Florida Public Service Commission

Preliminary Analysis of Placing Investor-Owned
Electric Utility Transmission and Distribution Facilities

UNDERGROUND

in Florida

MARCH 2005

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Executive Summary

The hurricane season of 2004 was the most active on record for the state of Florida. In the wake of Hurricanes Charlie, Frances, Ivan, and Jeanne, Florida suffered widespread damage and destruction to private homes and buildings, roads, bridges, and other public infrastructure. In the aftermath of each storm, widespread outages of electric service were experienced throughout the state. Because of the tracks taken by each storm, electric service in virtually every county in Florida was affected.

Outage durations ranged from relatively short periods of time in northeast and north central Florida to extended periods of up to two weeks along the southeast coast and in central Florida and the northwest panhandle. Some homes and businesses were without power for a much longer period of time because structural damage had to be repaired before restoration of electric power could take place.

Overhead electric service facilities were particularly hard hit. Hurricane strength winds and tornadoes toppled transmission and distribution towers and poles, flying debris impacted substations and switching stations, and falling trees and branches tangled or dropped overhead power lines. In many areas of the state, restoration of service has required more of a “rebuild effort” than repair.

Underground electrical systems were also adversely impacted by the storms. Underground distribution systems in coastal areas, particularly those serving barrier islands, were flooded by massive tidal surges. Salt water intrusion caused numerous pad-mounted transformers and cables to fail. In addition, underground lines in areas saturated by flood waters may be susceptible to failure for some time to come and will require monitoring.

The outage times experienced by many during the restoration process renewed interest in exploring the installation of underground electric utility facilities by Florida’s electric utilities. While, as stated above, existing underground services were not impervious to storm damage, questions have been raised as to whether undergrounding would have resulted in less damage to the electric system and a more rapid restoration of services.

In October 2004, the staff of the Committee on Utilities and Telecommunications, Florida House of Representatives, requested a study proposal from the FPSC on the cost of undergrounding electric facilities in Florida. In a letter dated October 20, 2004, the FPSC outlined three possible levels of study which, depending on the detail desired, would require differing times to complete – 90 days, 120 days, and 180 days. A 90 day study would rely more heavily on updating and extrapolating data from previous work done by the FPSC and information drawn from studies performed by other states, countries, and professional organizations. Additional time, up to 180 days, would be required for a more comprehensive study involving the collection and analysis of current cost and reliability data from Florida utilities and input from interested parties. In subsequent communications with the House staff, the FPSC offered to provide in the shortest time possible a preliminary estimate of the cost to convert, over a period of ten years, existing investor-owned utility transmission and distribution facilities from overhead to underground. As indicated, the proposed analysis would address only investor-owned utilities and would not include underground cost estimates for municipal and rural electric cooperative electric utilities. The results of this preliminary analysis were to be provided prior to the start of the 2005 Legislative Session.

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The purpose of this analysis is to develop a ballpark estimate of the cost for investor-owned electric utilities to place existing electric transmission and distribution facilities in Florida underground. Only the direct costs to the electric utility are considered. The cost estimates contained herein have been developed primarily from an extrapolation of historic data for investor-owned electric utilities. The five investor-owned electric utilities in Florida account for approximately seventy-eight percent of statewide electricity sales.

Cost estimates developed by Tampa Electric Company for residents of Davis Islands, as well as cost estimates developed in a recent study by JEA have been included for comparative purposes. Due to the variety of transmission and distribution facility configurations serving different demographic areas of the State, in-depth utility-by-utility analyses would be required to develop utility-specific cost estimates.

Estimated Cost of Placing Existing Investor-Owned Electric Transmission and Distribution Facilities Underground

At the end of 2003, Florida's five investor-owned utilities had, in aggregate, 14,566 miles of transmission with a net book value of approximately $2.4 billion. Only 183 miles of transmission are underground. Section IV of this document discusses some of the technical difficulties regarding the undergrounding of transmission facilities.

Using estimates from the previous 1991 Commission study on undergrounding and escalating them for inflation, it would cost approximately **$51.8 billion** to underground the existing transmission lines of the five electric investor-owned utilities. Assuming conversion and cost recovery over a ten-year period, the impact for such an undertaking, on a kWh basis, for all customers combined for these utilities would be an increase in rates of approximately **49.7%** with the increased rates continued for the ten-year period. This rate impact is with reference to all customer costs, including base rates and fuel.

At the end of 2003, the five investor-owned electric utilities owned an estimated 115,961 miles of primary distribution lines. Data is not available for the total secondary and lateral line miles serving the subdivisions and neighborhoods. The net book value of all distribution assets at the end of 2003 was approximately $7.0 billion. The estimated cost to place existing overhead distribution lines and feeders underground for the five investor-owned electric utilities is **$94.5 billion**. This estimate includes (1) the cost of converting existing overhead facilities within subdivisions to underground and (2) the cost of converting the feeders which connect the subdivisions and commercial districts to the generation and transmission supply system from overhead to underground.

This conversion cost estimate is primarily based on cost estimates from the previous 1991 Commission study escalated for inflation. For comparative purposes, cost estimates for the conversion of certain actual neighborhoods developed by Tampa Electric Company for residents of the Davis Islands and in a recent study by JEA were also examined. These local studies appear to only address the cost of converting distribution facilities within certain subdivisions and do not appear to address system-wide conversion of major distribution feeders. The results of the Tampa Electric and JEA analyses indicate that the Commission's 1991 based estimate for undergrounding within subdivisions may be conservatively low.

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Assuming conversion and cost recovery over a ten-year period, if the $94.5 billion estimated cost of undergrounding distribution feeders and subdivisions is spread over all rate payers for the combined IOUs, the impact on rates, on a kWh basis, would be an increase of 81.1% with the increased rates continued for the ten year period. If the costs are spread over only residential customers, the increase would be 141.5% with the increased rates continued over the ten year period. These rate impacts are with reference to all customer costs, including base rates and fuel.

It is emphasized that the estimated costs developed in this document to underground overhead transmission and distribution lines include only utility costs. No customer costs or other external costs were considered. For example, costs related to the removal of service masts or costs for any necessary modifications to the customer's meter socket, service panel or internal wiring are not considered.

In many existing homes, a change to underground service may trigger updating the customer's internal wiring to meet current electrical code requirements These costs would be borne by the homeowner. The electric utility company would not be allowed to reactivate service until these code improvements were made.

The cost estimates in this analysis only include conversion of existing facilities. No estimates were made for the cost of putting future facilities underground rather than overhead. Also, the undergrounding cost estimates do not include costs to underground the overhead facilities of other utility services, such as telephone and cable TV, which often rely on joint-use pole attachments or overhead poles of their own.

Financing Options

Options for financing the cost of conversion of overhead facilities to underground are outlined. The options presented include initial funding by the utility with cost recovery through higher customer rates, property owner funding, other private sector funding and taxpayer funding.

Alternatives to Undergrounding

There are a number of measures that utilities may undertake to lessen the impact of hurricanes and storms on overhead transmission and distribution systems, such as improved maintenance, more aggressive tree trimming (including widening of rights-of-way), increased wind loading standards, and enhanced flood protection. These measures are referred to as "hardening." Each such measure would require a cost-benefit analysis to determine whether it is cost-effective.

Other Studies and Reports and Some Existing State Regulations

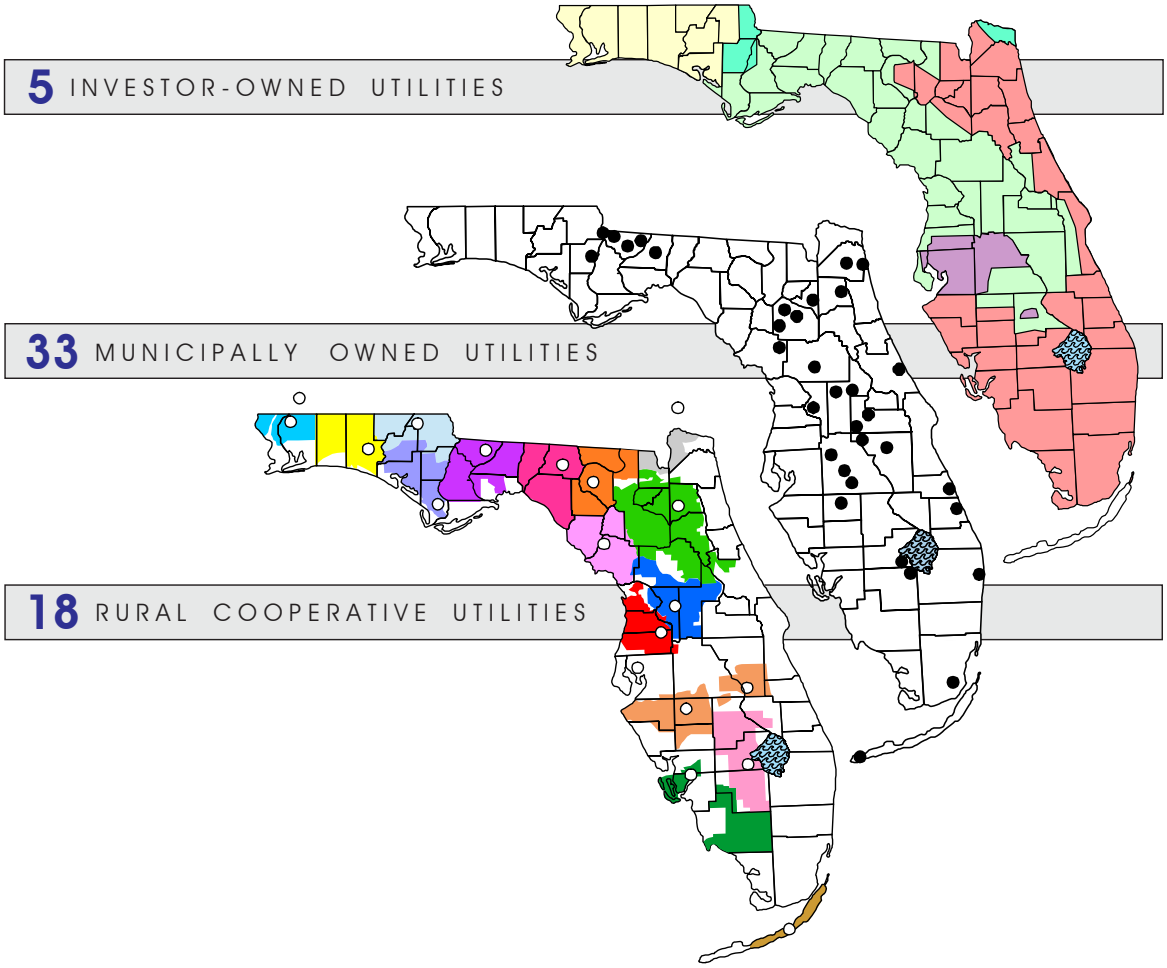
A brief summary of available studies conducted by State utility commissions, research firms, and other countries regarding costs and benefits of undergrounding is provided. Without exception, these studies show that the costs to convert existing overhead electric distribution lines to underground were determined to be significantly more than the costs of typical overhead installations. Although not a complete review, some of the existing state regulations pertaining to undergrounding electric facilities are also summarized.

I. Overview of Electric Power Delivery Systems in Florida

A. Electric Utilities in Florida

There are three basic types of electric utilities operating in Florida: (1) investor-owned utilities, (2) municipally owned utilities, and (3) member-owned utilities (i.e., rural electric cooperatives). The Florida Public Service Commission (FPSC or "Commission") has full regulatory authority over rates and services provided by the five (5) investor-owned electric utilities: Florida Power & Light Company (FPL), Progress Energy Florida (PEF), Gulf Power Company (Gulf Power), Tampa Electric Company (TECO), and Florida Public Utilities Company (FPUC). These investor-owned utilities account for approximately 78% of the retail electric energy sales in Florida.

The FPSC also has limited rate structure jurisdiction over thirty-three (33) municipally owned utilities (14.5% of energy sales) and the eighteen (18) rural electric cooperative utilities (7.5% of energy sales) located in Florida. Rate structure jurisdiction involves reviewing the rates charged by municipal and rural cooperative utilities to insure that the rates are not discriminatory. The FPSC also has statutory jurisdiction over all electric utilities in the areas of bulk power supply planning and reliability, power plant and transmission line need determinations, territorial disputes and agreements, and energy conservation.

