFI shall be established by each electric utility for system-wide operations, each operating area, and each circuit and be filed with the Commission. The Oregon PUC recommends that the following factors be used by the utilities in setting threshold levels:

- Past reliability information
- Demographic, geographic, and electrical characteristics
- Relative performance of the circuits to each other

Oregon defines a major event as a catastrophic event that exceeds the design limit of the eclectic power systems, causes extensive damage to the electric power system, and results in a simultaneous sustained interruption to more than 10% of the metering points in an operating area.

Annual Report

Oregon electric utilities must file an annual report with the Commission that includes reliability information for the previous calendar year. The report shall contain:

- SAIDI, SAIFI, and MAIFI indices and thresholds compared to the most recent four years with and without major events on a system-wide basis and for each operating area.

- SAIDI, SAIFI, and MAIFI indices and thresholds for each circuit, with major events excluded.

- A summary of system-wide interruption causes compared to the previous four year performance.

- Categories to be evaluated include
  - Adverse environment
  - Adverse weather
  - Customer equipment

- Equipment failure
- Foreign interference
- Human element
- Lighting
- Loss of Supply
- Major events
- Scheduled outages
- Unknown
- Other *(If used the electric utility must be specific as to cause)*

Major Event Filing

Oregon utilities must submit a report to the Commission within 20 days after an event. The report must include a description of the event and a discussion of why the utility considers it to be a major event. Additionally it must include:

- Total number of metering points affected, the number of metering points without service, and the longest service interruption.

- Number of crews assigned to restore service at periodic intervals.

- The estimated SAIDI and SAIFI impact.

- Damage cost estimates to the utility's facilities.

- The reason timely restoration was beyond the utilities control.

- A list of circuits that were affected with sustained interruptions lasting more than four hours.

Rhode Island (1997)

The Rhode Island Utility Restructuring Act of 1996 requires distribution companies to implement performance-based rate plans for the period January 1, 1997 through December 31, 1998. The Rhode Island PUC is required to establish performance standards to ensure that historic levels of safety, reliability, and customer service continue during the two year period. These standards are required to provide each distribution company the opportunity to incur an annual penalty or reward equal to one percentage point return on equity for variation above or below historic levels.

Texas *(1997)*

The Public Utility Commission of Texas adopted a rule mandating an electric service quality report in July 1997. All public utilities are required to submit service quality reports twice annually. They are required to keep a record of sustained interruptions, which include the type of interruption, cause, date and time, restoration time, number of interrupted customers, substation identifier, transmission line or distribution feeder and voltage, and, if pertinent, the action taken to restore service and to prevent recurrence.

Each utility in Texas operating electric facilities at 60,000 volts or greater must file a Transmission System Report. The report includes information for any line section experiencing a scheduled or unscheduled forced outage that results in a sustained interruption during the period.

Reliability Indices

Each utility providing electric distribution service in Texas must maintain data necessary to calculate SAIFI, SAIDI, and CAIDI by distribution circuit. Calculation of the SAIFI, SAIDI, and CAIDI indices shall exclude all momentary interruption events, but shall include all switching operations not completed within five minutes. Indices shall be calculated on a six month basis and reported twice annually.

Distribution Feeder Report

The Texas commission requires each utility to provide semi-annually:

- A list of five percent of the systems distribution feeders with the highest six month SAIFI values for forced interruptions, as of the end of the reporting period. Also included is the number of times that each listed feeder has been reported in the preceding two years.

- A list of five percent of the systems distribution feeders with the highest six month SAIDI values for forced interruptions, as of the end of the reporting period. Also included is the number of times that each listed feeder has been reported in the preceding two years.

- A list of five percent of the systems distribution feeders with the highest six month CAIDI values for forced interruptions, as of the end of the reporting period. Also included is the number of times that each listed feeder has been reported in the preceding two years.

- A list of five percent of the systems distribution feeders that have been identified by the utility as the worst performing feeders. This list may vary from the list produced by the highest SAIDI, SAIFI, or CAIDI values. The utility must provide a narrative describing the method and rational used by the utility to identify the worst performing distribution feeders.

Interruption Causes

Utilities must also submit a list of the causes of forced interruptions during the period, and the percentage of interruptions attributable to each cause. All causes with a percentage of 10 or greater must be included. Causes of forced interruptions will include lightning, other weather related, vegetation, animals, equipment failure, other, and unknown.

APPENDIX 3

A Compilation of Florida Electric Utilities Outage Related Inquiries 1996 to 1997

This appendix identifies a sample of the over 628 distribution service quality and reliability complaints which have been filed with the Florida Public Service Commission in 1996 and 1997. The purpose of the appendix is to display the specific type of complaints the utilities are receiving and to identify the cause of the complaints and what action the company took to resolve the concerns.

The following table reflects a breakdown of the 628 distribution service quality and reliability complaints received by the Commission.

Service Quality and Reliability-Related FPSC Inquires Received 1996-1997

Category	FPC		FPL		GPC		TEC		TOTAL	
	1996	1997	1996	1997	1996	1997	1996	1997	1996	1997
Frequent Outages (ES-02) (ES-05) (GI-15)	67	31	242	179	4	1	2	6	315	219
Tree Trimming (ES-04) (GI-18)	1	1	0	9	0	1	0	0	1	9
Momentary Outages (GI-19-21)	0	11	1	55	0	1	0	2	1	69
No Advanced Notice (ES-06)	1	0	0	4	0	0	0	0	1	4
Voltage Standards (ES-07)	1	0	4	2	0	0	1	1	6	3
Total	69	43	247	249	4	3	3	9	324	304

Of the 628 complaints received, the majority, or 79 percent, came from FPL customers. Another 18 percent were from FPC customers. Gulf and TEC only received one to two percent of the complaints, respectively. The following highlights the information derived from reviewing the sample data. No inferences are being made regarding the total population of inquiries filed with the Commission.

Florida Power Corporation

Because of the volume of complaints, only 50 percent of FPC service quality and reliability-related complaints are included in this appendix. Of the 58 randomly selected complaints, 91 percent are from urban customers, while nine percent are from rural customers. Of those filing complaints included in the sample, nine percent are residential customers, while eight percent are commercial customers.

