IN THE SUPREME COURT OF FLORIDA

CASE NOS. SC19-328; SC19-479

ADVISORY OPINION TO THE ATTORNEY GENERAL RE: RIGHT TO COMPETITIVE ENERGY MARKET FOR CUSTOMERS OF INVESTOR OWNED UTILITIES; ALLOWING ENERGY CHOICE

ADVISORY OPINION TO THE ATTORNEY GENERAL RE: RIGHT TO COMPETITIVE ENERGY MARKET FOR CUSTOMERS OF INVESTOR OWNED UTILITIES; ALLOWING ENERGY CHOICE (FIS)

UPON REQUEST FROM THE ATTORNEY GENERAL FOR AN ADVISORY OPINION AS TO THE VALIDITY OF AN INITIATIVE PETITION

APPENDIX TO INITIAL BRIEF OF FLORIDA CHAMBER OF COMMERCE AND FLORIDA ECONOMIC DEVELOPMENT COUNCIL IN OPPOSITION TO THE INITIATIVE PETITION

WHITE & CASE LLP
Raoul G. Cantero
rcantero@whitecase.com
David P. Draigh
ddraigh@whitecase.com
Zachary B. Dickens
zdickens@whitecase.com
200 S. Biscayne Blvd., Ste. 4900
Miami, Florida 33131
Telephone: (305) 371-2700
Facsimile: (305) 358-5744

Counsel for the Florida Chamber of Commerce and the Florida Economic Development Council

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was filed electronically with the Court's e-filing system and served by electronic mail on this 18th day of April 2019, on the following:

Laurel M. Lee
Secretary of State
c/o Brad McVay, General Counsel
Florida Department of State
R.A. Gray Building
500 S. Bronough St.
Tallahassee, Florida 32399-0250
brad.mcvay@dos.myflorida.com

James A. Patton Jr.
Chairperson
Citizens for Energy Choices
Post Office Box 1101
Alachua, Florida 32616
alex@flenergychoice.com

Ashley Moody
Attorney General of Florida
The Capitol, PL-01
Tallahassee, FL 32399-1050
oag.civil.eserve@myfloridalegal.com

Christopher J. Baum
Deputy Solicitor General of Florida
The Capitol, PL-01
Tallahassee, Florida 32399-1050
christopher.baum@myfloridalegal.com

The Honorable Bill Galvano
President, The Florida Senate
c/o Jeremiah Hawkes
Senate Office Building
404 S. Monroe St.
Tallahassee, FL 32399-1100
hawkes.jeremiah@flsenate.gov

The Honorable Ron DeSantis
Governor, State of Florida
c/o Joe Jacquot, General Counsel
The Capitol
400 S. Monroe St.
Tallahassee, FL 32399-0001
joe.jacquot@eog.myflorida.com

The Honorable Jose Oliva
Speaker, Florida House of
Representatives
c/o Adam Tanenbaum
The Capital, Room 420
402 S. Monroe St.
Tallahassee, FL 32399-1300
adam.tanenbaum@myfloridahouse.gov

Kenneth W. Sukhia
Sukhia Law Firm
Sukhia Law Group PLC
241 E 6th Avenue
Tallahassee, FL 32303
ksukhia@sukhialawfirm.com
Counsel for Citizens for Energy Choices

INDEX TO APPENDIX

Tab	Document	Appendix Pages
9.	U.S. ENERGY INFO. ADMIN., RANKINGS: AVERAGE RETAIL PRICE OF ELECTRICITY TO RESIDENTIAL SECTOR (Dec. 2018), https://www.eia.gov/state/ rankings/?sid=US#/ series/31 (last visited Mar. 27, 2019)	A. 326-475
10.	FLA. PUB. SERV. COMM'N, REVIEW OF FLORIDA'S INVESTOR-OWNED ELECTRIC UTILITIES 2017 SERVICE RELIABILITY REPORTS (Dec. 2018), http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/DistributionReliabilityReports/2017/Review%20of%20Florida%E2%80%99s%20Investor-Owned%20Electric%20Utilities%E2%80%99%20Service%20Reliability%20in%202017.pdf (last visited Mar. 27, 2019).	A. 476-644
11.	U.S. ENERGY INFO. ADMIN., STATUS OF CALIFORNIA ELECTRICITY SITUATION, https://www.eia.gov/electricity/policies/legislation/ california/ (last visited Apr. 1, 2019).	A. 645-646
12.	TEX. COAL. FOR AFFORDABLE POWER, DEREGULATED ELECTRICITY IN TEXAS, A MARKET ANNUAL (Dec. 2012), https://tcaptx.com/wp-content/uploads/2018/03/TCAP-HistoryofDeregulation-2018.pdf (last visited Mar. 27, 2019).	A. 647-786
13.	U.S. ENERGY INFO. ADMIN., FLORIDA PROFILE (Sept. 2018), https://www.eia.gov/state/?sid=FL (last visited Mar. 27, 2019).	A. 787-791
14.	ELECTRIC UTILITY RESTRUCTURING LEGIS. OVERSIGHT COMM., REPORT TO THE 77TH LEGISLATURE (Nov. 2000), https://senate.texas.gov/cmtes/76/c900/c900_elec_report.pdf (last visited Mar. 27, 2019).	A. 792-922
15.	ERCOT, HISTORY, http://www.ercot.com/about/profile/history (last visited Mar. 27, 2019).	A. 923-927

Tab	Document	Appendix Pages
16.	TEX. COAL. FOR AFFORDABLE POWER, ELECTRICITY PRICES IN TEXAS – A SNAPSHOT REPORT (2018), https://tcaptx.com/reports/snapshot-report-electricity-prices-texas-april-2018 (last visited Apr. 5, 2019)	A. 928-948
17.	U.S. ENERGY INFO. ADMIN., FORM EIA-861M (FORMERLY EIA-826) DETAILED DATA (Mar. 28, 2019), https://www.eia.gov/electricity/data/eia861m/ (last visited Apr. 4, 2019).	A. 949-951
18.	TEX. COAL. FOR AFFORDABLE POWER, ELECTRICITY PRICES IN TEXAS—A SNAPSHOT REPORT (2017), www.tcaptx.com/report/snapshot-report-electricity-prices-texas-july-2017 (last visited Apr. 8, 2019).	A. 952-971
19.	FLA. TAX WATCH, ANALYZING THE FISCAL IMPACT OF THE ENERGY DEREGULATION CONSTITUTIONAL AMENDMENT (Feb. 2019), https://floridataxwatch.org/DesktopModules/EasyDNNNews/DocumentDownload.ashx?portalid=210&moduleid=34407&articleid=18674&documentid=843 (last visited Mar. 27, 2019).	A. 972-992

TAB 1

CONSTITUTIONAL AMENDMENT PETITION FORM

Note:

- *All information on this form, including your signature, becomes a public record upon receipt by the Supervisor of Elections.*
- *Under Florida law, it is a first degree misdemeanor, punishable as provided in s. 775.082 or s. 775.08, Florida Statutes, to knowingly sign more than one petition for an issue. [Section 104.185, Florida Statutes]*
- *If all requested information on this form is not completed, the form will not be valid.*

Your name: ____

Please Print Name *as it appears on your Voter Information Card*

Your address:

____

City__________________________**Zip**__________**County**______________

☐ Please change my legal residence address on my voter registration record to the above residence address (check box, if applicable).

Voter Registration Number____________________**or Date of Birth** ______________

I am a registered voter of Florida and hereby petition the Secretary of State to place the following proposed amendment to the Florida Constitution on the ballot in the general election:

BALLOT TITLE: Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice.

BALLOT SUMMARY: Grants customers of investor-owned utilities the right to choose their electricity provider and to generate and sell electricity. Requires the Legislature to adopt laws providing for competitive wholesale and retail markets for electricity generation and supply, and consumer protections, by June 1, 2025, and repeals inconsistent statutes, regulations, and orders. Limits investor-owned utilities to construction, operation, and repair of electrical transmission and distribution systems. Municipal and cooperative utilities may opt into competitive markets.

ARTICLE AND SECTION BEING CREATED OR AMENDED: Article X, new section

FULL TEXT OF THE PROPOSED CONSTITUTIONAL AMENDMENT:

(a) POLICY DECLARATION. It is the policy of the State of Florida that its wholesale and retail electricity markets be fully competitive so that electricity customers are afforded meaningful choices among a wide variety of competing electricity providers.

(b) RIGHTS OF ELECTRICITY CUSTOMERS. Effective upon the dates and subject to the conditions and exceptions set forth in subsections (c), (d), and (e), every person or entity that receives electricity service from an investor-owned electric utility (referred to in this section as “electricity customers”) has the right to choose their electricity provider, including, but not limited to, selecting from multiple providers in competitive wholesale and retail electricity markets, or by producing electricity themselves or in association with others, and shall not be forced to purchase electricity from one provider. Except as specifically provided for below, nothing in this section shall be construed to limit the right of electricity customers to buy, sell, trade, or dispose of electricity.

[TEXT CONTINUES ON OTHER SIDE]

[TEXT BEGINS ON OTHER SIDE]

(c) IMPLEMENTATION. By June 1, 2023, the Legislature shall adopt complete and comprehensive legislation to implement this section in a manner fully consistent with its broad purposes and stated terms, which shall take effect no later than June 1, 2025, and which shall:
(1) implement language that entitles electricity customers to purchase competitively priced electricity, including but not limited to provisions that are designed to (i) limit the activity of investor-owned electric utilities to the construction, operation, and repair of electrical transmission and distribution systems, (ii) promote competition in the generation and retail sale of electricity through various means, including the limitation of market power, (iii) protect against unwarranted service disconnections, unauthorized changes in electric service, and deceptive or unfair practices, (iv) prohibit any granting of either monopolies or exclusive franchises for the generation and sale of electricity, and (v) establish an independent market monitor to ensure the competitiveness of the wholesale and retail electric markets.
(2) Upon enactment of any law by the Legislature pursuant to this section, all statutes, regulations, or orders which conflict with this section shall be void.

(d) EXCEPTIONS. Nothing in this section shall be construed to affect the existing rights or duties of electric cooperatives, municipally-owned electric utilities, or their customers and owners in any way, except that electric cooperatives and municipally-owned electric utilities may freely participate in the competitive wholesale electricity market and may choose, at their discretion, to participate in the competitive retail electricity market. Nothing in this section shall be construed to invalidate this State's public policies on renewable energy, energy efficiency, and environmental protection, or to limit the Legislature's ability to impose such policies on participants in competitive electricity markets. Nothing in this section shall be construed to limit or expand the existing authority of this State or any of its political subdivisions to levy and collect taxes, assessments, charges, or fees related to electricity service.
(e) EXECUTION. If the Legislature does not adopt complete and comprehensive legislation to implement this section in a manner fully consistent with its broad purposes and stated terms by June 1, 2023, then any Florida citizen shall have standing to seek judicial relief to compel the Legislature to comply with its constitutional duty to enact such legislation under this section.

DATE OF SIGNATURE　　　　SIGNATURE OF REGISTERED VOTER

Initiative petition sponsored by Citizens for Energy Choices, PO Box 1101, Alachua, FL 32616

If paid petition circulator is used:

Circulator's name

Circulator's address

For Official Use Only:

Serial Number: 18-10

Date Approved: 10/5/2018

TAB 2

INTRODUCTION

Retail Sales

Electric utilities in Florida are required to provide safe, adequate, and reliable electric service to the public at the lowest possible cost. Historically, electric utilities have been responsible for the production, transmission, and distribution of electricity, as well as the metering and billing of the electric energy sold to homes and businesses. This complete package of electric services has been termed "bundled retail service" or "integrated utility service," and, for the most part, customers purchase electricity at a fixed price for all these services.

In Florida, a total of 54 electric utilities currently provide bundled retail service to end-use customers in their service areas. The Florida Public Service Commission (FPSC) fully regulates the rates and services of five investor-owned utilities. They are Florida Power & Light Company (FPL), Florida Power Corporation (FPC), Florida Public Utilities Company (FPUC), Gulf Power Company (Gulf), and Tampa Electric Company (TECO). Together, these five investor-owned utilities provide approximately 79 percent of all electricity sold to retail customers in Florida. The remaining 21 percent is provided by 33 municipal electric utilities and 16 rural electric cooperatives. The rates charged by municipal electric utilities are set by local governments, while the rates of rural electric cooperatives are set by the Board of Directors acting on behalf of its members. However, the FPSC does have rate structure jurisdiction for municipal and cooperative electric utilities. Rate structure simply means that the rates set by municipals and rural electric cooperatives must be fairly divided among the customer classes (i.e., residential, commercial, industrial, etc.). The FPSC also has jurisdiction over all electric utilities in the areas of public safety, territorial boundaries, major power plant and transmission line need determinations, conservation, cogeneration, and power supply planning.

Wholesale Sales

In Florida, not all electric utilities generate all the electricity they sell to their retail customers. Many smaller municipal electric utilities, the rural electric cooperatives, and one small investor-owned utility in Florida purchase all or part of their customers' generation requirements from other utilities. They also purchase the transmission services necessary to move their purchased power from the power plants where the electricity is generated to the load centers where their retail customers reside. These partial requirements and full requirements purchases of generation and transmission services are one element of the wholesale market for electricity which has existed in Florida and the rest of the nation for some time.

The other element of the wholesale market is the interchange market. In the interchange market, utilities which would otherwise own and operate all their own generation may find it economical to purchase capacity and energy from generating units owned by other utilities. Purchases in the interchange market can take place on an hour-by-hour basis, on a short-term basis up to a year, or on a long-term basis for many years. The price, terms, and conditions associated with interchange purchases are either negotiated by the purchasing and selling utilities or determined by a formula tariff approved by the Federal Energy Regulatory Commission (FERC). Historically, the FPSC has encouraged generating utilities to pursue cost-effective purchased power alternatives. The revenues generated for the selling utility and the savings realized by the purchasing utility from these wholesale transactions flow back to the utility's retail customers through a cost recovery clause, resulting in reduced electric bills.

The FERC regulates the rates, terms, and conditions of wholesale energy sales and the transmission services necessary to accomplish these sales. In the past, there has been a bright line between the FERC's jurisdiction over wholesale sales and wholesale transmission and the States' jurisdiction over retail sales and retail transmission. Recently, however, certain Federal legislation and actions by the FERC have clouded the distinction between this Federal and State jurisdiction. This growing overlap between State and Federal jurisdiction will be discussed within this report.

CHAPTER TWO
WHOLESALE COMPETITION

Background

In the early years of its development, the electric industry was composed of individual electric utilities that served isolated industrial customers and local community lighting loads. Low voltage transmission was used to access individual industrial customers and community load centers. Utilities were not interconnected with each other, and each had to provide their own generating resources necessary to serve their customers. As advances were made in the development and operation of high voltage transmission technology, more and more utility systems found it advantageous to interconnect their systems.

At first, utilities interconnected to increase reliability. With transmission interconnections, utilities were able to rely on emergency generating assistance from neighboring utilities during major generating unit outages. Because of the enhanced reliability gained by these mutual assistance agreements, the need to maintain surplus reserve generating capacity for each utility was reduced. This reduced each utility's costs of providing reliable service. From these early beginnings, competition in the wholesale supply of generation emerged.

Wholesale Market in Florida

A. 10

Prior to 1980, peninsular Florida had limited transmission interconnections to the rest of the nation. At that time, the interconnections consisted of a few 230,000 volt and 138,000 volt transmission interties at the Florida/Georgia boundary. Together, peninsular Florida utilities could import a maximum of 400 MW of generation. In essence, peninsular Florida was an electrical island. Because of these weak interstate interties, the wholesale market in Florida consisted primarily of partial requirements and full requirements supply arrangements between peninsular Florida generating and non-generating utilities and, to a lesser degree, purchased power interchanges between peninsular Florida generating utilities

During the oil embargo of the 1970's, Florida's utilities were especially hard hit. Oil was the dominant fuel for electric power generation. As prices soared at the gas pump, so did customers' electric bills. Also, peninsular Florida utilities experienced several bulk power interruptions resulting in rotating customer blackouts. These interruptions were caused when recently constructed nuclear units in the state experienced forced outages. Because of their large size, an unplanned outage of one of these nuclear units would cause significant degradation in the quality of the power supplied by the state's bulk power grid (voltage and frequency decline). These declines in frequency would cause the weak tielines between peninsular Florida and the Southern Company to open, thereby aggravating the problem and increasing the magnitude of customer blackouts. In response to these concerns, the FPSC worked with the peninsular Florida utilities to investigate the feasibility and cost-effectiveness of strengthening the transmission interties between peninsular Florida and the Southern Company. As a result, certain peninsular Florida utilities decided to construct two 500,000 volt transmission lines interconnecting peninsular Florida with the Southern Company. These lines increased the maximum transmission import capability into peninsular Florida to its present level of 3600 MW. The FPSC allowed special cost recovery treatment for the construction of these lines.

With the increased ability to import generation into Florida, peninsular Florida utilities entered into purchased power contracts for "coal-by-wire" from the Southern Company. Both the Florida utilities and the utilities comprising the Southern Company benefited from these contracts. The members of the Southern Company were able to more efficiently utilize their existing coal-fired generation. Peninsular Florida's ratepayers enjoyed increased reliability and lower fuel costs.

Another FPSC action which has facilitated the development of the wholesale market in Florida was the creation of the Florida Energy Broker. The Energy Broker was developed to facilitate short-term economy sales between the state's electric utilities. The Energy Broker is a computerized system for marketing hourly non-firm electric energy. Every hour, the Energy Broker matches potential sellers and buyers and results in a benefit to the ratepayers of both utilities. To encourage use of the Energy Broker, an incentive mechanism was created by the FPSC for investor-owned utilities, in which they were allowed to retain 20 percent of the profit made on Energy Broker sales. In 1995, the Energy Broker allowed membership by entities other than traditional Florida utilities, including certain non-utility generators, known as Exempt Wholesale Generators, and power marketers. Since the inception of the Florida Energy Broker in 1978, total savings in energy cost have exceeded $750 million.

While the Energy Broker became an important catalyst in the development of the wholesale market in Florida, today most wholesale sales are made outside the Energy Broker system. Currently, wholesale sales in Florida run the gamut from short-term non-firm sales to long-term firm contracts lasting several years. Most economy transactions have migrated from the Energy Broker system to more flexible separately negotiated contracts. However, wholesale sales in Florida continue to be a relatively small portion of investor-owned utilities' sales and are predominantly conducted between Florida's utilities. The table below displays the percentage of 1998 operating revenues by type of wholesale sale for each of the three major peninsular Florida investor-owned utilities. As shown, the percentage of operating revenues derived from wholesale transactions is small relative to total revenues, with the bulk of wholesale revenue derived from full requirements, long-term wholesale sales.

Percent of 1998 Operating Revenues by Type of Wholesale Sale

	Energy Broker Sales	**Non-Broker Opportunity Sales**	**Long-Term Wholesale Sales**
Florida Power Company	0.12%	1.63%	6.17%
Florida Power & Light Corporation	0.08%	1.90%	1.31%
Tampa Electric Company	1.66%	0.21%	7.26%

Federal Legislation - Public Utilities Regulatory Policy Act

Many industry analysts attribute the beginning of increased wholesale competition to Congress' enactment of the Public Utilities Regulatory Policy Act of 1978 (PURPA). PURPA required electric utilities to purchase capacity and energy from qualifying cogeneration and small power production facilities, known as Qualifying Facilities (QFs). In implementing PURPA, the FERC required utilities to pay QFs their "full avoided cost," that is, the cost the utility would have incurred to construct the generation itself.

PURPA served as a catalyst to encourage the development of lower cost natural gas-fired generating technology. This new technology, known as a combined cycle unit, employs steam recovery boilers to recover waste heat exhausted from a conventional combustion turbine generating unit (similar to a jet engine) to produce additional electricity. Combined cycle units substantially increase fuel efficiency. They can be certified and constructed in a relatively short period of time at a fraction of the cost of building conventional fossil steam generation. These units also provide planning and operating flexibility because they can be constructed in a variety of modular sizes and operate over a wide range of load conditions. Combined cycle units also use less water and emit fewer air pollutants than other generation technologies. As a result of these technological gains in natural gas-fired generation and the current low cost of natural gas, the conventional view that generation is best provided by a regulated monopoly utility has been called into question.

Federal Legislation - Energy Policy Act of 1992

The Energy Policy Act of 1992 (EPACT) gave further impetus to wholesale competition in the electric industry by reducing the regulatory requirements for certain wholesale electric providers, known as Exempt Wholesale Generators (EWGs) or merchant plants. EWGs are entities that own or operate a generating facility strictly for wholesale energy sales. Prior to EPACT, any multi-state holding company entity which generated electric power was subject to the Public Utilities Holding Company Act of 1935 (PUHCA). This required filing with the Securities and Exchange Commission and various other regulatory requirements. These requirements made it difficult for affiliated entities of multi-state holding companies seeking to enter the generation market, as well as electric utilities seeking to create affiliate companies, to invest in and develop new sources of generation. EPACT encouraged the entry of new wholesale energy providers by exempting EWGs from the requirements of PUHCA. Also, EPACT authorized the FERC to allow certain EWGs to sell electricity in the wholesale marketplace at market prices, rather than the conventional cost-based rates required of monopoly electric utilities.

The rates charged by EWGs are generally set by the market. That is, if the FERC believes an EWG does not have excess market influence, the EWG can sell excess electricity at whatever price the market will bear. Unless specific contracts exist, load serving entities have the option, but are not required, to purchase electricity from EWGs.

EWGs/Merchant Plants in Florida

Hardee Power Station

The first EWG in Florida was the Hardee Power Station, a joint project between TECO Power Services, an affiliate of Tampa Electric Company (TECO), and Seminole Electric Cooperative. The unit is a 240 MW natural gas-fired combined cycle unit. The output of the unit is shared between TECO and Seminole for their respective retail customers' needs. The need for Hardee Power Station was approved by the FPSC on December 22, 1989 (Order No. 22335).Because TECO Power Services is an affiliate of TECO, a regulated investor-owned utility, the FERC initially decided that the rates charged for the plant's output should be cost-based. TECO petitioned FERC's ruling, contending that it does not have sufficient market power to adversely influence wholesale market rates in Florida. TECO has recently received the FERC's approval to charge market-based rates.

Duke New Smyrna

On March 4, 1999, the FPSC granted the determination of need for a 514 MW electrical power plant in Volusia County. The project, jointly requested by the Utilities Commission, City of New Smyrna Beach, and Duke Energy New Smyrna Beach Power Company Ltd., L.L.P. (Duke New Smyrna), was found to be needed and in the best interests of electric customers in Florida.

Based on the hearing record, 30 MWs from the project is needed by the City of New Smyrna Beach to partially replace 83 MWs of existing capacity contracts which will expire between September, 1999 and 2004. The price at which Duke New Smyrna has offered to sell the City these 30 MWs of replacement power is significantly less than what the City's retail customers are currently paying for purchased power. The City estimates that its energy costs will be reduced by $3.1 million per year net present value for the first ten years, and approximately $7.75 million total net present value for the following ten years, for a total estimated savings of approximately $39 million net present value. Also, the project will use approximately 2 million gallons of reclaimed waste water provided by the City that would otherwise be discharged into the Indian River. The low-cost power to be provided to the City is contingent upon the entire project being constructed. As such, if the project is not constructed, the City will have to construct or contract for higher cost capacity and energy.

The hearing record indicated that the availability and sale of the remaining 484 MW of capacity to other peninsular Florida utilities will enhance the reliability of the peninsular Florida electric grid and put downward pressure on wholesale power costs. Duke New Smyrna has elected to construct the 514 MW project as a merchant plant and received EWG status from the FERC. Other than the contract for 30 MWs to the City of New Smyrna Beach, Duke has decided to build the power plant without first entering into any long-term wholesale sales contracts with other Florida utilities. Duke asserts that the continued growth in electricity demand in Florida, coupled with the ability to economically displace high cost oil generation, will create market demand for the project's output. The direct risks associated with the construction of the project will be borne by Duke New Smyrna. No utility or its retail ratepayers will be obligated to purchase from the project. Rather, sales from the project will be made either on an as-needed, as-available basis or subject to negotiated contracts. As such, the Duke New Smyrna project presents another alternative for existing retail serving utilities, without putting Florida ratepayers at risk for the costs of the facility. Florida utilities will only purchase power from Duke New Smyrna if it proves to be the lowest cost alternative at the time a contract is entered.

In addition to these benefits to Florida's electric ratepayers, the hearing record indicated that the Duke New Smyrna Project will also provide other socio-economic benefits to the state. At a construction cost of approximately $160 million, the Duke New Smyrna Project will significantly add to the property tax base of Volusia County and other taxing districts. It is estimated that the project will provide $4.2 million annually to local taxing agencies. Peak employment during the construction of the project is expected to be 250 persons. Once construction is completed, approximately 20 permanent positions will be needed to operate the power plant with a total annual payroll of approximately $1 million.

The Commission's final order approving the need for the Duke New Smyrna project was issued on March 22, 1999. The major investor-owned utilities in peninsular Florida, FPL, FPC, and TECO, have appealed the Commission's decision to the Florida Supreme Court. These investor-owned utilities oppose the project because they contend that Duke New Smyrna should be required to enter into wholesale contracts with a retail-serving utility before construction of the power plant should be approved. They argue that EWGs such as Duke New Smyrna are not proper applicants for a determination of need by the FPSC. The investor-owned utilities also contend that only utilities with retail customers can (1) apply for a determination of need, or (2) sponsor the application for a determination of need by an EWG with which they have entered a long-term firm wholesale contract. The Florida Supreme Court is expected to hear oral arguments on the case by October, 1999 with a final decision expected by the end of the year. The final decision to approve the construction of the project has been postponed by the Governor and Cabinet, who make up the Power Plant Siting Board, until the Florida Supreme Court makes its ruling.

Constellation Power - Oleander Power Plant

Constellation Power, an unregulated subsidiary of Baltimore Gas and Electric Company, has announced its plans to construct a 950 MW natural gas-fired peaking power plant in Brevard County. The project will consist of five 190 MW gas turbines. The proposed plant will be an EWG merchant plant, selling capacity and energy through the wholesale electric market to Florida's utilities. Because the plant will consist of combustion turbines with no steam generation, it is not subject to the Power Plant Siting Act, and therefore is not required to obtain a determination of need from the FPSC. Applications have been filed for local environmental permitting. The project is currently being evaluated by the Florida Department of Environmental Protection for air and water permits. The anticipated in-service date of the plant is January, 2001.

El Paso Power Services Company

Florida Power Corporation (FPC) and El Paso Power Services Company (El Paso) have recently agreed to restructure certain existing cogeneration contracts. El Paso will acquire three existing contracts for the sale of capacity and energy to FPC. These three contracts were originally entered into in 1991 between FPC and Royster Phosphates, Inc. (Royster), Mulberry Energy Company (Mulberry), and CFR Bio-gen Corporation (CFR Bio-gen). In total, these contracts represent 184 MW of capacity and associated energy committed to be sold to FPC. Generation to supply these contracts is provided from two cogeneration facilities: (1) the natural gas-fired combined cycle Mulberry facility in Polk County, and (2) the natural gas-fired combined cycle Orange facility in Polk County.

Under the terms of the assignment, capacity payments made by FPC will be discounted for the remaining term of each contract, resulting in savings in excess of $100 million net present value. Associated energy savings are estimated to be approximately $15 million net present value. The agreement also provides that El Paso will waive its rights under PURPA to require FPC to purchase the capacity and energy from the two cogeneration facilities serving the contracts. El Paso will not be required to maintain the Mulberry and Orange units as QFs under PURPA. Rather, the Mulberry and Orange units will be operated as EWG merchant plants. FPC will continue to have first call on capacity and energy from El Paso up to the capacity commitments contained in the original contracts. However, when FPC is not using their full capacity commitment, El Paso is free to sell the energy from the Mulberry and Orange units on the wholesale market.

Reliant Energy

Reliant Energy (Reliant), a Texas based energy provider, has been pursuing the purchase of the Indian River Power Plant from the Orlando Utilities Commission (OUC). The Indian River Power Plant consists of three natural gas/oil-fired steam generating units which were originally built in 1960, 1964, and 1974. The total installed capacity of these three generating units is 608 MW. Initially, Reliant plans to sell capacity and energy from the units back to OUC. These sales to OUC would ramp down over a period of about four years. Capacity and energy not sold to OUC will be sold as EWG merchant capacity and energy on the wholesale market.

In a separate deal, Reliant has also been exploring the construction of a new EWG merchant peaking plant, named Reliant Energy Osceola, near Kissimmee, Florida. The proposed project would consist of approximately 460 MW of natural gas-fired combustion turbines with an in-service date of 2001. Reliant intends to sell approximately 300 MW to Seminole Electric Cooperative for an initial term of 5 years and 100 MW on the wholesale market. At the end of the proposed wholesale contract with Seminole, the full 460 MW capacity of the plant would be sold on the wholesale market.

Okeechobee Generating Company

Okeechobee Generating Company (Okeechobee), a wholly-owned subsidiary of California based Pacific Gas & Electric (PG&E), has recently filed an application for EWG status with the FERC. Okeechobee plans to construct a 500 MW class natural gas-fired, combined cycle power plant in Okeechobee County, Florida. The project will be interconnected with FPL's transmission facilities in the area and is expected to be placed in service in the Spring of 2003.

Merchant Plants in Other States

There are currently 10 states with fully operational merchant plants. These states include: California, Colorado, Connecticut, Massachusetts, Maine, New Mexico, New York, Texas, West Virginia and Wisconsin. Thirty-two additional states have merchant plants under various stages of development. Appendix A contains a map displaying the status of merchant plant development in each state.

A summary table showing the status of merchant plant capacity development in the United states, as of May 31, 1999, is given below.[(1)]

Stage of Development	Merchant Capacity
Currently Operational	13,349 MW
Under Construction or Development	14,886 MW
Reported Plans for Merchant Plants	56,021 MW
Total	84,256 MW

Over 80 percent of the 13,349 MW of U.S. installed merchant plant capacity is located in California. Most of these plants are not newly constructed plants, but existing plants that were previously owned by utilities and sold through divestiture. Appendix B contains further information on the location of these currently operational plants.

An additional 14,886 MW of merchant capacity is under construction or development. This includes 6,558 MW of capacity under construction in: Connecticut, Illinois, Massachusetts, Maine, Mississippi, Missouri, Nevada, Rhode Island and Texas. In addition, more than 8,000 MW of merchant capacity is under development. The plants characterized as under development have met or partially met the necessary siting requirements, and the completion of these projects is relatively certain. Appendix C provides further information on these plants.

There are also plans reported for 56,021 MW of additional merchant capacity. While these plants may have partially met the necessary siting requirements, completion is less certain than for plants under development. Appendix D contains further information on the location of these plants.

CHAPTER THREE
TRANSMISSION

FERC Orders No. 888 & 889

Transmission is the bridge between electric generation and end-use customers. An efficient wholesale generation market cannot exist without an adequate and efficiently operated wholesale transmission system. Therefore, in addition to creating a new class of EWG merchant plants to foster competition in the wholesale generation of electricity, the Energy Policy Act of 1992 (EPACT) also addressed the FERC's authority to pursue open access for wholesale transmission.

In 1996, the FERC issued Orders No. 888 and 889 to establish rules governing a more open wholesale transmission market. Order No. 888 required all transmission-owning public utilities to make their transmission facilities available to any user at a fair price and in a non-discriminatory manner. In order to achieve these goals, Order No. 888 required all public utilities to "functionally unbundle" their wholesale power services. Functional unbundling entails requiring transmission owning utilities to: (1) take transmission services under the same tariff rates, terms, and conditions as do others; (2) state separate rates for wholesale generation, transmission, and ancillary services; and (3) rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.

Order No. 889 required that all public utilities establish or participate in an Open Access Same-Time Information System (OASIS). It also established standards of conduct designed to prevent employees of a public utility engaged in wholesale power marketing functions from obtaining preferential access to pertinent transmission system information. An OASIS is an Internet based transmission service reservation system where participating utilities can: (1) post information about transmission capacity available for purchase by transmission customers, (2) post information about the status of the transmission system, and (3) provide a means for transmission customers to request transmission service over defined transmission paths. Order No. 889 also established the type, frequency and format of the transmission-related information which must be posted on OASIS.

Finally, in order to extend the provisions of Orders No. 888 and 889 to all transmission-owning systems, FERC also required that non-FERC regulated utilities (e.g., municipal electric utilities and rural electric cooperatives) must adopt reciprocating and conforming transmission access policies before being able to take service under a FERC regulated public utility tariff.

Impact on Florida

Order No. 888 has blurred the jurisdictional lines between state and federal regulation of wholesale and retail transmission. Prior to FERC Order No. 888, there was a clearer line of demarcation between state and federal jurisdiction. Under the Federal Power Act (FPA), the FERC was authorized to regulate the rates, terms, and conditions of wholesale energy sales and transmission in interstate commerce. In defining the FERC's jurisdiction over wholesale transmission, the FPA was careful not to usurp existing state jurisdiction over retail transmission service. Section 212 of the FPA states:

(g) Prohibition On Orders Inconsistent With Retail Marketing Areas. -- No order may be issued under this Act which is inconsistent with any state law which governs the retail marketing areas of electric utilities.

This section of the FPA enunciates the Congressional intent to preserve the status quo with regard to federal and state jurisdictions over retail services. In Order No. 888, however, the FERC extended its jurisdiction into several areas that have historically been the province of the states.<

One area in which the FERC has asserted jurisdiction is the regulation of unbundled retail transmission when a state orders retail access. Unbundling means the separation of the rates, terms, and conditions for generation, transmission, distribution, and other retail services provided by an electric utility on customer bills. If a state decides to allow retail competition, unbundling is a prerequisite. The FERC contends that if a state requires its electric utilities to provide retail competition for generation services, the state will relinquish its ratemaking authority over the transmission component of the unbundled rate. The FERC has also asserted jurisdiction over the recovery of costs, if any, stranded by state-directed or voluntary retail wheeling when a state commission lacks authority to address the issue or when a retail customer converts to a wholesale customer (municipalization).

While the FERC has expressed its intent to provide deference to the states on issues pertaining to stranded cost recovery and the transition from bundled to unbundled rates, it is not clear what voice state regulators will truly have at the FERC. Further, in states such as Florida where the Legislature has established a clear and pervasive state regulatory scheme, it makes little sense for the FERC to preempt the state's jurisdiction. Costs for facilities that are currently under the jurisdiction of state authorities do not suddenly become the FERC's jurisdiction because retail wheeling is instituted. Transmission lines still perform the same function of bringing power to the retail customer located within the territory of a state regulated utility. The states are in a much better position to judge the extent and value of assets which may become stranded as a result of retail wheeling. In most cases, the states have approved both the construction and the cost recovery for these facilities under bundled rate structures. In light of these concerns, on April 11, 1997, the FPSC filed a petition in the United states Court of Appeals challenging these elements of Order No. 888. The FPSC was joined in this appeal by the state commissions of New York, Arkansas, Idaho, North Carolina, Wyoming, Illinois, and Washington and the National Association of Regulatory Utility Commissioners (NARUC). Briefs have been filed in the case but the U.S. Court of Appeals has not yet acted.

Regional Transmission Organizations

On May 13, 1999, the FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to amend its regulations under the Federal Power Act (FPA) to facilitate the formation of Regional Transmission Organizations (RTOs). Perhaps because the FERC has not seen all the changes it envisioned from Order No. 888, it has begun looking into establishing RTOs as the next step toward ensuring fair and non-discriminatory access to transmission services and ancillary services for all users of the transmission system.

An RTO would perform all the functions currently performed by individual transmission owning utilities. The difference would be that an RTO would plan, construct, maintain, and operate all the transmission facilities within a entire region. As such, an RTO, rather than the current transmission owners, would exercise independent control over the development and operation of the transmission system. The transmission owners would receive compensation for their existing transmission investments based on the usage of their transmission lines. FERC looks at the formation of RTO's as a way to mitigate vertical market power associated with generators controlling access to the transmission system.

At the moment, the FERC's authority to mandate RTO's is not clear. Nevertheless, the FERC has proposed rulemaking to adopt certain minimum characteristics and functions for a transmission entity to qualify as an RTO. FERC's proposed characteristics of an RTO, as outlined in the FERC NOPR, are provided in Appendix E. The transmission organizations which have been approved by FERC are contained in Appendix F.

On July 30, 1999, the FPSC submitted comments on the FERC's proposed rules concerning RTOs. The FPSC has encouraged the FERC to continue to maintain a flexible policy toward the formation of RTOs. The FPSC believes that the FERC lacks the authority to mandate a one-size-fits-all solution and must proceed on a case-by-case basis to address specific transmission problems. This can best be accomplished by working with the states to develop regional approaches that achieve regional market consensus and are endorsed by state regulators.

Florida Transmission Issues

In Florida, the FPSC has broad authority under Sections 366.04(2)(c), and 366.05(8), Florida Statutes, over transmission grid-related matters (the Grid Bill). The FPSC is vested with jurisdiction over the planning, development, and maintenance of a coordinated electric grid throughout Florida. This jurisdiction includes establishing the provision for sharing of energy reserves of all electric utilities in the state for the establishment of conservation and reliability within a coordinated grid. To the extent that a deficiency is determined to exist in the Florida grid, the FPSC is authorized, after appropriate evidentiary proceedings, to order utilities to correct deficiencies and to allocate the costs of such improvements on the basis of benefits received.

In the enforcement of these responsibilities, each electric utility in Florida is required pursuant to Chapter 186, Florida Statutes, to file Ten Year Site Plans annually with the FPSC. These plans identify the utilities' forecasts of system load, demand-side conservation achievements, and plans for generation and transmission additions required to serve the electrical requirements of Florida's customers. These plans are reviewed by the Commission and a report of their suitability from a planning perspective is provided to the Florida Legislature. Ultimately, as a utility's plans come to fruition with the construction of additional bulk power facilities, the FPSC must determine and approve the need for major new generation and transmission facility additions pursuant to the Florida Electrical Power Plant Siting and Transmission Line Siting Acts. Under the Grid Bill, the FPSC also has the authority to initiate a need determination on its own motion. The need determination process is followed by environmental and land use review by the appropriate other Florida agencies. Finally, site certification is approved, or denied, by the Governor and Cabinet sitting as the Siting Board. The FPSC has a considerable history of oversight activities in its implementation of the Grid Bill and the Electrical Power Plant and Transmission Line Siting Acts, which have resulted in significant increased efficiency of Florida's electric grid and savings that have benefitted the state's electric consumers.

Pursuant to the FPSC's jurisdiction over grid related matters, work continues in Florida to explore Florida-specific transmission issues. The FPSC has held a series of public workshops in 1999, to solicit views of the Florida electric utilities and other interested parties regarding RTO formation. Three proposals have emerged from these workshops: (1) Independent Transmission Administrator (ITA) Proposal, (2) Regional Transmission Solution (RTS) Proposal, and (3) Public Not-for-Profit Transco Proposal. These proposals are summarized below.

ITA Proposal

The ITA proposal was developed and submitted by the following entities:

- Constellation Power Development, Inc.
- Duke Energy New Smyrna Beach Power Company LTD., L.L.P.
- Florida Municipal Power Agency
- Orlando Utilities Commission
- Reliant Energy, Inc.
- Seminole Electric Cooperative, Inc.
- Tampa Electric Company
- U.S. Generating Company

This proposal provides that the ITA would oversee and administer the planning and operation of peninsular Florida transmission grid facilities. The ITA would administer an Open Access Transmission Tariff for peninsular Florida that would provide fair, equitable, and non-discriminatory access and use by all eligible users. The current functions of the Florida Reliability Coordinating Council (FRCC) would be merged with the ITA, and efforts would be made to use the existing FRCC infrastructure under the ITA governance structure. The FRCC is currently one of ten reliability councils that make up the North American Electric Reliability Council (NERC). Each of these entities is responsible for ensuring and enhancing the reliability and adequacy of bulk power electricity supply in well-defined geographical and electrical regions in North America. The FRCC oversees the reliability of the region of Florida that lies east of the Appalachicola River, commonly referred to as peninsular Florida.

The ITA would not own or profit from any generation, transmission, or distribution facilities and would not engage in the purchase or sale of electric energy or capacity. The business affairs of the ITA would be governed by a "stakeholder" Board of Directors with fifteen members representing investor-owned utilities, municipal utilities, cooperative utilities, power marketers and independent power producers. Each of the voting members of the Board of Directors would be given one vote, and any action would require approval of a 2/3 majority of voting Board Members.

RTS Proposal

The proposal put forward by Florida Power and Light Company and Florida Power Corporation, the RTS Proposal, is <u>not</u> an RTO proposal. Their proposal would not require FERC approval. At this point in time, only FPL and FPC support this proposal.

The RTS proposal relies on the FPSC to provide independent oversight and governance over transmission planning and operations. The FPSC would resolve disputes with respect to the need for new transmission facilities or new interconnections. Under the proposal, an FPSC Security Coordinator Representative would be hired by the FPSC, and located on a permanent basis at the Control Center that performs the Security Coordinator function. The Security Coordinator Representative would be responsible for monitoring transmission services, auditing the Security Coordinator on a regular basis, and conducting unplanned audits in response to specific complaints of a transmission customer.

The FRCC would remain a reliability-only organization with a voting structure that will ultimately be established by nationwide criteria now being developed. A streamlined FPSC dispute resolution process which would be binding on all parties, would be created through the rulemaking process. FPL and FPC believe that there presently is sufficient authority under the Florida Grid Bill for the FPSC to perform the contemplated activities.

Under the RTS proposal, FPL and FPC also propose to discount transmission service to mitigate "pancaking" of transmission rates within peninsular Florida. These discounted rates would apply to new transactions that occur on or after October 1, 1999.

Public Not-for-Profit Transco Proposal

Jacksonville Electric Authority proposes a non-profit, publicly owned, transmission company (transco) to own and operate the transmission grid in peninsular Florida. The chief benefit of this proposal, according to JEA, is that a robust electric generation market could be facilitated without the accompanying fiduciary obligations to stockholders to maximize return on investment.

The JEA proposal would require substantial amendment to existing law for implementation. One of the difficult issues that would have to be determined, probably ultimately in the courts, is the compensation to be paid to the current owners of the transmission facilities.

Gainesville Regional Utilities (GRU) also filed a proposal supporting a not-for-profit transmission company. Neither JEA nor GRU provided details on how the transco would be developed. A spokesperson representing the City of Tallahassee also spoke favorably of the not-for-profit transco concept, but did not file written comments.

The FPSC will continue to pursue in-state solutions to transmission issues. To this end, an additional Commission workshop will be held to further discuss the three RTO proposals summarized above.

CHAPTER FOUR
RETAIL COMPETITION

Electric Utility Restructuring

Electric restructuring generally describes a movement from regulated monopoly electric utility services to market-based competitive electric services. A lot of different terms are being used to describe what is happening at the federal level and in other states in the transition to electric competition. Phrases such as restructuring, deregulation, competition, retail wheeling, retail access, and customer choice have all been used to describe a broad-based, national movement away from the traditional rate base regulation of vertically integrated, monopoly public utilities. Regardless of the name attached, what is generally being discussed is the breaking out of generation services into a separate, more competitive segment of the industry while transmission and distribution remain largely regulated monopoly services. These 'unbundled' services would each be priced separately on a customer's bill.

What is Happening in Other States

A number of states are exploring retail restructuring as a way of achieving lower rates and greater customer satisfaction. Higher than average electric rates appear to be the primary driver in these states. Most states experimenting with retail restructuring are using a phase-in system to allow some percentage of retail customers to select from alternative electric generation providers over a window of several years. In a few states, such as California and Massachusetts, all customers will be allowed to choose their generation supplier at once on a date certain. Transmission and distribution services (poles, lines, substations, meters, and monthly billing) will continue to be provided by the regulated utility. Only the generation portion of electric service will be subject to customer choice.

California, New Hampshire, New York, and Massachusetts were among the first states to move toward retail access. The average residential rate in these states is approximately 12 cents per kilowatt-hour (KWH). Because of these high rates, economic development appears to have suffered with the loss of jobs and the relocation of industry. In many high-cost states, large commercial and industrial customers have been the most active in encouraging a move toward competition. At present, a total of twenty-two states have enacted legislation or implemented regulations requiring retail restructuring, although the legal basis is being challenged in several states.

What is Happening in Florida

Florida's electric utility industry has provided very reliable service at competitive prices. On average, Florida's rates have been relatively stable for more than a decade. Adjusting for inflation, the price of electricity in Florida has actually been declining. Compared to prices around the nation, Florida's electric rates continue to be around the national average (approximately 7.2 cents per KWH statewide average). This is particularly commendable given Florida's unique peninsular geography. Florida has little low-cost hydropower, and all our generating fuels must be transported very long distances by rail, pipeline, or water. Also, unlike many other states, Florida's electrical grid is only tied to other utilities in one direction, to the north through the Southern Company. This limits the state's ability to rely on out-of-state purchases.

During the summer of 1996, the FPSC contracted with the University of Florida's Public Utilities Research Center for a series of staff training seminars. Three public forums were held in which experts from around the country addressed many outstanding issues surrounding retail restructuring. These public forums experienced a good turnout from participants representing views from all sides of the issues. Following these training sessions, the FPSC established an in-house team of staff members to continue to monitor and discuss restructuring issues as they develop.

In the national arena, the FPSC has intervened in the FERC's open transmission access docket and has filed comments advocating the preservation of state jurisdiction over transmission and distribution costs currently being paid by retail customers. The FPSC has also been an active participant in the National Association of Regulatory Commissioners (NARUC). Commissioner Susan Clark currently serves as the chair of the NARUC Electricity Committee. This committee plays a pivotal role in developing policy positions on restructuring matters affecting state regulation.

Who is Likely to Gain from Retail Competition

In Florida, as with the rest of the nation, industrial and large commercial customers have been the most vocal advocates of electric restructuring. These customers appear to have the most to gain from restructuring, since their size and business experience give them the ability to negotiate for low-cost generation or to install self-service generation. They also appear to represent the primary market segment to which merchant plants, brokers, and other alternative generation suppliers would most likely target. Small-use residential and commercial customers are less likely to have meaningful alternative generation supply choices in a competitive market and may be left paying higher costs.

One of the primary reasons some states are pursuing retail competition is high electric rates. Florida's electric rates, which are around the national average, have been relatively stable in nominal terms for more than a decade, and when adjusted for inflation, have actually declined by 22 percent. Florida has long supported competition in the wholesale bulk power markets. Savings achieved from the purchase of economic wholesale power alternatives are spread to all electric ratepayers, not a select few. It remains unclear whether all Florida ratepayers would benefit from a mandate for retail competition. In many states that have adopted retail competition, actual program implementation is just now going forward. In some states, implementation has been delayed because of litigation over major issues such as stranded cost recovery.

During the 105th Congress, a number of bills addressing the restructuring of the electric utility industry were introduced. Several bills would have required states to implement retail competition by a date certain. While none of these bills was passed into law, Congress is currently addressing electric utility restructuring in the 106th Congress. The FPSC, in concert with the NARUC, has encouraged Congress to refrain from including a "date certain" mandate in any electric utility restructuring law. The states should be allowed the flexibility to determine if and when retail competition should be enacted and should be free to implement such retail competition in a way that benefits all electric utility customers, not just a select few.

Summary of Individual State Restructuring Activity

Arizona

The Arizona Corporation Commission (ACC) initially undertook restructuring on its own motion. In 1996, the ACC issued Order 59943 which was a broad blueprint for competition and established staff working groups to deal with specific issues. By December 31, 1997, all utilities subject to ACC jurisdiction (only investor-owned) were to propose for ACC review and approval a plan on how customers will be selected for participation in the competitive market prior to 2003. The investor-owned utilities challenged the ACC's authority, but were ultimately denied by the Arizona Supreme Court. Thereafter, both Arizona Public Service and Tucson Electric Power submitted settlement agreements. Finally, on December 1, 1998, the Arizona Supreme Court blocked approval of the negotiated settlements submitted by these utilities on procedural grounds. Intervenors in the process argued that insufficient time had been allocated for a fair evidentiary hearing. The ACC vacated its order and plans to conduct new hearings on stranded cost and unbundling. This will likely delay implementation by at least a year.

HB 2663 passed the legislature in May, 1998 and applies only to public power utilities. Retail access will continue on schedule for the state's largest public power utility, Salt River Project, with full competition planned no later than December 31, 2000. The legislature mandated that 20 percent of customers could begin to choose alternative retail suppliers by December 31, 1998. The public power utilities have great flexibility to collect stranded costs by way of a temporary surcharge on the distribution portion of the bills. Recovery must end by December, 2004, and participation is required in some type of regional transmission authority or ISO.

Arkansas

SB 791, signed in April, 1999, set the ground rules for retail competition in Arkansas. January 1, 2002 is the initial target date with delays permitted until June, 2003. Municipal and cooperative utilities have the option to open their service areas to competition. Transmission owning utilities must participate in some form of an independent system operation. Nonmitigable and prudently incurred stranded costs and transitional costs are allowed to be recovered, and up to 100 percent can be securitized with PSC approval. Such costs will be recovered by a customer transition charge, and quarterly reports showing the amount of recoverable balances must be provided to the PSC. Rates are to be frozen for three years for utilities seeking recovery of stranded costs.

The PSC must analyze the potential abuse of market power by utilities and new service providers. After appropriate evidentiary hearings, the PSC has broad discretion to adopt mitigation measures including divestiture of generating assets as a last resort. In addition, the PSC must adopt rules for affiliate transactions and use of company personnel across operating companies. Finally, the PSC is charged with adopting rules to address customer protection such as understandable bills, environmental disclosure, and anti-slamming provisions.

California

The California Public Utilities Commission (CPUC) became involved in electric restructuring as early as 1993 when it issued its first strategy for restructuring. In September, 1996, the California Legislature adopted most of the CPUC plans for restructuring and incorporated them into AB 1890. This law directed the CPUC to make retail access available to all customers by January 1, 1998. The legislature indicated its intent for the stakeholders in the process to negotiate the necessary changes to achieve a competitive retail environment. Publicly-owned electric utilities were encouraged to participate in a retail market. A rate freeze is required between 1998 and 2002 with residential and small commercial accounts entitled to a 10 percent rate reduction.

AB 1890 permits the recovery of stranded costs. The prescribed method to calculate the amount involves netting the negative value of all above market utility generation assets against the positive value of all below market utility owned generation assets. These costs were anticipated to largely be regulatory assets, nuclear assets, and purchased power contracts. Approved costs are permitted recovery through a competitive transition charge. Recovery will not extend beyond December, 2001 except for some transition-related and nuclear costs. Utilities are permitted to use securitization as one means to recover these above market costs.

With respect to market power issues, the act requires that an ISO be formed with a power exchange. The role of the power exchange is to provide an open and centralized auction for buyers and sellers to reveal their prices. In addition, utilities are expected to divest 50 percent of their gas-fired generation. Functional unbundling and rules for affiliate transactions are required. AB 1890 anticipates that billing and metering services will become competitive.

The Act establishes public benefit programs for low income assistance, energy efficiency, R&D programs, and to encourage renewables. Approximately $540 million will be collected over four years by a non-bypassable wires charge.

Early evidence indicates that a substantial amount of industrial load has changed providers. However, few residential customers have switched. Perhaps more notable, a number of energy service providers have developed a market niche selling power that is either partially or fully derived from renewable resources. This so called "green power," while more expensive than non-green power, appeals to some customers, who place a premium on purchasing these kinds of products.

Connecticut

Public Act 98-28, entitled "An Act Concerning Electric Restructuring," was signed on April 29, 1998. This is a detailed, comprehensive restructuring package that provides for full retail choice for all customers by July 1, 2000. Municipal utilities who choose to participate in retail access must open their markets to alternative service providers and auction off their generation assets. Utilities are not required to divest their plants in order to obtain stranded cost recovery. Although securitization is permitted, utilities must attempt to auction both fossil and nuclear plants if they want recovery of stranded costs. Minimum acceptable bids will be prepared by the Connecticut PUC, and the difference between bid and net book values becomes the basis for administratively determining stranded costs. Nuclear plants do not have to be sold or even to receive acceptable bids in order to be eligible to receive stranded cost recovery. A competition transition assessment (CTA) will be developed after netting any proceeds from above book value sales and sales of other company property. Recovery of the CTA will be through 2004.

All utilities must unbundle generation, but transmission and distribution assets may remain with an incumbent. It is anticipated that transmission assets will revert to an ISO. Extensive market structure provisions are included in the Act such as requiring distribution companies to remain providers of last resort, permitting customers to change suppliers once a year without charge, retaining existing consumer protection measures, and specifying standards that must be met before a customer can be switched to a new supplier. This is to prevent slamming. Codes of conduct and affiliate transaction guidelines will be developed by the PUC by January, 1999.

System benefit charges are addressed in the bill. Beginning January 2000, the PUC is to set charges to cover consumer education, low income energy conservation, nuclear decommissioning and fuel storage, worker protection, and payments to municipal governments. In addition, the bill specifies that electric suppliers must provide at least 0.5 percent of their power from renewables. This percentage increases to 6 percent by 2009. A 0.05 ¢/kWh charge is imposed for a Renewables Energy Investment Fund which increases to 0.1¢/kWh in 2004, and an additional 0.3 ¢/kWh charge is imposed for funding energy efficiency programs. Environmental disclosure will also be provided on billing statements.

Delaware

On March 31, 1999, Governor Carper signed HB 10 entitled the "Electric Utility Restructuring Act of 1999" which mandates a path for retail competition in Delaware. Delaware is served by a single investor-owned utility -- Delmarva Power & Light (now called Conectiv) and a single cooperative -- Delaware Electric Coop (DEC). The bill, like those in many other states, has a phased approach for retail access. The schedule for Conectiv is:

- peak loads greater than 1 MW can choose alternative suppliers by October 1, 1999
- peak loads greater than 300 KW can choose by January 15, 2000
- all others (including residential) will have choice by October 1, 2000

The bill calls for rate freezes for all of Conectiv's non-residential customers from October, 1999 to September, 2002. A 7.5 percent rate reduction will be granted to residential customers for the same period. These caps may be extended one additional year depending on changes to the fuel costs assumed in the rates. A system benefit charge of 0.0095 ¢/kWh is imposed on the IOU for low income assistance programs and an environmental incentive charge of 0.0178 ¢/kWh will also be charged.

Interestingly, while no formal stranded costs are allowed, Conectiv will be permitted to collect some $18 million in costs from industrial customers. Even more notable, HB 10 forbids the use of telemarketing by energy suppliers in Delaware.

With respect to market structure, the Delaware PUC will conduct an inquiry after October 1, 1999 to determine if market power abuse is occurring. Upon an appropriate finding and as a last resort, the PUC can order divestiture of the generating assets of Conectiv. After 2002, the PUC can open up metering and billing to competitors. Conectiv will remain the supplier of last resort to customers who do not choose an alternative supplier, and their rates will be based on "market prices" as determined by the PUC.

The phase-in schedule for DEC is essentially lagged six months with full competition delayed until April 1, 2001. All cooperative utility customers will be entitled to a rate freeze for the period 1998 to 2005. The PUC will administratively determine what stranded costs will be recoverable, and there is no environmental or public benefits charges imposed on the cooperative. However, quarterly generation fuel disclosure information is to be printed on the bills for both types of utilities.

Illinois

The source for most of Illinois' electric restructuring activity is the "Electric Choice and Rate Relief Act" (HB 362), which was signed into law in December 1997. HB 362 mandates a four stage direct access plan in as follows:

1. Stage 1: By 10/1/1999 all of the following customer types are eligible:
   - 1) all customers with individuals loads > 4000 kW;
   - 2) all commercial retail customers with 10 or more separate locations which aggregate to > 9,500 kW; and
   - 3) 1/3 of the customers in each non-residential retail customer class (based on lottery).
2. Stage 2: By 10/1/2000, all governmental customers with > 9,500 kW are eligible.
3. Stage 3: By 12/31/2000, all remaining non-residential retail customers are eligible.
4. Stage 4: By 5/1/2002, all residential retail customers are eligible.

Utilities are permitted partial recovery of stranded costs through transition charges based on "lost revenues." An index of market prices is used as part of a very complex formula for determining the transition charge. The amount of the recovered charge is equal to the value of electricity sold under a tariffed, non-competitive rate minus the so-called competitive or market rate. This difference must be offset by credits gained by the utility for any revenues attributable to delivery charges, newly obtained revenues for being a service provider and the value of avoided energy and capacity that the utility freed up by not having to serve that customer. Finally, a "migration factor" is applied to reduce the lost revenue that begins at 6 percent of 1996 base rates and increases to 10 percent of 1996 base rates by 2006. This factor is simply an estimate of what the utility would be expected to earn in the new competitive environment and is applied against lost revenues even if no new revenues materialize. Securitization is permitted, but 80 percent of the returns on the securitized funds must be used to refinance or retire fuel-related obligations. The utility has until 2006 to collect any stranded costs, but this can be extended until 2008 with PUC permission.

Divestiture is not required, but functional unbundling of generation, transmission, and distribution is mandated by HB 362. Utilities do have broad authority to divest, lease, or transfer assets during the transition period into a fully competitive market. The utilities are encouraged to join a regional ISO to further mitigate market power, but failure to do so will lead to the formation of an Illinois ISO. Finally, the PUC has the discretion to issue and require codes of conduct and standards for affiliate transactions.

Nonresidential rates are frozen through 2004 at the 1996 levels. Residential customers of ComEd and Illinois Power will receive a 15 percent rate reduction in 1998 followed by 5 percent more in 2002. For other Illinois utilities, lower rate reductions are mandated in the bill.

Finally, public benefit charges will be collected to encourage the use of renewable and clean coal-generated energy. Disclosure of generating fuels will be required on all bills.

Maine

In July, 1995, the Maine Legislature directed the Maine Public Utilities Commission (MPUC) to devise a plan for the Legislature to consider which would achieve retail competition in the electricity market. The final report and plan were presented on December 31, 1996. On May 29, 1997, the Governor signed into law LD 1804, "An Act to Restructure the state's Electric Industry" (the Act). It provides for full retail competition to begin on March 1, 2000. It directs the MPUC to conduct rulemaking on several issues that must be addressed to implement retail access. Between the Fall of 1997 and the Fall of 1999, the MPUC will conduct 13 rulemakings on subjects such as unbundling, metering, consumer education, and renewable resources.

Under the provisions of the Act, all consumers of electricity will have the right to purchase generation services directly from competitive providers beginning on March 1, 2000. Beginning March 1, 2002, the provision of metering and billing services will be subject to competition. The MPUC is empowered to establish an earlier date for the provision of these services by rule, but the date can be no earlier than March 1, 2000.

Prior to October 1, 1999, the MPUC will complete an adjudicatory proceeding to address the design of transmission and distribution rates to recover stranded costs, transmission and distribution costs, decommissioning expenses for nuclear units, and any other charge required by law.

Before the start of retail access, the MPUC will estimate the stranded costs for each utility, and use those estimates to set a stranded cost charge to be collected by the transmission and distribution utilities when retail access begins. This will be done in the MPUC's adjudicatory proceedings ending by July 1, 1999. In 2003 and every three years after that, the Commission will correct any substantial inaccuracies in the stranded cost estimates except for those stranded costs associated with divested generation assets, and change the transmission a distribution charge accordingly. The Commission may also adjust the charge at any other time. Any changes to the stranded cost charge are to be made on a prospective basis and cannot address past inaccuracies in stranded cost estimates. In setting the stranded cost charges, the MPUC may not shift recovery of stranded costs among customer classes in a manner inconsistent with existing law.

The Act requires that on or before March 1, 2000, investor-owned electric utilities must divest all generation assets and generation-related business activities. Certain assets, such as contracts with qualifying facilities, contracts with demand-side management or conservation providers, ownership interest in nuclear units, and certain essential facilities, do not have to be divested.

Finally, Maine has a renewable portfolio standard which requires that at least 30 percent of generation must be derived from renewable resources. While this is a very high percentage, Maine does count its abundant hydro power resources toward this renewable standard. Additionally, distribution utilities must continue to offer energy efficiency programs and include them in their existing rates.

Maryland

In April, 1999, Maryland's governor signed a reconciled version of HB703 and SB300 which mandates retail competition. The bill sets startup dates of July 2000, for one-third of all residential customers, and within three years all customers will have the option to shop for alternative providers. Commercial and industrial customers may select providers beginning in January, 2001. Cooperatives must participate by 2003, but municipal utilities have an opt-out provision. This law largely supports the PSC-initiated restructuring proposals.

Full recovery of prudent and verifiable stranded cost is permitted by way of a customer transition charge. However, the PSC can require alternative collection mechanisms. Securitization is permitted.

The utilities must functionally unbundle their operations, but the PSC cannot require divestiture or prohibit voluntary divestiture of generating assets. If the PSC finds market power concerns, then it may take action within its prescribed authority or refer the case to the Maryland Attorney General's office.

Rates will be capped for at least four years. In addition, the PSC has discretion to reduce rates between 3 and 7.5 percent of June, 1999's base rates. The PSC must also develop procedures and rules addressing customer service and protection issues for all competitive suppliers. Disclosure of generation fuels and air quality impacts is required.

Maryland's law is flexible with respect to public benefits. A universal service fund of $34 million is to be established for low income customers. Utilities cannot generate less renewable energy than they did in 1998, and the PSC will report by 2000 on the feasibility of requiring a renewable portfolio standard. Finally, the Maryland Department of Environmental Quality must report on the impacts of deregulation on air quality.

Massachusetts

Massachusetts is one of the fully-transitioned states. It passed its restructuring law in November, 1997 and largely affirmed the PUC order issued a year earlier to guide the restructuring process. The implementation date was set for March, 1998, and it was to be accompanied by a 10 percent rate reduction. Another 5 percent reduction is required by September, 1999. Municipal utilities have the option to participate.

Recovery of stranded costs is permitted if conforming utilities properly demonstrate that they have divested all non-nuclear generation and attempted to mitigate all other costs. Utilities may then use securitization to help with recovery. If a utility is unwilling to divest its generation, then the Massachusetts Department of Telecommunications and Energy (DTE) will administratively determine the amount of stranded costs.

Unbundling of services and codes of conduct are required. While participation in an ISO or power exchange is not mandated in the act, it assumes an ISO or equivalent structure will be formed in the New England Power Pool (NEPOOL) control area.

With respect to public benefit programs, distribution companies must offer low income discounts, a Renewable Energy Trust Fund is established, beginning with a fee of 0.075 ¢/kWh in 1998 which increases to 0.125 ¢/kWh in 2000 and then phases down, and a charge of 0.33 ¢/kWh is established for funding energy efficiency programs. This fee is phased down to 0.25 ¢/kWh in 2002. Finally, a renewable portfolio standard is mandated, but hydro is considered an acceptable form of renewable energy. One percent new renewables are mandated by 2003. This rises by 0.5 percent each year until 2009 and then increases 1 percent per year thereafter.

Michigan

At the behest of Governor John Engler, the Michigan Jobs Commission completed their recommendations entitled *A Framework for Electric and Gas Utility Reform* in January, 1996. The report recommended six near-term objectives be achieved by January 1, 1997. These recommendations were: 1) allowing direct retail access for commercial and industrial accounts, 2) addressing stranded costs, 3) exploring replacing rate of return regulation with rate cap regulation, 4) allowing immediate file and use tariffs, 5) eliminating prescriptive regulatory measures, and 6) reorganizing the Michigan Public Service Commission (MPSC). Public hearings were conducted on the recommendations during the summer of 1996, and MPSC staff submitted their *Staff Report* in December, 1996. The *Staff Report* recommended that: 1) all customers -- not just commercial and industrials -- should be permitted to participate in retail access, and 2) rates should not increase for any customers and should decrease where possible. On June 5, 1997, the MPSC voted to adopt, for the most part, the restructuring strategy outlined in the *Staff Report*.

While the substantive aspects of the MPSC's implementation order were not appealed, challenges based on jurisdictional issues were filed. On June 19, pursuant to the MPSC's order, Detroit Edison and Consumers Energy submitted their proposed tariffs and requirements to begin restructuring. Interestingly, based in part on jurisdictional questions, both companies filed these tariffs as voluntary and conditional. Detroit Edison said it would proceed with the "voluntary" program if the MPSC approved it and the legislature approved securitization and authorized recovery of stranded costs.

In June, 1999, the Michigan Supreme Court ruled 4 to 3 that the MPSC exceeded its authority in issuing the restructuring order. This decision reversed an appeals court decision in support of the MPSC action. Discussions with MPSC staff indicated it is unclear what this means for retail competition in Michigan.

Montana

SB 390 (the Electric Utility Industry Restructuring and Customer Choice Act) was approved by the legislature and signed into law on May 2, 1997. The new law calls for retail choice for larger customers and pilot programs for smaller customers to begin on July 1, 1998. As soon as administratively feasible, but before July 1, 2002, all other customers must have retail choice. The PSC may extend the date for two years if it finds that it is not administratively feasible or that there is not workable competition. Utilities must file restructuring plans by July 1, 1997.

To the extent that a public utility is vertically integrated, a public utility must functionally separate the utility's electric supply, retail transmission and distribution, and unregulated retail energy services operations. The PSC may not order a public utility to divest itself of any generation assets or prohibit a public utility from voluntarily making such a divestiture. Montana Power, which serves most of the state, divested its entire portfolio of generation facilities during 1998.

The PSC shall allow recovery of unmitigable purchased power contracts, regulatory assets, and non-economic generation. Upon PSC approval of these costs, they can be recovered through a non-bypassable charge on all customers. A utility may, after July 1, 1997, apply to the PSC for a determination that certain transition costs may be recovered through issuance of transition bonds. If transition bonds are issued, the cost savings associated with the bonds must benefit customers. The utility retains sole discretion whether to sell, assign, or otherwise transfer or pledge, transition property.

Beginning January 1, 1999, 2.4% of each utility's annual retail sales revenue for the calendar year ending December 31, 1995, is established as the annual funding level for universal system benefits programs. This funding level remains in effect until July 1, 2003. These funds will be used to ensure continued funding of and new expenditures for energy conservation, renewable resource projects, and low-income energy assistance during the transition period and into the future.

Nevada

The Nevada Public Utilities Commission (Commission) prepared a draft bill on restructuring on February 6, 1997. This bill required the Commission to adopt restructuring rules within 18 months of approval and to oversee the restructuring process. This draft bill was formally introduced as Assembly Bill 366 (AB 366) on April 15, 1997. The Nevada Legislature ultimately passed AB 366 and the Governor signed the bill on July 16, 1997. The law permits retail access on December 31, 1999. The law also includes stranded cost recovery standards, competition guidelines for utility affiliates, distribution utility performance-based regulation, a renewables portfolio standard, consumer protections, and alternative supplier licensing.

Under the AB 366, the Commission will determine the recoverable costs associated with potentially competitive service as of the date on which alternative sellers begin providing the service. In determining stranded costs, the Commission will consider: 1) the extent to which the utility was legally required to incur the cost, 2) the extent to which the market value exceeds the cost, 3) the utility's efforts to mitigate the costs, 4) the extent to which rates previously set compensated shareholders for the risk of nonrecovery of the costs, 5) the effects of the difference between the market value and the cost, and 6) the utility's management practices compared to other utilities with similar obligations to serve.

The Commission must establish standards of conduct for competitive markets and monitor the markets for anticompetitive or discriminatory practices. The law also gives the Commission authority to set conditions and limitations on the ownership, operation, and control of a service providers assets in order to prevent anticompetitive behavior. The Commission also must conduct investigations to assess the effect of mergers, disposition of ownership or control of assets, transmission congestion, and anticompetitive behavior.

The law establishes a renewable portfolio standard for wind, solar, geothermal, and biomass. The goal is for renewables to provide one percent of Nevada's total electric needs. The standard must be derived from not less than 50 percent solar. The Commission may establish a system of credits to facilitate compliance. Credits must be issued for each kWh of renewable energy produced, and holders may trade or sell the credits.

One of the most interesting and unique aspects of Nevada's restructuring law is that it keeps the Commission involved in assuring adequate generating facilities are built. The new law requires the Commission to develop regular forecasts of electric capacity and energy. Providers of competitive services (i.e., end-use electricity providers) are to annually submit information to the Commission allowing it to monitor the development of competition and to ensure the availability of adequate, reliable, efficient, and economic electric service. If the Commission determines that insufficient capacity is forecasted, it may take remedial actions. The Commission may establish equitable, non-discriminatory obligations for customers, electric distribution utilities, or alternative sellers to ensure sufficient capacity is available.

New Hampshire

In May, 1996, HB 1392 (codified at RSA 374-F) was signed, calling for full retail access by March, 1998. In response, the New Hampshire PUC issued its *Final Plan* on February 28, 1997. This plan is the blueprint of the market and institutional structures necessary to provide customers with energy service choices and to ensure fair and efficient competition among retail market participants. The *Final Plan* directed each utility to file comprehensive plans, no later than June 30, 1997, which comply with the *Final Plan* and the supplemental orders.

In response to the *Final Plan*, Northeast Utilities (NU), parent of Public Service Company of New Hampshire (PSNH), filed suit in federal court on March 3, 1997. NU claimed that the restructuring order would illegally impose economic losses on PSNH and violate a 1989 rate agreement with the state. A federal judge agreed in part with the NU claims and issued a temporary restraining order limited to the issue of stranded cost recovery for PSNH. The judge also ordered the parties (i.e., the mediator, governor, state attorney general, and PSNH representatives) into a mediation process with a September 2, 1997 resolution deadline. However, the parties were unable to reach agreement.

Due to this delay, the New Hampshire Legislature passed SB 341 which delays the March, 1998 implementation date and allows negotiated settlements to achieve retail access. Finally, in June, 1999, a memorandum of understanding (MOU) was negotiated between the PSNH and the parties to the federal lawsuit. This MOU attempts to resolve the two-year federal court challenges to the PUC plan. Key highlights of the settlement call for PSNH to recover up to 85 percent of its stranded cost with up to $725 million to be securitized, to divest its plants and purchased power agreements, to immediately reduce rates by 18 percent, to continue to operate as a distribution and transmission company, and to collect system benefits charges totaling some $28 million over three years.

New Jersey

A law labeled A 16, "The Electric Discount and Energy Competition Act," was passed by the legislature in January 1999 and signed by the Governor on February 9, 1999. The law requires the New Jersey Board of Public Utilities (BPU) to open up the state's retail electricity market by August 1, 1999 and the retail natural gas market by December 31, 1999. Consumers will receive a 5 percent discount off their electric bills when competition starts and at least another 5 percent discount over the next three years. The BPU must decide the exact amount and timing of the second rate discount. Municipal and cooperative utilities are exempt from the act.

The BPU will determine the amount of stranded costs the utilities will be entitled to recover. Mitigation efforts are required. New Jersey will also use a competitive transition charge for recovery. Eight years is provided to recover stranded costs with the BPU having authority to extend this for certain kinds of assets (cogeneration contracts, generating assets greater than 20 percent of the total stranded costs and with longer than 10 years operating life).

Securitization is permitted for up to 75 percent of stranded costs and up to 100 percent for those utilities who divest generation. The BPU may require divestiture if market conditions warrant, and utilities must functionally unbundle competitive and noncompetitive services. Standards of conduct will be developed.

System benefit charges for energy efficiency and social programs are mandated. Every 4 years, the BPU will undertake a proceeding to determine the amount of funding for energy efficiency and renewables. For the first 4 years, the total amount must equal 50 percent of the amount currently being collected in regulated rates. Finally, a low income universal service fund is established.

New York

New York was one of the few states to use a different strategy to deregulate electric retail service. It did not have a legislative directive to restructure, but on May 16, 1996, the New York Public Service Commission (PSC) issued its plan (the "Competitive Opportunities Case," Opinion and Order No. 96-12) to introduce retail competition to the state. That order outlined the PSC's vision of what the restructured market should look like. The order required five IOU utilities (Orange and Rockland, Consolidated Edison, Rochester Gas and Electric, New York State Electric and Gas, Central Hudson) to file restructuring proposals and rate plans by October 1, 1996. Niagara Mohawk had already filed a proposal in 1995, and Long Island Lighting Company was not required to file because of the involvement of the Long Island Power Authority in their acquisition. The PSC believed, due to the differing circumstances of each utility, that restructuring plans were best addressed on an individual company basis. Following the filing of the utility plans, the PSC staff engaged in negotiations with each company to reach a settlement agreement.

In response to the PSC's May, 1996 order (Opinion 96-12) requiring utilities to file restructuring plans, the New York utilities filed suit against the PSC, claiming that it did not have jurisdiction to implement retail access or to mandate divestiture of generation assets. The case went to the New York Supreme Court which determined that the PSC, under New York law, has such jurisdiction. Consequently, the rate and restructuring proceeding continued.

The access dates approved in the final settlements varied by utility, but all used phase-in schedules. It is anticipated that full retail access will be available by July, 2001. However, customers of New York State Electric and Gas and Niagara Mohawk are scheduled to have full choice by August, 1999. All the orders call for either electric rate reductions or freezes for all classes of customers, whether or not such customers choose to purchase their electricity from an alternative supplier.

The settlements commit the utilities to divest most fossil generation. Codes of conduct are being developed. While stranded cost estimates were not addressed in the order, the order indicates utilities should have a "reasonable opportunity to recover strandable costs."

A significant issue in the restructuring proceedings was the maintenance of environmental protection and other public policy goals. In Opinion 96-12, the PSC directed that a non- bypassable system benefits charge be established to support investments in energy efficiency, research, development and demonstration, low income programs and environmental monitoring that might not be fully supported in a competitive market. Statewide, about $233 million in system benefits charges funds will be collected through wires charges over the three year period. The PSC designated the New York State Energy Research and Development Authority to be the statewide administrator for the system benefits charges program.

New Mexico

In April, 1999, SB 428 was signed, permitting retail competition in New Mexico. The New Mexico Supreme Court had ruled that the PSC did not have the authority to permit retail competition, and had vacated certain PSC orders to that affect. This new statute provides the enabling authority to permit such competition. January 1, 2002 is the initial choice date for residential and small commercial accounts with full access for all customers by January, 2002. Cooperatives and municipal utilities have the option to open their markets to retail competition. These entities will remain regulated by the newly-created New Mexico Public Regulatory Commission (PRC).

Subject utilities can collect up to 50 percent of unmitigable stranded cost by a surcharge on energy sales. The PRC can allow more than 50 percent recovery if such recovery does not raise residential or small commercial rates. Other standards must also be met as such recovery is necessary for reliability, to ensure financial operations, and to be in the public interest. The recovery period for stranded costs is through 2004, and other transition costs may be recovered until 2007.

Affected utilities must unbundle generation from transmission, distribution, and billing and collections. However, divestiture is not required. The PRC will adopt rules to address customer service, disclosure requirements and education functions. The PRC must also adopt codes of conduct to prevent inappropriate affiliate and noncompetitive transactions.

A system benefits charge of 0.03 ¢/kWh will be imposed beginning in 2002. This should collect about $5 million per year with the charge doubling to 0.06 ¢/kWH in 2007. The funds will be used for low income assistance, extending renewable energy to unserved communities, and educating consumers.
<

Ohio

In June, 1999, Governor Taft of Ohio signed SB 3. This bill expressly declares that beginning on January 1, 2001, retail electric generation, aggregation, power marketing, and brokerage services to consumers is deemed to be competitive. However, the PUC may delay this initial competitive date for up to six months. The transition period to a fully competitive market will be through December 31, 2005, or until all transition costs are recovered, whichever occurs first. The PUC also has the authority after an appropriate hearing to make billing, metering, and collections competitive.

Divestiture is permitted without PUC approval, but the act does give specific authority to the PUC over mergers and acquisitions and allows the PUC to intercede in cases where it suspects undue market power or where any utility interferes with a competitive market. In addition, by January 1, 2000, the incumbent utilities must submit a "corporate separation plan" that amounts to functional unbundling of services. Finally, an Independent System Operator is required to operate transmission assets.

During the market development period (up to 2005), all existing rates and charges will be unbundled on the bill and capped at their existing level with the exception of the generation portion, which shall be reduced by 5 percent.

The value of stranded costs and transition costs shall be administratively determined by the PUC and may be recovered through 2005. Such costs will be recovered through a customer transition charge. Recovery is permitted for regulatory assets (nuclear decommissioning and disposal costs, undepreciated radiation safety equipment, etc.) no later than 2010.

The act requires disclosure of the environmental characteristics of the energy produced (coal, nuclear, renewable, etc.) and creates a revolving loan fund of approximately $100 million over ten years for energy efficiency loans to residential customers, schools, small commercial customers, government accounts, and agricultural customers. Programs for low-income customers are consolidated within the Department of Development.

Oklahoma

Oklahoma Senate Bill 500, also known as the "Electric Restructuring Act of 1997," was approved on April 23, 1997. It requires that direct access be made available to retail consumers no later than July 1, 2002. In the event the state does not adopt a uniform state tax structure by this time, the start date for direct access will be deferred. The bill grants the Oklahoma Corporation Commission (OCC) considerable oversight of the details of the restructuring effort, but it also requires the OCC to study and report on a number of important issues which will ultimately be determined by a joint legislative restructuring task force. The task force, identified as the Joint Electric Utility Task Force, is comprised of 14 members, drawn equally from the state house and senate chambers.

The OCC is required by Senate Bill 500 to establish procedures for identifying stranded investment, quantifying stranded costs, and proposing a mechanism for the recovery of such costs. Utilities are required to determine the level of their stranded costs and identify a limited time period over which they can be recovered without raising rates. The costs are to be fully recovered over a three- to seven-year period. The Joint Electric Task Force must receive the OCC's report on stranded costs and other financial issues no later than December 31, 1999. Per Senate Bill 500, the application of the transition charge designed to recover stranded costs will not advantage one class of customers over another. An OCC report regarding consumer issues is due to the Joint Electric Utility Task Force by August 31, 2000.

In terms of market power, the bill calls for a task force report to address the formation of an independent system operator and power exchange (PX); functional unbundling of generation, transmission, and distribution; bill unbundling; and other methods of achieving open access. Other task force reports will address reliability, public purpose programs, and tax issues.

Pennsylvania

On November 25, 1996, the Pennsylvania Legislature voted to adopt HB 1509, "The Electricity Generation Customer Choice and Competition Act" (the Act). On December 3, 1996, Governor Tom Ridge signed the Act into law. Essentially, the Act restructures the electric industry by separating the services of generating electricity from the services of transmitting and distributing electricity. The Act permits customers to choose their electricity generation supplier, but requires them to purchase transmission and distribution services from their traditional electric utility. All subject utilities were required to file restructuring plans with the Pennsylvania Public Utilities Commission (PPUC) between April 1, 1997, and September 30, 1997.