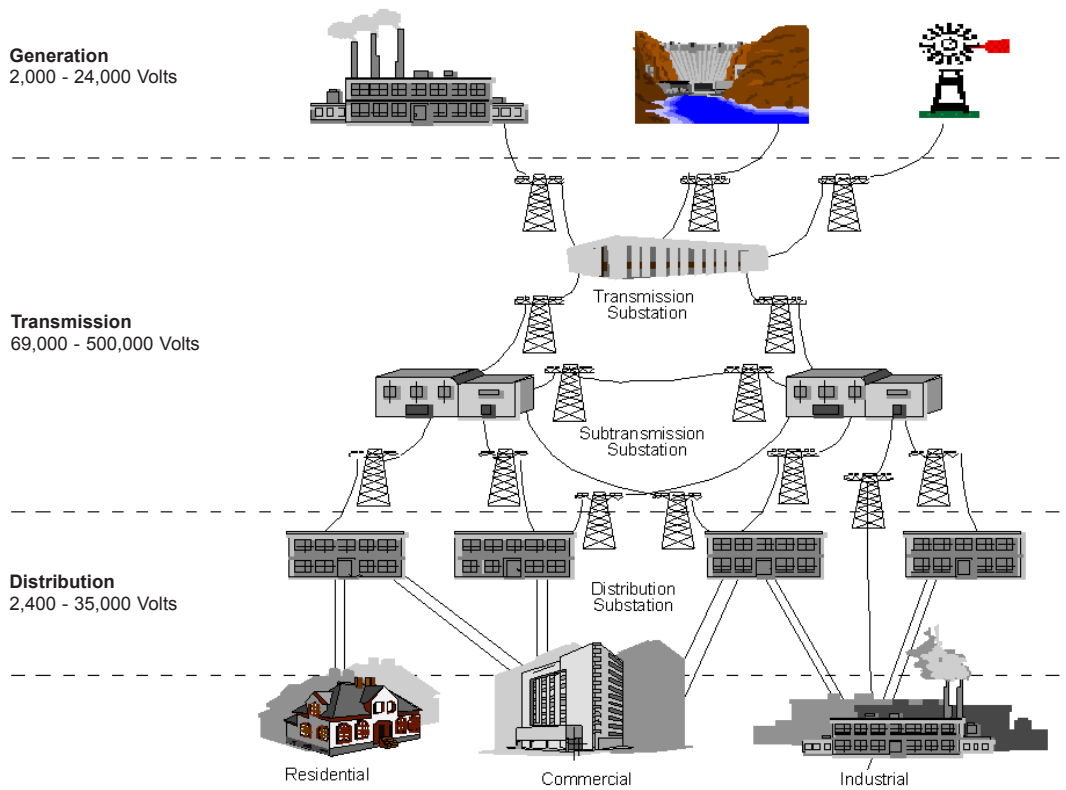


B. Major Components of Electric Power Delivery Systems

The basic structure of an electric power delivery system consists of three principal components:

1. generating power plants,
2. transmission lines and facilities, and
3. distribution lines and facilities.

TYPICAL ELECTRIC POWER DELIVERY SYSTEM [1]



Power plants generate electric power by converting the energy from various fuels such as uranium, coal, natural gas, and oil to electric energy. Once the electrical power is produced, its voltage is "stepped up" by a transformer at the power plant so that it can be transmitted economically over the transmission system. Transmission lines connect the power plants to each other and to the distribution system.

Transmission lines support the electric power delivery system in two ways. First, transmission lines interconnect the electric power delivery systems of neighboring electric utilities. These interconnections result in increased reliability and economic efficiency by allowing utilities to buy and sell power from and to each other. Today, all electric utilities in the continental United States are interconnected to at least one other electric utility. Second, the transmission system forms the link between the power plants and the distribution system which ultimately delivers the electricity that customers need to operate their homes and businesses.

At the distribution system level, the voltage is "stepped down" by a transformer at a substation for distribution to local neighborhoods and business districts. There is usually a final reduction in voltage by a distribution transformer at the service drops of residential and commercial customers.

Managing the flow of electricty throughout the electric power delivery system is the function of control centers. Control centers are located at strategic locations on the power grid from which the generation, transmission, and distribution systems are monitored and controlled. Real-time information is gathered to manage flows of electrical energy to wholesale and end-use customers in an efficient and reliable manner within and through utility systems.

One major tool used by operators in the utility's control center is the Supervisory Control And Data Acquisition (SCADA) system. The SCADA system allows operators to remotely monitor, control, and operate transmission and distribution equipment and devices in real time. This is done by placing remote telemetry units (RTUs) at substations and other points in the electric system that gather data on power flows, voltages and the status of various switching and relaying equipment in the power delivery system. This information is monitored by utility system operators who perform the necessary dispatch, switching, and maintenance functions.

Global positioning and geographic information systems (GPS/GIS) are used to map all the facilities that make up the system (lines, poles, substations), as well as for documenting size and location of inventories of equipment. Databases for resources are maintained so that specialized equipment or parts may be retrieved in a minimal amount of time. Electric utilities also establish maintenance yards and warehouses where equipment and materials (such as transformers, wire, poles and other spare parts) are stored and from which maintenance and repair crews are dispatched.

The interconnected electric power system is designed to deliver power safely and reliably wherever it is needed, every second of every day. It can be viewed as one large electric machine where hundreds of generator shafts are spinning in unison to produce electricity at the correct voltage level and frequency to simultaneously satisfy the electrical needs of industrial, commercial and residential customers.

C. Overhead and Underground Transmission and Distribution Facilities

Transmission lines are used to carry high-voltage three-phase power from power plants to various substations around the system. In Florida, transmission voltages vary from 69,000 volts to 500,000 volts. In Florida, transmission lines are usually constructed overhead. Overhead transmission lines are supported by large wood, steel, or concrete structures or poles. Because of the State's peninsular geography, Florida has many transmission lines that span long distances between the power plants and load centers.

The specific construction design of transmission facilities depends on a number of factors, including the number of circuits, the voltage, the amount of right-of-way required, and the weather conditions, such as high winds and lightning, that the lines will be subjected to.

Single-pole overhead transmission line structures rated at 115 kilovolts. [2]

A typical steel tower construction [3] *as well as an example of a transmission corridor with two sets of wooden structures side-by-side.*

While it is true that underground facilities have less exposure to damage from high winds than overhead facilities, both types of facilities are subject to lightning strikes.

Although collisions with overhead facilities are reduced with undergrounding, there is increased exposure to equipment damage and personal injury or death caused by accidentally digging into underground electrical facilities.

Transmission lines may be buried with no protection except a layer of insulation material (direct burial), or placed in conduit, tunnels, or oil-cooled pipes, depending on the capacity requirements and the design and materials involved. Less than 1.5 percent of the total miles of transmission lines in Florida have been placed underground. Placing transmission lines underground has its own set of problems and unique requirements. First and foremost, it is extremely expensive. It also takes significantly more time to diagnose and repair underground facilities. Finally, underground transmission lines are more prone to damage from flooding, especially in areas where salt water intrusion is a problem.

An underground transmission line laid in a concrete enforced trench. This example represents the type of construction which would be typically used in a rural setting where obtaining an unobstructed easement is less of a problem. [4]

SUBTERRANEAN TUNNELS

Underground transmission line installed in a subterranean tunnel. This illustrates the type of construction which would be used in an urban setting where obtaining an unobstructed easement is difficult or impossible because of the congestion.

To reduce costs, other utilities such as water, wastewater, telephone, fiber, cable, natural gas, etc., may be collocated with the electrical facilities. [4]

SUBSTATIONS

As discussed earlier, a typical electric power delivery system utilizes transmission substations as well as distribution substations. The main functions of substations are to step voltages up or down, to provide connection points to other parts of the system, and to perform certain electrical switching and breaking operations.

A step-up transmission substation is located near each power plant to increase the voltage for efficient transmission over long distances. Other transmission substations are located at various points in the transmission system to connect different parts of the transmission system together as well as to step the voltage down to sub-transmission levels for use by certain industrial customers or as a source for distribution substations. Transformers at a distribution substation lower the voltage of the power they receive from a transmission or sub-transmission substation to a level that is appropriate for distribution to residential, commercial and industrial facilities.

SUBSTATIONS *continued*

All transmission substations are built above ground in Florida as well as in most of the nation. Distribution substations are also built above ground. However, there are some locations where enclosed transformer vaults are used in a commercial building, or in downtown urban areas.

A typical distribution substation where high voltage power is transformed to a lower voltage for distribution to end-use customers. The box in the foreground on the left side of the picture is a transformer. Power from the transmission system is fed into this transformer and reduced to a lower voltage for distribution. Three voltage regulators can be seen at the right end of the station. Voltage regulators help maintain voltages at a constant level. This is necessary since all end-use electrical equipment is designed to operate at a constant voltage, plus or minus some design tolerance.

There is a chain link fence completely around the perimeter of the substation for security and to prevent public access in order to avoid serious injury or death caused by accidental contact with the high voltage equipment within the substation. The voltage of the power entering the substation typically ranges from 69 kV up to 500 kV. Power exiting the substation typically ranges from 2.4 kV up to 35 kV. [3]

DISTRIBUTION FEEDERS

Distribution feeders connect the distribution substations to neighborhoods and businesses. They provide bulk power to whole communities and business districts. Power generally exits the substation in three-phase feeders. In addition to the three lines for the three phases, there is usually a fourth wire, called the neutral wire, that is used for grounding the system. At some point, the three-phase main feeder may branch into separate three-phase or single-phase secondary feeders, also called laterals. Residential and smaller commercial customers use single-phase power while three-phase power is commonly used by larger commercial and industrial customers. Three-phase power provides a more constant level of power which is important for applications that use large motors. Rotating machines, such as motors, run more economically and efficiently on three-phase power.

TRANSFORMERS

By the time electricity reaches the end-use customer, there is usually a final reduction in voltage before the power can be used. Residential services and small businesses usually require 120/240 volt single-phase service. Power at this voltage is fed from a single distribution transformer located on a wood, metal, or concrete pole (overhead) or a concrete pad (underground) near the residence or business. A single distribution transformer usually serves several residences and is the last stage of voltage reduction in the distribution system before the power is fed into a residential home.

Larger businesses may require three-phase service at 120/240 volts, 120/208 volts, or 480 volts. This three-phase service is fed from three single-phase transformers electrically tied together on a pole (overhead) or from a three-phase transformer located on a concrete pad (underground) near the customer's location.

The same kind of pad-mounted transformer is used for both residential and commercial facilities, except that the residential transformer provides single-phase service while the commercial transformer may be single or three-phase and is larger in size.

An overhead single-phase transformer installation. [3]

A typical overhead three-phase, pole-mounted transformer arrangement. [3]

A pad-mounted transformer that serves the same purpose in an underground system. [12]

COMPONENTS OF POWER SYSTEMS

Some additional equipment used in a typical electric power delivery system is shown on this page.

High voltage substation fuses. A fuse has a strip of metal that is designed to melt when the current exceeds a certain limit. This opens the circuit and protects the equipment located electrically behind the fuse. Fuses must be manually replaced when the metal strip melts. [3]

A bank of three circuit breakers located in a substation. Circuit breakers are designed to protect equipment from overcurrent by opening automatically. They can be set to automatically reclose the circuit under certain conditions, or they can be operated remotely from the control center. [3]

A bank of capacitors mounted on a utility pole. Capacitor banks supply reactive power which helps to boost voltage near loads in the distribution system. [5]

A substation microwave communications tower. The microwave tower is used to monitor and control certain operations at the substation and is part of the communications link between the control centers and the electric power delivery system. [4]

Other components of a power system are insulators, lightning arresters, inductors, transfer switches, and much more.