When reviewing FPC's individual complaint files, it is apparent that the company attempts to ensure that customers who complain are given the name and number of a customer service representative to call if they have any future problems. The company appears to take complaints seriously and contacts the customers immediately following the receipt of a FPSC complaint. Their analysis provided in response to the Commission inquiry is typically detailed and complete.

Of the sample of FPC's customers who have filed a complaint with the Commission, 71 percent experienced four or fewer outages. Approximately 29 percent had five or more outages in the months prior to their inquiry. This percent excludes momentary outages. The outage duration for customers in the sample was also reviewed. Forty-eight percent of the sample of FPC's customers experienced a duration of less than 240 minutes. Approximately 52 percent experienced a total outage duration of more than 240 minutes in the months prior to their inquiry to the Commission.

Florida Power and Light

Because of the volume of complaints, only 20 percent of FPL's service quality and reliability-related complaints are included in this appendix. Of the 98 randomly selected complaints, 97 percent are from urban customers, while three percent are from rural customers. Of those filing complaints included in the sample, 87 percent are residential customers, while 13 percent are commercial customers.

Of the sample of FPL's customers who have filed an outage-related complaint with the Commission, 57 percent experienced four or fewer outages in months prior to their complaint. Approximately 43 percent had five or more outages. Reviewing the duration of outages of the FPL sample reveals that 16 percent of the sample experienced an outage duration of 240 minutes or less. Approximately 84 percent of the sample experienced an outage duration of more than 240 minutes in the months prior to their complaint. Inquiries regarding momentaries also appear to be more extensive at FPL than at the other electric companies.

Gulf Power Company

All seven service quality and reliability-related complaints received by the FPSC in 1996 and 1997 are included in this appendix. Of the seven complaints received from Gulf Power customers, one was from a rural customer, while the remaining six were from urban customers. Additionally, one of the seven complaints came from a commercial customer, while the remaining six came from a residential customer. Four of the complaints concern general outages, while three relate to momentary outages. No patterns were found in reviewing the cause of the outages based on the company response to the complaint.

Tampa Electric Company

All 12 of the service quality and reliability-related complaints received by the FPSC in 1996 and 1997 which fall into these service related categories are included in this appendix. Of the 12 service-related complaints filed by TEC customers, all appear to live in urban areas. Two of the 12 complainants were commercial customers, while the other 10 were residential. Two of the complaints were created by voltage fluctuations, while the remaining 10 were complaints regarding outages and momentaries. The company did not provide the Commission with information regarding duration of each of the outages experienced by the consumer, so additional statistics could not be compiled. No patterns were found in reviewing the cause of the outages based on the company response to the complaint.

Florida Power Corporation
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
No Advanced Notice of Outage	1334471	Ong	Winter Park	U	R	Customers lost power due to a preplanned outage to replace a transformer, but was not warned first.	"It is not cost effective for FPC employees to notify customers by telephone or a door hanger message that the company is planning a schedule outage for the following day, only to have it rescheduled unexpectedly." For the outage referenced, work crews made an attempt to knock on several doors.
Tree Trimming	1318971	Lak	Eustis	U	R	Trees not trimmed. 2 outages during 1996 for duration of 9 hours and 36 minutes.	First outage due to failed underground cable. Second outage due to tree limb.
Voltage Standards	1351061	Ong	Orlando	U	C	Power surges for last 6 months.	Connection checked and secondary moved to closer transformer. Problem continued in July and August. Increased transformer was needed as well as a change out of the service.
Tree Trimming	1751311	Mar	Reddick	R	R	Trees hitting lines.	Trees trimmed.
Outage	1077601	Pin	St Petersburg	U	R	2 outages.	Trees trimmed. Secondary conductor replaced.
Outage	1037871	Pin	Gateway Mall	U	R	1 outage for duration of 5 hours and 6 minutes	Transformer replaced.
Outage	1044161	Sem	Longwood	U	R	40 momentaries during 1 day.	Vines blowing into lines were removed.
Outage	1046781	Polk	Davenport	R	R	2 outages in January 1996.	Cold weather caused overloading, causing blown fuse and a broken insulator which dropped a primary line causing substation breaker to trip.
Outage	1049931	Pin	St Pete	U	R	Power surge damaged appliances. Service person missed scheduled appointment.	Service person arrived late, determined necessary repairs. FPC is paying for damage to appliances and loss of food in refrigerator.

Florida Power Corporation
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	1092681	Ong	Orlando	U	R	2 interruptions in January 1996 for duration of 249 minutes.	Road widening created need to moving existing poles, wire and equipment. Wire and equipment were upgraded in conjunction with roadwork. Trees in area trimmed. Letter sent to customers in the area.
Outage	1102881	Ong	Maitland	U	R	2 outages during February 1996 for duration of 347 minutes.	Replaced two transformers and two fuses.
Outage	1147531	Sem	Oviedo	U	R	Customer say they are having outages daily. Company records show no 1996 outages as of March 1996. 10 were reported in 1995 for duration of 641 minutes.	Causes were trees and defective equipment.
Outage	1162681	Sem	Altamonte Springs	U	R	Frequent outages.	No company response on file.
Outage	1164381	Ong	Winter Park	U	R	Frequent outages.	Pole to pole inspection conducted in neighborhood. Tree trimmed and equipment changed out. Additional protection devices added.
Outage	1165321	Ong	Orlando	U	R	Flickering lights.	Trees trimmed.
Outage	1172011	Ong	Orlando	U	R	12 outages in 15 month period.	7 of the outages were from trees, 1 caused by down wire, and 2 from defective equipment, 1 was unknown and 1 was preplanned maintenance.
Delay in Restoring	1177381	Vol	Pierson	U	R	1 outage for 4 hour duration. Once company responded to complaint, it only took 20 minutes to restore service. Because customer lives in a rural area FPC takes longer to respond.	Tree caused downed primary line. Several other outages were worked prior to this one because of location.
Outage	1198471	Sem	Longwood	U	R	10 outages in past 12 months for duration of 678 minutes.	Causes related to animals and trees.