The PPUC has established industry working groups to provide recommendations on areas of concern that have arisen in the restructuring process. These areas include consumer education, customer information and billing, universal service, conservation, reliability, direct retail access implementation schedule, metering, competitive safeguards, interaction between suppliers and customer utilities, and taxes.

The statute calls for a phase-in for allowing retail customers the right to choose. It provides that a maximum of 33% of the peak load of each customer class shall be eligible for direct access by January 1, 1999. A maximum of 66% of the peak load of each customer class shall be eligible for direct access by January 1, 2000, and all customers in the state shall be eligible by January 1, 2001.

The PPUC is authorized by the Act to determine the level of stranded costs that each utility is permitted to recover. The Act precludes cost-shifting between customers as a consequence of stranded cost recovery. Such costs can be recovered through a non-bypassable competitive transition charge (CTC) that will be reviewed annually and adjusted annually for each customer of the utility who elects to receive service from an alternative generation supplier. The CTC will be collected by utilities over a maximum period of nine years, unless the PPUC approves an alternate period.

The Act encourages, but does not mandate, market participants to coordinate their plans and transactions through an independent system operator or functional equivalent. It permits, but does not require, electric utilities to divest themselves of facilities or to reorganize their corporate structures, but unbundling of services is required.

Public benefits programs are funded by an energy surcharge to provide programs for low-income assistance, energy conservation, and other public purposes at the existing funding levels.

Texas

On June 18, 1999, Governor George W. Bush signed SB 7 that introduced retail competition in Texas. The bill mandates full retail access for all customers of investor-owned utilities by January 1, 2002, with the exception that if the Texas PUC finds that a region is not competitive, it can delay the retail access date. Municipal and cooperative utilities have the option to offer retail access after this date but are not mandated to do so. An interesting aspect of the Texas law prohibits competitors from only serving the more profitable industrial loads. To ensure that new electric providers do not selectively market only to large volume users, the law provides that any new competitor that serves at least 300 MWs of load must also serve at least 5 percent of the residential class or, alternatively, make payments to a systems benefit fund.

Recovery of stranded costs that cannot be mitigated is permitted, with the industrial and interruptible customers paying a disproportionate share. Up to 75 percent of stranded cost may be eligible for securitization. The act requires that generating utilities divest a percentage of their generating assets, and they are required to functionally separate their companies into power generation, retail service provider, and transmission and distribution affiliates.

A systems benefit charge (SBC) is set at $.50/mWh is set on all sales until 2001 at which time the PUC can increase it to $.65/MWH. The proceeds from this charge will be allocated to low-income assistance, education programs, and public schools. Revenues from the SBC will be administered as a trust fund by the PUC. In addition, the bill requires a phase-in of renewable generation resources with an ultimate goal of 2880 MWs by 2009. This is approximately 3 percent of forecasted generation. In addition, the legislature wants 50 percent of new generation to be fueled by natural gas and requires a credits trading program to achieve this. Interestingly, the bill defines natural gas-derived electricity as "green electricity" because of its perceived favorable environmental impact.

Finally, the PUC will undertake a series of task forces to do the necessary rulemaking to implement the provisions of SB 7. The goal is to begin the pilot programs by June 1, 2001.

Vermont

On October 17, 1994, the Vermont Public Service Board (the Board) opened an investigation (Docket No. 5854) with the aim of advancing restructuring through an open, more formal process. After a series of workshops and technical conferences, the Board issued a draft report and order on October 16, 1996. A final report and order were issued on December 31, 1996 based on the comments received on the draft report and order. This document, entitled "The Power to Choose: A Plan to Provide Customer Choice of Electricity Suppliers," included the Board's recommendations for electric restructuring.

On April 3, 1997, the Vermont Senate adopted a majority of the Board's recommendations in Senate Bill 62 (SB 62). The Vermont House of Representatives did not bring SB 62 up for a vote, and it stalled in committee. The House postponed formal consideration of restructuring. As a result of the actions in the Vermont Legislature, the Board suspended all hearings and activities associated with its restructuring plan. Formal restructuring activities will resume pending legislative approval.

On July 22, 1998, the Governor signed an executive order creating a five-member "Working Group on Vermont's Electricity System." The working group was directed to study restructuring activities regionally and nationally, the effects of the Hydro-Quebec contract on ratepayers, the state's competitive position within a deregulated environment, and the effect of recent regulatory activities on Vermont utilities. On December 18, 1998, the Working Group submitted its final report to the Governor who has endorsed the document and requested its immediate implementation. The report suggests that the Vermont electric system needs to be restructured and that the process should begin within the next 18 months.

Virginia<

In December, 1998, the Virginia State Corporation Commission (SCC) issued interim procedures to require pilot programs for electric and gas retail competition. Virginia adopted restructuring legislation (SB 1269) in April, 1998. The legislation is broadly written and does not go into specific details of implementation. It prescribes that future SCC and general assembly actions will be required for full implementation.

The Act broadly defines six requirements. These are:

- Necessary ISOs or regional transmission authorities and power exchanges should be established by January, 2001. This apparently will be a joint exercise between stakeholders and the SCC;
- Transition to competition is to begin by January, 2002, with full retail access by January, 2004;
- Just and reasonable stranded costs are to be recovered;
- Any implementation requirements must ensure reliability and just and fair rates for all classes;
- Any implementation decisions should recognize unique financial and tax conditions of all utilities and cooperatives; and,
- Pending legislation or SCC actions will not be affected by the statute;

The requirements for pilot programs continue in force. American Electric Power plans to submit a revised pilot program to permit about 2 percent of its load to have retail choice. Virginia Electric Power has plans to permit about 7 percent of its residential/commercial load to have retail choice by June 2000. This program would continue until full implementation in 2002, as prescribed by the restructuring act.

Conclusion to Individual State Restructuring Activity

As illustrated above, the states that are experimenting with retail access are at the beginning stages of that process. Some states are further along than others. The framework and safeguards that each state has adopted clearly shows the advantage of state legislatures and commissions asserting their traditional role of ensuring that retail competition benefits all classes of ratepayers in their respective states. The diversity of these approaches argues against a Federal mandate that would impose a "one size fits all" model on the states.

While it is too early to reach many conclusions, a couple of tentative observations can be made. First, in those states that have full retail access, the large industrial customers are most likely to have alternative suppliers to choose from, and to exercise their rights to obtain these new generation sources. It is also evident that residential customers have fewer real choices than larger customers, and therefore fewer residential customers are switching than anticipated. Second, states for the most part have been able to implement solutions to address stranded costs. Utilities that have been required to divest their generation and sell it on the open market have generally received offers substantially above what had been anticipated. Where divestiture has not been required, many states have adopted procedures to permit securitization for any remaining stranded costs. This has served to slow the transition to an open retail market. Third, those states which have crafted consumer protections and information disclosures to help assist customers have been more successful in reducing customer dissatisfaction during the transition to retail competition. Finally, it is too early to assess what consequences the transition to retail access will have on reducing overall customer rates. Some recent price spikes on the wholesale market in the Midwest have reached extremely high levels; however, they have been for short enough duration not to affect the overall cost of electricity. It is too early to foresee whether competition will develop to the level necessary to ensure adequate supplies of electricity while placing downward pressure on rates.

Appendix B

Operational Merchant Plants[1]

State	Number of merchant plants acquired from utility divestiture	MW	Parent Company	Status of Retail Restructuring Legislation [2]
California	16	10,594	Houston Industries, NRG/Dynergy Power, Thermo Ecoteck, AES, Duke Energy, Sunlaw Energy	Enacted
Colorado	1	80	Citizens Power	Ongoing Investigation
Connecticut	1	520	Bridgeport Energy	Enacted
Maine	2	88	Indeck Energy Services and Ridgewood Power, SAPI	Enacted
Massachusetts	1	188	American National Power, Indeck	Enacted
New Mexico	1	74	Williams Field Services	Enacted
New York	2	158	CH Resources	Order Issued
Texas	5	1,318	Dynergy Power, Calpine Corp. CSW Energy, Southern Energy	Enacted
West Virginia	1	276	Allegheny Power	Ongoing Investigation
Wisconsin	1	53	Mid-America Power	Ongoing Investigation
TOTAL	**31**	**13,349 MW**		

[1]Source: Merchant Power Scoreboard
[2]Source: Energy Information Administration

Appendix C

Merchant Plants Under Construction or Under Development[1]

State	Number of merchant plants	Total MW	Parent Company	Status of Retail Restructuring Legislation[2]
California	4	2,758	US Generating, Constellation Energy, Enron Capital, Calpine Corp.	Enacted
Connecticut	2	882	Bridgeport Energy, US Generating	Enacted
Illinois	2	850	Dominion Energy/Peoples Energy, Dynegy	Enacted
Maine	3	935	American National Power, U.S. Generating	Enacted
Massachusetts	4	1,353	US Generating, Berkshire Power, Energy Management and Calpine, American National Power	Enacted
Michigan	1	550	CMS Energy and DTE Energy	Order Issued
Mississippi	1	800	LS Power and Cogentrix	Ongoing Investigation
Missouri	1	250	Associated Electric Cooperative and Duke Energy	Order Pending
Nevada	1	480	Houston Industries and Sempra Corp.	Enacted
New Hampshire	1	15	Indeck	Enacted
Pennsylvania	2	155	PEI Power Corp, Williams Energy Group	Enacted
Rhode Island	1	265	Energy Management and Calpine	Enacted
Texas	8	5,293	Gregory Power, Tenaska, Occidental Energy Ventures, American National Power, Calpine Corp	Enacted

Virginia	1	300	Commonwealth Chesapeake Corp.	Enacted
TOTAL	**32**	**14,886 MW**		

[1] Source: Merchant Power Scoreboard
[2]Source: Energy Information Administration

Appendix D

Reported Plans for Merchant Plants[1]

State	Planned merchant plants	Total MW	Parent Company	Status of Retail Restructuring Legislation[2]
Alabama	1	100	Southeastern Electric Development	Ongoing Investigation
Arizona	2	1,100	PP&L Global, Inc., Calpine	Enacted
California	13	8,600	Summit Group International, Ogden Power, AES, Enron, Duke Energy, Power Development Company	Enacted
Connecticut	4	2,284	Power Development Company and El Paso Energy, AES, PPL Global	Enacted
Florida	2	1,350	Duke Energy, Constellation Power	Ongoing Investigation
Georgia	3	1,380	Sonat Energy Services, Southern Company, Carolina Power & Light	Ongoing Investigation
Idaho	1	270	Cogentrix and Avista Power	Ongoing Investigation
Iowa or Illinois	1	600	Calenergy and Mid-American Energy	Ongoing Investigation (Iowa) Enacted (Illinois)
Illinois	4	2,484	Dynegy, KN Energy, LS Power, Houston Industries	Enacted
Indiana	2	550	LS Power, Primary Energy	Ongoing Investigation
Kentucky	2	500	Dynegy, Enron Capital & Trade Resources	Ongoing Investigation
Louisiana	1	11	Nations Energy	Ongoing Investigation
Maine	7	3,130	Alternative Energy, Champion International, American National Power, International Power Partners, Indeck Energy Services, FPL Group, Industry and Energy Group	Enacted
Massachusetts	7	6,407	Infrastructure Development Corp, American National Power, US Generating, Constellation Power, Southern Energy, Power Development Corp, Sithe Energy, Inc.	Enacted
Michigan	2	1,480	US Generating, Wyandotte Energy	Order Issued
Minnesota	1	362	NRG Energy and Tenaska	Ongoing Investigation
Mississippi	3	1,125	Enron	Ongoing Investigation
Missouri	1	250	Associated Electric Cooperative and Duke Energy	Order Pending
Montana	3	2,420	Composite Energy, Glacier International, Cogentrix	Enacted
Nevada	2	556	Biogen Partners, Coastal Power	Enacted
New Hampshire	3	1,925	AES and Conservation Law Foundation, Tractebel Power and Sprague Energy, Southern Company	Enacted
New Jersey	2	1,900	US Generating	Enacted
New Mexico	2	600	Dynegy Power, QUIXX	Enacted
New York	5	4,080	US Generating, Megan-Racine Assoc., American National Power, Sithe Energies	Enacted
North Carolina	1	1,100	Carolina Power & Light	Ongoing Investigation
Ohio	3	1,149	Columbus Power Partners, Ohio National Energy, Duke Energy	Order Pending
Oklahoma	3	1,425	Associated Electric Coop and KAMO Power, Cogentrix and Power Resource Group, OGE	Enacted

			Energy	
Oregon	1	460	Hermistion Power Partners	Order Pending
Pennsylvania	3	1,800	Columbia Electric, PP&L Global, AES	Enacted
Rhode Island	2	1,250	Houston Industries, Tuspani Water Co.	Enacted
Tennessee	1	600	Enron	Ongoing Investigation
Texas	6	3,055	Tractebel Power, Dynegy, Panda Energy, Air Liquide America and Houston Industries, US Generating	Enacted
Vermont	1	1,225	Vermont Energy Park Holdings	Order Issued
Washington	3	1,198	FPL Energy, National Energy Systems, US Generating	Ongoing Investigation
West Virginia	1	240	MCN Energy Group	Ongoing Investigation
Wisconsin	5	1,700	Mid-American Power, SkyGen, Polsky Energy, Southern Energy, Wisconsin Electric Power,	Ongoing Investigation
Wyoming	3	570	Black Hills Corp, North American Power Group, Zeigler Coal Holding	Ongoing Investigation
TOTAL	**107**	**56,021 MW**		

[1]Source: Merchant Power Scoreboard and Energy Information Administration

Appendix E

Proposed Characteristics of an RTO

At a minimum, an RTO must have the following characteristics:[1]

- must be independent from market participants;
- has the appropriate scope and regional configuration;
- possesses the operational authority for all transmission facilities under its control; and
- has exclusive authority to maintain short-term reliability.

In addition, an RTO must perform these minimum functions:[(2)]

- administer its own tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities;
- create market mechanisms to manage transmission congestion;
- develop and implement procedures to address parallel path flow issues;
- serve as a supplier of last resort for all ancillary services required in Order No. 888 and subsequent orders;
- operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating its total transfer capability and available transfer capability;
- monitor markets to identify design flaws and market power; and
- plan and coordinate necessary transmission additions and upgrades.

Appendix F

Approved Transmission Entities

ISO New England

Utilities in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont created ISO New England through a voluntary agreement of participants to achieve compliance with Order No. 888. ISO New England's Board of Directors is comprised of ten independent members. ISO New England received conditional FERC approval on June 25, 1997.[(3)] FERC's approval was contingent upon ISO New England codifying its policy to allow non-ISO members to participate in the ADR process.

New York ISO

Utilities in New York created an independent transmission operator through a voluntary agreement of participants to achieve compliance with Order No. 888. The New York ISO's Board of Directors is comprised of 10 independent members. The New York ISO received conditional FERC approval on June 30, 1998.[2]

With its conditional approval, FERC deferred its decision on whether the New York ISO has a single, unbundled, grid-wide tariff to all eligible users and whether the New York ISO promotes efficient use, and investment in, generation, transmission, and consumption of electricity. Also, the New York ISO recognized the need to develop additional arrangements to coordinate with adjacent power pools.

Pennsylvania-New Jersey-Maryland (PJM) ISO

Utilities in Delaware, Maryland, Pennsylvania, New Jersey, Virginia, and the District of Columbia have created the Pennsylvania-New Jersey-Maryland ISO (PJM ISO) through a voluntary agreement of participants to achieve compliance with Order No. 888. PJM ISO received conditional

FERC approval in November, 1997[4] and started operations in April, 1998. The PJM ISO's Board of Directors is comprised of 8 independent members. With its conditional approval, PJM ISO has agreed to modify its Operating Agreement to prohibit the ISO from contracting with a participant for goods and services without an open and competitive bidding process.

Midwest ISO

Utilities in Illinois, Indiana, Kentucky, Maryland, Missouri, Ohio, Pennsylvania, Virginia, West Virginia, and Wisconsin have created the Midwest ISO (MISO) through a voluntary agreement of participants to achieve compliance with Order No. 888. MISO received conditional approval from FERC in September, 1998.[5] MISO's Board of Directors is comprised of 8 independent members. MISO expects to be fully functional by 2001. As a condition of FERC approval, MISO must follow through with its commitment to serve as Security Coordinator to ensure short-term reliability of grid operations.

California ISO

The California ISO (Cal-ISO) received FERC approval in October, 1997[6] and became operational on March 31, 1998. The Cal-ISO was created as part of California's efforts to de-regulate its retail electric utility industry. (A.B. 1890). The Cal-ISO's Board of Governors consists of 24 members. FERC granted a waiver of its OASIS requirements on an interim basis because the proposed Wenet meets the current needs of the WEPEX Market Participants, including the ISO's transmission customers. However, Cal-ISO will eventually need to comply with FERC's OASIS requirements.

The California Electricity Oversight Board (EOB), Cal-ISO's primary regulatory agency, monitors, evaluates, and represents the state's interests concerning the operation and reliability of the interconnected electric transmission system. However, California is considering establishing a new energy "superagency" to plan and site new electric and gas transmission and to exercise eminent domain power. The California Energy Reliability Agency would replace the current California Energy Commission and the EOB, as well as some of the functions of the California PUC and the Cal-ISO. The impetus behind this new agency is concern by elected officials that the stakeholder component of the ISO's board would be at odds with the public interest (i.e., utilities and competitive generators sit on the board of directors for Cal-ISO). The new reliability agency, composed of a 5-member commission made up of legislators and technical energy experts, would site transmission lines and gas pipelines, develop transmission plans for the future, certify new generators, exercise eminent domain, and administer energy-efficiency programs.[7]

ERCOT-Texas ISO

Because its boundaries are coincident with the intrastate ERCOT Interconnection boundaries, the state of Texas has jurisdiction. Hence, the Texas Legislature amended the state's Public Utility Regulatory Act in 1995 to deregulate the wholesale generation market. Subsequently, Public Utility Commission of Texas (PUCT) Rule 25.197 authorized an ISO in order to foster a healthy wholesale market within ERCOT. Finally, the PUCT established the ERCOT ISO by order on August 21, 1996.[8] The ISO's Board of Directors are comprised of three members from six market groups: investor-owned utilities; generation-owning or transmission-owning municipal utilities; generation-owning or transmission-owning electric cooperatives; transmission-dependent utilities; independent power producers; and power marketers.

1. Merchant Power Scoreboard, www.mwbb.com/services/energy-mp.htm, web site established by McGuire, Woods, Battle & Boothe
2.
3. 79 FERC 61,374
4. [2]83 FERC 61,352
5. 81 FERC 61,257
6. 84 FERC 61,231
7. 81 FERC 61,122
8. Electricity Daily, May 24, 1999.
9. Public Utilities Commission of Texas, Order on ERCOT Independent System Operator and Electronic Transmission Information Network. Project No. 16018. August 22, 1996.

TOP
Go to Index

Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
1-800-342-3552

TAB 3

Mission Statement and Goals

COMMISSION MISSION STATEMENT

To facilitate the efficient provision of safe and reliable utility services at fair prices.

COMMISSION GOALS

The Commission fulfills this mission by pursuing a number of goals, as follows:

GOALS FOR ECONOMIC REGULATION

To the extent possible, streamline regulatory requirements to provide an open, accessible and efficient regulatory process that is fair and unbiased.

Provide a regulatory process that results in fair and reasonable rates while offering rate base regulated utilities an opportunity to earn a fair return on their investments.

Encourage efficiency and innovation among regulated utilities.

Encourage and facilitate responsible use of resources and technology in the provision and consumption of utility services.

GOALS FOR REGULATORY OVERSIGHT

Identify and address regulatory barriers that impede the development of competitive telecommunications markets, as directed by law.

Provide appropriate regulatory oversight to protect consumers.

Ensure that all entities providing utility services to consumers comply with all appropriate requirements subject to the Commission's jurisdiction.

GOALS FOR SERVICE REGULATION AND CONSUMER ASSISTANCE

Facilitate the provision of safe utility services at levels of quality and reliability that comply with established industry standards and practices.

Inform utility consumers regarding utility matters.

Expedite resolution of disputes between consumers and utilities.

Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
1-800-342-3552

TAB 4

History of the PSC

The Public Service Commission was originally created to regulate the railroad industry in Florida.

The PSC, created by the Florida Legislature in 1887, was originally called the Florida Railroad Commission. The primary purpose of the Commission was the regulation of railroad passenger and freight rates and operations. The Legislature abolished the Commission in 1891, but re-established it in 1897.

As Florida's population grew and its industry base diversified, the Legislature conferred upon the Commission additional responsibilities. These ever changing charges include periods of both regulatory expansion and deregulation. Regulatory authority over various industries began as follows:

- 1911 Telephone & Telegraph
- 1929 Motor Carrier Transportation
- 1951 Investor-Owned Electrics
- 1952 Natural Gas
- 1959 Water and Wastewater
- 1972 Airlines

In 1974 the Legislature gave the Commission rate structure jurisdiction over municipal and rural cooperative electric utilities. Due to deregulation, the Commission lost jurisdiction over airlines in 1978. In 1980, motor carriers were deregulated; five years later, railroads were deregulated. The Commission received safety jurisdiction over all electric utilities in 1986. And in 1995, legislation was approved allowing competition for local exchange telephone service.

In 2011, legislation was approved that reduced the Commission's jurisdiction over the telecommunications industry. The Commission retains the authority to ensure that incumbent local exchange carriers meet their obligation to provide unbundled access, interconnection, and resale to competitive local exchange companies in a nondiscriminatory manner. And, the Commission oversees the federal Lifeline Assistance program in Florida, and the administration of a statewide telecommunications access system to provide Telecommunications Relay Services for the deaf, hard-of-hearing, or speech impaired.

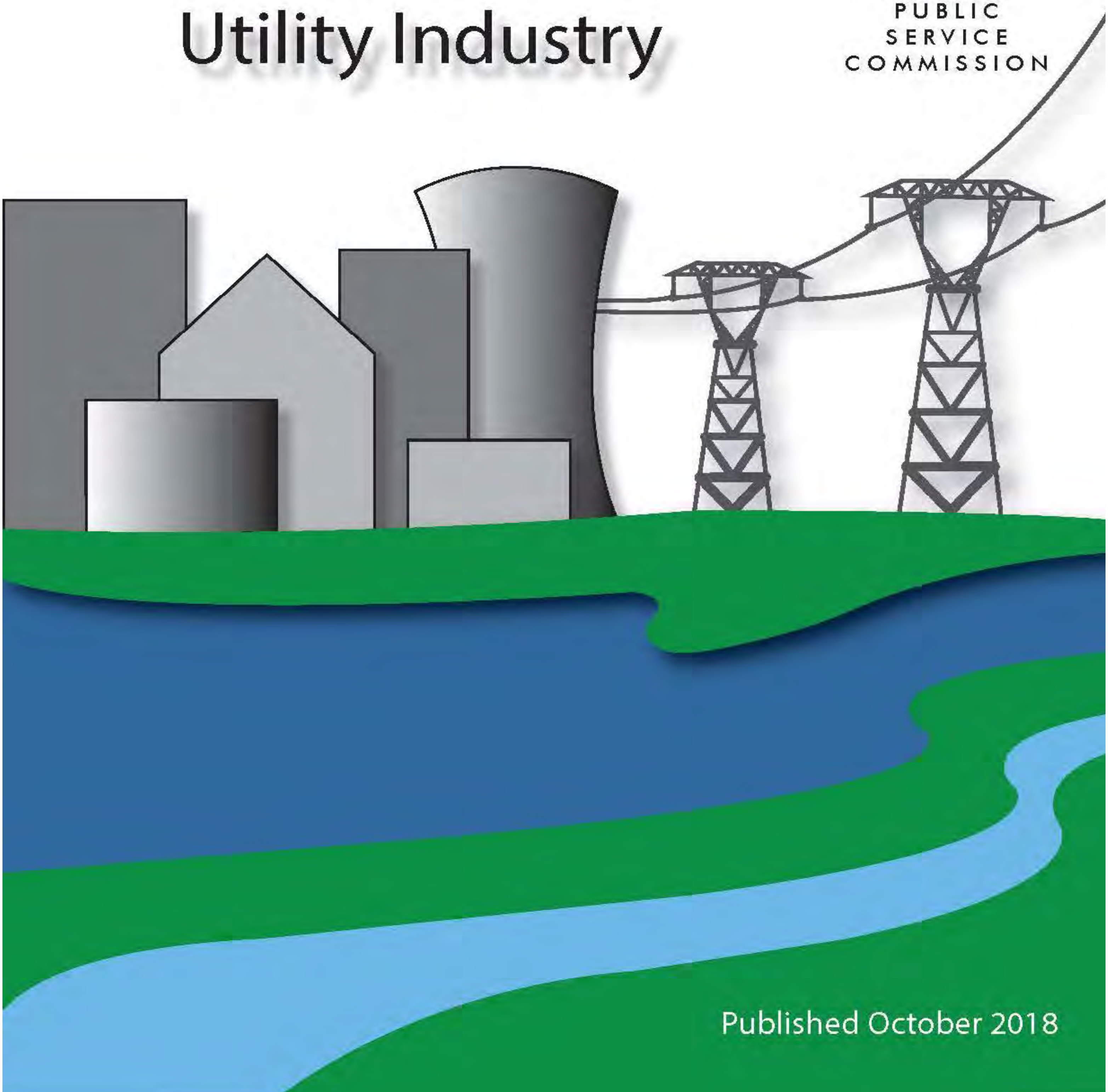
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
1-800-342-3552

TAB 5

STATISTICS OF THE

Florida Electric Utility Industry

FLORIDA
PUBLIC
SERVICE
COMMISSION



Published October 2018

Statistics of the
Florida Electric Utility Industry
2017

In partial fulfillment of Section 377.703, Florida Statutes, this publication provides a single comprehensive source of statistics on Florida's electric utility industry. Information was compiled from various sources: filings made with, and reports prepared by, the Florida Public Service Commission; the Florida Reliability Coordinating Council (FRCC); the Office of Economic & Demographic Research; the U.S. Census Bureau; the U.S. Government Publishing Office; the U.S. Department of Labor; and data provided by the Florida electric utilities. The Florida Public Service Commission has not audited the data for accuracy.

This report was compiled by the Florida Public Service Commission
Office of Industry Development and Market Analysis

Contents

Acronyms, Abbreviations, and Formulas

The following acronyms, abbreviations, and formulas are used in this report:

AFUDC	Allowance for Funds Used During Construction
EIA	Energy Information Administration
EEI	Edison Electric Institute
FCG	Florida Electric Power Coordinating Group, Inc.
FERC	Federal Energy Regulatory Commission (f/k/a FPC)
FPC	Federal Power Commission
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council (f/k/a FCG)

BBL	Barrel (42 gallons)
BTU	British Thermal Unit
ECS	Extended Cold Standby
IC & GT	Internal Combustion and Gas Turbine
MCF	= 1,000 cubic feet
SH-TON	Short ton (2,000 pounds)
THERM	100,000 BTUs

Kilowatt (KW) = 1,000 watts
Megawatt (MW) = 1,000 kilowatts
Gigawatt (GW) = 1,000 megawatts
Kilowatt-Hours (kWh) = 1,000 watt-hours
Megawatt-Hours (MWh) = 1,000 kilowatt-hours
Gigawatt-Hours (GWh) = 1,000 megawatt-hours

Unit Number (U)

r = Retirement
c = Change or modification of unit

Unit Type (T)

FS = Fossil Steam
CT = Combustion Turbine
D = Diesel
CC = Combined Cycle
N = Nuclear
UN = Unknown

Primary Fuel (F)

HO = Heavy Oil
LO = Light Oil
NG = Natural Gas
N = Nuclear
C = Coal
SW = Solid Waste
UN = Unknown

Continued

Acronyms, Abbreviations, and Formulas

Capability

MW-S = Megawatt Summer
MW-W = Megawatt Winter
NMPLT = Nameplate

Net summer and winter continuous capacity and generator maximum nameplate rating.

Load Factor Formula

$$\text{Percent Load Factor} = \frac{\text{Net Energy for Load (MWh)}}{\text{Peak Load (MW)} \times 8{,}760} \times 100$$

Where:

Net Energy for Load = Total MWh Generated – Plant Use + MWh Received – MWh Delivered

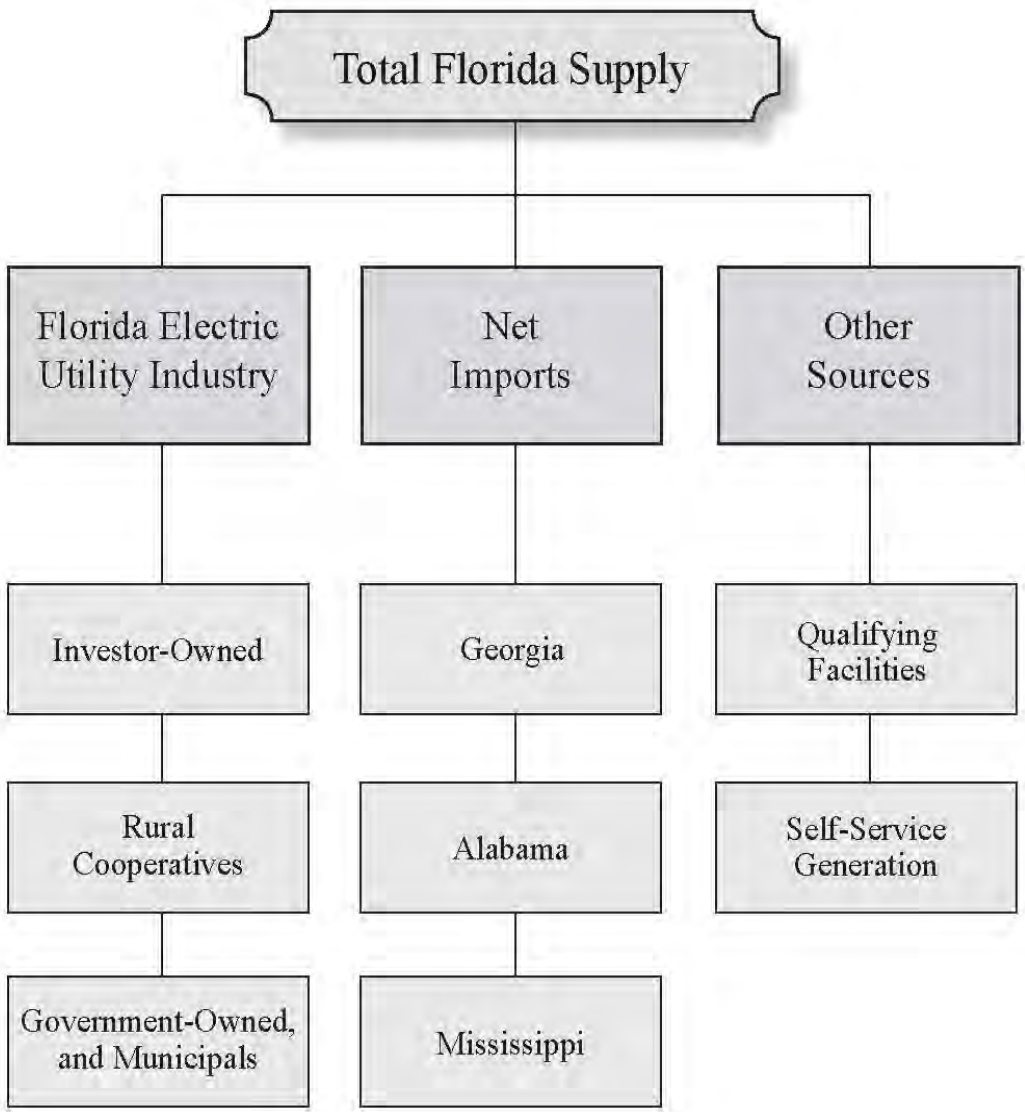
Peak Load = That 60 minute demand interval for which gross generated MWh was highest for the year.

The load factor for a specific utility is an index ranging from zero to one. The load factor reflects the ratio of total MWh actually generated and delivered to ultimate customers to the total MWh that would have been generated and delivered had the utility maintained that level of system net generation observed at the peak period (60 minutes) for every hour of the year or a total of 8,760 hours.

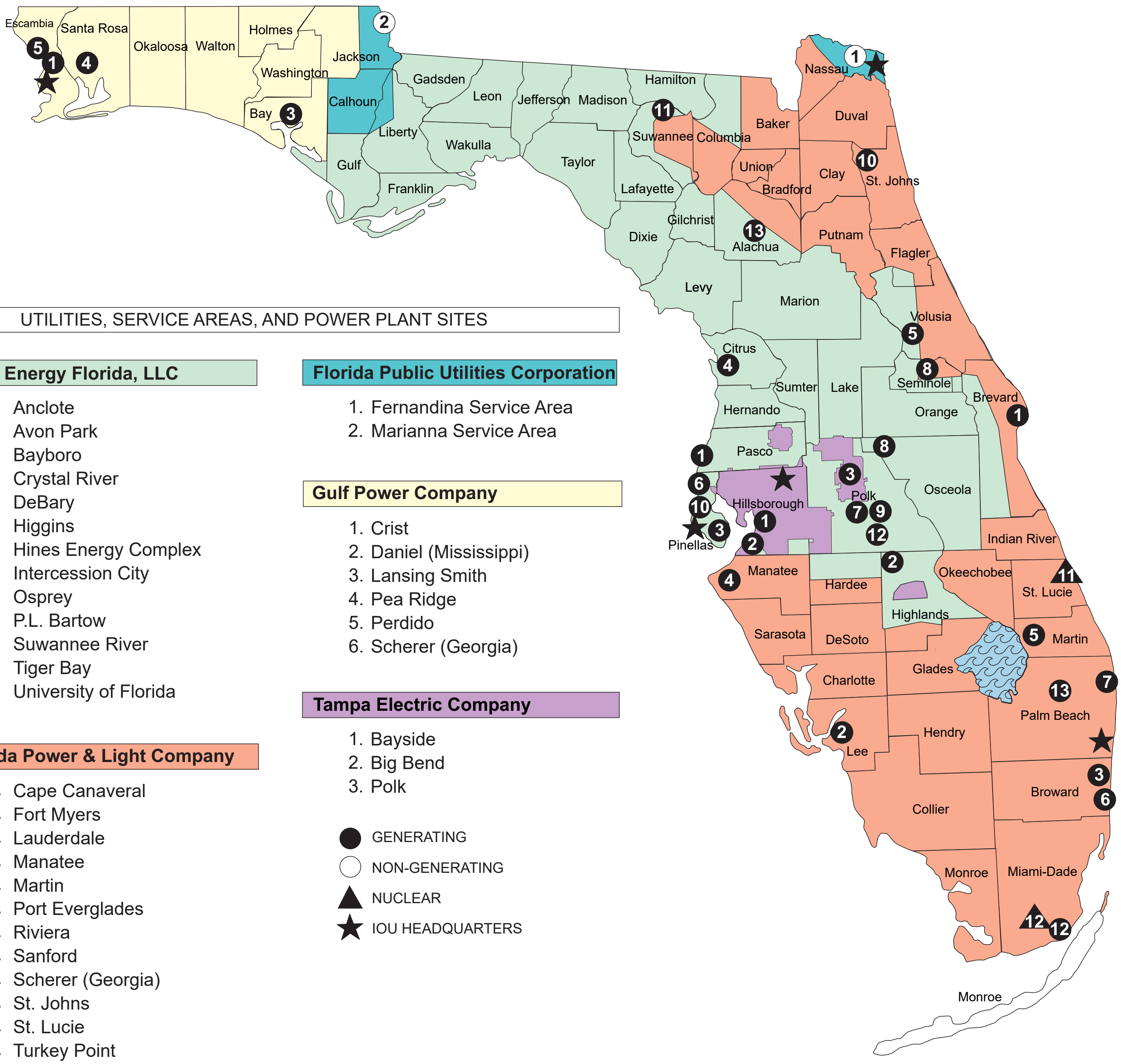
The closer the load factor is to one, the flatter the load curve is or the lower the difference between maximum and minimum levels of use over a one-year period. The closer the load factor is to zero, the greater this difference is, and therefore, the magnitude of peaking across the load curve is greater.

Overview

Florida Sources of Electricity by
Type of Ownership



Investor-Owned Electric



UTILITIES, SERVICE AREAS, AND POWER PLANT SITES

Duke Energy Florida, LLC

1. Anclote
2. Avon Park
3. Bayboro
4. Crystal River
5. DeBary
6. Higgins
7. Hines Energy Complex
8. Intercession City
9. Osprey
10. P.L. Bartow
11. Suwannee River
12. Tiger Bay
13. University of Florida

Florida Power & Light Company

1. Cape Canaveral
2. Fort Myers
3. Lauderdale
4. Manatee
5. Martin
6. Port Everglades
7. Riviera
8. Sanford
9. Scherer (Georgia)
10. St. Johns
11. St. Lucie
12. Turkey Point
13. West County

Florida Public Utilities Corporation

1. Fernandina Service Area
2. Marianna Service Area

Gulf Power Company

1. Crist
2. Daniel (Mississippi)
3. Lansing Smith
4. Pea Ridge
5. Perdido
6. Scherer (Georgia)

Tampa Electric Company

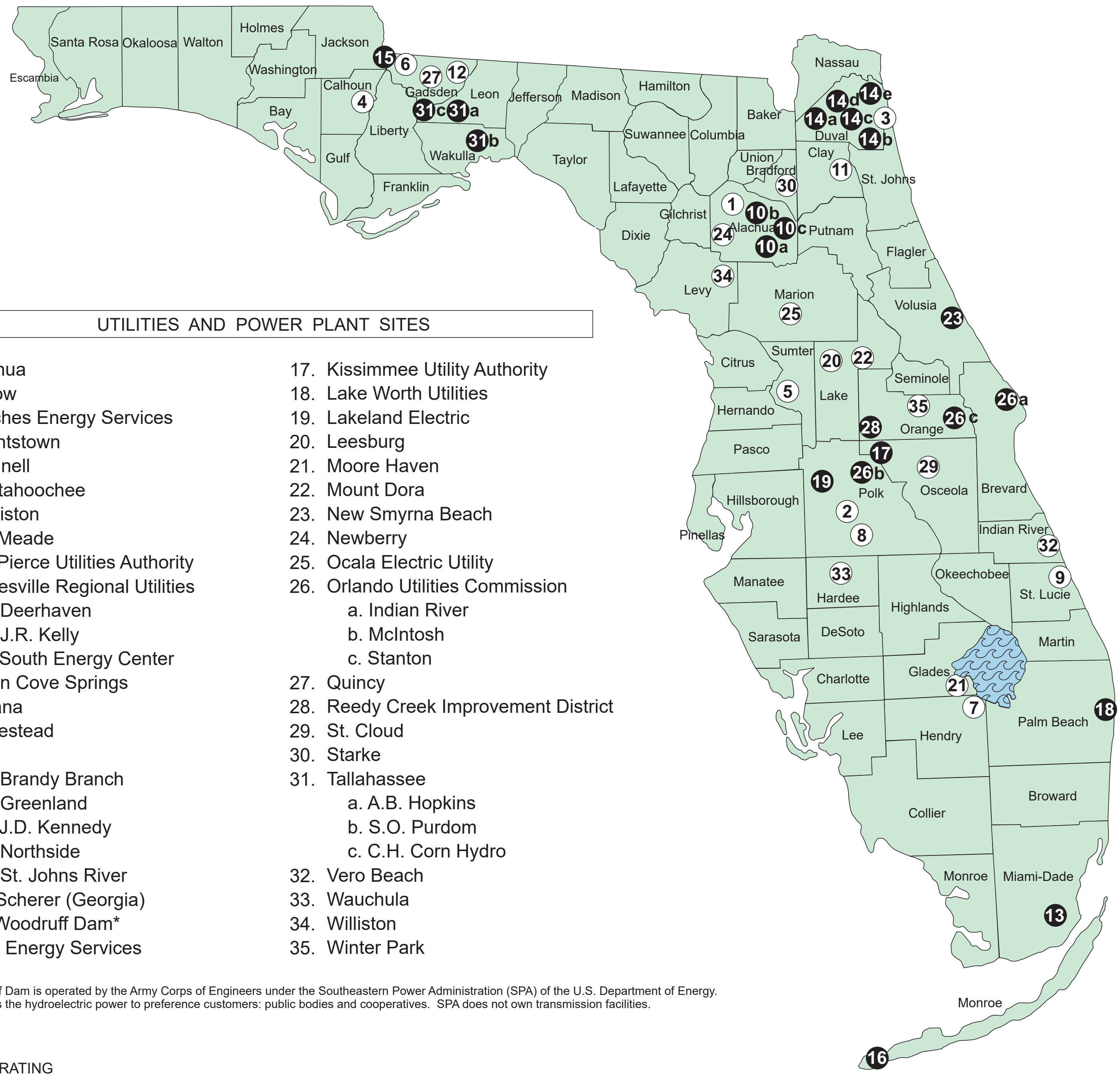
1. Bayside
2. Big Bend
3. Polk

GENERATING
NON-GENERATING
NUCLEAR
IOU HEADQUARTERS

Excludes solar generation. Service areas are approximations. Information on the map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source: Florida Public Service Commission

Municipal Electric



UTILITIES AND POWER PLANT SITES

1. Alachua
2. Bartow
3. Beaches Energy Services
4. Blountstown
5. Bushnell
6. Chattahoochee
7. Clewiston
8. Fort Meade
9. Fort Pierce Utilities Authority
10. Gainesville Regional Utilities
    a. Deerhaven
    b. J.R. Kelly
    c. South Energy Center
11. Green Cove Springs
12. Havana
13. Homestead
14. JEA
    a. Brandy Branch
    b. Greenland
    c. J.D. Kennedy
    d. Northside
    e. St. Johns River
    f. Scherer (Georgia)
15. Jim Woodruff Dam*
16. Keys Energy Services
17. Kissimmee Utility Authority
18. Lake Worth Utilities
19. Lakeland Electric
20. Leesburg
21. Moore Haven
22. Mount Dora
23. New Smyrna Beach
24. Newberry
25. Ocala Electric Utility
26. Orlando Utilities Commission
    a. Indian River
    b. McIntosh
    c. Stanton
27. Quincy
28. Reedy Creek Improvement District
29. St. Cloud
30. Starke
31. Tallahassee
    a. A.B. Hopkins
    b. S.O. Purdom
    c. C.H. Corn Hydro
32. Vero Beach
33. Wauchula
34. Williston
35. Winter Park

* Jim Woodruff Dam is operated by the Army Corps of Engineers under the Southeastern Power Administration (SPA) of the U.S. Department of Energy. SPA markets the hydroelectric power to preference customers: public bodies and cooperatives. SPA does not own transmission facilities.

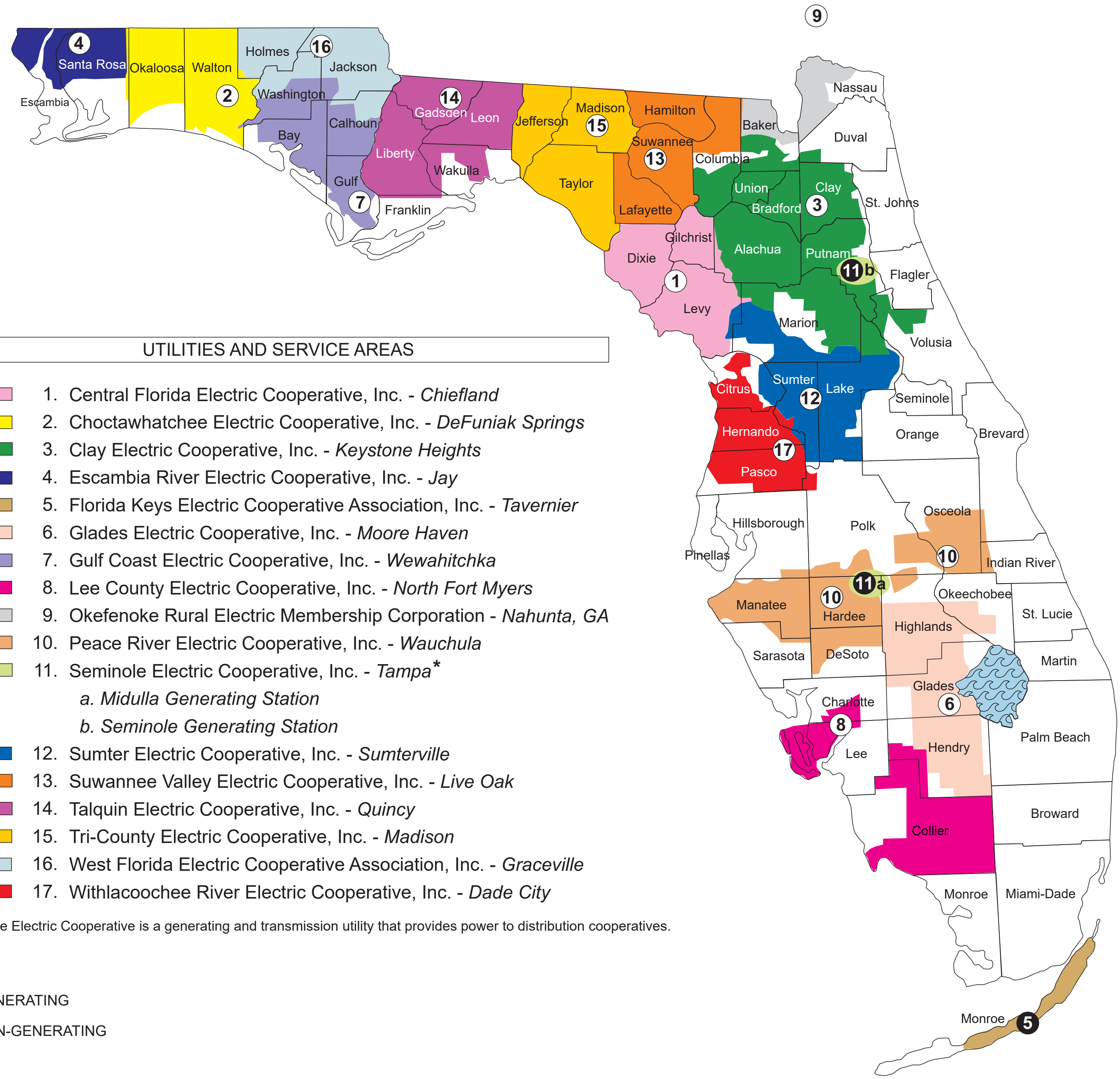
● GENERATING

○ NON-GENERATING

Excludes solar generation. Site locations are approximations. Information on the map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source: Florida Public Service Commission

Rural Electric Cooperatives



UTILITIES AND SERVICE AREAS

1. Central Florida Electric Cooperative, Inc. - *Chiefland*
2. Choctawhatchee Electric Cooperative, Inc. - *DeFuniak Springs*
3. Clay Electric Cooperative, Inc. - *Keystone Heights*
4. Escambia River Electric Cooperative, Inc. - *Jay*
5. Florida Keys Electric Cooperative Association, Inc. - *Tavernier*
6. Glades Electric Cooperative, Inc. - *Moore Haven*
7. Gulf Coast Electric Cooperative, Inc. - *Wewahitchka*
8. Lee County Electric Cooperative, Inc. - *North Fort Myers*
9. Okefenoke Rural Electric Membership Corporation - *Nahunta, GA*
10. Peace River Electric Cooperative, Inc. - *Wauchula*
11. Seminole Electric Cooperative, Inc. - *Tampa**
    - *a. Midulla Generating Station*
    - *b. Seminole Generating Station*
12. Sumter Electric Cooperative, Inc. - *Sumterville*
13. Suwannee Valley Electric Cooperative, Inc. - *Live Oak*
14. Talquin Electric Cooperative, Inc. - *Quincy*
15. Tri-County Electric Cooperative, Inc. - *Madison*
16. West Florida Electric Cooperative Association, Inc. - *Graceville*
17. Withlacoochee River Electric Cooperative, Inc. - *Dade City*

* Seminole Electric Cooperative is a generating and transmission utility that provides power to distribution cooperatives.

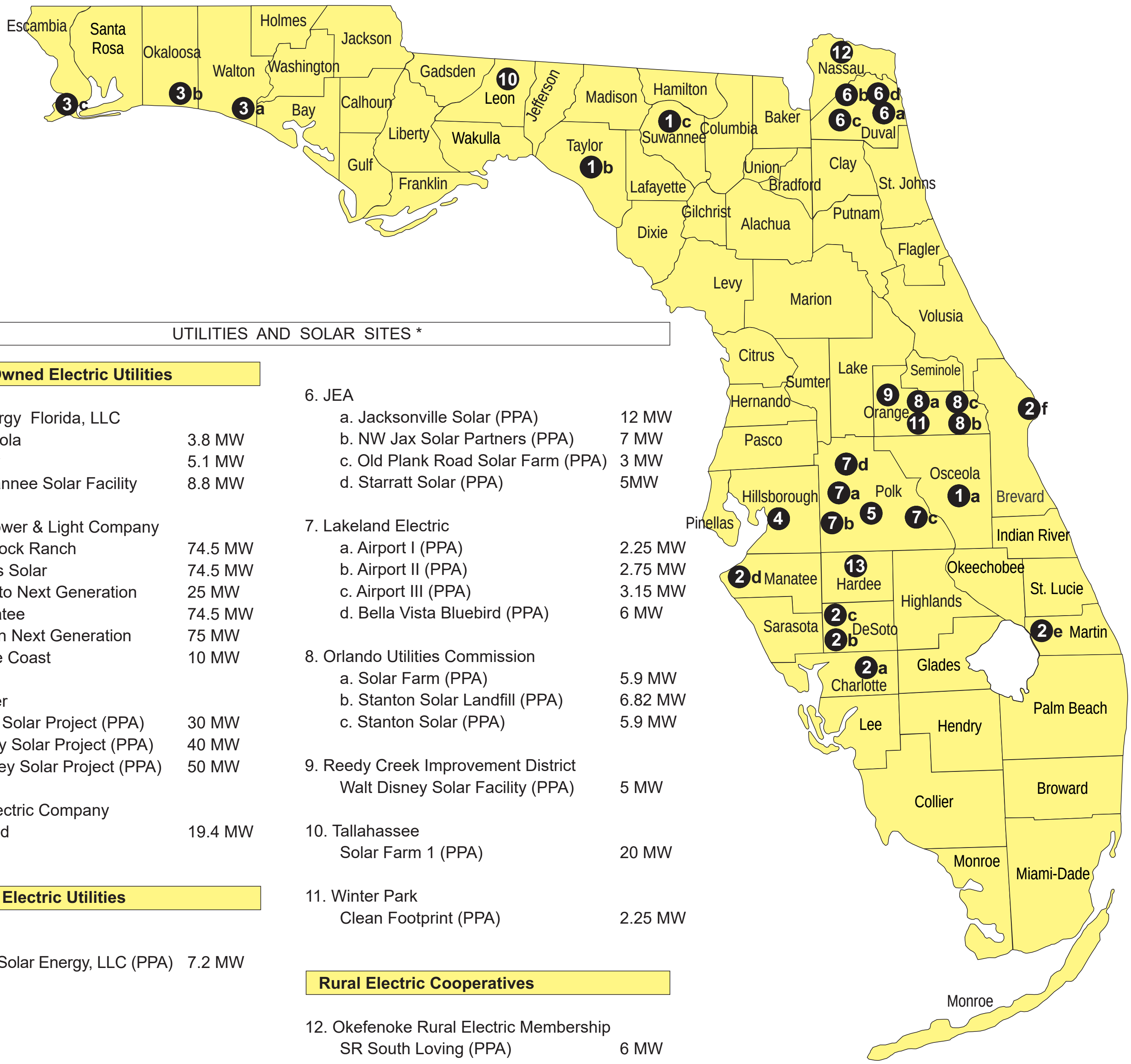
GENERATING

NON-GENERATING

Excludes solar generation. Service areas are approximations. Information on the map should be used only as a general guideline. For more detailed information, contact individual utilities.

Source: Florida Public Service Commission

Florida Solar Electric



UTILITIES AND SOLAR SITES *

Invester-Owned Electric Utilities

1. Duke Energy Florida, LLC
   - a. Osceola — 3.8 MW
   - b. Perry — 5.1 MW
   - c. Suwannee Solar Facility — 8.8 MW

2. Florida Power & Light Company
   - a. Babcock Ranch — 74.5 MW
   - b. Citrus Solar — 74.5 MW
   - c. Desoto Next Generation — 25 MW
   - d. Manatee — 74.5 MW
   - e. Martin Next Generation — 75 MW
   - f. Space Coast — 10 MW

3. Gulf Power
   - a. Eglin Solar Project (PPA) — 30 MW
   - b. Holley Solar Project (PPA) — 40 MW
   - c. Saufley Solar Project (PPA) — 50 MW

4. Tampa Electric Company
   - Big Bend — 19.4 MW

Municipal Electric Utilities

5. Bartow
   - Bartow Solar Energy, LLC (PPA) — 7.2 MW

6. JEA
   - a. Jacksonville Solar (PPA) — 12 MW
   - b. NW Jax Solar Partners (PPA) — 7 MW
   - c. Old Plank Road Solar Farm (PPA) — 3 MW
   - d. Starratt Solar (PPA) — 5MW

7. Lakeland Electric
   - a. Airport I (PPA) — 2.25 MW
   - b. Airport II (PPA) — 2.75 MW
   - c. Airport III (PPA) — 3.15 MW
   - d. Bella Vista Bluebird (PPA) — 6 MW

8. Orlando Utilities Commission
   - a. Solar Farm (PPA) — 5.9 MW
   - b. Stanton Solar Landfill (PPA) — 6.82 MW
   - c. Stanton Solar (PPA) — 5.9 MW

9. Reedy Creek Improvement District
   - Walt Disney Solar Facility (PPA) — 5 MW

10. Tallahassee
    - Solar Farm 1 (PPA) — 20 MW

11. Winter Park
    - Clean Footprint (PPA) — 2.25 MW

Rural Electric Cooperatives

12. Okefenoke Rural Electric Membership
    - SR South Loving (PPA) — 6 MW

13. Seminole Electric
    - Cooperative Solar facility - Hardee (PPA) — 2.2 MW

* 2 MW Threshold.

Site locations are approximations. Information on the map should be used only as a general guideline. For more detailed information, contact individual utilities.

Source: Florida Public Service Commission

Florida Electric Utility Industry
2017

Investor-Owned

Duke Energy Florida, LLC
Florida Power & Light Company
Florida Public Utilities Company
Gulf Power Company
Tampa Electric Company

Generating Municipal

Florida Municipal Power Agency *
Gainesville Regional Utilities
Homestead, City of
JEA (f/k/a Jacksonville Electric Authority)
Keys Energy Services (f/k/a Key West Utility Board)
Kissimmee Utility Authority
Lake Worth Utilities, City of
Lakeland Electric, City of
New Smyrna Beach, Utilities Commission of
Orlando Utilities Commission **
Reedy Creek Improvement District
Tallahassee, City of

Generating Rural Electric Cooperative

Florida Keys Electric Cooperative Association, Inc. ***
PowerSouth Energy Cooperative *
Seminole Electric Cooperative, Inc. *
USCE-Mobile District *

Generating - Other

Southeastern Power Administration *
(Jim Woodruff Dam)

Non-Generating Municipal

Alachua, City of
Bartow, City of
Beaches Energy Services (f/k/a City of Jacksonville Beach)
Blountstown, City of
Bushnell, City of
Chattahoochee, City of
Clewiston, City of
Fort Meade, City of
Fort Pierce Utilities Authority
Green Cove Springs, City of
Havana, Town of
Leesburg, City of
Moore Haven, City of
Mount Dora, City of
Newberry, City of
Ocala Electric Utility
Quincy, City of
St. Cloud, City of **
Starke, City of
Vero Beach, City of
Wauchula, City of
Williston, City of
Winter Park, City of

Non-Generating Rural Electric Cooperative

Central Florida Electric Cooperative, Inc.
Choctawhatchee Electric Cooperative, Inc.
Clay Electric Cooperative, Inc.
Escambia River Electric Cooperative, Inc.
Glades Electric Cooperative, Inc.
Gulf Coast Electric Cooperative, Inc.
Lee County Electric Cooperative, Inc.
Okefenoke Rural Electric Membership Corporation ****
Peace River Electric Cooperative, Inc.
Sumter Electric Cooperative, Inc.
Suwannee Valley Electric Cooperative, Inc.
Talquin Electric Cooperative, Inc.
Tri-County Electric Cooperative, Inc.
West Florida Electric Cooperative Association, Inc.
Withlacoochee River Electric Cooperative, Inc.

* Wholesale-only generating utility.
** Orlando Utilities Commission serves the City of St. Cloud.
*** The Florida Keys Electric Cooperative has a standby unit.
**** Okefenoke sells power in Florida and Georgia; figures reflect Florida customers only.

Counties Served by Generating Electric Utilities
2017

Utility	County
Investor-Owned	
Duke Energy Florida, LLC	Alachua, Bay, Brevard, Citrus, Columbia, Dixie, Flagler, Franklin, Gadsden, Gilchrist, Gulf, Hamilton, Hardee, Hernando, Highlands, Jefferson, Lafayette, Lake, Leon, Levy, Liberty, Madison, Marion, Orange, Osceola, Pasco, Pinellas, Polk, Seminole, Sumter, Suwannee, Taylor, Volusia, Wakulla
Florida Power & Light Company	Alachua, Baker, Bradford, Brevard, Broward, Charlotte, Clay, Collier, Columbia, DeSoto, Duval, Flagler, Glades, Hardee, Hendry, Highlands, Indian River, Lee, Manatee, Martin, Miami-Dade, Monroe, Nassau, Okeechobee, Palm Beach, Putnam, St. Johns, St. Lucie, Sarasota, Seminole, Suwannee, Union, Volusia
Gulf Power Company	Bay, Escambia, Holmes, Jackson, Okaloosa, Santa Rosa, Walton, Washington
Tampa Electric Company	Hillsborough, Pasco, Pinellas, Polk
Municipal	
Gainesville Regional Utilities	Alachua
Homestead	Miami-Dade
JEA	Clay, Duval, St. Johns
Keys Energy Services	Monroe
Kissimmee Utility Authority	Osceola
Lake Worth Utilities	Palm Beach
Lakeland Electric	Polk
New Smyrna Beach	Volusia
Orlando Utilities Commission *	Orange, Osceola
Reedy Creek Improvement District	Orange, Osceola
Tallahassee	Leon
Rural Electric Cooperative	
Florida Keys Electric Cooperative Association **	Monroe

* Orlando Utilities Commission serves the City of St. Cloud.

** The Florida Keys Electric Cooperative has a standby unit.

Counties Served by Non-Generating Electric Utilities

2017

Utility	County
Investor-Owned	
Florida Public Utilities Company	Calhoun, Jackson, Liberty, Nassau
Municipal	
Alachua	Alachua
Bartow	Polk
Beaches Energy Services	Duval, St. Johns
Blountstown	Calhoun
Bushnell	Sumter
Chattahoochee	Gadsden
Clewiston	Hendry
Fort Meade	Polk
Fort Pierce Utilities Authority	St. Lucie
Green Cove Springs	Clay
Havana	Gadsden
Leesburg	Lake
Moore Haven	Glades
Mount Dora	Lake
Newberry	Alachua
Ocala Electric Utility	Marion
Quincy	Gadsden
Starke	Osceola
St. Cloud *	Bradford
Vero Beach	Indian River
Wauchula	Hardee
Williston	Levy
Winter Park	Orange
Rural Electric Cooperative	
Central Florida Electric	Alachua, Dixie, Gilchrist, Lafayette, Levy, Marion
Choctawhatchee Electric	Holmes, Okaloosa, Santa Rosa, Walton
Clay Electric	Alachua, Baker, Bradford, Clay, Columbia, Flagler, Gilcrist, Lake, Levy, Marion, Putnam, Suwannee, Union, Volusia
Escambia River Electric	Escambia, Santa Rosa
Glades Electric	Glades, Hendry, Highlands, Okeechobee
Gulf Coast Electric	Bay, Calhoun, Gulf, Jackson, Walton, Washington
Lee County Electric	Charlotte, Collier, Hendry, Lee
Okefenoke Rural Electric **	Baker, Nassau
Peace River Electric	Brevard, DeSoto, Hardee, Highlands, Hillsborough, Indian River, Manatee, Osceola, Polk, Sarasota
Sumter Electric	Citrus, Hernando, Lake, Levy, Marion, Pasco, Sumter
Suwannee Valley Electric	Columbia, Hamilton, Lafayette, Suwannee
Talquin Electric	Franklin, Gadsden, Leon, Liberty, Wakulla
Tri-County Electric	Dixie, Jefferson, Madison, Taylor
West Florida Electric Cooperative Association	Calhoun, Holmes, Jackson, Washington
Withlacoochee River Electric	Citrus, Hernando, Pasco, Polk, Sumter

* The City of St. Cloud is served by Orlando Utilities Commission.

** Okefenoke sells power in Florida and Georgia; figures reflect Florida customers only.

Highlights of the Florida Electric Utility Industry

2013-2017

	2013	2014	2015	2016	2017
Total Installed Capacity (Megawatts) *	57,999	58,888	58,422	58,295	58,506
Installed Capacity by Fuel Type (Percentage)					
Natural Gas	54%	55%	55%	58%	63%
Coal	21	21	21	17	20
Nuclear	6	6	6	6	6
Other **	19	18	18	18	11
Total *	100%	100%	100%	100%	100%
Energy Sales (Gigawatt-hours)					
Residential	104,999	116,529	122,535	123,449	121,687
Commercial	74,146	76,238	88,530	85,147	84,617
Industrial	18,487	25,913	16,617	20,848	20,670
Other	6,973	7,998	6,437	6,708	6,746
Total	204,605	226,678	234,119	236,152	233,720
Number of Customers (Thousands)					
Residential	8,076	8,881	9,130	9,197	9,398
Commercial	985	1,079	1,133	1,134	1,150
Industrial	29	41	20	29	28
Other	131	199	132	135	143
Total	9,221	10,200	10,415	10,495	10,719
Average Residential Bill (1,000 KWh) ***	$123.75	$125.50	$116.62	$113.58	$115.86

* May not total due to rounding.

** Other includes: oil, interchange, non-utility generation, and renewables.

*** Unweighted average of all utilities: investor-owned, municipal, and rural electric cooperative.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Public Service Commission, Review of Ten-Year Site Plan, Nov. 2017; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 1.0, p. S-7; Responses to staff data request.

Financial Statistics of
Investor-Owned Utilities (IOUs)

Table 1

Rate of Return

2013-2017

	2013	2014	2015	2016	2017
Average per Book Rate of Return					
Duke Energy Florida, LLC	6.93%	6.10%	5.70%	5.97%	6.39%
Florida Power & Light Company	7.02	7.58	7.59	7.30	6.95
Gulf Power Company	5.53	5.55	5.45	5.01	5.41
Tampa Electric Company	6.16	6.56	6.52	6.36	6.31
Average Adjusted Rate of Return					
Duke Energy Florida, LLC	7.14%	6.48%	6.70%	6.34%	6.38%
Florida Power & Light Company	6.57	6.81	6.84	6.63	6.32
Gulf Power Company	5.10	5.73	5.79	5.18	5.68
Tampa Electric Company	6.12	6.66	6.64	6.48	6.41
FPSC Authorized Rate of Return *					
Duke Energy Florida, LLC	7.04%	7.02%	6.90%	6.65%	6.68%
Florida Power & Light Company	6.36	6.34	6.37	6.17	6.09
Gulf Power Company	5.75	5.75	5.56	5.45	5.47
Tampa Electric Company	6.48	6.30	6.22	6.12	6.03
Adjusted Jurisdictional Year-End Rate Base (Millions)					
Duke Energy Florida, LLC	$8,353	$9,556	$10,133	$10,485	$11,339
Florida Power & Light Company	24,417	26,472	27,760	31,457	34,619
Gulf Power Company	1,925	1,930	2,000	2,106	2,487
Tampa Electric Company	4,026	4,248	4,445	4,724	5,592

* Average Capital Structure - Midpoint.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Public Service Commission, December 2017 Earnings Surveillance Report, Schedule 1.

Table 2

Sources of Revenue
(Percentage of Total Sales) *
2013-2017

	2013	2014	2015	2016	2017
Duke Energy Florida, LLC					
Residential	58.49%	55.84%	56.32%	57.78%	57.71%
Commercial	28.11	26.28	25.98	25.39	26.08
Industrial	6.12	6.30	6.21	5.82	5.92
Other	7.28	6.89	6.80	6.56	6.76
Sales for Resale	4.68	4.69	4.70	4.45	3.52
Total	100%	100%	100%	100%	100%
Total Sales (Millions)	$3,917.13	$4,578.10	$4,661.86	$4,160.85	$4,248.08
Florida Power & Light Company					
Residential	56.45%	55.35%	56.14%	56.46%	56.77%
Commercial	38.65	37.42	36.79	36.59	36.52
Industrial	1.93	1.85	1.81	1.77	1.75
Other	0.85	0.80	0.79	0.82	0.85
Sales for Resale	2.13	4.58	4.47	4.37	4.12
Total	100%	100%	100%	100%	100%
Total Sales (Millions)	$9,947.18	$11,016.83	$11,196.35	$10,532.48	$11,421.96
Gulf Power Company					
Residential	44.91%	45.93%	49.30%	50.55%	49.86%
Commercial	27.77	26.73	28.78	28.83	28.53
Industrial	9.62	9.99	10.43	10.63	9.97
Other	2.24	0.30	0.31	0.31	0.33
Sales for Resale	15.46	17.05	11.17	9.69	11.31
Total	100%	100%	100%	100%	100%
Total Sales (Millions)	$1,337.71	$1,518.01	$1,489.56	$1,415.66	$1,443.92
Tampa Electric Company					
Residential	49.93%	51.17%	52.29%	52.55%	52.44%
Commercial	30.98	30.58	30.56	30.11	30.11
Industrial	9.18	8.35	8.05	8.17	8.24
Other	9.45	9.24	8.91	8.85	8.78
Sales for Resale	0.45	0.66	0.19	0.32	0.43
Total	100%	100%	100%	100%	100%
Total Sales (Millions)	$1,876.15	$1,969.01	$1,989.34	$1,970.65	$1,917.86

* May not total due to rounding.

Source: Florida Public Service Commission, 2017 Annual Report, FERC Form No. 1, p. 300; Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry.

Table 3

Uses of Revenue
(Percentage of Total Operating Revenue) *
2013-2017

	2013	2014	2015	2016	2017
Duke Energy Florida, LLC					
Fuel	33.04%	31.56%	27.38%	26.64%	27.84%
Other Operation and Maintenance	34.32	30.33	29.86	35.68	32.77
Depreciation and Amortization	-0.12	9.86	14.06	7.47	7.93
Taxes Other Than Income Taxes	7.29	6.92	7.10	7.42	7.66
Income Taxes	9.07	6.76	6.27	6.74	6.78
Interest	4.03	3.98	4.01	4.36	5.48
Net Operating Income Less Interest	12.36	10.60	11.32	11.70	11.56
Total	100%	100%	100%	100%	100%
Total Operating Revenue (Millions)	$4,498.24	$4,940.40	$4,936.08	$4,469.85	$4,512.68
Florida Power & Light Company					
Fuel	30.51%	31.34%	28.66%	26.68%	26.84%
Other Operation and Maintenance	22.80	20.74	21.99	18.36	28.10
Depreciation and Amortization	10.83	11.55	12.07	12.74	4.39
Taxes Other Than Income Taxes	11.00	10.44	10.55	11.17	11.15
Income Taxes	8.60	8.78	8.45	10.08	11.04
Interest	3.82	3.73	3.72	4.12	4.00
Net Operating Income Less Interest	12.44	13.41	14.57	16.86	14.47
Total	100%	100%	100%	100%	100%
Total Operating Revenue (Millions)	$10,214.49	$11,189.33	$11,467.74	$10,691.84	$11,594.06
Gulf Power Company					
Fuel	36.92%	37.92%	29.98%	29.07%	28.17%
Other Operation and Maintenance	27.51	28.29	32.97	32.24	33.90
Depreciation and Amortization	10.41	9.16	9.07	10.85	8.93
Taxes Other Than Income Taxes	6.83	6.99	7.94	8.07	7.67
Income Taxes	5.54	5.53	6.09	5.87	6.94
Interest	3.89	3.35	3.72	3.70	3.31
Net Operating Income Less Interest	8.90	8.76	10.24	10.21	11.07
Total	100%	100%	100%	100%	100%
Total Operating Revenue (Millions)	$1,440.41	$1,590.59	$1,483.01	$1,484.63	$1,516.49
Tampa Electric Company					
Fuel	35.54%	35.73%	31.78%	28.73%	30.99%
Other Operation and Maintenance	24.38	23.83	24.01	25.82	22.22
Depreciation and Amortization	12.05	11.20	13.88	15.58	11.33
Taxes Other Than Income Taxes	7.76	7.63	7.62	7.72	8.15
Income Taxes	6.02	6.53	6.98	6.39	8.49
Interest	4.77	4.60	4.66	4.53	5.24
Net Operating Income Less Interest	9.49	10.49	11.08	11.23	13.58
Total	100%	100%	100%	100%	100%
Total Operating Revenue (Millions)	$1,936.62	$2,029.54	$2,053.05	$2,024.12	$1,987.79

* May not total due to rounding.

Source: Florida Public Service Commission, 2017 Annual Report, FERC Form No. 1, pp. 114, 117, 311, 320-321, and 323; Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry.

Table 4

Proprietary Capital and Long-Term Debt *

December 31, 2017

	Duke Energy Florida, LLC	Florida Power & Light Company	Gulf Power Company	Tampa Electric Company
Proprietary Capital (Thousands)				
Common Stock	$0	$1,373,069	$678,060	$119,697
Preferred Stock	0	0	0	0
Retained Earnings	3,847,054	7,375,695	259,071	216,322
Other Paid-In Capital	1,766,035	8,294,959	594,193	2,250,840
Other Adjustments	4,835	-3,741	-491	-2,002
Total Proprietary Capital	$5,617,924	$17,039,982	$1,530,833	$2,584,857
Long-Term Debt (Thousands)				
Bonds	$5,025,000	$9,928,271	$0	$1,920,930
Other Long-Term Debt and/or Adjustments	765,015	1,463,205	1,294,202	-2,780
Total Long-Term Debt	$5,790,015	$11,391,476	$1,294,202	$1,918,150
Total Proprietary Capital and Long-Term Debt	$11,407,939	$28,431,458	$2,825,035	$4,503,007
Proprietary Capital (Percent)				
Common Stock	0.0%	4.8%	24.0%	2.7%
Preferred Stock	0.0	0.0	0.0	0.0
Retained Earnings	33.7	25.9	9.2	4.8
Other Paid-In Capital	15.5	29.2	21.0	50.0
Other Adjustments	0.0	0.0	0.0	0.0
Total Proprietary Capital	49.2%	59.9%	54.2%	57.5%
Long-Term Debt (Percent)				
Bonds	44.0%	34.9%	0.0%	42.7%
Other Long-Term Debt and/or Adjustments	6.7	5.1	45.8	-0.1
Total Long-Term Debt	50.7%	40.0%	45.8%	42.6%
Total Proprietary Capital and Long-Term Debt	100%	100%	100%	100%

* May not total due to rounding.

Source: Florida Public Service Commission, 2017 Annual Report, FERC Form No. 1, p. 112.

Table 5

Financial Integrity Indicators

2013-2017

	2013	2014	2015	2016	2017
Times Interest Earned with AFUDC					
Duke Energy Florida, LLC	3.77 x	4.35 x	4.35 x	5.01 x	3.59 x
Florida Power & Light Company	6.00	6.38	6.61	6.84	6.96
Gulf Power Company	4.56	5.05	5.09	5.21	5.56
Tampa Electric Company	4.23	4.64	4.70	4.68	5.23
Times Interest Earned without AFUDC					
Duke Energy Florida, LLC	3.71 x	4.34 x	4.31 x	4.82 x	3.35 x
Florida Power & Light Company	5.81	6.27	6.42	6.64	6.76
Gulf Power Company	4.40	4.75	4.79	5.21	5.55
Tampa Electric Company	4.12	4.48	4.45	4.34	5.20
AFUDC as a Percentage of Net Income Interest Coverage Ratio					
Duke Energy Florida, LLC	3.71 %	0.24 %	1.76 %	6.29 %	8.35 %
Florida Power & Light Company	5.25	2.94	4.88	5.09	4.90
Gulf Power Company	6.87	10.93	10.80	-0.01	0.07
Tampa Electric Company	4.45	6.08	9.26	12.44	0.75
Percent Internally Generated Funds					
Duke Energy Florida, LLC	119.03 %	116.65 %	82.02 %	96.78 %	69.21 %
Florida Power & Light Company	76.59	64.75	74.83	82.44	45.38
Gulf Power Company	71.13	51.15	100.65	142.32	90.11
Tampa Electric Company	91.61	62.78	75.04	87.81	112.53

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Public Service Commission, December 2017 Earnings Surveillance Report, Schedule 1.

Net Generation

Table 6

Net Energy for Load

2008-2017

Year	Total Net Energy for Load (Gigawatt-Hours)	Investor-Owned		Other *	
		Quantity (Gigawatt-Hours)	Percent of Total	Quantity (Gigawatt-Hours)	Percent of Total
2008	240,910	191,929	79.7%	48,981	20.3%
2009	239,414	187,345	78.3	52,069	21.7
2010	247,169	193,820	78.4	53,349	21.6
2011	237,658	186,328	78.4	51,330	21.6
2012	234,366	182,998	78.1	51,368	21.9
2013	235,025	183,156	77.9	51,869	22.1
2014	238,611	188,310	78.9	50,301	21.1
2015	248,406	197,137	79.4	51,269	20.6
2016	248,019	196,676	79.3	51,343	20.7
2017	246,033	195,679	79.5	50,354	20.5

* Includes municipal, rural electric cooperative, and federally-owned utilities.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Public Service Commission, Utility Ten-Year Site Plans (April 2018), Schedule Nos. 2.3 and 3.3; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 9.1, p. S-17.

Table 7

Net Energy for Load (NEL) by Fuel Type and Other Sources *

2008-2017

	Coal		Oil		Natural Gas		Nuclear		Hydro		NEL	Other Sources		NEL
Year	Gigawatt-Hours	Percent	Gigawatt-Hours	Percent	Gigawatt-Hours	Percent	Gigawatt-Hours	Percent	Gigawatt-Hours	Percent	Subtotal	NUG **	Other ***	Total
2008	69,116	33.2%	9,267	4.5%	97,386	46.8%	32,122	15.4%	22	1.1%	207,913	2,881	30,116	240,910
2009	57,901	27.6	6,283	3.0	116,062	55.4	29,202	13.9	28	0.0	209,476	2,956	26,982	239,414
2010	61,323	28.3	5,925	2.7	125,546	57.8	24,215	11.2	25	0.0	217,034	2,971	27,164	247,169
2011	56,014	25.8	1,178	0.5	137,243	63.2	22,828	10.5	8	0.0	217,271	2,611	17,776	237,658
2012	47,542	21.8	682	0.3	151,856	69.6	18,088	8.3	9	0.0	218,177	2,982	13,207	234,366
2013	50,775	23.3	487	0.2	140,187	64.3	26,672	12.2	29	0.0	218,150	3,182	13,693	235,025
2014	55,410	24.7	447	0.2	140,348	62.6	27,730	12.4	162	0.1	224,097	1,799	12,715	238,611
2015	46,685	20.2	592	0.3	156,348	67.5	27,872	12.0	162	0.1	231,659	1,841	14,906	248,406
2016	43,638	18.9	1,733	0.8	156,007	67.7	29,052	12.6	25	0.0	230,455	171	17,393	248,019
2017	42,573	18.4	487	0.2	159,719	68.9	29,080	12.5	17	0.0	231,876	1,942	12,215	246,033

* May not total due to rounding.

** Non-utility generation.

*** Includes net interchange, non-hydro renewables, and other.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 9.1, p. S-17.

Table 8

Projected Net Energy for Load by Fuel Type and Other Sources
(Gigawatt-Hours)
2018-2027

Year	Net Energy for Load	Interchange & Other *	Nuclear	Coal	Oil	Natural Gas	Hydro	NUG
2018	245,856	13,994	31,409	39,159	188	158,979	19	2,108
2019	248,490	15,287	31,486	37,486	140	161,963	19	2,109
2020	250,625	17,151	31,559	36,932	68	162,779	19	2,117
2021	252,352	18,622	31,481	38,166	72	161,880	19	2,112
2022	254,286	24,919	31,458	35,183	70	160,523	19	2,114
2023	255,658	26,016	31,486	28,319	61	167,642	19	2,115
2024	258,007	27,278	31,546	29,434	91	168,640	19	999
2025	259,742	26,405	31,462	30,443	109	170,614	19	690
2026	261,844	28,038	31,468	30,165	139	171,818	19	197
2027	264,070	27,817	31,445	31,196	152	173,243	19	198

* Includes net interchange, non-hydro renewables, and other.

Source: Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 9.1, p. S-17.

Table 9

Projected Net Energy for Load by Percentage of Fuel Type and Other Sources

2018-2027

Year	Net Energy for Load *	Interchange & Other **	Nuclear	Coal	Oil	Natural Gas	Hydro	NUG
2018	100%	5.69%	12.78%	15.93%	0.08%	64.66%	0.01%	0.86%
2019	100	6.15	12.67	15.09	0.06	65.18	0.01	0.85
2020	100	6.84	12.59	14.74	0.03	64.95	0.01	0.84
2021	100	7.38	12.48	15.12	0.03	64.15	0.01	0.84
2022	100	9.80	12.37	13.84	0.03	63.13	0.01	0.83
2023	100	10.18	12.32	11.08	0.02	65.57	0.01	0.83
2024	100	10.57	12.23	11.41	0.04	65.36	0.01	0.39
2025	100	10.17	12.11	11.72	0.04	65.69	0.01	0.27
2026	100	10.71	12.02	11.52	0.05	65.62	0.01	0.08
2027	100	10.53	11.91	11.81	0.06	65.60	0.01	0.07

* May not total due to rounding.

**Includes net interchange, non-hydro renewables, and non-utility generation.

Source: Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 9.1, p. S-17.