II. The 2004 Hurricane Season

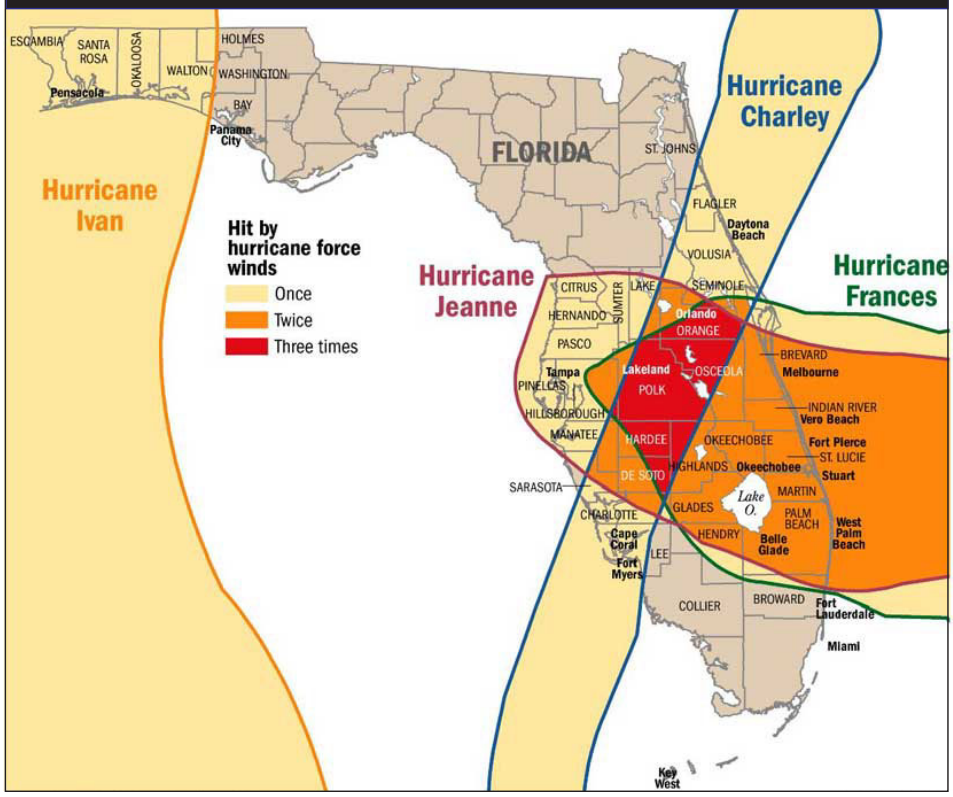
A. Geographic Scope and Dollar Impact

Hurricanes are characterized by high winds and heavy rain. In addition, tidal surges and sporadic tornadoes are often generated as by-products of the storm. Extreme winds and flooding typically result in damage to personal and business property, public infrastructure, and utility facilities. Broken limbs, falling trees, and flying debris making contact with overhead power lines result in electrical outages. The magnitude and duration of such outages is worsened if the power lines, poles, underground lines, and above ground electrical facilities fail.

Underground electrical facilities are not immune to the effects of a hurricane. Underground distribution systems in coastal and other low-lying areas may be adversely affected by flooding. Salt water intrusion causes numerous pad-mounted transformers and cables to fail. In addition, underground lines in areas saturated by flood waters may be susceptible to failure for some time to come and require monitoring long after the hurricane has passed. During the clean-up and restoration process, pad-mounted transformers are sometimes struck by garbage trucks or accidentally scooped up by bulldozers. Underground lines may also be inadvertently cut by road repair equipment.

The 2004 hurricane season was one of the most destructive in Florida's history. During the six-week period from August 13 through September 25, an unprecedented onslaught of four major hurricanes devastated the state. Tropical force winds extended much further than that shown for hurricane force winds, thereby increasing significantly the impact of each of these storms. The paths of Hurricanes Charley, Frances, and Jeanne overlapped in the central part of the state. Hurricane Ivan affected the northwestern panhandle region of the state.

Geographical Path of the Hurricane Force Winds [6]



Hurricane Charley made landfall on the Gulf coast of Florida near Ft. Myers on August 13, 2004, as a category 4 hurricane with sustained winds of 145 miles per hour. It swept through the state in a southwest to northeast direction and exited around Daytona Beach. In geographical terms, Charley was the narrowest of the four storms, with hurricane force winds spanning 60 miles and tropical storm force winds spanning 170 miles at the time of landfall.

Three weeks after Charley made landfall on the southwestern coast of Florida, Hurricane Frances, a category 2 storm, hit the southeastern part of the state just north of West Palm Beach with sustained winds of 105 miles per hour. Frances was a much wider storm than Charley, with hurricane force winds and tropical storm force winds spanning 150 miles and 400 miles, respectively, at the time of landfall.

Hurricane Ivan, a category 3 storm, made landfall at Gulf Shores, Alabama, just west of the Florida panhandle on September 16, twelve days after Frances hit the southeast coast of Florida. At landfall, winds were near 130 miles per hour. Hurricane force winds extended outward 105 miles, severely impacting the northeastern part of the Florida panhandle. Tropical storm force winds extended outward 580 miles at landfall.

On September 25, Jeanne, Florida's fourth hurricane within a six-week period, made landfall near the same place on the southeast coast that Frances hit three weeks earlier. Hurricane Jeanne was a category 3 storm with winds up to 120 miles per hour. It was also a wide storm, just as Frances was, with hurricane force winds spanning about 140 miles and tropical storm force winds spanning approximately 410 miles.

Table 1 summarizes some of the impacts of these four hurricanes from a statewide perspective:

TABLE 1

Impact of Hurricanes on Florida – Selected Indicators

	CHARLEY	FRANCES	IVAN	JEANNE
Category of storm	4	2	3	3
Highest winds	145 m.p.h.	105 m.p.h.	130 m.p.h.	120 m.p.h.
No. of evacuees	2.7 million	1.8 million	0.5 million	4.4 million
Total Customer Outages	1.8 million	4.5 million	0.4 million	3.5 million
No. of Utility Restoration Personnel*	6,800	7,250	2,200	9,350
Insured Damages**	6.8 billion	4.1 billion	3.8 billion	2.8 billion

Source: Florida Division of Emergency Management, Hurricane Impact Report

** Includes volunteers from non-Florida utilities from as far away as California and Canada.*

*** Insured damages include insured property damage claims from the general public, including investor-owned utility claims for damage to insured utility facilities such as power plants, central office buildings, and other buildings and structures. Insured damages do not include damage to investor-owned utility electric transmission and distribution facilities for which they are self-insured.*

Table 2 shows the estimated dollar damage impact on each of Florida's five investor-owned electric utilities for each of the four hurricanes that struck Florida during 2004. These amounts include the deductible amounts for insured property at power plants and other buildings, such as central office buildings as well as the amounts for damage to transmission and distribution facilities for which they are self-insured.

TABLE 2

Storm Damage Impact on Florida Investor-Owned Electric Utilities
(millions of $)

	CHARLEY	FRANCES	IVAN	JEANNE	TOTAL
FPL	$251.7	$316.0	$0.0	$322.3	$890.0
PEF	$146.0	$128.6	$5.7	$86.2	$366.5
TEC	$13.9	$25.3	$0.0	$33.5	$72.7
GPC	$0.0	$0.0	$124.3	$0.0	$124.3
FPUC	$0.026	$0.095	$0.116	$0.195	$0.432
Total	**$411.626**	**$469.995**	**$130.116**	**$442.195**	**$1,453.932**

Sources: Docket No. 041291-EI for FPL; Docket No. 041272-EI for PEF; Docket No. 050093-EI for Gulf Power Company; and answers to staff data requests for Tampa Electric Company and Florida Public Utilities Company.

Note: The amounts shown in Table 2 are not the final storm damage impact figures. They are preliminary amounts as of the date of the filings and data requests.

B. Electric Utility Restoration Efforts

The speed at which an electric utility is able to restore power to its customers following a hurricane hinges largely on the effectiveness of its pre-disaster contingency planning for such disasters. Such plans define the specific staging and organizational activities necessary to accomplish efficient restoration well in advance of landfall. Massive amounts of equipment and supplies, such as bucket trucks, poles, wire, transformers, crossarms, insulators and fuses, must be pre-positioned at strategic points in the state so that power can begin to be restored as soon as strong winds and rain subside. Arrangements for food and lodging for restoration crews and other support personnel must be made. Each utility must also be prepared to provide frequent updates of restoration efforts to its customers as well as to various governmental and private agencies.

Utility plans take into account the assistance that can be provided by other utilities. The electric utilities in the state have Mutual Aid Agreements with other utilities within the state as well as utilities in other states and Canada. Essentially, these agreements enable utilities to call on each other for manpower, equipment and supplies when responding to emergency situations, such as major storms. The assisting utilities bill the requesting utility for costs incurred at the end of restoration activities. Chapter 252, Florida Statutes, known as the State Emergency Management Act, provides the framework for dealing with the impact of natural and manmade disasters. The Act creates a Division of Emergency Management (DEM) within the Department of Community Affairs. The DEM is responsible for coordination with the federal government, with other departments and agencies of state government, with

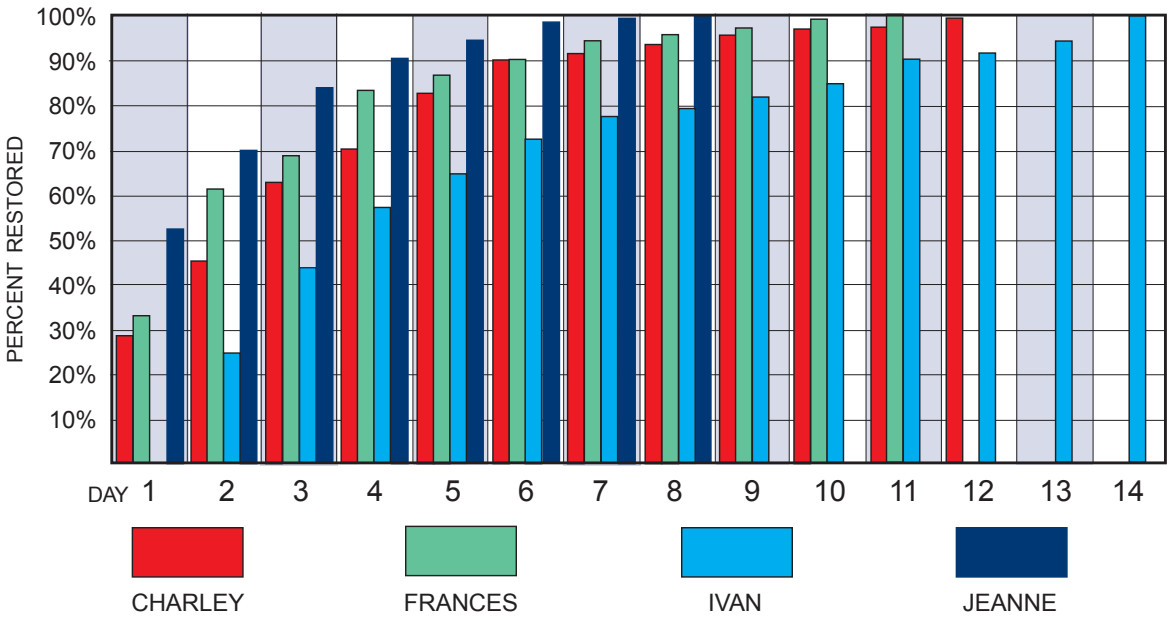
county and municipal governments and school boards, private agencies, and utility companies in responding to emergencies. The Act also requires the DEM to prepare a state comprehensive emergency management plan (State CEMP).

The State CEMP requires each county to adopt a County Comprehensive Emergency Plan (County CEMP) that is consistent with the standards and requirements of the State CEMP. State policy for responding to disasters is to support local emergency response efforts. Emergency activities are coordinated from a statewide perspective through the Emergency Operations Center (EOC) located in Tallahassee, Florida. Each county maintains a local EOC that coordinates power restoration, security, sheltering and feeding of displaced persons, and provides information to governmental agencies and the general public.

These coordination activities are especially important in order to minimize or eliminate the possibility of severe injury or death to workers involved in restoring the electrical system. This requires daily status reviews of assigned tasks such as staging of equipment and supplies, stringing wires, energizing circuits, repairing towers, and planning the next day's activities.

The chart below shows the progress of restoration of electricity over time for the four hurricanes. About 90% of customers had power restored after six days for Hurricanes Charley and Francis. For Hurricane Jeanne, 90% of customers had power restored after four days. It took eleven days before power was restored to 90% of customers affected by Hurricane Ivan.

Hurricane Restoration Times



Source: Prepared by FPSC staff from data supplied by Florida electric utilities.

STORM DAMAGE

The following series of photographs illustrate, better than words, the damage incurred by utility electrical facilities as a result of the hurricanes which struck the state during 2004.