Florida Power Corporation
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	119973I	Sum	Oxford	R	R	2 outages January to April 1996 for duration of 97 minutes.	Cause undetermined.
Momentary Interruption	120671	Pin	Clearwater	U	R	Frequent momentary interruptions.	Company explained to customer how the FPC distribution system works.
Outage	122032I	Orn	Maitland	U	R	3 outages from January to April 1996.	Replaced insulators, installed arrestor and conducted a pole by pole inspection.
Outage	122121I	Osc	Saint Cloud	U	R	6 outages in 1996 for duration of 715 minutes.	Customer is in a remote location. Causes of previous outages have been weather, animal and trees. FPC is unsure what further action to take to improve reliability.
Outage	122389I	Orn	Orlando	U	R	3 outages in past 12 months.	Feeder performance reviewed and found inadequate during extreme weather conditions. Pole by pole inspection done. Trees trimmed, equipment upgraded and additional protection devices installed. Load transferred to other feeders.
Outage	124331I	Vol	Debarry	U	R	3 outages in April to May 1996 for duration of 128 minutes.	Caused by animals and trees.
Outage	124716I	Pin	Palm Harbor	U	R	10 momentaries from Jan to May 1996.	FPC explained to customers that momentaries are induced by relay at substation to prevent damage to lines.
Outage	125589I	Mar	Dunnellon	R	C	Power spike are destroying office equipment per repairman.	Volt meter installed for 6 days. One feeder operation occurred. Caused by trees which were trimmed.
Outage	125772I	Pin	Largo	U	R	2 outages in past 12 months for duration of 150 minutes.	1 resulted from failure of service cable. Service wire replaced. Claim paid $250 for microwave damage.
Outage	127279I	Sem	Longwood	U	R	4 outages in 1996 for duration of 228 minutes.	3 outages caused by trees, 1 caused by storm. Trees trimmed. Distribution system discussed with customer.

Florida Power Corporation
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	128011I	Sem	Casselberry	U	C	4 outages in a three month period.	Corrected a fuse coordination problem, replaced damaged insulator. Could find no other problems or cause of latest outage. Will continue to monitor.
Outage	128422I	Jef	Monticello	U	R	Flickering lights.	Trees trimmed.
Outage	128624I	Sem	Lake Mary	U	R	2 outage in first 6 months of 1996 for duration of 82 minutes.	Incorrect outage history for customer was corrected. Transformer changed out, trees trimmed.
Outage	127697I	Pas	Elfers	U	R	9 momentaries in first 5 months of 1996. And 2 outages in 1996 for duration of 67 minutes.	Cause of 1996 outages unknown. FPC responded by letter explaining distribution system.
Outage	129024I	Polk	Lake Wales	U	C	2 outages in past 12 months. Takes longer to get service from company now they have reorganized.	Explained expansion of Winter Park Phone Center to handle calls from Lake Wales two years earlier eliminated calls to business office. Winter Park phone center is available 24 hour a day.
Outage	129044I	Pas	New Port Richey	U	R	2 outages in June 1996 for duration of 5 minutes.	Cause was construction in the area.
Outage	129059I	Pin	Seminole	U	R	3 outages in the last 12 months.	Caused by tree, animal and connector failure.
Outage	129254I	Orn	Winter Park	U	R	8 outages the first 6 months of 1996 for duration of 769 minutes.	3 of the outages were in 1 day. Causes included tree, defective equipment and 1 storm. FPC installed additional protective devices, changed out the transformer and trimmed trees.
Outage	129279	Sem	Winter Springs	U	R	2 outages in 2 days for duration of 116 minutes. 7 momentaries in 1996.	Outages were caused by a feeder lock out and a tree down.
Outage	129299I	Sem	Oviedo	U	C	Business had 7 outages in 1995 and 3 during first six months of 1996. Claim filed for lost business.	Vines in substation caused 80 amp fuse to go out.

Florida Power Corporation
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	129373I	Sem	Altamonte Springs	U	R	4 outages from January to June 1996 for duration of 255 minutes.	Causes include cable failure, defective equipment, weather and trees.
Outage	130091	Pin	Clearwater	U	R	Problem with voltage fluctuation and momentaries.	Installed volt meter on three occasions. No problems were found on FPC side on meter.
Outage	130254I	Org	Winter Park	U	R	8 outages in 1996 for duration of 769 minutes.	Causes included defective equipment (2), trees (3), storms (2) and generation (1). Installed additional protective devices, upgraded equipment, trimmed trees, and verified connections.
Outage	130496I	Lak	Eustis	U	R	2 outages in one month period for duration of 233 minutes. Response time from company is slow due to cut backs.	Truck was dispatched 20 minutes after call for outage received. FPC believes that this is acceptable. Outages were caused by storms.
Outage	130530	Org	Winter Park	U	R	7 outages in 1996.	Causes included defective equipment (1), trees (4), storm (2). Additional tree trimming was done.
Outage	130824I	Sem	Longwood	U	R	6 outages in 1996 for duration of 403 minutes.	Causes included storms(2) defective equipment (2), line maintenance and cable failure (2). Replaced lightning arrestor, trimmed trees. Letter sent to customer in areas explaining distribution system.
Outage	131138I	Sem	Winter Springs	U	R	4 outages in 1996 for duration of 515 minutes .	Causes included storm defective equipment (2), and unknown. Inspection constructed, trees trimmed, equipment changed, connection verified.
Outage	131730I	Org	Winter Park	U	R	Frequent outages.	Trees trimmed, equipment changed out and connections verified Insulator and lightning arrestor replaced.