Generating Capacity and Capability

Table 10

Installed Nameplate Capacity/Firm Summer Net Capability
(Megawatts)
2008-2017

Year	Hydro-Electric	Conventional Steam	Nuclear Steam	Combustion Turbine	Internal Combustion	Combined Cycle	Solar Photovoltaic	Total *
2008	63	21,719	3,931	8,333	239	16,260	0	50,544
2009	52	19,611	3,991	8,096	184	20,275	0	52,208
2010	52	20,563	3,913	7,278	175	21,245	0	53,226
2011	52	19,909	3,947	8,013	171	22,908	0	54,999
2012	52	17,837	3,471	8,697	153	22,192	0	52,402
2013	52	17,837	3,471	8,697	153	22,192	0	52,402
2014	52	17,684	3,600	7,755	115	25,312	15	54,533
2015	51	17,616	3,599	7,940	108	24,866	15	54,195
2016	51	16,774	3,599	7,345	108	26,130	132	54,139
2017	51	16,649	3,599	6,830	125	27,662	148	55,064

* May not total due to rounding.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 1.0, pp. 8-20, S-8, and S-9.

Table 11

Installed Nameplate Capacity/Summer Net Capability by Type of Ownership
(Megawatts)
2008-2017

Year	Total for State *	Investor-Owned		Municipal, Rural Electric Cooperative, and Other **	
		Quantity	Percent of Total	Quantity	Percent of Total
2008	50,544	38,218	75.61%	12,326	24.39%
2009	52,208	39,788	76.21	12,420	23.79
2010	53,226	40,161	75.45	13,065	24.55
2011	54,999	41,367	75.21	13,633	24.79
2012	52,402	38,890	74.22	13,512	25.78
2013	52,402	38,890	74.22	13,512	25.78
2014	54,533	41,266	75.67	13,267	24.33
2015	54,195	41,018	75.69	13,177	24.31
2016	54,139	41,050	75.82	13,089	24.18
2017	55,064	41,915	76.12	13,149	23.88

* May not total due to rounding.

** USCE-Mobile District and Jim Woodruff Dam.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 1.0, pp. 7-20, S-8, and S-9.

Table 12

Installed Capacity by Fuel and Technology
(Megawatts)
2015-2017

Fuel	Technology	2015	2016	2017
Natural Gas				
	Combined Cycle	24,383	24,384	25,758
	Turbine & Diesel	6,107	6,107	6,280
	Steam	2,057	2,057	5,060
Total Natural Gas		32,547	32,548	37,098
Percentage of Total		54.78%	58.38%	62.70%
Coal				
	Steam	12,116	9,161	11,736
	Combined Cycle	220	220	220
Total Coal		12,336	9,381	11,956
Percentage of Total		20.76%	16.83%	20.21%
Oil				
	Turbine & Diesel	2,497	2,390	1,551
	Steam	3,663	3,640	0
Total Oil		6,160	6,030	1,551
Percentage of Total		10.37%	10.82%	2.62%
Nuclear				
	Steam	3,600	3,599	3,599
Total Nuclear		3,600	3,599	3,599
Percentage of Total		6.06%	6.46%	6.08%
Other *				
		4,772	4,197	4,968
Total Other		4,772	4,197	4,968
Percentage of Total		8.03%	7.53%	8.40%
Total Installed Capacity		59,415	55,755	59,172
Percentage of Total **		100%	100%	100%

* Includes all renewable resources, net interchange, and non-utility generation.

** May not total due to rounding.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Public Service Commission, Review of the Ten-Year Site Plans, Nov. 2017.

Table 13

Installed Winter and Summer Net Capacity by Utility *
(Megawatts)
2016-2017

Utility	Winter Net Capacity		Summer Net Capacity	
	2016	2017	2016	2017
Investor-Owned				
Duke Energy Florida, LLC	9,447	9,807	8,323	8,720
Florida Power & Light Company	27,828	27,772	26,139	26,120
Gulf Power Company	2,290	2,311	2,251	2,272
Tampa Electric Company	4,728	5,196	4,337	4,803
Generating Municipal				
Florida Municipal Power Agency **	1,323	1,324	1,283	1,284
Gainesville Regional Utilities	550	659	521	630
Homestead	32	32	32	32
JEA	4,110	4,110	3,769	3,769
Keys Energy Services	37	37	37	37
Kissimmee Utility Authority	253	254	242	242
Lake Worth Utilities	80	80	77	77
Lakeland Electric	890	890	844	844
New Smyrna Beach	48	48	44	44
Orlando Utilities Commission ***	1,528	1,531	1,482	1,493
Reedy Creek Improvement District	55	54	55	54
Tallahassee	822	772	746	700
Generating Rural Electric Cooperative				
PowerSouth Energy **	2,098	2,086	1,902	1,887
Seminole Electric **	2,178	2,178	2,012	2,012
USCE-Mobile District **	44	44	44	44
Total Utility ^	**58,340**	**59,185**	**54,139**	**55,064**
Total Non-Utility ^^	4,446	3,709	4,156	3,442
Total State of Florida ^	**62,786**	**62,894**	**58,295**	**58,506**

* Includes generation physically located outside Florida if it serves load in Florida.

** Wholesale-only generating utility.

*** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

^ May not total due to rounding.

^^ Does not include the capacity of merchant plants.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 1.0, pp. 7 and S-7.

Table 14

Summer Net Capacity by Generation by Utility *

(Megawatts)

December 31, 2017

Utility	Hydro-Electric	Conventional Steam	Nuclear Steam	Combustion Turbine	Internal Combustion	Combined Cycle	Solar photovoltaic	Total
Investor-Owned								
Duke Energy Florida, LLC	0	3,201	0	1,954	0	3,557	8	8,720
Florida Power & Light Company	0	4,132	3,453	2,158	0	16,247	131	26,120
Gulf Power Company	0	1,648	0	44	3	577	0	2,272
Tampa Electric Company	0	1,602	0	280	0	2,911	10	4,803
Generating Municipal								
Florida Municipal Power Agency **	0	240	86	161	0	796	0	1,284
Gainesville Regional Utilities	0	406	0	110	7	108	0	630
Homestead	0	0	0	0	32	0	0	32
JEA	0	2,306	0	812	0	651	0	3,769
Keys Energy Services	0	0	0	19	18	0	0	37
Kissimmee Utility Authority	0	21	0	25	0	196	0	242
Lake Worth Utilities	0	22	0	46	9	0	0	77
Lakeland Electric	0	311	0	35	55	443	0	844
New Smyrna Beach	0	0	0	44	0	0	0	44
Orlando Utilities Commission ***	0	760	60	197	0	476	0	1,493
Reedy Creek Improvement District	0	0	0	0	0	54	0	54
Tallahassee	0	76	0	102	0	522	0	700
Generating Rural Electric Cooperative								
PowerSouth Energy **	7	665	0	574	0	641	0	1,887
Seminole Electric **	0	1,260	0	270	0	482	0	2,012
USCE-Mobile District **	44	0	0	0	0	0	0	44
Total Utility ^	**51**	**16,649**	**3,599**	**6,830**	**125**	**27,662**	**148**	**55,064**
Total Non-Utility ^^								3,442
Total State of Florida ^	**51**	**16,649**	**3,599**	**6,830**	**125**	**27,662**	**148**	**58,506**

* Includes generation physically located outside Florida if it serves load in Florida.

** Wholesale-only generating utility.

*** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

^ May not total due to rounding.

^^ Does not include the capacity of merchant plants.

Source: Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 1.0, pp. 7-20, S-8, and S-9.

Table 15

Nuclear Generating Units

December 31, 2017

Utility	Location	Commercial In-Service Month/Year	Maximum Nameplate Rating KW	Net Capacity Summer MW	Net Capacity Winter MW
Florida Power & Light Company					
St. Lucie #1	St. Lucie County	May-76	1,080,000	981	1,003
St. Lucie #2	St. Lucie County	Jun-83	919,128	840 *	860 *
Turkey Point #3	Miami-Dade County	Dec-72	877,200	811	839
Turkey Point #4	Miami-Dade County	Sep-73	877,200	821	848

* 14.9% of plant capacity is owned by Orlando Utilities Commission and Florida Municipal Power Agency; figures shown represent FP&L share.

Sources: Florida Public Service Commission, FP&L Ten-Year Site Plan (April 2018), Schedule 1, p. 26; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 1.0, p. 13.

Table 16, Page 1 of 2

Annual Peak Demand
(Megawatts)
2013-2017

Utility	2013	2014	2015	2016	2017
Investor-Owned					
Duke Energy Florida, LLC	8,779	9,219	9,475	9,728	9,296
Florida Power & Light Company	21,576	22,935	22,959	23,858	23,373
Florida Public Utilities Company	NR*	NR	161	147	144
Gulf Power Company	2,362	2,694	2,495	2,508	2,434
Tampa Electric Company	3,873	4,054	4,013	4,131	4,115
Generating Municipal					
Florida Municipal Power Agency **	NR	NR	NR	1,296	1,263
Gainesville Regional Utilities	416	409	421	428	418
Homestead	NR	101	102	105	110
JEA	2,596	2,823	2,863	2,763	2,727
Keys Energy Services	138	144	148	148	149
Kissimmee Utility Authority	314	327	335	354	353
Lake Worth Utilities	NR	92	93	96	95
Lakeland Electric	602	627	656	646	643
New Smyrna Beach	86	91	101	101	97
Orlando Utilities Commission ***	NR	1,297	1,171	1,189	1,378
Reedy Creek Improvement District	NR	190	189	195	191
Tallahassee	NR	574	600	597	598
Non-Generating Municipal					
Alachua	NR	26	27	28	28
Bartow	58	59	65	63	63
Beaches Energy Services	168	192	195	178	171
Blountstown	NR	9	9	8	9
Bushnell	NR	6	7	6	6
Chattahoochee	7	8	8	8	7
Clewiston	185	21	22	22	22
Fort Meade	9	10	11	9	9
Fort Pierce Utilities Authority	104	106	107	112	112
Green Cove Springs	NR	27	28	26	25
Havana	NR	6	6	6	6

* Not Reported.

** Wholesale-only generating utility.

*** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

Table 16, Page 2 of 2

Annual Peak Demand
(Megawatts)
2013-2017

Utility	2013	2014	2015	2016	2017
Non-Generating Municipal (Continued)					
Leesburg	106	100	106	112	116
Moore Haven	NR*	3	36	4	4
Mount Dora	22	22	22	22	22
Newberry	NR	8	9	8	8
Ocala Electric Utility	NR	285	287	305	291
Quincy	NR	30	28	26	13
Starke	15	15	15	16	15
Vero Beach	151	159	167	161	157
Wauchula	NR	13	13	14	14
Williston	NR	8	8	9	8
Winter Park	NR	96	95	79	83
Generating & Non-Generating Rural Electric Cooperative					
Central Florida Electric	129	128	136	129	123
Choctawhatchee Electric	178	234	225	192	205
Clay Electric	NR	775	839	788	735
Escambia River Electric	NR	59	55	46	51
Florida Keys Electric **	145	156	161	149	154
Glades Electric	61	76	78	68	67
Gulf Coast Electric	NR	104	100	90	90
Lee County Electric	NR	816	885	868	877
Okefenoke Rural Electric ***	26	31	31	28	27
Peace River Electric	134	139	154	161	164
PowerSouth Energy ^	392	541	510	440	470
Seminole Electric ^	3,707	3,218	3,403	3,318	4,010
Sumter Electric	678	714	805	788	756
Suwannee Valley Electric	108	117	120	107	120
Talquin Electric	NR	285	279	253	268
Tri-County Electric	NR	72	71	70	67
West Florida Electric	115	136	139	123	128
Withlacoochee River Electric	939	980	1,074	1,019	902

* Not Reported.

** The Florida Keys Electric Cooperative has a standby unit.

*** Okefenoke sells power in Florida and Georgia; figures reflect Florida customers only.

^ Wholesale-only generating utility.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Responses to staff data request.

Table 17

Projected Summer and Winter Peak Demand
(Megawatts)
2018-2027

Year	Summer Peak	Year	Winter Peak
2018	50,319	2018-2019	46,899
2019	51,101	2019-2020	47,451
2020	51,587	2020-2021	48,065
2021	52,201	2021-2022	48,558
2022	52,720	2022-2023	49,046
2023	53,248	2023-2024	49,597
2024	53,890	2024-2025	50,035
2025	54,463	2025-2026	50,623
2026	55,089	2026-2027	51,777
2027	55,730	2027-2028	51,662

Source: Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form History and Forecast, p. S-1.

Table 18

Load Factors of Generating Utilities

December 31, 2017

Utility	Net Energy for Load (Gigawatt-Hours)	Peak Load (Megawatts)	Load Factor (Percentage) *
Investor-Owned			
Duke Energy Florida, LLC	42,955	9,296	52.7%
Florida Power & Light Company	120,747	23,373	59.0
Gulf Power Company	11,703	2,434	54.9
Tampa Electric Company	20,296	4,115	56.3
Municipal			
Florida Municipal Power Agency **	5,984	1,263	54.1
Gainesville Regional Utilities	2,031	418	55.5
Homestead	560	110	58.1
JEA	12,830	2,727	53.7
Keys Energy Services	753	149	57.9
Kissimmee Utility Authority	1,599	353	51.7
Lake Worth Utilities	470	95	56.3
Lakeland Electric	3,086	643	54.8
New Smyrna Beach	414	97	48.8
Orlando Utilities Commission ***	8,225	1,378	68.1
Reedy Creek Improvement District	1,233	191	73.7
Tallahassee	2,758	598	52.7
Rural Electric Cooperative			
PowerSouth Energy **	1,986	470	48.2
Seminole Electric **	14,569	4,010	41.5

* May not total due to rounding.

** Wholesale-only generating utility.

*** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

Source: Responses to staff data request.

Renewable Energy, Energy Efficiency and Conservation

Table 19

Renewable Generation Capacity
(Megawatts)
2014-2017

Renewable Type *	2014	2015	2016	2017
Biomass	581	581	582	583
Hydro	64	64	63	63
Landfill Gas	49	47	87	83
Municipal Solid Waste	398	400	545	446
Solar	218	228	263	538
Waste Heat	308	308	310	306
Wind	0	10	10	188
Total	1,618	1,638	1,860	2,207

* Renewable generation includes investor-owned, customer-owned, and non utility-owned (acquired through purchase power agreements).

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Public Service Commission, Review of the Ten-Year Site Plans, Nov. 2017.

Table 20

Customer-Owned Photovoltaic Facilities *

2014-2017

	2014	2015	2016	2017
Number of Solar Energy Systems				
Duke Energy Florida, LLC	2,065	2,967	4,445	7,470
Florida Power & Light Company	3,234	4,250	5,411	7,518
Florida Public Utilities Company	59	69	87	109
Gulf Power Company	366	465	503	884
Tampa Electric Company	567	810	1,097	1,843
Municipal	1,202	1,616	2,375	3,410
Rural Electric Cooperative	1,053	1,423	2,047	2,895
Total	8,546	11,600	15,965	24,129
**Gross Power Rating (MW)(AC) ** **				
Duke Energy Florida, LLC	18	28	37	58
Florida Power & Light Company	30	40	49	68
Florida Public Utilities Company	0.0	0.3	0.5	0.6
Gulf Power Company	2	2	3	5
Tampa Electric Company	8	10	12	19
Municipal	10	13	19	28
Rural Electric Cooperative	6	9	13	18
Total ***	74.0	102.3	133.5	196.6
Energy Delivered to the Grid (MWh)				
Duke Energy Florida, LLC	8,090	12,153	20,611	29,171
Florida Power & Light Company	15,542	19,922	24,347	30,651
Florida Public Utilities Company	140	187	290	345
Gulf Power Company	991	3,849	5,507	8,431
Tampa Electric Company	3,870	4,307	5,983	8,239
Municipal	4,253	5,493	8,436	14,553
Rural Electric Cooperative	3,913	3,678	5,142	6,879
Total	36,799	49,588	70,316	98,269

* Includes demonstration sites.

** Alternating Current

*** May not total due to rounding.

Source: Annual Net Metering Report, 2017; Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry.

Table 21

Demand-Side Management Programs
Amount of Load Reduction at the Generator *
2014-2017

	2014	2015	2016	2017
Summer Peak Reduction (MW)				
Duke Energy Florida, LLC	61	60	176	82
Florida Power & Light Company	142	86	52	62
Florida Public Utilities Company	0.9	0.8	1.0	0.4
Gulf Power Company	22	20	5	5
JEA	3	3	7	4
Orlando Utilities Commission **	1	3	3	6
Tampa Electric Company	26	23	10	15
Total ***	255.9	195.8	254.0	174.4
Winter Peak Reduction (MW)				
Duke Energy Florida, LLC	71	69	193	81
Florida Power & Light Company	67	45	33	40
Florida Public Utilities Company	0.6	0.4	0.5	0.2
Gulf Power Company	21	17	5	4
JEA	3	3	5	2
Orlando Utilities Commission **	1	1	2	5
Tampa Electric Company	27	20	11	16
Total ***	190.6	155.4	249.5	148.2
Energy Reduction (GWh)				
Duke Energy Florida, LLC	100	76	151	82
Florida Power & Light Company	222	156	63	71
Florida Public Utilities Company	2.2	1.5	2.0	0.8
Gulf Power Company	61	48	7	7
JEA	17	7	16	11
Orlando Utilities Commission **	3	14	13	32
Tampa Electric Company	66	34	31	45
Total ***	471.2	336.5	283.0	248.8

* Annual achievements are reported. Includes residential, commercial, industrial, and other customers.

** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

*** May not total due to rounding.

Source: Annual Reports on Demand-Side Management Plans, 2017; Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry.

Table 22

Investor-Owned Photovoltaic Facilities *

December 31, 2017

Utility	Name of Plant	In-Service Date	Nameplate Capacity MW **	Total Energy MWh
Duke Energy Florida, LLC				
	Osceola Solar	May-16	3.8	5,840
	Perry Solar	Aug-16	5.1	7,990
	Suwannee Solar	Nov-17	8.8	1,870
Florida Power & Light Company				
	Babcock Ranch Solar Energy Center	Dec-16	74.5	164,072
	Citrus Solar Energy Center	Dec-16	74.5	165,028
	Coral Farms	Dec-17	74.5	0
	DeSoto Next Generation Solar Energy Center	Oct-09	25.0	48,199
	Horizon	Dec-17	74.5	0
	Indian River	Dec-17	74.5	0
	Manatee Solar Energy Center	Dec-16	74.5	169,049
	Martin Next Generation	Dec-10	75.0	12,157
	Non-Universal Solar	0	3.4	5,162
	Space Coast Next Generation Solar Energy Center	Apr-10	10.0	17,555
	Wildflower	Dec-17	74.5	0
Gulf Power Company				
	Eglin Solar Project	Oct-14	30	38,113
	Holley Solar Project	Oct-14	40	41,715
	Saufley Solar Project	Nov-14	50	42,470
Tampa Electric Company				
	Big Bend	Feb-17	19.4	39,036
Total			**792.00**	**758,256**

* Includes purchase power agreements and demonstration sites.

** 2 megawatt threshold.

Source: Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), Summary of Existing Capacity, p. 21; Responses to staff data request.

Fuel Analysis

Table 23

Fuel Requirements

2008-2017

Year	Coal (Thousands of Short Tons)	Oil * (Thousands of Barrels)	Natural Gas (Billions of Cubic Feet)	Nuclear (U-235) ** (Trillion BTUs)
2008	36,224	14,496	736	342
2009	26,238	10,285	845	315
2010	27,497	9,971	923	262
2011	25,420	2,395	1,006	253
2012	22,187	868	1,109	198
2013	23,547	911	999	301
2014	25,122	880	837	307
2015	23,217	1,111	1,149	309
2016	20,260	1,442	1,141	321
2017	21,374	4,343	1,190	318

* Residual and distillate.

** Uranium-235 is a naturally occurring isotope of Uranium metal.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 9.0, p. S-16.

Table 24

Projected Fuel Requirements

2018-2027

Year	Coal (Thousands of Short Tons)	Oil * (Thousands of Barrels)	Natural Gas (Billions of Cubic Feet)	Nuclear (U-235) ** (Trillion BTUs)
2018	17,334	385	1,137	333
2019	16,799	303	1,136	335
2020	16,513	158	1,132	336
2021	16,625	158	1,125	335
2022	15,815	160	1,114	335
2023	13,052	149	1,146	335
2024	13,984	242	1,152	335
2025	13,876	291	1,167	335
2026	13,827	359	1,176	335
2027	14,346	399	1,191	335

* Residual and distillate.

** Uranium-235 is a naturally occurring isotope of Uranium metal.

Source: Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 9.0, p. S-16.

Sales

Table 25

Retail Sales

(Megawatt-Hours)

2013-2017

Utility	2013	2014	2015	2016	2017
Investor-Owned					
Duke Energy Florida, LLC	36,615,987	37,240,099	38,553,183	38,773,961	38,024,013
Florida Power & Light Company	103,050,990	104,389,052	109,820,398	109,662,646	108,870,963
Florida Public Utilities Company	630,676	648,235	638,345	645,696	627,135
Gulf Power Company	10,929,745	11,390,697	11,085,872	11,081,505	10,808,617
Tampa Electric Company	18,417,662	18,525,739	19,006,474	19,234,525	19,186,517
Municipal					
Alachua	NR*	116,659	121,530	130,432	127,049
Bartow	257,304	261,505	273,041	277,393	269,667
Beaches Energy Services	687,865	702,194	713,708	722,486	690,398
Blountstown	NR	36,307	35,439	35,345	34,112
Bushnell	NR	23,801	23,252	23,892	23,618
Chattahoochee	35,796	36,574	37,890	37,277	36,711
Clewiston	93,753	95,925	100,978	101,094	99,699
Fort Meade	38,967	39,295	40,512	40,878	39,380
Fort Pierce Utilities Authority	516,235	518,446	550,871	551,618	555,768
Gainesville Regional Utilities	1,694,401	1,708,818	1,765,193	1,796,293	1,773,622
Green Cove Springs	NR	96,513	111,677	106,946	103,807
Havana	NR	24,107	24,079	23,483	22,820
Homestead	NR	493,636	535,095	526,881	546,703
JEA	11,829,364	12,224,128	11,090,657	12,215,148	12,067,476
Keys Energy Services	707,235	715,008	751,178	742,272	714,631
Kissimmee Utility Authority	1,350,728	1,383,233	1,472,391	1,521,688	1,532,011
Lake Worth Utilities	NR	373,598	430,307	434,758	439,747
Lakeland Electric	2,832,342	2,904,061	3,034,075	3,029,959	3,017,655
Leesburg	455,380	441,239	470,555	473,329	474,093
Moore Haven	NR	12,933	16,178	15,135	15,356
Mount Dora	85,683	87,009	89,184	89,184	87,050
New Smyrna Beach	372,081	386,381	396,602	414,356	406,222
Newberry	NR	32,774	33,986	34,480	35,348
Ocala Electric Utility	NR	1,221,227	1,256,904	1,296,691	1,249,383
Orlando Utilities Commission **	NR	6,210,381	6,535,984	6,598,932	6,568,198
Quincy	NR	125,747	123,847	120,177	115,981
Reedy Creek Improvement District	NR	1,127,952	1,149,020	1,154,677	1,156,067
Starke	64,825	66,269	67,841	68,775	66,627
Tallahassee	NR	2,637,695	2,654,983	2,639,582	2,617,331
Vero Beach	688,020	704,939	738,209	736,094	723,911
Wauchula	NR	59,712	63,349	59,293	58,990
Williston	NR	30,316	31,935	33,229	32,548
Winter Park	NR	420,523	433,409	437,232	425,029
Rural Electric Cooperative					
Central Florida Electric	447,305	464,089	471,129	491,417	482,551
Choctawhatchee Electric	748,286	805,232	818,143	835,460	830,572
Clay Electric	3,012,976	3,127,781	3,152,976	3,279,354	3,226,167
Escambia River Electric	NR	177,604	175,021	174,820	173,238
Florida Keys Electric ***	659,748	679,462	720,650	709,568	694,334
Glades Electric	305,418	307,948	315,608	315,891	316,748
Gulf Coast Electric	NR	336,426	339,769	341,231	328,655
Lee County Electric	NR	3,570,274	3,790,662	3,800,338	3,809,847
Okefenoke Rural Electric ^	151,761	157,544	157,160	161,794	158,872
Peace River Electric	602,492	624,492	679,718	708,465	736,663
Sumter Electric	2,836,670	2,982,645	3,149,363	3,238,522	3,232,485
Suwannee Valley Electric	442,172	479,238	505,520	533,673	519,391
Talquin Electric	NR	965,142	955,069	953,400	937,675
Tri-County Electric	NR	298,986	300,179	310,193	309,798
West Florida Electric	477,632	504,163	498,390	495,708	482,902
Withlacoochee River Electric	3,565,155	3,685,143	3,811,169	3,914,371	3,835,764
Respondent Total ^^ ^^^	**204,604,653**	**226,678,897**	**234,118,658**	**236,151,543**	**233,719,918**
FRCC State Total					**225,971,000**

* Not Reported.

** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

*** The Florida Keys Electric Cooperative has a standby unit.

^ Okefenoke sells power in Florida and Georgia; figures reflect Florida customers only.

^^ May not total due to rounding.

^^^ Respondent total includes sales to other public authorities; therefore, respondent totals are not comparable to FRCC totals.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 4.0, p. S-2; Responses to staff data request.

Table 26

Retail Sales by Class of Service

(Megawatt-Hours)

2017

Utility	Residential	Commercial	Industrial	Other *	Total
Investor-Owned					
Duke Energy Florida, LLC	19,790,794	11,917,602	3,120,175	3,195,441	38,024,013
Florida Power & Light Company	58,188,257	47,150,843	2,961,188	570,675	108,870,963
Florida Public Utilities Company	291,500	300,345	27,380	7,910	627,135
Gulf Power Company	5,229,276	3,813,561	1,739,653	26,127	10,808,617
Tampa Electric Company	9,029,286	6,362,086	2,024,309	1,770,836	19,186,517
Municipal					
Alachua	42,300	84,749	0	0	127,049
Bartow	135,671	42,370	81,421	10,205	269,667
Beaches Energy Services	427,479	262,919	0	0	690,398
Blountstown	10,469	22,085	0	1,559	34,112
Bushnell	8,381	7,870	7,367	0	23,618
Chattahoochee	11,012	3,484	20,595	1,621	36,711
Clewiston	50,492	47,026	1,732	448	99,699
Fort Meade	27,528	11,853	0	0	39,380
Fort Pierce Utilities Authority	237,129	314,739	0	3,900	555,768
Gainesville Regional Utilities	806,074	799,826	167,722	0	1,773,622
Green Cove Springs	48,652	55,155	0	0	103,807
Havana	12,914	9,907	0	0	22,820
Homestead	311,290	37,372	159,996	38,045	546,703
JEA	5,198,715	4,010,851	2,550,204	307,706	12,067,476
Keys Energy Services	353,756	357,777	0	3,099	714,631
Kissimmee Utility Authority	842,714	506,559	164,561	18,177	1,532,011
Lake Worth Utilities	255,928	101,772	0	82,047	439,747
Lakeland Electric	1,460,334	220,042	1,231,660	105,620	3,017,655
Leesburg	232,128	51,319	0	190,646	474,093
Moore Haven	9,051	5,934	0	372	15,356
Mount Dora	50,700	30,771	0	5,578	87,050
New Smyrna Beach	268,264	51,751	83,065	3,142	406,222
Newberry	19,244	3,141	6,755	6,208	35,348
Ocala Electric Utility	509,389	160,609	554,852	24,533	1,249,383
Orlando Utilities Commission **	2,480,892	424,190	3,479,627	183,489	6,568,198
Quincy	44,767	50,897	19,392	925	115,981
Reedy Creek Improvement District	137	1,146,743	0	9,187	1,156,067
Starke	23,156	43,472	0	0	66,627
Tallahassee	1,059,408	1,527,346	0	30,576	2,617,331
Vero Beach	368,093	341,267	14,552	0	723,911
Wauchula	27,316	30,143	0	1,531	58,990
Williston	12,977	14,311	133	5,127	32,548
Winter Park	185,434	239,595	0	0	425,029
Rural Electric Cooperative					
Central Florida Electric	342,777	69,034	53,253	17,487	482,551
Choctawhatchee Electric	611,225	219,347	0	0	830,572
Clay Electric	2,194,296	643,281	388,555	35	3,226,167
Escambia River Electric	135,089	32,654	4,986	510	173,238
Florida Keys Electric ***	402,703	102,310	188,850	470	694,334
Glades Electric	153,590	40,505	122,654	0	316,748
Gulf Coast Electric	255,942	30,747	29,908	12,058	328,655
Lee County Electric	2,635,807	1,145,391	0	28,649	3,809,847
Okefenoke Rural Electric ^	145,662	7,564	2,834	2,812	158,872
Peace River Electric	475,941	215,966	31,177	13,579	736,663
Sumter Electric	2,210,499	215,982	804,807	1,198	3,232,485
Suwannee Valley Electric	285,767	91,119	141,797	708	519,391
Talquin Electric	646,531	173,253	117,891	0	937,675
Tri-County Electric	162,988	57,467	80,356	8,987	309,798
West Florida Electric	303,879	36,718	109,414	32,891	482,902
Withlacoochee River Electric	2,663,325	973,441	177,382	21,616	3,835,764
Respondent Total ^^ ^^^	**121,686,929**	**84,617,059**	**20,670,201**	**6,745,729**	**233,719,918**
FRCC State Total	**116,739,000**	**85,681,000**	**17,084,000**	**6,467,000**	**225,971,000**

* Street and highway lighting, sales to public authorities, and interdepartmental sales.
** The City of St. Cloud is included in the figures of Orlando Utilities Commission.
*** The Florida Keys Electric Cooperative has a standby unit.
^ Okefenoke sells power in Florida and Georgia; figures reflect Florida customers only.
^^ May not total due to rounding.
^^^ Respondent total includes sales to other public authorities; therefore, respondent totals are not comparable to FRCC totals.

Source: Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 4.0, p. S-2; Responses to staff data request.

Table 27

Sales for Resale for Selected Utilities
(Megawatt-Hours)
2017

Utility	Sales for Resale	Total Retail Sales *	Total Sales	Resales as Percentage of Total
Investor-Owned				
Duke Energy Florida, LLC	2,266,281	38,024,012	40,290,293	5.62%
Florida Power & Light Company	9,002,219	108,870,964	117,873,183	7.64
Gulf Power Company	4,636,837	10,808,617	15,445,454	30.02
Tampa Electric Company	238,901	19,186,517	19,425,418	1.23
Municipal				
Gainesville Regional Utilities	219,783	1,773,622	1,993,405	11.03%
JEA	270,192	12,067,476	12,337,668	2.19
Orlando Utilities Commission **	1,327,711	6,568,198	7,895,909	16.82
Reedy Creek Improvement District	3,700	1,156,067	1,159,767	0.32
Tallahassee	82,022	2,617,331	2,699,353	3.04
Rural Electric Cooperative				
PowerSouth Energy ***	1,916,329	0	1,916,329	100%
Seminole Electric ***	14,356,111	0	14,356,111	100
Talquin Electric	12,136	937,675	949,811	1.28

* Includes residential, commercial, industrial, and other customers.

** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

*** Wholesale-only generating utility.

Source: Florida Public Service Commission, 2017 Annual Report, FERC Form No. 1, pp. 301 and 311; Responses to staff data request.

Table 28

Retail Sales by Class of Service
(Gigawatt-Hours)
2013-2017

Year	Residential	Commercial	Industrial	Other *	Total Retail Sales
2013	110,127	83,283	17,047	6,132	216,589
2014	111,826	83,326	17,223	6,271	218,646
2015	117,615	86,027	17,342	6,442	227,426
2016	118,453	86,158	17,248	6,548	228,407
2017	116,739	85,681	17,084	6,467	225,971

* Street and highway lighting, sales to public authorities, and interdepartmental sales.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 4.0, p. S-2.

Table 29

Retail Sales by Percentage of Class of Service *

2008-2017

Year	Residential	Commercial	Industrial	Other **
2008	50.85%	35.76%	9.93%	3.46%
2009	51.78	34.99	9.79	3.44
2010	53.25	33.96	9.42	3.36
2011	51.94	35.38	9.26	3.42
2012	51.06	36.43	9.06	3.45
2013	51.32	36.24	9.04	3.41
2014	51.41	33.63	11.43	3.53
2015	52.34	37.81	7.10	2.75
2016	52.28	36.06	8.83	2.84
2017	52.07	36.20	8.84	2.89

* May not total due to rounding.

** Street and highway lighting, sales to public authorities, and interdepartmental sales.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Table 26.

Revenues

Table 30

Revenues by Class of Service *

(Thousands)

2008-2017

Year	Residential	Commercial	Industrial	Other **	Total ***
2008	$12,718,094	$7,741,767	$2,089,924	$729,026	$23,278,811
2009	13,879,777	8,186,033	2,322,558	828,870	25,217,238
2010	13,130,852	7,165,633	1,869,629	774,006	22,940,120
2011	12,705,770	7,303,597	2,017,392	795,924	22,822,684
2012	11,852,134	6,990,684	1,597,629	739,474	21,179,921
2013	12,409,792	6,905,538	2,015,606	729,113	22,060,049
2014	13,808,364	7,325,378	2,321,203	826,222	24,281,166
2015	14,235,700	8,419,986	1,347,946	678,308	24,681,941
2016	13,550,470	7,495,717	1,622,082	680,756	23,349,026
2017	14,066,932	7,831,125	1,638,485	684,875	24,221,417

* The amounts shown reflect revenues for all Florida electric utilities (investor-owned, municipal, and rural electric cooperative).

** Street and highway lighting, sales to public authorities, and interdepartmental sales.

*** May not total due to rounding..

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Responses to staff data request.

Table 31

Revenues by Percentage of Class of Service *

2008-2017

Year	Residential	Commercial	Industrial	Other **
2008	54.6%	33.3%	9.0%	3.1%
2009	55.0	32.5	9.2	3.3
2010	57.2	31.2	8.2	3.4
2011	55.7	32.0	8.8	3.5
2012	56.0	33.0	7.5	3.5
2013	56.3	31.3	9.1	3.3
2014	56.9	30.2	9.6	3.4
2015	57.7	34.1	5.5	2.7
2016	58.0	32.1	6.9	2.9
2017	58.1	32.3	6.8	2.8

* May not total due to rounding.

** Street and highway lighting, sales to public authorities, and interdepartmental sales.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Responses to staff data request; Table 30.

Number of Customers

Table 32

Number of Customers

2013-2017

Utility	2013	2014	2015	2016	2017	Compound Growth Rate
Investor-Owned						
Duke Energy Florida, LLC	1,682,181	1,699,077	1,798,990	1,760,016	1,885,567	2.89%
Florida Power & Light Company	4,626,946	4,708,819	4,806,234	4,869,040	4,901,871	1.45
Florida Public Utilities Company	31,155	31,272	31,506	31,787	31,992	0.67
Gulf Power Company	437,698	442,370	449,471	455,415	461,806	1.35
Tampa Electric Company	694,734	706,160	718,712	730,503	744,691	1.75
Total Investor-Owned	7,472,714	7,587,698	7,804,913	7,846,761	8,025,927	1.80
Municipal						
Alachua	NR*	4,423	4,482	4,522	4,506	0.00%
Bartow	11,736	11,876	12,036	12,195	12,310	1.20
Beaches Energy Services	33,929	34,282	34,903	34,601	34,609	0.50
Blountstown	NR	1,349	1,312	1,324	1,330	0.00
Bushnell	NR	1,021	1,031	1,040	1,057	0.00
Chattahoochee	1,162	1,156	1,157	1,161	1,172	0.21
Clewiston	4,206	4,237	4,289	4,315	4,357	0.89
Fort Meade	2,722	2,652	2,803	2,660	2,628	-0.87
Fort Pierce Utilities Authority	27,738	28,166	28,251	28,306	28,257	0.46
Gainesville Regional Utilities	93,134	93,855	94,628	95,161	97,245	1.09
Green Cove Springs	NR	3,865	3,921	4,058	4,175	0.00
Havana	NR	1,391	1,427	1,448	1,458	0.00
Homestead	NR	23,032	23,211	24,031	24,402	0.00
JEA	419,299	426,373	449,263	456,894	464,118	2.57
Keys Energy Services	30,406	30,752	31,167	30,002	29,859	-0.45
Kissimmee Utility Authority	65,370	66,608	68,396	70,400	72,225	2.52
Lake Worth Utilities	NR	25,783	26,558	26,236	27,105	0.00
Lakeland Electric	122,803	124,018	125,666	127,152	129,113	1.26
Leesburg	22,709	23,483	23,793	24,597	24,400	1.81
Moore Haven	NR	1,017	863	1,059	1,137	0.00
Mount Dora	5,680	5,712	5,798	5,828	5,851	0.74
New Smyrna Beach	25,869	26,375	26,740	27,561	27,737	1.76
Newberry	NR	1,687	1,723	1,774	1,820	0.00
Ocala Electric Utility	NR	49,168	51,896	50,187	50,569	0.00
Orlando Utilities Commission **	NR	278,790	290,915	300,179	312,973	0.00
Quincy	NR	4,796	4,767	4,783	4,743	0.00
Reedy Creek Improvement District	NR	1,374	1,387	1,463	1,447	0.00
Starke	2,686	2,731	2,759	2,779	2,801	1.05
Tallahassee	NR	116,709	117,827	119,005	120,050	0.00
Vero Beach	33,924	34,616	34,538	34,893	35,565	1.19
Wauchula	NR	2,680	2,775	2,798	2,802	0.00
Williston	NR	1,473	1,552	1,707	1,718	0.00
Winter Park	NR	14,150	14,392	14,947	15,061	0.00
Total Municipal	903,373	1,449,600	1,496,226	1,519,066	1,548,600	14.42
Rural Electric Cooperative						
Central Florida Electric	32,641	32,734	32,943	33,176	33,434	0.60%
Choctawhatchee Electric	45,290	46,656	47,291	48,675	50,181	2.60
Clay Electric	237,625	239,735	170,429	172,861	174,587	-7.42
Escambia River Electric	NR	10,254	10,467	10,700	11,012	0.00
Florida Keys Electric ***	31,832	32,292	32,415	32,723	32,224	0.31
Glades Electric	16,054	16,180	16,373	16,368	16,370	0.49
Gulf Coast Electric	NR	20,013	20,274	20,565	20,780	0.00
Lee County Electric	NR	204,023	208,626	211,685	214,668	0.00
Okefenoke Rural Electric ^	10,028	10,037	10,999	10,189	10,528	1.22
Peace River Electric	34,848	36,387	38,674	40,296	41,729	4.61
Sumter Electric	181,674	187,106	193,110	194,964	198,656	2.26
Suwannee Valley Electric	25,244	25,426	25,415	25,648	25,932	0.67
Talquin Electric	NR	52,894	53,213	53,593	53,832	0.00
Tri-County Electric	NR	17,716	17,830	17,932	18,212	0.00
West Florida Electric	28,168	28,036	28,202	28,347	28,487	0.28
Withlacoochee River Electric	202,353	204,362	208,761	211,243	214,244	1.44
Total Rural Electric Cooperative	845,757	1,163,851	1,115,022	1,128,965	1,144,876	7.86
Respondent Total ^^ ^^^	9,221,844	10,201,149	10,416,161	10,494,792	10,719,403	3.83
FRCC State Total	9,585,729	9,607,315	9,764,790	9,901,223	10,044,518	1.18

* Not Reported.
** The City of St. Cloud is included in the figures of Orlando Utilities Commission.
*** The Florida Keys Electric Cooperative has a standby unit.
^ Okefenoke sells power in Florida and Georgia; figures reflect Florida customers only.
^^ May not total due to rounding.
^^^ Respondent total includes sales to other public authorities; therefore, respondent totals are not comparable to FRCC totals.

Source: Florida Public Service Commission, 2017 Statistics of the Florida Electric Utility Industry; Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 4.0, p. S-2; Responses to staff data request.

Table 33

Number of Customers by Class of Service

December 31, 2017

Utility	Residential	Commercial	Industrial	Other *	Total
Investor-Owned					
Duke Energy Florida, LLC	1,677,197	179,206	2,135	27,029	1,885,567
Florida Power & Light Company	4,338,224	547,908	11,654	4,085	4,901,871
Florida Public Utilities Company	24,575	4,409	2	3,006	31,992
Gulf Power Company	404,273	56,700	255	578	461,806
Tampa Electric Company	659,393	74,992	1,608	8,698	744,691
Total Investor-Owned	7,103,662	863,215	15,654	43,396	8,025,927
Municipal					
Alachua	3,787	719	0	0	4,506
Bartow	10,578	1,288	321	123	12,310
Beaches Energy Services	29,906	4,703	0	0	34,609
Blountstown	988	300	0	42	1,330
Bushnell	769	277	11	0	1,057
Chattahoochee	989	119	1	63	1,172
Clewiston	3,452	625	1	279	4,357
Fort Meade	2,331	297	0	0	2,628
Fort Pierce Utilities Authority	23,180	5,075	0	2	28,257
Gainesville Regional Utilities	86,100	11,132	13	0	97,245
Green Cove Springs	3,404	771	0	0	4,175
Havana	1,137	321	0	0	1,458
Homestead	21,761	2,008	561	72	24,402
JEA	407,957	52,196	199	3,766	464,118
Keys Energy Services	25,342	4,436	0	81	29,859
Kissimmee Utility Authority	62,424	9,746	55	0	72,225
Lake Worth Utilities	23,357	2,945	0	803	27,105
Lakeland Electric	107,703	10,686	1,758	8,966	129,113
Leesburg	20,693	3,446	0	261	24,400
Moore Haven	975	127	0	35	1,137
Mount Dora	4,969	787	0	95	5,851
New Smyrna Beach	24,330	2,175	139	1,093	27,737
Newberry	1,506	172	41	101	1,820
Ocala Electric Utility	41,678	7,480	1,047	364	50,569
Orlando Utilities Commission **	206,959	24,323	5,839	75,852	312,973
Quincy	3,905	787	1	50	4,743
Reedy Creek Improvement District	9	1,358	0	80	1,447
Starke	2,047	754	0	0	2,801
Tallahassee	100,921	14,992	0	4,137	120,050
Vero Beach	29,355	5,822	1	387	35,565
Wauchula	2,231	506	0	65	2,802
Williston	1,166	394	3	155	1,718
Winter Park	12,358	2,703	0	0	15,061
Total Municipal	1,268,267	173,470	9,991	96,872	1,548,600
Rural Electric Cooperative					
Central Florida Electric	30,127	2,311	516	480	33,434
Choctawhatchee Electric	43,945	6,236	0	0	50,181
Clay Electric	154,930	19,605	30	22	174,587
Escambia River Electric	9,689	1,297	5	21	11,012
Florida Keys Electric ***	26,528	5,192	487	17	32,224
Glades Electric	12,527	3,481	362	0	16,370
Gulf Coast Electric	19,331	923	14	512	20,780
Lee County Electric	196,164	18,298	0	206	214,668
Okefenoke Rural Electric ^	9,978	472	1	77	10,528
Peace River Electric	34,597	7,064	3	65	41,729
Sumter Electric	180,953	16,408	1,267	28	198,656
Suwannee Valley Electric	22,675	3,165	9	83	25,932
Talquin Electric	49,871	3,957	4	0	53,832
Tri-County Electric	16,391	1,554	13	254	18,212
West Florida Electric	25,178	2,687	1	621	28,487
Withlacoochee River Electric	192,997	20,788	24	435	214,244
Total Rural Electric Cooperative	1,025,881	113,438	2,736	2,821	1,144,876
Respondent Total ^^ ^^^	9,397,810	1,150,123	28,381	143,089	10,719,403
FRCC State Total	8,914,734	1,106,790	22,994	N/A	10,044,518

* Street and highway lighting, sales to public authorities, and interdepartmental sales.

** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

*** The Florida Keys Electric Cooperative has a standby unit.

^ Okefenoke sells power in Florida and Georgia; figures reflect Florida customers only.

^^ May not total due to rounding.

^^^ Respondent total includes sales to other public authorities; therefore, respondent totals are not comparable to FRCC totals.

Source: Florida Reliability Coordinating Council, Regional Load and Resource Plan, State Supplement (July 2018), FRCC Form 4.0, p. S-2; Responses to staff data request.

Table 34

Investor-Owned Utilities: Customer Count and Population

2017-2027

Utility	Year	Residential	Commercial	Industrial	Other	Total Customers	Population
Duke Energy Florida, LLC	2017	1,677,197	179,206	2,135	27,029	1,885,567	3,906,975
	2021 *	1,678,881	186,255	2,056	26,956	1,894,148	4,087,879
	2027 *	1,820,557	202,040	1,994	27,876	2,052,467	4,324,564
Florida Power & Light Company	2017	4,338,224	547,908	11,654	4,085	4,901,871	9,820,171
	2021 *	4,561,850	570,102	14,005	4,406	5,150,363	10,344,947
	2027 *	4,894,983	597,482	14,921	4,864	5,512,250	11,106,216
Gulf Power Company	2017	404,273	56,700	255	578	461,806	969,430
	2021 *	422,689	58,866	255	574	482,384	1,029,170
	2027 *	445,404	61,635	255	574	507,868	1,113,470
Tampa Electric Company	2017	659,393	74,992	1,608	8,698	744,691	1,379,302
	2021 *	714,059	77,726	1,666	8,795	802,246	1,493,987
	2027 *	788,098	80,830	1,715	9,171	879,814	1,649,944

* Projected.

Source: Florida Public Service Commission, Utilities' Ten-Year Site Plan (April 2018), Schedule Nos. 2.1, 2.2, and 2.3; Table 33.

Prices

Table 35, Page 1 of 3

Typical Electric Bill Comparison - Residential Charges *

December 31, 2017

Investor-Owned	Minimum Bill or Customer Charge	100 kWh	250 kWh	500 kWh	750 kWh	1,000 kWh	1,500 kWh
Duke Energy Florida, LLC	$8.76	$19.30	$35.11	$61.46	$87.79	$114.12	$178.90
Florida Power & Light Company	7.87	17.07	30.92	53.94	76.97	99.99	156.06
Florida Public Utilities Company							
Northwest Division	14.00	26.16	44.38	74.76	105.12	135.50	208.76
Northeast Division	14.00	26.16	44.38	74.76	105.12	135.50	208.76
Gulf Power Company	19.50	30.97	48.18	76.86	105.52	134.19	191.55
Tampa Electric Company	16.62	25.17	37.98	59.35	80.71	102.06	155.33

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as separate line items. Includes cost recovery clause charges.

Table 35, Page 2 of 3

Typical Electric Bill Comparison - Residential Charges *

December 31, 2017

Municipal	Minimum Bill or Customer Charge	100 kWh	250 kWh	500 kWh	750 kWh	1,000 kWh	1,500 kWh
Alachua	$9.14	$19.57	$35.21	$61.27	$87.34	$113.40	$170.63
Bartow	8.00	20.03	38.09	68.16	98.25	128.32	188.48
Beaches Energy Services	4.50	15.74	32.60	60.71	88.81	116.91	173.12
Blountstown	3.50	15.39	33.21	62.93	92.64	122.35	181.78
Bushnell	7.40	19.67	38.06	68.73	99.39	130.05	191.38
Chattahoochee	6.50	15.26	28.41	50.32	72.23	94.14	137.96
Clewiston	6.50	16.06	30.42	54.32	78.24	102.14	149.96
Fort Meade	12.96	24.62	42.11	71.26	100.41	129.56	187.86
Fort Pierce Utilities Authority	6.01	17.03	33.57	61.12	88.68	118.84	179.16
Gainesville Regional Utilities	14.25	25.66	42.79	71.33	99.86	131.55	199.12
Green Cove Springs	12.00	22.20	37.50	63.00	89.50	116.00	171.00
Havana	6.00	15.00	28.51	51.02	73.53	96.03	141.05
Homestead	5.60	16.46	32.76	59.92	87.07	114.23	168.55
JEA	5.50	15.80	31.26	57.00	82.76	108.50	160.00
Keys Energy Services	15.03	27.53	46.27	77.52	108.76	140.00	202.49
Kissimmee Utility Authority	10.17	18.86	31.91	53.64	75.39	97.12	146.92
Lake Worth Utilities	10.53	20.61	35.73	60.91	86.11	111.29	161.67
Lakeland Electric	9.50	18.69	32.47	55.43	78.39	101.35	150.30
Leesburg	12.20	23.15	39.58	66.96	94.34	121.72	187.38
Moore Haven	8.50	18.44	33.35	58.20	83.05	107.90	157.60
Mount Dora	9.31	20.00	36.04	62.77	89.50	116.22	169.68
New Smyrna Beach	5.65	15.57	30.43	55.22	80.00	104.78	154.35
Newberry	7.50	18.25	34.38	61.25	88.13	115.00	168.75
Ocala Electric Utility	9.33	20.16	36.41	63.49	90.56	117.64	171.80
Orlando Utilities Commission **	8.00	17.80	32.51	57.00	81.51	106.00	165.00
Quincy	6.00	15.62	30.05	54.11	78.16	102.21	150.32
Reedy Creek Improvement District	2.85	13.02	28.27	53.69	79.11	104.52	155.36
St. Cloud **	8.32	18.52	33.80	59.29	84.76	110.24	171.61
Starke	6.45	17.15	33.20	59.95	86.70	113.44	177.94
Tallahassee	7.59	18.11	33.90	60.20	86.51	112.81	165.42
Vero Beach	8.33	19.79	36.99	65.64	94.30	122.95	180.26
Wauchula	11.50	20.44	33.85	56.20	78.55	100.90	145.60
Williston	8.00	18.14	33.36	58.72	84.08	109.44	160.16
Winter Park	14.04	23.53	37.77	61.50	85.21	108.94	172.37

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as separate line items. Includes cost recovery clause charges.

** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

Table 35, Page 3 of 3

Typical Electric Bill Comparison - Residential Charges *

December 31, 2017

Rural Electric Cooperative	Minimum Bill or Customer Charge	100 kWh	250 kWh	500 kWh	750 kWh	1,000 kWh	1,500 kWh
Central Florida Electric	$28.50	$37.40	$50.75	$73.00	$95.25	$117.50	$173.50
Choctawhatchee Electric	26.00	35.48	49.69	73.38	97.07	120.75	168.13
Clay Electric	20.00	28.99	42.48	64.95	87.43	109.90	164.25
Escambia River Electric	30.00	40.70	56.75	83.50	110.25	137.00	190.50
Florida Keys Electric	30.00	38.00	49.99	69.98	89.96	109.95	166.43
Glades Electric	45.00	53.95	67.38	89.75	112.13	134.50	198.00
Gulf Coast Electric	30.00	39.71	54.28	78.55	102.83	127.10	175.65
Lee County Electric	15.00	23.75	36.88	56.15	79.33	102.50	154.20
Okefenoke Rural Electric **	25.00	34.17	47.93	70.85	93.78	116.70	165.90
Peace River Electric	26.50	36.51	51.52	76.53	101.54	126.56	186.59
Sumter Electric	20.00	29.49	43.73	67.45	91.17	114.90	172.35
Suwannee Valley Electric	25.00	34.50	48.75	72.50	96.25	120.00	178.20
Talquin Electric	30.00	39.65	54.13	78.25	102.38	126.50	185.55
Tri-County Electric	22.00	32.90	49.25	76.50	103.75	131.00	195.50
West Florida Electric	24.95	35.46	51.22	77.50	103.77	130.04	192.36
Withlacoochee River Electric	30.00	38.51	51.28	72.57	93.85	115.13	158.83

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as separate line items. Includes cost recovery clause charges.

** Okefenoke sells power in Florida and Georgia; figures reflect Florida customers only.

Source: Florida Public Service Commission, Comparative Rate Statistics (December 2017), pp. A-1, A-2, and A-3.

Table 36, Page 1 of 3

Typical Electric Bill Comparison - Commercial and Industrial Charges *

December 31, 2017

Investor-Owned	75 KW 15,000 kWh	150 KW 45,000 kWh	500 KW 150,000 kWh	1,000 KW 400,000 kWh	2,000 KW 800,000 kWh
Duke Energy Florida, LLC	$1,431	$3,800	$12,639	$31,592	$63,173
Florida Power & Light Company	1,627	4,035	13,761	32,383	63,281
Florida Public Utilities Company					
Northwest Division	1,858	5,160	17,101	43,618	87,106
Northeast Division	1,858	5,160	17,101	43,618	87,106
Gulf Power Company	1,744	4,581	15,339	36,168	72,073
Tampa Electric Company	1,585	3,900	12,924	30,910	61,787

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as separate line items. Includes cost recovery clause charges.

Table 36, Page 2 of 3

Typical Electric Bill Comparison - Commercial and Industrial Charges *

December 31, 2017

Municipal	75 KW 15,000 kWh	150 KW 45,000 kWh	500 KW 150,000 kWh	1,000 KW 400,000 kWh	2,000 KW 800,000 kWh
Alachua	$1,814	$4,799	$15,891	$39,846	$79,646
Bartow	2,099	5,593	18,598	46,618	93,216
Beaches Energy Services	2,125	5,706	18,983	47,760	95,504
Blountstown	2,004	5,997	19,975	53,255	106,503
Bushnell	2,165	5,890	19,580	49,693	99,363
Chattahoochee	1,738	4,411	14,646	37,341	74,657
Clewiston	1,671	4,660	15,438	39,898	79,754
Fort Meade	1,976	5,667	18,792	46,902	93,762
Fort Pierce Utilities Authority	1,889	5,081	18,834	45,781	91,523
Gainesville Regional Utilities	2,406	6,379	21,030	51,650	102,950
Green Cove Springs	1,888	4,925	16,300	37,725	75,225
Havana	1,356	4,057	13,511	36,018	72,030
Homestead	1,919	5,209	17,280	43,898	87,760
JEA	1,715	4,345	14,286	35,567	70,799
Keys Energy Services	2,306	6,094	20,095	50,612	101,130
Kissimmee Utility Authority	1,702	4,328	14,296	35,066	70,076
Lake Worth Utilities	2,325	6,076	20,068	50,098	100,116
Lakeland Electric	1,543	3,959	13,501	32,257	64,134
Leesburg	2,038	5,023	17,100	40,223	83,393
Moore Haven	1,806	4,672	15,494	38,244	76,454
Mount Dora	1,466	3,973	13,195	33,453	66,885
New Smyrna Beach	1,855	4,992	15,686	39,606	79,178
Newberry	1,895	4,904	16,310	38,045	76,045
Ocala Electric Utility	1,723	4,675	15,851	39,478	78,932
Orlando Utilities Commission **	1,602	4,147	13,753	33,247	66,419
Quincy	1,481	4,022	13,265	33,940	54,243
Reedy Creek Improvement District	1,570	4,144	13,768	34,349	68,678
St. Cloud **	1,666	4,313	14,303	34,578	69,078
Starke	1,921	5,746	19,133	51,005	102,001
Tallahassee	1,918	4,626	15,169	35,951	71,831
Vero Beach	1,901	5,289	18,138	46,088	92,136
Wauchula	1,526	4,038	13,308	33,555	67,045
Williston	1,684	4,626	15,140	38,290	76,530
Winter Park	1,529	4,182	13,903	35,383	70,751

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as separate line items. Includes cost recovery clause charges.

** The City of St. Cloud is included in the figures of Orlando Utilities Commission.

Table 36, Page 3 of 3

Typical Electric Bill Comparison - Commercial and Industrial Charges *

December 31, 2017

Rural Electric Cooperative	75 KW 15,000 kWh	150 KW 45,000 kWh	500 KW 150,000 kWh	1,000 KW 400,000 kWh	2,000 KW 800,000 kWh
Central Florida Electric	$1,820	$4,667	$15,324	$37,449	$74,799
Choctawhatchee Electric	1,509	3,983	12,540	31,730	63,416
Clay Electric	1,567	4,216	13,865	35,390	67,285
Escambia River Electric	2,008	5,285	17,500	43,750	87,450
Florida Keys Electric	1,622	4,714	15,544	41,310	82,546
Glades Electric	2,115	5,445	17,800	44,550	88,950
Gulf Coast Electric	1,981	4,869	16,135	39,743	79,443
Lee County Electric	1,533	4,019	12,369	30,054	60,084
Okefenoke Rural Electric **	1,652	4,159	13,535	33,560	66,980
Peace River Electric	1,816	4,579	14,463	35,098	70,046
Sumter Electric	1,584	4,212	13,910	35,085	70,115
Suwannee Valley Electric	1,718	4,592	15,310	37,610	74,970
Talquin Electric	1,701	4,720	15,920	36,592	72,884
Tri-County Electric	1,995	5,010	16,350	40,350	80,550
West Florida Electric	1,828	5,008	16,575	43,708	87,316
Withlacoochee River Electric	1,446	3,818	12,646	31,663	63,291

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as separate line items. Includes cost recovery clause charges.

** Okefenoke sells power in Florida and Georgia; figures reflect Florida customers only.

Source: Florida Public Service Commission, Comparative Rate Statistics (December 2017), pp. A-4, A-5, and A-6.

Economic and Financial Indicators

Table 37
Population
(Thousands)
2008-2017

Year	Florida Population	National Population
2008	18,424	304,375
2009	18,538	307,007
2010	18,839	309,330
2011	19,058	311,592
2012	19,074	314,917
2013	19,553	316,129
2014	19,893	318,857
2015	20,271	321,419
2016	20,612	323,128
2017	20,984	325,719
Compound Annual Growth Rate, 2008-2017	1.46%	0.76%
Compound Annual Growth Rate, 2013-2017	1.78%	0.75%

Source: U.S. Census Bureau, State & County Quick Facts (July 2018), 2017 Population estimate. Retrieved from http://quickfacts.census.gov/qfd/states/12000.html

Table 38
Projected Population
(Thousands)
2020-2040

Year	Florida Population	National Population
2020	21,527	332,555
2030	24,357	354,840
2040	26,492	373,121
Compound Annual Growth Rate, 2020-2040	1.10%	0.61%

Sources: The Office of Economic & Demographic Research (May 2018), Data: 2017 Population by County: Projections of Florida Population by County (EDR - 2020-2040). Retrieved from http://edr.state.fl.us/Content/population-demographics/data/index.cfm

U.S. Census Bureau, Population Projections (March 2018), 2017 National Population Projections Tables: Summary Tables, Projections of population size: Table 1. Projected population size and births, deaths, and migration (CSV - 2015 to 2060). Retrieved from https://www.census.gov/population/projections/data/national/2014/summarytables.html

Table 39

Consumer Price Index
All Urban Consumers
Annual Rate of Change
2008-2017

Year	All Urban Consumers
2008	3.8%
2009	-0.4
2010	1.6
2011	3.2
2012	2.1
2013	1.5
2014	1.6
2015	1.0
2016	1.3
2017	2.1

Source: U.S. Government Publishing Office, Economic Indicators (January 2018), Prices: Changes in Consumer Prices - All Urban Consumers. Retrieved from http://www.gpo.gov/fdsys/browse/collection.action?collectionCode=ECONI

Table 40

Consumer Price Index
For All Items and Energy Total
2008-2017

Year	All Items	Energy Total *
2008	215.3	220.0
2009	214.5	211.0
2010	218.1	214.2
2011	224.9	220.4
2012	229.6	219.0
2013	233.0	224.0
2014	236.7	243.5
2015	237.0	202.9
2016	240.0	189.5
2017	245.1	204.5

* Includes household energy (electricity, gas, fuel, oil, etc.).

Source: U.S. Government Publishing Office, Economic Indicators (January 2018), Prices: Consumer Prices - All Urban Consumers. Retrieved from http://www.gpo.gov/fdsys/browse/collection.action?collectionCode=ECONI

Table 41

Producer Price Index
Total Finished Goods and Capital Equipment
2008-2017

Year	Finished Goods	Capital Equipment
2008	177.1	153.8
2009	172.5	156.7
2010	179.8	157.3
2011	190.5	159.7
2012	194.2	162.8
2013	196.1	165.3
2014	191.9	167.7
2015	189.8	169.3
2016	195.6	170.6
2017	201.3	172.0

Source: U.S. Department of Labor, Bureau of Labor and Statistics (January 2018), Producer Price Index. Retrieved from http://www.bls.gov/schedule/archives/ppi_nr.htm#current

Glossary

Average Annual KWh Use per Customer – Annual kilowatt-hour sales of a class of service (see **Classes of Electric Service** for list) divided by the average number of customers for the same 12-month period (usually refers to all residential customers, including those with electric space heating). A customer with two or more meters at the same location because of special services, such as water heating, etc., is counted as one customer.

Average rate of return - This method of appraisal measures the net return from an investment as a percentage of its original cost.

> **Average Adjusted Rate of Return** –This method of appraisal measures the net return from an investment as a percentage of its original cost to include Florida Public Service Commission (FPSC) approved adjustments

> **FPSC Authorized Rate of Return** - This method of appraisal measures the midpoint rate of return based on the FPSC approved return on equity and utility financial statements

BTU (British Thermal Unit) – The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

> **Content of Fuel, Average** – The heat value per unit quantity of fuel expressed in BTU as determined from tests of fuel samples. Examples: BTU per pound of coal, per gallon of oil, etc.

BTU per Kilowatt-Hour – See **Heat Rate**.

Capability – The maximum load which a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time, without exceeding approved limits of temperature and stress.

> **Customer-Owned Solar Photovoltaic Generation** – Customers who install renewable energy generation systems (RGS) on their homes or businesses, such as solar photovoltaic (PV) systems, can interconnect with the distribution system and receive a billing credit for the solar energy they do not use.

> **Gross System** – The net generating station capability of a system at a stated period of time (usually at the time of the system's maximum load), plus capability available at such time from other sources through firm power contracts.

> Note: The Florida Electric Power Coordinating Group and much of the utility industry prefer a different definition. Their use of the word relates to the capability at the generator terminals and would therefore be defined as the "total capability of a system's generating units measured at their terminals."

> **Margin of Reserve** – See **Capability Margin**.

> **Net Generating Station** – The capability of a generating station as demonstrated by test or as determined by actual operating experience less power generated and used for auxiliaries and other station uses. Capability may vary with the character of the load, time of year (due to circulating water temperatures in thermal stations or availability of water in hydro stations), and other characteristic causes. Capability is sometimes referred to as Effective Rating.

> **Net System** – The net generating station capability of a system at a stated period of time (usually at the time of the system's maximum load), plus capability available at such time from other sources through firm power contracts, less firm power obligations at such time to other companies or systems.

> **Peaking** – Generating capability normally designed for use during the maximum load period of a designated time interval.

Capability Margin/Reserve Margin – The difference between net system capability and system maximum load requirements, operating requirements, and unforeseen loads.

Capacity – The load for which a generating unit, generating station, or other electrical apparatus is rated either by the use or by the manufacturer. See also Nameplate Rating.

Dependable – The load-carrying ability for the time interval and period specified when related to the characteristics of the load to be supplied. Dependable capacity of a station is determined by such factors as capability, operating power factor, and

Hydraulic – The rating of a hydroelectric generating unit of the sum of such ratings for all units in a station or stations.

Installed Generating – See **Nameplate Rating**.

Peaking – Generating units or stations which are available to assist in meeting that portion of peak load which is above base load.

Purchase – The amount of power available for purchase from a source outside the system to supply energy or capacity.

Renewable Generation Capacity – is generally defined as energy that is collected from resources which are naturally replenished on a human timescale, such as sunlight, wind, rain, tides, waves, and geothermal heat.

Reserve:

Cold – Thermal generating units available for service but not maintained at operating temperature.

Hot – Thermal generating units available, up to temperature, and ready for service, although not actually in operation.

Margin of – See **Capability Margin**.

Spinning – Generating units connected to the bus and ready to take load.

Thermal – The rating of a thermal electric generating unit or the sum of such ratings for all units in a station or stations.

Total Available – See **Capability, Gross System**.

Charge, Electric Energy – See **Energy, Electric**.

Classes of Electric Service – See class name for each definition.

Sales to Ultimate Customers: *

- Residential
- Commercial and Industrial
  - Commercial
  - Industrial
  - Small Light and Power
  - Large Light and Power
- Public Street and Highway Lighting
- Other Public Authorities
- Railroads and Railways
- Interdepartmental

Sales for Resale (Other Electric Utilities):

- Investor-Owned
- Cooperatively-Owned
- Municipally-Owned
- Federal and State Electric Agencies

* Companies serve rural customers under distinct rural rates and classify these sales as "Rural." However, many companies serve customers in rural areas under standard Residential, Commercial, and Industrial rates and classify such sales similarly. Consequently, "Rural" is a rate classification rather than a customer classification, and since "Rural" is frequently confused with "Farm Service" (a type of Residential and/or Commercial service), the "Rural" classification has been generally discontinued as a customer classification.

Classes of Electric Systems – Federal Power Commission groupings (as of 1968) of operating systems based on volume and kinds of electric output for the purpose of reporting power system operations.

Basis of Classification	**Class of System**
Systems which generate all or part of system requirements and whose net energy for system for the year reported was:	
More than 100,000,000 kilowatt-hours.	**I**
20,000,000 to 100,000,000 kilowatt-hours.	**II**
Less than 20,000,000 kilowatt-hours.	**III**
Systems engaged primarily in sales for resale and/or sales to industrial, all other sales being negligible.	**IV**
Systems which obtain entire energy requirements from other systems.	**V**

Combined Cycle – Consists of three components: two combustion turbines, each with its own generator, and one steam boiler with associated steam turbine generator. The normally wasted combustion may also be supplementally fired.

Conventional Fuels – The fossil fuels: coal, oil, or gas.

Cooperative, Rural Electric – See **Rural**.

Cooperatives (Cooperatively-Owned Electric Utilities) – A joint venture organized for the purpose of supplying electric energy to a specified area. Such ventures are generally exempt from the federal income tax laws. Most cooperatives have been financed by the Rural Electrification Administration.

Customer (Electric) – A customer is an individual, firm, organization, or other electric utility which purchases electric service at one location under one rate classification, contract, or schedule. If service is supplied to a customer at more than one location, each location shall be counted as a separate customer unless consumption is combined before the bill is calculated.

Note 1: If service is supplied to a customer at one location through more than one meter and under several rate classifications or schedules but only for one class of service (for example, separate meters for residential regular and water heating service), such multiple rate services shall be counted as only one customer at the one location.

Note 2: Where service is used for one part of a month (prorated period), only initial bills of customers during such month only shall be counted; final bills should not be counted as customers.

Note 3: See also **Ultimate Customers**.

Demand – The rate at which electric energy is delivered to or by a system, part of a system, or a piece of equipment expressed in kilowatts, kilovolt-amperes, or other suitable unit at a given instant or averaged over any designated period of time. The primary source of "Demand" is the power-consuming equipment of the customers. See **Load**.

Annual Maximum – The greatest of all demands of the load under consideration which occurred during a prescribed demand interval in a calendar year.

Annual System Maximum – The greatest demand on an electric system during a prescribed demand interval in a calendar year.

Demand Continued

Average – The demand on, or the power output of, an electric system or any of its parts over any interval of time, as determined by dividing the total number of kilowatt-hours by the number of units of time in the interval.

Billing – The demand upon which billing to a customer is based, as specified in a rate schedule or contract. Billing may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.

Coincident – The sum of two or more demands which occur in the same demand interval.

Instantaneous Peak – The maximum demand at the instant of greatest load, usually determined from the readings of indicating or graphic meters.

Integrated – The demand usually determined by an integrating demand meter or by the integration of a load curve. An integrated demand is the summation of the continuously varying instantaneous demands during a specified demand interval.

Maximum – The greatest of all demands of the load under consideration which has occurred during a specified period of time.

Noncoincident – The sum of two or more individual demands which do not occur in the same demand interval. This term is meaningful only when considering demands within a limited period of time, such as a day, week, month, a heating or cooling season, and usually not for more than one year.

Electric Utility Industry or Electric Utilities – All enterprises engaged in the production and/or distribution of electricity for use by the public, including investor-owned electric utility companies; cooperatively-owned electric utilities; government-owned electric utilities (municipal systems, federal agencies, state projects, and public power districts); and, where the data are not separable, those industrial plants contributing to the public supply.

Energy, Electric – As commonly used in the electric utility industry, electric energy means kilowatt-hours.

Fuel Costs (Most Commonly Used by Electric Utility Companies)

Cents per Million BTU Consumed – Since coal is purchased on the basis of its heat content, its cost is measured by computing the "cents per million BTU" of the fuel consumed. This figure is the total cost of fuel consumed divided by its total BTU content, and the answer is then divided by one million.

Coal – Average cost per (short) ton (dollars per ton) – includes bituminous and anthracite coal and relatively small amounts of coke, lignite, and wood.

Gas – Average cost per MCF (cents per thousand cubic feet) – includes natural, manufactured, mixed, and waste gas. Frequently expressed as cost per therm (100,000 BTU).

Nuclear – Nuclear fuel costs can be given on a fuel cycle basis. A fuel cycle consists of all the steps associated with procurement, use, and disposal of nuclear fuel. According for the cost of each step in the fuel cycle including interest charges, nuclear fuel costs can be given in cents per million BTU or mills per kilowatt-hour for the cycle lifetime of the fuel which is normally five to six years.

Oil – Average cost per barrel – 42 U.S. gallons (dollars per barrel) – includes fuel oil, crude and diesel oil, and small amounts of tar and gasoline.

Fuel Efficiency – See **Heat Rate**.

Fuel for Electric Generation – Includes all types of fuel (solid, liquid, gaseous, and nuclear) used exclusively for the production of electric energy.

Gas – A fuel burned under boilers by internal combustion engines and gas turbines for electric generation. Includes natural, manufactured, mixed, and waste gas. See **Gas – MCF** and also **Therm**.

Gas - Fuel Costs – See **Fuel Costs**.

Gas - MCF – 1,000 cubic feet of gas.

Generating Capability – See **Capability, Net Generating Station**.

Generating Station (Generating Plant or Power Plant) – A station with prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy.

Atomic – See **Nuclear**.

Gas Turbine – An electric generating station in which the prime mover is a gas turbine engine.

Generating Station Capability – See **Capability, Net Generating Station**.

Generating Unit – An electric generator together with its prime mover.

Generation, Electric – This term refers to the act or process of transforming other forms of energy into electric energy, or to the amount of electric energy so produced, expressed in kilowatt-hours.

Gross – The total amount of electric energy produced by the generating units in a generating station or stations.

Net – Gross generation less kilowatt-hours consumed out of gross generation for station use.

Geothermal – An electric generating station in which the prime mover is a steam turbine. The steam is generated in the earth by heat from the earth's magma.

Hydroelectric – An electric generation station in which the prime mover is a hydraulic turbine.

Internal Combustion – An electric generating station in which the prime mover is an internal combustion engine.

Nuclear – An electric generating station in which the prime mover is a steam turbine. The steam is generated in a reactor by heat from the fissioning of nuclear fuel.

Steam (Conventional) – An electric generating station in which the prime mover is a steam turbine. The steam is generated in a boiler by heat from burning fossil fuels.

Gigawatt-Hour (GWh) – One million kilowatt-hours, one thousand megawatt-hours, or one billion watt-hours.

Heat Rate – A measure of generating station thermal efficiency, generally expressed in BTU per net kilowatt-hour. The heat rate is computed by dividing the total BTU content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

Industrial – See **Commercial and Industrial**.

Interdepartmental Sales – Kilowatt-hour sales of electric energy to other departments (gas, steam, water, etc.) and the dollar value of such sales at tariff or other specified rates for the energy supplied.

Internal Combustion Engine – A prime mover in which energy released from rapid burning of a fuel-air mixture is converted into mechanical energy. Diesel, gasoline, and gas engines are the principal types in this category.

Investor-Owned Electric Utilities – Those electric utilities organized as tax-paying businesses usually financed by the sale of securities in the free market, and whose properties are managed by representatives regularly elected by their shareholders. Investor-owned electric utilities, which may by owned by an individual proprietor or a small group of people, are usually corporations owned by the general public.

Kilowatt (KW) – 1,000 watts. See **Watt**.

Kilowatt-Hour (kWh) – The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Kilowatt-Hours per Capita – Net generation in the United States divided by the national population, or the corresponding ratio for any other area.

Large Light and Power – See **Classes of Electric Services, Sales to Ultimate Customers**.

Load – The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power-consuming equipment of the customers. See **Demand**.

> **Average** – See **Demand, Average**.
>
> **Base** – The minimum load over a given period of time.
>
> **Connected** – Connected load is the sum of the capacities or rating of the electric power-consuming apparatus connected to a supplying system, or any part of the system under consideration.
>
> **Peak** – See **Demand, Maximum** and also **Demand, Instantaneous Peak**.

Load Factor – The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, also may be derived by multiplying the kilowatt-hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

Loss (Losses) – The general term applied to energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system. Losses occur principally as energy transformations from kilowatt-hours to waste heat in electric conductors and apparatus.

> **Average** – The total difference in energy input and output or power input and output (due to losses) averaged over a time interval and expressed either in physical quantities or as a percentage of total input.
>
> **Energy** – The kilowatt-hours lost in the operation of an electric system.
>
> **Line** – Kilowatt-hours and kilowatts lost in transmission and distribution lines under specified conditions.

Loss (Losses) Continued

> **Peak Percent** – The difference between the power input and output, as a result of losses due to the transfer of power between two or more points on a system at the time of maximum load, divided by the power input.
>
> **System** – The difference between the system net energy or power input and output, resulting from characteristic losses and unaccounted for between the sources of supply and the metering points of delivery on a system.

Margin of Reserve Capacity – See **Capability Margin**.

Maximum Demand – See **Demand, Maximum**.

Maximum Load – See **Demand, Maximum**.

Megawatt (MW) – 1,000 kilowatts. See **Watt**.

Megawatt-Hour (MWh) – 1,000 kilowatt-hours. See **Kilowatt-Hours**.

Municipally-Owned Electric System – An electric utility system owned and/or operated by a municipality engaged in serving residential, commercial, and/or industrial customers, usually, but not always, within the boundaries of the municipality.

Nameplate Rating – The full-load continuous rating of a generator, prime mover, or other electrical equipment under specified conditions as designated by the manufacturer. The nameplate rating is usually indicated on a nameplate attached to the individual machine or device. The nameplate rating of a steam electric turbine-generator wet is the guaranteed continuous output in kilowatts or KVA (kilovolt-amperes = 1,000 volt-amperes) and power factor at generator terminals when the turbine is clean and operating under specified throttle steam pressure and temperature, specified reheat temperature, specified exhaust pressure, and with full extraction from all extraction openings.

Net Capability – See **Capability, Net Generating Station**.

Net Energy for Load – A term used in Federal Energy Regulatory Commission reports and comprising:

1. The net generation by the system's own plants, plus
2. Energy received from others (exclusive of receipts for borderline customers), less
3. Energy delivered for resale to those Class I and II systems which obtain a part of their power supply from sources other than the company's system.

Net Energy for System – A term used in Federal Energy Regulatory Commission reports and comprising:

1. The net generation by the system's own plants, plus
2. Energy received from others (exclusive of receipts for borderline customers), less
3. Energy delivered for resale to those Class I and II systems which obtain a part of their power supply from sources other than the company's system, plus
4. Energy received for borderline customers, less
5. Energy delivered for resale to all systems other than those specified in Item 3 preceding.

Net Generating Station Capability – See **Capability, Net Generating Station**.

Net Generation – See **Generation, Electric – Net**.

Net Plant Capability – See **Capability, Net Generating Station**.

Nuclear Energy – Energy produced in the form of heat during the fission process in a nuclear reactor. When released in sufficient and controlled quantity, this heat energy may be used to produce steam to drive a turbine-generator and thus be converted to electrical energy.

Nuclear (Atomic) Fuel – Material containing fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.

Prime Mover – The engine, turbine, water wheel, or similar machine which drives an electric generator.

Public Street and Highway Lighting – A customer, sales, and revenue classification covering electric energy supplied and services rendered for lighting streets, highways, parks, and other public places, or for traffic or other signal service, for municipalities or other divisions or agencies of federal or state governments.

Publicly Owned Electric Utilities (Government-Owned Electric Utilities and Agencies) – When used in statistical tables to indicate class of ownership, this term includes municipally-owned electric systems and federal and state public power projects. Cooperatives are not included in this grouping.

Renewable Generation Capacity – See **Capacity**.

Reserve Capacity – See **Capacity**.

Residential – A customer, sales, or revenue classification covering electric energy supplied for residential (household) purposes. The classification of an individual customer's account where the use is both residential and commercial is based on principal use.

Rural – A rate classification covering electric energy supplied to rural and farm customers under distinct rural rates. See **Classes of Electric Service.**

Sales for Resale – A customer, sales, and revenue classification covering electric energy supplied (except under interchange agreements) to other electric utilities or to public authorities for resale or distribution. Includes sales for resale to cooperatives, municipalities, and federal and state electric agencies.

Service Area – Territory in which a utility system is required or has the right to supply electric service to ultimate customers.

Solar Photovoltaic (PV) – These devices generate electricity directly from sunlight via an electronic process that occurs naturally in certain types of material, called semiconductors. Electrons in these materials are freed by solar energy and can be induced to travel through an electrical circuit, powering electrical devices or sending electricity to the grid.

Station Use (Generating) – The kilowatt-hours used at an electric generating station for such purposes as excitation and operation of auxiliary and other facilities essential to the operation of the station. Station use includes electric energy supplied from house generators, main generators, the transmission system, and any other sources. The quantity of energy used is the difference between the gross generation plus any supply from outside the station and the net output of the station.

Summer Peak – The greatest load on an electric system during any prescribed demand interval in the summer or cooling season, usually between June 1 and September 30.

System, Electric – The physically connected generation, transmission, distribution, and other facilities operated as an integral unit under one control, management, or operating supervision.

System Load – See **Demand**.

System Loss – See **Loss (Losses)**.

Therm – 100,000 BTUs. See **BTU (British Thermal Unit)**.

Thermal – A term used to identify a type of electric generating station, capacity or capability, or output in which the source of energy for the prime mover is heat.

Turbine (Steam or Gas) – An enclosed rotary type of prime mover in which heat energy in steam or gas is converted into mechanical energy by the force of a high velocity flow of steam or gases directed against successive rows of radial blades fastened to a central shaft.

Ultimate Customers – Those customers purchasing electricity for their own use and not for resale. See **Classes of Electric Service**.

Uses and Losses – "Uses" refers to the electricity used by the electric companies for their own purposes and "losses" refers to transmission losses.

Utility Rate Structure – A utility's approved schedule of charges for billing utility service rendered to various classes of its customers.

Volt-Ampere – The basic unit of apparent power. The volt-amperes of an electric circuit are the mathematical product of the volts and amperes of the circuit.

Watt – The electrical unit of power or rate of doing work; also the rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor. A watt is analogous to horsepower or foot-pounds per minute of mechanical power. One horsepower is equivalent to approximately 746 watts.

Winter Peak – The greatest load on an electric system during any prescribed demand interval in the winter or heating season, usually between December 1 of a calendar year and March 31 of the next calendar year.