Some of the effects of wind and rain on an overhead distribution feeder. [28]

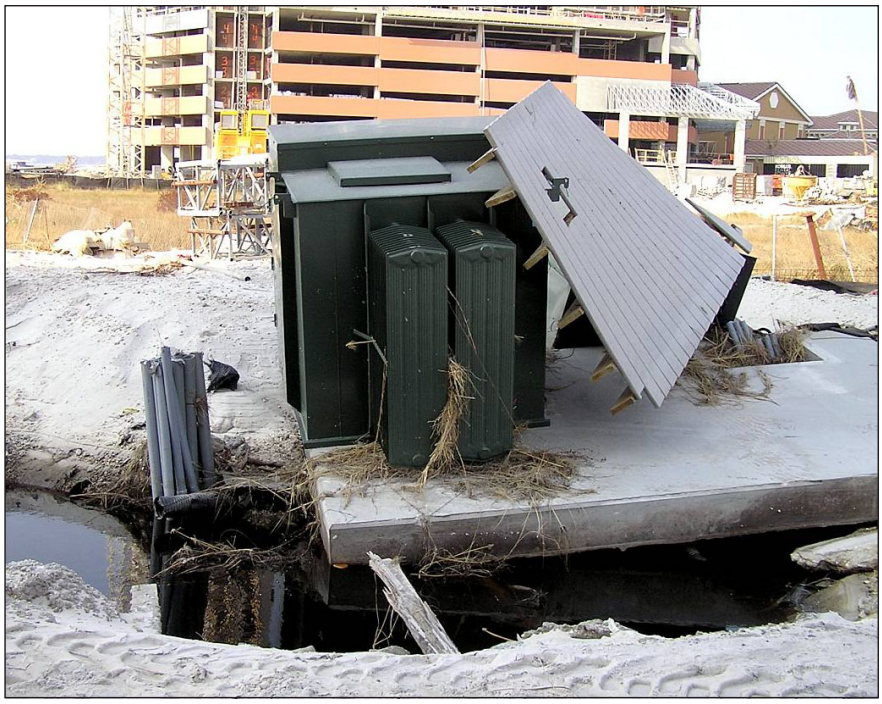
Most storm damage to power facilities is caused by high winds or flooding. The high winds can cause damage directly to the facilities or by blowing nearby trees, tree limbs or other structures into the electric power facilities. Flooding can cause serious problems with the proper functioning of electric circuits as well as restrict access to key parts of the system, thereby lengthening the time needed to restore the system. [7]

UNDERGROUND DAMAGE - INLAND

Flooding from Hurricane Jeanne of a pad-mounted transformer for an underground system. [29]

Wind and flood damage from Hurricane Ivan to pad-mounted transformers for an underground system. [29]

UNDERGROUND DAMAGE - COASTAL



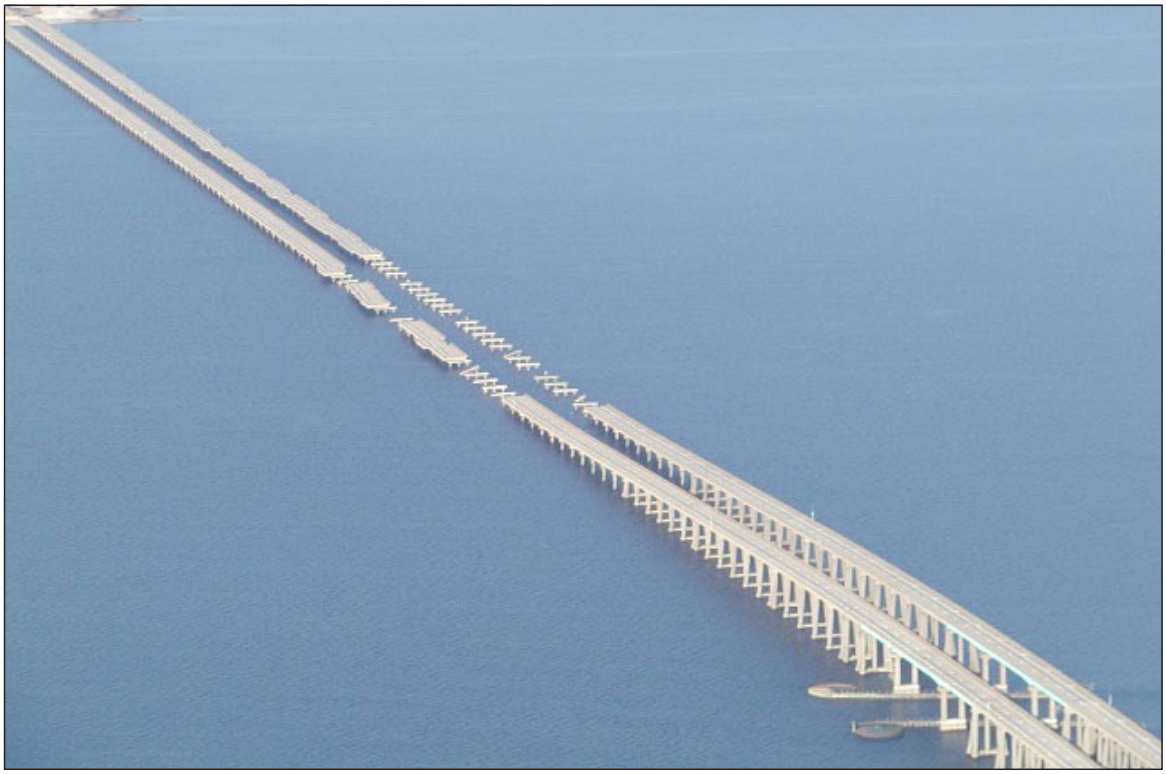
Destruction of pad-mounted transformer facilities caused by tidal surge and beach erosion from Hurricane Ivan. [29]

Buried pad-mounted transformer caused by Hurricane Ivan winds and tidal surge. [29]

Damage to underground system switching cabinet from Hurricane Ivan. [29]

INFRASTRUCTURE DAMAGE

Some of the damage that occurred to highway infrastructure from Hurricane Ivan. This kind of damage can cause delays in the restoration of power. [29]



III. Previous Commission Study and Current Commission Rules on Undergrounding

A. Previous Commission Study on Undergrounding

In 1989, the Legislature directed the FPSC to conduct a study on the cost-effectiveness of undergrounding electric transmission and distribution facilities. The study was completed in December, 1991. [8]

A data request for utility cost information on five non-coastal subsystems and on a 100 percent coastal system was sent to investor-owned, municipal, and electric cooperative utilities in the state. Rural and urban feeders as well as low and high density subdivisions were included in the subsystems analyzed.

Non-utility cost data were developed for the following categories:

- Storm outage costs
- Non-storm outage costs
- Surge and Sag costs
- Pole accident costs
- Electric contact accident costs
- Direct customer costs

A separate Cost Differential Model was developed for each of the three utility sectors: investor-owned utilities, municipal utilities and electric cooperatives. This was necessary to accommodate different financing and tax treatments. The Cost Differential Model involved three major steps. First, revenue requirements of the utility were computed for both overhead and underground facilities over a period of thirty years. Next, nonutility costs were added to the utility's revenue requirements. The third step was to compute the present value of the total life cycle costs.

Total life cycle costs were calculated for the six distribution subsystems and for four construction scenarios (new, relocation, replacement and conversion) for both overhead and underground facilities. After these initial model runs, a number of sensitivity runs were made. These included higher rates of inflation, lower O&M costs for underground, and lower O&M costs for underground for a 100 percent coastal system. In its Final Report, dated December 1991, the Commission found that undergrounding of electric distribution facilities was not cost-effective for any of the scenarios that were examined. [9]

B. Current Commission Rules on Undergrounding

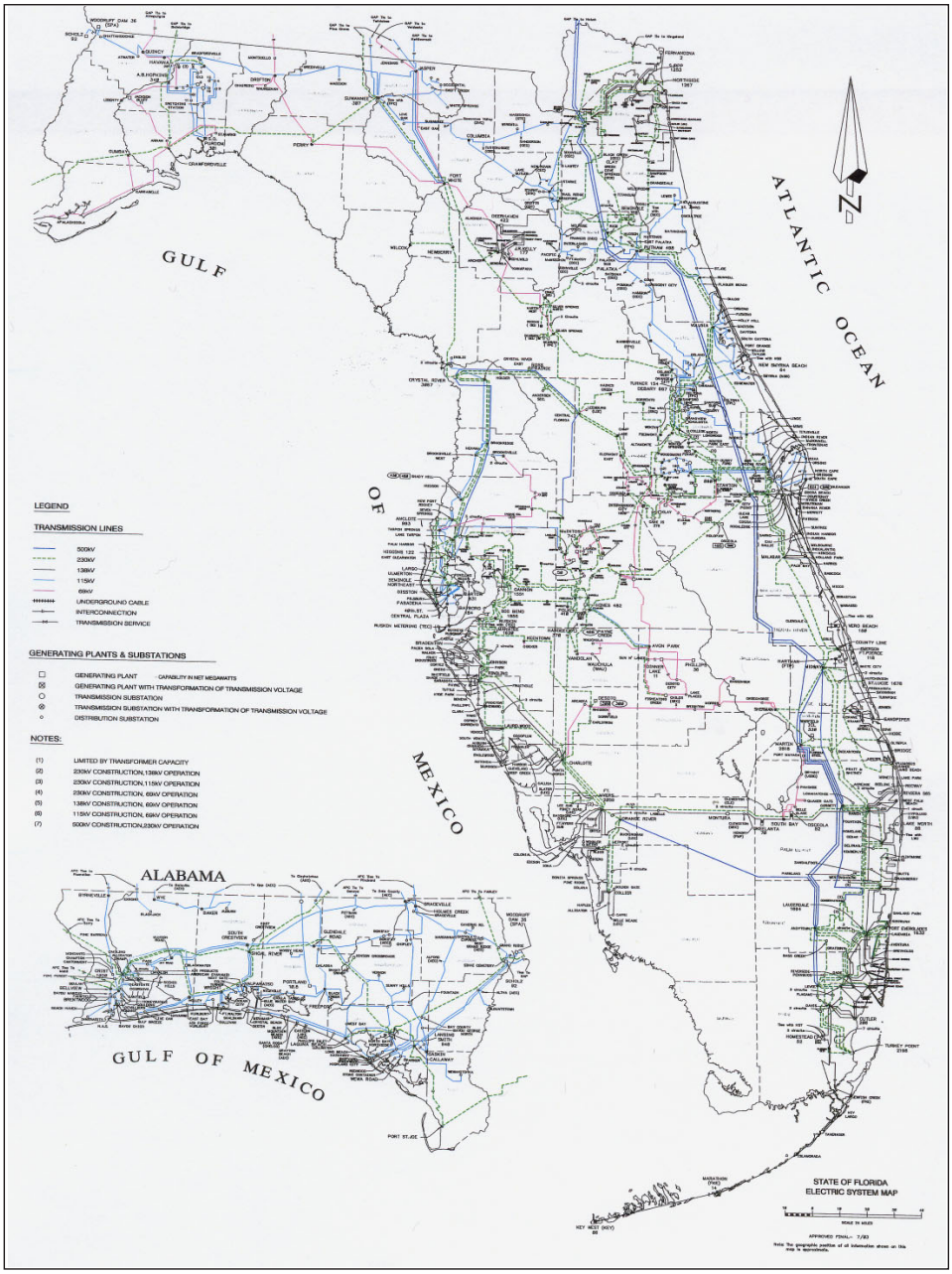
FPSC Rule 25-6.078, Schedule of Charges, requires each investor-owned utility to file with the Commission a written policy that will become a part of the utility's tariff rules and regulations regarding undergrounding electric facilities in new residential subdivisions. Such policy is subject to review and approval by the Commission and (1) must include an Estimated Average Cost Differential, if any, (2) must state the basis upon which the utility will provide underground service, and (3) must specify the method for recovering the difference in cost of an underground system and an equivalent overhead system from the applicant at the time service is extended. The charges to the applicant cannot be more than the estimated difference in cost of an underground system and an equivalent overhead system.