Florida Power Corporation
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	131804	Sem	Casselberry	U	R	1 outage lasting 13 hours and 15 minutes.	Storm caused 107 outages that day. This outage was caused by a tree on primary and secondary lines that had to be removed before restoration efforts could begin. Lines were located in the backyard area of customer homes. Once tree was removed, crew worked steadily from 11pm to 6am to complete work.
Outage	132821I	Org	Orlando	U	R	2 outages caused by storm for duration of 6 hours and 22 minutes.	Cause of outage was storm and involved an 80 amp fuse.
Outage	134707I	Ala	Gainesville	U	R	2 outages in one month for duration of 3 hours and 15 minutes. In 1996 had 6 outages.	Current outage was caused by a wire damage in one spot by lightning which did not fail until normal load condition caused it to burn in half. Previous outages caused by tree(2), lightning (2), and storms(2).
Outage	135336I	Sem	Longwood	U	R	3 outages in 1996 for duration of 436 minutes. Also had 32 momentaries from April 1996 to August 1996.	Causes included storm, failure of underground primary cable and generation. Lines patrolled. Connections checked. Metering wire found to be aluminum and was showing signs of burning. Loss of power could be caused by internal wiring heating up.
Outage	135476I	Ong	Winter Park	U	R	7 outages from January to August 1996.	Causes included statewide generation problems (2), storms(3), trees(1) and one unknown. Trees trimmed.
Outage	136103I	Ong	Winter Park	U	R	4 outages from June to August 1996.	Lines patrolled repairs and upgrades made as needed. 2 of the outages were caused by line maintenance.
Outage	136232I	Lak	Grand Island	U	R	2 outages in month of August 1996 for duration of 2 hours and 9 minutes.	Outages were due to weather and lightning.
Outage	1378691I	Cit	Homosassa	R	R	Frequent momentary interruptions.	Transformer changed out.
Outage	138250I	Ong	Orlando	U	R	3 outages for duration of 393 minutes.	Causes included tree(2) and construction(1). Trees trimmed.