Sources: Edison Electric Institute
Florida Electric Power Coordinating Group, Inc.
Florida Office of Energy

TAB 6

FLORIDA
PUBLIC
SERVICE
COMMISSION

2018

Facts & Figures of the Florida Utility Industry

This publication is a reference manual for anyone needing quick information about the electric, natural gas, telecommunications, and water and wastewater industries in Florida. The facts have been gathered from in-house materials, outside publications, and websites. Every effort has been made to accurately reference the source of the information used. Though most of the data refers specifically to Florida, some data from other states and national averages are included for comparison purposes. If you have questions about this publication, please contact:

Office of Consumer Assistance & Outreach
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
(850) 413-6482

Table of Contents

ELECTRIC

NATURAL GAS

TELECOMMUNICATIONS

WATER & WASTEWATER

Quick Facts

Customers & Rates

Maps

Regulatory Authority

Pursuant to Chapter 366, Florida Statutes (F.S.), as of December 2017, the Florida Public Service Commission (FPSC) has regulatory authority over:

- **5 investor-owned electric companies** (all aspects of operations, including rates and safety)
- **35 municipally owned electric utilities** (limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning)
- **18 rural electric cooperatives** (limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning)

Generating Capacity
(Utility and Non-Utility)
As of December 31, 2016

- Summer: 58,295 Megawatts (MW)
- Winter: 62,786 MW*

Transmission Capability for Peninsular Florida

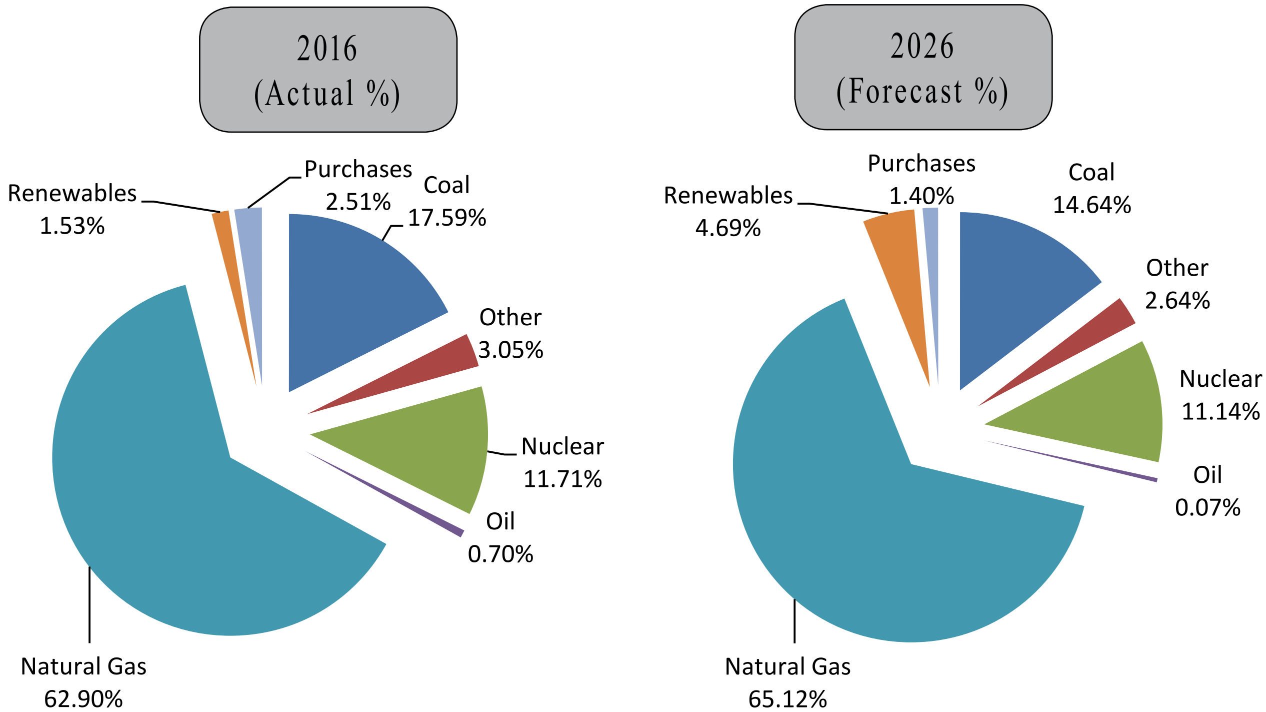
- Import: Summer: 3,400 MW
  Winter: 3,200 MW
- Export: Summer: 800 MW
  Winter: 400 MW**

* Generating capacity is higher in winter due to thermodynamics/cooling water.
** Export transmission capability is higher in winter due to thermal ratings of lines and seasonal load patterns.

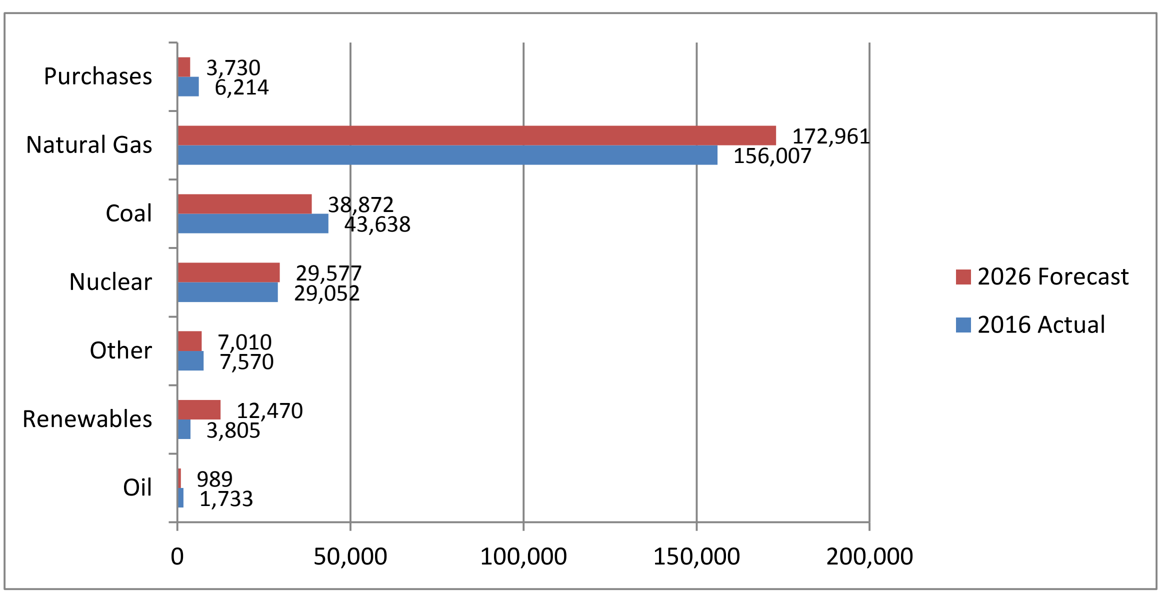
Sources:
Statistics of the Florida Electric Utility Industry, October 2017
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/2016.pd

2017 Ten-Year Site Plan Workshop FRCC Studies and Reports

Florida Energy Generation by Fuel Type

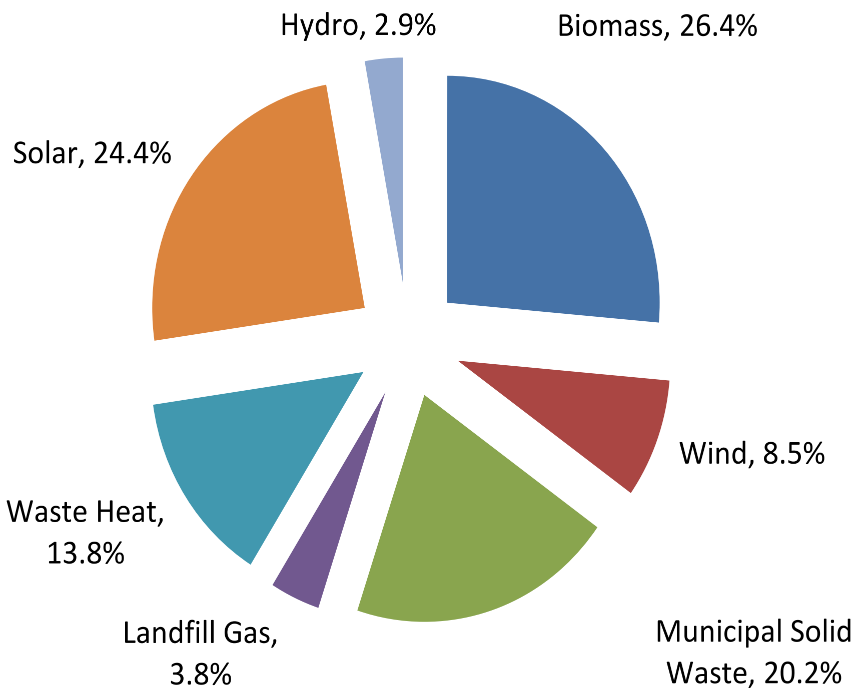


Energy Sources (GWH)



Source:
FRCC 2017 Regional Load & Resource Plan, July 2017
http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/TenYearSitePlans/201 /FRCC.pdf

Florida's Renewable Capacity in MW(2016)
(Total: 2,206 MW)



Total Florida Renewable Capacity: 2,206 MW
Total Florida Electric Generation Capacity: 58,295 MW (Summer)

Biomass: Material collected from wood processing, forestry, urban wood waste, and agricultural waste.
Landfill Gas: Methane collected from landfill
Waste Heat: Collected in processing phosphate into fertilizer and other products.

Source:
FPSC's *Review of 2017 Ten-Year Site Plans for Florida's Electric Utilities*, November 2017
http://www.floridapsc.com/Files/PDF/Utilities/Electricgas/TenYearSitePlans/201 /Review.pdf

Average Number of Customers

Average Number of Customers for Investor-Owned Utilities By Class of Service 2017

Utility	Residential	Commercial	Industrial	Other	Total
Florida Power & Light Co.	4,309,280	543,850	11,884	4,026	4,869,040
Florida Public Utilities Company	24,345	4,418	2	3,022	31,787
Gulf Power Company	398,501	56,091	254	569	455,415
Duke Energy Florida	1,559,248	172,503	2,148	26,117	1,760,016
Tampa Electric Company	646,221	74,313	1,615	8,354	730,503
Total	**6,937,595**	**851,175**	**15,903**	**42,088**	**7,846,761**

Source:
Statistics of the Florida Electric Utility, October 2017, Table 33
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/201 .pdf

Typical Electric Bill Comparisons

Residential Service Provided by Investor-Owned Utilities
December 31, 2017

Utility	Minimum Bill or Customer Charge	1,000 Kilowatt Hours*
Florida Power & Light Company	$7.87	$99.99
Duke Energy Florida	$8.76	$114.12
Tampa Electric Company	$16.62	$102.06
Gulf Power Company	$19.50	$134.19
Florida Public Utilities Company	$14.00	$135.50
Northwest	$14.00	$135.50
Northeast		

Commercial/Industrial Service Provided by Investor-Owned Utilities
December 31, 2017

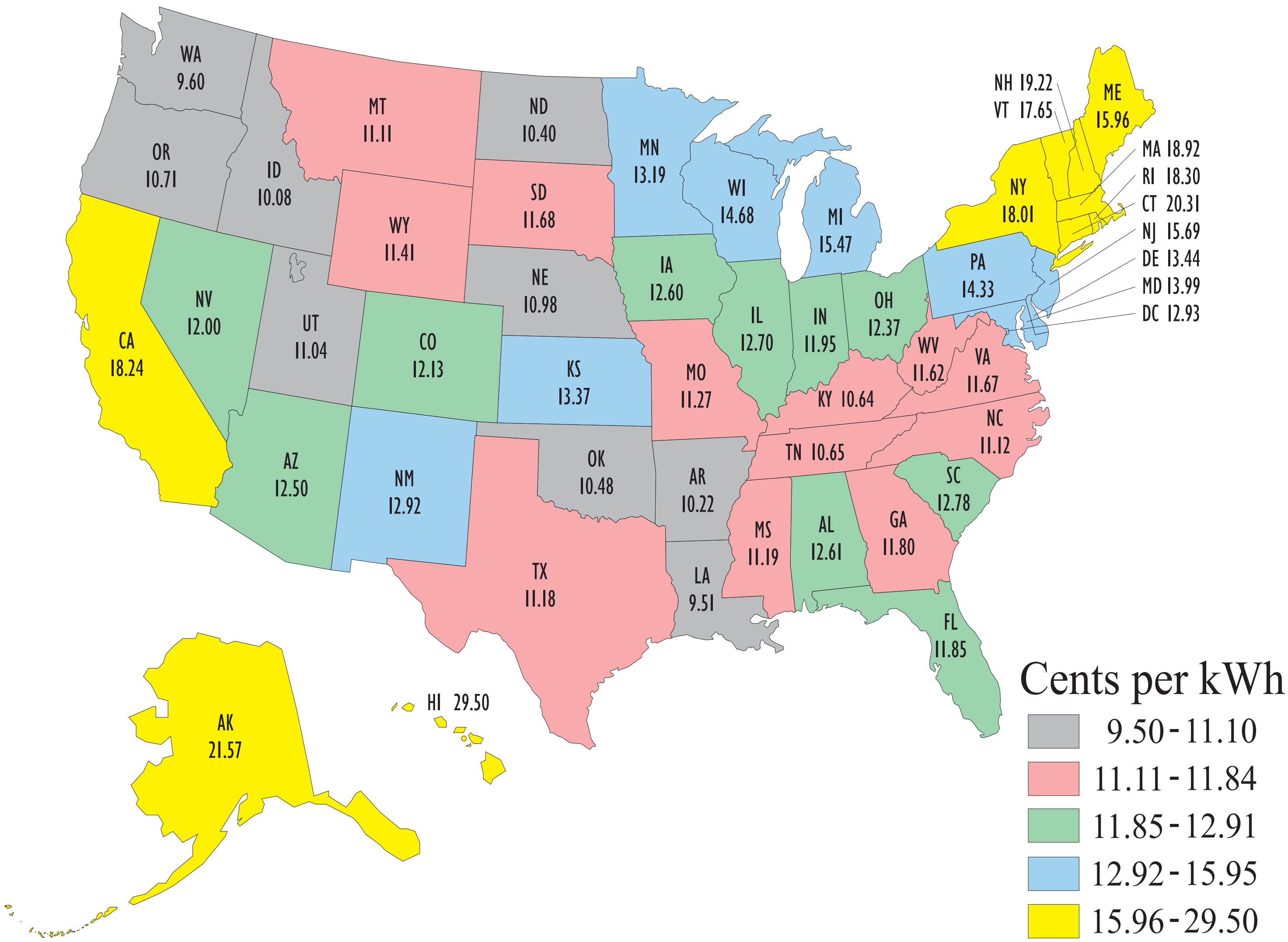
Utility	400,000 Kilowatt Hours 1,000 KW Demand*
Florida Power & Light Company	$32,383
Duke Energy Florida	$31,592
Tampa Electric Company	$30,910
Gulf Power Company	$36,168
Florida Public Utilities Company	
Northwest	$43,618
Northeast	$43,618

* Excludes local taxes, franchise fees, and gross receipts taxes that are billed as a separate line item. Includes cost recovery clause factors effective December 2017.

Note: Typical electric bill comparisons for municipally and cooperatively owned electric utilities are available in the *Comparative Rate Statistics* report available at: http://www.floridapsc.com/Publications/Reports

Average Residential Price of Electricity by State (2017)

(U.S. Residential Average Price per kWh = 13.52 cents)



Source:
Energy Information Administration's Electric Power Monthly, Table 5.6.B.
https://www.eia.gov/electricity/monthly/archive/february2018.pdf

Nuclear Waste Policy

Florida Power & Light Company (FPL) currently stores radioactive waste called "spent nuclear fuel" in water-filled pools inside containment structures at plant sites. As the pools become filled to capacity, some of the spent fuel is removed and placed in concrete storage containers (dry casks) on-site. Duke Energy Florida, LLC (DEF) has moved all of its spent nuclear fuel into dry cask storage.

Federal law requires the U.S. Department of Energy (DOE) to store and ultimately dispose of spent nuclear fuel and high-level radioactive waste in a geologic repository. Since 1983, Florida ratepayers have paid $903.6 million ($1.6895 billion with interest) into the federal nuclear waste fund established to cover the cost of transportation, storage, and disposal of spent fuel. DOE suspended collection of the nuclear waste fee in May 2014.

Florida Nuclear Power Reactors

December 31, 2016

Reactor	Utility	Metric Tons in Spent Fuel Pool	Metric Tons in Dry Cask Storage	NRC License Expires
St. Lucie 1	FPL	580	223	2036
St Lucie 2	FPL	523	137	2043
Turkey Point 3	FPL	558	131	2032
Turkey Point 4	FPL	571	131	2033

* Duke Energy Florida filed notification of cessation of operations with the Nuclear Regulatory Commission on February 20, 2013.
** Duke Energy Florida completed transfer of all spent fuel to dry cask storage in January 2018.

Proposed Nuclear Power Reactor

Reactor	Utility	Estimated In-Service Date
Turkey Point 6	FPL	2031
Turkey Point 7	FPL	2032

Sources:
Responses to information requests provided by Florida Power & Light Company and Duke Energy Florida

Operating Nuclear Reactors

Alabama
Browns Ferry
Units 1, 2, and 3

Joseph M. Farley
Units 1 and 2

Arizona
Palo Verde
Units 1, 2, and 3

Arkansas
Arkansas Nuclear One
Units 1 and 2

California
Diablo Canyon
Units 1 and 2

Connecticut
Millstone
Units 2 and 3

Florida
St. Lucie
Units 1 and 2

Turkey Point
Units 3 and 4

Georgia
Edwin I. Hatch
Units 1 and 2

Vogtle
Units 1 and 2

Illinois
Braidwood
Units 1 and 2

Byron
Units 1 and 2

Clinton

Dresden
Units 2 and 3

La Salle County
Units 1 and 2

Illinois (Continued)
Quad Cities
Units 1 and 2

Iowa
Duane Arnold

Kansas
Wolf Creek
Unit 1

Louisiana
River Bend
Unit 1

Waterford
Unit 3

Maryland
Calvert Cliffs
Units 1 and 2

Massachusetts
Pilgrim
Unit 1

Michigan
D. C. Cook
Units 1 and 2

Fermi
Unit 2

Palisades

Minnesota
Monticello

Prairie Island
Units 1 and 2

Mississippi
Grand Gulf
Unit 1

Missouri
Callaway

Nebraska
Cooper

Nebraska (Continued)
Fort Calhoun

New Hampshire
Seabrook
Unit 1

New Jersey
Hope Creek
Unit 1

Oyster Creek

Salem
Units 1 and 2

New York
James A. Fitzpatrick

Ginna

Indian Point
Units 2 and 3

Nine Mile Point
Units 1 and 2

North Carolina
Brunswick
Units 1 and 2

McGuire
Units 1 and 2

Shearon Harris
Unit 1

Ohio
Davis-Besse

Perry
Unit 1

Pennsylvania
Beaver Valley
Units 1 and 2

Limerick
Units 1 and 2

Pennsylvania (Continued)
Peach Bottom
Units 2 and 3

Susquehanna
Units 1 and 2

Three Mile Island
Unit 1

South Carolina
Catawba
Units 1 and 2

Oconee
Units 1, 2, and 3

H. B. Robinson
Unit 1

Summer

Tennessee
Sequoyah
Units 1 and 2

Watts Bar
Units 1 and 2

Texas
Comanche Peak
Units 1 and 2

South Texas Project
Units 1 and 2

Virginia
North Anna
Units 1 and 2

Surry
Units 1 and 2

Washington
Columbia
Generating Station

Wisconsin
Point Beach
Units 1 and 2

Source:
Nuclear Regulatory Commission: http://www.nrc.gov/info-finder/region-state/#listAlph

Reliability Councils

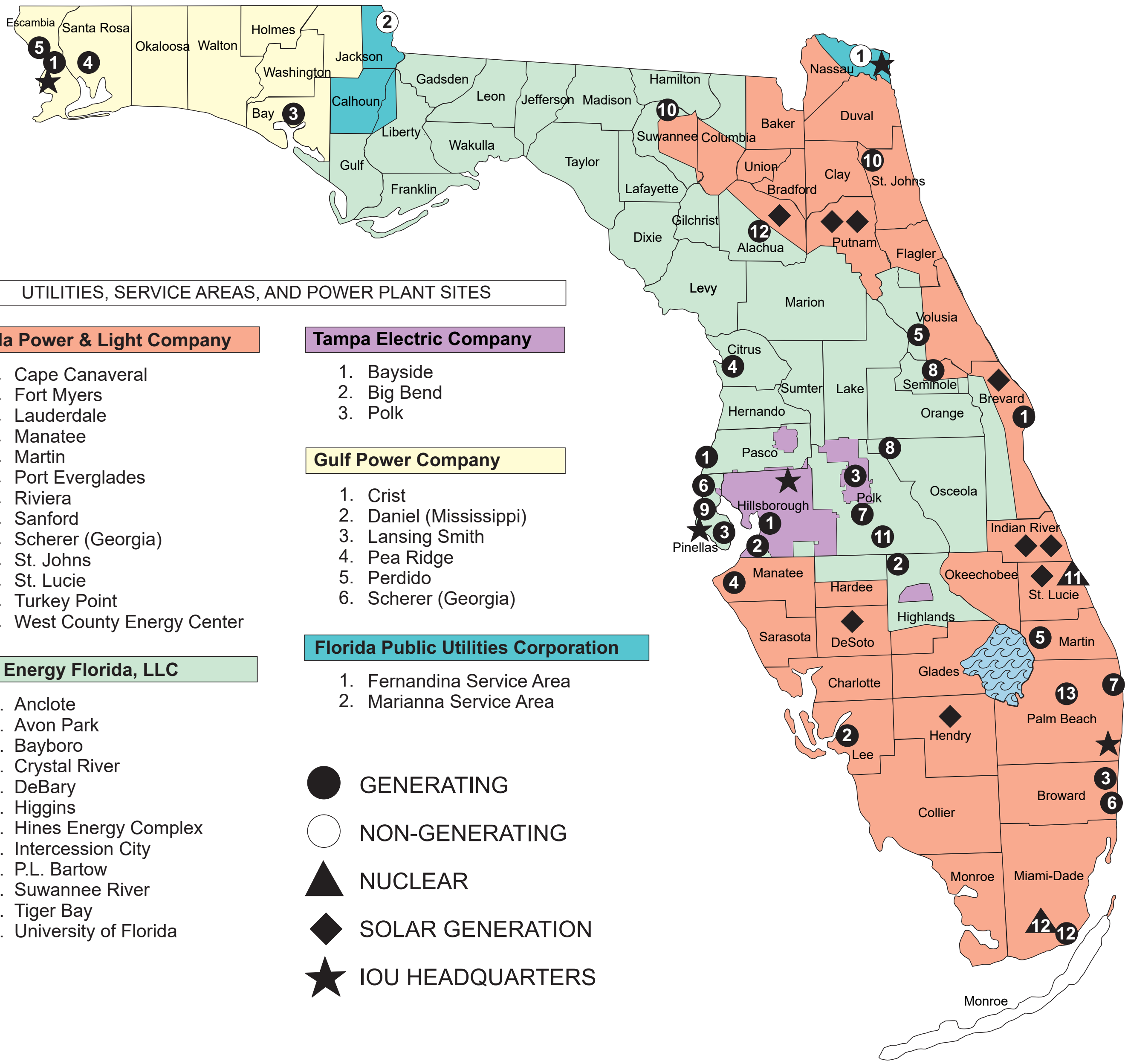
NERC REGIONS

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool, RE
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Source: North American Reliability Council
http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

Investor-Owned Electric Utilities

Approximate Company Service Areas



UTILITIES, SERVICE AREAS, AND POWER PLANT SITES

Florida Power & Light Company

1. Cape Canaveral
2. Fort Myers
3. Lauderdale
4. Manatee
5. Martin
6. Port Everglades
7. Riviera
8. Sanford
9. Scherer (Georgia)
10. St. Johns
11. St. Lucie
12. Turkey Point
13. West County Energy Center

Duke Energy Florida, LLC

1. Anclote
2. Avon Park
3. Bayboro
4. Crystal River
5. DeBary
6. Higgins
7. Hines Energy Complex
8. Intercession City
9. P.L. Bartow
10. Suwannee River
11. Tiger Bay
12. University of Florida

Tampa Electric Company

1. Bayside
2. Big Bend
3. Polk

Gulf Power Company

1. Crist
2. Daniel (Mississippi)
3. Lansing Smith
4. Pea Ridge
5. Perdido
6. Scherer (Georgia)

Florida Public Utilities Corporation

1. Fernandina Service Area
2. Marianna Service Area

GENERATING

NON-GENERATING

NUCLEAR

SOLAR GENERATION

IOU HEADQUARTERS

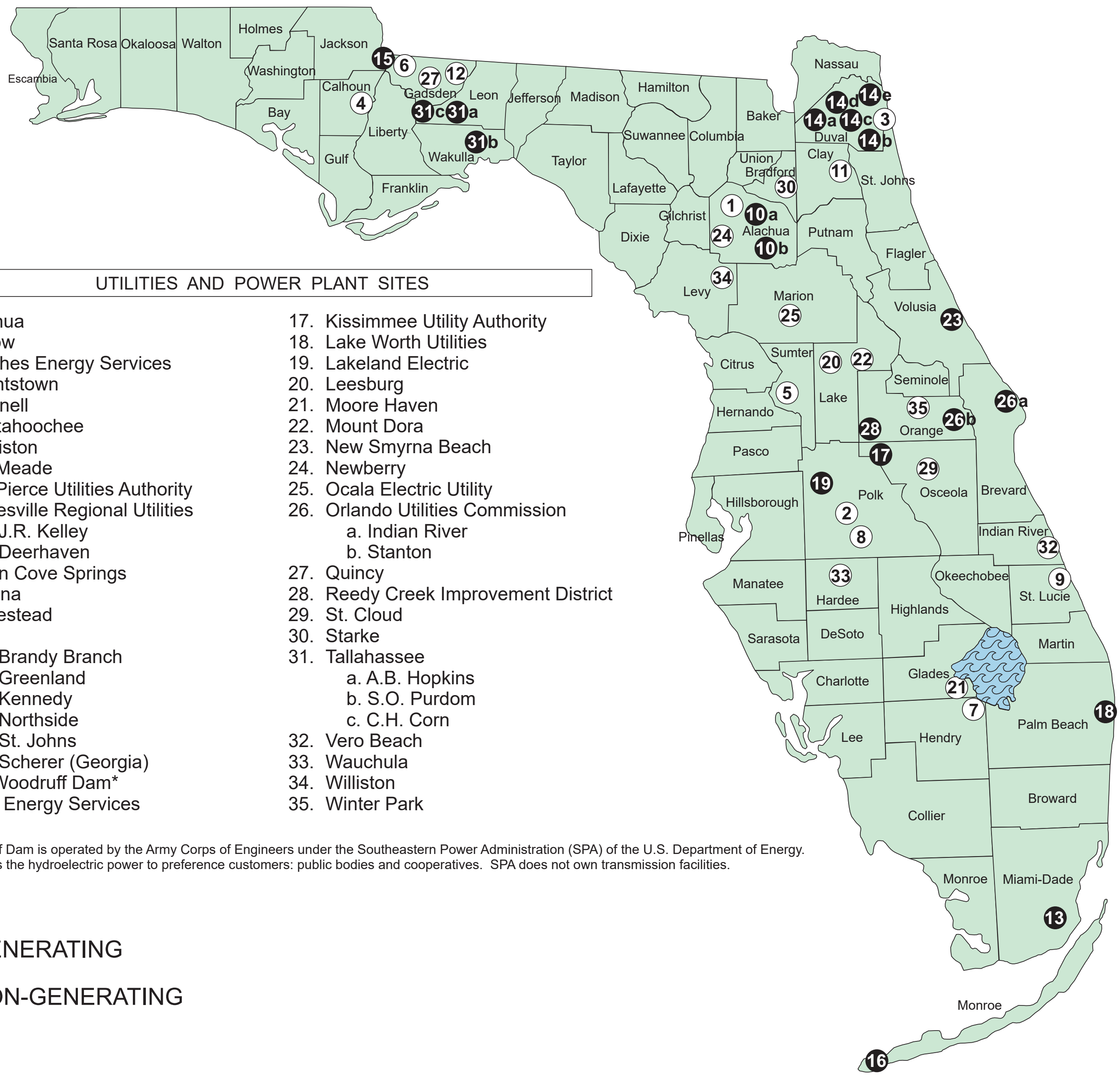
Service areas are approximations.
Information on this map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source:
Florida Public Service Commission

Additional information about Florida's investor-owned electric utilities is available from:
FPSC's *Statistics of the Florida Electric Utility Industry*, October 2017
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/2016.pd

Municipal Electric Utilities

Approximate Utility Locations



UTILITIES AND POWER PLANT SITES

1. Alachua
2. Bartow
3. Beaches Energy Services
4. Blountstown
5. Bushnell
6. Chattahoochee
7. Clewiston
8. Fort Meade
9. Fort Pierce Utilities Authority
10. Gainesville Regional Utilities
    a. J.R. Kelley
    b. Deerhaven
11. Green Cove Springs
12. Havana
13. Homestead
14. JEA
    a. Brandy Branch
    b. Greenland
    c. Kennedy
    d. Northside
    e. St. Johns
    f. Scherer (Georgia)
15. Jim Woodruff Dam*
16. Keys Energy Services
17. Kissimmee Utility Authority
18. Lake Worth Utilities
19. Lakeland Electric
20. Leesburg
21. Moore Haven
22. Mount Dora
23. New Smyrna Beach
24. Newberry
25. Ocala Electric Utility
26. Orlando Utilities Commission
    a. Indian River
    b. Stanton
27. Quincy
28. Reedy Creek Improvement District
29. St. Cloud
30. Starke
31. Tallahassee
    a. A.B. Hopkins
    b. S.O. Purdom
    c. C.H. Corn
32. Vero Beach
33. Wauchula
34. Williston
35. Winter Park

* Jim Woodruff Dam is operated by the Army Corps of Engineers under the Southeastern Power Administration (SPA) of the U.S. Department of Energy. SPA markets the hydroelectric power to preference customers: public bodies and cooperatives. SPA does not own transmission facilities.

GENERATING

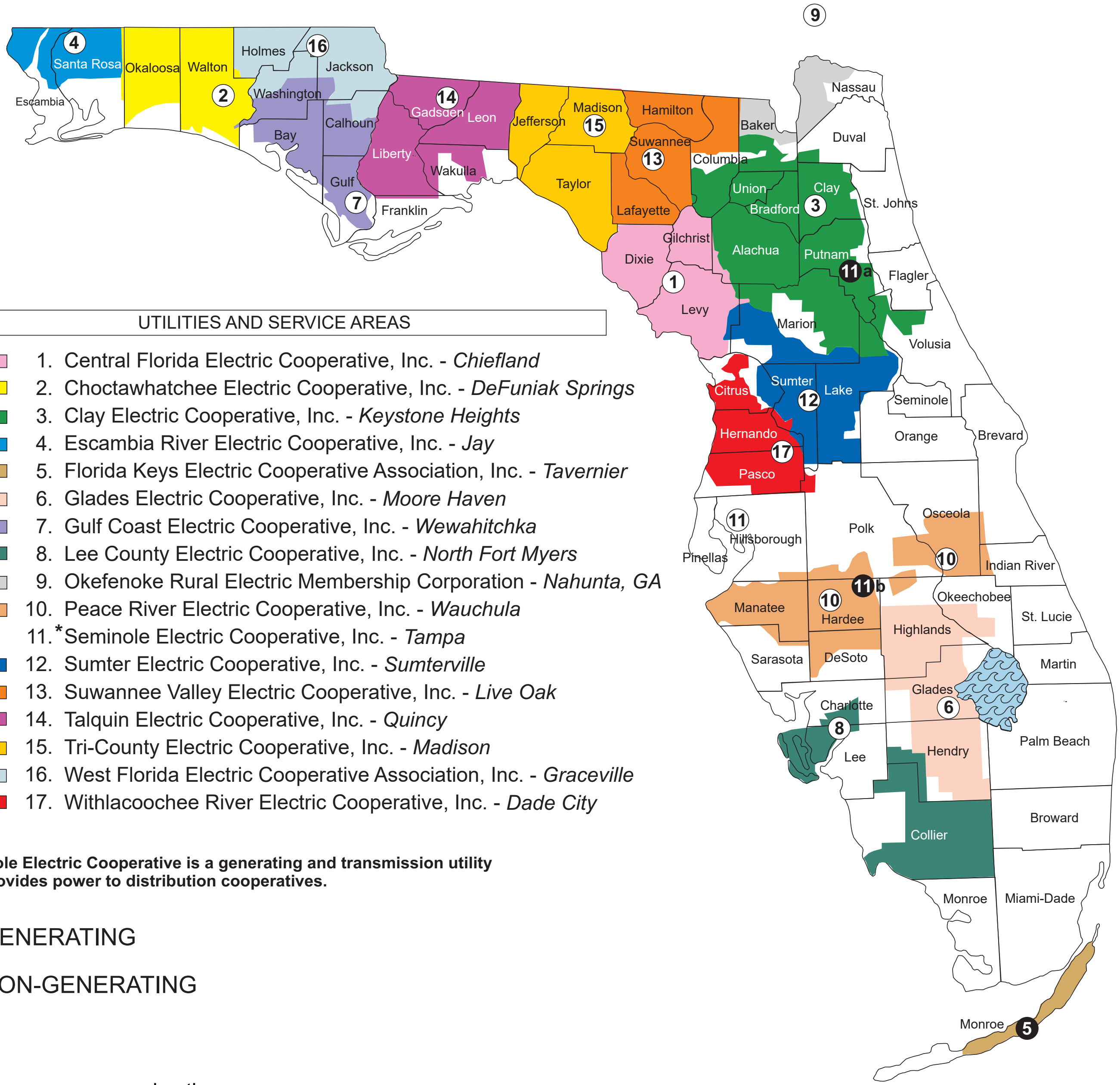
NON-GENERATING

Service areas are approximations.
Information on this map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source:
Florida Public Service Commission
Additional information about Florida's investor-owned electric utilities is available from FPSC's *Statistics of the Florida Electric Utility Industry*, October 2017
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/2016.pd

Rural Electric Cooperatives

Approximate Company Service Areas



UTILITIES AND SERVICE AREAS

1. Central Florida Electric Cooperative, Inc. - *Chiefland*
2. Choctawhatchee Electric Cooperative, Inc. - *DeFuniak Springs*
3. Clay Electric Cooperative, Inc. - *Keystone Heights*
4. Escambia River Electric Cooperative, Inc. - *Jay*
5. Florida Keys Electric Cooperative Association, Inc. - *Tavernier*
6. Glades Electric Cooperative, Inc. - *Moore Haven*
7. Gulf Coast Electric Cooperative, Inc. - *Wewahitchka*
8. Lee County Electric Cooperative, Inc. - *North Fort Myers*
9. Okefenoke Rural Electric Membership Corporation - *Nahunta, GA*
10. Peace River Electric Cooperative, Inc. - *Wauchula*
11. *Seminole Electric Cooperative, Inc. - *Tampa*
12. Sumter Electric Cooperative, Inc. - *Sumterville*
13. Suwannee Valley Electric Cooperative, Inc. - *Live Oak*
14. Talquin Electric Cooperative, Inc. - *Quincy*
15. Tri-County Electric Cooperative, Inc. - *Madison*
16. West Florida Electric Cooperative Association, Inc. - *Graceville*
17. Withlacoochee River Electric Cooperative, Inc. - *Dade City*

* **Seminole Electric Cooperative is a generating and transmission utility that provides power to distribution cooperatives.**

● GENERATING

○ NON-GENERATING

Service areas are approximations.
Information on this map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source:
Florida Public Service Commission

Additional information about Florida's investor-owned electric utilities is available from:
FPSC's *Statistics of the Florida Electric Utility Industry*, October 2017
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/Statistics/2016.pd

Regulatory Authority

Pusuant to Chapter 366, F.S., as of December 31, 2017, the FPSC has regulatory authority over:

- **8 investor-owned natural gas utilities** (all aspects of operations, including safety)
- **27 municipally-owned natural gas utilities** (limited to safety and territorial boundaries)
- **4 special gas districts** (limited to safety and territorial boundaries)

Transmission

- Natural gas is transported to Florida customers through two major and two small interstate pipelines:

  Major ⟶ 1. Florida Gas Transmission Company (FGT)
  2. Gulfstream Natural Gas System
  3. Sabal Trail Interstate Pipeline

  Small ⟶ 1. Gulf South Pipeline Company
  2. Southern Natural Gas

- FGT's pipeline capacity is nearly 3 million cubic feet per day.
- Gulfstream's pipeline capacity is 1.3 billion cubic feet per day.
- Sabal Trail's pipeline capacity is 1 billion cubic feet per day.

Sources:
Florida Gas Transmission Company
http://fgttransfer.energytransfer.com/ipost/FGT

Gulfstream Natural Gas System
http://wp.gulfstreamgas.com/

Number of Customers

Number of Customers for Investor-Owned Utilites By Customer Type

December 31, 2016

Utility	Residential	Commercial & Industrial	FTS*	Other**	Total
Florida City Gas	99,983	4,921	2,668	0	107,572
Florida Division of Chesapeake Utilities***	0	0	16,806	0	16,806
Florida Public Utilities Company	52,019	4,128	1,759	79	57,985
Florida Public Utilities Company - Ft. Meade Division	609	27	0	0	635
Florida Public Utilities Company - Indiantown Division***	0	0	699	0	699
Peoples Gas System	334,290	12,049	23,855	64	370,258
Sebring Gas System***	0	0	559	0	559
St. Joe Natural Gas Company	2,785	206	1	1	2,993

* Firm Transportation Service
** Other includes Off System Sales, Interruptible Sales, Natural Gas Vehicle Sales, and Other Sales to Public Authorities
*** Exited the merchant function. All sales are firm transportation customers.

Source:
FPSC, 2016 Annual Reports filed by Natural Gas Utilitie

Typical Natural Gas Bill Comparisons

Residential, Commercial, and Industrial Service Provided by Investor-Owned Utilities

December 31, 2017

	Residential		Commercial		Industrial	
Utility	Minimum Bill or Customer Charge	Therms Sold (20)	Minimum Bill or Customer Charge	Therms Sold (90)	Minimum Bill or Customer Charge	Therms Sold (700)
Florida City Gas	$9.50 - $15	$41.88	$11 - $15	$133.21	$15 - $30	$945.60
Florida Division of Chesapeake Utilities *	$19 - $40	$34.50	$19 - $108	$85.59	$108 - $210	$415.68
Florida Public Utilities Company	$11.00	$50.09	$20.00	$172.28	$20 - $90	$1,149.11
Florida Public Utilities Company - Ft. Meade Division	$8.50	$49.31	$17.50	$173.68	$17.50 - $175.00	$1,050.32
Florida Public Utilities Company - Indiantown Division *	$9 - $25	$16.82	$9 - $25	$31.97	$25.00	$282.77
Peoples Gas System	$15 - $20	$40.34	$25 - $35	$141.88	$35 - $50	$873.04
Sebring Gas System *	$9 - $35	$23.62	$12 - $35	$81.65	$35 - $150	$397.80
St. Joe Natural Gas Company	$13 - $20	$53.55	$20 - $70	$163.78	$70.00	$953.35

December 2017 gas costs are included for those companies participating in purchased gas adjustment clause: (Florida City Gas, Florida Public Utilities Company, Florida Public Utilites Company - Fort Meade Division, Peoples Gas System, and St. Joe Natural Gas.)

* No longer purchase gas for their customers. These companies deliver gas that the end use customers purchase; therefore, no gas costs are included.

Source: Company Tariffs

Annual Therm Sales

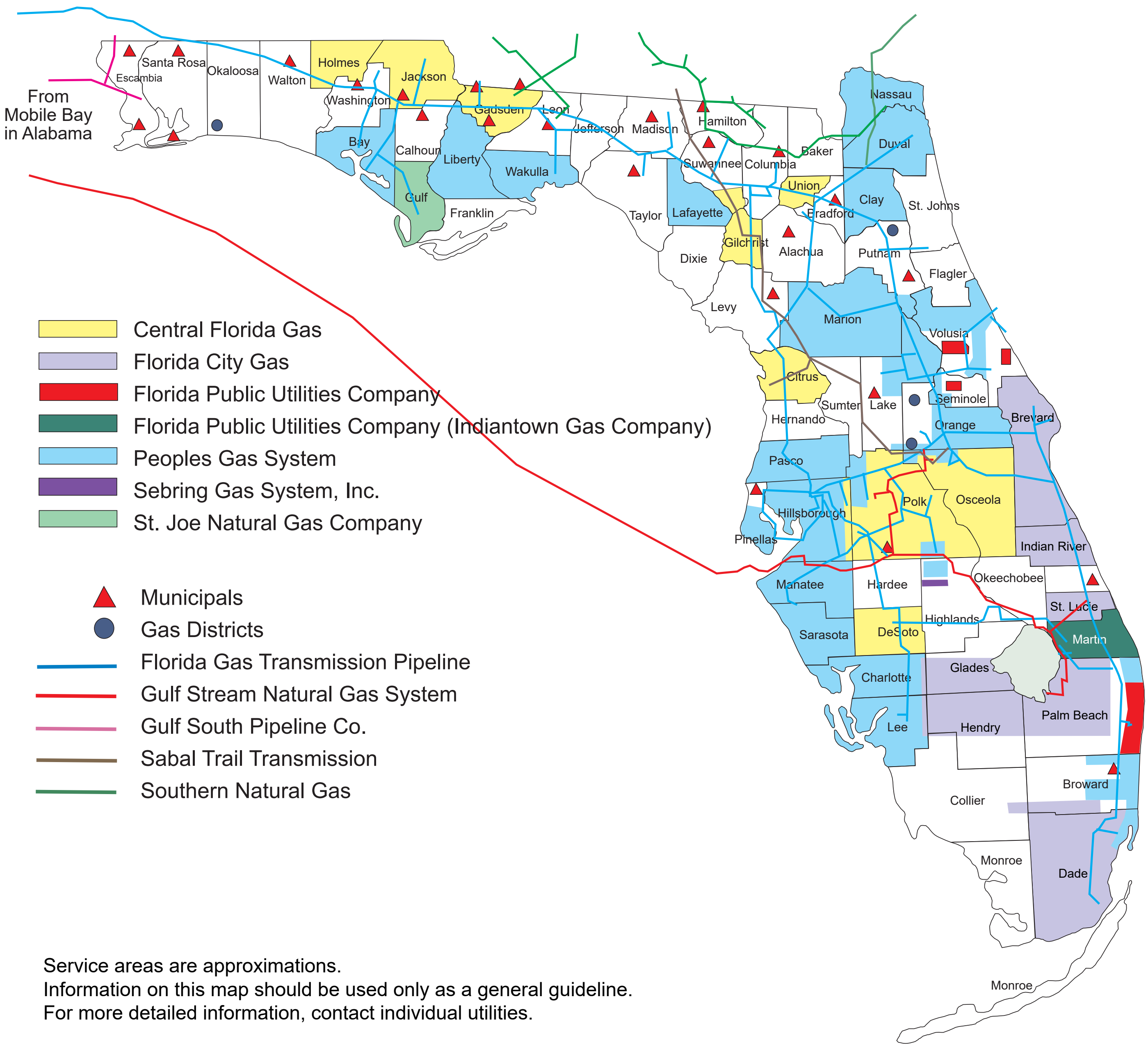
Annual Therm Sales for Investor-Owned Utilities
December 31, 2016

Utility	Residential	Commercial & Industrial	FTS*	Other**	Total
Florida City Gas	15,689,313	22,805,737	101,667,766	0	140,162,816
Florida Division of Chesapeake Utilities	0	0	174,092,670	0	174,092,670
Florida Public Utilities	12,932,946	21,027,651	34,276,307	7,540,568	75,777,472
Florida Public Utilities - Ft. Meade Division	74,872	74,766	0	0	149,638
Florida Public Utilities - Indiantown Division	0	0	1,535,931	0	1,535,931
Peoples Gas System	68,082,439	30,477,017	463,849,102	1,325,577,449	1,887,986,007
Sebring Gas System***	0	0	1,169,058	0	1,169,058
St. Joe Natural Gas Company	528,015	375,742	381,518	4,800	1,290,075

* Firm Transportation Service
** Other includes Off System Sales, Interruptible Sales, Natural Gas Vehicle Sales, and Other Sales to Public Authorities
*** Exited the merchant function. All sales are firm transportation customers.

Source:
FPSC, 2016 Annual Reports filed by Natural Gas Utilitie

Natural Gas Companies in Florida



Service areas are approximations.
Information on this map should be used only as a general guideline.
For more detailed information, contact individual utilities.

Source:
FPSC Map
http://www.floridapsc.com/Files/PDF/Publications/Reports/Electricgas/naturalgasutilities.pd

Regulatory Authority

Pursuant to Chapter 364, F.S., as of December 2017, the FPSC has regulatory authority over:

- **10 incumbent local exchange companies (ILECs)**
- **274 competitive local exchange companies (CLECs)**
- **46 pay telephone companies**

Definitions

- **Incumbent Local Exchange Telecommunications Company (ILEC) -** any company certificated by the Commission to provide local exchange telecommunications service in this state on or before June 30, 1995.
- **Competitive Local Exchange Telecommunications Company (CLEC) -** any company certificate by the Commission to provide local exchange telecommunications service in this state on or after July 1, 1995.
- **Pay Telephone Service Company (PATS) -** any certificated telecommunic - tions entity which provides pay telephone service.

Source:
Forida Public Service Commission Records

FPSC's *Telecommunications Terms and Definitions*
http://www.psc.state.fl.us/publications/telecomterminolog

Broadband, VoIP, and Wireless

Broadband is a term describing evolving digital technologies offering consumers integrated access to voice, high-speed data services, video on demand services, and interactive information delivery services. Voice over Internet Protocol (VoIP) and wireless services compete with traditional wireline service and represent a significant portion of today's communications market in Florida. VoIP is not the same as the Internet. It is a technology that allows you to make voice calls using a broadband internet connection instead of a regular telephone line. Broadband service also provides the basis for some VoIP services. These three services are not subject to FPSC jurisdiction.

Broadband

- In Florida, approximately 75 percent of household fixed broadband connections at download speeds of 10 megabytes per second (Mbps) or greater and 53 percent are greater than or equal to 25 Mbps in 2015.
- Residential subscribership in Florida reached 91 percent in 2015, above the national average of 79 percent.

VoIP

- As of December 2016, there were an estimated 2.8 million interconnected residential VoIP subscribers in Florida, about the same number estimated in 2015.
- The Florida Cable Telecommunications Association (FCTA) reported an estimated 2 million residential cable digital voice (VoIP) subscribers as of December 2016, about the same number as reported for the preceeding four years.

Wireless

- There were more than 20 million wireless voice subscriptions in Florida as of December 2016.
- The Centers for Disease Control (CDC) estimates that nationally over 50 percent of households are wireless-only as of December 2016.

Source:
FPSC's *Report on the Status of Competition in the Telecommunications Industry*, As of December 31, 2016
http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Telecommunication/TelecommunicationIndustry/2017.pdf

Access Lines

An access line is a telephone line extending from the telecommunications company's central office to a point of demarcation, usually on the customer's premises.

Florida Access Lines
As of December 2016

	Residential*	Business*	Total*	Change since 2015
AT&T Florida	425	592	1,017	-18%
CenturyLink FL	539	249	788	-7%
Frontier FL	138	227	365	-6%
Rural ILECs	85	37	122	-6%
CLECs	14	681	695	-2%
Total	**1,201**	**1,786**	**2,987**	**-9%**

* In thousands, rounded to the nearest thousand.

Sources:
FPSC's *Report on the Status of Competition in the Telecommunications Industry*, As of December 31, 2016, Figures 4-3 & 4-4
http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Telecommunication/TelecommunicationIndustry/2017.pd

Universal Service Programs

The Federal Communications Commission (FCC) and Congress recognize that telephone service provides a vital link to emergency services, government services, and surrounding communities. To help promote telecommunications service nationwide, the FCC, as directed by Congress, developed the Federal Universal Service Fund (USF). The USF is administered by the Universal Service Administrative Company (USAC). The USF includes the High-Cost, Low-Income, Schools and Libraries, and Rural Health Care Programs.

1 **High-Cost Program.** The federal universal service high-cost program (also known as the Connect America Fund) is designed to ensure that consumers in rural, insular, and high-cost areas have access to modern communications networks capable of providing voice and broadband service, both fixed and mobile, at rates that are reasonably comparable to those in urban areas. The program fulfills this universal service goal by allowing eligible carriers who serve these areas to recover some of their costs from the federal Universal Service Fund.

2 **Low-Income Program.** Provides telephone service discounts to qualifying low-income consumers. It offers benefits through the Lifeline Assistance program:

- ▲ **The Lifeline Assistance Program:** Provides a monthly credit of $9.25 on basic monthly service or the option of receiving a free Lifeline cell phone and monthly minutes at the primary residence for qualified telephone subscribers. The telephone subscriber may receive a credit less than $9.25 if the subscriber's bill for basic local telephone service is less than that amount.

- ▲ **Tribal Benefits:** Residents living on federally recognized tribal lands may receive a one-time discount of up to $100.00 in Link-Up support and enhanced Lifeline support (up to an additional $25.00 in support beyond current levels). Link-Up helps income-eligible consumers on tribal lands with initial installation or activation of a wireline or wireless telephone for the primary residence.

- ▲ **Monthly Lifeline Credit:** Under the FCC's rules, monthly federal Lifeline support consists of a $9.25 monthly credit on basic monthly service or the option of receiving a free Lifeline cell phone and monthly minutes. Eligible subscribers living on tribal lands can receive a monthly discount of up to $34.25 ($9.25 plus an additional $25).

Low-Income Program (continued)

▲ **Customer Eligibility:** Customers with annual incomes up to 135 percent of the federal poverty guidelines may be eligible to participate in the Lifeline program. In addition, eligibility is determined by customer enrollment in any one of the following programs:

> Supplemental Nutritional Assistance Program (SNAP)

> Medicaid

> Supplemental Security Income (SSI)

> Federal Public Housing Assistance (Section 8)

> Veteran's Benefit and Survivo 's Pension Programs

> Bureau of Indian Affairs Programs*

Beginning December 2, 2016, Lifeline assistance is available for voice (home phone or cell phone), broadband (Internet) or a bundle of the two services. Prior to this, only voice services were eligible for Lifeline discount. While many companies will now be offering Lifeline Assistance for broadband, consumers will need to check with their local company for its offerings. There is still only one Lifeline discount per household that can be used for phone service and/or broadband.

3 **Schools and Libraries (or E-Rate) Program.** Helps to ensure that the nation's classrooms and libraries receive access to the vast array of educational resources that are accessible through the telecommunications network. While funding for the program is capped, the FCC has included an index for inflation to preserve the purchasing power of the program. The FCC increased the annual cap by 1.8 percent to $3.99 billion. The E-Rate program offers the following benefits:

▲ Eligible schools and libraries receive discounts on telephone service, Internet access, and internal connections (i.e., network wiring) within school and library buildings.

▲ The discounts range from 20 percent to 90 percent, depending on the school's eligibility for the National School Lunch program (or a federally approved alternative mechanism) and whether or not the school or library is located in an urban or rural area.

* Eligible consumers living on tribal lands qualify for Link-Up and Lifeline if they participate in one of the following federal assistance programs: (1) Tribal TANF, (2) Bureau of Indian Affairs General Assistance, (3) Head Start Subsidy, or (4) Food Distribution Program on Indian Reservations.

4 **Rural Health Care Program.** The Rural Health Care Program supports health care facilities in bringing world class medical care to rural areas through increased connectivity. It provides up to $400 million annually in reduced rates for broadband and telecom services. There are two subprograms in the Rural Health Care Program: the Healthcare Connect Fund Program and the Telecommunications Program.

- ▲ The Healthcare Connect Fund supports high-capacity broadband connectivity and broadband networks for eligible Health Care Providers with a 65 percent discount. The Healthcare Connect Fund will reform, expand, and modernize the FCC's existing universal service health care programs.

- ▲ The Rural Health Care Telecommunications Program ensures that eligible Health Care Provider's pay no more than their urban counterparts for telecommunication services. The Telecommunications Program supports the urban-rural difference for telecommunications services for rural Health Care Providers.

Source:
Federal Communications Commission
http://www.fcc.gov/cgb/consumerfacts/universalservice.html

Universal Service Program Developments in Florida

Low-Income Program

▲ **Coordinated Enrollment Process** In 2006, FPSC and the Department of Children and Families (DCF) staff developed a process whereby potential Lifeline customers, once certified through a DCF program, could receive Lifeline discounts. From the perspective of the client, the coordinated enrollment process established by the FPSC and DCF is seamless, from filling out the DCF web application to receiving Lifeline discounts

The coordinated enrollment process entails the DCF client checking a "yes" or "no" box. DCF then forwards the names of the clients who have chosen and been approved for Lifeline, along with their relevant enrollment information, to the FPSC. The FPSC electronically sorts the information by eligible telecommunications carrier (ETC) and places the names on a secure website for retrieval and enrollment by the appropriate ETC.

▲ **Lifeline Annual Recertificatio** All ETCs are now required to perform an annual recertification of their Lifeline subscribers to verify their ongoing eligibility. Subscribers failing to respond to recertification efforts must be de-enrolled from Lifeline. ETCs may contact and receive recertification responses from subscribers in writing, by phone, by text message, by e-mail, by Interactive Voice Response, or otherwise through the internet using an electronic signature. If an ETC is unable to recertify a subscriber because the subscriber did not respond to the recertification request, the ETC must de-enroll the subscriber. If an ETC receives a response that the subscriber is no longer eligible, the subscriber must be de-enrolled within five business days, and offered transitional Lifeline benefits for up to 12 months.

▲ **National Lifeline Accountability Database (NLAD)** The FCC directed the Universal Service Administrative Company (USAC) to establish a database to both eliminate existing duplicative support and prevent duplicative support in the future. To prevent waste in the Universal Service Fund, the FCC created and mandated the use by ETCs of a National Lifeline Accountability Database to ensure that multiple ETCs do not seek and receive reimbursement for the same Lifeline subscriber. The NLAD conducts a nationwide real-time check to determine if the consumer, or another person at the address of the consumer, is already receiving a Lifeline-supported service. In 2016, the FCC directed USAC to establish a national Lifeline eligibility verifier to confirm the eligibility of consumers. Currently, ETCs verify the eligibility of consumers. The FCC has established a three year phase in schedule that concludes by December 2019.

Source:
FPSC's *Number of Customers Subscribing to Lifeline Service and the Effectiveness of Procedures to Promote Participation*, December 2017
http://www.floridapsc.com/Files/PDF/Publications/Reports/Telecommunication/LifelineReport/2017.pd

Low-Income Program (continued)

- **Eligible Telecommunications Carriers (ETC)** A carrier that is granted ETC status is eligible to receive federal universal service support pursuant to FCC rules. To qualify as an ETC, a common carrier must offer services that are supported by federal universal service support mechanisms either using its own facilities or using a combination of its own facilities and another carrier's resold service. Additionally, the carrier must advertise the availability of such services and charges using media of general distribution. As of June 2017, Florida had 18 ETCs, comprised of 10 incumbent local exchange companies, 4 competitive local exchange companies, and 4 wireless companies. FCC rules allow state commissions, upon their own motion or upon request, to designate a common carrier that meets certain requirements as a landline ETC. As of July 2012, the Federal Communications Commission approves wireless providers applying for ETC designation in Florida. As of June 2017 there were 35 Florida ETC wireless petitions pending at the FCC.

Universal Service Support Mechanisms by Program for Florida

2016
(Annual Payments and Contributions in Thousands)

Program	Payments from USAC	Estimated Contributions to USAC	Estimated Net Dollar Flow
High-Cost	$60,719	$272,713	($211,994)
Low-Income	$97,382	$93,378	$4,004
Schools & Libraries	$96,709	$144,966	($48,257)
Rural Health Care	$4,466	$18,105	($13,639)
Administrative Expense		$10,426	($10,426)
Total	**$259,276**	**$539,589**	**($280,312)**

2015
(Annual Payments and Contributions in Thousands)

Program	Payments from USAC	Estimated Contributions to USAC	Estimated Net Dollar Flow
High-Cost	$64,604	$277,602	($212,998)
Low-Income	$86,593	$93,380	($6,787)
Schools & Libraries	$68,089	$128,359	($60,265)
Rural Health Care	$896	$17,211	($16,315)
Administrative Expense		$8,858	($8,858)
Total	**$220,182**	**$525,405**	**($305,224)**

2014
(Annual Payments and Contributions in Thousands)

Program	Payments from USAC	Estimated Contributions to USAC	Estimated Net Dollar Flow
High-Cost	$63,601	$232,510	($168,908)
Low-Income	$106,617	$103,379	$3,238
Schools & Libraries	$81,541	$141,342	($59,801)
Rural Health Care	$185	$12,019	($11,834)
Administrative Expense		$7,407	$7,407
Total	**$251,944**	**$496,657**	**$(244,712)**

Source:
Federal Communications Commission's *Universal Service Monitoring Reports*
https://www.fcc.gov/general/federal-state-joint-board0monitoring-reports

Universal Service Support Mechanisms by State (2016)

State	Payments from USAC (in Thousands)	Estimated Contributions to USAC (in Thousands)	Estimated Net Dollar Flow
Alabama	$107,715	$122,348	($14,633)
Alaska	$378,637	$22,701	$355,937
American Samoa	$4,352	$764	$3,588
Arizona	$184,317	$181,100	$3,217
Arkansas	$174,415	$76,180	$98,235
California	$714,016	$976,777	($262,761)
Colorado	$95,786	$167,028	($71,242)
Connecticut	$32,931	$119,429	($86,498)
Delaware	$9,781	$34,848	($25,068)
Dist. of Columbia	$11,507	$52,128	($40,620)
Florida	**$259,276**	**$539,589**	**($280,312)**
Georgia	$262,198	$273,110	($10,912)
Guam	$13,261	$4,253	$9,008
Hawaii	$19,517	$39,533	($20,016)
Idaho	$55,540	$42,080	$13,460
Illinois	$245,962	$354,549	($108,587)
Indiana	$201,873	$166,992	$34,881
Iowa	$204,710	$86,758	$117,952
Kansas	$200,932	$75,706	$125,226
Kentucky	$227,309	$118,381	$108,929
Louisiana	$178,400	$117,059	$61,340
Maine	$43,308	$39,488	$3,820
Maryland	$49,135	$212,613	($163,477)
Massachusetts	$63,061	$206,090	($143,029)
Michigan	$201,359	$242,099	($40,739)
Minnesota	$217,526	$163,183	$54,343
Mississippi	$239,709	$67,491	$172,218
Missouri	$232,831	$165,255	$67,576
Montana	$110,052	$31,590	$78,463
Nebraska	$106,966	$59,032	$47,934
Nevada	$49,958	$77,804	($27,846)
New Hampshire	$20,052	$43,789	($23,737)
New Jersey	$87,779	$308,828	($221,049)
New Mexico	$134,306	$57,129	$77,177
New York	$248,554	$583,162	($334,608)
North Carolina	$221,338	$273,805	($52,467)
North Dakota	$124,160	$22,656	$101,503
Northern Mariana	$4,900	$815	$4,084
Ohio	$225,573	$304,626	($79,052)
Oklahoma	$289,577	$92,474	$197,103
Oregon	$106,892	$107,619	($728)
Pennsylvania	$193,242	$390,161	($196,919)
Puerto Rico	$224,395	$92,133	$132,263
Rhode Island	$9,639	$28,484	($18,846)
South Carolina	$185,480	$125,326	$60,154
South Dakota	$107,246	$24,694	$82,552
Tennessee	$187,112	$170,451	$16,661
Texas	$647,969	$625,888	$22,081
Utah	$59,800	$70,605	($10,805)
Vermont	$26,907	$22,890	$4,016
Virgin Islands	$19,827	$7,104	$12,723
Virginia	$159,179	$266,621	($107,442)
Washington	$137,941	$191,410	($53,469)
West Virginia	$87,361	$59,917	$27,443
Wisconsin	$256,475	$159,572	$96,902
Wyoming	$50,230	$17,819	$32,411
Total	$8,712,276	$8,883,939	($171,663)

* Estimated contributions include an administrative cost of approximately $172 million.

Source: Federal Communications Commission's *2017 USF Monitoring Report*, Table 1.9
https://www.fcc.gov/general/federal-state-joint-board-monitoring-reports

Telephone Subscribership

Percentage of Households with Telephone in Unit

	2012	2013	2014	2015	2016
Florida	94.2%	93.5%	94.1%	94.8%	95.3%

Lifeline Subscribership

Lifeline Assistance Subscribers in Florida

Date	Lifeline Enrollment	Eligible Households	Participation Rate
6/2010	642,129	1,422,837	45.1%
6/2011	943,854	1,690,512	55.8%
6/2012	1,035,858	1,864,183	55.6%
6/2013	918,245	1,952,890	47.0%
6/2014	957,792	1,930,106	49.6%
6/2015	833,612	2,011,166	41.4%
6/2016	852,255	1,712,005	49.8%
6/2017	685,864	1,662,374	41.3%

Source:

FCC Universal Service Monitoring Report
https://www.fcc.gov/general/federal-state-joint-board-monitoring-reports

United States Department of Agriculture Supplemental Nutrition Assistance Program: Number of Households Participating June 2017

FPSC's *Number of Customers Subscribing to Lifeline Service and the Effectiveness of Procedures to Promote Participation*, December 2017
http://www.floridapsc.com/Files/PDF/Publications/Reports/Telecommunication/LifelineReport/2017.pd

FPSC's Report on the Status of Competition in the Telecommunications Industry
https://www.floridapsc.com/files/PDF/publications/reports/telecommunication/telecommunicationsindustry/2017.p

Lifeline Subscribership

Lifeline Subscribership by Eligible Telecommunications Carriers
As of June 2017

Company	Access Lines Subscribed to Lifeline Service
SafeLink**	346,488
Assurance**	224,282
i-wireless/Access**	89,904
CenturyLink	9,108
AT&T	7,871
Frontier Florida	3,116
Windstream	2,004
Cox Telecom*	675
T-Mobile**	630
Fairpoint	561
NEFCOM	366
TeleCircuit*	321
Phone Club*	148
TDS Telecom	138
Global Connection*	95
ITS Telecom	69
Knology d/b/a WOW*	58
Frontier of the South	26
Smart City	4
Total	**685,864**

* Competitive Local Exhange Carrier
**Wireless Carrier

Source:
FPSC's *Number of Customers Subscribing to Lifeline Service and the Effectiveness of Procedures to Promote Participation*, December 2017
http://www.floridapsc.com/Files/PDF/Publications/Reports/Telecommunication/LifelineReport/2017.pd

Regulatory Authority

Pursuant to Chapter 367, F.S., as of December 2017, the FPSC has jurisdiction over 131 investor-owned water and/or wastewater utilities in 38 of Florida's 67 counties.

Use of Reclaimed Water Data for 2016

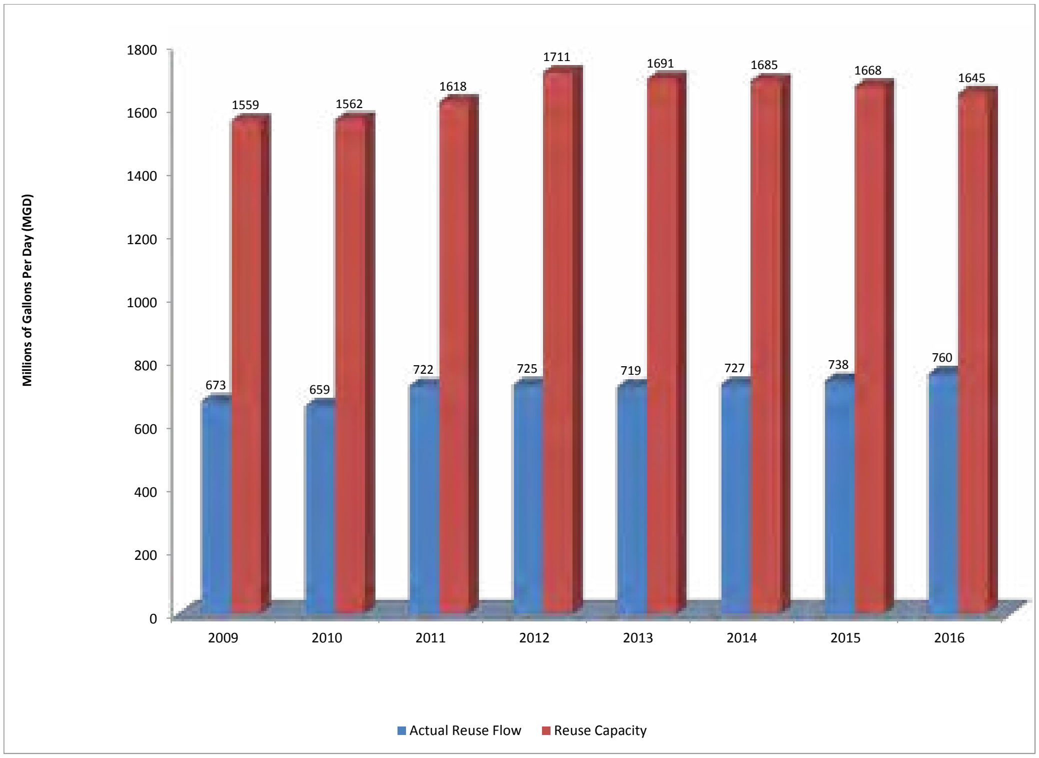
- Approximately 760 mgd* of reclaimed water from these facilities was reused for beneficial purposes and represents approximately 44% of the total domestic water flow in the state

- The 1,645 mgd of reuse capacity represents approximately 64% of the total domestic wastewater treatment capacity in the state.

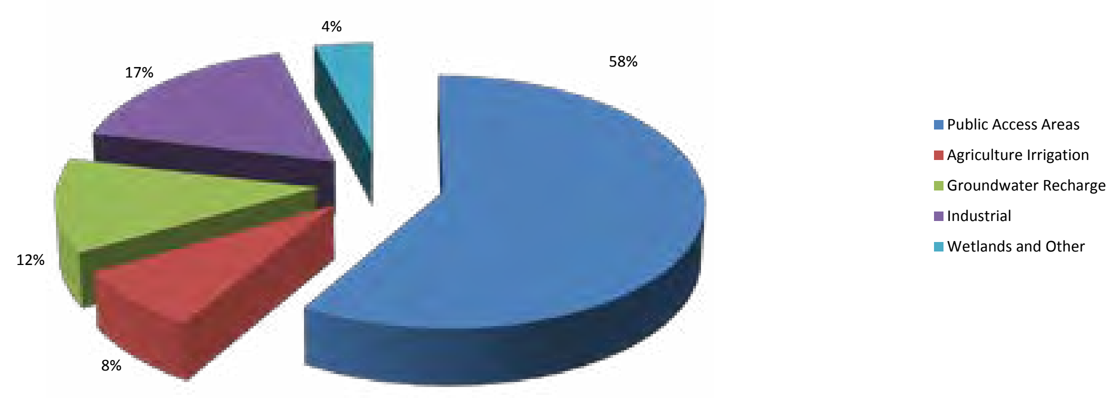
* Million gallons per day

Source:
Florida Department of Environmental Protection's *2016 Reuse Inventory Report*, May 2017
https://www.floridadep.gov/sites/default/files/2016_reuse-report_0.p

Florida's Reuse Growth
Millions of Gallons Per Day (mgd)



Reclaimed Water Utilization (2016)



Source: Florida Department of Environmental Protection's *2016 Reuse Inventory Report*, July 2017
https://www.floridadep.gov/sites/default/files/2016_reuse-report_0.p

Utility Classifications

The National Association of Regulatory Utility Commissioners uses three classes to define the size of water and wastew - ter utilities:

Class A	Utilities having annual water or wastewater revenues of $1,000,000 or more
Class B	Utilities having annual water or wastewater revenues of $200,000 or more but less than $1,000,000
Class C	Utilities having annual water or wastewater revenues of less than $200,000

• A Class C utility may serve as few as 50 customers, while a Class A utility serves thousands.

• The number of customers served may be obtained from each utility's annual report filed at the FPSC and available o - line at http://www.floridapsc.com/UtilityRegulation/CompaniesRegulatedByPSC

Rate Structure

• The base facility charge and gallonage charge rate structure is the most common rate structure used by FPSC-regulated water and wastewater utilities.

• The base facility charge is a flat charge that recovers the fixed costs of utility service that remain the same each month regardless of consumption.

• The gallonage charge recovers the variable costs associated with the utility service such as electricity, chemicals, and labor.

• The gallonage charge is assessed for each 1,000 gallons of water that is registered on the customer's meter.

• Inclining block rate structures are used to encourage water conservation. (The inclining block is similar to the base facility charge and gallonage charge rate structure, but includes additional gallonage charges for higher levels or blocks of usage.)

Residential Wastewater Gallonage Cap

• A maximum (or cap) is set on the number of gallons of water consumption a customer is billed for wastewater service.

• The monthly cap is normally between 6,000 and 10,000 gallons. (Any water consumption over that amount is generally considered to be used for purposes such as irrigation or washing cars.)

Water & Wastewater Utility Rates

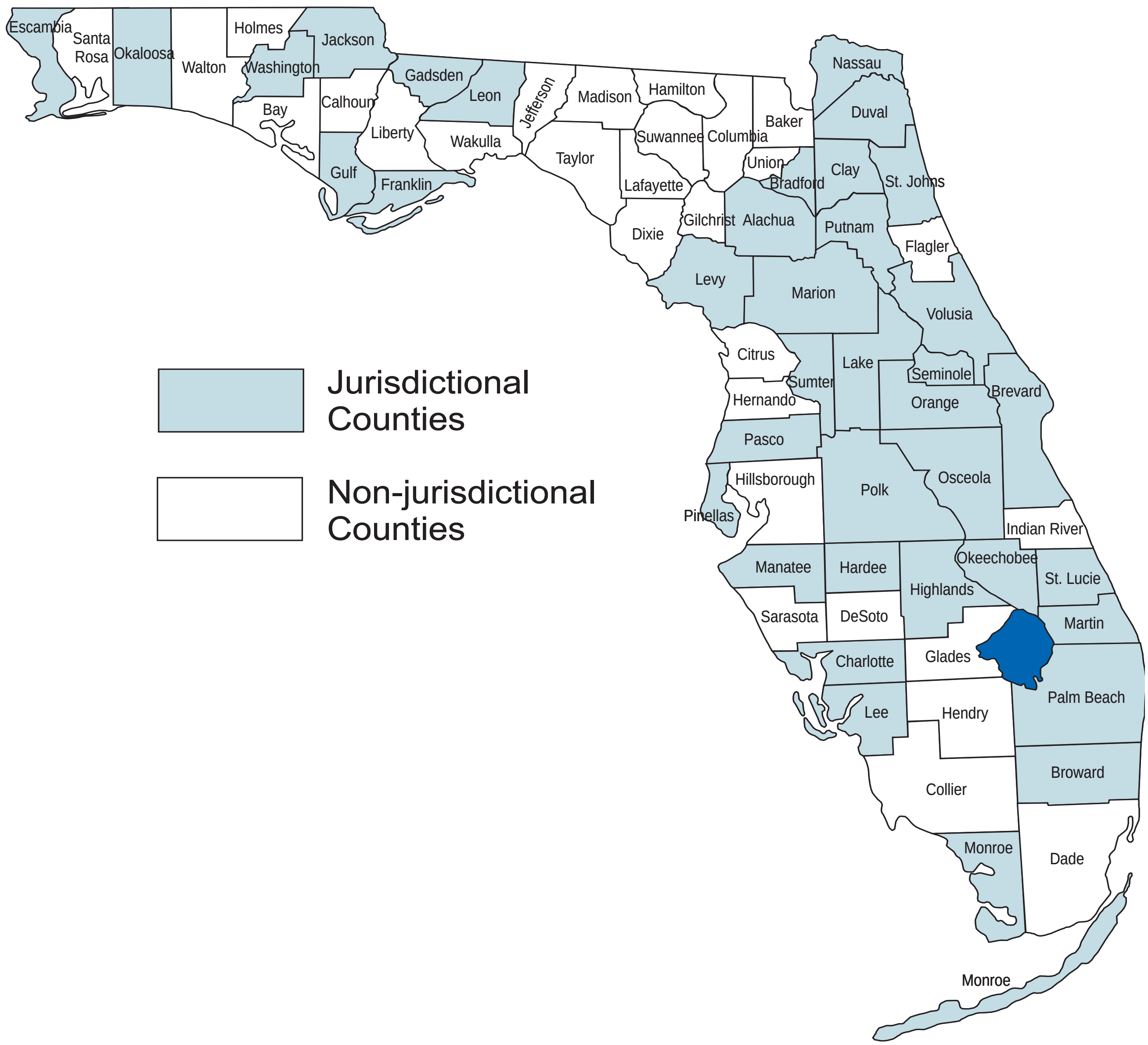
• The rates charged by all water and wastewater utilities under the Commission's jurisdiction are shown in alphabetical order by county in the FPSC's *Comparative Rate Statistics Report*, available online at http://www.floridapsc.com/Public - tions/Reports#.

Source: FPSC Staff

Water & Wastewater Jurisdictional Counties (38)

WATER & WASTEWATER

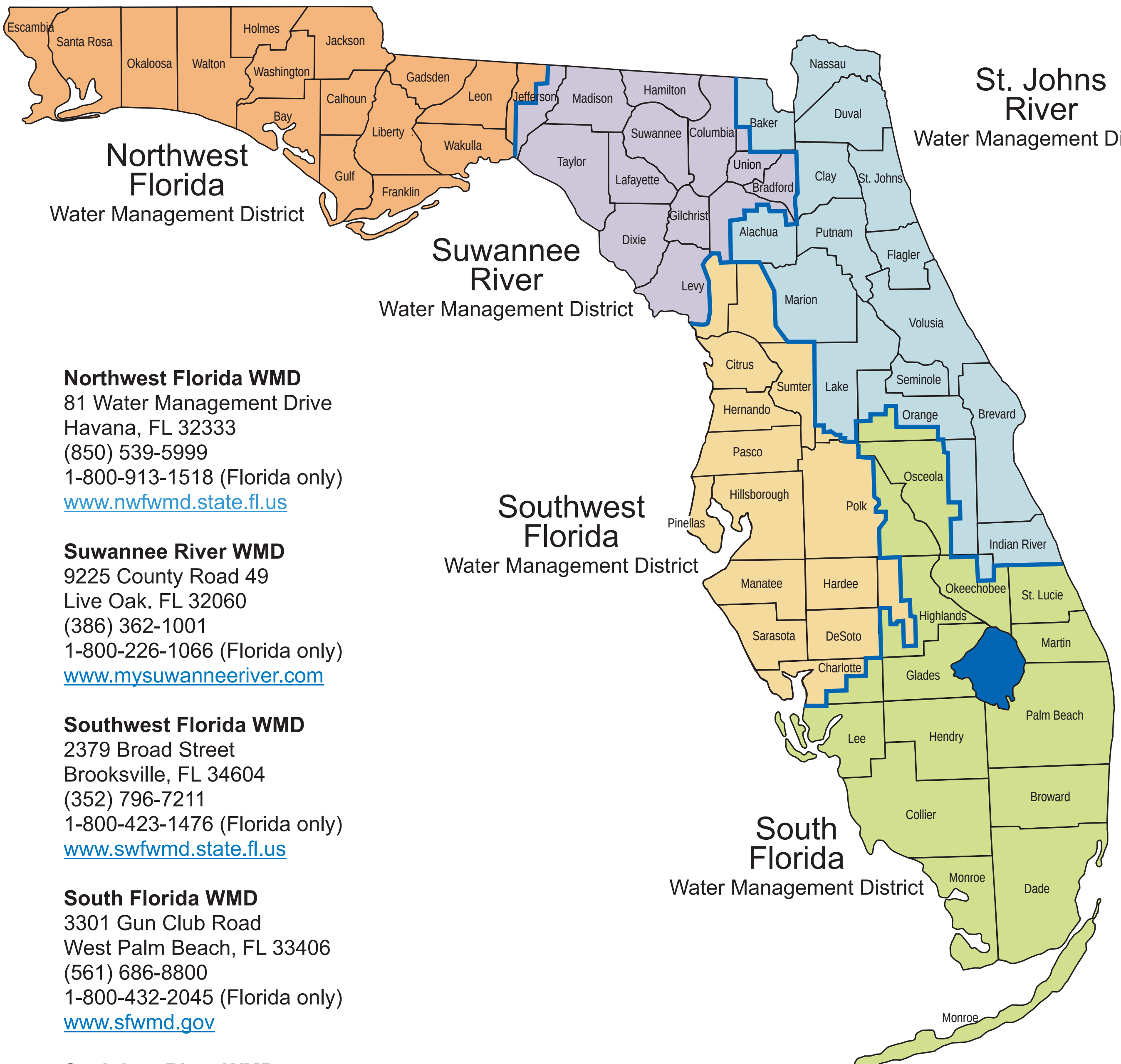
38 Jurisdictional Counties



2017

Source:
Florida Public Service Commission Map
http://www.floridapsc.com/Files/PDF/Publications/Reports/Waterandwastewater/wawmap.pd

Florida's Water Management Districts (5)



Northwest Florida WMD
81 Water Management Drive
Havana, FL 32333
(850) 539-5999
1-800-913-1518 (Florida only)
www.nwfwmd.state.fl.us

Suwannee River WMD
9225 County Road 49
Live Oak. FL 32060
(386) 362-1001
1-800-226-1066 (Florida only)
www.mysuwanneeriver.com

Southwest Florida WMD
2379 Broad Street
Brooksville, FL 34604
(352) 796-7211
1-800-423-1476 (Florida only)
www.swfwmd.state.fl.us

South Florida WMD
3301 Gun Club Road
West Palm Beach, FL 33406
(561) 686-8800
1-800-432-2045 (Florida only)
www.sfwmd.gov

St. Johns River WMD
4049 Reid Street
Palatka, FL 32177
(386) 329-4500
1-800-451-7106 (Florida only)
www.sjrwmd.com

Source: Florida Department of Environmental Protection, www.dep.state.fl.us/secretary/watman/

TAB 7

All Topics

Population estimates, July 1, 2018, (V2018)

QuickFacts

Florida

QuickFacts provides statistics for all states and counties, and for cities and towns with a ***population of 5,000 or more***.