Another Commission rule, Rule 25-6.115, requires each investor-owned utility to file a tariff addressing new construction and the conversion of existing overhead to underground facilities not covered by Rule 25-6.078. The tariff must include the general provisions and terms under which the investor-owned utility and applicant may enter into a contract for the purpose of new construction or conversion of existing overhead electric facilities to underground electric facilities. [10]

IV. Estimated Cost of Placing Existing Electric Transmission and Distribution Facilities Underground

A. Estimated Cost of Placing Existing Investor-Owned Electric Transmission Facilities Underground

Transmission facilities are the backbone of the electric power delivery system. Transmission moves bulk power generated at the power plants to substations for distribution to end-use customers. Transmission interconnections with the electric power systems of other utilities also enable utilities to buy and sell bulk power for reliability and economic purposes. At lower voltage levels (69 kV to 115 kV), transmission provides looped service to whole communities to ensure local reliability and economical power exchange.



Transmission lines and connecting substations traverse the length and breadth of the state. They range in size from 69 kV to 500 kV. [30]

At the end of 2003, Florida's investor owned utilities had, in aggregate, approximately **14,566** miles of transmission in service with a net book value of approximately $2.4 billion. These transmission lines and connecting substations traverse the length and breadth of the state. They range in size from 69 kV to 500 kV. A typical 69 kV transmission line can carry up to 22 million watts (MW) of electrical power, while a 500 kV transmission line may carry up to 1,200 MW of power. This is equivalent to the electric power used by 23,000 and 1,200,000 residential homes, respectively.

1. Factors to Consider when Undergrounding Transmission Facilities

There are a number of important factors that should be considered when determining the feasibility of placing high-voltage transmission lines underground. Conductors suitable for undergrounding are much more expensive, costing ten to fourteen times as much per foot as overhead conductors, depending on the voltage of the line. [11] The expensive design is necessary to minimize damage from water and to meet insulation and heat dissipation requirements. Costs for burying the conductors vary depending on the voltage level and whether the line is placed in an urban, suburban or rural area. The type of soil is also important. For example, sand and clay are relatively easy to trench, but coral rock found in South Florida is extremely difficult and expensive to trench.

Higher voltage lines must be placed in concrete encased conduit to protect them from dig-in damage and possible injury or death resulting from dig-ins. Typical trenches for high-voltage lines are five to eight feet in depth and four feet in width.

Underground cable is much thicker and heavier than overhead conductors designed to carry the same amount of power. Because of the extra thickness and weight, only short segments of cable can be pulled through the conduit, thus requiring splices and underground access vaults every 1,000 to 2,000 feet, depending on the voltage requirements.

This photo illustrates the comparative sizes of a 230 kV underground cable to a 230 kV overhead conductor. [11] The larger underground cable weighs about ten times as much as the smaller overhead conductor per foot and is about four times as thick. Three such cables are required, one for each phase of the three-phase transmission system. Because of the additional time it takes to repair underground facilities, a fourth cable is often included when undergrounding transmission lines so that three-phase power can be maintained in the event that one of the other three cables fails.

Finding and repairing underground transmission line failures generally takes considerably more time than for overhead lines. Since a transmission line affects far more customers than lower voltage distribution lines, any problems with an underground transmission line will result in vastly more customer outage hours than is the case with distribution feeder lines. In addition, some studies show that the life expectancy of underground lines may be less than that for overhead, so future replacement costs may be higher with underground facilities.

Electric and Magnetic Fields (EMF) are not eliminated by burying transmission lines. Tests have shown that magnetic fields are greater in strength at the surface directly above an underground line than at ground level directly under an overhead line.

Most overhead high-voltage transmission towers and lines are less susceptible to damage from weather than the lower voltage distribution lines because of their greater structural strength. Also, the greater height of higher voltage transmission facilities makes them less susceptible to damage from falling trees. Thus, there is less benefit to undergrounding transmission lines than undergrounding distribution lines from avoided weather-related problems such as wind and falling trees. [11]

2. Estimated Cost and Rate Impacts of Undergrounding Existing Investor-Owned Electric Transmission Facilities

To estimate the cost for undergrounding existing overhead transmission facilities, cost data from the 1991 Commission undergrounding study was escalated to account for inflation. Based on the 1991 study, the cost per mile to underground a 138 kV transmission line was approximately $2.8 million per mile in 1990.

The $2.8 million per mile estimate was the cost to remove and replace existing 138 kV overhead transmission facilities. The estimate included the following categories of cost:

(a) planning and permitting
(b) labor to remove existing facilities
(c) new underground transmission facilities
(d) labor to install the new underground facilities
(e) trucks and other equipment to remove and install facilities
(f) credits for existing overhead facilities that could be employed in the future
(g) disposal of facilities that could not be employed in the future

Assuming this cost is representative of the cost to underground all overhead transmission lines, the total cost for undergrounding all overhead transmission facilities for the investor-owned utilities is estimated using a simple escalation factor to account for inflation as shown in Table 3.

TABLE 3

Estimated Cost of Converting Existing Overhead Transmission to Underground for the Combined Investor-Owned Electric Utilities

Cost per mile in 1990	$2.8 million
Ratio of 2003 GDP Inflator index to 1990 GDP Inflator index	1.299
Estimated cost per mile in 2003	$3.6 million
Number of miles of IOU overhead transmission *(based on 2003 FERC data)*	14,383
Estimated total cost	**$51.8 billion**

To estimate the average rate impact of the cost of conversion on the combined customers of the investor-owned utilities, the following procedure was used. First, a weighted average rate of return (ROR) on investment, grossed up for regulatory assessment fees and state and federal taxes, was derived using the capital structure of the five investor-owned electric utilities. These calculations are shown in Table 4. The grossed up weighted rate of return of 12.04% from Table 4 was used to determine the revenue requirements associated with the return on utility investment needed to convert overhead transmission facilities to underground. The construction period assumed for the calculation of revenue requirements is ten years. It is further assumed that all costs would be recovered over a ten year period. A property tax rate of 1.86% is also assumed.

TABLE 4

Calculation of Weighted Rate of Return

UTILITY (a)	RATE BASE (b)	PERCENT OF TOTAL RATE BASE (c)	REQUIRED ROR (d)	WEIGHTED ROR (e)
FPL	10,618,332,328	57.14%	7.52%	4.30%
FPUC	35,607,567	0.19%	8.11%	0.02%
GPC	1,201,111,552	6.46%	7.56%	0.49%
PEF	3,962,453,143	21.32%	8.36%	1.78%
TEC	2,764,875,218	14.88%	8.29%	1.23%
Total	18,582,379,808	100.00%	--	7.82%
			Net Operating Income Multiplier	1.5404
			Grossed Up Weighted Rate of Return	**12.04%**

Note: Column (e) of Table 4 is the product of columns (c) and (d).

Table 5 shows the estimated levelized annual revenue requirements and the customer rate impact, on a kilowatt-hour basis, if these costs are spread over all customers of the five investor-owned electric utilities combined. An inflation rate of 2.44% per year over the ten-year period is assumed. Also, it is assumed that O&M savings will be approximately 0.7% of the gross investment in underground facilities each year. This savings percentage is based on comparing the respective costs for overhead and underground O&M expenses as reported in the 2003 FERC Form 1 for distribution facilities. Distribution data was used since O&M expense data for underground transmission facilities was not separately identified in the FERC Form 1. The percent rate impact is with respect to all customer electric utility costs, including base rates and fuel.

TABLE 5

Ten-Year Annual Revenue Requirement and Rate Impact of Converting Existing Overhead Transmission Facilities to Underground

Estimated Cost of Conversion	$51.8 billion
Estimated Cost adjusted for inflation over 10 yrs	$57.9 billion
Levelized Annual Revenue Requirement	$6.5 billion
% Rate Impact – (spread over all kWhs)	**49.7%**

3. Estimated Manpower Requirements for Undergrounding Existing Investor-Owned Electric Transmission Facilities

The man-hours required to convert overhead transmission facilities to underground depends on many factors, including the type of soil, the thickness and weight of the cable, the type of undergrounding (e.g., direct burial, concrete encased ducts, etc.), and the number of access facilities (vaults) needed.

An undergrounding study conducted by North Carolina reported man-hours per mile ranging from 1,458 in rural areas to 9,500 in urban areas for undergrounding distribution facilities. [14] Assuming the same manpower requirements per mile for conversion of transmission lines, and assuming a mid-range number of 5,000 man-hours per mile, it would take approximately 72 million man-hours to convert the 14,383 miles of overhead transmission of the investor-owned utilities. If the conversion were done over a ten-year period, this would imply 7.2 million man-hours per year. This would require approximately 3,600 employees, assuming each employee worked 2,000 hours per year.

B. Estimated Cost of Placing Existing Investor-Owned Electric Distribution Facilities Underground

The distribution network delivers power from the bulk power system to each individual residential, commercial, and industrial end-use customer. As such, distribution lines and equipment permeate every road, avenue, and highway of the state distributing electricity to consumers. Because of this omnipresence, distribution facilities are most susceptible to the wind, tree, lightning, and flood damage that accompany major hurricanes and storms.

Typically, the distribution systems of the investor-owned utilities operate at voltages ranging from 2.4 kV to 35 kV. These voltages are stepped down to 120/240 volts at the point of delivery to serve residential and commercial customers. Industrial customers typically take service at higher voltages, up to transmission level, depending on the nature of their internal process equipment.

As of year end 2003, Florida's investor-owned electric utilities owned approximately **115,961** miles of primary distribution lines. This estimate is based on the number of miles reported in the 1991 study as well as an FPSC staff survey in the year 2000 for 1999 mileage data. The annual growth rate since 1999 was assumed to be the same as the average growth rate for the 1990 to 1999 period. The combined net book value for all distribution facilities of the five investor-owned utilities is approximately $7.0 billion for the year ending 2003.

In developing an estimate of the cost of replacing existing overhead distribution facilities in Florida with underground facilities, several sources were considered. The first source was data compiled in the Commission's 1991 study on undergrounding. The data from that source was updated based on simple numeric escalations to obtain current estimates adjusted for inflation. The next source considered was the estimate provided by Tampa Electric Company to residents of Davis Islands for placing existing overhead facilities underground. The third source of information was a recent undergrounding study conducted by JEA. These are discussed below, along with the corresponding rate impacts and manpower requirements.

1. Updated 1991 Study Cost Data for Undergrounding Existing Distribution Facilities

One method used to estimate the cost of converting overhead distribution to underground was based on updating cost data developed in the Commission's 1991 undergrounding study. The 1991 Study included cost estimates for four residential conversion cases and one commercial feeder case. Table 6 lists these cases along with the corresponding total costs and cost per customer.

TABLE 6

Costs of Residential Conversion Cases Considered in 1991 FPSC Study

1991 STUDY CASE	TOTAL COST	# OF CUSTOMERS	COST PER CUSTOMER
Low Density Subdivision	$430,579	226	$1,905
High Density Subdivision	$293,581	176	$1,668
Urban Residential Feeder	$477,942	55	$8,690
Rural Residential Feeder	$172,557	8	$21,570
Main Line Urban Commercial Feeder	$622,191	22	$28,281

These estimates from the 1991 FPSC study included the following categories of cost:

(a) planning and permitting
(b) labor to remove existing facilities
(c) new underground distribution facilities
(d) labor to install the new underground facilities
(e) trucks and other equipment to remove and install facilities
(f) credits for existing overhead facilities that could be employed in the future
(g) disposal of facilities that could not be employed in the future

Since it is not known how the five study cases above correspond to current demographics, focus was placed on updating the cost of conversion for the low density subdivision case and the urban residential feeder case for residential customers and the main line urban feeder case for commercial customers. From Table 6 it can be seen that the cost for converting the low density subdivision case, on a per-customer basis, somewhat overstates the cost for converting a high-density subdivision and the cost for converting the urban residential feeder significantly understates the cost of converting the rural residential feeder. The updated estimates given in Tables 7, 8 and 9 are based on simple escalations of the costs derived in 1991 using the percent change in the GDP Deflator inflation index from 1990 to 2003. Table 7 shows the development of the updated estimate for the low density subdivision case, Table 8 shows the updated estimate for the urban residential feeder case and Table 9 shows the updated estimate for the main line urban feeder case.

In order to estimate the total cost to convert overhead service to underground service for the investor-owned residential and commercial customers, it is necessary to estimate the percentage of customers currently being served by overhead service. The precise percentage of customers currently served by overhead facilities is not known. A time-intensive survey would be required to assess the ratio of overhead to underground facilities because in some instances, only the service

laterals have been undergrounded, while in other instances the facilities in the entire neighborhood have been undergrounded. Based on information provided by the investor-owned electric utilities pursuant to an informal PSC staff data request, approximately 47% of all customers were served by overhead service in 2003.