Florida Power Corporation
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Oty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	1396531	Ong	Winter Park	U	R	7 outages in first nine months of 1996.	Causes included tree(3), storm/lightning (2), and 1 unknown. Trees trimmed, installed additional protection devices, verified connections, and changed transformer.
Outage	1414771	Ong	Winter Park	U	R	Frequent outages.	Line inspected, trees trimmed, and feeder reconductored.
Outage	1424641	Pin	Tarpon Springs	U	R	Frequent outages.	Replacing many of the primary underground cables in neighborhood. Those not being replaced will be injected.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Frequent Outage	1357261	Bro	Fort Lauderdale	U	R	5 outages from January 1996 to August 1996 for duration of over 19 hours. Also experienced 2 momentaries during this period. Additionally customer is having a problem with voltage fluctuations.	Outages were due to OH cable failures. Cable failure causes included abnormal switching, wire damage, and lightning. Voltage fluctuations due to bad connectors. Service drop entrance conductors needed to be upgraded .
Frequent Outage	1535861	Dad	Miami	U	R	Customer has had 13 interruptions from June 1996 to December 1996 for a duration of 94 hours and 52 minutes.	Cause of all outages was a lateral cable failure. Cable had been injected, but it didn't solve problem. Job engineered to reconductor the entire lateral to be completed in mid-1997.
Frequent Outage	1157581	Plb	Royal Palm Beach	U	R	6 outages in 6 months for duration of 9 hours and 32 minutes.	Cause on 5 occasions were 2 separate cable failures which have now been replaced.
Frequent Outage	1359371	Dad	Hialeah	U	R	3 outages from June to August 1, 1996 for duration of 10 hours and 35 minutes.	Causes included resetting customer breaker, replacing transformer/run ground strap, repair ground strap, and refusing transformer.
Voltage Standards	1505871	Bro	Fort Lauderdale	U	R	Voltage fluctuations.	Bad cable. Customer continued to have problems after repairs made. Bad neutral cable. Customers service will be abandoned and a new underground service installed.
Frequent Outage	1355411 1355531 1357801	Plb	Boca Raton	U	R	7 interruptions in six months for over 32.5 hours. Also had 14 momentaries during the same period.	Underground cable failures. After fifth interruption, FPL began cable injection/replacement.
Frequent Outage	1069491	Bro	Miramar	U	R	2 interruptions in one month for duration of 13 hours and 32 minutes. Extensive damage to property.	Cause of first outage was trees. Second outage was due to downed line requiring extensive line clearance. Tree limbs left behind and truck damaged property. FPL removed limbs, resodded and filled ruts, fixed service drop, and straightened pole.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	110867I	Coll	Naples	U	R	On February 5-6, 1996, customer experienced 5 outages for duration of 30 hour and 42 minutes.	Growth in subdivision resulted in transformers exceeding load limitations. Transformer scheduled for upgrade.
Voltage Standard	140037I	Bro	Dania	U	R	Low voltage.	Additional transformer installed.
Voltage Standard	137111I	Bro	Deerfield Beach	U	R	Low voltage.	Additional transformer installed.
Voltage Standard	118877I	Dad	Miami	U	R	High voltage.	Substation automatic system equipment failure. Voltage regulator repaired. **Claim filed and denied.**
Voltage Standard	146533I	Dad	Miami	U	C	Voltage fluctuations.	Additional transformer installed.
Voltage Standard	145169I	Coll	Naples	U	C	Wrong voltage provided to golf course, which took several weeks to correct.	Changed service type.
Voltage Standard	149639I	Bro	Pompano Beach	U	R	Experiencing momentary interruptions.	Told customer momentaries are a part of system design and they help reduce longer duration outages.
Voltage Standard	136900I	Dad	Miami	U	R	Voltage fluctuations.	Cause was recent installation of ground strap in the neighborhood. Permanent repairs made and ground strap removed.
Momentary Outage	104560I	St. J	St. Augustine	R	R	Momentary outages.	FPL installed sentry device to monitor momentaries. Line clearing performed.
Outage	173862I	Bro	Pembroke Pines	U	R	Customer has had 21 momentary interruption from February to May, 1997.	A letter was mailed to the customer addressing his concerns. A brochure explaining momentaries was included.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	1783841	Dad	Miami	U	C	2 outages in June 1997 for duration of 2 hours and 27 minutes. Additionally customer has experienced 16 momentaries in the 3 month period preceding outage. Customer filed claim for damage to air conditioner.	To improve reliability in this area FPL had reconductored sections of this feeder. **Damage claim was denied** since cause of outage was equipment failure, which was beyond FPL's control.
Outage	1824451	Plb	Loxahachee	R	R	13 outages between March 1997 and August 1997 for duration of 30 hours and 19 minutes. Additionally, customer had 125 momentaries from January to September 1997.	Company is currently working several projects to improve overall reliability in the area. Major line clearing efforts are underway. Two new feeders will be added by end of 1997 and two more in 1998 to handle customer growth.
Outage	Campbell	Coll	Naples	U	R	Power was out for 16 hours. Company was not responsive to phone calls.	Company response not on file.
Voltage	Fowel	Coll	Naples	U	C	Voltage fluctuations.	Replaced voltage regulator.
Outage	Dobbins	Dad	Coral Gables	U	R	Numerous outages in neighborhood. On July 28 there was 1 outage, duration was 3 hours and 45 minutes.	Jumper wire replaced and tee trimming performed.
Outage	Weidener	Dad	Miami	U	C	7 outages in 1996 for duration of 15 hours and 15 minutes.	Outages caused by salt build-up and winds.
Outage	Towers of Quayside (Marcus)	Dad	Miami	U	R	Numerous outages at apartment complex. Claim for $670 filed.	**Claim denied.** Outage caused by fire in pole. Substation breaker was replaced. Tree trimming to be done.
Outage	Warminger	Dad	Miami	U	R	4 outages from May 1996 to August 1996.	Outages caused by overloading of the line, FPL redistributed loads.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	Freire	Dad	Miami	U	R	From October to November 1996 customer had 4 outages for duration of 29 hours 20 minutes.	Sent brochure on causes of momentaries.
No Notification of Outage	Ginieczki	Plb	Boca Raton	U	R	FPL took customer's neighborhood service out for over an hour without giving residents prior notice of maintenance activities.	FPL apologized.
Outage	McFann	Plb	N. Palm Beach	U	R	Numerous momentary and several long outages in customer's neighborhood.	Cause was salt build-up on insulators.
Voltage	Regency Homes	Plb	DelRay Beach	U	C	Poor power quality to sewer lift station.	FPL ultimately swapped primary feeder to different circuit to resolve problem.
Outage	Albin	Plb	W. Palm Beach	U	R	2 outages for duration of 9 hours and approximately 110 momentary outages during 1996.	35 MPIs related to weather, 21 related to lightning, and 8 related to outages. FPL found tree conditions and a blown lightning arrestor. Flashed insulators and a bad feeder terminator in a switch cabinet.
Voltage	Radiology Associates	Sar	Venice	U	C	Voltage fluctuations.	No resolution on file.
Outage	Cheseboro	Vol	Daytona Beach	U	R	Numerous power outages at customer's residence. One day power was out for 4 times for 8 hour duration.	Tree trimming conducted and lightning arrestor replaced.
Outage	Troxell	-----	Parrish	U	R	Numerous outages to customer and neighbors. 1 outage on December 1, 1996 for a duration of 4 hours and 46 minutes plus 22 momentaries from January to November 1996.	No resolution on file.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	Libell		Deltona	U	R	3 outages in 1996 for duration of 2 hour and 43 minutes.	Patrol of feeder conducted. No problem found. Entire feeder was trimmed in 1996. Falling sand pines was indicated as problem for one of the outages.
Outage	130537I	Plb	West Palm Beach	U	R	19 momentaries in first 7 months of 1996.	Discussed surged protectors with customer.
Outage	130567I	Vol	Deltona	U	R	44 momentary operations from January to July 1996.	Causes due to trees and lightning. Trees trimmed.
Outage	130595I	Dad	Miami	U	R	3 interruptions during first six months of 1996 for duration of 13 hour and 42 minutes. 23 momentary interruptions in 1996.	18 momentaries and one outage are related to failing switch cabinet.
Outage	130756	Sar	North Point	U	R	1 outage for duration of 120 minutes during 1996. 21 momentaries from Jan to June 1996. Equipment damaged.	Momentaries caused by storms. Trees trimmed. **Damage claim denied.**
Outage	130800I	Dad	Miami	U	R	4 outages in 3 months for duration of 4 hour and 13 minutes. Additionally, customer had 37 momentaries from March to July 1996.	Abnormal switched load and hot humid weather caused outages and momentaries.
Outage	130873I	Dad	Miami	U	R	1 outage for 9 hours and 6 minutes in June. FPL was not responsive to calls and took too long to restore service.	Outage was caused by transformer failure.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	1308821	Dad	Miami	U	R	5 outages for 3 month period in 1996 for duration of 10 hours and 4 minutes Also had 37 momentaries.	FPL had problem with feeder in areas. Extensive maintenance work done. During maintenance, customer was switched to adjacent feeder. Hot weather and abnormal load caused feeder breaker at substation to lock out.
Outage	1310371	Dad	Miami	U	R	8 outages from January to June 1996 for duration of 19 hours and 54 minutes	Outages were due to trees. Trees trimmed in May, but outages have continued. Trimming will continue.
Outage	1311621	Dad	Miami	U	R	1 outage in June 1996 for duration of 5 hours 29 minutes. Additionally had 30 momentaries in June 1996.	Outage in June caused by OH cable failure. Momentaries were caused by same event.
Outage	131341	Dad	Miami	U	R	5 outages from February to July 1997. Also had 35 momentaries during first 7 months of 1996.	Caused by switching load to an adjacent feeder to allow for air drying in the feeder pull off to the substation. After switching customers back to original feeders MPIs and outages stopped.
Outage	1313781	Dad	Miami	U	R	6 outages in first 7 months of 1996 for duration of 6 hours and 29 minutes. Also had 27 momentaries in May-Jul.	Maintenance performed on feeder. Load switched to adjacent feeder, when load returned to original feeder, normal operations were resumed.
Outage	1313881	Bro	Hollywood	U	R	3 outages in May to July 1996 for 10 hours and 15 minutes.	Cause of 2 outages was cable failure. 1 was unknown. Cables repaired.
Outage	1315081	Dad	Miami	U	R	4 outages from April to July 1996 for duration of 7 hours and 42 minutes. Also had 35 MPIs during same period.	Cause for 2 outages was cable failure. 2 were unknown.
Outage	131644	Bro	Pompano Beach	U	R	4 outages from January to July 1996 for duration of 8 hours and 56 minutes. Also have had 37 MPIs January to July 1996.	Cause of outages are unknown in 2 cases. Other 2 were caused by transformer failure and overloading. Investigation was initiated. New feeder to be on-line by end of 1996.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	1317491	Bre	Palm Bay	U	R	13 outages January to July 1996 for duration of 12 hours and 26 minutes.	Causes included lightning (6), vehicle (1), equipment failure (3), unknown (3) . Feeder runs 4-50 miles through SW Palm Bay. Feeder inspected several times. Blown/cracked arrestors replaced. A failed disconnect switch was replaced.
Outage	1321221	Dad	Miami	U	R	6 outages from March to July 1996 for duration of 10 hour and 18 minutes. Also had 20 MPIs during same period.	Causes included cable failure, breaker failure, switches and relays. FPL will patrol feeder.
Outage	1321251	Coll	Naples	U	R	3 outages in from January to July 1996 for duration of 3 hour and 38 minutes.	Causes included dig in, equipment failure and tree. Neighbor refuses to allow tree trimming.
Outage	1321551	Dad	Miami	U	R	22 MPIs during first seven months of 1996.	Volt meter installed, no problems found.
Outage	1322021	Bro	Coral Springs	U	R	Frequent outages and MPIs. FPL records only reflect 1 outage for duration of 30 minutes and 17 MPIs.	14 MPIs associated with outage. Outage was caused by feeder overload due to abnormal switching condition.
Outage	1328271	Dad	Miami	U	R	3 outages in July 1996 for duration of 1 hour 48 minutes. 24 MPIs in July 1996.	Load switched to adjacent feeder for maintenance. Switching caused overload.
Outage	1328381	Dad	Miami	U	R	5 outages from January to July 1996 for duration of 13 hours and 15 minutes. Also had 39 MPIs during same period.	Causes of outages were cable failure (1), dig-in (1), wire down (2) and tree (1). Majority of MPIs were caused by lightning and broken insulator. Insulator replaced.
Outage	1329391	Dad	Miami	U	R	2 outages in July plus numerous MPIs. Outage duration was 2 hours 57 minutes.	Cause of outages were transformer failure and feeder overload.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	1330221	Lee	Ft Myers	U	R	6 outages from January to July, 1996 for duration of 6 hours 6 minutes. Also had 19 MPIs during same period.	Causes included tree (2) maintenance, (1) animal, (1) and unknown (2). Lightning arrestor replaced and trees trimmed.
Outage	1331151	Plb	Delray Beach	U	R	3 outages in 2 month period for duration of more than 11 hours.	Causes included feeder cable failure and a lateral cable failure. Same cable had failed in May, therefore, cable had to be replaced rather than spliced. This caused outage to be long. Failure was under a paved road so temporary repair had to be made.
Tree Trimming	1389181	Oke	Okeechobee	U	R	22 MPIs from May to September 1996.	Trees trimmed. Damaged insulator and pole replaced. Customer was told MPIs are a part of system design.
Outage	1390851	Dad	Miami	U	R	4 outages from August to September 1996 for duration of 4 hours and 35 minutes.	Causes included cable failure (2) and other. FPL in process of reconductoring feeder.
Outage	1397291	Man	Bradenton	U	R	6 outages during 6 month period for duration of 17 hours and 39 minutes. Also had 26 MPIs.	Causes included lightning (4), cable failure (1), and equipment failure (1). Feeder patrolled. Trees trimmed, six blown lightning arrestors replaced, vines cut, and insulator replaced.
Outage	1402491	Bro	Plantation	R	R	5 outages during six month period for 10 hours and 39 minutes.	Causes of outages included equipment failure (2), cable cut (1), cable failure (1), and maintenance (1). FPL had coated switch cabinets to prevent future failures.
Outage	1432361	Bro	Ft Lauderdale	U	R	6 outages from May to October 1996 for duration of 6 hours and 27 minutes.	Causes of outages were unknown. Feeder breaker will be inspected.
Outage	1457701	Bro	Hillsboro Beach	U	R	1 outage in October for duration of 15 hours and 36 minutes.	Caused by a vehicle accident downing two poles, wires and a transformer. **Claim for food spoilage filed and denied.**