Table

PEOPLE

Population	
Population estimates, July 1, 2018, (V2018)	**21,299,325**
Population estimates, July 1, 2017, (V2017)	20,984,400
Population estimates base, April 1, 2010, (V2018)	18,804,580
Population estimates base, April 1, 2010, (V2017)	18,804,594
Population, percent change - April 1, 2010 (estimates base) to July 1, 2018, (V2018)	13.3%
Population, percent change - April 1, 2010 (estimates base) to July 1, 2017, (V2017)	11.6%
Population, Census, April 1, 2010	18,801,310
Age and Sex	
Persons under 5 years, percent	5.4%
Persons under 18 years, percent	20.0%
Persons 65 years and over, percent	20.1%
Female persons, percent	51.1%
Race and Hispanic Origin	
White alone, percent	77.4%
Black or African American alone, percent (a)	16.9%
American Indian and Alaska Native alone, percent (a)	0.5%
Asian alone, percent (a)	2.9%
Native Hawaiian and Other Pacific Islander alone, percent (a)	0.1%
Two or More Races, percent	2.1%
Hispanic or Latino, percent (b)	25.6%
White alone, not Hispanic or Latino, percent	54.1%
Population Characteristics	
Veterans, 2013-2017	1,454,632
Foreign born persons, percent, 2013-2017	20.2%
Housing	
Housing units, July 1, 2017, (V2017)	9,441,153
Owner-occupied housing unit rate, 2013-2017	64.8%
Median value of owner-occupied housing units, 2013-2017	$178,700
Median selected monthly owner costs -with a mortgage, 2013-2017	$1,432
Median selected monthly owner costs -without a mortgage, 2013-2017	$475
Median gross rent, 2013-2017	$1,077
Building permits, 2017	122,719
Families & Living Arrangements	
Households, 2013-2017	7,510,882
Persons per household, 2013-2017	2.64
Living in same house 1 year ago, percent of persons age 1 year+, 2013-2017	84.1%
Language other than English spoken at home, percent of persons age 5 years+, 2013-2017	28.7%
Computer and Internet Use	
Households with a computer, percent, 2013-2017	88.1%
Households with a broadband Internet subscription, percent, 2013-2017	78.6%
Education	
High school graduate or higher, percent of persons age 25 years+, 2013-2017	87.6%
Bachelor's degree or higher, percent of persons age 25 years+, 2013-2017	28.5%
Health	
With a disability, under age 65 years, percent, 2013-2017	8.6%
Persons without health insurance, under age 65 years, percent	15.9%
Economy	

All Topics

Population estimates, July 1, 2018, (V2018)

In civilian labor force, total, percent of population age 16 years+, 2013-2017	58.4%
In civilian labor force, female, percent of population age 16 years+, 2013-2017	54.1%
Total accommodation and food services sales, 2012 ($1,000) (c)	[illegible]
Total health care and social assistance receipts/revenue, 2012 ($1,000) (c)	124,061,425
Total manufacturers shipments, 2012 ($1,000) (c)	96,924,106
Total merchant wholesaler sales, 2012 ($1,000) (c)	252,626,608
Total retail sales, 2012 ($1,000) (c)	273,867,145
Total retail sales per capita, 2012 (c)	$14,177
Transportation	
Mean travel time to work (minutes), workers age 16 years+, 2013-2017	27.0
Income & Poverty	
Median household income (in 2017 dollars), 2013-2017	$50,883
Per capita income in past 12 months (in 2017 dollars), 2013-2017	$28,774
Persons in poverty, percent	14.0%

BUSINESSES

Businesses	
Total employer establishments, 2016	546,218[1]
Total employment, 2016	8,169,642[1]
Total annual payroll, 2016 ($1,000)	363,336,322[1]
Total employment, percent change, 2015-2016	5.0%[1]
Total nonemployer establishments, 2016	2,053,914
All firms, 2012	2,100,187
Men-owned firms, 2012	1,084,885
Women-owned firms, 2012	807,817
Minority-owned firms, 2012	926,112
Nonminority-owned firms, 2012	1,121,749
Veteran-owned firms, 2012	185,756
Nonveteran-owned firms, 2012	1,846,686

GEOGRAPHY

Geography	
Population per square mile, 2010	350.6
Land area in square miles, 2010	53,624.76
FIPS Code	12

About datasets used in this table

All Topics

Population estimates, July 1, 2018, (V2018)

Value Notes

1. Includes data not distributed by county.

Estimates are not comparable to other geographic levels due to methodology differences that may exist between different data sources.

Some estimates presented here come from sample data, and thus have sampling errors that may render some apparent differences between geographies statistically indistinguishable. Click the Quick Info left of each row in TABLE view to learn about sampling error.

The vintage year (e.g., V2018) refers to the final year of the series (2010 thru 2018). *Different vintage years of estimates are not comparable.*

Fact Notes

(a) Includes persons reporting only one race
(b) Hispanics may be of any race, so also are included in applicable race categories
(c) Economic Census - Puerto Rico data are not comparable to U.S. Economic Census data

Value Flags

- Either no or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowes interval of an open ended distribution.
D Suppressed to avoid disclosure of confidential information
F Fewer than 25 firms
FN Footnote on this item in place of data
NA Not available
S Suppressed; does not meet publication standards
X Not applicable
Z Value greater than zero but less than half unit of measure shown

QuickFacts data are derived from: Population Estimates, American Community Survey, Census of Population and Housing, Current Population Survey, Small Area Health Insurance Estimates, Small Area Poverty Estimates, State and County Housing Unit Estimates, County Business Patterns, Nonemployer Statistics, Economic Census, Survey of Business Owners, Building Permits.

TAB 8

COMPETITIVE ENERGY MARKET FOR CUSTOMERS OF INVESTOR-OWNED UTILITIES

SUPPORT FOR FIEC FINANCIAL IMPACT STATEMENT

Contents

Tables:

Figures:

Appendices:

GLOSSARY OF TERMS

Amendment – Ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*".

Franchise Agreements – Agreements with the local communities the IOUs serves. In general, these agreements provide the IOU with the exclusive right, and obligation, to serve the community's customers as well as access to rights of way.

Independent System Operator ("ISO") or Regional Transmission Organization ("RTO") – ISOs and RTOs are not-for-profit entities that are formed to perform three basic functions: (1) operate the bulk electric power system, (2) develop, oversee, and administer the wholesale electric market, and (3) manage the power system planning processes to address transmission needs. Florida, like many traditionally regulated states, does not currently have an ISO, RTO, or similar organization.

Price to Beat – In Texas, a price that was designed as a price floor to prevent the incumbent providers from offering artificially low rates to stifle competition and undercut new market players.

Provider of Last Resort – A company who is required to provide service to customers who for some reason (e.g., their chosen supplier goes out of business) do not have a competitive service provider.

Retail Energy Supplier, Retail Electric Provider, Retail Marketer, or Energy Service Company ("ESCO") – A company that serves as a middleman or an intermediary between the electricity buyer (residential, commercial and industrial customers) and the wholesale electric market. Retail marketers purchase electricity through wholesale electricity markets and resell it to consumers.

Slamming – Unauthorized switching of customers to a competitive supplier without proper authorization from customers.

Stranded Costs – Costs that are created when the market value of utility assets in a restructured market is less than the net book value on the utilities' books.

Vertically-Integrated Utilities – Utilities that own all levels of the supply chain (generation and transmission and distribution).

LIST OF ABBREVIATIONS

AG	Attorney General
CAISO	California ISO
EDR	The Office of Economic and Demographic Research
ERCOT	Electric Reliability Council of Texas
ESCO	Energy Service Company
FERC	Federal Energy Regulatory Commission
FIEC	Financial Impact Estimating Conference

FMPA	Florida Municipal Power Agency
FPC	Florida Power Corporation
FPL	Florida Power & Light Company
IOU	Investor Owned Utility
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	ISO New England
LNG	Liquefied Natural Gas
MISO	Midwest ISO
NERC	National Electric Reliability Corporation
NYISO	New York ISO
NY PSC	New York Public Service Commission
OUC	Orlando Utilities Commission
PJM	Pennsylvania-New Jersey-Maryland Interconnection
POLR	Provider Of Last Resort
PPA	Power Purchase Agreement
PUCN	Public Utilities Commission of Nevada
PUCT	Texas Public Utility Commission
ROE	Return on Equity
RTO	Regional Transmission Organization
SB7	Texas Senate Bill 7
SPP	Southwest Power Pool
T&D	Transmission and Distribution Systems
TCAP	Texas Coalition for Affordable Power
TCE	Texas Commercial Energy
TECO	Tampa Electric Corporation

I. INTRODUCTION

Purpose of Report

This report was prepared and is submitted on behalf of Florida's four major investor-owned utilities ("IOUs"): Duke Energy Florida, Florida Power & Light Company ("FPL"), Gulf Power Company, and Tampa Electric Company ("TECO"). The purpose of this report is to provide information and analysis for the consideration of the Financial Impact Estimating Conference ("FIEC") in its development of a Financial Impact Statement for the Florida ballot measure entitled "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" ("Energy Market Amendment" or "Amendment").

If approved, the Amendment would "destructure" not "restructure" the state's electricity markets and cost state and local government $1.3 to $1.7 billion in upfront or one-time costs, and in excess of $825 million in annual, ongoing costs, and would dramatically increase the risk and volatility of the state's energy markets. Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone.

Proposed Constitutional Amendment

The proponents of this constitutional Amendment summarize their proposal as follows:

> "Grants customers of investor-owned utilities the right to choose their electricity provider and to generate and sell electricity. Requires the Legislature to adopt laws providing for competitive wholesale and retail markets for electricity generation and supply, and consumer protections, by June 1, 2025, and repeals inconsistent statutes, regulations, and orders. Limits investor-owned utilities to construction, operation, and repair of electrical transmission and distribution systems. Municipal and cooperative utilities may opt into competitive markets."

What does this Amendment mean? The plain language of the Amendment is clear: Florida's IOUs would be limited to the construction, operation and repair of transmission and distribution ("T&D") systems, and would be precluded from owning generation, T&D and other electric infrastructure.

Regardless of any hope, wish or alleged intent of the proponents of the Amendment, the provisions of a state Constitution do not merely serve as "guidance" to legislators or citizens. Neither the Legislature nor the Executive Branch will have the ability to supply additional terms to the core provisions of the Amendment. Courts will not interpret the Constitution as a "guide;" on the contrary, presumptively the Amendment will be given the meaning that the words convey. As noted later in this report, citizens may sue the state for any perceived failure to comply with the Constitution and any of its amendments. The proposed Amendment was drafted differently than key elements of the Texas legislation and, as written, will create a risky and costly electricity system in Florida. Indeed, as written, the Amendment could not even hope to achieve the less than ideal outcomes that continue to worry Texas lawmakers and regulators. But, at least in Texas as in other states that have attempted to repair market failures or other deficiencies in their restructured markets, they have the ability to amend Texas Senate Bill 7 ("SB7") that enacted restructuring or agency rules through normal legislative and administrative processes without being constrained by a set of constitutionally enshrined "rights" that instead would impose serious limitations on the State of Florida's efforts to ensure the development of adequate electric infrastructure, the institution of consumer price protections, and the implementation of good public policy in general.

While the sponsors of the Amendment assert that the Amendment is modeled after Texas' restructuring and does not preclude the IOUs from owning T&D, that is not the case. As discussed in more detail later in this report, SB7, which mandated the manner in which restructuring would be carried out, required each electric utility to separate its business activities from one another into the following units: (i) a power generation company; (ii) a retail electric provider; and (iii) a T&D utility. The electric utility could accomplish the separation required by either through the creation of separate non-affiliated companies or separate affiliated companies owned by a common holding company or through the sale of assets to a third party. SB7 specifically provided that T&D utilities would own and operate T&D infrastructure. To the contrary, the Amendment, and the ballot measure voters would be asked to vote on, does not contemplate IOU ownership of any electric infrastructure.

Instead, the Amendment would forcibly expel from Florida's electric energy market IOUs that currently supply electricity to approximately 70% of Floridians. IOUs would be forced to dispose of their ownership of more than $60 billion of current investment in generation, T&D and other electric infrastructure. This enormous void would ostensibly be filled by yet-to-be determined and qualified providers of electric service in a so-called "competitive" market with none of the price oversight or other protections currently provided through regulation by the Florida Public Service Commission. The Legislature and Executive Branch agencies would be required to design and implement a complex series of laws and regulations in an effort to comply with the Amendment, as written, and would be faced with significant risk exposure ensuring the efficacy of the Amendment if the "competitive" market does not materialize for all customers or otherwise falters or fails.

The Amendment is poorly drafted and unclear. It does not say what its Sponsors say it means. They casually assert that IOUs would continue to own T&D and that generation may "simply" be transferred to non-regulated affiliates of IOUs, but in doing so, the Sponsors read more into the Amendment than its plain language states. For the Sponsors to state or imply that the Legislature will embrace the Sponsor's view of the Amendment, rather than its plain meaning, is naïve and irresponsible and should be rejected by the conference. Despite its poor drafting, ambiguities and uncertainties, the Legislature and the citizens of Florida will be forced to live with its language and its consequences in perpetuity – if it makes it on to the ballot and is approved by the voters. As discussed in more detail below, those consequences are enormously negative for state and local government, to say nothing of the almost certainly catastrophic impact this would have on Florida's energy markets for years to come.

Key Conclusions

Proposals to restructure a state's energy markets are not new. A proposal was considered and rejected in Florida at the turn of the century, as well as more recently when a very similar Amendment was rejected by the Constitutional Revision Committee. No proposal to restructure a state's electricity market, however, has been adopted in the United States in over 18 years.[1] This is because the experience of other jurisdictions, including Texas, demonstrates the costs and risks to state and local government and to all customers are just too great.

Based on the information and analysis described in detail in the remainder of this report, it is very clear that the proposed Energy Market Amendment at a minimum would:

- Eliminate the state's IOUs from Florida's electric energy market and force the sale or "divestiture" of their nearly 50 power plants, more than 150,000 miles of T&D, and other electric infrastructure, creating ***billions of dollars*** in "stranded" costs, which will need to be paid for by or through government action to avoid an unconstitutional "taking;"

[1] The most recent restructuring proposals were adopted in 2000 by the District of Columbia and Michigan. (See, DC Bill 13-284 and PSC Order 11796 (September 19, 2000) and Michigan Public Acts 141 and 142 of 2000).

- Require the formation of an independent system operator ("ISO"), costing customers, including state and local government, ***hundreds of millions of dollars*** in start-up costs and on-going administrative costs;
- Force the state legislature and executive branch of government and other agencies and organizations to expend an ***enormous amount of time, resources and money*** to comply with the Amendment, implement "competitive" electric markets, defend their decisions in litigation, be the ultimate back-stop for market failures and be exposed to substantial new risks;
- ***Put at risk billions of dollars*** in annual franchise fees and other taxes paid by the state's IOUs, resulting in significantly lower revenues to local, municipal and state government;
- ***Put at risk the billions of dollars*** the IOUs have committed in Power Purchase Agreements ("PPA") and natural gas supply and transportation contracts;
- Prohibit municipal and cooperative utilities from purchasing their power from IOUs, abrogating the contracts that are in place and requiring these utilities to find new suppliers of their electricity;
- As a replacement, a new market would be created for companies such as the main proponent (Infinite Energy) with no obligation to provide essential electric service to all customers on a non-discriminatory basis and whose rates are not regulated by the state or any other entity;
- Threaten electric reliability and expose Floridians to consumer fraud and market manipulation as has been the experience in states that have restructured their electric markets; and
- Put the state in the position of having to organizationally and financially backstop any aspect of the supply and delivery of electricity if the new market fails in any respect.

Financial Impact

The financial impact of the Amendment is best summarized as:

- Significantly increasing energy costs to state and local government by $1.3 billion to $1.7 billion in upfront or one-time costs and more than $825 million in ongoing annual costs by eliminating low cost providers from the marketplace and by forcing uneconomic divestitures of electric system infrastructure by the IOUs, the costs of which would be paid by to all customers, including state and local governments;
- Imposing extensive implementation and litigation costs on state government and Florida taxpayers; and
- Resulting in significantly lower revenues to local government through reduced eligible franchise fees and other taxes.

Table 1, below, summarizes the financial impacts of the proposed Energy Market Amendment on state and local government. For those costs that would be borne by all Florida electricity customers, state and local governments would only a bear a portion of the costs based on their proportionate share of electricity purchases (approximately 11%). The assumptions and support underlying this table are provided in APPENDIX 1 Analysis of Financial Impact.

TABLE 1: SUMMARY OF RESULTS

Cost Category	Quantification/Total Impact on Florida Customers	State and Local Government Portion	
		Low Estimate	High Estimate
	Upfront or One-Time Costs		
Generation Stranded Costs[2]	• $10 billion to $12.3 billion • These costs will be experienced even under the proponent's interpretation of the Amendment since all these assets must be transferred to new entities	• $1.1 billion	• $1.4 billion
T&D and Electric Infrastructure Stranded Costs	• The net book value investment in IOUs' T&D assets is $24.3 billion • A substantial portion of this investment could be stranded when IOUs divest their T&D ownership • No other state that has restructured prohibited IOU ownership of T&D • Stranded costs for T&D and other electric infrastructure have not been specifically quantified because there is no precedent for restructuring of this type	• Unknown	• Unknown
Creation of a Wholesale Market and ISO Start-up/RTO Integration Costs	• Start-up costs range from $100 to $500 million • Other costs (*e.g.*, customer education) approximately $20 million • These costs will occur even under the proponent's interpretation of the Amendment since the Amendment specifically calls for the establishment of a market monitor	• Start-up costs of $11.0 million • Other costs (e.g., consumer education) of $20 million	• Start-up costs of $55.0 million • Other costs (e.g., consumer education) of $20 million

2 Note, stranded costs are typically recovered from electricity customers over a period of years through a "competitive transition charge." For purposes on this analysis they are presented as upfront, one-time costs.

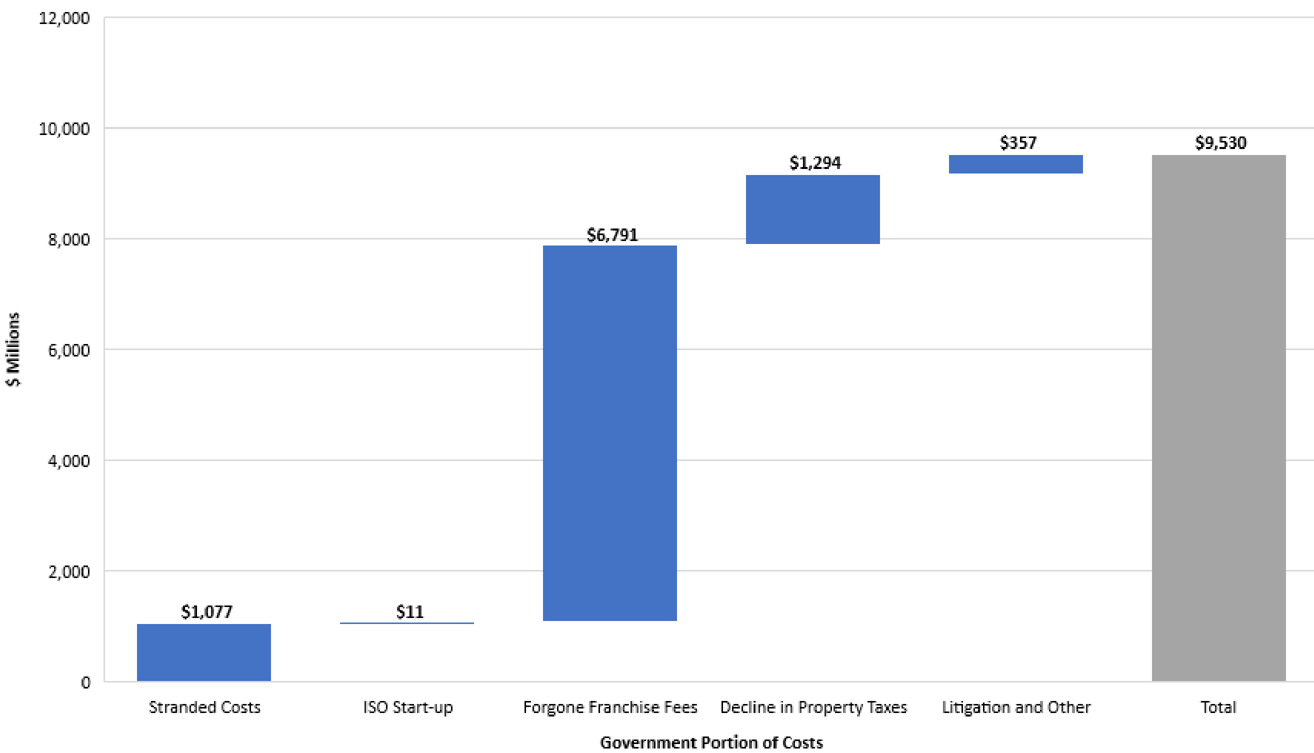
Cost Category	Quantification/Total Impact on Florida Customers	State and Local Government Portion	
		Low Estimate	High Estimate
Litigation Costs	• Litigation costs to implement the Constitutional Amendment range from $150 million to $300 million	• $150 million	• $300 million
Total Upfront or One-Time Costs	• $10.1 billion to $13.2 billion	• $1.3 billion	• $1.7 billion
	On-Going Annual Costs or Lost Revenues		
Franchise Fees	• $679.1 million in *annual* local municipality revenues would be eliminated • These costs will occur under the proponent's interpretation of the Amendment since franchises will be eliminated	• $679.1 million per year	• $679.1 million per year
Tax Revenues	• Decrease in *annual* property tax revenues by approximately $129.4 million to $173.8 million • Numerous additional risks related to declines in other state and local taxes, such as gross receipts tax and municipal public service tax • These costs will occur even under the proponent's interpretation of the Amendment since the taxable value of generation-related property will be lower	• $129.4 million per year	• $173.8 million per year
ISO Management and Administrative Costs	• Annual operating costs of $170.0 to $228.0 million • These costs will occur even under the proponent's interpretation of the Amendment since the Amendment specifically calls for the establishment of a market monitor	• $18.7 million per year	• $25.1 million per year
Total On-going Annual Costs or Lost Revenues	• $978.5 million to $1.1 billion per year	• $827.2 million per year	• $878.0 million per year

Cost Category	Quantification/Total Impact on Florida Customers	State and Local Government Portion	
		Low Estimate	High Estimate
	Other Costs		
	While not quantified herein, there are numerous other costs that would occur post-restructuring, meaning the results above are the minimum impact to Florida and state and local governments. Those costs include: • Additional costs to state and local governments related to implementation and ongoing administrative costs under restructuring. • Stranded costs beyond those quantified above, including those related to natural gas pipeline contracts, PPAs, regulatory assets, and other stranded assets. • Costs to the IOUs for the early retirement of debt related to their infrastructure. • The costs associated with any additional degree of state involvement as an operational or financial backstop to ensure the constitutionally guaranteed rights of this Amendment or to address the political or practical realities of any market failures. • Costs to the state economy due to lost productivity and disruption caused by the dismantling of the state's reliable and low-cost electricity system during the uncertain transition to the new competitive market, including lost economic development opportunities.		

As detailed in the table above, the financial impact of the Amendment on state and local government is estimated to be no less than $1.3 billion and as much as $1.7 billion in one-time costs and more than $825 million in on-going annual costs and lost revenues. Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone. As noted in the table above, there are numerous other costs that would be incurred post-restructuring. As such, the cost impact described above is the minimum level that would be incurred by state and local governments. ***The eventual cost to Florida and its governmental agencies would be much larger***.

Figure 1, below, illustrates the building blocks of the cost impact, based on the minimum cost impacts provided in the table above.

FIGURE 1: STATE & LOCAL GOVERNMENT COSTS OF RESTRUCTURING OVER 10 YEARS ($MILLIONS)[3]



3 "Other" includes costs such as ongoing wholesale market operations costs and customer education costs.

II. THE AMENDMENT IS UNPRECEDENTED IN THE ENERGY INDUSTRY

The ballot initiative is not a "simple" proposal to restructure Florida's energy markets and is clearly not similar to restructuring proposals implemented in Texas and some other states as its proponents would have the FIEC believe. The many problems with the Amendment are addressed here at length so that the reader understands the extent of disruption and negative financial consequences associated with the Amendment, which exacerbates the costs to all customers including state and local governments. Among many things, the proposed Amendment would:

- Irrevocably amend the state Constitution creating a constitutional right for "***every person or entity*** that receives electricity service from an investor owned utility… the right to choose their electricity provider, including, but not limited to, ***selecting from multiple providers in competitive wholesale and retail electricity markets***, or by producing electricity themselves or in association with others, and ***shall not be forced to purchase electricity from one provider;***"
- Provide that "any citizen shall have standing to ***seek judicial relief*** to compel the Legislature to comply with its constitutional duty to enact such legislation…;"
- Constitutionally mandate that "wholesale and retail markets be fully competitive so that electricity customers are ***afforded meaningful choices among a wide variety of competing electricity providers***.;" and
- "[L]imit the activity of investor-owned utilities to the construction, operation, and repair of electrical transmission and distribution systems."

The Amendment Would Change the State Constitution

No other U.S. state has ever implemented electric market restructuring through a constitutional Amendment. This is a very important distinction that has significant and potentially costly implications for all customers and for state and municipal governments in particular. The Amendment would catastrophically disrupt the electric market in Florida and create hardships for customers and state and local government, as illustrated below.

No other state provides citizens a constitutional right to select their electricity provider "from multiple providers in competitive wholesale and retail markets" and grants citizens standing to seek judicial relief if enacting legislation does not yield the desired results. The state will be legally responsible if "multiple competitive providers in competitive wholesale and retail electricity markets" do not present themselves to citizens or entities that receive electricity. How can a Provider of Last Resort ("POLR") be mandated where the costs of that service could not be socialized without offending the constitutional right to a "fully competitive market?" What happens if the market produces inadequate electric infrastructure as has been seen in other states such that "black outs" occur or reliability deteriorates? In short, customers, either citizens or entities, who currently purchase electricity from the state's IOUs may seek judicial relief from the state. In addition to guaranteeing certain constitutional rights, this Amendment guarantees years of litigation with potentially enormous financial consequences for the state.

The Amendment Eliminates Any Obligation to Provide Essential Electric Service

By eliminating the state's IOUs as electric providers, the Amendment eliminates any obligation to provide essential electric service on a non-discriminatory basis to all customers and eliminates the Florida Public Service Commission's regulation of the electricity rates charged to retail customers for this service. What does this mean? "Competitive providers" may charge whatever rates the market will bear and may discount rates for certain customers while overcharging other customers or entire customer classes. As discussed later in this report, vulnerable customers, in particular low income and elderly customers, have been the victims of fraud and exorbitant prices in many restructured states. In fact, these market abuses have been so bad that some states have responded by suspending retail choice.

The Amendment specifically prohibits "forcing" a Floridian to purchase electricity from one provider (*e.g.*, customers could not remain with their existing provider). States that have legislatively restructured energy markets and allowed customers to choose their electricity suppliers, have also established a POLR that provides service to ensure that customers receive electric supply if they do not choose a retail marketer (or in the event that their retail supplier exits the market). The Amendment makes no provision for a POLR and by specifically prohibiting "forcing" a customer to purchase electricity from a single provider appears to provide no backstop for customers who are unable to secure this essential service. Indeed, the legislature may be constitutionally precluded from establishing such a regime (or at least precluded from creating a regime that socializes the higher costs of providing rural service in favor of ensuring that all Floridians enjoy affordable access to quality electric service) if it is found to offend the concept of a "fully competitive market" under this Amendment.

The Amendment Would Constitutionally Prohibit IOUs From Owning Electric Infrastructure

By explicitly limiting Florida's IOUs "to the construction, operation, and repair of electrical transmission and distribution systems," and omitting the words "own" and "generation," it constitutionally prohibits IOUs from owning generation and selling electricity, and from owning T&D and other electric infrastructure. No other U.S. state, including Texas, has placed this breadth of limitations on its IOUs. Prohibiting IOU ownership of generation and T&D amounts to nothing less than a government taking of the vast majority of assets held by investor-owned companies. As noted earlier, while the sponsors of the Amendment may suggest that what they meant was that IOUs would continue to own T&D, that is not what the Amendment says and the FIEC, the state Supreme Court, voters, the legislature and the executive branch would be limited by the specific Amendment language.

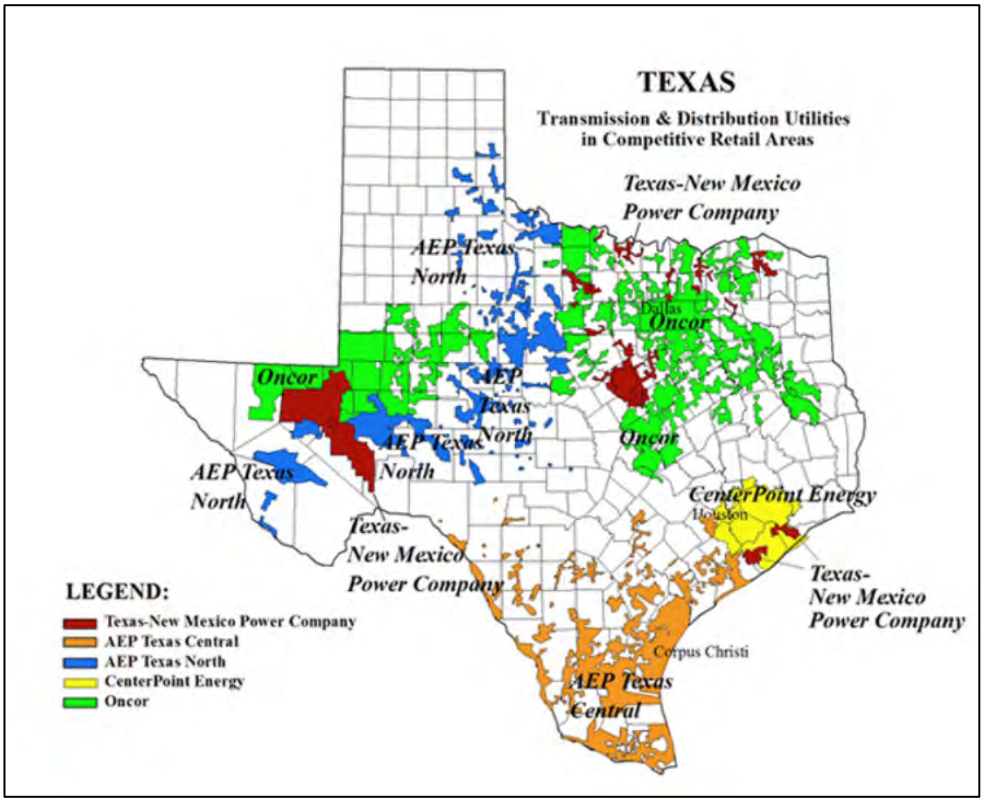
Prohibiting IOU ownership of generation and T&D leaves the state's entire electric system in the hands of yet-to-be identified entities, reducing the current IOU T&D operations to potential subcontractor status for the yet-to-be-identified T&D owner (assuming the IOUs even choose to enter this business). It also creates uncertainty around many important functions, including who is responsible for the restoration of service after a major storm. During the February 11, 2019 FIEC meeting, the sponsors of the Amendment "explained" that customers would receive their bills from their new competitive electricity supplier and would call them with any issues, but that it would be the responsibility of the IOUs to address service interruptions. There are two issues with this statement: 1) the explanation by the sponsors of the Amendment regarding what competitive electricity suppliers do amounts to acting as nothing more than a "middle man" buying power, marking it up and reselling it to customers, and 2) the IOUs are limited to T&D subcontractors, at best, and such subcontractors do not typically also provide customer service functions.

The Amendment Differs from Texas Restructuring

While the sponsors of the Amendment assert that the Amendment is modeled after Texas' restructuring there are a number of clear and important differences. Under SB7, which governed restructuring in Texas, vertically-integrated utilities operating within the Electric Reliability Council of Texas ("ERCOT") region were required to split into three discrete entities: generation companies, the still regulated transmission and distribution utilities, and retail electric providers. The entities could remain under the same corporate owners, even IOUs, but each entity had to function separately. SB7 allowed for continued ownership of transmission and distribution systems by IOUs under the definition of a transmission and distribution utility, defined as "a person or river authority that owns or operates for compensation in this state equipment or facilities to transmit or distribute electricity…"[4]

As noted earlier, Texas specifically provides for IOU ownership of transmission and distribution facilities, while the Amendment expressly restricts IOUs to the construction, operation, and repair of electrical transmission and distribution systems. Further, SB7 did not codify a customer's right to generate and sell power, while the Amendment specifically allows for customers to produce their energy themselves or in association with others. Finally, SB7 did not require a single state-wide competitive market, and did not result in a complete restructuring across the state, as shown in Figure 2.

FIGURE 2: COMPETITIVE RETAIL AREAS IN TEXAS[5]



The Amendment, however, would restructure all areas within the state served by IOUs, including remote areas where transmission interconnections are limited. Transmission systems were not built with a restructured market in mind, but rather were built by each utility to serve their own customers with relatively few links to one another that existed for reliability purposes. As a result, there are areas of Florida, specifically the Florida Panhandle, with limited interconnectivity that will hamper the free exchange of electricity under restructuring. These regions currently operate as separate reliability regions. While it could be more efficient for the entire State of Florida

4 Senate Bill 7, Section 31.002, Utilities Code.
5 Public Utilities Commission of Texas.

to operate under a single regional reliability entity with a uniform set of transmission planning and operational procedures, this would be a costly and time-consuming undertaking.

This Amendment, and its implications, are unprecedented in the industry. It would completely dismantle Florida's electric industry, establish constitutional rights and requirements (some of which may not be within the authority of the legislature and executive branch), and essentially direct the legislature to "work out the details."

III. TEXAS IS NOT A "SHINING STAR" IN ELECTRICITY RESTRUCTURING

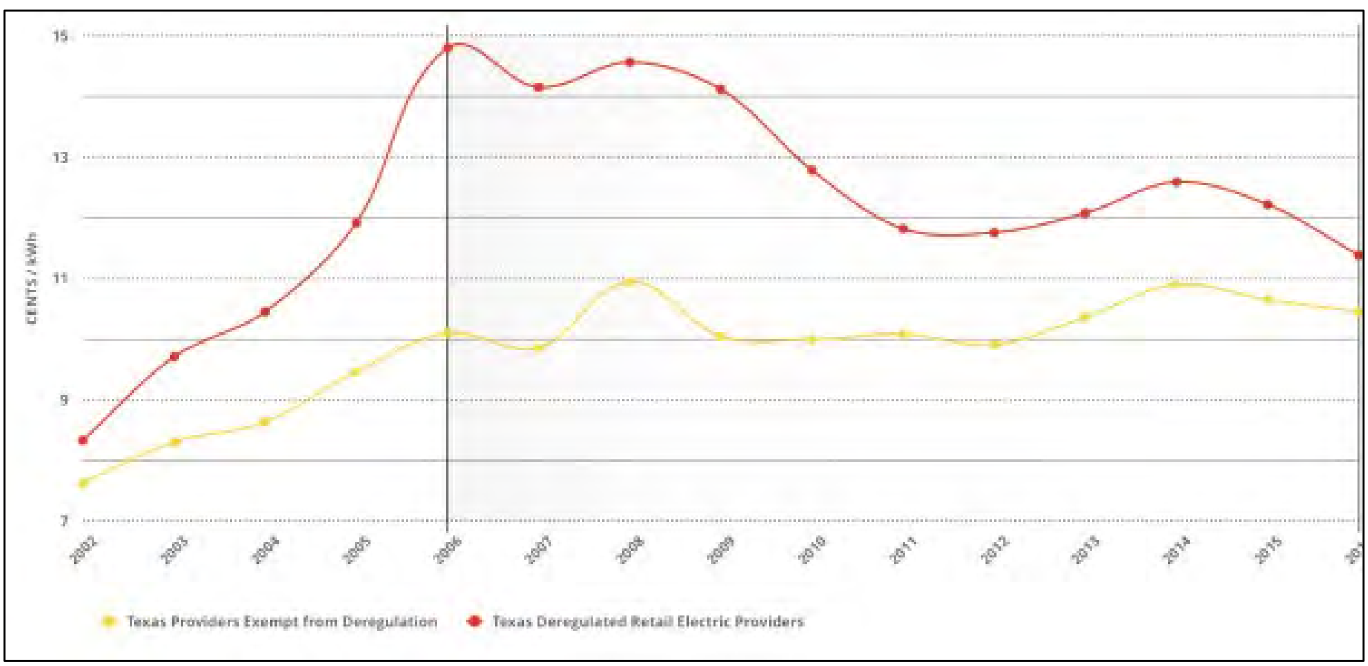
The sponsors of the Amendment point to Texas as the shining example of the success of electric restructuring.

The differences between Texas and Florida make the adoption of the Texas model risky and costly for Florida customers and governments. Further, the experience with electric competition in Texas has been fraught with challenges, including price increases, decreasing reserve margins, blackouts, bankruptcies, and unprecedented levels of customer complaints.

Texas Competitive Energy Prices Exceed Its Regulated Prices

Texas has experienced unexpected price increases since it opened its markets to competition. The Texas Coalition for Affordable Power ("TCAP") produces annual analyses that assess the competitive market and the impact on retail prices. In its 2014 study, TCAP found that restructuring had cost Texas customers $22 billion from 2002 – 2012.[6] This annual trend began during the very first year of the retail electric deregulation in Texas and has continued through 2016, as shown in Figure 3.

FIGURE 3: AVERAGE RESIDENTIAL ELECTRICITY PRICES IN TEXAS



6 TCAP 2014 Electric Restructuring Report.

In its most recent 2018 report, TCAP found that Texans have consistently paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation.

In Texas, electricity providers affiliated with the incumbent utility were required to charge a "price to beat" until the incumbent utility lost sufficient market share to alternative providers. This price was designed as a price floor to prevent the incumbent from offering artificially low rates to stifle competition and undercut new market players. When the price to beat was set, it included a 6% discount off the utility's base rates, as adjusted for fuel costs. However, prices in the deregulated areas steadily climbed as natural gas prices rose in the mid-2000s. From 2002 to 2006, the price to beat rose 88% and the price of competitive offers rose 62%. In contrast, rates in regulated areas of Texas rose only 24% during this period.

Rolling Blackouts and Shrinking Reserve Margins Threaten Texas

Competitive markets have introduced added system reliability risks in Texas. In early 2006, rolling blackouts in Texas left more than 200,000 people unexpectedly without power, including about 78,000 customers in the CenterPoint Energy service territory (around Houston) and about 80,000 customers in the North Texas service territory of TXU Electric Delivery. The crisis began when the grid operator saw usage begin to peak and concluded that it might not have enough generation online to meet demand. All available generation was called to operate at its highest output. However, demand continued to spike, and ***the grid operator was forced to cut power to various industrial customers***. A subsequent loss of four generators representing over 900 MW was too large of a contingency for the system to handle, and ***rolling blackouts were called. These rolling blackouts were the first in more than a decade.***

ERCOT blamed a confluence of events, including the planned outage of about 14,000 megawatts of capacity for plant maintenance, a spate of unseasonably hot weather that went unpredicted by ERCOT's computers, and some unexpected last-minute plant shutdowns.[7] Officials pledged to make corrections to better handle such events in the future. However, approximately two years later, on February 26, 2008, ERCOT officials took emergency action to avoid blackouts. A sudden loss in wind power, coupled with other factors, caused grid operators to take emergency actions once again to avoid a catastrophic system collapse. Additional operator actions to avoid blackouts have been necessary in subsequent years. This represents reliability risks and added costs to the system, which are ultimately borne by customers.

Electric competition in Texas has also resulted in shrinking reserve margins, which poses a serious threat to system reliability. Reserve margins are a measure of the generating capacity available to serve customer demand, which poses a serious threat to system reliability. Because power shortfalls can put a system at risk for blackouts, the reserve margin measurement is a good indicator of system reliability. ***In 2001, prior to deregulation, Texas had the highest reserve margin in the nation[8]. By 2011, these reserve margins had shrunk to alarmingly low levels.*** The National Electric Reliability Corporation ("NERC") reported ERCOT's reserve margin ratio in 2011 at about 14 percent, which marked a nearly 40 percent decline from pre-deregulation levels and far below the national average in 2011 of around 25 percent.[9] In fact, ***after 10 years of deregulation, Texas possessed the lowest reserve margin in the nation***, according to NERC. This was especially alarming, since electricity prices increased over this same time period. The reserve margin in Texas continues to dwindle, with the grid operator projecting reserve margins in the summer of 2019 to be 7.4%, while ERCOT's target reserve margin is 13.75%[10]. Just

[7] Deregulated Electricity in Texas, A Market Annual, 2018, pg.19.
[8] Jim Forsyth, "Texas Launches Electric Power Deregulation," United Press International, June 1, 2001.
[9] NERC Long Term Reliability Assessment 2011.
[10] ERCOT Capacity, Demand and Reserves Report, December 2018.

prior to the summer of 2018, ERCOT warned of the risk of rotating blackouts due to expected reserve margins in the range of 6%. It is likely that with the projected summer 2019 reserve margins, ERCOT will issue a similar warning.

Bankruptcies Followed Restructuring

In 2014, roughly twelve years after the introduction of electric competition in Texas, Energy Future Holdings, the then-parent of Luminant Generation Company and Oncor Electric Delivery, filed for bankruptcy, representing one of the biggest Chapter 11 bankruptcy filings in corporate history. The filing also marked the colossal collapse of a heavily-leveraged $45 billion bet taken by private equity firms, who borrowed enormous amounts of money on the wager that natural gas prices would continue rising compared to coal and, in the process, elevate wholesale electricity prices. Instead, new natural gas exploration technology led to a fall in natural gas prices, and electricity prices were driven down to historic lows.

Price volatility has also caused the bankruptcy of some retail electric providers. Texas Commercial Energy ("TCE") filed for bankruptcy protection in 2003 following a sudden and dramatic rise in the price of wholesale electricity. Because TCE did not own generating assets, it acquired the electricity in the wholesale market and then resold it on a retail basis to its customers. When the wholesale price of power exceeded the price TCE was charging its retail customers, TCE was unable to pay its bills as they came due.

Retail electric providers continue to face headwinds in Texas. In 2018, Breeze Energy, a Dallas retail electric company with thousands of customers in Houston, was shut down by Texas regulators after the company defaulted on its financial obligations, leaving industry analysts to speculate that the anticipation of higher wholesale electricity prices this summer may have put the retail electric provider in a financial squeeze.

Customer Complaints Skyrocketed

The number of complaints regarding electric service filed at the Texas Public Utility Commission increased steadily since the market opening and peaked in July and August of 2003. Over the course of the fiscal year, the Texas Public Utility Commission ("PUCT") Customer Service Division received about 17,000 electricity complaints — about half relating to billing, although many consumers also complained about service disconnections and faulty service. This was a more than 1,200% increase over the average number of annual electricity complaints received by the PUCT in the years prior to restructuring and would mark an all-time high for the number of annual complaints under the Texas deregulation law.[11]

IV. WHAT WOULD THE PROPOSAL DO TO FLORIDA'S ENERGY MARKETS?

Florida's Energy Markets Today

As in most U.S. states, incumbent IOUs supply electricity to the majority of Florida's residents, more than 70%, at retail rates regulated by the Florida Public Service Commission. Municipal electric companies or rural electric cooperatives serve the remainder of the state's electricity consumers, as shown in Table 2, but are not subject to this Amendment.

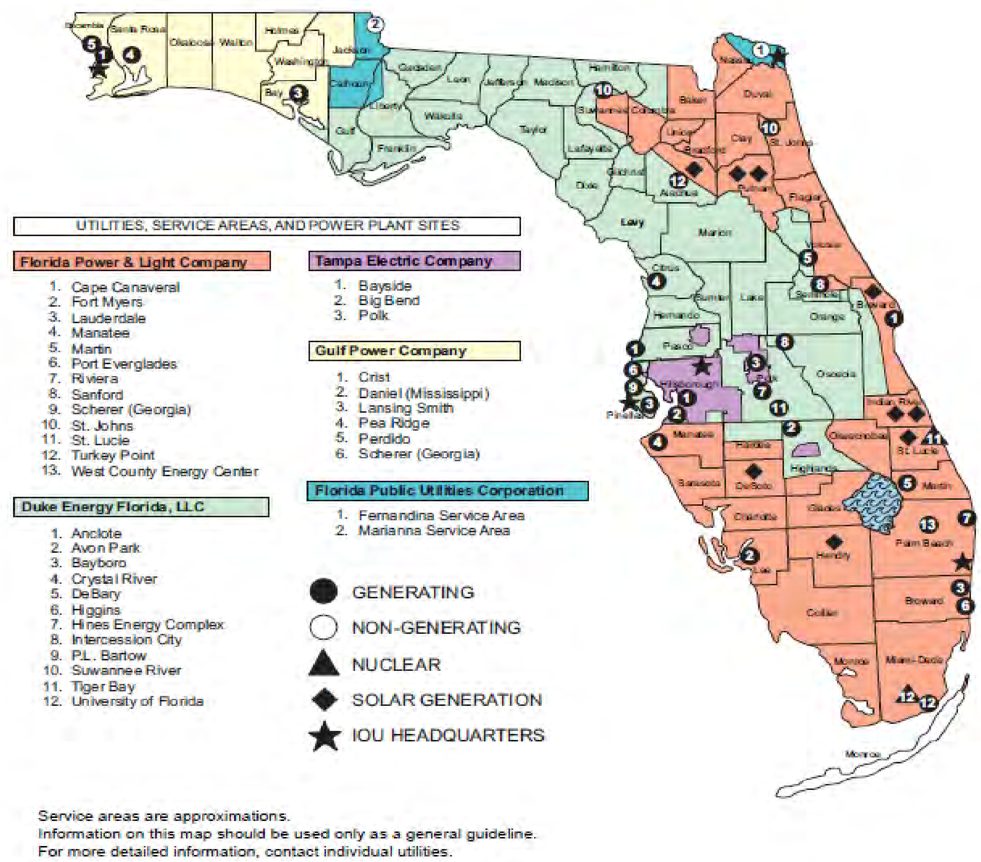
[11] TCAP History of Deregulation 2018, pg. 32.

TABLE 2: FLORIDA CUSTOMERS BY PROVIDER, CUSTOMER CLASS

	No. of Providers	Total	% Total	Residential Customers	Commercial Customers	Industrial Customers
IOU	5	7,912,950	75%	6,997,244	900,050	15,656
Municipal	33	1,447,183	14%	1,248,540	196,257	2,386
Cooperative	16	1,144,913	11%	1,025,506	116,294	3,133
Total:	**54**	**10,505,066**		**9,271,290**	**1,212,601**	**21,175**

Each IOU has a specific service territory, as shown in Figure 4, within which it provides non-discriminatory electric service to all residents, businesses, schools, hospitals, houses of worship and state and local government facilities. The IOUs cannot pick and choose their customers, charge two different customers who are purchasing the same service different prices, or otherwise discriminate in the ways that they serve the public. All customers, including remotely-located customers and low income, elderly, and other vulnerable customers, are provided non-discriminatory access to essential electric service. As discussed later in the report, in many states which have restructured their electricity markets, vulnerable customers, in particular low-income and elderly customers, have been the victims of fraud.

FIGURE 4: ELECTRIC IOU SERVICE TERRITORIES AND IOU-OWNED GENERATION RESOURCES[12]



Source:
Florida Public Service Commission

Many municipal and cooperative electric companies also purchase a portion of their electricity for their customers from the IOUs. For example, Lee County Electric Cooperative, one of the largest electric cooperatives in the country with nearly 200,000 customers, purchases 100% of its electricity under a long-term contract with FPL. The Amendment would prohibit municipal and cooperative utilities from purchasing their power from IOUs, abrogating the contracts that are in place creating both legal issues and electricity supply and cost issues. Municipal and cooperative utilities would have to find new suppliers of their electricity if the Amendment passes.

The IOUs supply electricity by making substantial investments on behalf of their customers, including owning and operating electric generating plants, purchasing electric power from others, and owning and operating T&D systems necessary to deliver power to their customers. As of December 31, 2018, the IOUs have currently invested $60 billion in electric infrastructure investments.[13]

In addition, Florida IOUs are responding to customer demand for affordable and reliable clean energy by investing in substantial amounts of solar energy. In addition to the plants listed in Figure 4 above, FPL owns 18 other currently operating solar power plant sites throughout Florida (totaling over 1,250 MW of capacity),

[12] As discussed later in this report, there are additional solar generating facilities that are not reflected in this map.
[13] IOU Earnings Surveillance Reports.

Duke owns four other solar plants (totaling over 92 MW) and TECO has five additional solar plants (totaling over 318 MWs).[14] The IOUs will also be adding significant amounts of solar generation in the near future. In 2019, Duke will add 74.9 MW and TECO will add 282 MW.[15] Further, earlier this year, FPL announced its "30-by-30" program that has as its goal the installation of 30 million solar panels by the year 2030 and Duke will add an additional 551Mws by 2021. As FPL and other utilities continue to expand their solar fleets, enhancing economies of scale, customers will benefit from increasingly carbon-free electricity sources while maintaining low prices and reliability.

When a storm hits, the IOUs work diligently to restore service. Despite being the "lightning capital" of the U.S., Florida has achieved a level of reliability in electric service that has won national awards and industry recognition. Florida's IOUs and their parent companies have been recognized for outstanding performance in many categories:

- Reliability
- Storm restoration and emergency response
- Innovation
- Customer service
- Employer

APPENDIX 4 IOU Awards provides additional detail regarding awards received by the IOUs and their parent companies.

In many cases, an IOU has franchise agreements with the local communities it serves. In general, these agreements provide the IOU with the exclusive right, and obligation, to serve the community's customers as well as access to rights of way. Franchise agreements include a franchise fee paid by the IOU to the community for those rights. The Florida IOUs pay almost $670 million per year in franchise fees, as discussed in more detail later in this report. IOUs also pay substantial sales, property and other taxes. Most taxes paid by IOUs are based on their revenues. Finally, Florida's IOUs play other important roles in their communities including as employers and charitable givers (both in terms of the IOUs' millions of dollars in charitable contributions each year to causes like STEM education and environmental sustainability, and their employees donating thousands of hours of time to community endeavors).

[14] Source: S&P Financial and Company Site Plans and news releases.
[15] Company Site Plans.

Florida's IOUs do all of this at electricity rates well-below national averages and the average rates charged in states that have restructured their electricity markets as shown in Table 3, below.

TABLE 3: AVERAGE ELECTRIC RATES IN FLORIDA, OTHER STATES

	Residential	Commercial	Industrial	All Sectors
Florida IOU	11.61	9.20	7.67	10.37
Restructured Average	16.24	12.71	9.53	13.32
U.S. Average	12.87	10.74	6.91	10.46

Source: EIA, Electric Power Monthly, October 2018

The proposed Amendment would radically change this favorable situation, increasing energy costs to state and local governments and all customers and adding unnecessary risk and uncertainty to Florida's heretofore stable and reliable electric markets.

Florida's Energy Market if the Amendment is Implemented

If the Amendment is implemented, Florida's energy market would be radically and forever changed. IOUs would be limited to only the "construction, operation, and repair of electrical transmission and distribution systems," thus prohibiting IOUs from owning the generation, transmission and distribution that they have successfully built, operated and maintained on behalf of their customers for more than 100 years.[16] To comply with the policies put forth in the Amendment, IOUs would be forced to sell their generating plants for a market price. While the sponsors of the Amendment suggest that the assets could simply be transferred to non-regulated affiliates of the IOUs, the Amendment does not address this, there is nothing simple about such a transfer, and it would still require establishing the current market value of the assets transferred. Based on the experience in states that have restructured and on the current market for generating plants, it is clear the market value of the IOUs' generating plants would be less than the current book value of the plants, and, for certain types of generating plants (*e.g.*, coal and nuclear plants), there may be no market value at all. And, while IOUs could construct, operate and repair T&D systems, the plain language of the Amendment also prohibits IOU ownership of those systems. As discussed in more detail later in this report, massive amounts of IOU investment would be rendered uneconomic or "stranded" and customers would be required to foot the bill for those costs.

The Amendment posits "a wide variety of competing electricity providers" would own the generation and provide electricity service to Floridians. The Amendment, however, is either vague or completely silent on the innumerable facts and details critical to state and local government and Florida's other energy consumers. Those facts and details include the following, each of which creates the likelihood of litigation, increased costs in administration of the market, or risks to reliability issues:

- The elimination of any obligation to provide electric service to all customers means that customers would not be assured non-discriminatory access to this essential service. Low-income customers, medically essential services, and customers in sparsely populated and remotely located communities that are currently served by IOUs would be particularly at risk.
- If competing electricity providers are not willing to take on all customers or if providers materialize but they charge rates that are much higher and are not guaranteed because that is what the market will

[16] Florida Keys Electric Cooperative, Jerry Wilkinson. Accessed February 9, 2019, http://www.keyshistory.org/fkec.html.

bear for this essential service with no substitute, there is no backstop for customers. In particular, the Florida Public Service Commission, which currently regulates the price of electricity in Florida, would not be able to intervene as it would not have jurisdiction over new entrants.

- Who would a customer call if their lights go out? Who would restore electric service after a hurricane? The Amendment is silent on these key questions.
- The Amendment would grant all customers the constitutional right to generate their own electricity, which means that potentially millions of customers could each have their own power plant. Customers would have the constitutional right to connect these plants to the electric grid. Such an unplanned approach could create significant reliability, predictability and stability issues for Florida's electric system.
- The Amendment requires the implementation of a competitive wholesale market. Florida, unlike many states, is not part of a regional transmission organization ("RTO") or similar organization that is necessary for the state to have a competitive wholesale electricity market. All of this would have to be formed in only a few years.
- The Amendment states that electricity customers would be protected against certain abusive practices retail marketers might employ. Yet a competitive retail electric market, whose participants are not regulated by the state, cannot provide these protections, as has been demonstrated in other restructured states including Texas.
- The Amendment carves out cooperatives and municipally-owned electric utilities but does not address the fact that the IOUs supply a substantial portion of the electricity that these organizations sell to their end-use customers. The state's cooperative and municipal providers would be required to replace this electricity and keep the lights on for governmental and other customers.
- The Amendment would eliminate comprehensive resource planning to ensure the adequacy, diversity, and environmental sustainability of energy resources. The Amendment's statement that it does not limit or expand the State's public policies on energy is misleading and ignores the fact that competitive energy market participants would not be regulated by the State.
- Franchise agreements are specific contracts between IOUs and municipalities. If these IOUs go away, so do the franchise agreements and franchise fees. This risk was exposed by the League of Cities at the February 11, 2019 FIEC meeting.
- Many taxes paid by the state's IOUs would be substantially reduced. The Amendment's statement that the authority to levy and collect taxes, fees and other charges would be unchanged ignores the fact that state and local government revenues would decrease as a result of this Amendment unless state and local government increases taxes. The recently passed Amendment requiring a supermajority vote of the legislature to impose new taxes or to increase current taxes would make it more difficult for the legislature to mitigate tax losses resulting from restructuring the state's electric industry.

State and Local Governments would be Harmed by the Amendment

The Amendment would increase costs and reduce revenues to state and local governments. As discussed in this report, there is no reasonable scenario under which costs would not increase and revenues would not decrease. ***State and local governments, both as energy consumers and through forgone revenues, would be responsible for approximately $1.3 billion to $1.7 billion in one-time costs and more than $825 million in on-going annual costs and lost revenues. Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone.*** What do state and local government and the state's energy consumers get in return for this multi-billion-dollar price tag? They will get a middleman inserted into their energy transaction, by way of a marketer or competitive generator. They would get the right to choose their electricity provider (just not an IOU, and not if they are served by a municipal or co-operative utility) and to purchase competitively-priced electricity (which, importantly, does not mean lower price or better). They would also be faced with all the unanswered questions and risks that this Amendment would create. As other parties commented at the FIEC's February 11, 2019 meeting, Florida's electricity markets work well, service is reliable, and energy costs are competitive. There is no reason to dismantle or "destructure" Florida's electricity market.

V. THE AMENDMENT WOULD IMPOSE IMPLEMENTATION AND OTHER COSTS

Implementing full retail choice for all customers of Florida's IOUs as required by the proposed Amendment necessitates the design, implementation, and ongoing administration and monitoring of functioning competitive energy markets in the state. The legislature and executive branch would be required to commit substantial time, resources and money to design and implement a complex set of laws and regulations in an effort to create these markets and comply with the plain language of the Amendment as written. This would be complicated and contentious, would take many years and would result in extensive implementation costs, litigation and other administrative costs. These costs would be borne by all electric customers and would negatively impact state and local government.

Forming a Functioning Wholesale Market is Costly

It is not possible to introduce full retail choice in Florida as put forth in the Amendment without establishing a functioning wholesale market. A functioning wholesale electricity market is necessary to facilitate the buying and selling of electricity for all retail customers. All states that have restructured their electricity markets to provide full retail choice (commercial, industrial and residential) are part of either an ISO or a RTO.[17] ISOs and RTOs are not-for-profit entities that are formed to perform three basic functions: (1) operate the bulk electric power system, (2) develop, oversee, and administer the wholesale electric market, and (3) manage the power system planning processes to address transmission needs. Florida, like many traditionally regulated states, does not currently have an ISO, RTO, or similar organization. See also APPENDIX 6: *Wholesale Market Implementation*.

States that have implemented ISOs or RTOs have spent years and hundreds of millions of dollars to do so. States that have recently considered an ISO or RTO formation have estimated that implementation could take up to 10 years and cost between $100 million and $500 million. There is no reason to believe Florida would be any different. In fact, given the unique nature of Florida as a peninsula with limitations on inter-state infrastructure, implementation of a wholesale market could cost even more.

It is also worth remembering that Florida previously considered, and rejected, forming an RTO in part due to the extensive implementation costs.[18] In 2006, Florida Power Corporation ("FPC"), FPL, and TECO developed a proposal referred to as "GridFlorida" in response to the U.S. Federal Energy Regulatory Commission ("FERC"), which required all public utilities that own, operate or control interstate transmission facilities to file a proposal to form or participate in an RTO. GridFlorida engaged the ICF consulting firm to conduct a study to determine the costs and benefits of developing and operating an RTO for Florida. The study found:

> … the prospect of a basic Day-1 RTO operation as proposed are "bleak," with the Peninsula Florida costs exceeding the Peninsula Florida benefits by over $700 million over the three-year operating period. Under a more advanced Day-2 RTO operation ICF concludes that the total

17 RTOs and ISOs have similar (virtually indistinguishable) functions. The primary difference lies in the governance structure.

18 Before the Public Service Commission of Florida, Docket No. 020233-EI, Order No. PSC-06-0388-FOF-EI, May 9, 2006.

project benefits are a negative $285 million in Peninsular Florida over the ten-year operating period.[19]

As a result of the GridFlorida study, FPC, FPL and TECO withdrew their proposal. The Florida Public Service Commission and the FERC approved the withdrawal. In 2018 dollars, the estimate of costs relied on by the Florida Public Service Commission and the FERC would exceed the benefits by ***$1 billion for basic Day-1 RTO operations and over $400 million over the ten-year operating period.***

Other Annual Costs Would Rise

In addition to the upfront implementation costs, there are on-going annual costs to administer an ISO or RTO. Those costs include, but are not limited to, salaries and benefits for employees, IT costs, hardware and software maintenance costs, consultant costs, marketing monitoring costs and training and travel costs. ISOs and RTOs are sophisticated organizations with substantial organizational infrastructure and employees. Annual costs to administer the ISO/RTO would be in the range of $170 to $228 million based on other single state ISO/RTOs like New York ISO and ERCOT, respectively.

In addition to annual administrative costs, there are various ongoing costs that would be incurred if the Amendment proceeds. Those costs include consumer outreach and education, software and other information technology upgrades, and monitoring and oversight costs. For example, Texas had a budget of $24 million to educate customers during the first two years after retail choice was implemented.[20] In addition to customer education, Texas hired additional customer service representatives to deal with skyrocketing complaints and bill resolutions pertaining to issues with implementing a restructured market. Estimated education costs for Florida would be approximately $18 million.[21] The staff of the Public Utilities Commission of Nevada ("PUCN") noted additional specific software and computer system technology costs, increased costs to maintain electric grid reliability, and costs associated with maintaining the new systems that would need to be created to implement Nevada's failed restructuring ballot initiative, including approximately $2.2 million for increased PUCN regulatory and workload costs. The PUCN staff's paper also noted that "regulatory uncertainty is generally bad for business" and concluded that it was likely that all of these costs would have been added to Nevadan's monthly electric bills in an open and competitive electric market.[22]

An additional approximately $170 to $228 million in annual administrative costs and $20 million in other costs that are passed onto Floridian electricity customers is clearly bad for business.

The Florida Legislature and Executive Branch Would be Required to Commit Extensive Time, Resources and Money to Implement the Amendment

The Florida legislature and executive branch would be required to design and implement a complex series of laws and regulations in an effort to comply with the Amendment. In so doing, they would be faced with answering many questions that are unaddressed in the Amendment, including but not limited to determining:

- How to fill the market void left by IOUs;

19 Before the Public Service Commission of Florida, Docket No. 20020233-EI, Order No. PSC-06-0388-FOF-EI, May 9, 2006.
20 PUCN, Energy Choice Initiative Final Draft Report, Docket No. 17-10001, April 2018, at 62-63.
21 Estimated education costs were based on a ratio of Texas education costs and its population and applied to Florida's current population.
22 Ibid., at 65-67.

- How to implement, oversee and administer a new restructured market through which service would be provided but without the overarching price protection currently provided by the Florida Public Service Commission;
- How to provide for competitive wholesale electric markets as required by the Amendment without infringing upon the jurisdiction of the FERC;
- The constitutionally permissible role of the "market monitor" required by the Amendment, its structure and who would bear the costs of this new agency;
- How the forced divestiture requirements can be effectuated without running afoul of either the U.S. or Florida constitutions;
- Which of the existing laws and extensive regulations would be struck to ensure the "purposes" of the Amendment are met;
- How to reconcile public policy mandates such as renewables and conservation with the competitive market required by the constitutional Amendment;
- The myriad of rules and regulations necessary to address, for a potentially unwieldy number of individual service providers, issues such as: licensing requirements; unwarranted service disconnections; deceptive or unfair practices; consumer safety and education; and complaint resolutions;
- Whether the state can compel a private entity (and if so who) to:
  - Serve customers who otherwise would go unserved in a "competitive" market because they are unable to pay the "market" price for service or are not cost-effectively servable, or cannot meet credit check requirements;
  - Repair electric infrastructure (power plants, transmission structures and/or distribution poles) following a hurricane or other natural disaster and who would bear the costs of those repairs or rebuilds.
- Whether and how to address public policies on renewable energy, energy efficiency, fuel diversity and environmental protection (all of which exist in current Florida law and may be stricken);
- What entity or bureaucracy would have responsibility for the reliability of the operation and coordination of the state's electric grid, to ensure the system remains properly balanced and maintained minute by minute, 24 hours a day, 7 days a week, 365 days a year; and
- How to ensure that there continues to be adequate electric infrastructure such that the needs of Florida's expanding economy and population continue to be reliably and cost-effectively met.

In attempting to implement the Amendment, the legislature and the executive branch would also have to determine what role the state might have to play (and at what cost) to ensure that:

- Adequate infrastructure is built and maintained in the event that the legislature's effort to design a new "market" structure results in an inadequacy of energy supply or reliable infrastructure;
- <u>All</u> residents and businesses in Florida continue to have the right to affordable and reliable electric service;
- Florida's electric infrastructure is promptly repaired or rebuilt following a hurricane or natural disaster and how those costs would be funded; and

- Florida's electric grid continues to be properly operated and coordinated minute by minute, 24 hours a day / 7 days a week, although much of the regulatory responsibility would be shifted to the Federal government (which has been challenged in meeting this responsibility).

The state of Florida would have the ultimate responsibility to ensure that any new system works properly. Whether due to political realities or the newly enshrined constitutional rights, the state would face significant financial exposure for market failures.

Litigation is Inevitable

Because the Amendment leaves many important questions unanswered, hundreds of millions of state dollars could be spent on lawyers and consultants alone.[23] The Amendment is expected to create substantially more litigation costs than any other energy-related litigation in the state in recent years. Finally, as noted earlier, the Amendment constitutionally grants Floridians standing to seek judicial relief if, among other things, "meaningful choices among a wider variety of competing electricity providers" do not present themselves.

VI. PROHIBITING IOUS FROM OWNING GENERATION AND T&D WOULD INCREASE COSTS

IOUs currently have approximately $60 billion in current investment (i.e., net book value) in electric system infrastructure to serve the state's energy consumers.[24] IOUs also have significant commitments and obligations under purchase power agreements, fuel contracts, and collective bargaining agreements with union labor. The forced sale, or divestiture, of electricity infrastructure puts those investments and commitments at risk and would result in substantial costs for Florida electricity customers in the form of "stranded costs."

Stranded costs are created when the market value of utility assets in a restructured market is less than the value on the utilities' books. There are three primary drivers of this devaluation: (1) the forced sale of assets creates uneven bargaining power for asset purchases, leading to low (i.e., "fire sale) valuations; (2) assets would be heavily discounted due to the risks and uncertainty of operating in an unproven merchant market; and (3) the market does not value the same factors that have led to certain prudent IOU investments. Those factors include fuel diversity, environmental goals, and long-term planning considerations. As described below, the forced divestiture (or even the forced spinoff to an unregulated affiliate) of the IOUs electricity infrastructure would generate significant stranded costs. These stranded costs for generation assets alone can reasonably be expected to exceed $10 billion and could range much higher. The state of Florida would have to either fund the compensation for the billions of dollars of this property "taken" as a result of the Amendment or pass those costs on to current customers (including state and local government customers) through a non-bypassable recovery charge on electric bills as other states have elected to do.

Estimating the Generation Stranded Costs Created by the Amendment

There is a wealth of experience with stranded costs in the states that have restructured their electricity markets. There is also market data on generating plant sales in the U.S. Using these two data sets, one can reasonably

23 In a well-known case between Florida and Georgia over upstream water rights, litigation has cost the state $57 million in just the past four years. Since the ballot initiative could result in multiple litigation cases, that $57 million could be three times as much at the low end and six times as much at the high end. Tampa Bay Times, "Supreme Court Finally Rules on Florida's 30-year Water War with Georgia. And it's not over," June 28, 2018.

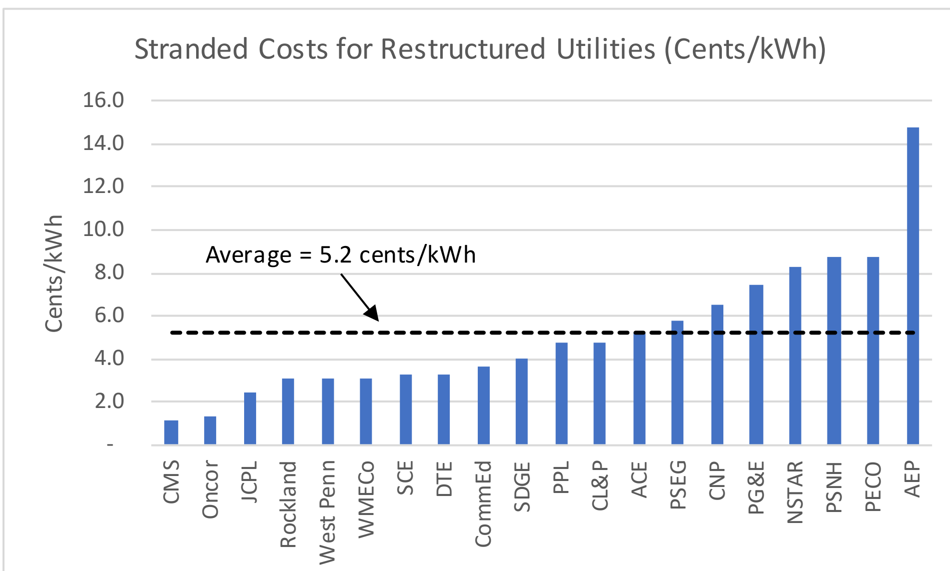
24 IOU Earnings Surveillance Reports.

estimate the amount of generation stranded costs that the Amendment would create. Based on an analysis of stranded costs in other states that have restructured and other current market data, the forced "divestiture" caused by the Amendment would create stranded costs for the generation assets that can reasonably be expected to exceed $10 billion. Lost value during generation asset sales has been an experienced feature of all prior market restructuring in other states. Even if the Amendment and associated legislation allow for the spinning off some or all the IOUs generation into unregulated affiliates, those spin-offs would be recorded at fair market value, generating the same level of stranded costs as if the utilities sold those assets on the open market. As electricity consumers, state and local governments can expect to bear over $1 billion of the $10 billion amount.[25] In addition, if any portion of the IOUs' investments in their $24.3 billion in T&D assets, in addition to hundreds of millions of commitments under power and fuel purchase agreements, become stranded, that would add significantly to stranded costs.

Stranded Cost Experience in Restructured States

In states that have restructured, including California, Connecticut, Illinois, Massachusetts, Michigan, New Hampshire, New Jersey, Pennsylvania, and Texas, utilities have been authorized to recover over $40 billion in stranded costs.[26] Figure 5, below, shows those stranded costs, on a cents-per-kWh basis. To arrive at the ¢/kWh of delivered energy, the total amounts of electric restructuring-related stranded costs, by company, were divided by the five-year average annual kWh sales for that utility beginning with and prior to the initial stranded cost authorization date. Expressing stranded costs on a ¢/kWh basis makes it possible to apply this metric to kWh sales in Florida to impute a level of stranded costs for Florida.

FIGURE 5: STRANDED COSTS FOR RESTRUCTURED UTILITIES (¢/KWH)



Applying this experience to Florida's IOUs would result in a range of stranded costs from $2.2 billion to $27.9 billion, with an average of $9.8 billion, which is 36.9% of 2017 net book value.[27]

[25] Based on the proportion of IOU sales of electricity to governmental agencies.
[26] Regulatory Research Associates, "Utility Asset Securitization in the U.S.," March 4, 2013. Supplemented by Concentric research.
[27] $9.80 billion divided by $26.50 billion in generation net book value.

How are these data best interpreted? A few key conclusions can be drawn from them: (1) stranded costs would be significant in Florida; (2) even if Florida were to experience the minimum level of stranded costs experienced among other restructured utilities, that would result in 1.2¢/kWh, or $2.2 billion total; and (3) stranded costs can reasonably be expected to exceed $10 billion. Furthermore, the restructuring embodied in the Amendment goes further than restructuring in other states (e.g., through the prohibition on IOU ownership of T&D assets), meaning that the above stranded costs estimates are conservative.

Stranded costs will be passed on to electricity customers, including state and local governments. State and local government, as electric customers, could pay more than $1 billion in stranded costs, in addition to the costs of procuring their electricity from a new "competitive" supplier. *See* APPENDIX 1 Analysis of Financial Impact for details on those calculations.

Recent Power Plant Sales

Data from over 60 recent power plant sales was also analyzed to estimate the value of the IOUs generation fleet. This analysis, based on median sales prices for power plants in the U.S. over the last five years, indicates that the Florida IOUs generating assets would be valued at between approximately 10% and 100% below their net book value (depending on fuel type, as discussed below nuclear generation, which is a significant portion of FPL's generation fleet, is particularly at risk), with an average discount of approximately 49.6%. Applying that approximately 49.6% average discount to the Florida IOUs generation net book value (excluding certain plants that are planned to be retired in the near term), results in a stranded cost estimate of $12.3 billion. That analysis, by fuel type, is provided in the table below, and is further discussed in APPENDIX 1 Analysis of Financial Impact. Market values for generation in particular are also highly dependent on the structure of the market the plants serve. If the Amendment is implemented, the electricity market structure in Florida would be new and uncertain, further negatively influencing the value of the divested plants.

TABLE 4: ESTIMATE OF STRANDED COSTS IN FLORIDA BASED ON RECENT ASSET SALES – BY FUEL TYPE

Fuel Type	IOU Plant Count	IOU 2017 Capacity (MW)	2017 Net Book Value ($/KW)	Median Market Comp. Sale ($/KW)[28]	Discount/ (Premium) of Market Value to Net Book Value ($/KW)	% Discount/ (Premium)
	[A]	**[B]**	**[C]**	**[D]**	**[E] = [C] – [D]**	**[F] = [E]/[C]**
Coal	6	5,332	1,046	0	1,046	100.0%
Natural Gas	30	28,801	468	420	47	10.2%
Nuclear	2	3,502	1,468	0	1,468	100.0%
Residual Fuel Oil	6	1,051	87	67	21	23.8%
Solar	9	285	2,094	1,252	842	40.2%
MW-weighted Average % Discount/(Premium)						**49.6%**
Total Net Book Value of IOU Generation (ex. near-term retirements) ($billions)						**$24.9**
Estimated Stranded Generation Costs ($billions)						**$12.3**

28 Note: includes sales across the U.S. for the period 2014 through 2018. Nuclear and coal generation are assumed to have no available market for the sale of those types of plants. As such, the market value is assumed to be $0.

Nuclear Divestiture Alone Will Create Billions of Dollars in Stranded Costs

Florida has benefited from emission-free nuclear generation for decades. Currently there are a total of four operating nuclear units at two sites in Florida: the St. Lucie Nuclear and Turkey Point sites, which are both owned and operated by FPL. The Florida Municipal Power Agency ("FMPA") and the Orlando Utilities Commission ("OUC") also own minority interests in St. Lucie Unit 2 (of 8.81% and 6.09% respectively). FPL has invested in and is maintaining an option to construct and operate two new nuclear units at the Turkey Point Nuclear Plant. The net book value of FPL's investment in the nuclear plants is currently $5.68 billion.

While there may be some market for other types of generation (*e.g.*, natural gas, solar), there is currently no active market for nuclear plants as operating concerns in the U.S. There have been no plant-level transactions involving majority ownership stakes in any operating nuclear plant in the U.S. since 2007. There have been attempts: Dominion attempted to sell the Kewaunee Nuclear Power Plant and Entergy attempted to sell Vermont Yankee[1] – but both failed to sell and both plants were subsequently shut down by their owners. If the Amendment passes and FPL is forced to divest its nuclear plants there is no reason to believe that its experience will be any different than Dominion's or Entergy's, rendering 100% of its $5.68 billion current investment stranded. FPL would continue to be responsible for the future decommissioning of these facilities, including any costs above the balances in the existing nuclear decommissioning trust funds. Customers would be liable for both stranded costs and decommissioning costs.

The stranded cost challenges would not be isolated to the IOUs. The Amendment would also force a sale of the St. Lucie plant on FMPA and the OUC. FMPA and OUC will be forced to write-down the value of their investments in the station. Depending on how the FMPA and OUC municipalities have financed their investment in St. Lucie, it may be necessary to raise revenue through taxes or through rate adjustments to pay off bonds related to the nuclear ownership. It is likely that FMPA and the OUC would seek judicial relief.

Further, the impact of nuclear divestiture on local economies would be substantial. These effects were seen in Florida following Duke Energy Florida's closure of the Crystal River nuclear power plant in 2013. When Crystal River's closure was announced in 2013, the plant had 585 full-time employees, not including security personnel and contractors.[2] By early 2018 that number had fallen to 70.[3] In 2008, the county's appraiser assessed the tax on two parcels at the Crystal River site at $10.5 million. In 2016 this decreased to $413,990, according to county records. Duke Energy Florida, as a regulated utility with deep roots in the region, was able to mitigate the impact to the community and employees from the plant's closure by, for example, making every effort to transfer the plant's employees to other generating stations in Duke's fleet as well as siting a new natural gas combined cycle generating station in the same city and county. In a restructured market, it is unlikely that new generation providers would feel or act on the same responsibility.

Substantial Stranded Costs Would be Created

The analyses of stranded costs described above indicate an average range of $9.8 billion to $12.3 billion of potential stranded costs in Florida, as shown in the table below. In addition, if any portion of the IOUs investments in their $24.3 billion in T&D assets, in addition to hundreds of millions of commitments under power and fuel purchase agreements, becomes stranded, that would add significantly to stranded costs.

TABLE 5: STRANDED COSTS SUMMARY

Stranded Cost Measure	Mean Result ($billions)	Middle 50% ($billions)
Stranded costs based on experiences in other U.S. states	$9.8	$5.9 to $12.8
Stranded costs estimated based on sales of power plants	$12.3	

VII. THE AMENDMENT WOULD LOWER REVENUES TO STATE AND LOCAL GOVERNMENT

Florida's IOUs contribute significantly to the revenues that support the budgets of state and local government. In 2017, Florida's IOUs paid nearly $3 billion in taxes and fees to state and local government. The Amendment would significantly reduce these taxes and fees. While there is a potential that some of these decreases could be made up through a combination of taxes paid by new entrants and changes to statutes and local ordinances, there is significant uncertainty regarding that outcome and a likelihood of increased legal and other costs. The recently passed Amendment requiring a supermajority vote of the legislature to impost new taxes or to increase current taxes would make it more difficult for the legislature to mitigate tax losses resulting from the Amendment.

Taxes Paid by IOUs Would Decrease

Florida IOUs and their customers are assessed a number of state and local taxes related to the ownership of utility assets and the purchase and sale of electricity. The reduction in utility-owned assets and electricity sales caused by the Amendment would result in significantly less taxes and fees being paid by IOUs and their customers to state and local governments. Table 6 and Table 7, below, summarize the types of taxes that are assessed, as well as the annual rate of each tax paid by each IOU.

TABLE 6: TYPES OF TAXES PAID BY FLORIDA IOUS

Tax	Percentage	Tax Basis	Applies to	Assessed by
Sales Tax	6.95%[29]	Sales price of electricity	Commercial customers (exemptions apply)	State
Local Option Tax (Discretionary Sales Tax)	0.5% - 2.5%	Sales price of electricity	Commercial customers (exemptions apply)	Counties
Gross Receipts Tax	2.5%	Gross receipts of utility	Utility	State
Corporate Income Tax	5.5%	Taxable Income	Utility	State

[29] The tax percentage varies by county across Florida.

Tax	Percentage	Tax Basis	Applies to	Assessed by
Property Taxes	Up to 10 mills	Net book value of assets	Utility	Cities/Counties
Municipal Utility Tax (Public Service Tax)	Up to 10%	Purchase of electricity	All customers	Cities/Counties

In 2018, IOUs paid $2.9 billion in state and local taxes. Over $350 million of annual property taxes alone are jeopardized by the proposed Amendment because of the projected decline in the value of the generation-related tax base. Sales, Gross Receipts, Local Option and Municipal Utility tax revenues are also at risk of declines if these taxes are interpreted as not applicable to the T&D portion of customers' bills, or as customers become able to purchase electricity from suppliers outside the state of Florida. Florida cities and counties have expressed particular concern over the loss of Municipal Utility Tax revenues, of which IOUs paid over $780 million in 2017,[30] and over $860 million in 2018. In addition to lost revenues, local governments would have to contend with the administrative challenges of collecting these taxes from multiple providers in a context in which it is unclear at what point the actual taxable purchase of electricity occurs. All else being equal, if the proposed Amendment renders these taxes not applicable to unbundled electricity sales, then the impact on state and local government tax revenues would be substantial.