Table 7 shows that the updated cost of conversion for the low density subdivision case in 2003 is estimated to be **$2,475** per residential customer. Using $2,475 as representative of the cost per customer, Table 7 develops an estimate of the total cost to convert all existing residential customers served by overhead facilities to underground, assuming that approximately 47% of residential customers are currently served by overhead facilities. With these assumptions, the total cost estimate is **$6.7 billion**. This cost estimate does not include the cost of undergrounding the feeders from the substation to the vicinity of the residential customers' premises, which is developed in Table 8.

TABLE 7

2003 Estimated Cost to Convert Existing Overhead Residential Distribution Facilities to Underground

Estimate from 1991 Study to convert a low density subdivision in 1990 from overhead to underground	$430,579
Number of single family homes in subdivision	226
1990 cost per residential lot	$1,905
Ratio of 2003 GDP Inflator index to 1990 GDP Inflator index	1.299
Estimated 2003 cost per residential customer	**$2,475**
Number of IOU residential customers in Florida	5.8 million
Assumed percent of IOU residential customers served by overhead facilities	47%
Total cost to convert existing IOU residential subdivision/neighborhood overhead facilities to underground	**$6.7 billion**

Table 8 shows that the updated cost of conversion for urban residential feeders in 2003 is estimated to be **$11,288** per residential customer. Using $11,288 as representative of the cost per customer, Table 8 develops an estimate of the total cost to convert all existing residential feeders to underground. This estimate assumes that all feeders from the substation to the vicinity of the customers' premises are currently overhead. With these assumptions, the total cost estimate is **$65.5 billion**.

TABLE 8

2003 Estimated Cost to Convert Existing Overhead Distribution Facilities to Underground - Urban Residential Feeder Case

Estimate from 1991 Study to convert an urban residential feeder in 1990 from overhead to underground	$477,942
Number of customers connected to feeder	55
1990 cost per customer	$8,690
Ratio of 2003 GDP Inflator index to 1990 GDP Inflator index	1.299
Estimated 2003 cost per residential customer	**$11,288**
Number of IOU residential customers in Florida	5.8 million
Total cost to convert all existing IOU residential overhead feeders to underground	**$65.5 billion**

Table 9 shows that the updated cost of conversion for main line urban feeders in 2003 is estimated to be **$36,737** per commercial customer. Using $36,737 as representative of the cost per customer, Table 9 develops an estimate of the total cost to convert all existing main line urban feeders to underground. Because of the lack of data, the analysis assumes that 47% of commercial customers are served by overhead facilities, which is the same percentage assumed previously in Table 7. With these assumptions, the total cost estimate is **$12.4 billion**.

TABLE 9

2003 Estimated Cost to Convert Existing Overhead Distribution Facilities to Underground - Main Line Urban Commercial Feeder Case

Estimate from 1991 Study to convert a main line urban feeder in 1990 from overhead to underground	$622,191
Number of customers connected to feeder	22
1990 cost per customer	$28,281
Ratio of 2003 GDP Inflator index to 1990 GDP Inflator index	1.299
Estimated 2003 cost per commercial customer	**$36,737**
Number of IOU commercial customers in Florida	720,000
Assumed percent of IOU commercial customers served by overhead feeders	47%
Total cost to convert existing IOU overhead main line urban commercial feeders to underground	**$12.4 billion**

As was the case with the costs developed in the FPSC 1991 study, the cost estimates reflected in Tables 7, 8 and 9 do not include any costs related to the removal of service masts or any costs necessary to modify meter sockets, service panels, or internal wiring.

These cost estimates only include conversion of existing overhead facilities. No estimates were made for the cost of putting future facilities underground rather than overhead. Also, the undergrounding cost estimates do not include costs to underground the overhead facilities of other utility services, such as telephone and cable TV, who often rely on joint-use pole attachments or overhead poles of their own.

2. Davis Islands Conversion Project

There has been significant community interest in looking at the feasibility of undergrounding electric utilities on Davis Islands for more than eight years. As a result of this community interest, a Utilities Task Force was formed to conduct a phased analysis of the costs and benefits of undergrounding. Task Force members include the Davis Islands Civic Association, the City of Tampa, the University of South Florida (USF) College of Engineering, Tampa Electric Company and Verizon Communications.

USF completed the first phase of the analysis on July 31, 1999. The first phase results were obtained by applying escalation rates to the data collected in the 1991 FPSC undergrounding study. In addition, USF used costs that were specific to Tampa Electric Company rather than IOU average costs.

A second phase was completed in 2002 in which Tampa Electric Company assisted in developing detailed conversion costs. Tampa Electric Company provided Davis Islands residents an estimate for underground conversion of **$3,200** per electrical connection for a 3,000 customer project in the Tampa Bay island community. The efforts of the Davis Islands Utilities Task Force are ongoing.

The $3,200 estimate does not include the costs to replace street surfaces, sidewalks, shrubbery, grass or other property disturbed by the conversion efforts. In addition, this estimate does not include any costs related to removal of service masts or any costs necessary to modify meter sockets, service panels, internal wiring, or other costs associated necessary to bring customer facilities up to current code requirements.

3. JEA 2004 Study Results

JEA's study was in response to requests from several neighborhoods within JEA's service territory for undergrounding existing overhead electrical facilities. The study focused on five specific residential neighborhoods with a combined total of 327 homes.

According to information obtained from a presentation made to the JEA Board in April of 2004 by its Chief Operating Officer, approximately 40 percent of JEA's distribution facilities are currently underground. In November of 2004, estimates were presented to the JEA Board on the cost to convert existing overhead distribution facilities to underground. The conversion program included two main cost components: (1) distribution facilities conversion in the rights-of-way owned by JEA; and (2) customer-owned service conversion.

The first component includes all work necessary to remove the existing overhead system, to install underground conduit and cables, and to install new overhead primary and secondary riser poles in certain areas. The second component of the conversion program includes all costs incurred beyond the rights-of-way owned by JEA, such as trenching within private property and any costs associated with service entrance modifications and inside wiring.

JEA staff estimated conversion costs ranging from $3,103 to $7,080 per house, depending on the specific neighborhood, the customer participation rate, and whether the service is single or three phase. The estimated average cost per customer for all five neighborhoods combined ranges from **$3,649 to $4,761**.

4. Estimated Cost and Rate Impacts of Undergrounding Existing Investor-Owned Electric Distribution Facilities

Table 10 summarizes the revenue requirement and rate impact, on a kWh basis, if conversion costs are spread over (1) residential customers, and (2) all customers of the five IOUs combined. The revenue requirements shown in Table 10 are based on the same assumptions (rate of return, property tax rate, inflation rate and O&M savings rate) as those used in the previous section on the cost of undergrounding transmission facilities.

TABLE 10

2003 Estimated Cost to Convert Existing Overhead Distribution Facilities to Underground

Estimated cost for converting subdivision/neighborhood facilities	$6.7 billion
Estimated cost for undergrounding residential feeders from substations	$65.5 billion
Estimated cost for undergrounding main line urban commercial feeders	$12.4 billion
Total cost of converting overhead distribution facilities	$84.6 billion
Total cost of conversion including future inflation	$94.5 billion
Levelized Annual Revenue Requirement	$10.6 billion
% Rate impact – costs spread over only residential kWhs	**141.5%**
% Rate impact – costs spread over all kWhs	**81.1%**

Table 10 shows that if undergrounding costs are spread over only residential customers, the rate impact is **141.5%**. If costs are spread over the kilowatt-hours consumed by all customers, the rate impact is **81.1%.** These rate impacts are with reference to all customer costs, including base rates and fuel.

5. Estimated Manpower Requirements for Undergrounding Existing Investor-Owned Electric Distribution Facilities

The man-hours required to convert all existing overhead distribution depends on the extent of urbanization, traffic flow, whether the circuit is single or three-phase, available easements, and the local topography and geology. Consequently, local conditions will affect the man-hour requirements for each segment of a distribution conversion project.

The 2004 study conducted by North Carolina [14] reported man-hours per mile ranging from 1,458 in rural areas to 9,500 in urban areas. Since the investor-owned utilities in Florida typically serve mostly urban areas, the upper end of this range is used to estimate the manpower requirements to underground existing IOU distribution facilities. Under this assumption, it would take approximately 719 million man-hours to convert the 75,642 miles of existing overhead distribution of the investor-owned utilities. If the conversion were done over a ten-year period, this would imply 71.9 million man-hours per year. This would require approximately 35,950 employees, assuming each employee worked 2,000 hours per year.

C. Impact of Undergrounding on Other Utility Services

There are other types of utility services that use overhead facilities, such as telephone and cable TV utilities. In many cases, these utilities share the poles installed by electric utilities and pay rent (a fee) pursuant to a joint-use contract/agreement. Table 11 shows the number of joint-use poles and separately owned poles as reported by the companies listed in the table.

TABLE 11

Jointly and Separately Owned Telephone Poles in Florida

TELEPHONE COMPANY	JOINT-USE POLES	TELEPHONE COMPANY POLES
Sprint	261,547	42,596
Alltel	9,637	5,226
Frontier (100% underground)	n/a	n/a
Smart City (100% underground)	n/a	n/a
GT Com/Florala	3,456	377
TDS Telecom	1,077	428
Verizon	377,046	107,565
BellSouth	742,937	454,603
Northeast Telephone	530	1,587
TOTALS	**1,396,230**	**612,382**

If electric utilities place their joint-use poles underground, then telephone and cable companies would have to decide what to do with their facilities. Depending on the specific type of facilities (e.g., copper or fiber) and National Electric Safety Code (NESC) requirements, these facilities may not be able to be placed in the same trench as electric facilities. Lines that are located on poles owned by telephone or cable TV companies could be placed underground on a separate time schedule from that for joint-use poles.

If cable, telephone and other utilities that share poles with electric utilities do not place their facilities underground, then they will have to bear the entire cost of the poles, thus increasing the cost of these services to customers. In addition, there would also be no improvement in aesthetics.

Utility companies, municipalities, and other owners of rights-of-way must carefully manage these assets to minimize costs of construction as well as to prevent accidental dig-ins. For example, serious flooding can occur if underwater mains are cut. Also, devastating explosions can occur if underground gas pipelines are struck.

V. Financing Options for Overhead to Underground Conversion

There are two basic questions that must be answered with regard to financing options for conversion of overhead facilities to underground: (1) who should be responsible for paying for undergrounding, and (2) how should the payment be collected, including financing costs and a reasonable return on equity? Based on a review of available studies conducted by state utility commissions and others, the following methods for paying for underground conversion could be considered Several of the options listed below raise issues of equity among ratepayers. In particular, ratepayers who have already paid for undergrounding their facilities could be required, under certain options, to also pay for the undergrounding of other ratepayers' facilities.

A. Electric Utility Company Funded

Utilities fund the initial cost which is recouped through higher rates applied to all customers (residential, commercial and industrial). An advantage to this method is relatively low administrative costs. A disadvantage of this option is that it may involve a cross-subsidy to those who enjoy the primary benefits of lines being underground (urban residents) from those who do not benefit as much (rural residents). Some communities, including some industrial customers, do not place a high value on the aesthetic benefits of undergrounding. This method could also be considered regressive due to its disproportionate impact on low income households.

B. Electric Utility Company Set-Asides

A state/local fee is placed on utilities which is set aside and allowed to accrue over a period of time to be used to cover the cost of government undergrounding projects. An advantage of this method is it has very little effect on utility rates. A disadvantage is the extended length of time involved to accrue the necessary funding. This is the method that has been used in California for the past 30 years. The California Public Utility Commission (CPUC) requires utilities to set aside between one and two percent of gross revenues annually for use by the counties in undergrounding projects. The counties must then act through ordinances to establish areas that will be eligible for the funds.

C. Property Owner Funded

Payments are made to the city or county government. Payments are made for a fixed term such as one year with no interest charged, payment over five years with an interest component, or a deferred payment option that allowed qualified elderly residents to defer payment until their property is sold. An advantage of the property owner funded option is the closer alignment between those who pay and those who benefit. However, before an entire subdivision can be converted to underground, each property owner must agree to bear his/her proportional cost of the conversion.