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/O	Description of Customer Complaint	Company Resolution
Outage	1460401	Bro	Pembroke Pines	U	R	2 outages from May to Oct 1996 for duration of 2 hours and 14 minutes. Also 13 MPIs.	Causes unknown. Inspection conducted. Mechanism lubrication problem identified. No tree problems identified.
Outage	1477051	Dad	Bay Harbour	U	R	1 outage in six months for duration of 2 hours and 55 minutes. Also had 25 MPIs.	MPIs serve a useful purpose.
Outage	1478661	Dad	N. Miami	U	R	5 outages from May to November 1996 for duration of 17 hours and 16 minutes.	Causes were trees (4) and maintenance (1). City of N. Miami was restricting FPL efforts to maintain proper line clearance.
Outage	1491491	Bro	Coral Springs	U	R	4 outages in past 6 months for duration of 20 hours and 49 minutes.	Cause of all outages was underground cable failure. Cable has been scheduled for replacement.
Outage	11497091	Plb	Delray Beach	U	`R	5 outages from June to December 1996 for duration of 39 hours and 7 minutes.	Causes include equipment failure, broken insulator, and lateral-double underground cable fault. Various section of the underground loop has been replaced.
Outage	1497151	Dad	Miami	U	R	23 MPIs for past six months.	Unusual build up of salt spray and dirt on the insulators of major transmission lines. The build up, when dampened by dew and fog, causes short circuits that customer see as momentary interruptions.
Outage	15027991	Bro	Coral Springs	U	R	7 outages from June to November, 1996 for duration of 10 hours and 25 minutes.	Causes include cable failure, failed switch, follow up, feeder overload, and feeder cable fault. Feeder serving this customer has been overloaded. Two new feeders were brought on-line.
Outage	15029991	Bro	Coral Springs	U	R	3 outages from August to November, 1996 for a duration of 11 hours.	Causes include cable failure, lightening and transformer failure. 10 sections of cable in the area have recently been injected and two sections were replaced.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	150871I	Plb	Boca Raton	U	R	5 outages from June to December, 1996 for duration of 26 hours and 36 minutes.	Causes include lateral cable fault (4) and tree (1). A section of cable was replaced.
Outage	151374R	Cha	Port Charlotte	U	R	Numerous MPIs from December 1, 1996 to December 7, 1996.	Causes include severe thunderstorm and blown lightening arrestor.
Outage	151449L	Sar	Sarasota	U	C	Delay in restoration of service on December 3, 1996.	Outage was caused by a blown lateral fuse (cause unknown). The crew assigned had been on a call prior to being dispatched to sight. FPL apologized.
Outage	152121R	Dad	Miami	U	C	8 outages from July to December, 1996 for duration of 18 hours and 2 minutes.	Causes include animal (1), palm tree (1) and pole fire (6). When storms caused a build up of salt on FPL facilities, the salt combined with no rain caused the pole fires. FPL will patrol the circuit.
Outage	152417I	Mart	Palm City	U	R	Numerous power outages.	Customer service cable had failed and was replaced.
Outage	152478I	Man	Palmetto	U	C	4 outages during 1996 for duration of 26 hours and 34 minutes. Also had 48 MPIs.	Trees trimmed and volt meter installed. All voltages were within allowable standards.
Outage	153050I	Bre	Satellite Beach	U	R	5 outages in 1996 for duration of 5 hours and 46 minutes. Also had 71 MPIs.	Momentaries were caused by wind storms, tree conditions and salt spray/dirt build up on the insulators. Extensive efforts were made to wash FPL transmission and substation facilities. Fault indicators were installed at various locations on the feeder. Trees were trimmed and substation breaker was adjusted to further isolate intermittent MPIs.
Outage	153199I	Dad	Miami Beach	U	R	2 outages in November - December 1996 for a duration of 8 hours and 26 minutes.	Cause was a wire down. FPL removed one of the phases which was not in use.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	1532021	Plb	Palm Beach Gardens	U	R	7 outages during 1996 for a duration of 18 hours and 43 minutes. Also had 129 MPIs during 1996.	Causes include lightening (2), wire down (3), and equipment failure (2). Lines patrolled, trees trimmed. Transmission line being relocated which will afford better protection from lightening. New feeder position was engineered to reduce the distance from the point of service to this customer.
Outage	1535031	Man	Holmes Beach	U	R	30 MPIs for 1996. Had difficulty in reaching company to request restoration of service.	Causes include storms, salt spray/dirt build up. FPL explained that during extreme weather conditions it is difficult to contact FPL, but FPL is usually aware of were the problems and are working to restore service a timely manner.
Outage	1546841	Dad	Coral Gables	U	C	Frequent outages and MPIs and delay in restoring service.	Records reflect no outages on customer circuit, only 21 MPIs. Crews were dispatched within 30 minutes of receiving first call.
Outage	1548171	Bro	Fort Lauderdale	U	R	6 outages from June 1996 to February 1997 for duration of 30 hours and 36 minutes.	Causes include equipment failure, trees, and vehicle. Line patrolled and trees trimmed.
Outage	1557151	Dad	Miami	U	R	5 outages during 1996 and January 1997 for duration of 4 hours and 31 minutes.	Cause was equipment failure. FPL discussed protective devices that would minimize the effect of MPIs for customer.
Outage	1560231	Sar	Nokomis	U	R	5 outages in past 6 months for duration of 7 hours and 53 minutes.	Causes include equipment failure (1), unknown (2), and weather (2). FPL increased the lateral fuse size from 65 ks to 80 ks. Trees trimmed.
Outage	1561091	Plb	Boca Raton	U	R	77 MPIs for October 1996 to January 1997.	Causes include weather, excessive load, and equipment failure. A failed switch was replaced.
Outage	1820751	Dad	Miami	U	R	2 outages from February to August 1997 for duration of 11 hours and 7 minutes.	Causes include problem with line capacitor and storm. Load transferred to newly extended feeder, and FPL apologized for inconvenience.