TABLE 7: STATE AND LOCAL TAXES PAID BY FLORIDA IOUS IN 2018 ($MILLIONS)[31]

	State		Local		
	Sales Tax & Use Tax	Gross Receipts Tax	Property Taxes	Local Option Tax	Municipal Utility Tax
Florida Power & Light	$289.3	$268.7	$716.4	$14.1	$576.8
Gulf Power Company	$27.9	$32.7	$12.5	$2.9	$26.8
Tampa Electric Company	$36.0	$48.5	$107.0	$3.8	$58.6
Duke Energy Florida	$105.0	$112.1	$251.5	$6.9	$206.0
Total	**$458.2**	**$462.0**	**$1,087.4**[32]	**$27.6**	**$868.2**

Property Tax Revenues Would be Dramatically Reduced

Florida's IOUs paid more than $1 billion in property taxes in 2018. The impact of the forced sale of generating assets on property taxes is immense. If Florida IOU-owned power plants are sold at a discount to net book value (*i.e.*, stranded costs are created), the property tax basis would be impaired. As discussed earlier, the IOUs generating facilities would face value impairments of between 36.9% and 49.6%. Those new, lower valuations would then flow through to the taxable base, leading to a decline in annual property tax revenues. The table below provides a summary of the associated forgone annual property tax revenues earned by Florida municipalities.

30 Florida League of Cities presentation given at the FIEC Public Workshop, February 11, 2019.
31 Source: IOU provided data.
32 Approximately $350.2 million of this amount is paid for Florida IOUs for generation property.

TABLE 8: PROPERTY TAX IMPACT OF RESTRUCTURING

Impaired Value %	Total Property Taxes Paid by Florida IOUs for Generation Property ($ millions)[33]	Estimated Annual Property Impact of Restructuring ($ millions)
36.9% - 49.6%	$350.2	$129.4 to $173.8

The impact on property tax revenues could be especially disastrous for communities that currently host nuclear generating facilities. As discussed above, the closure of the Crystal River nuclear generating unit in Citrus County, Florida mitigated by the construction of a new natural gas combined cycle still led to a major budget shortfall for the county after Duke Energy Florida's local tax liability fell by approximately 63%.[34] Similar circumstances have prevailed in other areas of the U.S. following restructuring.

- Following the upcoming closure of Entergy's Pilgrim nuclear plant in Plymouth Massachusetts, the town of Plymouth Massachusetts will lose $9.3 million annually in payments from Entergy, representing 7% of the town's tax base. In addition, the property taxes paid by the plant's 190 employees who reside in Plymouth – approximately $950,000 – are also in jeopardy.[35]
- When the Zion nuclear station in Illinois closed, its annual property taxes to the community in which it resided fell from nearly $20 million to $1.6 million. To fill the gap created by this loss, property taxes on a $300,000 home surged from $8,000 to $20,000 per year, which has made it extremely difficult to attract new businesses to the region according to local officials.
- Similar effects are expected in New York following the closure of the Indian Point nuclear plant. Municipalities in the surrounding areas anticipate $32 million in annual losses to their budgets as a result of the plant's closure. The village of Buchanan will face a $2.6 million hole in a $6.2 million annual budget from the loss of property-tax revenue. The Hendrick Hudson school district faces annual losses of more than $26 million after its payment-in-lieu-of-taxes agreement with Entergy expires. From 2021, when Indian Point closes, through 2025, municipal property tax revenue will plunge dramatically from $24.8 million to $1.3 million. Officials estimate that an *average* annual tax increases of 13 percent would be required to make up for such a loss.

Franchise Fees are at Risk

Prohibiting IOUs from owning generation and providing generation-related services, prohibiting IOUs from owning T&D, and prohibiting exclusive franchises would impact municipality's franchise agreements with the IOUs and put franchise fee revenues earned by municipalities from IOUs (currently approximately $679.1 million) at risk. Simply stated, with no franchise there can be no franchise fees.

This same concern was voiced by the League of Cities during the FIEC public workshop on February 11, 2019. At the public workshop, the League of Cities discussed how franchise fees: (1) provide compensation to cities for fair rent for the utility's use of public rights of way and the cities' agreement not to compete with electric providers within their jurisdictions; and (2) offset the costs associated with maintenance of rights of way. The

33 Source: IOU provided data.

34 Behrendt, B., "Crystal River Nuclear Plant Closure Devastates Citrus County," Tampa Bay Times, https://www.tampabay.com/news/business/energy/fallout-from-crystal-river-nuclear-plants-closure-devastates-citrus-county/1273833.

35 Spillane, G., "Plymouth braces for economic blow," Cape Cod Times, https://www.capecodtimes.com/article/20151014/news/151019748.

League of Cities expressed concern that franchise fees are at risk of being eliminated entirely. The proposed Amendment specifically provides that future legislation must "prohibit any granting of either monopolies or exclusive franchises for the generation and sale of electricity." This language introduces uncertainty over the continued purpose of franchise agreements with utilities. It also increases the likelihood that IOUs would be incentivized to either exit or not renew existing franchise fee agreements as a result of losing exclusivity within a municipality.[36]

VIII. ELECTRIC SYSTEM RELIABILITY WOULD BE JEOPARDIZED

Four elements of the proposed restructuring combine to give Florida reason to be concerned about the impacts on reliability and resource adequacy. These are: (1) the abandonment of integrated resource planning processes and Florida Public Service Commission requirement that regulated utilities build infrastructure to accommodate growth, efficiency and environmental policy; (2) the failure of competitive markets to ensure fuel diversity and fuel supply; (3) the threat to system reliability; and (4) the transfer of jurisdiction from the Florida Public Service Commission to the FERC. The unique nature and isolation of peninsular Florida introduces additional complexities that must be considered and included in the analysis of the costs and benefits of energy market reforms in Florida. The challenges imposed by restructured markets on resource adequacy and related issues are more fully described in APPENDIX 8 Resource Adequacy.

Integrated Resource Planning Would be Abandoned

Municipal electric utilities and cooperatives in Florida are part of the integrated Florida resources and reliability planning. These citizen-owned utilities enjoy the benefits of system stability provided by the Florida Public Service Commission-directed resource adequacy for the IOUs. Under the current regulatory model, Florida utilities conduct long-term planning under the oversight of the Florida Public Service Commission and invest in adequate generation resources to meet a specified reserve margin (or back-up power) for their customers' demands. The current model ensures that Florida utilities have "steel in the ground" with a diverse portfolio of resources sufficient to keep the lights and air conditioning on for their customers. While municipalities and cooperatives are excluded from the deregulation initiative, it is very likely that their costs are also going to go up as the generation assets previously owned by IOUs no longer provide a stable and reliable statewide system that municipalities and cooperatives rely upon. In contrast, restructured states make no such requirements of their energy marketers, such as Infinite Energy, who need not own a single megawatt of generation capacity to make promises to deliver power to customers.[37]

The State's Fuel Diversity and Fuel Supply Would be at Risk

Due to factors such as low natural gas prices, environmental restrictions on coal generation, and other economic factors, restructured states have seen their reliance on natural gas steadily increase. In the Mid-Atlantic region,

[36] For example, several franchise agreements between FPL and Florida municipalities contain clauses allowing FPL (the "Grantee") to terminate the agreement early (see, e.g., Palm Beach County Franchise Agreement, Section 8: "If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the unincorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the unincorporated areas of the Grantor in which the Grantee may lawfully serve, and determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter.").

[37] See, e.g., the requirements for energy suppliers in Maryland (available at http://goo.gl/S14NoZ) and for retail energy providers in Texas (available at http://goo.gl/S2nMbx).

coal and natural gas have reversed roles as fuel sources for electric power. Coal is expected to decline from 42 percent in 2007 to 27 percent in 2020, while the share for natural gas is expected to increase from 33 percent to 43 percent over this same time period. While the grid operator has taken steps to ensure the reliability of the system while accommodating more gas-fired generating capacity, they continue to introduce mechanisms to ensure the resiliency of the grid.

Similarly, in New England, natural gas generation made up over 60 percent of generation to serve load in 2017. ISO New England ("ISO-NE") has struggled with how to address this increasing reliance on natural gas-fired generation citing the "fuel-security risks to system reliability." An ISO-NE report discussed the causes of this risk, including: heavy reliance on natural-gas-fired capacity; reliability issues due to limited natural gas transmission infrastructure into the region, as well as limited fuel storage; lack of firm fuel contracts by natural gas generators; retirement of non-gas-fired generation (nuclear, coal, etc.); exposure to winter electricity price spikes; and higher variable cost peaking units (e.g., Liquefied Natural Gas ("LNG")).[38]

Under a competitive market structure fuel supply has the potential to be at risk, resulting in higher costs to the region. Many competitive markets across North America do not require generators to have firm fuel supply in the form of either firm gas supply or fuel oil back up. Restructured jurisdictions have experienced severe fuel shortages at times when system reliability was at risk due to lack of firm fuel supply. For example, in the winter of 2014, the cost of electricity at the wholesale level totaled approximately $3.2 billion dollars for December, January and February alone due to high prices as a result of gas shortages.[39] To put this in context, in a typical year, wholesale energy costs total $5 billion for the entire twelve-month period. A deliberate approach to resource diversity, which is absent in a restructured market, provides important protections against high costs, particularly as regions become more dependent on natural gas resources.

System Reliability Would be Threatened

As discussed above, competitive markets can introduce system reliability risks, as has been the case in Texas and California. Electric competition in Texas has resulted in shrinking reserve margins. Over the first decade of electric restructuring, reserve margins in Texas declined almost forty percent. The reserve margin for the upcoming summer period is expected to be 7.4%, far below the target reserve margin of 13.75%.

These shrinking reserve margins have very real consequences, notably in the form of blackouts. Blackouts have occurred in Texas on three separate occasions since the introduction of competition. California has experienced similar system emergencies. In June of 2000, a series of localized, rolling blackouts affected 97,000 Pacific, Gas & Electric consumers in the Bay Area.[40] The grid operator ordered the cuts because supplies were low due to the closure of several plants for maintenance purposes. The rolling blackouts were declared in hopes of avoiding a major statewide, uncontrolled blackout. Since that time, California has instituted rolling blackouts on no less than three separate occasions, the most recent occurring in 2011 that resulted in the loss of power to approximately 1.4 million people in the San Diego area.

Decision-Making Power Would be Transferred to the FERC

Restructuring would also severely restrict the Florida Public Service Commission's jurisdiction over generation. With a move to retail choice comes a loss of the utility's obligation to build and a corresponding loss of Florida

38 Source: ISO-NE 2017 Regional System Plan.
39 Winter Reliability Program Updated, Restructuring Roundtable, September 25, 2015.
40 Frontline, The California Crisis.

Public Service Commission jurisdiction over power prices. Instead, jurisdiction over regulatory policies that drive electricity prices would be transferred from the Florida Public Service Commission to the FERC, a federal agency whose broad agenda may not always align with Florida customers' best interests from both a cost and reliability standpoint. Under competition, energy marketers and Independent Power Producers ("IPP") are subject to FERC-jurisdictional RTO tariff rules, rather than state-regulated utilities, decide whether, when, and how to enter the market and what supply and demand side resources to develop, and at what price.

IX. RETAIL RESTRUCTURING EXPOSES CUSTOMERS TO INCREASED COST AND RISK

While the Amendment language promises consumer protections, states with restructured electricity markets have struggled to protect customers from deceptive marketing practices of competitive retail energy suppliers. Customers, in particular vulnerable customers including low income and elderly customers, have suffered the most. This has prompted a number of states to suspend retail choice.

What is a Retail Energy Supplier?

In states that have adopted electric restructuring, "retail energy supplier," "retail electric provider", "retail marketer," or "energy service company ("ESCO")" refers to a company that serves as a middleman or an intermediary between the electricity buyer (residential, commercial and industrial customers) and the wholesale electric market. Retail marketers purchase electricity through wholesale electricity markets and resell it to consumers. Today, in most restructured states, customers that do not choose a retail marketer remain on electricity supply service provided by the utility, which is referred to by terms such as "default service," "standard offer service," "basic service," or POLR. Notably, in Texas, utilities are not allowed to provide electricity supply service, and so select retail electric providers supply POLR service. The Amendment would preclude the Florida IOUs from providing POLR service, as such customers would only be able to receive retail service from marketers.

Adding ESCOs Will Add Costs

Like other competitive businesses, retail marketers develop and sell products, pay their costs, and seek to earn a profit in doing so. They must buy electricity, hire staff, market to customers, sell their services and deliver these services to their customers. In addition, retail marketers must also perform a supply management function in which customer supply obligations are matched with wholesale supply purchases. Retail marketers incur costs for the products they supply (cost of goods sold) and a variety of operating expenses. ESCOs are not obligated to serve other than what they contract for with customers. If their rates are out of market, they can leave the service area and the customer has no real recourse.

Adding ESCOs to Florida's energy markets would create additional, and duplicative, costs including:

- Acquisition costs – Retail supplier service costs include customer acquisition expenses which the utility does not incur. Costs for an ESCO to market its services and "acquire" customers, including sales commissions, branding and marketing expenses, average approximately $121/customer, based on analysis of publicly available information of financial reports of ESCOs.[41] If these

[41] Sources: Crius Energy Trust, Management Discussion and Analysis ("MD&A"), March 8, 2018, pages 10 and 12; Just Energy MD&A, May 16, 2018, pages 4 and 30; Genie Energy Ltd, 2017 Form 10-K, pages 27 and 28; Spark Energy Inc., 2017 Form10-K; pages 52 and 93. Calculated as average

costs were to be incurred in Florida, the state's nearly 6.3 million residential electricity consumers served by the IOUs can expect to pay an additional $1.1 billion as retailers seek to recover these costs in their fees.

- Billing, customer care and other corporate functions - In most restructured markets, utilities and retailers both provide customer care and billing functions. Utilities maintain billing systems for determining transmission and distributes rates and retailers calculate supply charges. These redundant billing requirements mean that each consumer served by a retailer is supporting two billing platforms. The average "cost to serve" for competitive retailers was $112/customer/year. The impact of these higher operating costs could be considerable for Florida consumers. Based on this estimated retailer "costs to serve" Florida consumers would pay an additional $1.0 billion per year assuming all consumers were to switch to a retail supplier.[42]

Consumer Fraud and Deceptive Marketing, Billing, and Pricing are Risks

States with restructured electricity markets have experienced extensive problems in retail supplier marketing, customer acquisition, billing, and pricing practices. There are numerous cases in which state regulators and attorneys general have undertaken punitive action against energy marketers for practices ranging from illegal bait and switch schemes, to fraudulent claims about savings, to "slamming" (unauthorized switching of customers to a competitive supplier without proper authorization from customers). APPENDIX 6: Impact of Electric Restructuring on Retail Energy Costs and Service provides an illustrative list of punitive actions and fines against retail marketers for violations including: forged signatures on contracts; promising savings that did not materialize; inaccurately communicating and displaying rates on bills; fraudulent marketing under the guise of the local utility; and not communicating fees and contract lengths. Such deceptive and fraudulent practices are often targeted at low-income, elderly, and non-English speaking customers. Beyond such one-time actions, several states have undertaken broader studies and actions to try to end the retail supplier industry for residential customers, including the following:

- After reporting aggressive sales tactics, false promises and the targeting of low-income, elderly, and minority residents, Massachusetts has proposed legislation to end electricity choice for individual residential customers;[43]
- Illinois' Attorney General ("AG") has also called for an end to residential choice, based on similar deceptive marketing practices;[44] and
- This month, Consumer Counsel, in collaboration with AARP, other consumer advocates, and a U.S. senator, called for the end of residential choice that "economically harms consumers" in Connecticut.[45]

While decision-making of the Florida Public Service Commission over generation and transmission would transfer to the FERC under restructuring, the job of the Florida Public Service Commission would become more complex regarding oversight of retail prices and service in Florida. First, the Florida Public Service Commission would no

of Crius, Just Energy, Genie, and Spark total acquisition costs and cost to serve, divided by acquired new customers and total customers, respectively. See APPENDIX 6: Impact of Electric Restructuring on Retail Energy Costs and Service for details.

42 Ibid.

43 "AG Healey Calls for Shut Down of Individual Residential Competitive Supply Industry to Protect Electric Customers" Press Release, March 29, 2018. https://www.mass.gov/news/ag-healey-calls-for-shut-down-of-individual-residential-competitive-supply-industry-to-protect.

44 "[Attorney General] Madigan Sues Another Alternative Retail Electric Supplier & Reaches $3 Million Settlement for Defrauded Customers" Press Release, November 19, 2018. http://illinoisattorneygeneral.gov/pressroom/2018_11/20181119b.html.

45 "Time to End the Third-Party Residential Electric Supply Market" AARP Connecticut. February 2, 2019. https://states.aarp.org/time-to-end-the-third-party-residential-electric-supply-market/.

longer have regulatory jurisdiction over retail electric prices and service, as it does now over the IOUs. Nonetheless, it would likely undertake efforts to try to address aggressive and deceptive pricing, marketing, and billing practices for residential customers in particular. Florida's large population of elderly, low-income, and non-native-English speaking residents, as compared to the rest of the country,[46] would be especially vulnerable to deceptive marketing practices, and state agencies would need to incur additional expenses to ensure they are protected. For example, after restructuring was implemented in Texas, there was a significant jump in customer complaints, slamming of customers, marketers going bankrupt, and massive telemarketing campaigns. Complaints to the Texas Public Utilities Commission averaged 1,300/year prior to restructuring; after restructuring, complaints rose to as much as 17,250 in a given year.[47] This burden imposes costs on state government and leads to far lower customer satisfaction. The Florida Public Service Commission would need to undertake significant effort to shift from regulation to restructured markets and establish and monitor the competitive electric retail market.

X. THERE IS NO CLEAR ADVANTAGE TO RESTRUCTURING

High electricity prices were a major driver in states that have restructured. Florida's electricity prices are already below both the national average and the average of restructured states. And while the sponsors of the Amendment have suggested that Florida's energy prices could be reduced by restructuring, there is no conclusive evidence to support such a conclusion. As discussed below, this is the same conclusion that was reached by the Office of Economic and Demographic Research ("EDR") during the FIEC meeting on February 11, 2019.

Restructuring has been used as a method to attempt to address inefficiencies or high energy prices in particular states. However, as discussed below, Florida does not face the challenges that other states have felt the need to address. The proposed Amendment is a solution in search of a problem.

Florida's Energy Prices are Already Competitive

From 1990 to 2017, rates in restructured markets have been on average 42% percent higher than rates in regulated markets, as shown below.[48] Over the same period, rates in restructured markets have been approximately 26% higher than rates in Florida.

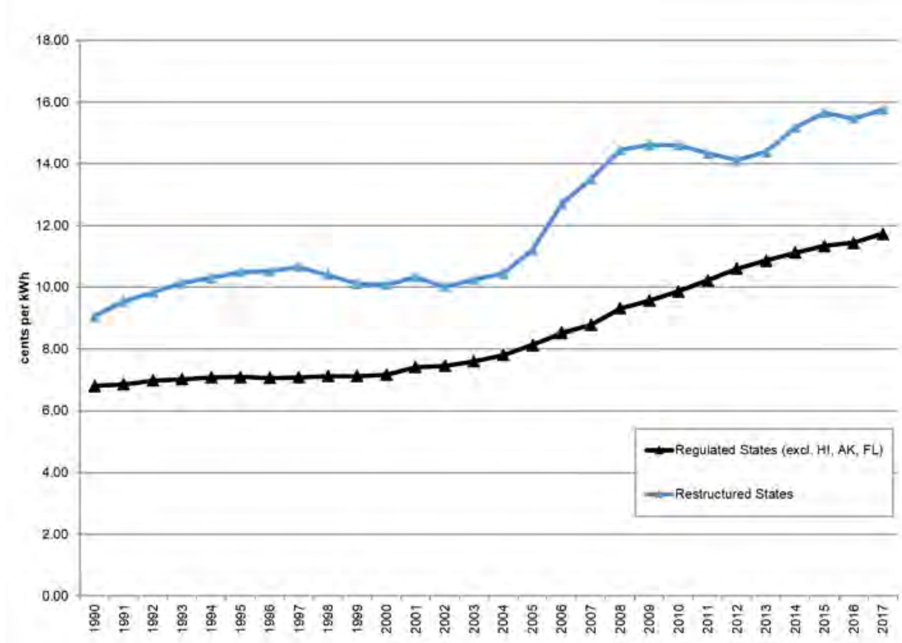
---

46 20.1% of Floridians are over the age of 65, as of July 1, 2018, as compared to the national average of 15.6%; 28.7% of Floridians speak a language other than English at home (from 2013-2017), as compared to the national average 21.3%, and 14% of Floridians live below the poverty line (from 2013-2017), as compared to the national average of 12.3%.
Source: https://www.census.gov/quickfacts/fl; https://www.census.gov/quickfacts/fact/table/US/PST045218

47 Deregulated Electricity in Texas, A History of Retail Competition – The First 10 Years, Appendix C: Electricity Complaints Under Deregulation, Texas Coalition for Affordable Power, found at hhtp://historyofderegulation.tcaptx.com/chapter/appendix-c-electricity-complaints-increase-under-deregulation/, accessed 6/26/2013.

48 Regulated markets exclude Alaska, Hawaii, and Florida.

FIGURE 6: AVERAGE RESIDENTIAL RATE OF RESTRUCTURED AND REGULATED STATES (BEFORE AND AFTER RESTRUCTURING)



Source: EIA Electric Power Monthly, October 12, 2018[49,50]

In the Literature: Assessments of Restructuring

EDR reviewed a wide array of academic and industry literature on the impact of restructuring and provided a summary of its research and findings during the FIEC meeting on Monday February 11, 2019. In particular, EDR reviewed five evaluations of the restructuring experience in the state of Texas, [51] which is described by proponents as the model environment for the Amendment's intent. Each of these resources found that restructuring led to negative or neutral outcomes in terms of cost, customer experience, and other qualitative measures of the benefits promised by advocates of restructuring.

A dissenting report, by the Perryman Group[52] was also mentioned at the FIEC February 11 meetings. The report estimated annual savings to Florida customers if electric restructuring had been implemented. The Study presents two analyses that are based on fundamentally flawed assumptions, and the results do not produce credible indications of changes in electric rates resulting from retail choice. The first Perryman Group analysis examines the changes in retail prices in Texas, adjusted for inflation, prior to and after the introduction of retail choice.

---

49 Rate calculations do not include fuel costs.

50 Restructured states include: CA, CT, DC, DE, IL, MA, MD, ME, MI, NH, NJ, NY, OH, PA, RI, and TX.

51 Texas Coalition for Affordable Power. "Deregulated Electricity in Texas: A Market Annual 2018 Edition" (2018).
Texas Coalition for Affordable Power. "Electricity Prices in Texas: A Snapshot Report, 2018 Edition" (April 2018).
Public Utilities Commission of Texas. "Scope of Competition in Electric Markets in Texas: Report to the 86th Texas Legislature" (January 15, 2019).
Hunter, Tom, Public Utility Commission of Texas. "History of Electric Deregulation in ERCOT" (April 17, 2012).
Public Sector Consultants Inc. "Electric Industry Deregulation: A Look at the Experiences of Three States" (2016)

52 The Perryman Group. "Potential Economic Benefits of Statewide Competition in the Florida Electric Power Market: A Preliminary Assessment" (December 2017).

The second Perryman Group analysis examines changes in retail electric prices for areas in Texas that were restructured and those that were not.

There are several problems with these analyses. First, the changes estimated in Texas occurred over a period when the fundamental economics of the utility industry were changing. The single largest driver of changing electricity costs was the sharp decline in natural gas prices. These lower gas prices flowed through wholesale electric costs for both regulated and retail choice states, but not equally, depending on the degree of reliance on gas for generation. Second, electric rates are the result of many cost drivers that changed over time, and it is not possible to reliably estimate the path of rates absent retail choice over such a dynamic period. Third, even if such results were achieved in Texas, one cannot say such results would apply in Florida with a completely different utility cost structure and generation mix.

Simply comparing electricity prices in Texas that existed prior to 2002 with electricity prices today does not sufficiently account for changes in technology, load, generation mix and fuel costs. Similarly, a comparison of electricity rates in Texas today with those that currently exist in Florida, provides little insight into the rates that would exist in Florida if retail competition was enacted. To suggest an implied reduction in Florida's electric rates is simply not realistic or reliable.

The IOUs have reviewed the reports that were included EDR's review and agree with its conclusion that there is no conclusive evidence of a retail price benefit to restructuring. Therefore, there is no offsetting cost savings to help with the significant cost increases and revenue losses that state the local governments are certain to experience.

State Evaluations of Restructuring Experience

Many states have recently completed evaluations of whether residential and small commercial customers are better or worse off by switching to retail providers. For example, the Massachusetts AG delivered a paper in March 2018 to determine "whether residential consumers in Massachusetts pay more or less for their electric supply when they buy it from the competitive marketplace rather than their electric company."[53] The final analysis showed that:

> "Massachusetts consumers in the competitive supply market paid $176.8 million more than they would have paid if they had received electric supply from their electric company during the two-year period from July 2015 to June 2017. A third year of data shows residential customers lost another $76.2 million, for a three-year total of $253 million."

The Massachusetts AG's recommendation was to eliminate the electric supply market for individual residential customers because the cost of retail supply was higher by far than the basic service provided by the utilities.

Similarly, in New York, the Public Service Commission ("NY PSC") ordered competitive electric suppliers to cease signing up new customers due to customers paying more for electricity provided by competitive suppliers than what they would have paid based on utility rates. The NY PSC order demonstrates the market's poor performance and frustration the commission had in overseeing the competitive retail market for the public's benefit. In particular, the NY PSC wrote:

[53] Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, p. viii.

> "experience shows that, with regard to mass market customers, [energy service companies or "ESCOs"] cannot effectively compete with commodity prices offered by utilities. This may be for a number of reasons, including customer acquisition costs, the greater economies of scale of utilities, and the fact that utilities do not profit from the sale of energy commodity. In addition, the Department of Public Service continues to receive a large number of complaints from ESCO customers about unexpectedly high bills."[54]

Other states have reached similar conclusions after similar reviews. A Rhode Island evaluation conducted over four years found that customers who switched from their utility to retail providers had paid $56 million more than the default service costs.[55] In Connecticut a study completed by the Office of the Consumer Counsel concluded that in 2015 customers who switched to a competitive supplier paid almost $58 million more than they would have if they had remained with their default supplier.[56] A 30-month study conducted by the NY PSC found that customers who switched electric and gas suppliers paid nearly $820 million more than if they had remained with their default suppliers.[57]

The Amendment Would Expose Floridians to More Volatile Energy Prices

If the Amendment is enacted, Florida ratepayers would be exposed to electricity prices for energy and capacity that could be subject to extreme market risks. Due to its unique nature, electricity is the most volatile energy commodity. Moreover, because wholesale electricity markets are an unusual combination of market-driven participants and regulated utilities that are for the most part indifferent to market prices, they harbor higher risk than other commodity markets. This can be seen in the recent history of spot prices of various energy commodities in the U.S. (See Figure 7, below).

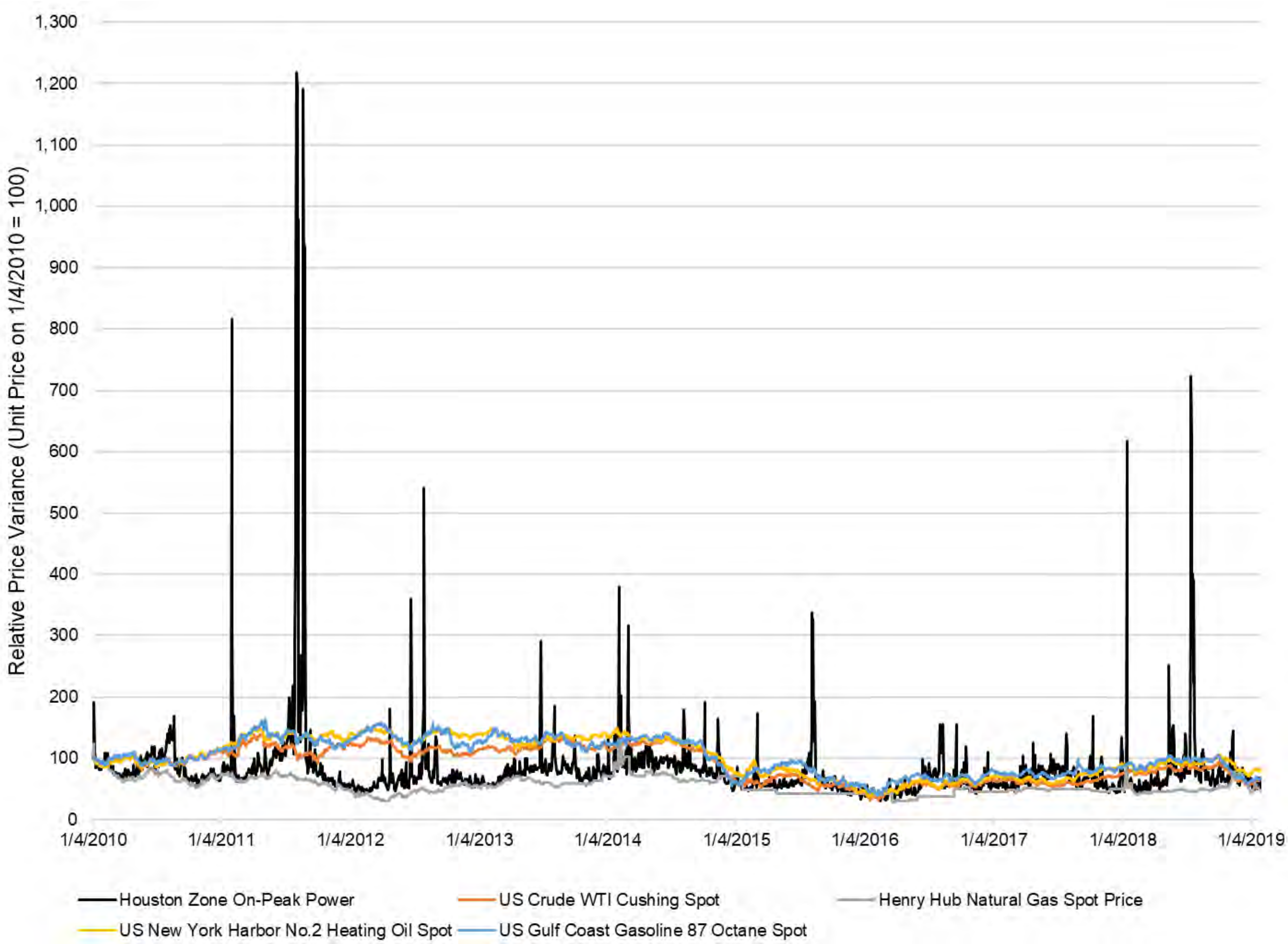
54 New York Public Service Commission Order Resetting Retail Energy Markets and Establishing Further Process, CASE 15-M-0127, (2/23/2016), p. 2. This Order was challenged in the New York court system, and subsequent process is ongoing.

55 National Grid: The Narragansett Electric Company, Standard Offer Supply Procurement Plan / 2019 Renewable Energy Standard Procurement Plan. March 1, 2018, p. 9.

56 Gregory B. Hladky, Study: Consumers Pay Extra for Retail Electricity. Hartford Courant. April 20, 2016. http://www.courant.com/news/connecticut/hc-retail-electricity-costs-above-state-standard-20160420-story.html.

57 Jeff Platsky, AT RISK: NY Reviews Electric, Gas Free-Choice Program; Consumers Ended Up Paying More. Press Connects. February 9, 2018. https://www.pressconnects.com/story/news/2018/02/09/risk-ny-groundbreaking-program-allowing-customers-select-electric-gas-suppliers/302146002/

FIGURE 7: SPOT PRICES FOR POWER AND FUELS (2010-2019)



To the extent the Florida market would embody these risky attributes, as IOUs are removed from the generation marketplace and municipal electric utilities are not, generators in the state would be exposed to more market price volatility than in other regional markets. Layer on top of that Florida's unique geography – a peninsula with more limited transmission access than other parts of the U. S. – and a high degree of reliance on one type of fuel (natural gas) for much of its electric generation, the risk profile of competitive electric generators in Florida would be quite high. Competitive generation risk is generally very high among all industries,[58] and in Florida would almost certainly be even higher.

The Amendment Would Turn the State's Power Plants and Energy Markets Over to Unregulated Companies at the Expense of Floridians

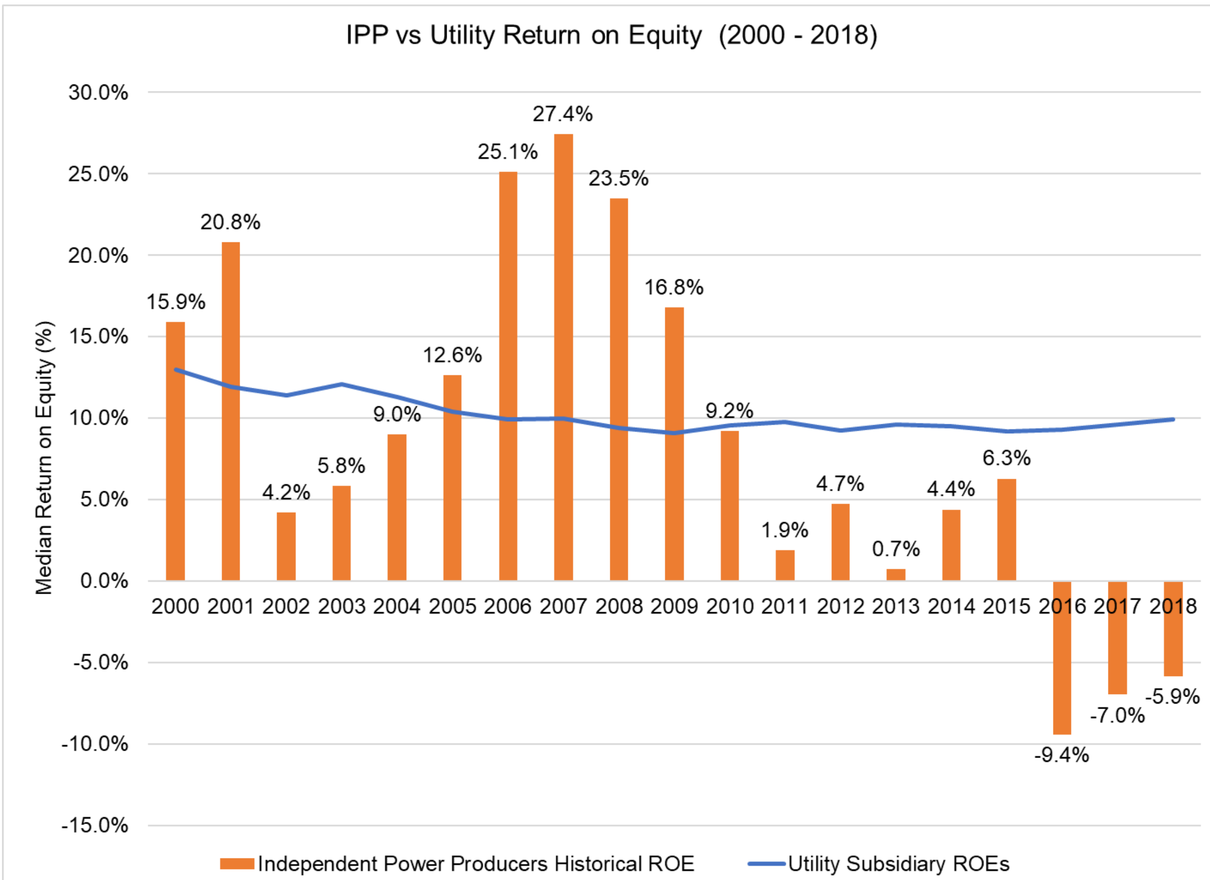
Under the Amendment, IOUs (whose rates are regulated by the Florida Public Service Commission and who currently supply more than 76%[59] of Florida's electric energy at below national average prices) would be

[58] See, for instance, S&P Global Ratings, *Criteria: Key Credit Factors for The Unregulated Power & Gas Industry*, March 26, 2018, where the industry is portrayed as "moderately high risk" compared to the "very low risk" regulated utilities industry.

[59] EIA Table 6, 7, 8, 10 https://www.eia.gov/electricity/sales_revenue_price/

replaced by as yet unidentified electricity providers' whose rates would not be regulated. While the average return on equity ("ROE") allowed by the Florida Public Service Commission for IOUs is approximately 10.3%, some merchant generators have ROEs as high as 19% reflecting the additional risk associated with their business model. Because the risk for merchant generators is so high, tied to the extreme volatility of electricity commodity markets, returns would also underperform at times. The earnings record (see Figure 8) shows this as well, especially in the most recent years following the shock of the 2008 financial crisis and severe recession that followed in the U.S.

FIGURE 8: COMPARISON OF REQUIRED RETURNS FOR INDEPENDENT POWER PRODUCERS, REGULATED UTILITIES[60]



The collapse of industry profitability has important consequences for grid stability and has led to questions about the ability of competitive markets to provide the necessary support for electric system reliability. Florida customers, including municipalities and cooperatives, would consequently be highly reliant on a riskier group of companies for their electricity. Merchant energy companies have experienced much greater periods of financial distress than utilities during the course of electricity restructuring, have had issues with market manipulation and are riskier than regulated electric companies. From the very beginning, the risks of the merchant model became evident as bankruptcies and near-bankruptcies proliferated as early market participants learned to manage the new energy market landscape. The most well-known bankruptcy was that of Enron Corp. in 2001, but there were numerous merchant failures that came in its wake, including high-profile companies NRG Energy in 2002,

60 IPPs in the chart include Allegheny Energy Supply, Calpine, Exelon Generation, FirstEnergy Solution, NRG Energy, PSEG Power and Vistra Energy.

Atlanta-based Mirant Corp. in 2003, and Calpine Corp. in 2005. Another prominent generator, Dynegy Corp., experienced considerable distress at that time but managed to stay afloat until new stresses in merchant generation led to a default in 2012. The merchant energy industry's travails continue to this day, with a 2017 report led by respected Wall Street analyst Hugh Wynne describing the industry as undergoing a "breakdown".[61] The latest industry leaders to fail were Texas-based Energy Future Holdings in 2014 and Mirant-successor GenOn Energy in 2017.

There are numerous examples of market abuses by profit-motivated competitive generators. Since 2007, $332 million in civil penalties for market manipulation actions in electric restructured markets have been imposed by FERC.

Many States have Not Restructured for Good Reason

Currently, 30 states remain fully regulated, while some form of electric retail choice is available in 20 states nationwide. Retail choice in these states varies from full retail choice for commercial, industrial and residential customers to partial retail choice for large industrial customers capped at a percentage of total retail sales. The success of these restructuring efforts in terms of cost to consumer has varied widely. In states that have claimed victory in terms of lower costs to consumers, this is largely due to lower gas prices, and not directly correlated to restructuring. In other states, retail competition has largely been stagnant, and regulators have decided that the risks posed by restructured markets outweigh the potential benefits. As a result, many states that embarked on restructuring efforts have decided to halt or roll back competition.

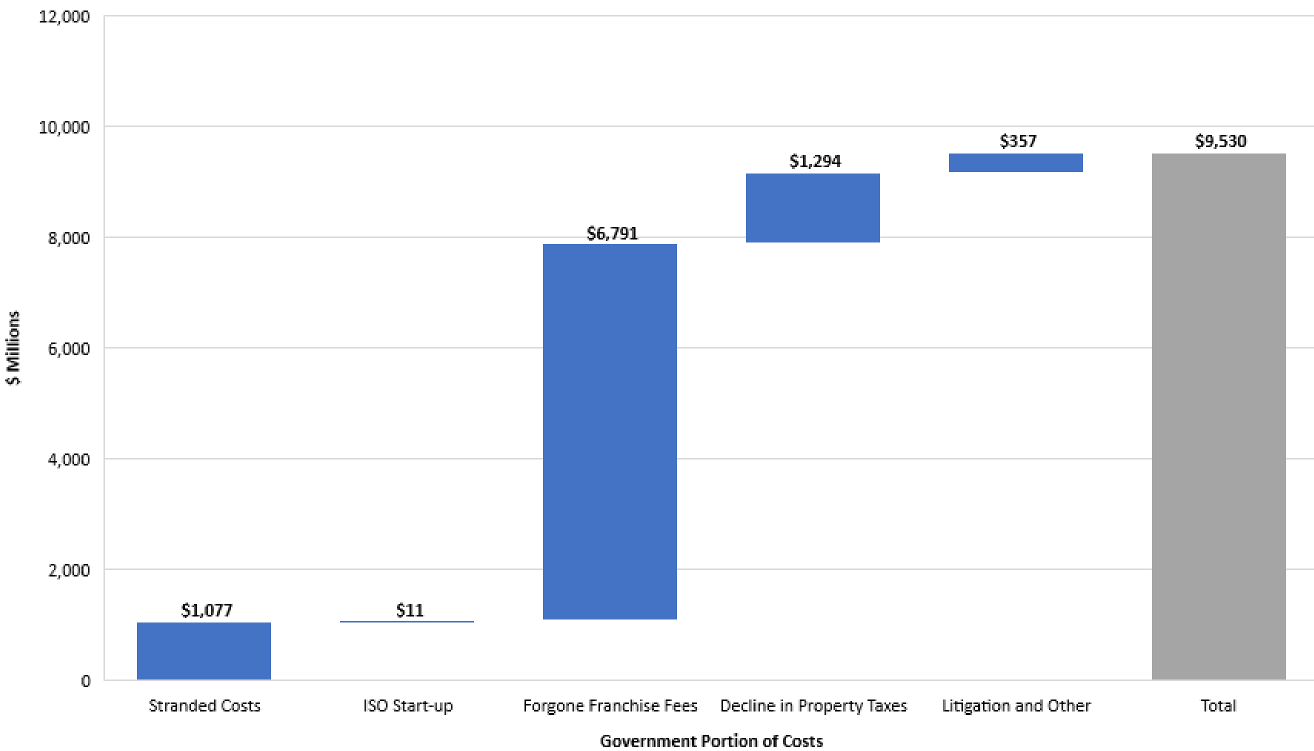
XI. CONCLUSION

The Amendment would negatively impact state and local governments

The financial impact of the Amendment on state and local government is estimated to be no less than $1.3 billion and as much as $1.7 billion in one-time costs and more than $825 million in on-going annual costs and lost revenues. ***Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone, as shown in* Figure 9 *below*.** There are numerous other costs that would be incurred post-restructuring. As such, the cost impact described above is the minimum level that would be incurred by state and local governments. ***The eventual cost to Florida and its governmental agencies would be much larger*.**

[61] The Breakdown of the Merchant Generation Business Model: A clear-eyed view of risks and realities facing merchants, June 2017.

FIGURE 9: IMPACT TO STATE & LOCAL GOVERNMENTS (10 YEARS, $MILLIONS)



The Amendment would:

- Eliminate the state's IOUs from Florida's electric energy market and force the sale or "divestiture" of their 50 power plants, more than 150,000 miles of T&D, and other electric infrastructure, creating ***billions of dollars*** in "stranded" costs which are necessarily compensated by or through government action to avoid an unconstitutional "taking;"
- Require the formation of an ISO, costing customers, including state and local government, ***hundreds of millions of dollars*** in start-up costs and on-going administrative costs;
- Force the state legislature and executive branch of government and other agencies and organizations to expend an ***enormous amount of time, resources and money*** to comply with the Amendment, implement "competitive" electric markets, defend their decisions in litigation, be the ultimate back-stop for market failures and be exposed to substantial new risks;
- ***Put at risk the billions of dollars*** in annual franchise fees and taxes paid by the state's IOUs, resulting in significantly lower revenues to local, municipal and state government;
- ***Put at risk the billions of dollars*** the IOUs have committed in power purchase agreements and natural gas supply and transportation contracts;
- Prohibit municipal and cooperative utilities from purchasing their power from IOUs, abrogating the contracts that are in place and requiring these utilities to find new supplies of their electricity;
- As a replacement, a new market would be created for companies such as the main proponent (Infinite Energy) with no obligation to provide essential electric service to all customers on a non-discriminatory basis and whose rates are not regulated by the state or any other entity;

- Threaten electric reliability and expose Floridians to consumer fraud and market manipulation as has been the experience in states that have restructured their electric markets; and
- Put the state in the position of having to organizationally and financially backstop any aspect of the supply and delivery of electricity if the new market fails in any respect.

If approved, the Amendment would "destructure" not "restructure" the state's electricity markets and cost state and local government $1.3 to $1.7 billion in one-time costs, and in excess of $825 million in annual, ongoing costs, and would dramatically increase the risk and volatility of the state's energy markets. Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone.

APPENDICES

APPENDIX 1: ANALYSIS OF FINANCIAL IMPACT

Purpose

This report was prepared by Concentric Energy Advisors, Inc. ("Concentric") to provide the results of Concentric's analysis of the costs associated with the Florida ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*."

The following costs were considered:

TABLE AP1- 1 RESTRUCTURING COST CATEGORIES

Cost Category	Description
Stranded Costs	Stranded costs are a utility's existing costs that are rendered unrecoverable by restructuring. Examples include: the costs associated with generation assets divested by IOUs where those assets sell for less than the value on the books of the utilities; "out of the money" PPAs and fuel contracts; and regulatory assets on the books of the utilities associated with the generation function.
Franchise Fees and Tax Revenue	A franchise fee is paid for use by utilities of public rights of way and for the right to provide service free from competition by the local government. In those municipalities in which utilities have franchise agreements, the utilities currently pay franchise fees and other taxes in exchange for franchise rights. The loss of this franchise poses a risk to franchise payments to cities in Florida. IOUs also make substantial tax payments related to their generation assets and the sale of electricity, which will be materially reduced if, as has occurred in other states, the utilities' tax bases (*i.e.*, property values and electricity sales) decline.
Creation of a Wholesale Market and ISO Start-up/RTO Integration Costs	Deregulated states have implemented wholesale markets in order to provide transparency regarding generation and transmission costs. Implementation of a wholesale market would have its own costs and would also require a grid operator such as an ISO or RTO, which would lead to additional start-up and ongoing operating costs.
Other Implementation, Litigation and Administrative Costs	Restructuring will increase the burden on state and local governments, including government agencies such as the Florida Public Service Commission. Such costs will be the most significant in the years leading up to and immediately following restructuring.
Impact on Electricity Prices	Many of the costs discussed above, such as stranded costs and reliability costs, will have an impact on the all-in cost of electricity in Florida.

Status Quo

Quantifying the status quo, where applicable, serves two purposes. First, it provides context for the overall scope of the Florida IOUs' generation functions. Second, for many of the components of the cost analysis, the status quo provides the foundation for the cost quantification. The following tables provide the status quo related to key value components that will be impacted by restructuring.

TABLE AP1- 2; TOTAL OPERATING AND PLANNED GENERATING CAPACITY – BY IOU[1]

	Generating Plant Count	Current Capacity (MW)	Planned Capacity (MW)
Florida Power & Light	40	27,848	6,149
Gulf Power Company	8	2,249	3
Tampa Electric Company	20	5,358	2,989
Duke Energy Florida	22	11,466	505
	90	**46,921**	**9,645**

TABLE AP1- 3: TOTAL OPERATING AND PLANNED IOU GENERATING CAPACITY – BY FUEL TYPE[2]

Fuel Type	Generating Plant Count	Current Capacity (MW)	Planned Capacity (MW)
Coal	7	5,699	-
Coal-Derived Syn Gas	1	294	630
Distillate Fuel Oil	3	990	-
Landfill Gas	1	3	2
Natural Gas	33	31,989	5,745
Nuclear	2	3,515	2,200
Oil	-	-	-
Residual Fuel Oil	2	3,308	-
Solar	41	1,123	1,069
Total	**90**	**46,921**	**9,645**

TABLE AP1- 4: NET BOOK VALUE OF FLORIDA IOU GENERATING ASSETS – BY IOU ($000S)[3]

	2013	2014	2015	2016	2017
Florida Power & Light	$13,524,650	$14,773,358	$15,010,672	$17,055,889	$17,094,789
Gulf Power Company	1,732,738	1,684,087	2,091,510	1,996,410	1,998,932
Tampa Electric Company	2,651,400	2,722,089	2,796,700	2,755,288	3,302,925
Duke Energy Florida	3,693,143	3,721,109	3,717,683	3,808,705	4,101,091
Total	**$21,601,931**	**$22,900,644**	**$23,616,565**	**$25,616,292**	**$26,497,737**

1 Source: SNL Financial.
2 Source: SNL Financial.
3 Source: IOU Annual Status Reports.

TABLE AP1- 5: NET BOOK VALUE OF FLORIDA IOU GENERATING ASSETS – BY FUEL TYPE ($000S)[4]

	2013	2014	2015	2016	2017
Net Steam Plant	$6,693,140	$6,872,206	$7,339,182	$7,108,165	$6,940,042
Net Nuclear Plant	5,104,116	5,072,758	5,232,235	5,210,157	5,087,020
Net Hydro Plant	-	-	-	-	-
Net Other Prod. Plant	9,804,675	10,955,679	11,045,149	13,297,970	14,470,674
Total	**$21,601,931**	**$22,900,644**	**$23,616,565**	**$25,616,292**	**$26,497,737**

TABLE AP1- 6: NET BOOK VALUE OF FLORIDA IOU T&D ASSETS ($000S)[5]

	2013	2014	2015	2016	2017
Florida Power & Light	$10,183,209	$10,794,364	$11,706,248	$12,770,622	$14,246,769
Gulf Power Company	1,073,824	1,140,411	1,327,046	1,345,851	1,372,919
Tampa Electric Company	1,647,849	1,698,529	1,779,964	1,981,844	2,878,889
Duke Energy Florida	4,403,026	4,629,665	4,965,051	5,319,531	5,816,800
Total	**$17,307,908**	**$18,262,969**	**$19,778,309**	**$21,417,849**	**$24,315,378**

Note, the net book value data above are as of December 31, 2017. As of the IOUs November 2018 Earnings Surveillance Reports, total net book value of the IOUs assets was over $60 billion.

TABLE AP1- 7: STATE AND LOCAL TAXES AND FRANCHISE FEES PAID BY FLORIDA IOUS IN 2018 ($MILLIONS)[6]

	State		Local			
	Sales Tax & Use Tax	**Gross Receipts Tax**	**Franchise Fees**	**Property Taxes**	**Local Option tax**	**Municipal Utility Tax**
Florida Power & Light	$289.3	$268.7	476.4	$716.4	$14.1	$576.8
Gulf Power Company	$27.9	$32.7	42.8	12.5	2.9	$26.8
Tampa Electric Company	36.0[7]	48.5	46.6	107.0	3.8	58.6
Duke Energy Florida	105.0	112.1	113.3	251.5	6.9	206.0
Total	**$458.2**	**$462.0**	**$679.1**	**$1,087.5**[8]	**$27.6**	**$868.2**

---

4 Source: IOU Annual Status Reports.
5 Source: IOU Annual Status Reports.
6 Source: IOU provided data.
7 Includes sales tax only.
8 Approximately $350.20 million of this amount is paid for Florida IOUs for generation property.

TABLE AP1- 8: TOTAL SALES OF ELECTRICITY (TWH)[9]

	2013	2014	2015	2016	2017	5-Year Average
Florida Power & Light	107.37	112.93	119.41	119.28	117.87	**115.37**
Gulf Power Company	14.91	16.03	14.03	14.62	15.45	**15.01**
Tampa Electric Company	18.64	18.78	19.12	19.44	19.43	**19.08**
Duke Energy Florida	38.16	38.73	39.99	40.66	40.29	**39.57**
Total	**179.08**	**186.47**	**192.55**	**194.00**	**193.04**	**189.03**

Stranded Costs

Concentric's stranded costs analysis uses two sets of market-related data to estimate the level of stranded costs in Florida after restructuring. First, Concentric analyzed data related to stranded costs approved for recovery from electricity customers in other U.S. states that restructured. Second, Concentric reviewed data from recent sales of power plants in the U.S. to estimate generation-related stranded costs in Florida, post-restructuring. The evaluation of recent sales of power plants results in a conservative estimate of stranded costs, as it specifically estimates generation asset-related stranded costs only. In other words, it excludes other sources of stranded costs, such as "out of the money" PPAs and regulatory assets. Appendix 4 Stranded Costs provides background on the other categories of stranded costs.

Concentric's analysis is focused on the generation function. The ballot measure, however, also states that utilities will be limited to the "construction, operation, and repair of electrical transmission and distribution systems." If the IOUs are no longer able to own transmission and distribution assets, that will be another source of potential stranded costs. As provided earlier in this report, as of December 31, 2017 the IOUs had a total of over $24.3 billion in net book value of transmission and distribution assets. Those assets would be at risk if IOU ownership was no longer authorized under the state Constitution.

Stranded Costs Approved for Recovery from Electricity Customers

As discussed above, Concentric analyzed data related to stranded costs approved for recovery from electricity customers in other U.S. states that restructured. Stranded costs analyzed by Concentric were expressed in total and on a dollars-per-kilowatt hour ("¢/kWh") of delivered energy. To arrive at the ¢/kWh of delivered energy, Concentric divided the total amounts of electric restructuring-related stranded costs, by company, by the five-year average annual kWh sales for that utility beginning with and prior to the initial stranded cost authorization date. Expressing stranded costs on a ¢/kWh basis makes it possible to apply this metric to kWh sales in Florida to impute a level of stranded costs for Florida. The tables below provide the results of that analysis.

9 Source: SNL Financial. Includes sales for resale.

TABLE AP1- 9: STRANDED COSTS AUTHORIZED FOR RECOVERY FROM ELECTRICITY CUSTOMERS IN OTHER RESTRUCTURED U.S. STATES[10]

State	Utility	Total Stranded Costs ($ billions)	¢/kWh[11]	Details on Stranded Costs
California	Pacific Gas & Electric	$5.64	7.4	• 1997—$2.9 billion authorized • 2005—$1.9 billion authorized (part of settlement resolving bankruptcy proceeding) • 2005—$844 million authorized
California	San Diego Gas & Electric	$0.70	4.0	• Authorized in 1997
California	Southern California Edison	$2.50	3.3	• Authorized in 1997
Connecticut	Connecticut Light and Power	$1.44	4.8	• Authorized in 2000
Illinois	Commonwealth Edison	$3.40	3.7	• Authorized in 1998
Massachusetts	Boston Edison (NSTAR Electric)	$1.40	8.3	• 1999—$725 million authorized • 2005—$675 million authorized
Massachusetts	Western Mass Electric	$0.150	3.1	• Authorized in 2001
Michigan	Consumers Energy	$0.470	1.2	• Authorized in 2001
Michigan	Detroit Edison	$1.75	3.3	• Authorized in 2000
New Hampshire	Public Service Co. of New Hampshire	$1.21	8.7	• 2000—$575 million authorized • 2018—$636 million authorized

10 Source: Regulatory Research Associates, "Utility Asset Securitization in the U.S.," March 4, 2013.
11 The kWh equals the five-year average of the utility's sales prior to the first year of authorized stranded costs. For utilities for which stranded costs authorization was provided in multiple proceedings, Concentric used the five-year kWh average from the first authorization date.

State	Utility	Total Stranded Costs ($ billions)	¢/kWh[11]	Details on Stranded Costs
New Jersey	Public Service Gas & Electric (PSEG)	$2.65	5.8	• 1999—$2.5 billion authorized • 2005—$150 million authorized
New Jersey	Atlantic City Electric (ACE)	$0.47	5.2	• 2002—$320 million authorized • 2003—$152 million authorized
New Jersey	Jersey Central Power & Light	$0.502	2.4	• 2001—$320 million authorized • 2003—$182 million authorized
New Jersey	Rockland Electric	$.046	3.1	• Authorized in 2004
Pennsylvania	PECO Energy	$5.00	8.8	• 1998—$4 billion authorized • 2000—$1billion authorized
Pennsylvania	PPL Electric	$2.40	6.5	• 1998—$2.4 billion authorized • 2001—$900 million authorized
Pennsylvania	West Penn Power	$0.70	3.1	• 1998—$600 million authorized • 2005—$100 million authorized
Texas	CenterPoint Energy Houston Electric	$4.78	6.5	• 2000—$749 million authorized • 2005—$1.85 billion million authorized • 2006—$488 million authorized • 2011—$1.70 billion authorized

State	Utility	Total Stranded Costs ($ billions)	¢/kWh[11]	Details on Stranded Costs
Texas	AEP Texas Central Co.	$3.38	14.8	• 2000—$797 million authorized • 2006—$1.74 billion million authorized • 2012—$800 million authorized
Texas	Oncor	$1.29	1.3	• 2002—$500 million authorized • 2002—$790 million authorized
Range		**$.05-$5.6 billion**	**1.2¢ - $14.8¢/kWh (average 5.2¢/kWh)**	

As shown in the table above, this measure of stranded costs ranges from 1.2¢/kWh to 14.8¢/kWh. The table below applies that range to IOU sales of electricity in Florida to provide a range of stranded cost estimates.

TABLE AP1- 10: ESTIMATE OF STRANDED COSTS IN FLORIDA BASED ON AMOUNTS AUTHORIZED FOR RECOVERY IN OTHER U.S. STATES

	TWh Sales (5-Year Average)	Stranded Costs (¢/kWh)	Total Stranded Costs
Florida IOUs (based on range of results from the table above)	189.03	1.2¢ - 14.8¢/kwh	$2.2 - $27.9 billion
Florida IOUs (based on average result from the table above)		5.2¢/kWh	$9.8 billion

Stranded Costs Estimated Based on Power Plant Sales

Concentric also reviewed data from recent sales of power plants in the U.S. as a proxy for the values that Florida power plants might sell for as part of restructuring-driven divestitures. By comparing those proxies of value to the Florida IOU's net book value for generation assets, Concentric estimated generation-related stranded costs in Florida as a result of restructuring, as shown below. This analysis was performed by fuel type. A summary of the transactions analyzed is provided in Appendix A to this report. In performing this analysis, Concentric excluded certain of the IOUs generation plants that were nearing retirement.

TABLE AP1- 11: ESTIMATE OF STRANDED COSTS IN FLORIDA BASED ON RECENT ASSET SALES – BY FUEL TYPE[12]

Fuel Type	IOU Plant Count	IOU 2017 Capacity (MW)	2017 Net Book Value ($/KW)	Median Market Comp. Sale ($/KW)[13]	Discount/ (Premium) of Market Value to Net Book Value ($/KW)	% Discount/ (Premium)
	[A]	[B]	[C]	[D]	[E] = [C] – [D]	[F] = [E]/[C]
Coal	6	5,332	1,046	0	1,046	100.0%
Natural Gas	30	28,801	468	420	47	10.2%
Nuclear	2	3,502	1,468	0	1,468	100.0%
Residual Fuel Oil	6	1,051	87	67	21	23.8%
Solar	9	285	2,094	1,252	842	40.2%
MW-weighted Average % Discount/(Premium)						**49.6%**
Total Net Book Value of IOU Generation (ex. near-term retirements) ($billions)						**$24.9**
Estimated Stranded Generation Costs ($billions)						**$12.3**

Based on the analysis above, the estimated market value of the Florida generation fleet is approximately 49.6% less than net book value, on average. Applying that result to the entirety of the Florida IOU generation net book value included in the analysis of $24.9 billion results in a stranded cost estimate (*for generation only*, i.e., before consideration of PPAs, fuel contracts, and other stranded assets) of approximately $12.3 billion, with an impairment (*i.e.*, the difference between market value and book value) range of approximately 10% to 100%, depending on the fuel type.

Stranded Costs Conclusion and Impact on Florida State and Local Governments

Concentric's analyses indicates a range from $9.80 billion to $12.3 billion of potential stranded costs in Florida, based on the average results from stranded cost data in other U.S. states and recent generating plant sales. Looking more broadly at the results (*i.e.*, at the middle 50% of the stranded costs data) provides a range of results from $5.9 billion to $12.8 billion. Those results indicate that stranded costs will be significant, and likely to exceed $10 billion. The results of Concentric's analysis are summarized in the table below.

TABLE AP1- 12: STRANDED COSTS SUMMARY

Stranded Cost Measure	Mean Result ($billions)	Middle 50% of Results ($billions)
Estimate based on stranded costs experience in other U.S. states	$9.8	$5.9 to $12.8
Stranded costs estimated based on sales of power plants	$12.3	

12 As noted above, this analysis excluded certain of the IOUs generation plants. As such, the plant count and capacity figures listed in this table are less than the actual plant count and capacity totals for the IOUs.

13 Note: includes sales across the U.S. for the period 2014 through 2018. Nuclear and coal generation are assumed to have no available market for the sale of those types of plants. As such, the market value is assumed to be $0.

Florida's government agencies currently purchase approximately 11% of the Florida IOU's sales of electricity, based on kWh. Since stranded costs will be recovered from electricity customers, government agencies can expect to bear 11% of those costs. The table below provides those figures.

TABLE AP1- 13: ESTIMATE OF STRANDED COSTS APPLICABLE TO FLORIDA GOVERNMENT AGENCIES

Stranded Costs Borne by Government Agencies (11% of Total)	Mean Result ($billions)	Middle 50% of Results ($billions)
Estimate based on stranded costs experience in other U.S. states	$1.1	$0.6 to $1.4
Stranded costs estimated based on sales of power plants	$1.4	

Franchise Fees and Tax Revenue

As discussed in Concentric's separate report regarding franchise fees and tax revenues, restructuring in Florida puts a significant amount of state and local tax and franchise fee revenue at risk of significant declines. Furthermore, the "Status Quo" section of this report summarizes the current annual tax and franchise fee payments made by the IOUs. The following table provides brief summaries of the specific risks to those taxes.

TABLE AP1- 14: STATE AND LOCAL TAX RISK FACTORS

Tax/Fee	Description	Risk Factors from Restructuring
Sales Tax/Use Tax	6.95% sales tax levied on all sales of bundled electricity to commercial customers. Use tax imposed on utilities for purchases. (certain exemptions apply).	• If sales tax does not apply to unbundled sales of electricity, then customers will not pay sales tax on the transmission and distribution portions of electricity purchases. • Likely loss in revenues from large electricity consumers deciding to purchase electricity from non-Florida suppliers, thereby avoiding the sales tax.
Gross Receipts Tax	2.5% tax on gross receipts of utility companies. These taxes are passed through to customers.	• Applicable sales of electricity could diminish under restructuring as consumers can purchase electricity from suppliers outside of Florida and avoid the gross receipts taxes. • Based on the current phrasing of statute, it is unclear whether the gross receipts tax would continue to apply at all.
Franchise Fees	Typically, 6% fee levied on all electricity sales within municipal boundaries. Specific rates negotiated by municipality and utility.	• At a minimum, franchise fee revenues will decline as electric services are unbundled and generation service is no longer provided by the IOU. Moreover, there is the risk that, in addition to or even superseding the decline in franchise fees attributable to a decline in IOU revenues, franchise fees may no longer be assessable at all depending on the impact that the ballot initiative has on the current laws that allow for franchise agreements, the continued existence of franchises as currently defined by law, and the continued enforceability of franchise agreements.

Tax/Fee	Description	Risk Factors from Restructuring
Property Tax	Up to 10 mills levied by municipalities, counties, school districts and water management districts.	• If regulated utilities divest their generation assets pursuant to industry restructuring, and the sales prices for those assets are at less than net book value, there will be a decrease in the property base and an associated decrease in property taxes, all else being equal.
Local Option Tax	0.5%-2.5% tax levied by counties. Functions as an additional sales tax.	• Like with the sales tax, if local option tax does not apply to unbundled sales of electricity, then customers will not pay the tax on the transmission and distribution portion of electricity purchases. • Likely loss in revenues from large electricity consumers that purchase electricity from suppliers in other parts of the state with less or no local option taxes.
Municipal Utility Tax	Up to 10% tax levied by municipalities and counties on sales of bundled electricity.	• Possible decrease in municipal utility revenues if relevant statutes are interpreted to no longer apply to unbundled sales of electricity.

The most directly quantifiable components of state and local taxes that will be impacted by restructuring are franchise fees and property taxes. Specifically, if franchise fees are eliminated by the ballot measure, that will result in a decline in county and municipal revenue of $679.1 million in franchise fees. In addition, if Florida IOU-owned power plants are sold at a discount to net book value (*i.e.*, stranded costs are created), the property tax basis related to Florida generation will be impaired. Concentric's analysis of stranded costs in other U.S. states indicates that generating property values could be impaired by approximately 36.94% (*i.e.*, $9.80 billion divided by $26.50 billion in generation net book value). Concentric's analysis of U.S. power plant transactions indicate that Florida power plants would sell at a discount of between 10.2% and 100% of net book value, with a weighted average discount of 49.6%. Those new, lower valuations would then flow through to the taxable base, leading to a decline in annual property taxes. The table below provides a summary of the associated forgone annual tax revenues earned by Florida municipalities.

TABLE AP1- 15: PROPERTY TAX IMPACT OF RESTRUCTURING

Valuation Method	Impaired Value %	Total Property Taxes Paid by Florida IOUs for Generation Property ($ millions)[14]	Estimated Annual Property Impact of Restructuring ($ millions)
Stranded costs in other U.S. states	36.9%	$350.2	$129.4
Sales of Power Plant	49.6%		$173.8

Creation of a Wholesale Market and ISO Start-up/RTO Integration Costs

As discussed in Concentric's report titled "Implementation, Litigation and Other Costs," it could take Florida up to five years to implement electric restructuring and then another five to ten years to appropriately implement a working ISO/RTO. The start-up costs could range anywhere between $100 to $500 million with annual revenue requirements in the range of $178 to $228 million.

[14] Source: IOU provided data.

Implementation, Litigation and Administrative Costs

In addition to wholesale market and ISO/RTO start-up and operations costs, there will be litigation, customer education, regulatory and grid reliability costs. While not directly quantified by Concentric, cost estimates from other restructured states for customer education alone have been in the range of $10-$25 million for initial outreach and education, with additional ongoing annual costs. These types of costs are discussed further in Concentric's report titled "Implementation, Litigation and Other Costs."

Other Costs

While not quantified as part of Concentric's initial analysis, there are likely to be other costs borne by the state of Florida and its local municipalities following restructuring. Those include costs related to:

- State and local government administrative expenses to negotiate/procure electricity;
- Loss of Florida jobs;
- Grid reliability measures; and
- Loss of IOU economies of scale.

These costs should be considered as part of the evaluation of the impacts of the ballot measure. Because their quantification is not provided in this report, the estimates of the cost of restructuring that are provided herein likely understate the total cost of the ballot measure.

Impact on Electricity Prices

Many of the costs discussed herein, such as stranded costs and reliability costs, will have an impact on the all-in cost of electricity in Florida. This relative increase in the cost of electricity will directly impact state and local government agencies through their electricity bills. Concentric has not estimated a customer bill impact directly, due to the significant number of assumptions required regarding cost recovery timelines, the financing of stranded costs, and other issues. The customer bill impact of restructuring, however, is likely to be significant, and customers could be paying transition charges for decades.

Conclusions

The following table summarizes Concentric's analytical results related to the costs discussed herein. State and local governments currently purchase approximately 11% of total IOU kWh sales. For those costs that will borne by all Florida electricity customers, the following table also provides the state and local government impact based on their 11% share. For state and local government costs related to forgone fees and revenues, the state and local government impact is equal to the entirety of restructuring's costs.

TABLE AP1- 16: SUMMARY OF RESULTS

Cost Category	Total Quantification/Impact	State and Local Government Impact
Stranded Costs	• $10 billion - $12.3 billion	• $1.1 to $1.4 billion
Franchise Fees and Tax Revenue	• Decrease in *annual* property tax revenues of $129.4 million to $173.8 million	• Property taxes: $129.4 million to $173.8 million

Cost Category	Total Quantification/Impact	State and Local Government Impact
	• Risk of elimination of $679.1 million in franchise fees • Numerous additional risks related to declines in state and local taxes	• Franchise fees: $679.1 million
Creation of a Wholesale Market and ISO Start-up/RTO Integration Costs	• Start-up costs $100 to $500 million • Other costs (e.g., consumer education) of $20 million	• Start-up costs $11.0 million to $55.0 million • Other costs (e.g., consumer education) of $20 million
Annual ongoing ISO costs	• $170 million -$228 million	• $18.7 million to $25.1 million
Litigation Costs	• $150 million to $300 million	• $150 million to $300 million
Other implementation, litigation and administrative costs	• Additional costs to state and local governments related to implementation, litigation, and ongoing administrative costs under restructuring.	
State and local government administrative expenses to negotiate/procure electricity	• Additional costs to state and local governments to procure electricity from new suppliers.	
Florida Jobs	• Job loss due to plant sales and closures.	
Grid Reliability Measures	• Increased electricity costs due to needed infrastructure investments and other costs to mitigate reliability concerns under restructuring.	
Loss of IOU economies of scale	• Increased costs due to lack of scale in decentralized market.	
Impact on Electricity Prices	• Many of the costs discussed above, such as stranded costs and reliability costs, will have an impact on the all-in cost of electricity in Florida.	

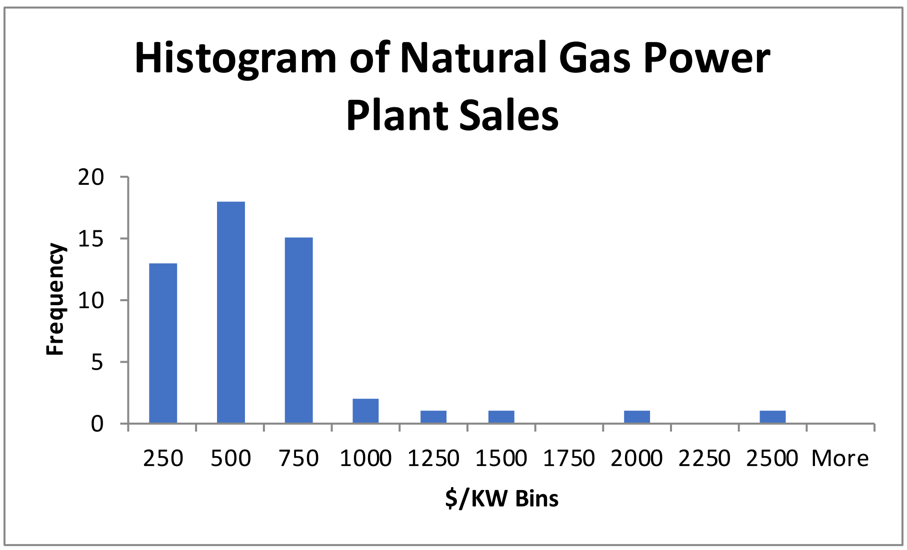
As shown in the table above, significant costs borne by state and local governments can be expected from restructuring. Those costs include both one-time costs (*e.g.*, hundreds of millions of dollars to establish an ISO/RTO) and on-going costs (*e.g.*, stranded costs recovered through electricity rates and declines in taxes and fees).

Attachment A: US Power Plant Sale Summary

U.S. power plant sales data was obtained for the period 2014 through 2018. The analysis focused on power plants transactions that involved only one fuel type (*i.e.*, fleet sales that involved multiple fuel types were excluded).

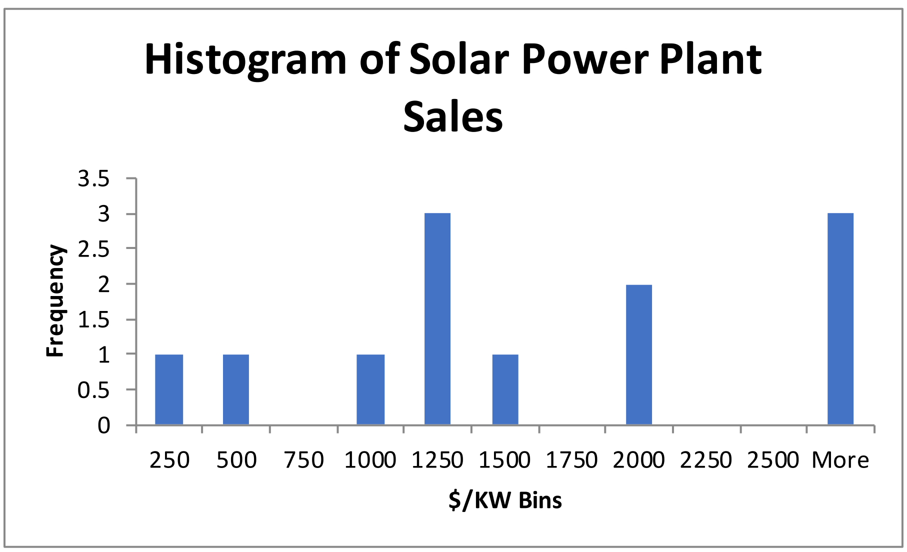
Natural Gas

Average Transaction Value ($/KW)		$494.60
Median Transaction Value ($/KW)		$420.36
Transaction Value Frequency	*Frequency*	*Cumulative %*
$0 - $250	12	23.53%
$250 - $500	18	58.82%
$500 - $750	15	88.24%
$750 - $1,000	2	92.16%
$1,000 - $1,250	1	94.12%
$1,250 - $1,500	1	96.08%
$1,500 - $1,750	0	96.08%
$1,750 - $2,000	1	98.04%
$2,000 - $2,250	0	98.04%
$2,250 - $2,500	1	100.00%
Total	**52**	



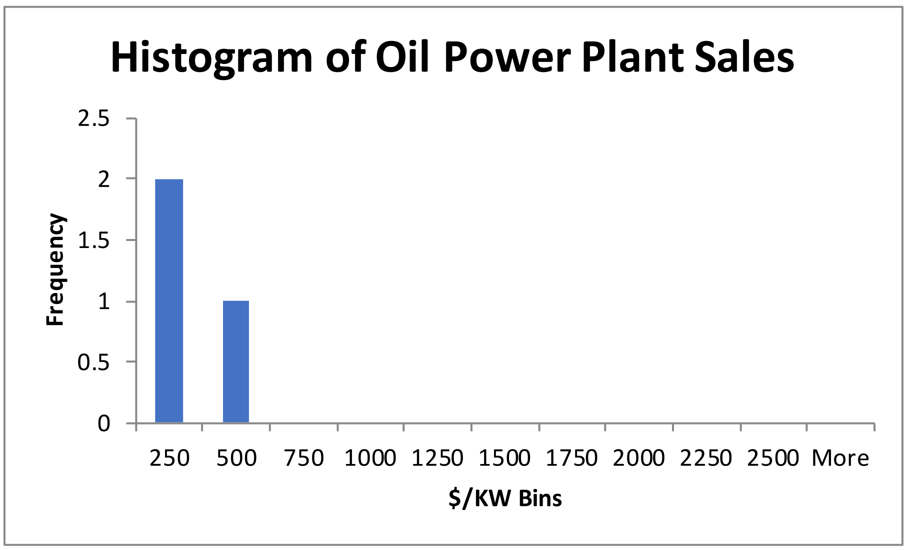
Solar

Average Transaction Value ($/KW)		$1,655.20
Median Transaction Value ($/KW)		$1,251.76
Transaction Value Frequency	*Frequency*	*Cumulative %*
$0 - $250	1	8.33%
$250 - $500	1	16.67%
$500 - $750	0	16.67%
$750 - $1,000	1	25.00%
$1,000 - $1,250	3	50.00%
$1,250 - $1,500	1	58.33%
$1,500 - $1,750	0	58.33%
$1,750 - $2,000	2	75.00%
$2,000 - $2,250	0	75.00%
$2,250 - $2,500	0	75.00%
$2,500 +	3	100.00%
Total	**12**	



Oil

Average Transaction Value ($/KW)		$1,655.20
Median Transaction Value ($/KW)		$1,251.76
Transaction Value Frequency	*Frequency*	*Cumulative %*
$0 - $250	2	66.67%
$250 - $500	1	100.00%
$500 - $750	0	100.00%
$750 - $1,000	0	100.00%
$1,000 - $1,250	0	100.00%
$1,250 - $1,500	0	100.00%
$1,500 - $1,750	0	100.00%
$1,750 - $2,000	0	100.00%
$2,000 - $2,250	0	100.00%
$2,250 - $2,500	0	100.00%
$2,500 +	0	100.00%
Total	**3**	



APPENDIX 2: IMPLEMENTATION AND OTHER COSTS

Purpose of Report

This report was prepared by Concentric to provide information and analysis of the potential implementation, litigation and other costs associated with implementing the ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment").

Background and Key Conclusions

Currently, Floridian's purchase their electricity from either rural electric cooperatives, municipal electric companies or investor-owned utilities ("IOUs"). The state's IOUs are vertically integrated and are regulated by the Florida Public Service Commission and other state and federal regulatory bodies. The Amendment would provide all customers of Florida's IOUs the right to choose their electricity provider. Implementing full retail choice necessitates the design, implementation, and ongoing administration and monitoring of functioning competitive energy markets. The legislature and executive branch will be required to commit time, resources and money to design and implement laws and regulations in an effort to create these markets.

As discussed in more detail below, forming and maintaining a functioning wholesale market is a very lengthy process, which can be litigious, and requires substantial investment in both development and ongoing administrative costs. Initial implementation will take years and is likely to require ongoing refinement extending the timeframe to full implementation of a functioning independent system operator. One-time implementation costs will be no less than $100 million and as much as $500 million or more. On-going, annual costs of administering and monitoring the newly formed competitive markets will be between $200 million and $300 million per year. In addition to these on-going costs, there will be tens of millions of dollars of litigation, customer education, regulatory and grid reliability costs. These costs would be fully borne by the state's electric customers, including state and local government. Finally, if the proposed Amendment is approved, it would be the first time a state restructured its energy markets by amending its Constitution. This is expected to increase the complexity, time, and cost of implementation.

Timeframe – State Restructuring

Through the 1990s and early 2000s a number of state legislators and regulators passed legislation and implemented regulations to provide for retail choice and competitive energy markets. This process took approximately four to five years in most states, but up to ten years or more in some cases.[1] The table below provides a summary of the number of years it took to implement state-level restructuring.

[1] See Pennsylvania and New Hampshire in the table. In Pennsylvania, Legislation was passed in 1996 and price caps for POLR customers were still in place until 2011. In New Hampshire in 2018, Eversource completed the sale of its hydroelectric facilities completing the final milestone in the restructuring of the electric industry in NH after 20 years.