D. Private Sector Funded

A special purpose finance vehicle (SPFV) could be developed solely for the purpose of privately financing undergrounding according to a study conducted by an Australian Working Group in 1998. Shareholders of a SPFV could include a range of stakeholders such as Local Government, utility companies, community groups and financial investors. Revenue might come from a hybrid pricing approach which would levy part payment from the property owner and part from utilities by way of an electricity surcharge. Special tax concessions or other regulatory incentives would likely be needed in order to attract investors. A drawback to this approach is that it can be extremely complex and expensive to set up such a vehicle.

E. Taxpayer Funded

A general tax is applied at the local or state level, rather than a levy only on the utility or property owner. For example, the State could create a special undergrounding fund and earmark monies, from public utility fees, to be deposited into the fund. Taxpayers and utility customers could also be allowed to make voluntary contributions into such a fund. This option has the disadvantage of allowing some persons to receive greater benefits than others, depending upon the area in which they live and the timing of undergrounding for each.

F. Special Taxing Districts

Dare County in North Carolina successfully secured the enactment of a local act (NC Session Law 1999-127) authorizing the creation of one or more Utility Districts for the purpose of raising and expending funds to underground electric utility lines in the district. The county commissioners define the boundaries of a utility district and any municipality may join the district. The county commissioners may levy a tax of up to $1 per month on each bill for residential electric service within the district, and up to $5 per month on each bill for commercial service. The electric utilities collect the tax and retain a percentage as compensation for their collection services. The proceeds of the tax are used for the purpose of undergrounding electric utilities within the district. However, there has been concern expressed that even if the taxes are collected for a number of years, they may not be sufficient to cover the costs of undergrounding.

G. Federal Funding

The State Department of Transportation uses federal funds for undergrounding when eligible highways are being constructed. The federal Transportation Enhancements Program, under the Transportation Equity Act for the 21st Century allows communities to apply for funds for utility burial or relocation under the categories of landscaping, scenic beautification, or scenic/historic highway programs and welcome centers. Federal Community Development Block Grants have also been used to fund utility relocation projects. The Federal Emergency Management Agency (FEMA) makes funding available for qualified projects through its Hazard Mitigation Grant Program.

VI. Hardening Overhead Facilities as an Alternative to Undergrounding

There are a number of measures that utilities may undertake to lessen the impact of hurricanes and storms on overhead transmission and distribution systems, such as improved maintenance, more aggressive tree trimming (including widening of rights-of-way), increased wind loading standards, and enhanced flood protection. These measures are referred to as "hardening." Each such measure would require a specific study to determine whether or not it is cost-effective.

A. Improved Substation Equipment, Maintenance and Looping

Electric utilities may consider modernizing substation equipment as well as enhancing or accelerating maintenance schedules for substation equipment. For example, Dominion Virginia Power reports that it has converted substation automation efforts from older analog equipment that required much maintenance to newer, low-maintenance digital equipment with remote monitoring capability. In addition, it has invested heavily in "loop schemes,'' where circuits from two different substations serve a geographic area. This allows the utility to isolate a problem to the fewest number of customers while maintaining service for other customers served by the loop.

B. Tree Trimming / Vegetation Management

As a result of the hurricane activity experienced during 2004, both Florida Power & Light Company (FPL) and Progress Energy Florida, Inc. (PEFI) have filed petitions before the FPSC for the recovery of extraordinary storm related expenditures. Dockets No. 041291EI and 041272-EI, respectively have been established to address these petitions. Total estimated costs due to hurricane damage requested in these dockets are $890 million and $366 million, respectively. Public hearings have been scheduled on April 20, 21, and 22 for FPL and March 30, 31 and April 1 for PEFI. During these hearings, the FPSC will thoroughly examine the prudence of the storm expenditures made by each company and management practices regarding maintenance of the electric system, including tree trimming.

On an on-going basis, the FPSC routinely monitors the tree trimming practices of investor-owned electric utilities such as FPL. Pursuant to Rule 25-6.0455, Florida Administrative Code, each investor-owned electric utility in Florida is required to file a Distribution Service Reliability Report annually with the FPSC. This annual data and multi-year trends in the data are analyzed to identify areas for ongoing review. Areas scrutinized include utility vegetation management practices, compliance with voltage standards, electric outage causation, and customer complaints.

In addition, in September 2004, the FPSC initiated a quality of service management review of all five investor-owned electric utilities that addresses both distribution and transmission functions. This review will provide a comprehensive report on current utility management practices affecting reliability and quality of service, including tree trimming practices. The review is currently scheduled to be completed in 2005.

Pursuant to 366.04(6)(b), Florida Statutes, Florida's electric utilities are required to adhere to the National Electric Safety Code (NESC). The NESC addresses, among many other topics, right-of-way clearances. Utility tree trimming practices, including trim cycles, are designed to comply with the NESC. However, the NESC does not have specific standards for tree trimming practices – it simply states that tree limbs and other vegetation are to be kept clear of the lines. Also, most cities

have ordinances that control the trimming or removal of trees within its jurisdiction. There may be a need for better coordination between utility tree trimming practices and the requirements of local governments.

C. Increased Wind Loading Standards for Construction

The NESC discusses grades of construction, strength requirements, and wind loading requirements for overhead structures in Sections 24, 25, and 26. The FPSC has safety jurisdiction over transmission and distribution facilities built after 1986. When NESC requirements change, the changes apply only to new facilities – older facilities are grandfathered with respect to the new requirements. One area which may warrant additional study is whether current utility wind loading standards should be made comparable to current requirements for housing.

D. Enhanced Flood Protection

Flood plain history must be carefully researched before substations and other utility facilities are built and placed in service. A review of the flooding experience of existing properties and facilities may be warranted. Although most equipment in substations are placed two or more feet above ground level, it may be cost-effective in certain cases to further raise such equipment or to consider water-proofing to some degree.

Plans should be reviewed to ensure that utility crews inspect all substation sites well in advance of landfall of any major storm, otherwise, roads to substations or other facilities could become impassable because of evacuations or weather conditions (downed trees, flooding, etc.). Substations and surrounding areas should be examined for objects that could be blown into or float into energized substation equipment.

VII. Other Studies and Reports and Some Existing State Regulations

A review of available studies conducted by State utility commissions, research firms, and other countries regarding costs and benefits of undergrounding is instructive. Without exception, the costs to convert existing overhead electric distribution lines to underground were determined to be significantly more than the costs of typical overhead installation by all the studies.

In general, the studies also showed that though undergrounding electric utilities offered greater reliability, these gains in reliability were offset by increased repair time. In other words, if electric distribution lines were placed underground, consumers would likely experience fewer outages but outages would typically last longer.

Only one of the studies reviewed reached the conclusion that conversion to underground could be considered cost effective. The College of Engineering at the University of South Florida prepared a report in 1999, at the request of the Davis Islands Civic Association that included the expected increase in real estate values that contributed to the perceived cost effectiveness of undergrounding.

The studies used varying levels of analysis and methodologies to arrive at their conclusions. The use of quantitative data such as labor and capital costs is customary. For example, using the known dollar amount per mile for burying lines produces a hard number that can be used to project future costs. However, studies also had to give consideration to qualitative data such as customer perceptions, the aesthetic benefits of underground utilities and the unpredictable nature of the weather.

A brief synopsis of the studies and reports reviewed appears below. In order to present information on how states have elected to pay for undergrounding utilities, some of the existing state regulations regarding electric utility undergrounding are also summarized.

A. Studies and Reports

1. Edison Electric Institute Report [13]

One of the most comprehensive reviews is the Edison Electric Institute's summary of previously completed studies on undergrounding published in January 2004. Some of EEI's findings are: 1) Burying overhead power lines would cost about 10 times what it costs to install overhead power lines. 2) Underground power systems have fewer outages but the outages last longer. 3) Reliability benefits associated with burying existing overhead power lines are uncertain and in most instances do not appear to be sufficient to justify the high costs.

One of the most interesting features of EEI's report is its summaries of innovative programs that communities and local governments have adopted to help pay for burying their overhead power lines. These include special assessment areas, undergrounding districts, and state and local government initiatives.

When a community establishes a "special assessment area," subscribers pay extra on their monthly bill to fund the underground project. These areas are typically created through a petition of the majority of the property owners in the area. For example, Commonwealth Electric in Massachusetts has used special assessments since 1970 to fund burial efforts in historic communities such as Nantucket.

Another approach, employed in California and Oregon, is the establishment of "underground districts." The California Public Utilities Commission collects a percentage of revenue from wire-based utilities for a special undergrounding fund. To receive these funds, a community must form an undergrounding district, approved by at least 70% of the property owners in that district. The property owners must also agree to pay the $500 to $2,000 it costs to connect their homes to a new underground system.

Investor-owned Hawaii Electric has a program where it pays for up to one-third of the cost to place existing neighborhood electric distribution lines underground. Hawaii electric will undertake the conversion as part of a community or government-initiated underground project, subject to public utility commission approval.

Another investor-owned utility, South Carolina Electric and Gas (SCE&G) has established a special undergrounding program, approved by the South Carolina Public Service Commission. Under the program, if a local municipality agrees to contribute a matching amount, SCE&G contributes .5% of the gross receipts it is obligated to pay to the municipality. This money goes into a special underground fund.

2. North Carolina Utilities Commission Public Staff Report [14]

After a major ice storm caused unprecedented power outages to over two million electric utility customers, the Public Staff of the North Carolina Utilities Commission investigated the feasibility of replacing the existing overhead distribution lines of the state's three investor-owned utilities (Utilities) with underground lines. In its report, released in 2003, the Public Staff concluded that replacement would be prohibitively expensive, costing approximately $41 billion, nearly six times the net book value of the Utilities' current distribution assets. In addition, it would take approximately 25 years to complete the replacement.

The ultimate impact of the capital costs alone on an average residential customer's monthly electric bill would be an increase of more than 125%. Rates would also be impacted by the higher operating and maintenance costs associated with direct-buried underground systems, particularly in urban areas, where underground conductors are four times more costly to maintain than overhead facilities. In addition to the impact on the cost of providing utility service, conversion to underground would impose costs on individual customers, municipalities, and other utilities. While these costs have not been quantified, they could be significant, the Public Staff concluded.

Although underground systems are more reliable than overhead systems under normal weather conditions, they are not impervious to damage (for example, dig-ins and water intrusion). The repair time for underground systems is almost 60% longer than for overhead systems when damage does occur. Consequently, the Public Staff did not recommend that the Utilities undertake the wholesale conversion of their overhead distribution systems to underground.

The Public Staff recommended that each of the Utilities (1) identify the overhead facilities in each region it serves that repeatedly experience reliability problems based on measures such as the number of outages or number of customer hours out of service, (2) determine whether conversion to underground is a cost-effective option for improving the reliability of those facilities, and, if so, (3) develop a plan for converting those facilities to underground in an orderly and efficient manner, taking into account the outage histories and the impact on service reliability.

The report also recommended that the Utilities continue their current practices of (1) placing new facilities underground when the additional revenues cover the costs or the cost differential is recovered through a contribution in aid of construction, (2) replacing existing overhead facilities with underground facilities when the requesting party pays the conversion costs, and (3) replacing overhead facilities with underground facilities in urban areas where factors such as load density and physical congestion make service impractical from overhead feeders.

3. Virginia State Corporation Commission Study [15]

The Virginia State Corporation Commission (VSCC) released its study of placing utility distribution lines underground in January, 2005. The Virginia General Assembly had directed VSCC to conduct the study, partly in response to damage caused to existing overhead utility lines by Hurricane Isabel in September 2003. The study concluded that a comprehensive statewide relocation initiative does not appear to be reasonable from an economic viewpoint.

The VSCC study found that the primary advantages of underground utility lines are aesthetics and overall improved reliability. Underground circuits eliminate the need for most tree trimming maintenance, eliminate vehicular crashes with utility poles, reduce some electrical hazards, and nearly eliminate the need for extensive restoration efforts after major storms.

However, the VSCC report states that the wholesale replacement of overhead utility distribution lines would be prohibitively expensive for local and state governments, utilities, and ultimately consumers who would pay the costs, either directly or indirectly, in the form of prices, taxes, or utility rates.

In Virginia, there are 96,830 miles of overhead electric distribution lines owned by investor-owned utilities and electric cooperatives serving 3.1 million customers. The cost associated with placing these overhead electric utility distribution facilities underground was estimated by utilities to be over $80 billion. This equates to approximately $800,000 per mile of overhead line with an average cost per customer of $27,000. Assuming a total investment by electric utilities of $80 billion to relocate currently existing overhead distribution lines to underground, the annual levelized revenue requirement on a per customer basis would be approximately $3,000 per year over the life of the facilities. However, the VSCC notes that cost estimates provided by the utilities are based on simplifying assumptions as opposed to detailed engineering studies; therefore, actual costs could vary significantly from such projections.