Florida Power and Light
Outage Related Consumer Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	1821491	Dad	Miami	U	R	5 outages from January to August 1997 for duration of 6 hours and 43 minutes.	Causes include cable failure, re-dashed fused transformer, abnormal switching, trees, and unknown. Lines patrolled, trees trimmed, and FPL apologized.
Outage	1823181	Dad	Miami	U	R	5 outages from January to August 1997 for duration of 20 hours and 52 minutes.	Causes include cable failure (3) and lightening (2). The underground lateral was reconductored.
Outage	1824351	Dad	Miami	U	R	2 outages from January to August 1997 for duration of 5 hours and 57 minutes. Additionally had 42 MPIs.	A patrol of the area by FPL to determine improvement opportunities did not reveal any action was necessary.
Outage	1826531	Dad	Hialeah	U	R	3 outages from January to August 1997 for duration of 10 hours and 45 minutes.	Lines patrolled and some lightening arrestors replaced.
Outage	1828921	Plb	Singer Island	U	C	4 outages from January to August 1997 for duration of 8 hours and 22 minutes.	Causes include trees, cable failure, and wire down. Switching was performed to accommodate load.
Outage	1830671	Lee	Ft. Myers	U	R	5 outages during 1997 for duration of 10 hours and 2 minutes.	Causes include trees (4) and lightening. Customer feeder was relocated away from a heavy-growth area and trees trimmed from main feeder line.
Outage	1840491	Dad	Miami	U	R	1 outage in 1997 for duration of 2 hours and 53 minutes. 38 MPIs.	No obvious cause found.
Outage	1843741	Dad	North Miami	U	C	3 outages in 1997 for duration of 9 hours and 18 minutes. Also, 16 MPIs.	Causes include lightening (2) and maintenance. Lines patrolled and trees trimmed.
Outage	1848591	Dad	Miami	U	R	4 outages in 1997 for duration of 14 hours and 13 minutes. Also, 29 MPIs.	Causes include lightening. Lines patrolled, no improvement opportunities identified.