TABLE AP2 - 1:

State	Legislation/ Regulation	Years	# of Years	Restructured Market (Yes/No/ Partial)	Summary
Arizona	Regulation	1999-2003	4	No	Ultimately did not restructure due in part to insufficient competitive suppliers in state. Restructuring was considered again in 2013 but not pursued due to a variety of issues/costs/risks.
California	Legislation	1998-2001	3	Partial	Direct access for all customers was suspended in 2001 because of significant issues and litigation. Currently, there is limited access to competitive electricity for non-residential customers only.
Connecticut	Legislation	1998-2003	5	Yes	All IOU customers have retail choice.
Delaware	Legislation	1999-2006	7	Yes	All IOU customers have retail choice. Rate caps were in place through 2006.
District of Columbia	Regulation, Legislation	1999 -2005	6	Yes	All IOU customers have retail choice. Rate caps were in place through 2005.
Georgia	Legislation	1973	N/A	Partial	Choice for commercial and industrial customers with load of 900 kW or more only.
Illinois	Legislation	2002-2007	5	Yes	All IOU customers have retail choice. Rates were frozen through 2007.
Maine	Legislation	1997-2000	3	Yes	All IOU customers have retail choice.
Maryland	Legislation	2000-2008	8	Yes	All IOU customers have retail choice. Rate stabilization plans (rate caps) were in place through 2008.
Massachusetts	Legislation	1997-1999	2	Yes	All IOU customers have retail choice. Rate were frozen for specified periods of time for each utility.
Michigan	Legislation	2000-2006	6	Partial	Currently under state law, no more than 10% of an electric utility's average weather-adjusted retail sales for the preceding calendar year may take electric choice service from an alternative electric supplier at any time. If your utility's 10% cap is fully subscribed, you will be placed in its queue. Residential rates were initially capped until 2006.
Montana	Legislation	1997-2000	3	No	In 2007 Legislation repealed competition entirely.
Nevada	Legislation	1997-2002	5	Partial	Failure of CA restructuring effort led to a repeal of retail access for residential customers in 2001. Retail law enacted in 2002 allows choice for commercial/industrial/governmental end users with load of 1 MW or more. Ballot initiative to introduce retail energy choice for all customers failed in 2018.
New Hampshire	Legislation	1998-2018	20	Yes	All IOU customers have retail choice. Significant litigation followed the NH PUC's 1997 approval of a restructuring plan. PSNH finally divested its generation assets in 2018.

State	Legislation/ Regulation	Years	# of Years	Restructured Market (Yes/No/ Partial)	Summary
New Jersey	Legislation	1999-2003	4	Yes	All IOU customers have retail choice. Rate reductions and rate caps were implemented through 2003.
New Mexico	Legislation	1999-2002	3	No	Retail competition law repealed in 2003.
New York	Regulation	1996-1998	2	Yes	All IOU customers have retail choice.
Ohio	Legislation	1999-2008	9	Yes	All IOU customers have retail choice. Rates were frozen through 2005 and rate stabilization plans were in place through 2008.
Oregon	Legislation	1999-2002	3	Partial	Commercial and industrial IOU customers using at least 30 kW per month have retail choice
Pennsylvania	Legislation	1996-2011	15	Yes	All IOU customers have retail choice. Rates were frozen in some instances through 2011.
Rhode Island	Legislation	1996-1998	2	Yes	All IOU customers have retail choice.
Texas	Legislation	1999-2006	7	Yes	All IOU customers have retail choice. Customers that did not select a generation provider were serviced under a price to beat (rate cap) through 2006.
Virginia	Legislation	1999-2004	5	Partial	Non-residential customers (customer with annual demand greater than 5 MW) have retail choice. 2007 legislation repealed 1999 restructuring statutes and limited retail access to large non-residential customers.

Source: SNL, American Coalition of Competitive Energy Suppliers

A technical report written by the Guinn Center regarding the 2018 Nevada Retail Choice Ballot Initiative provides additional information on the implementation of electric restructuring in several states in the U.S. For instance, the study notes that:

> New Jersey produced one investigative study, three pieces of legislation, and seven regulatory orders by 2000. New York had three investigative studies, three pieces of legislation, and six regulatory orders through 2001. Ohio conducted one investigative study, enacted one piece of enabling legislation, and issued twelve regulatory orders through 2002. Texas released six investigative studies, enacted four pieces of legislation, and implemented nineteen regulatory orders by 2002. As one report notes, though, the state did not anticipate certain issues in its enabling legislation; they only came into full view during the implementation phase and include information technology struggles, setup of the POLR (i.e., the safety [net] for those instances in which the retail supplier cannot continue service), costly market redesign (related to issues regarding market manipulation and a need to redesign the wholesale market), and stranded costs.
>
> Michigan perhaps best exemplifies the challenges surrounding implementation of retail electric choice, as its plans were considered carefully yet thwarted through the process. In 2000 two companion pieces of legislation—Public Act 141 and Public Act 142—were enacted to enable restructuring. Five regulatory orders had been issued through August 1999 to lay the groundwork for a retail electric choice market. By 2002, the Michigan Public Service Commission implemented 25 additional regulatory orders. Michigan requires annual reports on the status

of electric competition in the state. Its report for 2006 states that "the Commission issued 40 orders to further establish and implement the framework for Michigan's electric customer choice programs and the provisions of 2000 PA 141.[2]

The struggles discussed above were very common during the 1990s and early 2000 as states proceeded with energy restructuring implementation. Given the fact that the proposal is a constitutional Amendment, the complexity of implementation in Florida is expected to be even higher than that experienced in other states. No state has imposed retail choice and competitive wholesale and retail electric markets through a constitutional Amendment.

Timeframe – ISO/RTO Implementation

At the same time that states began restructuring their retail electric markets, FERC issued Orders 888 and 889 establishing and promoting competition in the wholesale market by ensuring fair access and market treatment to customers. Order No. 888 introduced the concept of ISOs as a way as a way of administering the transmission grid non-discriminately on a regional basis. In FERC Order No. 2000, the Commission encouraged the voluntary formation of RTOs. The Order required an RTO to have four basic characteristics: 1) it must be independent of market participants; 2) it must service an appropriate region of sufficient scope and configuration to permit it to maintain reliability; 3) it must have operational authority overall transmission facilities under its control; and 4) it must have exclusive authority for maintaining the short-term reliability of the grid that it operates. As shown in the table below, the establishment of the ISOs/RTOs was an evolutionary process and, in some cases, it took many years to complete.

TABLE AP2 - 2: ISO/RTO DEVELOPMENT OVER TIME

ISO/RTO	Timeline
CAISO[3] (CA)	The California ISO was created in September 1996 as a nonprofit public benefit corporation with the passage of California Assembly Bill 1890 that restructured the state's power market. It incorporated in May 1997 and in March 1998 began serving 80 percent of the state, or 30 million people, with the purpose of managing the state's transmission grid, facilitating the spot market for power and performing transmission planning functions. The California Power Exchange operated the state's competitive wholesale power market and customer choice program until the 2000-2001 energy crisis forced it into bankruptcy in January 2001. The exchange ultimately ceased operation leaving the state without a day-ahead energy market until spring 2009 when the ISO opened a nodal market.
ERCOT[4] (TX)	Formed in 1970, established as an ISO in 1996, with certain market protocols established by 2000. In 2001, wholesale power sales between electric utilities began as the existing 10 control areas in ERCOT consolidated into one. In 2002, retail electric markets opened. A nodal market, featuring locational marginal pricing for generation at more than 8,000 nodes was finally launched in 2010 after over six years of planning.

2 Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, at 68.
3 California Independent System Operator Corporation, 2010 ISO/RTO Metrics Report, Appendix D, at 28.
4 History of ERCOT, http://www.ercot.com/about/profile/history.

ISO/RTO	Timeline
SPP[5] (AR, IO, KS, LA, MN, MT, MO, NM, ND, OK, SD, TX, WY)	Formed in 1941, SPP joined NERC in the 1960s. SPP implemented a regional open-access tariff in 1998. The tariff provided non-firm and short-term firm, point-to-point transmission service across the systems of 14 members. Long-term firm service followed in 1999 and network service in 2001. It took SPP several attempts before the FERC gave it RTO status in 2004. In 2007, SPP implemented the Energy Imbalance Service, which took two years to put in place at a cost of $33 million.
MISO[6] (AR, IL, IN, IO, KY, LA, MI, MN, MS, MO, MT, TX, WI)	MISO was initially established in 1998. FERC accepted MISO's organizational plan and initial transmission tariff on Sept. 16, 1998, then approved the MISO as an RTO in December 2001. On April 1, 2005, MISO launched the Energy Markets and began centrally dispatching generating units throughout much of the central United States based on bids and offers cleared in the market.
PJM[7] (DE, IL, IN, KY, MD, MI, NJ, NC, OH, PA, TN, VA, WV, DC)	Founded in 1927 as a power pool, PJM opened its first bid-based energy market on April 1, 1997. Later that year, the FERC approved PJM as an ISO. In 2000, PJM launched both a market for regulation service, its first ancillary services market, and the Day-Ahead Energy Market. PJM became an RTO in 2001. From 2002 through 2005, PJM integrated several utility transmission systems into its operations. They included: Allegheny Power in 2002; Commonwealth Edison, American Electric Power and Dayton Power & Light in 2004; and Duquesne Light and Dominion in 2005. These integrations expanded the number and diversity of resources available to meet consumer demand for electricity and increased the benefits of PJM's wholesale electricity market. In 2007, PJM completed its first capacity auction under the Reliability Pricing Model which secures power supply resources for the future.
NYISO[8] (NY)	The creation of the NYISO was authorized by the FERC in 1998. In November 1999, New York State's competitive wholesale electricity markets were opened to utility and non-utility suppliers and consumers as the NYISO began its management of the bulk electricity grid. The formal transfer of the grid operation responsibilities from the New York Power Pool to the NYISO took place on December 1, 1999. NYISO studied the implementation of a forward capacity market but did not implement this market change.
ISO-NE[9] (CT, MA, ME, NH, RI, VT)	The New England Power Pool was established in 1971. In 1997, ISO New England ("ISO-NE") was created to operate the regional power system, implement wholesale markets, and ensure open access to transmission in New England. In 1999 ISO-NE launched a regional wholesale electricity markets to expand its competitive market to regional generation and sales of wholesale electricity. In 2003 ISO-NE added locational pricing, day-ahead and real-time markets to more accurately reflect the cost of wholesale power and provide clearer economic signals for infrastructure investment. In 2005, ISO-NE began operation as an RTO assuming broader authority over day-to-day operation of region's transmission system. In 2006, ISO-NE launched locational a forward reserve market for better valuation of reserves. In 2008, ISO-NE launched a new Forward Capacity Market to replace the old ICAP market.

As shown above, there are numerous steps required to form an RTO, with many regulatory approvals along the way, including:[10]

5 The Power of Relationships, 75 Years of Southwest Power Pool, Nathania Sawyer and Les Dillahunty, 2016.

6 Midwest Independent Transmission System Operator, 2010 ISO/RTO Metrics Report, Appendix E, at 144. MISO History, https://www.misoenergy.org/stakeholder-engagement/learning-center/miso-history.

7 PJM Interconnection, 2010 ISO/RTO Metrics Report, Appendix H, at 260.

8 New York Independent System Operator, 2010 ISO/RTO Metrics Report, Appendix G, at 196.

9 New England Independent System Operator, Our History, https://www.iso-ne.com/about/what-we-do/history.

10 For the most part these steps are dependent on the previous approval.

- Negotiations among the various stakeholders on operating protocols and RTO structure (a year or longer);
- Filing and approval with the FERC (six to eighteen months);
- Additional FERC filings to transfer operational control of transmission assets (at least six months);
- Modifications to existing transmission Open Access Transmission Tariffs (twelve months or longer);
- Additional approvals from other reliability governing bodies (six months or longer);
- Once approved, developing operating systems, policies and staffing (a year or longer); and
- Development of an internal market monitoring function and retention of a qualified independent market monitor to identify and report market violations, market design flaws and market power abuses.

In addition, all the following must be addressed when designing the market and determining competition rules. This process also could take several years.

- Capacity, ancillary and energy markets: Rules and rates must be established to set up each of these markets and trading policies.
- POLR: Rates and rules must be set for the POLR, the provider who must serve a customer when another provider defaults or drops a customer. This includes determining who the POLR would be.
- Generation divestiture: Existing utilities may be required by restructuring rules to sell off or spin off their power generation business.
- Stranded costs: A process must be put in place for existing utilities to recover investments made in power plants.
- Systems and Processes: Computer information systems and cybersecurity protocols must be established and procedures for switching customers to and from retail suppliers must be revisited.[11]

Overall, the initial formation of an ISO/RTO and establishment of energy, ancillary and potentially capacity markets and related financial hedging tools should be expected to take at least five years and an investment in the hundreds of millions of dollars. Further, the issues and effort to operate in the resulting new environment, regulated by FERC, must be considered. Considerable investments will be required to develop information systems to operate new markets and to form a new legal entity that will have hundreds of employees.

As discussed in APPENDIX 9 Wholesale Market Implementation, markets that have long since restructured are still struggling with updating existing rules and writing new rules as they learn from their experiences. Almost twenty years after the initial market transition restructured markets are still "changing." For example, in New England, there is a large emphasis on state policies for clean energy. Wholesale energy markets were not designed to address public policy mandates, and the influx of state-sponsored clean energy resources have challenged the wholesale market design. As a result, the New England ISO must continually make changes to the market structure to address the unintended consequences of these resources on the market. If Florida pursues retail restructuring it should expect to spend years participating at the FERC developing the market model and rules and then participating at the FERC in perpetuity as the model evolves.

[11] The Commission approved Statewide Standards and processes established by the Process Standardization Working Group must be reevaluated.

Implementation Costs

Estimates

Estimates of the cost to form an RTO/ISO range from $100 million to upwards of $500 million and could take up to ten years to fully implement. Concentric has reviewed several papers that have estimated the cost to implement an ISO/RTO like structure.

Most recently, the Public Utilities Commission of Nevada ("PUCN") was asked by the Nevada Governor's Committee on Energy Choice to open an investigatory docket to examine issues related to Nevada's Energy Choice Initiative. The PUCN finalized the Energy Choice Initiative Final Draft Report ("PUCN Report") in April 2018. The PUCN Report noted the following:

> NV Energy states that a Nevada-only ISO would have new operational and administrative costs that would be paid by all Nevadans NV Energy estimates that it would cost approximately 100 million dollars in new investment for NV Energy to set up a Nevada-only ISO wholesale market. This estimate does not include ongoing annual costs to operate the wholesale market.
>
> ***
>
> NV Energy estimates it will take 6 to 10 years to fully establish a Nevada-only ISO. This estimate is based on Nevada stakeholders needing one year or more to establish governance and a process to identify a market operator. This step could be shortened if the Nevada State Legislature designates NV Energy to perform the system and market operator functions. Thereafter, two to three years would be needed for a stakeholder process to establish the complex tariff for rules, price formation, and settlement formulas needed for the wholesale market operation systems. Like Nevada joining CAISO, FERC approval would be necessary.[12]

In addition, the PUCN Report noted, there would be ongoing costs associated with operating and maintaining the new ISO/RTO. Specifically, the PUCN Report stated that a key finding was "Adding up these yearly maintenance costs totals approximately 45.7 million dollars…"

In 2017, the California ISO formed the "Committee on Energy Choice Technical Working Group on Open Energy Market Design & Policy". The President and CEO, Steve Berberich, presented findings from the Committee that concluded that "creating a new ISO could cost upwards of $500 million." He also noted that when the CAISO nodal market went live in 2009, it cost approximately $200 million and the Texas nodal market cost $600 million.[13]

In 2004, FERC studied the cost of developing an ISO/RTO. The Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization ("FERC RTO Cost Report") was written to:

> …inform the Commission and facilitate discussions with the industry and the states regarding Regional Transmission Organization (RTO) formation. Specifically, the purpose of this Study is to estimate the cost of developing a Day One RTO that provides independent and non-discriminatory transmission service and satisfies the minimum requirements of Order No. 2000

12 Energy Choice Initiative Final Draft Report, Public Service Commission of Nevada, April 2018, at 79-80.

13 California ISO, Committee on Energy Choice Technical Working Group in Open Energy Market Design & Policy, July 10, 2017. Nodal ERCOT Program Update from November 2010, noted cumulative actual and forecast costs for the nodal program of $526.1 million.

> to operate as an RTO. Further, the Study estimates the annual operating expenses necessary to run such an organization. Estimates of the costs of RTO formation vary widely and market participants cite the cost of RTO development as a significant barrier to RTO formation.

FERC concluded that the Day-1 RTOs required investments of between $38 million to $117 million, which converts to 2018 dollars of $54 to $167 million. The information included in this report came from PJM, MISO, ERCOT and SPP and only included implementation and estimates of revenue requirement costs through 2000, therefore missing any costs added after that time. It should be noted that Day-1 RTO costs (as shown in the table below) only include the following: 1) administration of open access transmission tariffs; 2) performance of reliability functions and transmission planning; and 3) management of transmission through traditional methods, such as redispatch and transmission loading relief. On the other hand, Day-2 RTO costs include the administration of the same functions as Day-1 RTOs but also include costs associated with market operations for day-ahead and real-time energy, and for transmission congestion. In addition, many Day-2 RTOs operate ancillary services markets and capacity markets. The cost to implement a Day-2 RTO is much higher since there are additional systems that must be added for day-ahead and capacity and ancillary services markets. In order to achieve the promised benefits of full retail reform in Florida, a functioning day-2 electricity market is necessary to facilitate the buying and selling of electricity for all retail customers.

GridFlorida

FERC Order 2000 required all public utilities that own, operate or control interstate transmission facilities to file a proposal to form or participate in an RTO. In response to the FERC, FPC now Duke Energy Florida, FPL and TECO engaged the consulting Firm ICF to develop a proposal referred to as "GridFlorida." GridFlorida conducted a study to determine the costs and benefits of developing and operating an RTO for Florida. The study found the following:

> The ICF Cost-Benefit Final Report concludes that the prospect of a basic Day-1 RTO operation as proposed are "bleak," with the Peninsula Florida costs exceeding the Peninsula Florida benefits by over $700 million over the three-year operating period. Under a more advanced Day-2 RTO operation ICF concludes that the total project benefits are a negative $285 million in Peninsular Florida over the ten-year operating period.[14]

In 2018 dollars the costs would exceed the benefits by $1 billion for basic Day-1 RTO operations and over $400 million over the ten-year operating period. As a result of the ICF study, FPC, FPL and TECO withdrew their proposal for GridFlorida. The Florida Commission and the FERC granted an approval of the withdrawal.

Actual Costs

The actual implementation costs for the development of the ISOs/RTOs noted above is difficult to calculate since they were developed, in some cases over several years or decades through many different iterations. Concentric has researched background cost information for ISOs/RTOS and found the following:

[14] Before the Public Service Commission of Florida, Docket No. 020233-EI, Order No. PSC-06-0388-FOF-EI, May 9, 2006.

TABLE AP2 - 3: ESTIMATE OF COSTS TO IMPLEMENT EXISTING ISO/RTOS

ISO/RTO	Implementation Cost
CAISO	No publicly available data found
ERCOT	Day 1 estimates of $179 million with 188 employees, with an estimated annual budget of $101 million.[15]
SPP	Day 1 estimate of $60 million with 140 employees, with an estimated annual budget of $56 million.[16]
MISO	Day 1 estimates of $184 million with 187 employees, with an estimated annual budget of $115 million.[17]
PJM	Day 1 estimates of $110 million with 263 employees, with an estimated annual budget of $122 million.[18] Day-2 estimate of capital investment of additional $332.6 million
NYISO	No publicly available data found
ISO-NE	No publicly available data found

Further, once an ISO/RTO is established, it must evolve. For example, PJM opened a new control room in 2001. That control room took five years to construct and cost approximately $215 million to place in service.[19] Those costs are not included in the table above.

GDS Associates, Inc. ("GDS") produced a report in 2007 that compared the 2001-2005 actual annual costs of all U.S. RTOs excluding ERCOT. That study found the following:

> Over the five-year study period 2001-2005, total aggregate costs increased for ISO-NE by 98 percent, for MISO by 228 percent, for NYISO by 66 percent, and for PJM by 94 percent. Costs for CAISO declined.[20]

GDS noted that the main reason for the 228% increase in MISO costs was because of the start-up of the MISO energy market in 2005. This cost was not included in the Day-1 costs noted in the table above since that is a Day-2 market operation. Prior to implementing the energy market, MISO had to invest in new systems and additional staff to support the energy market.[21]

Designing markets is certainly not a "one and done" activity, nor is it limited to state-wide issues. In fact, states with retail electricity competition have continually shifted their policies with respect to retail access and retail rates, to address obvious flaws in the initial market design. Wholesale electric markets that have long since restructured are still struggling with updating existing rules and writing new rules as they learn from their experiences, especially in the area of providing sufficient incentives to encourage necessary investment in infrastructure. In addition, IOUs have to continually evolve to address state policies and priorities, such as

15 Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization, Docket No PL04-16-000, October 2004, Exhibit 3, page 1. Converted to 2018 dollars.

16 Ibid. Converted to 2018 dollars.

17 Ibid. Converted to 2018 dollars.

18 Ibid. Converted to 2018 dollars.

19 PJM prepare to open 2nd control center, SNL Financial, October 24, 2001.

20 American Public Power Association, Electric Market Reform Initiative, Task 2, Analysis of Operational and Administrative Cost of RTOs, February 5, 2007, Prepared by GDS Associates, Inc. This study analyzed annual costs, not implementation costs.

21 Ibid., at 22.

legislation requiring utilities to solicit and enter into long term contracts for renewable energy (e.g., Massachusetts).[22]

The interplay between competitive wholesale electricity markets and state-level retail access has also caused conflict. As shown by the examples of Maryland and New Jersey, state regulatory bodies have found it necessary to actively participate in FERC-regulated wholesale markets by passing legislation that allows customers of investor-owned utilities to help finance new power plant construction in an effort to address serious reliability concerns after the market consistently failed to result in new projects within their higher-priced PJM zones. The cost for these kinds of legal battles has been significant.

On-Going Administrative Costs

In addition to the upfront implementation costs, there are on-going annual costs to administer an ISO/RTO. Those costs include, but are not limited to, salaries and benefits for employees, IT costs, hardware and software maintenance costs, consultant costs, marketing monitoring costs and training and travel costs. ISOs/RTOs are sophisticated organizations with substantial organizational infrastructure and employees. The table below provides information on the 2019 Budgets for U.S. ISOs/RTOs.

TABLE AP2 - 4: ANNUAL BUDGETS FOR EXISTING ISO/RTOS (2019)

ISO/RTO	2019 Budget ($000,000s)	Employees
CAISO[23]	$193.5 ($0.807/Mwh)	643
ERCOT[24]	$228.01 ($0.555/Mwh)	749
SPP[25]	$193.8	~605
MISO[26]	$339.8	~900
PJM[27]	$363.08	~920
NYISO[28]	$168.2 ($1.071$/Mwh)	~570
ISO-NE[29]	$196.90 ($1.310/Mwh)	~584

The FERC RTO Cost Report discussed above noted that annual revenue requirement estimates for 2004 were between $35 million to $78 million, which converts to 2018 dollars of $50 million to $111.5 million. As one can see from the table above those past estimates are considerably lower than the current 2019 budgets for an ISO/RTO. NYISO's 2019 Budget of $168.2 million is one of the lowest, yet considerably higher than what was

22 These types of policies essentially provide out of market revenue that distorts the price formation of the market for non-renewable resources (i.e., essentially suppresses the price because these resources can bid in at a very low price, because they get their revenues elsewhere).
23 CAISO Briefing on Draft FY2019 Revenue Requirement, November 13, 2018.
24 ERCOT's 2018/2019 Biennial Budget Submission.
25 SPP 2019 Budget Preliminary Draft, Prepared by Accounting Department, 10/8/2018.
26 2019 Budget, Board of Director Meeting, December 6, 2018. Budget of $339.8 includes both operating and capital budgets.
27 Finance Committee Letter to the PJM Board, September 21, 2018.
28 NYISO 2019 Budget Overview, October 31, 2018.
29 ISO New England Proposed 2019 Operating and Capital Budgets, August 10, 2018.

estimated by the FERC. The FERC RTO Cost Report estimated 2004 PJM staff of 263, increasing to 328 in 2005. As shown above, PJM has total staff in 2018 of approximately 920, over three times as many staff members as estimated in 2004.

Other Costs

There are various ongoing costs that will be incurred by Florida utilities and ultimately ratepayers if the ballot initiative proceeds. Since Nevada most recently went through an energy choice ballot initiative the information that was revealed throughout that process is very informative. For instance, the PUCN Staff studied the cost for consumer education and outreach and received information from the Texas Commission personnel that noted that Texas had a budget of $24 million dollars to educate customers during the first two years after retail choice was implemented. The annual budget in Texas for consumer outreach is $750,000. PUCN Staff also found that Pennsylvania spent $15.5 million dollars for customer education and outreach. With that information as a backdrop, the PUCN determined that given Nevada's size and based on what other states have spent that, Nevada would need to spend at least $10 million for its initial consumer education and outreach.[30] Other costs not quantified included hiring additional customer service representatives to deal with complaint and bill resolution pertaining to issues with implementing a restructured market.

The PUCN Staff report discussed various other costs including, specific software and computer system technology costs for NV Energy for both wholesale and retail markets, potential increased costs to maintain electric grid reliability, new costs associated with maintaining the new systems created to implement the Energy Choice Initiative, including approximately $2.2 million for increased PUCN regulatory and increased workload costs. Finally, and maybe most importantly, the PUCN paper notes that "regulatory uncertainty is generally bad for business". A review of all the possible costs ended with a conclusion by the PUCN Staff that it is reasonably likely that these costs will be added to Nevadan's monthly electric bills in an open and competitive electric market.[31] The prospect of multi-year implementation of energy choice in Florida could be stalling development since its unknown outcome could be financially disruptive.

Some of the costs discussed above will be borne by regulatory agencies, others by market participants, but in the end, all will be borne by ratepayers.

Potential Litigation

The implementation of certain states' retail restructuring plans in the late 1990's and early 2000s were fraught with litigation, including California, Montana, Nevada and New Hampshire. This same type of litigation could occur in Florida, which could add significant expense, time and headache to the electric restructuring process. The PUCN Staff study notes that:

> If history is a guide to the future, then the future will likely hold significant state and federal court litigation for Nevada if the Energy Choice Initiative passes. Nevada's exploration into deregulation in the 1990s resulted in state and federal lawsuits. Litigation was commenced in state court before the First Judicial District Court, State of Nevada in Carson City Case No. 00-00416A in the year 2000. Litigation was also commenced in federal court in the United States District Court, District of Nevada Case No.CV-N-00-0157- DWH-VPC, in the year 2000,

30 PUCN, Energy Choice Initiative Final Draft Report, Docket No. 17-10001, April 2018, at 62-63.
31 Ibid., at 65-67.

whereby Nevada Power Company and Sierra Pacific Power Company (NV Energy) sued the PUCN for injunctive and declaratory relief.

In federal court, NV Energy raised, among other things, federal claims that Nevada violated NV Energy's rights under the United States Constitution and that actions to deregulate were superseded by federal laws and violated the Supremacy Clause, interfered with NV Energy's contracts and violated the Contracts Clause, failed to adequately consider evidence and violated the Due Process Clause, violated NV Energy's Civil Rights, and constituted a taking of property without just compensation and violated the Takings Clause. Deregulation caused NV Energy's stock value to fall and resulted in a loss of its revenue. The lawsuit was eventually settled. If the Energy Choice Initiative is approved by voters in 2018, state and federal litigation involving Nevada is reasonably foreseeable.[32]

Other litigation related to the ISO/RTOs could be very lengthy. Capacity design cases at ISO-NE and NYISO have taken years and involved more than a dozen litigants. Litigation at the FERC surrounding market manipulation is likely to occur. The so-called "competitive markets" are characterized by protracted litigation at the FERC and in the courts and a number of regulatory initiatives to protect against adverse outcomes. The states and regions that implemented restructuring—a path from which return is costly and difficult—are still, almost 20 years later, trying to figure out how to design a "competitive" electricity industry that can deliver the same benefits already enjoyed by Floridians under the present regulatory framework. ISO/RTO market participants have a profit incentive to exert market power up to the edge set by rules and the law. Market manipulation is an important issue; since 2007 the FERC has levied significant fines and penalties for these abuses. For instance, in February 2017, GDF Suez Energy Marketing, Inc. was fined $41 million by the FERC for "inflating their receipt of lost opportunity cost credits paid to combustion turbines that cleared the day-ahead market, however, the turbines were not dispatched in the real-time market"[33].

State commissions in restructured states have effectively been transformed from the decision-maker in state proceedings to simply another party in FERC proceedings. State commissions have banded together and formed organizations that can participate as a bloc in certain ISO discussions and FERC litigation matters but states do not always share the same interests. The FERC certainly does not defer to the states in its decision-making. This presents an enormous resource challenge for states to simply keep up with issues before the FERC that have an impact on customers within their jurisdictions, particularly if those customer interests are not effectively represented by other parties, as is often the case. Of course, keeping up with issues is one challenge; participating as a litigant in FERC proceedings is also a resource-intensive and expensive proposition.

Litigation Related to the Ballot Measure

The basic construct of the ballot proposal increases the likelihood of costly litigation in Florida. No state has ever initiated electric restructuring via a state constitutional Amendment; the states that have restructured did so via the legislative process.

Although the Florida Proposal contemplates a significant implementation role for the Florida Legislature, the framework for restructuring in the Proposal is so sparse, vague and open to different interpretations that Florida can expect an additional level or type of litigation, namely state court litigation over whether implementing

[32] Ibid., at 58-59.
[33] Source: http://www.ferc.gov/enforcement/civil-penalties/civil-penalty-action.asp

legislation and regulatory decisions are constitutional or unconstitutional under the Amendment. This type of litigation could add years and millions of dollars of costs to the implementation process.

Moreover, because the ballot proposal would to create a constitutional right for individuals to select from multiple energy suppliers, the state can expect litigation from individuals claiming violation of a constitutional right if the retail market established during implementation does not actually give consumers in some areas of the state a choice among multiple providers. It's easy to imagine – in the third largest state in America and one that is as geographically diverse as Florida - that customers in remote and rural areas of Florida could find themselves without multiple offers to supply electricity and then seek damages from the state for failing to properly implement the Amendment.

Conclusion

Based on the information in this appendix, the estimated range of costs for the implementation of an ISO/RTO would be between $100 to $500 million. Annual costs to administer the ISO/RTO would be in the range of $170 to $228 million based on other single state ISO/RTOs like New York ISO and ERCOT, respectively. In addition, other costs for education and Commission costs would be incurred. In addition, there will be litigation costs. Please see the table below for a summary of the information provided in this appendix.

TABLE AP2 - 5: ESTIMATED IMPLEMENTATION COSTS FOR A NEW ISO/RTO

	Low ($000,000)	High ($000,000)
Implementation Costs	$100	$500
Administrative costs	$170	$228
Other Costs	$20	$20

APPENDIX 3: IOU AWARDS

Florida Power & Light and Gulf Power

Customer & Community

PA Consulting Group ReliabilityOne™ National Reliability Excellence Award: Florida Power and Light (FPL) was named the winner of the 2018 ReliabilityOne™ National Reliability Excellence Award presented by PA Consulting Group, demonstrating its continued efforts to improve reliability. This marked the third time in four years that FPL has received the national award.

EEI Emergency Recovery and Emergency Assistance Awards: Both FPL and Gulf Power have been awarded Emergency Recovery and Emergency Assistance Awards by the Edison Electric Institute (EEI) on numerous occasions; most recently in January 2019 for Gulf's outstanding power restoration efforts after Hurricane Michael and for FPL's contributions in restoring power to hard-hit North Carolina communities following Hurricane Florence. Both utilities were presented with the special 2018 Emergency Assistance Award for Puerto Rico Power Restoration for their contributions to the unprecedented emergency power restoration mission in Puerto Rico following Hurricane Maria. The utilities have also received awards in recent years for restoration efforts following Hurricanes Irma, Hermine and Matthew and other severe weather, including tornadoes.

J.D. Power Residential Customer Satisfaction: FPL received the top ranking for residential customer satisfaction among large electric providers in the southern U.S., according to the J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study. FPL also ranked second-highest in the nation among all large electric providers.

Benchmark Portal Center of Excellence: In 2016, FPL's Customer Care Center was certified as a Center of Excellence for the third time by Benchmark Portal. The prestigious recognition is awarded to call centers that rank in the top 10 percent of call centers surveyed for efficiency and effectiveness.

Chartwell Best Practices Awards: FPL's outage prediction technology earned national recognition as Chartwell's 12th Annual Best Practices Awards Gold Outage Communications winner in 2016.

International Smart Grid Action Network Award of Excellence: FPL's Automated Fault Mapping Prediction System was recognized with an Award of Excellence by the International Smart Grid Action Network in 2016.

Environmental

Market Strategies Environmental Champion: FPL was recognized as an Environmental Champion in 2017 among the nation's largest electric and gas utilities in a nationwide study of utility customers by Market Strategies International.

Southeastern Electric Exchange Industry Excellence Award: FPL was recognized by the Southeastern Electric Exchange with its Chairman's Award for the company's response to numerous environmental challenges encountered during an important transmission line project.

EI New Energy Top 100 Green Utilities: In 2017, NextEra Energy was ranked as the top green utility in the United States and No. 2 in the world based on carbon emissions and renewable energy capacity by EI Energy Intelligence

U.S. Green Building Council Recertification: NextEra Energy's headquarters in Juno Beach, Florida, achieved the prestigious Leadership in Energy and Environmental Design (LEED) Gold recertification for existing buildings in 2015. LEED is the U.S. Green Building Council's leading rating system for designating the world's greenest, most energy-efficient and high-performing buildings.

Economic & Governance

Fortune World's Most Admired Companies: In 2019, NextEra Energy was ranked No. 1 in the electric and gas utilities industry on Fortune's list of "Most Admired Companies" for the 12th time in 13 years. We were also named one of the top 25 companies in the world, across all industries, for innovation, use of corporate assets, social responsibility and long-term investment value.

Fortune Change the World: NextEra Energy was ranked No. 21 among the top 57 companies globally that "Change the World" by Fortune. This annual list recognizes companies that have a positive social impact, and NextEra Energy was the only energy company from the Americas and one of only two electric companies in the world to be included in 2018.

Ethisphere Institute World's Most Ethical Companies: In 2018, NextEra Energy was named one of the World's Most Ethical Companies® by the Ethisphere Institute, the global leader in defining and advancing the standards of ethical business practices. NextEra Energy is one of only 20 companies in the world to achieve this honor 11 or more times.

Nuclear Energy Institute Top Innovative Practice Award: NextEra Energy's nuclear energy fleet received the Nuclear Energy Institute 2016 top innovation award for pioneering a unique program that significantly improves plant performance.

Forbes' America's Best Employers: For the third consecutive year, NextEra Energy was named by Forbes as one of America's Best Employers. Working with research firm Statista, Forbes asked thousands of U.S. workers employed by large companies whether they would recommend their employer.

Forbes' Best Employers for Diversity: NextEra Energy was named to Forbes' first-ever list of America's Best Employers for Diversity in 2018. In partnership with research firm Statista, Forbes ranked 250 employers across all industries in the U.S. according to results from employee surveys, examination of diversity policies, and analysis of diversity in executive boards and management teams.

OSHA Voluntary Protection Program: Numerous NextEra Energy locations have received the prestigious U.S. Occupational Safety and Health Administration Voluntary Protection Program Star status. The honor is awarded to worksites with exemplary occupational safety and health.

National Business Group on Health Best Employers for Healthy Lifestyles: NextEra has been honored 10 times by the National Business Group on Health for its ongoing commitment to promoting a healthy work environment and encouraging its workers to live healthier lifestyles.

Duke Energy Florida

Reliability

Electric Energy Institute (EEI) 2018 Advocacy Excellence Award: EEI recognized Duke Energy for its leadership in developing solar power and bringing customer-focused smart grid technology to its customers in Florida.

The company received an EEI Advocacy Excellence Award honorable mention for developing Florida's smart grid, additional renewable resources and enhanced services to customers. The award recognizes companies that use a range of advocacy and engagement activities to achieve company goals and effect change. Under the terms of a settlement with the state, the company will invest $6 billion in the state over the next four years, including $1.2 billion for modernizing the electric grid to make it more customer-focused, resilient, reliable and amenable to emerging technologies including renewable energy. The company also plans to develop or acquire up to 700 megawatts (MW) of solar energy through 2022. Duke Energy is also involved in a pilot program to enable "community" solar programs that allow customers without solar panels to subscribe to "blocks" (50 kilowatt-hours) of solar energy that come from arrays owned and operated by Duke Energy in Florida.

2016 Greentech Media's Grid Edge 20: Duke Energy is always innovating and embracing new technologies and forward-thinking strategies to power the communities we serve. Greentech Media named Duke Energy to the Grid Edge 20, honoring companies that are shaping the electrical power sector's transformation.

Storm Restoration and Emergency Response

Duke Energy earns EEI's 'Emergency Recovery Award' for power restoration efforts in Carolinas after Hurricane Florence: In September 2018, Duke Energy received the Edison Electric Institute's "Emergency Recovery Award" for the company's outstanding power restoration efforts after Hurricane Florence hit North Carolina and South Carolina.

Duke Energy wins award for its successful restoration effort after Winter Storm Jonas: In June 2016, the Edison Electric Institute (EEI) presented Duke Energy with the association's Emergency Recovery Award for its outstanding power restoration efforts after Winter Storm Jonas assaulted the Carolinas. The award is presented twice annually to EEI member companies in recognition of their extraordinary efforts to restore power to customers after service disruptions caused by severe weather conditions or other natural events. Duke Energy has earned the award 12 times since EEI began presenting it in 1998.

Innovation

2018 Wind Technician Team of the Year Award: Duke Energy Renewable Services' technicians received the 2018 Wind Technician Team of the Year Award at the 10th Annual Wind Operations forum in Dallas. This team is operating and maintaining DTE Energy's wind fleet in Michigan and was recognized for its accomplishments in safety performance, innovation, environmental stewardship and customer service.

Top performing solar assets by the Solar Finance Council: Duke Energy Renewables' Highlander I, Seville I and Seville II solar power projects in California were recognized by the Solar Finance Council as three of the top 100 performing solar assets in the country. The Solar Finance Council, which launched in May of this year, partnered with kWh Analytics to present their findings on solar project output in the U.S.

Blue Diamond Award for Data Efficiency Project: Duke Energy Renewables also has won the prestigious Blue Diamond Award for its Data Efficiency Project. The 2018 Blue Diamond Awards is an annual event recognizing technology as an economic driver for innovation in the Charlotte, N.C., region and has been in place for more than 25 years.

Top sustainable companies: Duke Energy makes it 13 years in a row: Building on its long-running record of sustainability leadership, Duke Energy was recently named to the Dow Jones Sustainability Index for North America for the 13th consecutive year in 2018.

Duke Energy economic development team honored by Site Selection magazine for 14 years straight: For the 14th consecutive year, Duke Energy has been named to Site Selection magazine's annual list of "Top Utilities in Economic Development" in 2018.

Newsweek's 2017 Green Rankings: Duke Energy ranked in the top 15% of Newsweek's 2017 Green Rankings. One of the most recognized environmental performance assessments of the world's largest publicly traded companies, the Green Rankings rate the top 500 U.S. companies, top 500 Global, and best in industry. Duke Energy received high marks for waste productivity. In 2016, Duke Energy recycled about 75 percent of the coal combustion byproducts (coal ash and gypsum) produced in North Carolina.

2017 Energy for Wildlife National Achievement Award: Presented by the National Wild Turkey Federation (NWTF), the Energy for Wildlife National Achievement Award recognized Duke Energy for our commitment to protect and restore wildlife and natural resources in the communities we serve. Duke Energy has teamed up with NWTF to help conserve or enhance more than 6,000 acres of critical habitat across Florida, the Carolinas and Indiana.

2017 Governor's Business Ambassador Award: Florida Gov. Rick Scott presented Duke Energy Florida with the state's Business Ambassador Award for its contributions to the state's economic vitality. The award is presented to Florida companies and individuals for their efforts in creating jobs and opportunities for families across the state.

Make it an even dozen: Duke Energy economic development team honored by Site Selection magazine for 12th consecutive year: For the 12th consecutive year, Duke Energy has been named to Site Selection magazine's annual list of "Top Utilities in Economic Development" in 2016.

2016 Outstanding Stewards of America's Waters Award: Maintaining water quality and shoreline management is essential to protect our communities. The National Hydropower Association recognized Duke Energy with the 2016 Outstanding Stewards of America's Waters Award for successfully developing the Pines Recreation Area and High Falls Trail as part of the West Fork Hydroelectric Project in North Carolina.

2016 Circle of Excellence Award: At Duke Energy, we believe sustainability is the key to our success, and so we incorporate that belief in all that we do. In recognition of our sustained commitment to corporate responsibility, the Distribution Business Management Association honored Duke Energy with the 2016 Circle of Excellence Award.

Tree Line USA Utility: The Arbor Day Foundation highlighted Duke Energy efforts in quality tree care by recognizing Duke Energy Florida as a Tree Line USA utility for the 10th consecutive year. The Tree Line USA Program demonstrates how trees and utilities can co-exist for the benefit of communities and citizens by highlighting best management practices in public and private utility arboriculture.

Customer Service

2017 CS Week's Best Mobility Implementation Award: CS Week presented Duke Energy with its Best Mobility Implementation Award for the company's proactive customer outage notification program, which automatically provides registered customers with information about their power outage. Duke Energy is committed to meeting our customers' needs by providing them with real-time information about outages so they can make decisions.

Duke Energy recognized for mobile app that shares power outage information: In 2016, CS Week presented Duke Energy with its Best Mobility Implementation Award for the company's proactive customer outage notification program, which automatically provides registered customers with information about their power outage.

Light shines on Duke Energy's customer service: Duke Energy was recognized for its superior customer service to its large commercial, industrial and government business accounts during the Edison Electric Institute’s (EEI) fall National Key Accounts Workshop in 2015.

Employer

Duke Energy receives highest honor from the U.S. Department of Defense for its support of National Guard and Reserve employees: Duke Energy has received the 2018 Secretary of Defense Employer Support Freedom Award, the highest honor the U.S. Department of Defense gives to companies for their outstanding support for employees who serve in the National Guard and Reserve. Duke Energy was one of only 15 companies nationwide to be selected out of more than 2,300 nominations.

Pro Patria Award presented by the North Carolina Employer Support of the Guard and Reserve: Duke Energy received the ESGR award for large employer in North Carolina. The award is in recognition of the company's support of employees who serve in the National Guard and Reserve. The award is the highest level awarded by the ESGR State Committee.

Duke Energy named one of America's Best Employers by Forbes: Duke Energy has been named to Forbes magazine’s 2018 list of America’s Best Employers. Out of 500 companies ranked, Duke Energy moved up 38 spots to #106.

Duke Energy named one of Fortune's "World's Most Admired Companies": Duke Energy has been named to Fortune magazine's 2018 list of the World's Most Admired Companies. Duke Energy was ranked 5th among gas and electric utilities, up from 9th last year.

Duke Energy earns perfect score in 2018 Corporate Equality Index: Duke Energy received a perfect score of 100 percent in Human Rights Campaign’s national benchmarking study that annually ranks companies on LGBT-friendly corporate practices and policies.

Duke Energy receives top award for supplier diversity: The Edison Electric Institute (EEI) has awarded Duke Energy the top honor in the electric utility association’s 2017 Business Diversity Awards program.

2017 Above and Beyond Award: Piedmont Natural Gas, a subsidiary of Duke Energy, was honored with the prestigious "Above and Beyond Award" by the North Carolina Committee for Employer Support of the Guard and Reserve. The award recognizes employers who provide job security for employees while they are on active duty.

2016 United Way North Carolina's Power of Commitment Award: Duke Energy has a long-standing commitment to addressing the needs of the communities where our customers live and work. The United Way of North Carolina recognized Duke Energy with the Power of Commitment Award for our investment to expand the North Carolina 2-1-1 system, which helps people find health and human services resources in their community, to all 100 counties in the state.

2015 Enable America ADA Award: For several decades, Duke Energy has made it a corporate priority to offer employment opportunities to those with disabilities. Enable America Raleigh recently honored those efforts by presenting us with their ADA Award. We are delighted to partner with Enable America to advance its mission to help veterans and people with disabilities find employment and live independently.

2015 North Carolina Business Leadership Employer of the Year: Duke Energy was named "Employer of the Year" at the fall conference of the North Carolina Business Leadership Network. The organization is dedicated to showing businesses how they can gain a competitive edge by including the disabled in their workforce.

DailyWorth's 25 Best Companies for Women: In 2014, financial website DailyWorth ranked Duke Energy #16 on its list of "The 25 Best Companies for Women." The site considered factors such as upward mobility opportunities and leadership development programs, as well as a culture of support for women and their families.

2013 100 Best Corporate Citizens: Duke Energy's dedication to balancing the diverse interests of customers, communities, employees and shareholders was recognized for the fifth consecutive year by Corporate Responsibility (CR) magazine through placement on their 100 Best Corporate Citizens list. Duke Energy was ranked 26th on the 2013 list after being independently assessed in seven key areas: environment, climate change, human rights, philanthropy, employee relations, financial and governance.

Tampa Electric Awards / Recognition

2017 SAP Excellence in Customer Experience Award SAP, the market leader in enterprise application software, honored TECO with the Excellence in Customer Experience award in recognition of our hard work to modernize our systems and business processes to improve how we serve our more than 1.1 million valued customers.

2017 EPA Energy Star Certified Homes Market Leader Award ENERGY STAR named Tampa Electric among the winners of its 2017 Certified Homes Market Leader Award. The award goes to organizations that are leaders in "promoting energy-efficient construction and helping homebuyers experience the peace of mind, quality, comfort, and value that come with living in an ENERGY STAR-certified home."

2015 Edison Award the Edison Electric Institute (EEI) today named Tampa Electric Co. as the winner of the 2015 Edison Award, the electric industry's most prestigious honor. The award was given for Tampa Electric's innovative partnership to create a reclaimed water project at its Polk Power Station, near Mulberry.

2014 Sustainable Florida Award Tampa Electric wins award for LEGOLAND partnership solar array from Sustainable Florida, an organization that "promotes sustainable best management practices through collaborative educational efforts throughout Florida".

2013 National Assistance Award for Hurricane Sandy efforts Tampa Electric has won the Edison Electric Institute (EEI) Emergency Assistance Award for 2012, in recognition for the utility's outstanding support to restore power and natural gas service after last year's devastating Hurricane Sandy.

2012 Industry Excellence Award the Southeastern Electric Exchange (SEE), a non-profit, non-political trade association of investor-owned electric utilities, named Tampa Electric the winner of its 2012 Industry Excellence Award in the Transmission Line category.

2009-2018 Tree Line USA The National Arbor Day Foundation™ has certified Tampa Electric a Tree Line USA ® utility for its efforts to protect the health of trees the company must trim near power lines.

2004 U.S. EPA's Gulf Guardian the Manatee Viewing Center was recognized by the U.S. Environmental Protection Agency's Gulf of Mexico program offices during the annual Gulf Guardian Awards Program. The Gulf of Mexico Program is dedicated to finding and applying environmental solutions that work in concert with sound economic development.

APPENDIX 4: STRANDED COSTS

Purpose

This report was prepared by Concentric to provide information and analysis regarding Investor Owned Utility ("IOU") generation stranded costs that may be created by implementing the ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment"). This report provides background information on types of stranded costs, identifies how such costs are typically recovered by IOUs (including associated calculations), and provides data and analysis from several other jurisdictions that have restructured their electric industries.

Background

Currently, Florida residents purchase their electricity from either municipal electric companies, rural electric cooperatives, IOUs, and/or they may generate electricity for their own consumption. The state's IOUs are vertically integrated and are regulated by the Florida Public Service Commission and other state and federal regulatory bodies. The Amendment would limit IOUs to the "construction, operation, and repair of electrical transmission and distribution systems." While the ballot measure is silent on many key issues, its implementation would, at a minimum, prohibit the IOUs from owning generation and selling electricity. Furthermore, a straightforward reading of the ballot language indicates that IOUs also would be prohibited from owning transmission and distribution ("T&D") assets, and would instead be limited to their construction, operation, and repair. To comply, the IOUs would need to dispose of their generation assets and other electric infrastructure assets. This disposal would most likely occur through the sale or "divestiture" of those assets, although there is the potential that the ballot measure and associated legislation would allow for the assets to spun out to unregulated affiliates of the IOUs. If electricity infrastructure is spun out to unregulated affiliates, accounting rules would require those assets to be recorded on the affiliates' books at fair market value.

Stranded costs are the differences between the market value of a utility's assets in a restructured, competitive market and the value of those assets on the books of the utility. There are two primary drivers of this devaluation: (1) the forced sale of assets creates uneven bargaining power for asset purchases, leading to low (i.e., "fire sale) valuations; and (2) the market does not value the same factors that have led to certain prudent IOU investments. Those factors include fuel diversity, environmental goals, and long-term planning considerations. Examples of generation-related stranded costs include the costs associated with generation assets divested by IOUs where those assets sell for less than the value on the books of the utilities, "out of the money" PPAs, and fuel contracts, long-term pipeline transportation contracts that are unlikely to be attractive to merchant generators, and stranded costs and regulatory assets on the books of the utilities that are associated with the generation function (or other "stranded" functions). Utilities are compensated for these stranded costs, typically through a recovery charge or non-bypassable wires charge on electric bills.

Categories of Stranded Costs

General categories of stranded costs are provided in Table AP4- 1, below. This table is non-exhaustive but provides the major categories of stranded costs that have historically been authorized for recovery by IOUs from electricity customers.

TABLE AP4- 1: TYPES OF STRANDED COSTS

Cost Type	Description
Unrecoverable Costs of Generation Assets and Infrastructure	If a plant is sold, shut down, or spun off to an unregulated affiliate, its potential stranded costs are measured as the unrecovered capital costs, or "net book value," offset by its market value or salvage value. Generation assets include power plants, solar facilities, substations, land associated with future generation sites that no longer can be constructed by the utility, and other associated infrastructure.
Uneconomic PPAs and Fuel Purchase Contracts	Uneconomic (or "out of the money") PPAs and fuel purchase contracts are contracts that cost more than the utility's incremental cost of producing or procuring the same generation or fuel. This category also refers to renewable contracts that were agreed to in order to comply with state mandated Renewable Portfolio Standards requirements, and can further include transmission contracts, service contracts, and other contracts. Experience in other regions demonstrates that merchant generators are unwilling to sign firm transportation contracts on pipelines, and prefer short term, or city gate contracts. This has a very significant adverse effect on reliability and creates an inability to underpin gas transportation infrastructure in the state. For a state such as Florida that is reliant on gas for electric generation, this is likely to be one of the biggest adverse impacts arising out of the Amendment.
Regulatory Assets/Liabilities	A regulatory asset is a specific cost that a regulator permits an IOU to defer on its balance sheet because it is probable the cost will be recovered in future periods. Regulatory assets may become stranded under restructuring if they no longer meet the accounting requirements for deferral, and thus would need separate treatment from regulators to ensure recovery. The same is true for regulatory liabilities, which are revenue items that are deferred on the balance sheet.
Investments in Programs Mandated by Regulators [1]	These investments include demand-side management programs, low-income programs, pollution control, and provisions of universal service. Demand-side management ("DSM") programs are often capitalized, included in rate base, and amortized over time.[2]
Intangibles	Intangibles include early retirement and severance packages, job retraining, computer data, and IT systems. Legislators or regulators in California, Michigan, New Jersey, Maine, Pennsylvania, and

1 Regulators in restructured states often include this category in general "regulatory-related" stranded costs.

2 The treatment of DSM costs under restructuring would likely depend on the means by which the utility recovers DSM costs. A 1998 from the Congressional Budget Office titled "Electric Utilities: Deregulation and Stranded Costs" (at 14) argues that because the utility provides rebates for customers that use energy efficient appliances/light bulbs, though the utility no longer owns the generation that benefits from the greater efficiency, the DSM programs are a stranded cost: "Since those costs [*i.e.*, for DSM rebates] are not part of generating power, the market price for electricity will not reflect spending on DSM programs, and utilities will not be able to recover un-expensed DSM costs."

Cost Type	Description
	Massachusetts have included such expenditures as stranded costs that can be recovered from electricity customers.[3]
Costs to Retire Debt and Capital	These costs include the costs associated with paying down the principle and interest of the existing loans.

Stranded Costs Created by Industry Restructuring

APPENDIX 1 Analysis of Financial Impact provides information regarding stranded costs that was compiled by Regulatory Research Associates, supplemented by Concentric research. In addition, Concentric has performed independent research of stranded cost recovery authorized in other U.S. states. This data is largely consistent with the stranded costs information provided by Regulatory Research Associates. In addition, restructuring was recently considered in Nevada in 2017-2018 in the context of a ballot initiative.[4] During the Public Utility Commission of Nevada's investigation into the proposal, NV Energy submitted several reports and comments that outlined the risks involved with restructuring, including stranded costs. NV Energy estimated that stranded costs would range from $5.18 billion to $6.13 billion, the majority of which related to retiring baseload generation.[5]

Stranded Cost Recovery

The most common stranded cost recovery mechanism is a "transition charge," which may be referred to as competition transition charge ("CTC") or a market transition charge ("MTC"). Approved stranded costs are then passed on to customers through transition surcharges.

Transition Charges

A transition charge is an additional charge added to customer's bills that provides for the payment of the stranded costs incurred as a result of restructuring. Typically, the charges are based on actual energy use as a per kWh or kilowatt ("kW") charge, rather than applied as a flat rate to all customers.

Table AP4- 2, below, provides a summary of several states' stranded costs recovery mechanisms.

TABLE AP4- 2: EXAMPLES OF STRANDED COST RECOVERY MECHANISMS[6]

State	Name	Recovery Adjustment Mechanism Description
Connecticut	Competitive Transition Assessment ("CTA")	IOUs were permitted to recover, through a CTA (1) above-market generating plants recognized in rates before the restructuring bill passed, (2) regulatory assets recognized a year after the restructuring bill was passed; and, (3) non-utility generation contracts entered into before the stranded costs proceeding began.

3 Congressional Budget Office Paper, Electric Utilities: Deregulation and Stranded Costs, October 1998, page 11.
4 Energy Choice Initiative Final Report, Investigatory Docket No.17-10001, PUC of Nevada.
5 Final Comments, Nevada Power Company NV Energy and Sierra Pacific Power Company, Docket No.17-10001, at 1.
6 SNL Research; and Concentric research of state utility dockets.

State	Name	Recovery Adjustment Mechanism Description
Delaware	Non-residential Wire Charge	Delmarva Power divested most of its generation assets, and the Delaware Commission authorized the recovery of $16 million of stranded costs through a non-residential surcharge.[7]
Illinois	CTC	Commonwealth Edison recovered stranded costs through a non-bypassable CTC that varied periodically with the market price of power.
Maine	CTC	The stranded costs were re-set every two-to-three years with periodic "true-ups" until the stranded costs were fully recovered.
Massachusetts	Transition Charge	The Massachusetts Department of Public Utilities approved company-specific transition plans, and virtually all generation assets were divested. The utilities were permitted to recover stranded costs through a transition charge.
Michigan	N.A.	The 2000 and 2008 legislation provided for full recovery of PSC-approved stranded costs.
Montana	CTC	Northwestern has a CTC adjustment mechanism in place in its rates. This rider allows the company to recover restructuring-related out-of-market costs for certain power purchase contracts.
New Hampshire	Stranded Cost Recovery Charge ("SCRC")	The PSNH Proposed Restructuring Settlement allowed for recovery through the SCRC.
New Jersey	Market Transition Charge ("MTA")	New Jersey utilities recover stranded costs through a market transition charge. This MTC is a four-to-eight-year adjustment mechanism that allows the utility to recover stranded costs, though the amount changes based on market prices and customer demand. [8]
New York	N.A.	The New York Public Service Commission did not adopt a generic adjustment mechanism for cost recovery; instead, they approved plans on a company-by-company basis.
Ohio	N.A.	Stranded cost recovery extended to at least year-end 2005 for generation-related assets, and to year-end 2010 for regulatory assets.
Pennsylvania	CTC	The law permitted stranded cost recovery through competition transition charges, or CTCs. The CTC is now expired.

7 Delmarva was permitted to recover a maximum of $50 million on a system-wide basis but only $16 million through the non-residential wire charge (Docket 99-163, Order, August 31, 1999, at 5).

8 2013 New Jersey Revised Statutes, Section 48:3-61 – Market transition charge for stranded costs.

State	Name	Recovery Adjustment Mechanism Description
Rhode Island	Transition Charge	A non-bypassable transition charge for the recovery of generation-related stranded costs is to be collected from all distribution customers through Dec. ember 31, 2029.
Texas	CTC	As part of the 1997 legislation, Texas established a "true-up" mechanism whereby the restructured utilities would recover stranded costs through a CTC.

Conclusion

Stranded costs are a utility's existing costs that are rendered unrecoverable by restructuring. Examples include the costs associated with generation assets divested by IOUs where those assets sell for less than the value on the books of the utilities, "out of the money" PPAs and fuel contracts, and regulatory assets on the books of the utilities that are associated with the generation function. Significant stranded costs are a common outcome of electric industry restructuring, and, depending on the market value for restructured assets, are often billions of dollars, depending on the size of the restructured utility. Stranded costs are important to consider in any assessment of the restructuring being proposed by the Amendment.

APPENDIX 5: WHOLESALE MARKET IMPLEMENTATION

Purpose of Report

This report was prepared by Concentric to provide information and insights on the potential impact of ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment"). The design and implementation of a competitive wholesale market is a complicated and resource intensive effort that continues long after competition has been introduced. Wholesale markets require constant monitoring and frequent redesign to ensure that the outcomes are competitive and system costs are minimized. Florida is required to provide non-discriminatory access to its transmission system, with a wholesale market consisting of bilateral contracts and tariffs to access the transmission system and sell power, but this is a far simpler "market" than what is required to accommodate full retail restructuring.

Goals of Wholesale Competition

A well-functioning wholesale market is vital to capturing the promised benefits of retail competition. An effective wholesale market is necessary to provide the region with reliable wholesale electricity at competitive prices. This is accomplished by providing appropriate incentives for investment in and retirement of generating capacity, evaluating transmission investments, and providing generators a reasonable opportunity to recover their fixed and variable costs. In addition, a wholesale market is an effective means of supporting the lowest possible retail energy prices that reflect marginal production cost including the costs of congestion, losses, and scarcity of energy.

Designing and Implementing Wholesale Markets

Wholesale electricity markets are complicated and resource intensive. The basic standard wholesale market design in operation in the U.S. is effective in minimizing system costs and maintaining reliability. Wholesale electricity markets generally consist of an organized day-ahead and real-time market for energy. The day-ahead market allows for market participants to submit bids and offers for energy for next day delivery. These bids and offers reflect financial positions that generation and load serving entities "lock-in" prior to the operating day. The real-time market is a physical market in the operating day where the grid operator dispatches generation based on offers to supply energy and bids to consume energy. Prices paid by load and paid to generating resources are known as locational marginal prices ("LMPs"). LMPs reflect the value of electric energy at hundreds and sometimes thousands of different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. LMPs consist of an energy component (the price for energy), a congestion component (the marginal cost of congestion at a given location), and a loss component (the costs of system losses at a given location). The market is settled at the location-based LMP based on deviations between bids and offers in the day-ahead and real-time markets.

In addition to the markets for energy, there are markets for: i) capacity which represents an insurance policy for "steel in the ground" when needed; ii) ancillary services to ensure the system can reliably meet demand during unexpected system conditions; iii) transmission congestion and loss management tools; and iv) other financial mechanisms that allow for efficient market outcomes and risk management.

Implementing a competitive wholesale market entails massive efforts that require multiple years and numerous resources, with start-up costs ranging anywhere between $100 to $500 million and annual revenue requirements in the range of $200 to $300 million. First, the region must form an ISO or a RTO. ISOs/RTOs are non-profit entities that were created as a part of electricity restructuring in the U.S., beginning in the 1990s. The history of the ISO/RTO dates back to FERC Orders 888 and 889, which suggested the concept of the independent system operator to ensure non-discriminatory access to transmission systems. FERC Order 2000 encouraged, but did not quite require, all transmission-owning entities to form or join such an organization to promote the regional administration of high-voltage transmission systems. FERC Order 2000 contains a set of technical requirements for any system operator to be considered a FERC-approved RTO, since RTOs are regulated by FERC, not by the states (i.e., RTO rules are determined by a FERC-approved tariff and not by state Public Utility Commissions) Each RTO establishes its own rules and market structures, but there are many commonalities. Broadly, the RTO performs the following functions: i) management of the bulk power transmission system within its footprint; ii) ensuring non-discriminatory access to the transmission grid by customers and suppliers; iii) dispatch of generation assets within its footprint to keep supply and demand in balance and administration of the entirety of the wholesale markets; and iv) regional planning for generation and transmission. In many ways, ISOs/RTOs perform the same functions as the vertically-integrated utilities that were supplanted by electricity restructuring. There are, however, a number of important distinctions between ISOs/RTOs and utilities: i) ISOs/RTOs do not sell electricity to retail customers; ii) ISOs/RTOs purchase power from generators, resell it to electric distribution utilities, who then resell it again to end-use customers; iii) ISOs/RTOs may not earn profits; iv) ISOs/RTOs do not own any physical assets – they do not own generators, power lines or any other equipment; v) ISO/RTO decision-making is governed by a "stakeholder board" consisting of various electric sector constituencies. In some cases, the RTO can implement policy unilaterally without approval by the stakeholder board, but this is generally rare. Generally, however, policies must be approved by the FERC; and vi) ISOs/RTOs monitor activity in their markets to avoid manipulation by individual generators or groups of generators.

Wholesale Market challenges

Shrinking Reserve Margins

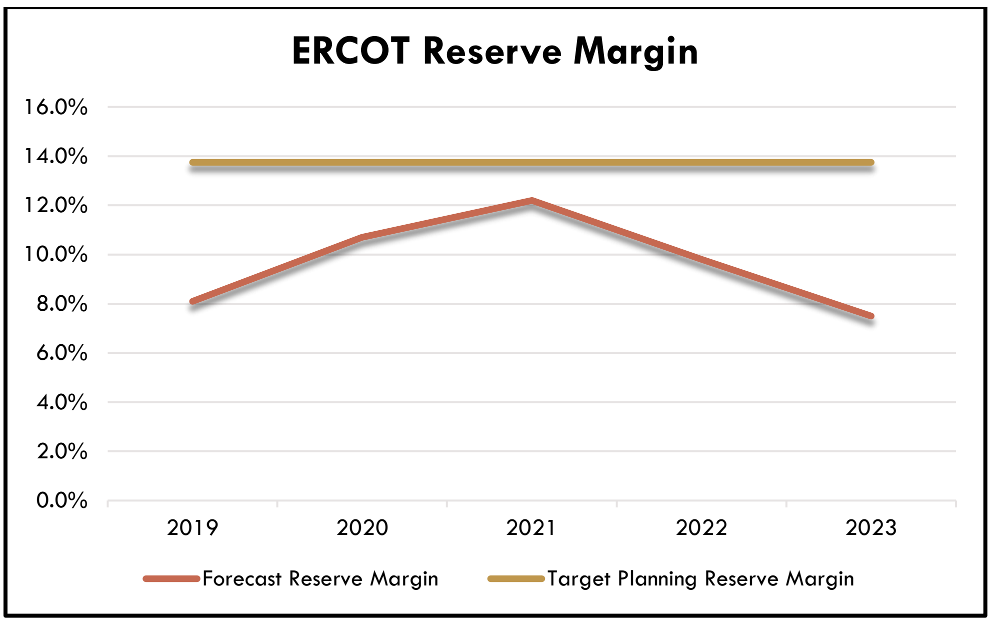
Wholesale energy markets are designed to send price signals to incent new entry and retain existing generation when needed for bulk power system reliability. New entry, as well as existing generation, has been challenged in their ability to recover their fixed and variable operating costs, including fuel, fixed and variable operating and maintenance expenses, and a return on and of investment. The percentage of recovered operating costs for new gas-fired resources is shown in Table AP5- 1.

TABLE AP5- 1: PERCENTAGE OF RECOVERED COSTS FOR NEW RESOURCES– 2016[1]

	ISO-NE	NYISO	PJM	Midwest ISO
Combined Cycle	45%	53%	92%	44%
Simple Cycle	66%	92%	79%	38%

The inability of generating resources to recover their operating costs has the potential to threaten the reliability of supply. For example, the development of adequate supply resources in a restructured market continues to be an issue in Texas. This is illustrated in the figure below from the Electric Reliability Council of Texas ("ERCOT"), which provides information on ERCOT's projected reserve margin, which is a measure of the percentage by which available capacity is expected to exceed forecasted peak demand across the region. As the figure below shows, ERCOT's own projections for its reserve margin in the coming years illustrate a persistent shortfall relative to the target, highlighting the magnitude of the resource adequacy challenges currently being faced by ERCOT.

FIGURE AP5- 1: ERCOT RESERVE MARGINS 2019-2023[2]



Fuel Diversity

A related issue regarding restructuring is the resulting impact on fuel diversity. With restructuring, the planning of generation is largely removed from the jurisdiction of the public utility commission and the state in general. The state would presumably retain siting and environmental oversight, but the state would be constrained

1 Values are from the 2016 State of the Market Reports and are approximate. The values reflect an unconstrained zone (NY West/ISO-NE West/Michigan/Dominion (PJM).
2 ERCOT

regarding other elements of planning. This has been illustrated recently by the efforts of Maryland, New Jersey, and other states to contract for certain generation resources that these states deemed would be advantageous for customers and the system. However, due to the legal changes associated with restructuring, these efforts were negated by the US Supreme Court. Details for several of these states is provided in the table below.

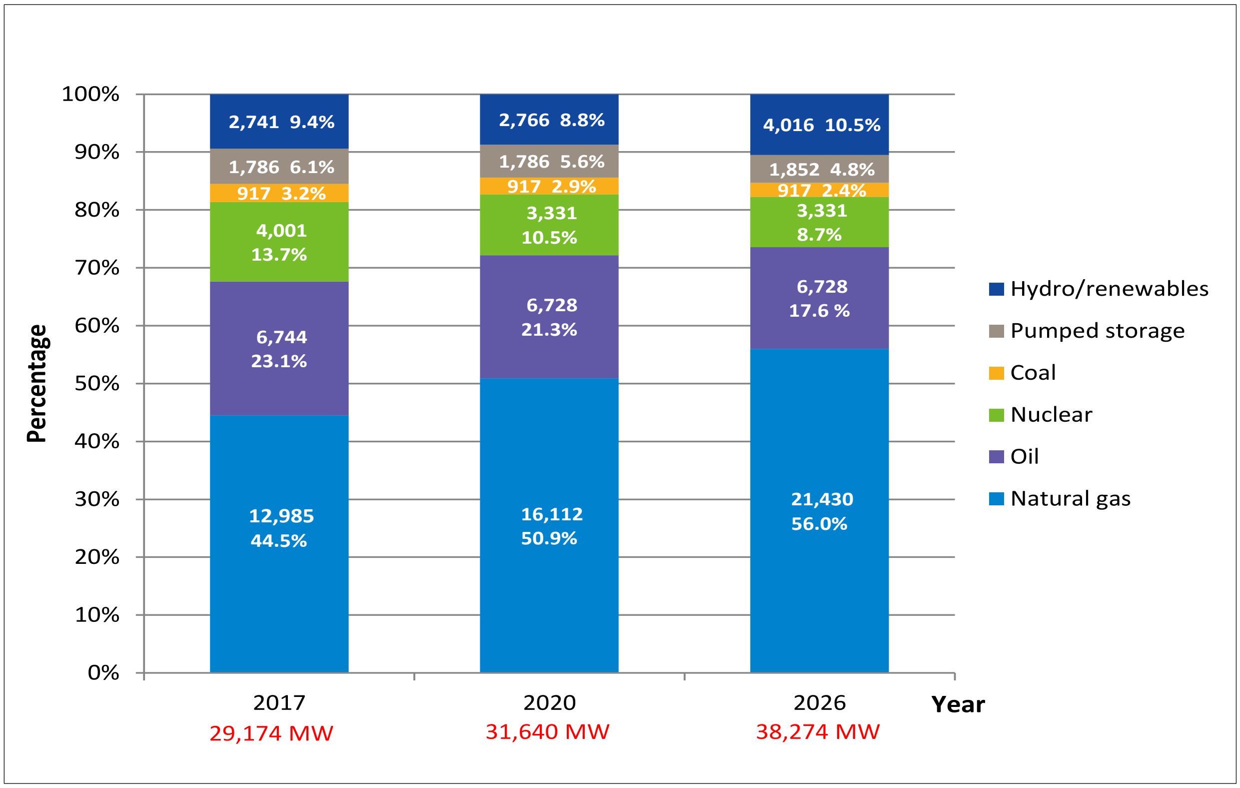
TABLE AP5- 2: EXAMPLES OF RESTRUCTURED STATE EFFORTS TO ACHIEVE RESOURCE PLANNING GOALS

Maryland[3]	On April 19, 2016 the US Supreme Court overturned a Maryland Public Service Commission approval of a compensation arrangement for a new in-state power plant, ruling that, in approving the plan/ PPAs, the PSC encroached on FERC authority over PJM.
New Jersey[4]	On April 25, the US Supreme Court declined to hear an appeal of a lower court decision that overturned New Jersey's Long-term Capacity Agreement Pilot Program law, which required the NJ Board of Public Utilities to develop a program under which the state's electric utilities would enter into long term contracts for 2,000 MW of generation.
Ohio[5]	The Ohio Public Utilities Commission Order of March 31, 2016 approved Ohio Edison, Toledo Edison and Cleveland Electric Illuminating to enter into PPAs with unregulated generating affiliate, FirstEnergy Solutions, for a portion of output of plants, i.e., "contract for differences" from revenues from PJM markets. The plants subject to the PPA have all been adversely impacted in recent years by weak wholesale power prices and would likely be uneconomic to operate if the current market environment persists. A FERC ruling negated that decision, and the utilities changed the mechanism to a rider.
NY & Illinois[6]	In light of the recent and potential retirement of nuclear generation plants, several states have developed programs to ensure the continued operation of such units for clean energy and reliability purposes. New York[7] and Illinois[8] have zero emission credit ("ZECs") programs, which provide subsidies for nuclear generation, as part of the NY Clean Energy Standard (finalized by the NY Public Service Commission in August 2016) and Illinois statute (passed in December 2016). These programs are currently being challenged in state and federal courts by competitive market proponents.

Massachusetts and New England more broadly provide another example of the impacts of restructuring on resource and fuel diversity. Due to factors such as low natural gas prices, environmental restrictions on coal generation, and various economic factors, New England has seen its generation fleet becoming increasingly comprised of natural gas units, which provided over 60 percent of generation to serve load in 2017. This presents potential cost and reliability risks for the region, and planners at ISO New England ("ISO-NE") have struggled with how to address this increasing reliance on natural gas-fired generation. ISO-NE, as the market operator, has struggled to find fuel and technology neutral mechanisms to increase the fuel diversity and reliability of the generation fleet, as shown below.

3 Lillian Federico, S&P Global; "As a follow up to Maryland PPA decision, U.S. Supreme Court declines to review nullification of NJ's LCAPP law" (April 25, 2016).
4 Ibid.
5 Russell Ernst, S&P Global; "Ohio PUC to consider FirstEnergy's latest proposal in controversial PPA affair" May 11, 2016).
6 S&P Global; State Power Project: "Examining State Authority in Interstate Electricity Markets – Illinois".
7 "Why Court Victories for New York, Illinois Nuclear Subsidies are a Big Win for Renewables." Julia Pyper, Greentech Media. July 31, 2017.
8 State Power Project: "Examining State Authority in Interstate Electricity Markets – Illinois"

FIGURE AP5- 2: NEW ENGLAND'S SUMMER CAPACITY BY FUEL TYPE



Source: ISO-NE 2017 Regional System Plan

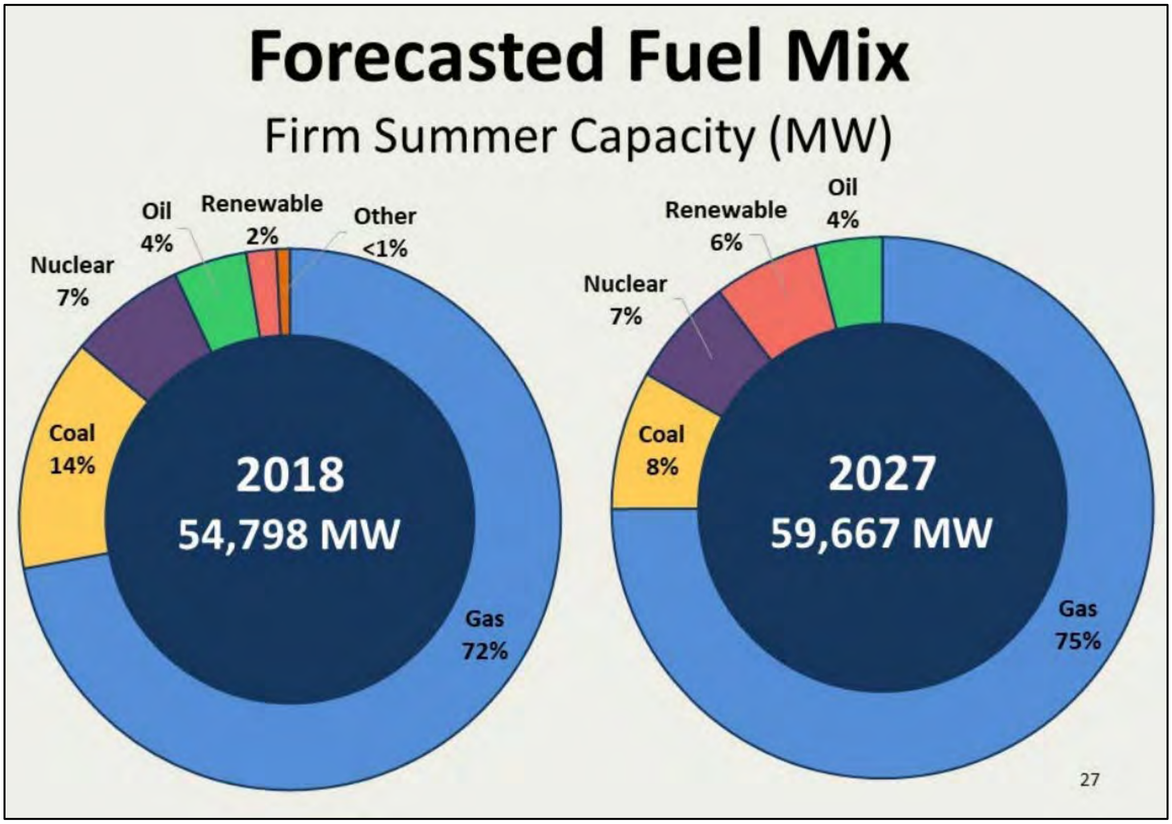
ISO-NE has outlined the challenges, citing the "fuel-security risks to system reliability." An ISO-NE report discusses the causes of this risk, including heavy reliance on natural-gas-fired capacity; reliability issues due to limited natural gas transmission infrastructure into the region, as well as limited fuel storage; lack of firm fuel contracts by natural gas generators; retirement of non-gas-fired generation (nuclear, coal, etc.); exposure to winter electricity price spikes; and higher variable cost peaking units (e.g., LNG).[9]

Under a competitive market structure, fuel supply has the potential to be at risk, resulting in higher costs to the region. Many competitive markets across North America do not require generators to have firm fuel supply in the form of either firm gas supply or fuel oil back up. Restructured jurisdictions have experienced severe fuel shortages at times when system reliability was at risk due to lack of firm fuel supply. For example, in the winter of 2014, the cost of electricity at the wholesale level totaled approximately $3.2 billion dollars for December, January and February alone due to high prices as a result of gas shortages.[10] To put this in context, in a typical year, wholesale energy costs total $5 billion for the entire twelve-month period. A deliberate approach to resource diversity, which is absent in a restructured market, provides important protections against high costs, particularly as regions become more dependent on natural gas resources.

9 Source: ISO-NE 2017 Regional System Plan.
10 Winter Reliability Program Updated, Restructuring Roundtable, September 25, 2015.

With its increasing reliance on natural gas generation, Florida faces its own challenges. As shown in Figure AP5- 4, below, Florida has even higher percentage of its capacity met by natural gas resources.