In public comments received by the VSCC for the study, residential customers overwhelmingly favored placing utilities underground. But in follow-up questions, these same customers generally indicated they were not willing to pay enough to fully fund the work.

The VSCC concluded that a major relocation initiative could take decades to complete and encounter complications from conflicts with other existing underground utilities. Attaining new easements for utilities could involve significant time, negotiations with property owners and potential legal proceedings.

In the preparation of the study, the VSCC invited the participation of interested parties, including local governments, utility companies, industry groups, and consumer organizations. It was the general consensus of this group that decisions concerning the placement of lines underground can be implemented most effectively at the local level. The VSCC concluded localities would be able to

judge each individual project on its merits and based on local citizens' values and willingness to pay. Localities would be in the best position to determine the most appropriate funding of such projects, coordinate work among utilities, and classify projects in a way that affords favorable tax and tariff treatment.

4. Maryland Task Force Study [16]

Since 1969 all new low-voltage electric and telephone lines have been buried underground based on the Maryland Public Service Commission's determination that it was in the interest of public health and safety. Utilities are permitted to recover through rate structure the cost of undergrounding ***new*** low-voltage electric and telephone distribution lines.

In 2003, the Maryland Task Force was charged by the legislature with making recommendations on how to facilitate and lower the cost of relocating overhead utility lines underground [17]. Similar studies had been conducted in Maryland in response to severe weather related power outages in 1999. These earlier studies estimated the costs of undergrounding existing overhead power lines at $900,000 per mile, or 5 to 10 times the cost of installing overhead lines. In addition, the useful life of underground cable is about 30 years, compared to 50 years for overhead. In a report prepared in 2000, one of the conclusions reached was that overhead lines offered a much less expensive method of providing reliable service [18]. The example offered to illustrate this point is that if a 10 percent return is imputed to the great amounts of capital freed up by building overhead instead of underground lines, the earnings alone would pay for substantial ongoing overhead maintenance.

The Task Force reviewed these studies and reported that their findings regarding cost and benefits do not differ substantively from the prior studies. The Task Force made three recommendations:

(1) The Attorney General should solicit an opinion and clarification from the Internal Revenue Service on the applicability of the Contributions in Aid of Construction (gross-up tax). This tax represents approximately 27.4 percent of the cost of undergrounding, and there are conflicting opinions regarding the applicability of the tax. Undergrounding projects being completed primarily for aesthetic purposes are subject to the tax. However, undergrounding projects that are undertaken for public safety reasons would not be defined as an addition to capital, and not a Contribution in Aid of Construction, and thus should not be subject to the gross-up tax.

(2) The Maryland Department of Planning should serve as a clearinghouse to assist local jurisdictions and groups that are interested in undergrounding. Although current law and regulations provide a framework for implementing an underground plan, there is no place an interested party can go to get comprehensive advice on the most effective and low-cost ways to complete an undergrounding project.

(3) Local governments, State and local highway authorities, Maryland Department of Planning, and owners of overhead facilities should identify opportunities for undergrounding in construction and repair planning, and all parties should work closely to coordinate undergrounding activities. This would increase efficiency and reduce overall project costs by allowing the placement of multiple utilities in a single trench when construction activities may already be planned for other reasons.

5. Kentucky Utilities
Report to the Kentucky Public Service Commission [19]

This report primarily addressed restoration activities following severe ice storms that occurred in February 2003. Undergrounding is mentioned only briefly – noting it is impractical and financially prohibitive for Kentucky Utilities to move an entire distribution system underground simply to minimize the risk of outages due to trees and ice loading. The report recommends that an extensive cost/benefit analysis be conducted before making decisions about moving any portion of the distribution system from overhead to underground.

6. University of South Florida, College of Engineering Report [20]

A report evaluating the benefits of underground utility distribution was published in 1999, as a result of a collaborative effort between the Davis Islands Civic Association, the University of South Florida and the Florida Department of Community Affairs. The report concluded that conversion to underground would be cost effective due to lower external, operation and maintenance costs, and because increased real estate values were expected to offset the higher construction costs. The report also recommended that an engineering design study be completed to determine the actual cost of carrying out an underground conversion.

7. Hawaii Legislative Reference Bureau
Report to the Hawaii Legislature – 1999 [21]

The Hawaii Legislature asked the Legislative Reference Bureau to study the policies and issues on the undergrounding of public utilities. The bureau's report concluded that more needed to be known about measuring intangible costs, allocating cost and resources, and reducing the built-in bias from the information collection process. However, the report did present two recommendations of interest:

(1) The Hawaii Public Utility Commission (HPUC) could be directed to establish a program that requires utilities to set aside funds for undergrounding to be available to counties for a period of time. If within that period of time, a county passes an ordinance to establish an undergrounding district, the county would be eligible to use a relative percentage of the available funds. The HPUC may set rules and criteria that control eligibility for the program and availability of funds, and the contributions required of consumers as any undergrounding projects relate to privately owned property.

(2) An undergrounding fund could be established, which would be administered by the HPUC and into which the funds would be deposited by: legislative appropriation; voluntary contributions from income tax return check offs; rounding up of utility bills; and utilities, as authorized or directed by the HPUC. Counties could be authorized to take the lead in undergrounding and could be assisted by the HPUC's establishment of a clear authority for cost allocations in special improvement districts from the undergrounding fund.

8. Commonwealth of Australia Underground Working Group Report – 1998 [22]

One of the most thorough reports, it quantified both costs and benefits in a detailed manner. The level of quantifiable benefits was estimated to be around 10 percent of total costs. The national cost model used two broad cost elements: (1) the amount of infrastructure required (lengths of cable, number of pad-mounted transformers, etc.); and (2) the cost of material and labor used to put the network underground. The categories of costs identified in the model were: excavation costs; installation and material costs; cost of service lead-ins to individual premises; reinstatement costs; transformer costs; streetlight costs; and net cost of dismantling and removing existing infrastructure. Benefits were calculated for the following categories: avoidance of tree trimming; savings on repairs and maintenance; reduced revenue loss from outages; reduced electrical losses; avoidance of overhead capital improvement expenditure; and reduced motor vehicle accidents. In addition to chapters on regulatory, legal, and funding issues, the report included an administrative guide. This guide described the decisions that would need to be made and provided a framework for implementation of an undergrounding program. The report was submitted to the House of Parliament in 1998.

9. ICF Consulting Report on the Potential for Undergrounding of Electricity Networks in Europe [23]

Although over 95 percent of the high voltage networks within the European Union (EU) are overhead lines, the construction of new aerial lines has met with strong opposition by local communities and authorities, as well as by environmental organizations, to the extent that the construction of new lines has become almost impossible in some EU countries. Severe storms in 1999 caused blackouts and substantial damage to the French electricity network. As a result, an agreement was reached that 90 percent of all new medium voltage distribution network, two-thirds of all new low voltage distribution network and 25 percent of all high voltage transmission networks in France should be constructed underground. In addition, it was determined that equivalent lengths of existing aerial line should be placed underground. The EU is considering adopting a similar policy to solve the environmental problems related to the construction of new electricity lines as well as reduce congestion and increase reliability. The study acknowledged the difficulty in estimating the impact of undergrounding on transmission prices due to the number of factors that must be considered, such as: funding mechanisms; impact of running system in a non-optimized manner while work is carried out; and costs of writing off parts of the overhead line system prematurely. This study differed from others in that it involved separate cost/benefits analysis for undergrounding the interconnections between various countries.

B. Some Existing State Regulations Regarding Undergrounding

1. California Public Utilities Commission [24-25]

Beginning in 1967, the California Public Utilities Commission (CPUC) required new electric service connections to be placed underground and funded a gradual program to convert existing overhead lines, including concomitant communication lines, to underground service.

The CPUC's Rule 20 sets policies and procedures for the conversion of overhead power lines and other equipment to underground facilities. Under Rule 20, undergrounding projects are financed by utility rate money, combined rate funds and local tax proceeds, or private funds, depending on whether Rule 20A, Rule 20B or Rule 20C provisions apply.

Rule 20A projects are paid for by all electric utility ratepayers, not just those who live in locations where facilities will be undergrounded. City and county governments choose these projects, using a process that includes public participation. To qualify for full funding through utility rate proceeds, projects must produce a benefit to the general public, not just customers in the affected area, by satisfying one or more of these criteria:

- The location has an unusually heavy concentration of overhead facilities.
- The location is heavily traveled.
- The location qualifies as an arterial or major collector road in a local government's general plan.
- The overhead equipment must be located within or pass through a civic, recreational or scenic area.

Using CPUC formulas, the utility allocates rate funds to communities for undergrounding based on previous allocations, the ratio of customers served by overhead facilities to all the customers in the community, and the fraction that customers in the community represent of all utility customers.

Local governments use these formulas to project allocations, which allows them to prioritize projects and develop project schedules. Because funds are limited, local governments sometimes must wait and accumulate their allocations before starting an undergrounding project.

If an area is not eligible for Rule 20A or if local government cannot or chooses not to rely on the Rule 20A allocation process, Rule 20B allows rate funds to subsidize an undergrounding project. The subsidy includes an amount equal to the cost of an equivalent overhead electric system, usually about 20% of the total undergrounding project cost, plus the cost of removing the existing overhead system, which can be 5% to 20% of the total cost. The remaining cost is funded by local governments or through neighborhood special assessment districts. Rule 20B projects must be sited along public streets or roads, or other locations mutually agreed to by the applicant organization and the utility.

Rule 20C enables property owners to pay for undergrounding electric lines and equipment if neither Rule 20A nor 20B applies.

After two years of study and development, the CPUC in June 2002 approved the first phase of changes designed to improve the scheduling, designing and construction of undergrounding projects under Rule 20. The new Rule 20 is intended to increase local government flexibility by:

- Adding "arterial" and "collector" to the types of location that qualify for Rule 20A.
- Allowing up to five years of mortgaging, or "saving up," allocations levels by local governments, provided adequate utility capital and personnel are available.
- Allowing a local governments to use allocation levels as "seed money," a value that the local government can borrow against to perform initial engineering and design studies for Rule 20B projects. In the event the project is not approved within 2 ½ years after planning stages are complete, the city or county has 90 days to reimburse the seed money.
- Providing the cost of removing overhead facilities will be paid by the utility.

The new Rule 20 is also intended to improve coordination and communications between utilities, local governments and residents. At a local government's request, the utility will meet with government officials and residents to provide status on any Rule 20 project that has been approved. Each utility is required to have a single point of contact to answer questions on Rule 20 for the general public.

A second phase of Rule 20 changes is currently under study. Topics include competitive bidding, incentive mechanisms, establishing a point after which no more overhead facilities will be constructed, and cost recovery for telecommunications undergrounding projects.

2. State of Washington [26]

Conversion of overhead electric and communications facilities to underground were declared substantially beneficial to the public safety and welfare in the public interest by the Washington State Legislature in 1967. Every city or town has the power to convert existing overhead electric and communication facilities to underground where such facilities are owned or operated by the city or town. When the city or town does not own the facilities, they have the power to contract with the utility companies to convert overhead facilities to underground facilities. To provide funds to pay part or all of the costs of conversion, every city or town was given the power to create local improvement districts and to levy and collect special assessments against the real property that will benefit from the conversion.

3. New Mexico Public Regulation Commission [27]

Because of the increasing number of requests by communities to place electric service underground, New Mexico's largest electric and natural gas provider, Public Service Company of New Mexico (PNM), asked the New Mexico Public Regulation Commission to develop an undergrounding tariff. The New Mexico Public Regulation Commission approved a tariff in 2002 that links the added cost of placing power lines underground to the communities that directly benefit from such projects.

Under the tariff, communities requesting power lines be placed underground are required to pay the added costs which can range from two to ten times more than overhead power lines. A city or county government that wants a power line placed underground can either pay the additional cost itself or have it paid by customers within its jurisdiction through a line-item added to their monthly bills. The additional cost would be the difference between the total underground project cost and what a typical overhead line would cost – and would be collected over a period not to exceed seven years. The tariff also allows a city or county government to have input on the costs, route and construction plans for a proposed underground power line.

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