Tampa Electric Company
Outage Related Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Voltage Standard	109620I	Pas	Dade City	U	R	Voltage fluctuations.	Transformer installed closer to residence.
Outage	123542I	Hill	Seffner	U	R	6 momentaries from January 1996 to April 1996.	Non-preventable breaker operations.
Outage	136424I	Hill	Lutz	U	C	13 momentaries in 1996.	Tree trimmed, squirrel guards installed, and replaced lightning arrestor.
Outage	140605I	Hill	Tampa	U	R	36 momentaries outages from January 1996 to September 1996.	Patrol circuit and trim trees.
Outage	155270I	Hill	Lithia	U	R	17 momentaries outages from July 1996 to December 1996.	Storm related.
Outage	158059I	Hill	Lutz	U	C	9 momentaries in 1 month in 1997.	Cause was file on pole and road widening.
Outage	160204I	Hill	Lutz	U	R	47 momentaries in 1996.	Tree trimmed, patrolled lines, and reviewed protective devices.
Outage	167596I	Hill	Tampa	U	R	8 momentaries from January 1997 to April 1997.	Patrol circuits, tree trimming, reconfigure loading.
Outage	182150I	Hill	Sun City	U	R	3 outages in 1 month.	Weather and animal caused outages.
Momentarie s	164660I	Hill	Odessa	R	R	39 momentaries in 1996.	Caused by weather, animal and faulty equipment patrolled lines.
Momentarie s	172746I	Hill	Tampa	U	R	18 momentaries from January to May 1997.	Caused by trees, bad lightning arrestor and faulty transformers.
Voltage	157037I	Hill	Brandon	U	R	20 momentaries in a two day period in 1997.	Revised loading and circuit framing.

Gulf Power Company
Outage Related Complaints
1996-1997

Category Code	Complaint No.	Cty	City	R/U	R/C	Description of Customer Complaint	Company Resolution
Outage	1123091	SNR	Gulf Breeze	U	R	Three or more outages in first 2 months of 1996. 1 outage was 59 minutes in length.	Cut cable and bad weather caused outages. Letter sent to customer.
Outage	1330261	Bay	Panama City	U	R	Power Surges/Momentary Outages.	Oil Circuit reclosures were tested and replaced. Rearranged loads. Tested voltage.
Outage	1391131	Esc	Pensacola	U	R	Outage.	Patrolled area.
Outage	1413411	Esc	Pensacola	U	C	29 momentaries in 1996.	Trees trimmed.
Momentarie s	1759961	Esc	Pensacola	U	R	2 outages for duration of 3 hours.	Caused by car hitting pole and failure of capacitor bank. Line patrolled and trees trimmed.
Tree Trimming	1827771	Esc	Molino	R	R	Trees hitting lines.	Lines patrolled.
Outage	1681211	Bay	Panama City	U	R	1 outages for 54 minutes.	Panel shorted out.

APPENDIX 4

Company Comments

The four companies were given the option of providing comments regarding the report. FPC was the only company to respond.

Florida Power Corporation Comments:

To accurately compare reliability and service data, consistency in reporting is critical, even essential. With this in mind, Florida Power has long supported the implementation of consistent calculation methods, and better clarification of which exclusions are allowed. Embedded within Florida Power's five-year reliability data are impacts from Hurricanes Allison and Opal in 1995, and Hurricane Josephine in 1996. Tornado-related damage is included in all five years' reliability data. For 1997, these major storm items amount to over 20 minutes of interruption to the average customer (SAIDI measure). As noted on page 12 of this review, <u>all</u> of this data is allowable for exclusion, but Florida Power's internal standard was more stringent (i.e., no exclusions, unless more than 10% of customers were affected for more than 24 hours.) As a consequence, Florida Power's data is in fact negatively "skewed" with events beyond our ability to control. This fact is worth noting when reviewing this report.

When discussing the appropriate reliability measures to use in the future, Florida Power strongly believes that measures which allow for comparability between utilities should be developed and utilized. While this report appropriately notes on page 9, section 2.2 the difficulty of inter-utility comparisons, these comparisons do occur with regularity. The media seeks to compare us, and the customers want to compare us. Surprisingly, one utility even uses the data--which is clearly cited here as being unsuitable for comparison--to demonstrate reliability in promotional mailings to its customers. So why not strive for measures better suited for comparisons? For example, interruptions are currently tracked in total by each utility. Because each utility serves different sized geographic areas, with different customer densities, such a measure is only useful in comparing the utility to itself. If, however, you track interruptions per mile of conductor you have a measure that allows for comparisons, and one that automatically takes into account the growth a system experiences. As well, reliability could be reported by sub-group within each utility to allow areas with similar geographics and population density to be compared. For example, Florida Power's Suncoast region is very similar in geographic size and population to TECO's service territory and would be well suited to such comparisons. Such measures will increase the incentive and the focus of utilities. Undoubtedly such comparisons will continue to be made, and today's measures will continue to be exploited. As a result, let us strive for measures that are equitable and lend themselves to such comparisons.

As performance based rates continue to be evaluated and discussed it is important that the discussion include opportunities for reward as well as penalties, and that care be taken to set standards at appropriately challenging levels. Achievement should not be automatic nor impossible. Since significant investments are sometimes necessary to achieve the desired results, financial rewards are appropriate as incentives for the utilities to make those investments.

Florida Power is a utility company that values its customers and their service expectations. We began to review our service reliability results in late 1995, and dissatisfied with the trend developing, we quickly moved to make changes in mid-1996. Significant increases in tree trimming expenditures and increased funding for pole and equipment maintenance are key features of actions taken. Expenditures over and above our initial 1996 budgets -- amounting to \$13.2 million--have been invested in these programs, and we are already beginning to see significant results. We are in the midst of deploying a new technology, at a cost of nearly \$1 million, that will automatically track and report outages, momentary interruptions and voltage sags. An organizational realignment was implemented in mid-1997 to heighten the focus on reliability issues. Early programs to be funded from this group's analysis include a \$1 million program to complete the automated control of all distribution breakers by early 1998. This was made possible by the 1997 deployment of an enhanced distribution automation software control program (SCADA), at a cost of \$1.3 million. As well, a targeted reliability enhancement program of \$5.3 million for the Central Florida area (greater Orlando) has been initiated.

To further enhance our reliability and responsiveness to our customers, we are beginning a significant retooling of our Energy Delivery business unit. The implementation of a new \$22 million technology platform was recently approved, featuring a new outage management system, computers in field response vehicles, and global positioning devices to enhance dispatch capabilities. A new geographical information system will enhance the integrity of our reliability information and improve our response time during outage restoration. These investments are the proactive actions of a utility concerned about its reliability performance and in anticipation of increased customer expectations. We have taken and will continue to take action because our customers expect and deserve reliable electric service.