FIGURE AP5- 3: FLORIDA FORECASTED FUEL MIX

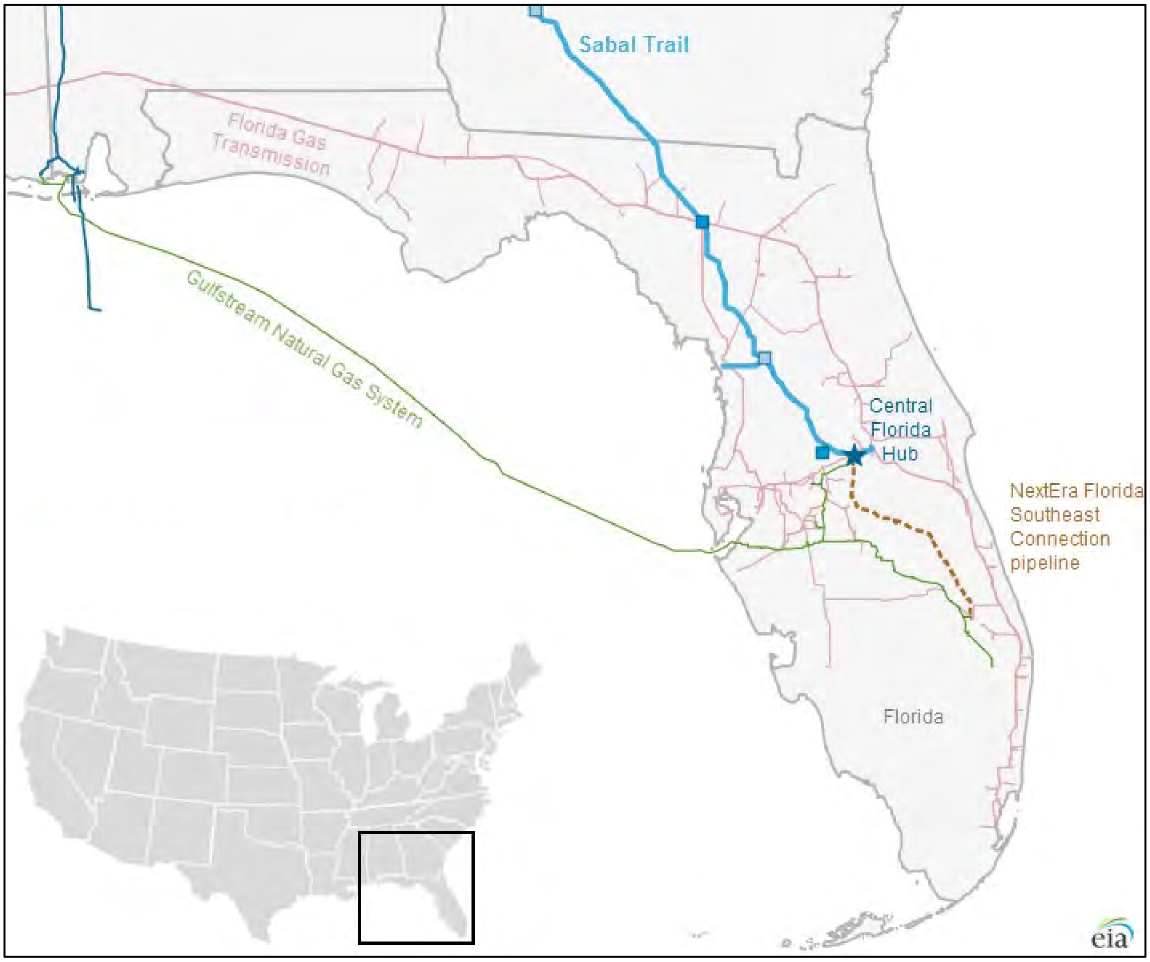


Source: FRCC[11]

Further, just as New England has limited pipeline transmission capacity into the region, Florida, as a peninsula, faces similar challenges. Florida currently receives natural gas supplies from several interstate pipelines: Gulf South Pipeline Company, Southern Natural Gas Company, Florida Gas Transmission and Gulfstream Natural Gas System. The completion of the Southeast Market Pipelines Project, composed of three separate, but related, interstate natural gas transmission pipeline projects subject to FERC jurisdiction, including: 1) the Transcontinental Gas Pipe Line Company, LLC's (Transco) Hillabee Expansion Project; 2) the recently completed Sabal Trail Transmission, LLC's (Sabal Trail) Sabal Trail Project; and 3) the Florida Southeast Connection, LLC's (FSC) Florida Southeast Connection Project provides additional natural gas supplies for Florida. The figure below illustrates the location of Florida's Natural Gas Pipelines.

[11] FRCC, Slide 27.

FIGURE AP5- 4: FLORIDA NATURAL GAS PIPELINES



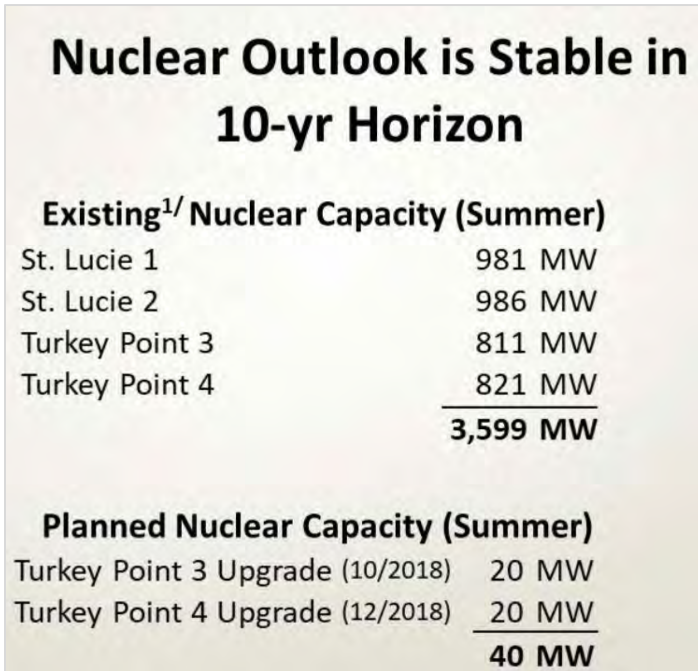
Source: Energy Information Administration

Massachusetts, which is a fully restructured competitive electric market, provides an instructive example of a restructured state struggling with reliance on natural gas in a transmission constrained area. As a potential measure to address this in recent years, the Massachusetts State Energy Office put forth, and the Department of Public Utilities ("DPU") supported, a measure allowing the electric distribution utilities to contract for capacity to support new natural gas pipeline infrastructure, even though the distribution utilities own no generation. This effort was eventually defeated by a Massachusetts Supreme Judicial Court decision, due to a restructuring related statute.

Additional examples may be seen in states such as Ohio, New York, and Illinois, as they have sought to create mechanisms to support the continued operation of baseload power plants. In the case of nuclear plants, policy makers see them as an important source of electricity with no greenhouse gas emissions, which is vital in a carbon-constrained future. This is informed by the closure of many nuclear units throughout the country, which have closed, or are slated to close, due to the inability to survive in restructured wholesale electric markets.

An important issue for Florida in assessing restructuring is the impact on Florida's nuclear fleet. A recent FRCC presentation noted the steadfast footing of Florida's nuclear reactors.[12] If Florida were to restructure, the continued operation of these nuclear units would be highly in doubt, as is evidenced by the many nuclear retirements in restructured markets throughout the U.S. If these units were to retire, customers would be saddled with massive stranded costs, and reliance on natural gas would be significantly exacerbated. Further, retirement of Florida's nuclear generation would represent a loss of carbon-free baseload resources, an invaluable resource in addressing climate change. Florida's nuclear plants are shown in Figure AP5- 6, below.

FIGURE AP5- 5: EXISTING AND PLANNED NUCLEAR CAPACITY IN FLORIDA[13]



Source: FRCC[14]

Market Manipulation

One of the most important functions of an ISO/RTO is to ensure that wholesale markets are competitive. Electricity markets are especially vulnerable to market power challenges, even in the absence of intentional abuse. Market monitoring is essential to control potential market abuses by market participants but is also important simply to monitor how the markets are working, and to look for ways to improve market rules and practices for better overall performance over time. Market monitoring requires the exercise of considerable judgment, as well as the use of advanced tracking and modeling techniques.

To deliver any of the potential benefits of market competition, the market must be structured to minimize the potential for the exercise of generator market power. By tracking market data such as prices, loading, and congestion, market monitors can assess the extent to which a market is operating in a competitive manner. When

12 FRCC, Slide 22.
13 Ibid.
14 Ibid.

departures from competitive conditions are found, the ISO/RTO conducts detailed studies to identify underlying causes and problems and allows system operators to take mitigating actions. Long-term market monitoring also serves to illuminate deficiencies in market design and operation and leads to enhancements to improve market structure.

Even with well-designed market abuse screening mechanisms, abuses still occur, driving up system costs. For example, in 2012, Constellation Energy Group Inc's ("CEG") agreed to a $245 million settlement with regulators over charges of power market manipulation, which at the time was the largest fine handed out by the FERC since 2005. A unit of CEG agreed to pay a civil penalty of $135 million, return $110 million in unjust profits and reassign four traders following a FERC investigation into manipulation of the New York wholesale power market from September 2007 to December 2008.[15]

In July of 2013, the FERC ordered Barclays Bank PLC ("Barclays") and four of its traders to pay $453 million in civil penalties for manipulating electric energy prices in California and other western markets between November 2006 and December 2008. FERC also ordered Barclays to disgorge $34.9 million, plus interest, in unjust profits to the Low-Income Home Energy Assistance Programs of Arizona, California, Oregon, and Washington. In the order, FERC found that Barclays' actions demonstrated an affirmative, coordinated and intentional effort to carry out a manipulative scheme, in violation of the Federal Power Act and FERC's Anti-Manipulation Rule.[16]

[15] Reuters Business News, March 12, 2012.
[16] https://www.ferc.gov/media/news-releases/2013/2013-3/07-16-13.asp#.XGgZe-hKiUk.

APPENDIX 6: ELECTRIC RESTRUCTURING AND RETAIL MARKET CONSIDERATIONS

Purpose of Report

This paper was prepared by Concentric to provide information and insights on the potential impact of ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment") on retail energy costs and service. In particular, this paper addresses: (1) the implications of electric restructuring and retail choice on the Florida Public Service Commission ("FPSC"); (2) experiences of residential customers served by competitive suppliers ; (3) actions taken against retail marketers; (4) analysis of costs incurred by competitive suppliers to provide retail service; and (5) the relatively low participation in competitive retail markets by residential consumers.

Background

Implementing retail choice as contemplated by the Amendment would require the design, implementation, ongoing administration and monitoring of functioning wholesale and retail electricity markets. Establishing, maintaining, and providing oversight over a functioning retail market is a lengthy and complex process, which would require substantial investment. In addition, shifting to a fully restructured market for retail electric service could subject Floridians, particularly residential customers, and especially low-income, elderly, and non-native English-speaking customers, to aggressive marketing practices, billing and customer service issues, and higher cost for services as compared to regulated utility services. Finally, there is relatively low participation rates among residential customers in most restructured states and low levels of satisfaction with competitive supply.

What is a Retail Marketer?

In states that have adopted electric restructuring, "retail energy supplier," "retail marketer," or "energy service company ("ESCO")" refers to a company that serves as an intermediary between the electricity buyer (residential, commercial and industrial customers) and the wholesale electric market. Retailer marketers purchase electricity through wholesale electricity markets and resell it to consumers. Like other competitive businesses, retail marketers develop and sell products, pay their costs, and seek to earn a profit in doing so. They must buy electricity, hire staff, market to customers, sell their services and deliver these services to their customers. In addition, retail marketers must also perform a supply management function in which customer supply obligations are matched with wholesale supply purchases. Retail marketers incur costs for the products they supply (cost of goods sold) and a variety of operating expenses.

Today, in most restructured states, customers that do not choose a retail marketer remain on electricity supply service provide by the utility, which is referred to by terms such as "default service," "standard offer service," "basic service," of POLR service. The term "POLR" reflects that the supply service is provided to ensure that customers receive electric supply if they do not choose a retail marketer or in the event that their retail supplier goes out of business or exits the market. The Amendment does not address POLR service.

Impact of Restructuring on FPSC and State Regulation

Moving from a traditionally regulated retail market to full retail choice has implications for the activity, role, and jurisdiction of the FPSC. One main impact is that the FPSC, or another agency, would need to undertake significant work to shift from regulation to restructuring and establish and monitor the restructured electric retail market. For example, the FPSC would need to:

- Implement rules and regulations for the restructured retail electricity market;
- Implement and administer licensure or certification requirements for retail providers;
- Set protocols for customer enrollment, de-enrollments, shut-offs, late fees, billing formats, contract language, third-party sales verification and consumer protections;
- Establish data exchange protocols for communications between the utilities, marketers and independent system operator ("ISO");
- Initiate an unbundling proceeding;
- Take enforcement actions against providers that do not comply with these rules;
- Review applications for licensure and issue certificates;
- Review applications from retail providers to cease providing service;
- Oversee transition of customers from retail providers that exit the market;
- Oversee customer education regarding the competitive market;
- Address additional questions/complaints from customers to the FPSC.

The FPSC may require additional staff with additional expertise to fulfill these functions and should expect to spend significant time, particularly in the early years of restructuring, with implementation issues. This additional administrative burden may lead to cost increases for the FPSC as it needs to add economic, technical and legal staff to conduct and administer these functions.

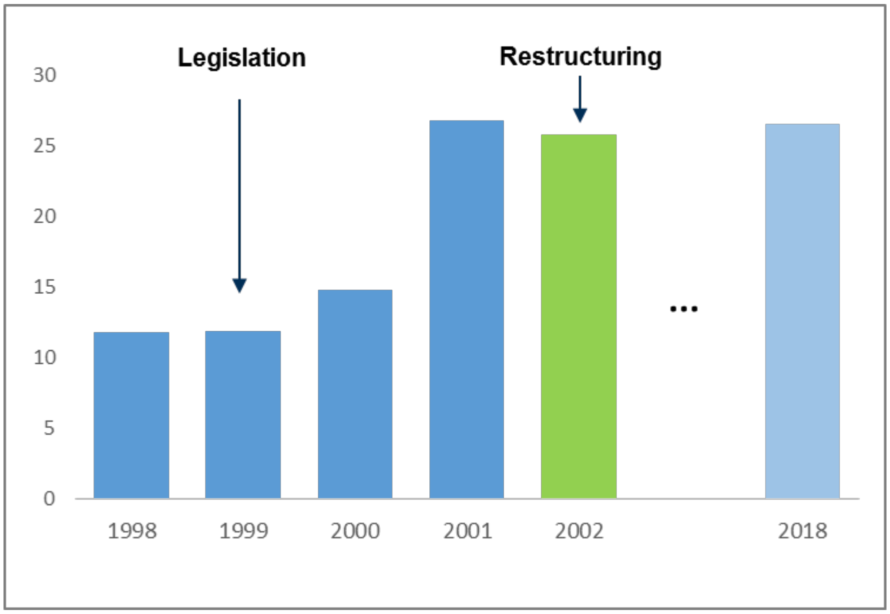
Texas Public Utility Commission Cost Increases due to Restructuring[1]

In order to establish the new deregulated market, the Texas Public Utilities Commission ("Texas PUC") had to significantly expand resources in order to prepare for the new market, ensure execution, and oversee the new market structure. Although some oversight costs were shifted to the regional transmission organization that was created in Texas (i.e., the Electric Reliability Coordinating Council of Texas or "ERCOT"), the new Texas PUC responsibilities more than offset any cost reductions associated with this shift – as can be seen in Figure AP6- 1 below.[2]

There was a significant ramp-up in costs in the years immediately preceding restructuring following the enactment of restructuring legislation, and Texas PUC costs have remained at considerably higher levels ever since. There was an 81% increase in costs between 2000 and 2001 alone.[3] Some of the additional costs included professional fees to contractors / consultants to address the various challenges as highlighted in the previous section. One particular program worth noting in 2001 was a large increase in costs to develop, implement, and manage consumer education across the state.

1 Charles River Associates conducted research and analysis on public utility commission costs due to restructuring on behalf of the Florida Chamber of Commerce. This section summarizes the results of that work.
2 Legislative Appropriations Request for Fiscal Years 2018 and 2019; Governor's Office of Budget, Planning and Policy
3 Legislative Summary Document Regarding PUC Texas – January 2003; State Auditor's Office (SAO 03-377)

FIGURE AP6- 1: TEXAS PUBLIC UTILITY COMMISSION COSTS ($ MILLIONS)



Customer Rates and Marketing Practices

Reduction in FPSC jurisdiction over retail electric service in a restructured market structure could impact customers, particularly residential customers, through increased bills and deceptive marketing, billing, and pricing practices. Many states have recently performed evaluations of their restructured market including whether residential customers are better or worse off than with retail providers.

The Massachusetts AG developed a study in March, 2018 to determine "whether residential consumers in Massachusetts pay more or less for their electric supply when they buy it from the competitive marketplace rather than their electric utility (such as National Grid, Eversource, and Unitil); and (2) identify remedies if warranted."[4] The final analysis showed that "Massachusetts consumers in the competitive supply market paid $176.8 million more than they would have paid if they had received electric supply from their electric company during the two-year period from July 2015 to June 2017. A third year of data shows residential customers lost another $76.2 million, for a three-year total of $253 million."[5] This report looked only at residential electric supply and not the commercial or industrial market, and noted that "Unlike the commercial and industrial market, where sophisticated buyers with demands for large volumes are likely able to negotiate more favorable rates, individual residential consumers are not getting a bargain."[6] Following the publication of this study, the AG issued a press release citing aggressive sales tactics, false promises, higher costs, and the targeting of low-income, elderly, and minority residents, and proposed legislation to end electricity choice for individual residential customers.[7]

---

4 Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, p. viii.

5 Rebecca Tepper, Massachusetts Attorney General's Office, "Suppliers Are Not Providing Value to Individual, Residential Customers" Presentation to the New England Restructuring Roundtable, *October 12, 2018*, slide 4.

6 Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, p. viii., p. 15.

7 "AG Healey Calls for Shut Down of Individual Residential Competitive Supply Industry to Protect Electric Customers" Press Release, March 29, 2018. https://www.mass.gov/news/ag-healey-calls-for-shut-down-of-individual-residential-competitive-supply-industry-to-protect

- A Rhode Island evaluation conducted over four years found that customers who switched from their utility to retail providers had paid $56 million over the default service costs.[8] In Connecticut a study completed by the Office of the Consumer Counsel concluded that in 2015 customers who switched to a competitive supplier paid almost $58 million more than remaining with their default supplier.[9] A 30-month study conducted by the New York Public Service Commission found that customers who switched electric and gas suppliers paid nearly $820 million more than if they had remained with their default suppliers.[10] Illinois AG Lisa Madigan reported that residential and small commercial customers enrolled with competitive suppliers paid over $600 million more for electricity in the last four years than if they continued to purchase their electricity from the regulated utility. [11]

Following the filing of a lawsuit against a retail provider in Illinois for violations of that state's consumer fraud laws, Illinois' AG Madigan also called for an end to residential choice, due to deceptive marketing practices.[12] This month, Connecticut Consumer Counsel, in collaboration with AARP, other consumer advocates, and a U.S. senator, called for the end of residential choice that "economically harms consumers" in Connecticut.[13]

In New York, the Department of Public Service Commission ("NY DPS") ordered competitive electric suppliers to cease signing up new customers, due to customers paying more for electricity provided by competitive suppliers than what they would have paid based on utility rates. The NY DPS order demonstrates the market's poor performance and frustration the commission had in overseeing the competitive retail market for the public's benefit. In particular, the New York Commission wrote:

> "experience shows that, with regard to mass market customers, ESCOs cannot effectively compete with commodity prices offered by utilities. This may be for a number of reasons, including customer acquisition costs, the greater economies of scale of utilities, and the fact that utilities do not profit from the sale of energy commodity. In addition, the Department of Public Service continues to receive a large number of complaints from ESCO customers about unexpectedly high bills."[14]

The NY DPS reported that it received over 5,000 initial complaints against ESCOs in 2015, with 1,076 "escalated complaints," (i.e., not initially resolved by ESCOs) which fall into the following categories:

- 30% - "questionable marketing practices"
- 25% - "dissatisfaction with prices charged – no savings realized"
- 22% - "slamming – enrollment without authorization."[15]

---

8 National Grid: The Narragansett Electric Company, Standard Offer Supply Procurement Plan / 2019 Renewable Energy Standard Procurement Plan. March 1, 2018, Testimony of Stephen A. McCauley, p. 9.

9 Gregory B. Hladky, Study: Consumers Pay Extra for Retail Electricity. Hartford Courant. April 20, 2016. http://www.courant.com/news/connecticut/hc-retail-electricity-costs-above-state-standard-20160420-story.html.

10 Jeff Platsky, AT RISK: NY Reviews Electric, Gas Free-Choice Program; Consumers Ended Up Paying More. Press Connects. February 9, 2018. https://www.pressconnects.com/story/news/2018/02/09/risk-ny-groundbreaking-program-allowing-customers-select-electric-gas-suppliers/302146002/

11 "[Attorney General] Madigan Sues Another Alternative Retail Electric Supplier & Reaches $3 Million Settlement for Defrauded Customers" Press Release, November 19, 2018. http://illinoisattorneygeneral.gov/pressroom/2018_11/20181119b.html

12 Ibid.

13 "Time to End the Third-Party Residential Electric Supply Market" AARP Connecticut. February 2, 2019. https://states.aarp.org/time-to-end-the-third-party-residential-electric-supply-market/

14 New York Public Service Commission Order Resetting Retail Energy Markets and Establishing Further Process, CASE 15-M-0127, (2/23/2016), p. 2.

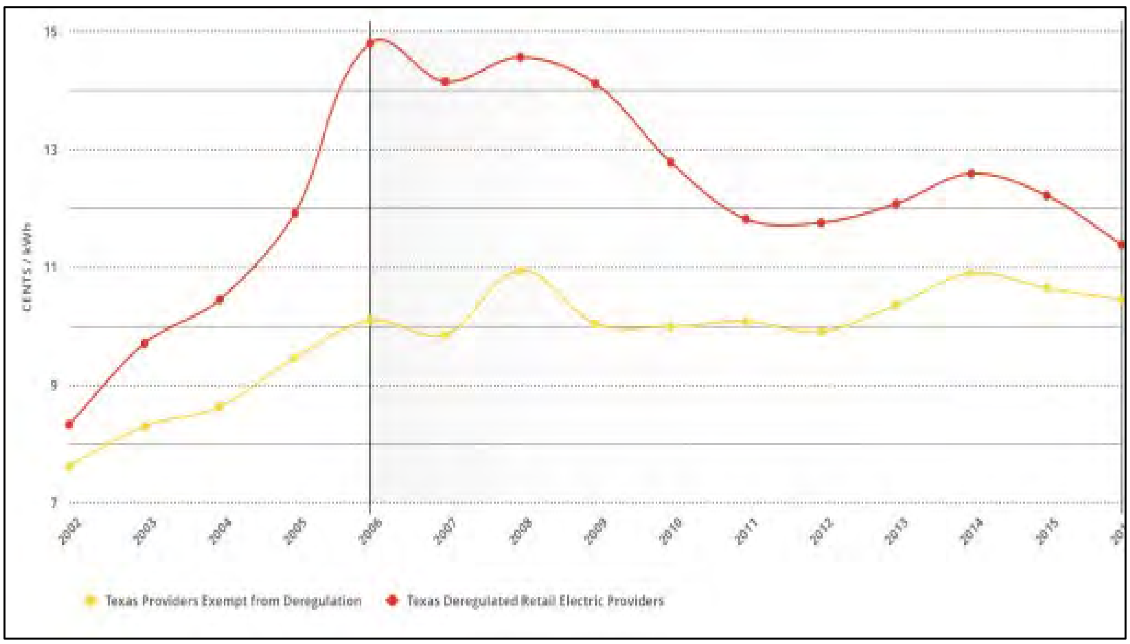
15 Ibid., pp. 12-13.

The NY Commission ordered that ESCOs may only enroll/ renew retail customers based on contracts that: (1) guarantee savings in comparison to what the customer would have paid as a full-service utility customer, or (2) provide at least 30% renewable electricity. Ultimately this order was challenged, and the process is ongoing.

Texas provides another example of an increase of customer complaints following restructuring. After restructuring was implemented in that state, there was a significant increase in customer complaints, as complaints to the Texas Public Utilities Commission, which averaged 1,300/year prior to restructuring rose to as much as 17,250 in a given year.[16] While recent years have shown some decline in these numbers, they are still far above pre-restructuring levels.

Texas has experienced price increases since it opened its markets to competition. According to a 2014 report from the Texas Coalition for Affordable Power ("TCAP"), restructuring has cost Texas customers $22 billion from 2002 – 2012.[17] In its most recent 2018 report, TCAP found that Texans have consistently paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation. This annual trend began during the very first year of the retail electric deregulation in Texas and has continued through 2016, as shown in Figure AP6- 2.

FIGURE AP6- 2: AVERAGE RESIDENTIAL ELECTRICITY PRICES IN TEXAS[18]



Restructured states often find that their residential—particularly low-income, non-native English speaking, and elderly—customers are the victims of aggressive and misleading marketing practices. As Florida has a large population of low-income, elderly, and non-native English-speaking customers, this represents a considerable risk of restructuring in the state.[19]

16 Texas Coalition for Affordable Power, "Deregulated Electricity in Texas 2017 Edition" p. 84.
17 Ibid., citing to TCAP's 2014 report. p. 74.
18 TCAP Report on Electricity Prices in Texas, April 2018.
19 20.1% of Floridians are over the age of 65, as of July 1, 2018, as compared to the national average of 15.6%; 28.7% of Floridians speak a language other than English at home (from 2013-2017), as compared to the national average of 21.3%, and 14% of Floridians live below the poverty line (from 2013-2017), as compared to the national average of 12.3%. Source: https://www.census.gov/quickfacts/fl; https://www.census.gov/quickfacts/fact/table/US/PST045218

These case studies demonstrate the significant risk of retail price increases, particularly for residential customers, from retail restructuring. These case studies also demonstrate that a decision to rely on markets to set prices can lead to customers suffering higher prices than those offered under regulated utility service. Put another way, it is impossible to have both market and regulation setting the prices at the same time. Particularly because the Amendment would preclude Florida's regulated utilities from offering retail service, a decision to rely on market prices means abandoning a safety net for customers and results in a significant loss of control for the Commission over retail pricing and associated practices.

Actions Against Marketers

There are numerous cases in which regulators and attorneys general have undertaken punitive action against energy marketers for an array of violations. Table AP6- 1, below, summarizes a selection of such actions.

TABLE AP6- 1: ILLUSTRATIVE REGULATOR AND ATTORNEY GENERAL ACTIONS AGAINST ENERGY MARKETERS

State/ Province	Illustrative Complaints, Enforcement Actions, Settlements, etc.
Connecticut	In 2018 Spark Energy was fined twice by the Connecticut Public Utility Regulatory Authority. They were first fined in $900,000 in August for displaying inaccurate rates on their bills. The second fine for $750,000 was issued on September 5, 2018 in response to Spark sending automated calls to customers under the guise of Eversource.[20] Connecticut AG and Consumer Counsel petitioned the Public Utilities Regulatory Authority to investigate the marketing practices of Energy Plus, after customers claimed the company failed to adequately disclose energy rates, culminating in a $4.5 million settlement paid by the company.[21]
Illinois	In October 2018, Sperian Energy settled a lawsuit issued by AG Lisa Madigan for deceptive market practices like failing to notify customers of contract lengths and fees. Sperian was required to refund $2.65 million to 60,000 Illinois customers and was banned from marketing to customers in Illinois for the next two years.[22] Illinois Commerce Commission fined Just Energy in relation to deceptive sales and marketing practices and ordered an independent audit of the company's sales program.[23] Illinois AG reached settlement with U.S. Energy Savings Corp. (now Just Energy) allowing hundreds of customers to terminate contracts and receive $1 million in restitution for misleading sales tactics.[24]

20 Matt Pilon, "Spark Energy Hit with Second Fine", September 11, 2018.
21 Dowling, Brian, "Settlement with NRG Energy Subsidiary Nets State $4.5M For Enforcement," *The Hartford Courant*, May 22, 2014.
22 "Attorney General Lisa Madigan: Secures $2.6 Million in Refunds for Illinois Residents Defrauded by Sperian Energy", Press Release, October 21, 2018.
23 Illinois Commerce Commission, "Illinois Commerce Commission Fines Just Energy for Deceptive Sales and Marketing Practices, Orders Audit," Press Release, April 15, 2010.
24 "Madigan Secures $1 Million in Consumer Restitution from Alternative Gas Supplier for Deceptive Claims," Press Release, May 14, 2009.

State/ Province	Illustrative Complaints, Enforcement Actions, Settlements, etc.
Maryland	Maryland Public Service Commission fined North American Power $100,000 for misleading advertisements and ordered the suspension of telemarketing activities in the state.[25] The Maryland Public Service Commission fined TES Energy for brokering electric service without a license.[26]
New Jersey	Energy Plus was the target of a class action lawsuit for allegedly perpetrating an illegal bait-and-switch scheme and defrauding thousands of New Jersey consumers of millions of dollars.[27]
New York	Liberty Power was required to pay $550,000 in refunds to New York customers in April 2018, due to tricking customers into signing contracts by impersonating utility representatives and disguising contracts as billing corrections.[28] In 2017 Energy Plus was ordered to reimburse $800,000 to customers in a lawsuit filed by New York AG Schneiderman. The AG's office found that Energy Plus had wrongly promised savings and had misrepresented their cancellation policy.[29] New York AG reached a settlement with U.S. Energy Savings Corp. (now Just Energy) requiring the company to waive hundreds of thousands of dollars in customer termination fees and pay $200,000 to the state.[30]
Ohio	In 2016 Just Energy was fined $125,000 by the Ohio Public Utilities Commission for deceptive marketing practices. Customers complained to the PUC that they had received bills from Just Energy without ever signing up for their service.[31]
Ontario	Ontario Energy Board fined Direct Energy for a string of forged signatures on energy contracts. Ontario Energy Board fined Ontario Energy Savings Corp. (now Just Energy) for a string of forged signatures on energy contracts.[32]

Retail Marketers' Cost Structure

Retail marketers incur many of the same types of costs as utilities for billing and customer care. A result of retail restructuring is that instead of a single IOU providing these functions, as many ESCOs as function in the market provide these functions, creating duplicative and additive costs. Finally, retail providers incur significant costs to establish their brand and market and sell their product to consumers. Ultimately, retail providers seek to recoup these costs from retail customers through rates.

25 Cho, Hanah, "Electric Choice: Know Your Rights," *Baltimore Sun*, January 7, 2012.
26 "License Briefs," EnergyChoiceMatters.com, April 14, 2011.
27 "Sanford Wittels & Heisler File Class Action Against Energy Plus," Press Release, May 2, 2012.
28 Bill Heitzel, "Liberty Power Agrees to Fund Customers for Unscrupulous Tactics," April 12, 2018
29 "A.G. Schneiderman Announces $800K Settlement with Energy Service Company That Falsely Advertised Lower Utility Bills", Press Release, August 30, 2017.
30 "Attorney General Cuomo Reaches Agreement with WNY Natural Gas Provider After Consumer Complaints," Press Release, November 10, 2009.
31 Dan Gearino, "Electricity Marketer Just Energy Fined Over Complaints", November 5, 2016.
32 Ibid.

Acquisition Costs

Retail supplier service costs include customer acquisition expenses which the utility does not incur. These costs can vary widely depending on the sales channel used by the retailer. A review of certain retailers that report acquisition costs suggests that these costs average approximately $121/customer including costs for door-to-door sales commissions, branding and marketing expenses.[33] If the Amendment is approved, an additional $850 million of costs may be incurred as retailers seek to acquire customers and then recover these costs in their rates.[34] This cost estimate does not include customer acquisitions costs for commercial and industrial accounts of which there are over 915,000 in Florida.

Duplicative Systems

In most restructured markets, utilities and retailers both provide customer care and billing functions. Utilities maintain billing systems for determining transmission and distributes rates and retailers calculate supply charges. These redundant billing requirements mean that each consumer served by a retailer is supporting two billing platforms.

Further, under cost of service regulation, electric utilities enjoy significant back-office economies of scale which benefits consumers in the form of lower and more stable monthly electricity bills. Given the relative lack of scale of retailers operating within a single service territory, it is reasonable to expect that actual supplier costs are far higher than what utilities incur for these services on a unit basis. (In this case the comparable utility service costs would include only billing, customer care and some corporate allocation and would not include transmission and distribution system operating costs and associated depreciations expenses.)

The average "cost to serve" for competitive retailers in a review of publicly available information was $112/customer/year. [35] The impact of these higher operating costs could be considerable for Florida customers. As Florida has nearly 7 million residential electricity customers served by IOUs, estimated retailer "costs to serve" alone would cost Florida customers an additional $784 million per year assuming all customers were to switch to a retail supplier.

Limited Residential Customer Uptake of Competitive Retail Service

Residential customers have not demonstrated a strong desire for retail choice. This is demonstrated in a recent US Energy Information Administration ("EIA") report that showed that electricity residential retail choice participation has declined since its peak in 2014 and includes the following table.[36]

---

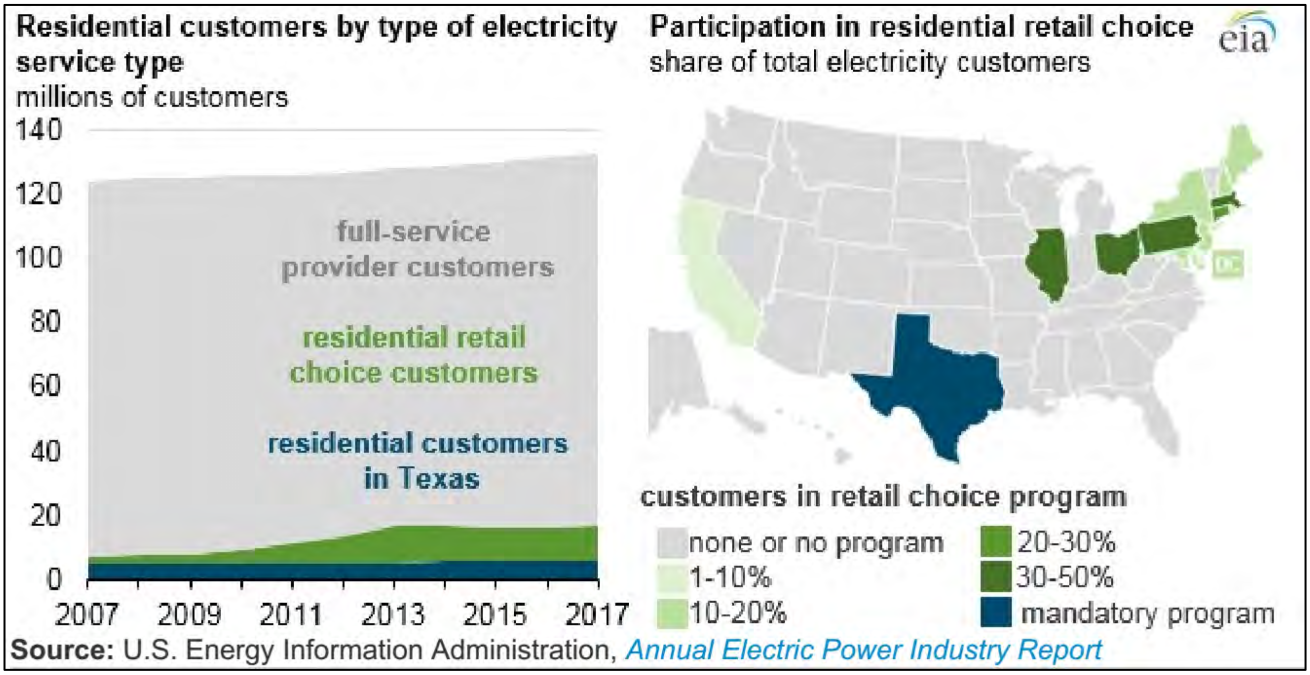
33 Sources: Crius Energy Trust, Management Discussion and Analysis ("MD&A"), March 8, 2018, pages 10 and 12; Just Energy MD&A, May 16, 2018, pages 4 and 30; Genie Energy Ltd, 2017 Form 10-K, pages 27 and 28; Spark Energy Inc., 2017 Form10-K; pages 52 and 93. Calculated as average of Crius, Just Energy, Genie, and Spark total acquisition costs, divided by acquired new customers.

34 $850 million is calculated as the product of the cost of $121.48 per customer multiplied by the number of residential customers served by Florida's IOUs, 6,997,244, rounded from $850,053,527.

35 Sources: Crius Energy Trust, Management Discussion and Analysis ("MD&A"), March 8, 2018, pages 10 and 12; Just Energy MD&A, May 16, 2018, pages 4 and 30; Genie Energy Ltd, 2017 Form 10-K, pages 27 and 28; Spark Energy Inc., 2017 Form10-K; pages 52 and 93. Calculated as average of Crius, Just Energy, Genie, and Spark total cost to serve, divided by total customers.

36 US EIA, "Today in Energy: Electricity residential retail choice participation has declined since 2014 peak." (Nov. 8, 2018).

FIGURE AP6- 3: RESIDENTIAL PARTICIPATION IN RETAIL CHOICE IN U.S.



It is observed that residential customers exhibit "stickiness," meaning that when they are presented with retail choice, many customers either do not switch providers and take service from the POLR, or switch and then return to their original provider or the POLR.

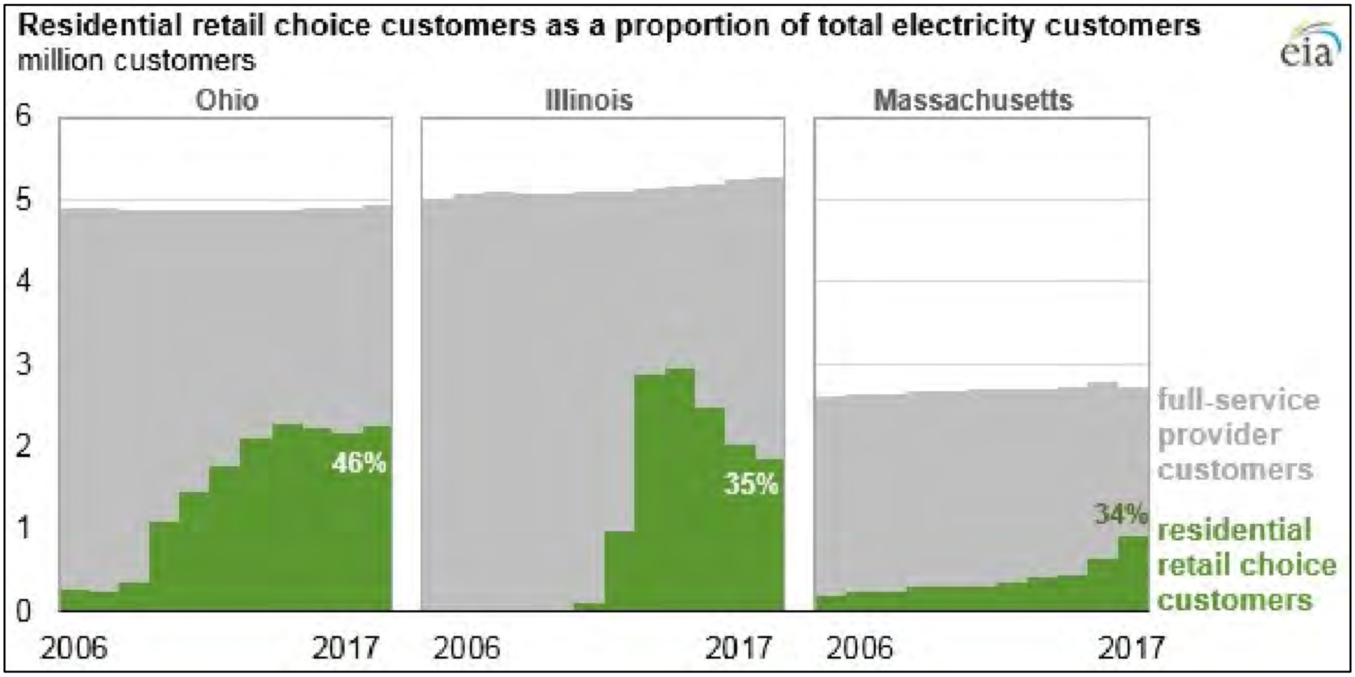
One factor impacting residential participation in competitive retail markets that also have utility provided service is "community choice aggregation" ("CCA") or "municipal aggregation." CCA legislation enables local governments to enter into contracts whereby customers participate in competitive retail supply arrangements, unless they individually opt-out. This has driven increases in residential participation in states like Massachusetts, where the vast majority of residential customers served by competitive supply are part of CCAs. In 2014 in Massachusetts, which implemented restructuring in 1999, approximately 18% of residential customers. This number has grown in the last four years to approximately 42% of customers in 2018, due largely to numerous new CCAs.[37] This is reflected in Figure AP6-4, below.

CCAs are not immune, however, to negative potential outcomes associated with competitive electric supply service. Illinois saw an increase in residential customer participation in competitive retail electric service as CCAs were introduced in that state from 2009-2013. However, following extreme cold weather in January 2014, FirstEnergy Solutions, a major retail power marketer in Illinois, announced it would impose a one-time surcharge of $5 to $15 on its customers, including in Illinois, to cover extra costs. (FirstEnergy Solutions also applied this surcharge to its Ohio customers, which led to a broad investigation by the Public Utilities Commission of Ohio; ultimately, FirstEnergy Solutions decided to exclude its almost three million residential customers from the charge.) After this event, residential customers in Illinois switched back to their default providers at a rate of 16% in 2015 and 18% in 2016. As of 2017, retail choice providers serviced 35% of total residential customers

[37] Electric Customer Migration Data, Mass.gov. https://www.mass.gov/service-details/electric-customer-migration-data. 2014 data is annual; 2018 data is for Sept. 2018, the most recent month available.

in Illinois, down from the peak of 57% in 2014.[38] Figure AP6- 4 below shows recent increase in Massachusetts, as well as declines in Illinois and Ohio.

FIGURE AP6- 4: CHANGE IN RESIDENTIAL CUSTOMERS PARTICIPATING IN RETAIL ELECTRIC SUPPLY IN THREE STATES

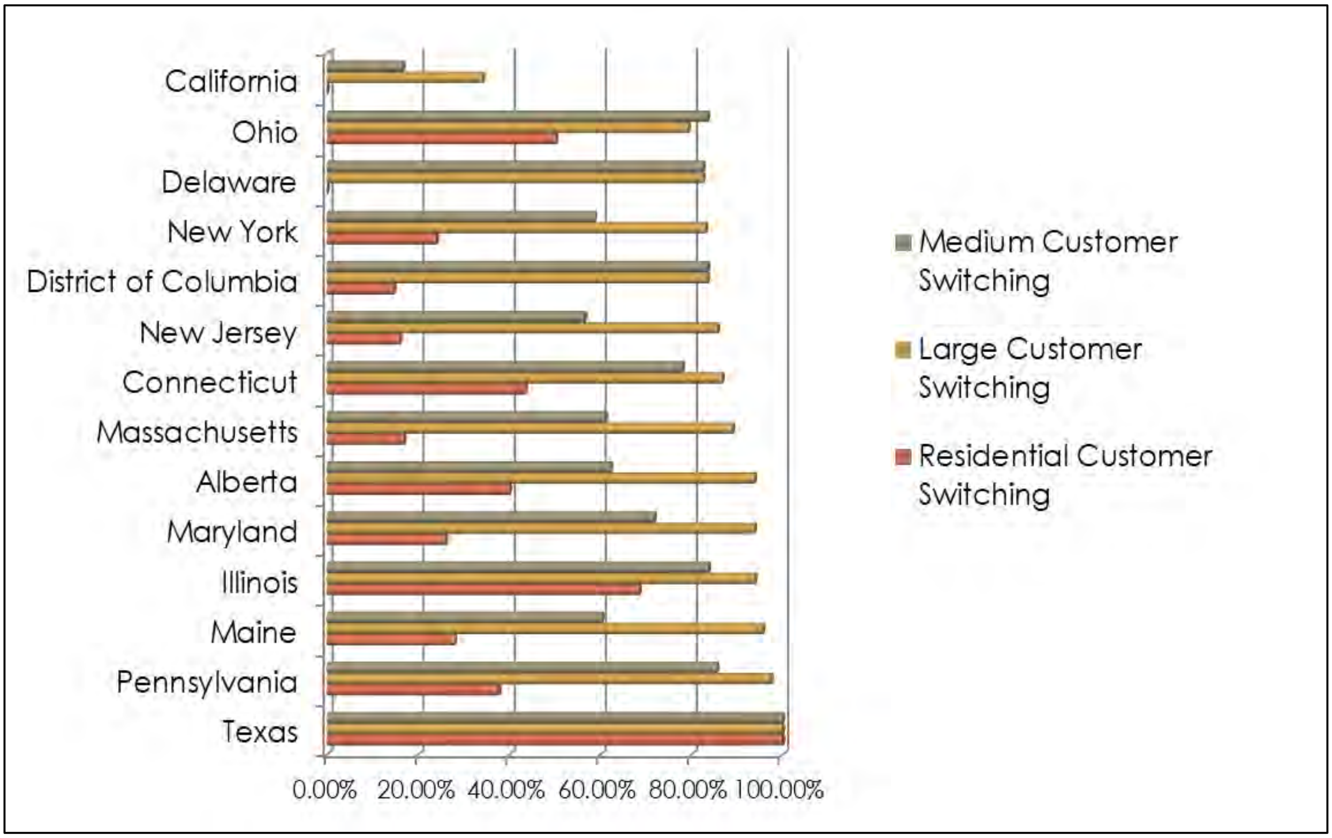


In contrast to residential customers, the migration to retail suppliers by industrial customers has been much greater. In Massachusetts in 2014, 73% of large commercial and industrial customers used retail supply and this grew to 85% in 2018.

Figure AP6- 5: below, illustrates that retail access has been popular with commercial and industrial customers; but less popular with residential customers.

38 US EIA, "Today in Energy: Electricity residential retail choice participation has declined since 2014 peak." (Nov. 8, 2018).

FIGURE AP6- 5: PERCENT OF CUSTOMERS ON RETAIL ELECTRIC SUPPLY BY STATE AND RATE CLASS[39]



[39] "Annual Baseline Assessment of Choice in Canada and the United States" January 2014, pages 14, 26.

APPENDIX 7: RE-REGULATION EFFORTS

Purpose of Report

This report was prepared by Concentric to provide information and insights on the experience of those states that began efforts to restructure their electricity markets only to decide to halt electric restructuring or re-regulate. This report discusses the experiences of California as the first state to introduce competitive electricity markets, as well as other states that started and then reversed restructuring efforts, largely impacted by the experience of California.

Background

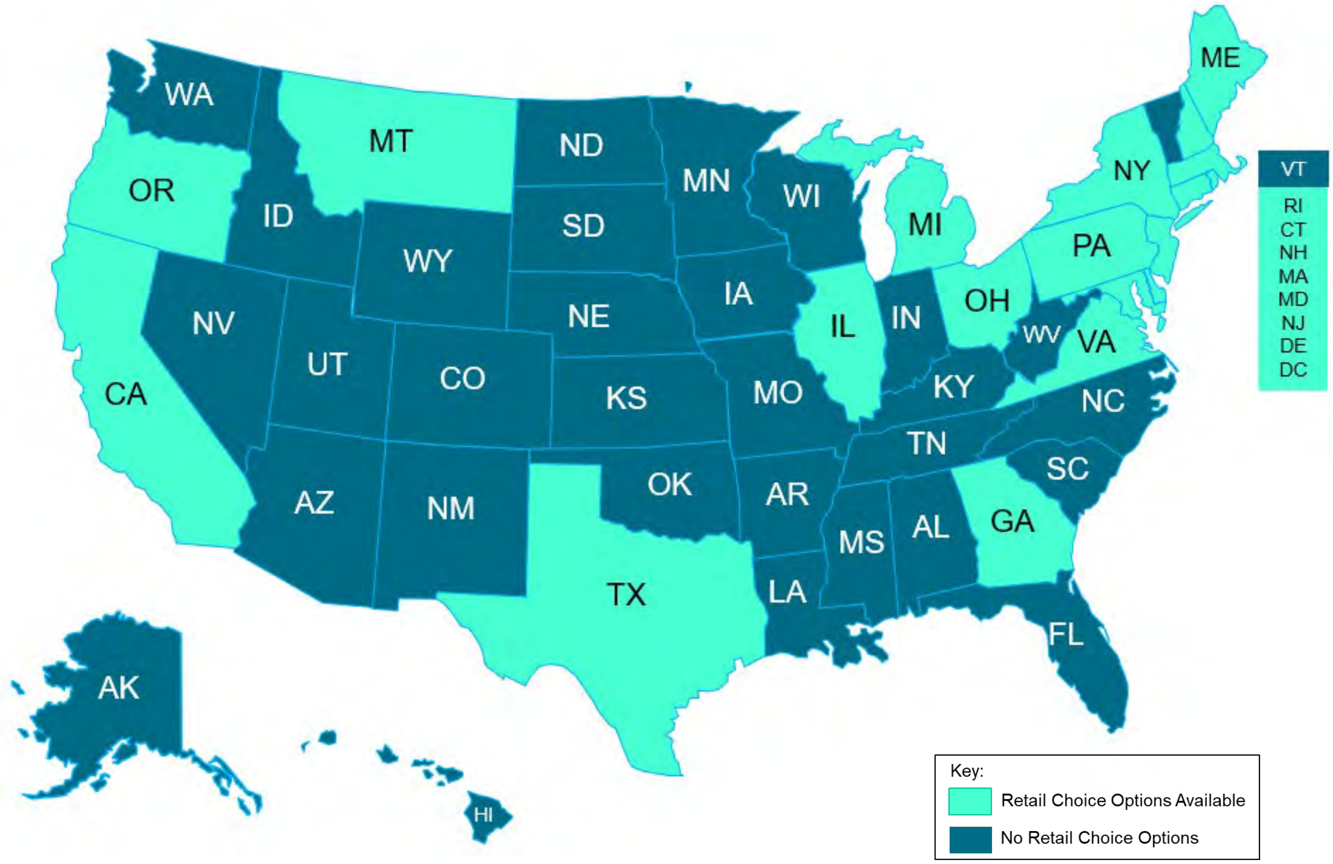
Currently, Floridians' electricity service is provided either by municipal electric companies, electric cooperatives or investor owned utilities ("IOUs"). The state's IOUs are vertically integrated and are regulated by the Florida Public Service Commission ("FPSC") and other state and federal regulatory bodies. Ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" would provide all customers of Florida's IOUs the right to choose their electricity provider, and the right to generate electricity either alone or in association with others. IOUs would be limited to the "construction, operation, and repair of electrical transmission and distribution systems." IOUs would no longer own generation, and the existence of sufficient generation and other supply resources, as well as transmission investment, would be shifted to competitive market forces under the jurisdiction of federal regulatory bodies.

The realities of competitive electricity markets have been experienced in several states across the country. Florida should consider these lessons learned as it considers the costs, benefits, and risks of introducing competition in the state of Florida.

Retail Choice Today

Currently, some form of electric retail choice is available in 20 states nationwide. Retail choice in these states varies from full retail choice for commercial, industrial and residential customers to partial retail choice for large industrial customers capped at a percentage of total retail sales. The states that have implemented electric restructuring in some form is show in Figure AP7- 1.

FIGURE AP7- 1: STATUS OF ELECTRIC RESTRUCTURING BY STATE[1]



Re-Regulation Efforts

California

California was one of the first states to restructure its energy market. The 1996 law that restructured California's electricity industry was intended to be the first step toward lower electricity prices for 70 percent of the state's population. The restructuring plan was enacted to change the sources and pricing of electricity for customers of the state's three large investor-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. Together, those utilities served almost three-quarters of the state's electricity users. California's restructuring plan was based on the assumption that greater competition among independent power generators would cause wholesale prices for electricity to fall. By the summer of 2000, however, demand for electricity had outpaced the generating capacity available to supply the market. Wholesale prices per megawatt hour in California, which were near $30 in April of 2000 rose significantly to more than $100 by

[1] American Coalition of Competitive Energy Suppliers

June 2000.[2] By November, prices had increased to between $250 MWh and $450 MWh.[3] The first five months of 2001 were characterized by soaring wholesale prices, energy emergencies, and a small number of rolling blackouts. The pain was severe. The California grid operator was forced to institute statewide rolling blackouts to prevent the whole grid from collapsing. Emergency rate hikes were ordered since utility retail price caps had been instituted when the market was first established. However, these rate hikes were insufficient in protecting the financial assets and the borrowing power of the big electric utilities. With their monetary resources depleted, the utilities were no longer credit worthy, and Pacific Gas & Electric eventually filed for bankruptcy. By December of 2000, under orders of the FERC, purchase price controls were replaced by a "soft cap" on wholesale markets. The FERC ordered the soft price cap to limit price changes while allowing cost-based price increases above the wholesale price-controlled levels. But these soft caps were not effective and encouraged gaming of the system by generators and marketers. Eventually, the FERC ordered refunds of large sums from retail marketers to California, as massive market abuses by Enron and other marketers were proven. As a result of the California crisis, states that had been moving towards electric restructuring suspended further action, or even repealed restructuring schemes on the books. The FERC continued to press for a standard market design and regional transmission organizations.

The California Public Utilities Commission ("CPUC") suspended retail choice on September 20, 2001, in Decision 01-09-060. At the time, the CPUC estimated that about 5% of the state's peak load of 46,000 MW was under direct access contracts, mostly with large industrial customers. Contracts in place were allowed to continue until their expiration. Efforts to restore choice have not been successful to date.

Arizona

Arizona opened its energy market to retail competition on January 1, 2001. Customers could remain with their distribution utility, choose a competitive supplier or aggregate together to receive service. With the California market experiencing rolling blackouts and escalated electric bills, Arizona became concerned about electric restructuring. In 2002, the Arizona Corporation Commission ("ACC") stated, "The wholesale market is not currently workably competitive; therefore, reliance on that market will not result in just and reasonable rates."[4] In 2004 in a case before the Arizona Supreme Court, the court decided that the Arizona state constitution allocated the authority to prescribe just and reasonable rates solely to the ACC. Electric restructuring would lead to rates being set by participants in a competitive market. This decision held that rates set by a competitive market would imply that the ACC was neglecting its constitutional responsibility. Efforts to revisit electric restructuring have not been successful.

Arkansas

The Electric Consumer Choice Act of 1999 mandated electric competition by January 1, 2002. As the California energy crisis unfolded, energy traders poised to compete in the newly opened markets in Arkansas saw their stocks plummet, and Arkansas legislators, alarmed by the disastrous consequences of electric restructuring in California, postponed open access. Shortly thereafter Enron Corporation collapsed, with its market cap dropping from $77 billion to $500 million in a matter of a few weeks. As a result, Arkansas regulators determined that continued movement toward retail competition was not in the public interest.

2 ASU Energy Policy Innovation Council, October 2013.
3 Ibid.
4 Ibid.

Montana

In 1997, the Montana legislature voted to pass an electric restructuring bill. Montana Power then sold its electric generating assets as well as a portion of its distribution assets for $2.5 billion, funneling the profits into a telecommunications company, Touch America, which then went bankrupt and dissolved within 19 months, taking the pensions of Montana Power workers and stockholders' investments with it.[5] By the summer of 2003, electricity prices in Montana had risen by 15%.[6] Consequently, politicians began to agree that electric restructuring had been a huge mistake. The state's power companies were allowed to purchase generation, and retail competition was suspended. There are not currently plans to re-introduce a competitive electricity market.

Nevada

Nevada flirted with, but never consummated, a transition away from a regulated monopoly structure to a competitive, retail electric market in the late 1990's and early 2000's. The first official legislative steps towards a restructured energy market came from a 1995 resolution. That resolution kickstarted a process that dominated the next six years of legislative sessions and regulatory proceedings. One of the first products of that resolution was a 360-plus page report produced by the state's regulatory commission, which after years of research, countless hearing and tens of thousands of pages in docket filings summed up their findings with the statement that "Implementation would be complicated, but achievable."[7] Despite thousands of man-hours and countless hearings in front of the legislators and regulators, state leaders ultimately backed away from the effort after watching California's energy market implode and lead to mass rolling blackouts across the state.

Recently, a statewide ballot initiative was introduced to open up the electricity market to competition. The statewide ballot initiative went before voters in the November 2016 and 2018 general elections. After significant time and expense, the initiative failed.

New Mexico

New Mexico began on its path toward electric restructuring in January of 1998 with a call for legislative adoption of electric restructuring standards by the autumn of 1999 and full retail competition by January of 2001. In March 1999, however, electric restructuring hit a road block. The State Supreme Court ruled that the energy commission had exceeded its authority when it ordered Public Service of New Mexico to open its power lines to a competitor.

In April of 2000, New Mexico's investor-owned utilities sought a delay of the start of competition for a year. They claimed to be unprepared to implement new billing and computer systems. In August, even before the delayed date could come into play, New Mexico's AG, the New Mexico Industrial Energy Consumers, and the New Mexico Rural Electric Cooperative Association cited California's crisis and asked for a postponement of the decision to authorize the unbundling. New Mexico's energy market continues to be fully regulated.

Michigan

Michigan opened its retail electric market to competition in 2001. Public Act 141, commonly known as the "Customer Choice and Electric Reliability Act" mandated choice for all retail customers of investor-owned utilities

5 Great Falls Tribune, December 6, 2014.
6 Ibid.
7 What Nevada Can Learn from its Attempt (and Failure) to deregulate the energy market in the 1990s, November 17, 2017

by January 1, 2002. In anticipation of the introduction of competitive suppliers to the Michigan utility system, and to allow them to functionally participate in the retail electric market, the law directed the three largest utilities in the state (Consumers Energy, Detroit Edison, and Indiana Michigan Power Company) to file a joint plan by January 1, 2002 to permanently expand available transmission capacity by at least 2,000 MW by 2004, and directed all utilities serving the state to immediately take "all necessary steps" to connect merchant power plants with more than 100 KW to their transmission and distribution systems. In addition, existing utilities were required to relinquish commercial control over any generation exceeding 30% of relevant market capacity.

With regard to residential customers of Consumers Energy and Detroit Edison, Public Act 141 called for an immediate 5 percent rate reduction, and for a rate freeze until at least January 1, 2006. Under the implementation rules filed by these utilities and approved by the Michigan Public Service Commission, customers that failed to choose an alternative supplier, or that were not offered service from another supplier, would retain total service from their existing utility company. In addition, Public Act 141 imposed certain protections for residential customers, including increased winter shut-off protection for senior citizens and low-income customers.

For a variety of reasons related to high wholesale prices and low retail price caps, and competitive choice of suppliers, few consumers switched electricity suppliers. As a result, in 2008, the governor of Michigan agreed to cap participation in electric choice programs, guaranteeing utilities a 90 percent market share, in exchange for a commitment to deploy more renewable energy. Michigan has since debated fully opening its energy market to competition but has not done so to date.

Virginia

In 1999, the Virginia General Assembly passed a law that was intended to restructure Virginia's energy market and bring competition for electric generation to the Commonwealth. After several years, however, the General Assembly determined that sufficient competition had not developed, primarily due to high gas prices and low retail rates, and that retail electric restructuring of electric generation should not go forward. Therefore, in 2007, the General Assembly passed a comprehensive re-regulation law. The Re-Regulation Act established new procedures for reviewing each utility's rates and earnings. The law also allowed utilities to recover certain costs, including money spent on new power plants and renewable energy programs, outside of their base rates and through new single-issue rate riders called rate adjustment clauses. Currently, customers using at least 5 megawatts a year or any customer that will use 100 percent renewable energy can buy electricity from a company other than the regulated utility. There has been no progress to date in moving forward with full retail competition.

APPENDIX 8: RESOURCE ADEQUACY, SYSTEM PLANNING, AND RELIABILITY

Purpose of Report

This report was prepared by Concentric to provide information and insights on the potential impact of ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment") on resource adequacy and bulk power system reliability in the state of Florida. This report discusses potential impacts on resource adequacy in terms of the generation resources to meet customer demand, the unique nature and isolation of peninsular Florida and potential impacts of jurisdictional changes on system reliability.

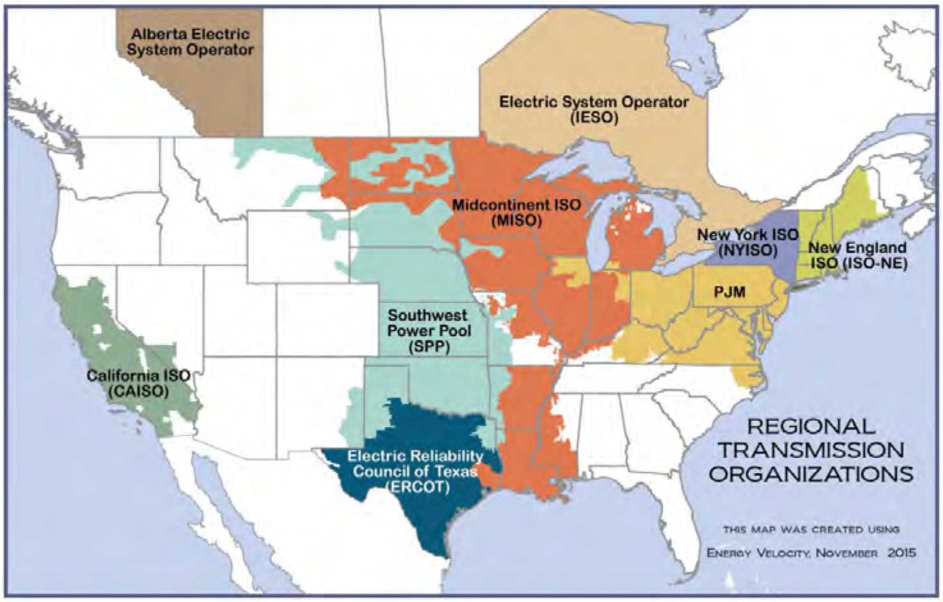
Background

Currently, electricity service is provided either by rural electric cooperatives, municipal electric companies or investor owned utilities ("IOUs"). The state's IOUs are vertically integrated and are regulated by the Florida Public Service Commission ("FPSC") and other state and federal regulatory bodies. The Amendment would provide all customers of Florida's IOUs the right to choose their electricity provider, and the right to generate electricity either alone or in association with others. IOUs would be limited to the "construction, operation, and repair of electrical transmission and distribution systems." IOUs would no longer own generation or transmission and distribution, and the existence of sufficient generation and other supply resources, as well as transmission investment, would be shifted to competitive market forces under the jurisdiction of federal regulatory bodies.

Implementing full retail choice as proposed in the ballot measure, and the right to engage in electric generation, would require the design, implementation, ongoing administration and monitoring of functioning wholesale and retail electricity markets. While there are a very small number of states where retail choice is available without a competitive wholesale market (e.g. Georgia), the ability to choose a retail provider in these states is limited to large commercial and industrial customers. In order to achieve the promised benefits of full retail reform, a functioning wholesale electricity market is necessary to facilitate the buying and selling of electricity for all retail customers. All states that have restructured their electricity markets to provide full retail choice (commercial, industrial and residential) are part of either an ISO (Independent System Operator) or an RTO (Regional Transmission Organization). ISOs/RTOs are not-for-profit entities that were formed to perform three basic functions: (1) operate the bulk electric power system, (2) develop, oversee, and administer the wholesale electric market, and (3) manage the power system planning processes to address transmission needs. Florida, like many traditionally regulated states, does not currently have an ISO/RTO or like organization.

A number of traditionally regulated states are part of an ISO/RTO but do not have a competitive retail electric market/retail choice. The current configuration of ISOs/RTOs is shown in the figure below.

FIGURE AP8- 1: MAP OF CONTINENTAL ISO/RTO FOOTPRINTS[1]



Florida is geographically isolated from existing ISO/RTOs, meaning that it would likely need to establish its own wholesale power market to manage the services that would be required to support the form of restructuring contemplated in the ballot initiative, which would restructure the electric market at both the retail and wholesale levels. As discussed in more detail below, forming and maintaining a functioning wholesale market is a very lengthy process, and will require substantial investment in the development and on-going administration of the competitive market, including the establishment of an ISO/RTO.

Key Conclusions

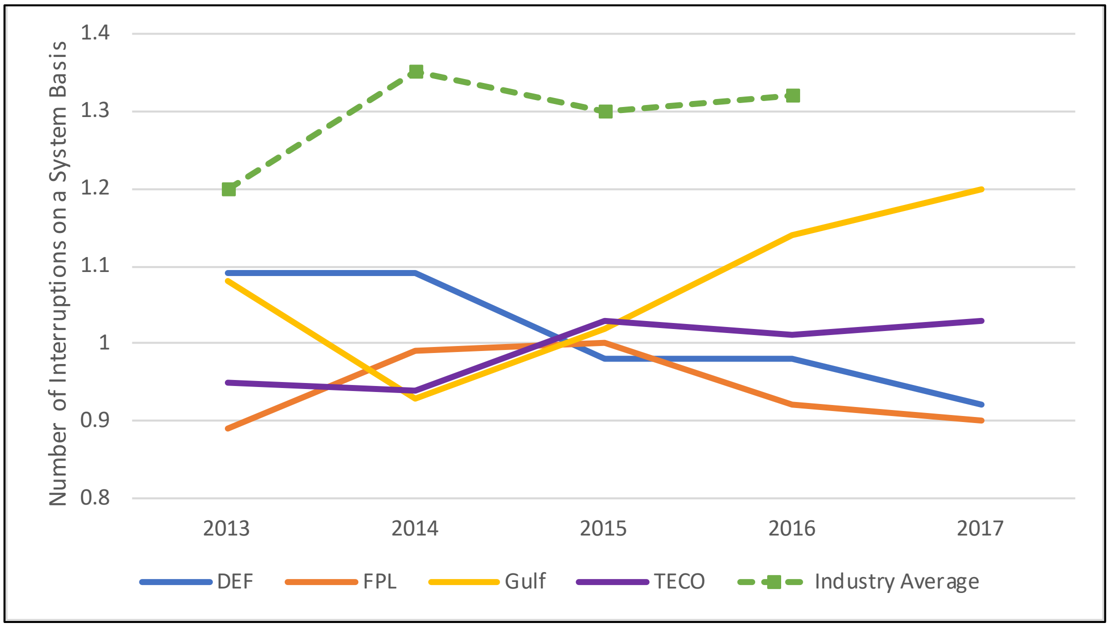
Three elements of restructuring combine to give Florida reason to be concerned about the impacts of restructuring on reliability and resource adequacy. These are: (1) the transfer of jurisdiction from the FPSC to the FERC; (2) the abandonment of integrated resource planning processes and recourse to regulated utilities to build infrastructure to accommodate growth, efficiency and environmental policy; and (3) the ongoing challenges of incenting new entry in competitive markets. It is precisely these three factors that have caused several states (e.g., Connecticut, Illinois, Maryland, and New Jersey) to take belated "re-regulation" actions in an attempt to address reliability concerns that restructuring theorists, led by Enron and academicians, had successfully argued would be taken care of by "the market."[2,3] Further, the unique nature and isolation of peninsular Florida introduces additional complexities that must be considered and included in the analysis of the costs and benefits of retail energy market reforms in Florida.

1 Federal Energy Regulatory Commission, Regional Transmission Organizations (RTO)/Independent System Operators (ISO), October 18, 2018, https://www.ferc.gov/industries/electric/indus-act/rto.asp
2 Wayne, Leslie, "Enron's Many Strands: The Politics; Enron, Preaching Deregulation, Worked the Statehouse Circuit," *New York Times*, February 9, 2002.
3 Hogan, William, "Restructuring the Electricity Market: Institutions for Network Systems," Harvard University, April 1999.

Resource Adequacy

One of the most significant concerns with the proposed ballot measure is the potential threat to resource adequacy in Florida. Currently, IOUs are responsible for the planning of, investment in, and maintenance of the electric grid, including ensuring sufficient generation and other resources (such as demand side management and demand response programs) to meet customer demand. The FPSC provides regulatory oversight of these functions. Over time, this has resulted in Florida having a high degree of reliability. For example, a review of recent system reliability data shows that the major Florida IOUs demonstrate considerably higher system reliability than the industry wide averages based on widely accepted measures, as shown in the tables below. This exceptional performance is the result of not only the proper planning and maintenance of the electric delivery system, but also a deliberate approach to generation resource planning to ensure that generating resources are available to meet customer demand.

FIGURE AP8- 2: SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX[4]



[4] Review of Florida's Investor-Owned Electric Utilities 2017 Service Reliability Reports; 2016 Distribution Reliability Study 2017 IEEE PES General Meeting.

FIGURE AP8- 3: SYSTEM AVERAGE INTERRUPTION DURATION INDEX[5]

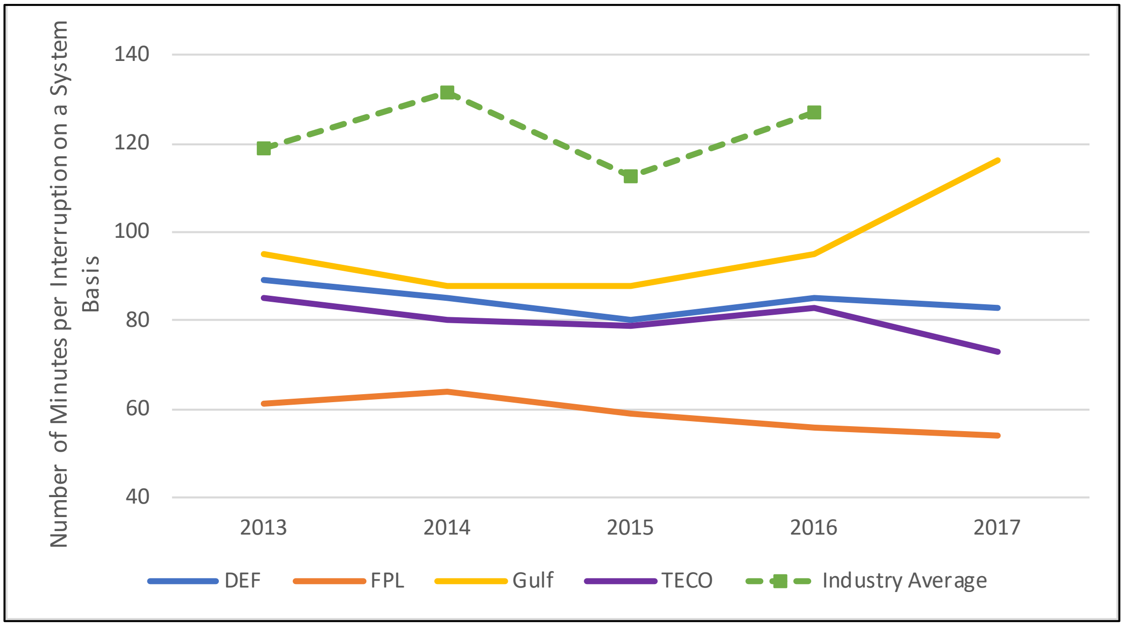
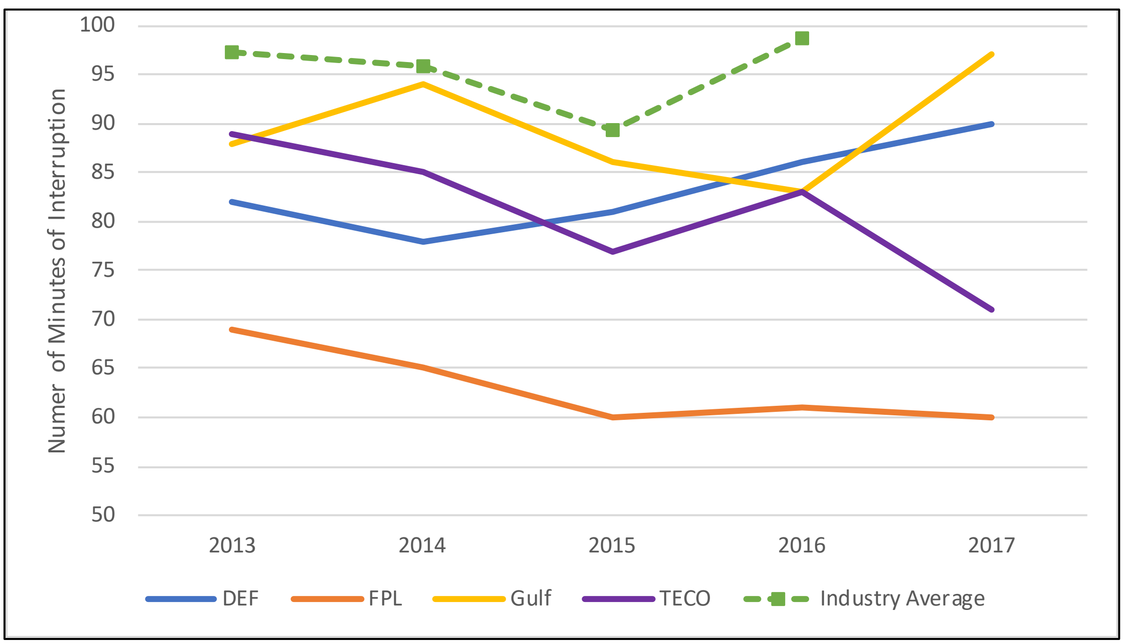


FIGURE AP8- 4: CUSTOMER AVERAGE INTERRUPTION DURATION INDEX [6]



---

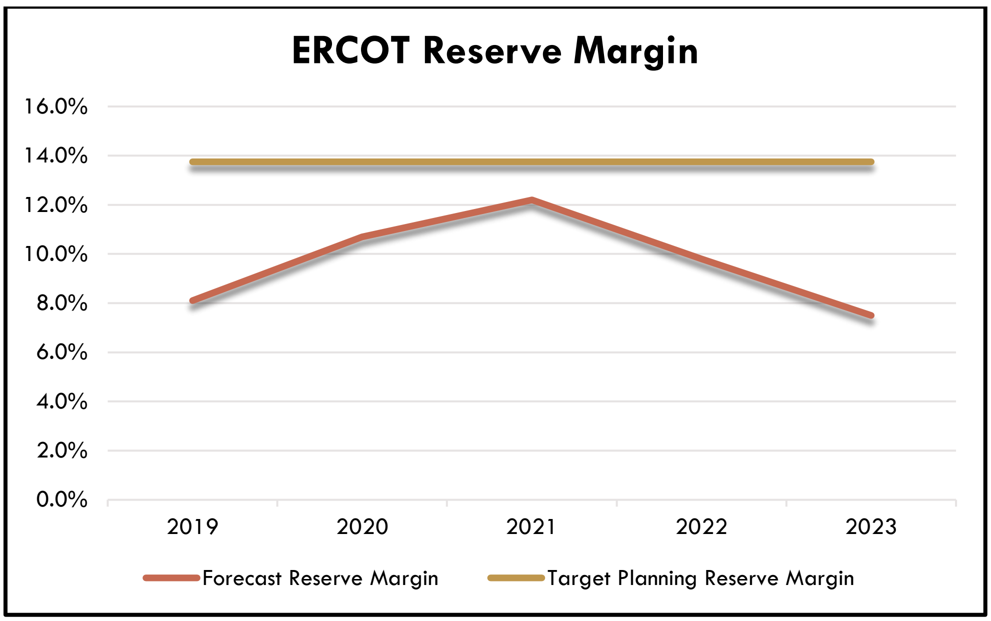
5 Ibid.

6 Ibid.

This planning of generation resources that is so critical to the provision of reliable service is a casualty of restructured markets, under which the amount and type of new generation is left to market forces. In the case of Florida, this resource planning void would happen at precisely the time when fuel price, technology, and environmental regulation uncertainties necessitate constructive, long-term resource planning among regulators, utilities, and the broad group of stakeholders that depend on a reliable, affordable, environmentally responsible portfolio of resources.

Experience has shown that restructured electricity markets struggle with the how to provide the incentives necessary to encourage generation when and where it is needed. In markets where electric utilities are prevented from owning generation, there is no longer any utility responsibility for generation resource planning to ensure reliable service. Merchant generators' short-run, profit-driven decisions to construct and retire generation capacity replace the vital role served by integrated resource planning. In Texas, this has resulted in shrinking reserve margins, as shown in Figure AP8- 5 below.

FIGURE AP8- 5: ERCOT RESERVE MARGINS 2019-2023



Source: ERCOT.[7]

When this information was released by ERCOT in December 2018, Texas Public Utility Commission Chair DeAnn Walker referred to the report as "pretty scary." A few weeks later, ERCOT announced that a 470 MW plant was being mothballed, which further reduced ERCOT's projected 2019 reserve margin from 8.1% to 7.4%, far below its target planning reserve margin of 13.75%.[8] With this announcement, PUC Chair Walker stated, "I was already concerned, and with [this plant] coming out, it's heightened my concerns."[9] It should be noted that part of the reason for this shortfall is cancelation of projects that had been planned. In particular, three

7 2019-2023 reserve margins from ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT Region, 2019-2028, December 4, 2018, p.9. As noted below, some industry participants are advocating for a capacity market that would alleviate these issues, but after almost 20 years, nothing has been implemented.

8 On Dec. 26, 2018, it was announced that the Texas Municipal Power Agency's 470 MW Gibbons Creek coal plant would be mothballed indefinitely, which reduces the forecast planning reserve margin for summer 2019 to 7.4%. Watson, Mark, S&P Global Market Intelligence, "Texas PUC directs ERCOT to implement price adder, market efficiency reforms" January 18, 2019.

9 Kleckner, Tom, RTO Insider, "Texas PUC Responds to Shrinking Reserve Margin" January 17, 2019.

proposed gas-fired projects totaling 1.8 GW of capacity and five wind projects totaling 1.1 GW have been canceled since May, and another 2.5 GW of gas, wind and solar projects have been delayed.[10]

Some economists have argued that the answer to the current Texas electricity crisis is to allow more price volatility and price spikes to promote incremental electricity production from existing facilities, as well as new facilities, to alleviate the threat of brownouts. In addition, several Texas electricity industry stakeholders have advocated for creation of a capacity market in the state, including the former Texas PUC Chairman.[11][12] ERCOT's own independent market monitor issued a report in June 2013 that concluded that "it is our view that if the planning reserve margin is viewed as a minimum requirement, implementation of a capacity market is the most efficient mechanism to achieve this objective."[13] Unfortunately, as the PJM experience indicates, it is not yet evident how to construct a capacity market that works as well as traditional regulation.[14]

In stark contrast to the plight of Texas under deregulation, Florida has robust reserve margins, due in large part to resource planning requirements as mandated by the FPSC. Pursuant to Florida Statutes, each IOU must submit a Ten-Year Site Plan to the FPSC which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. This plan is based on an integrated resource planning process that includes load forecast assumptions, a reliability analysis to determine when resources may be needed to meet expected load, and a screening of demand-side and supply-side resources to meet the expected resource need in the most cost-effective manner. This provides a solid framework for flexible, cost-effective utility resource planning to ensure resource adequacy and system reliability. The following figure shows Florida's reserve margins, which far exceed those of Texas and meet or exceed Florida Reliability Coordinating Council ("FRCC") criteria.

10 Kleckner, Tom, RTO Insider, "ERCOT Predicts Tight Reserve Margin for 2019" Dec. 4, 2018.

11 SNL Energy, "PUCT Votes Unanimously to Raise ERCOT Price Caps to $9,000/MWh," October 26, 2012.

12 Energy markets are designed to allow generators to recover their variable operating costs and utilize caps on offer prices to protect against extreme price levels. Many wholesale energy market designs include a capacity market which is designed to provide generators with the opportunity to recover their fixed operating costs. Energy only markets similar to ERCOT allow energy pricing to reach levels that are high enough to allow a generator the opportunity to recover its fixed costs in the energy market.

13 SNL Energy, "Market Monitor Sees Capacity Market as Most Efficient Route to ERCOT Reliability Goals," June 24, 2013.

14 As noted in the Implementation, Litigation and Other Costs White Paper, the implementation of the ISO/RTOs and new market structures within these markets are difficult and costly to implement. For example, PJM has a 2019 annual budget of $360 million. *Finance Committee Letter to the PJM Board, September 21, 2018.*

FIGURE AP8- 6: FLORIDA PLANNED RESERVE MARGIN

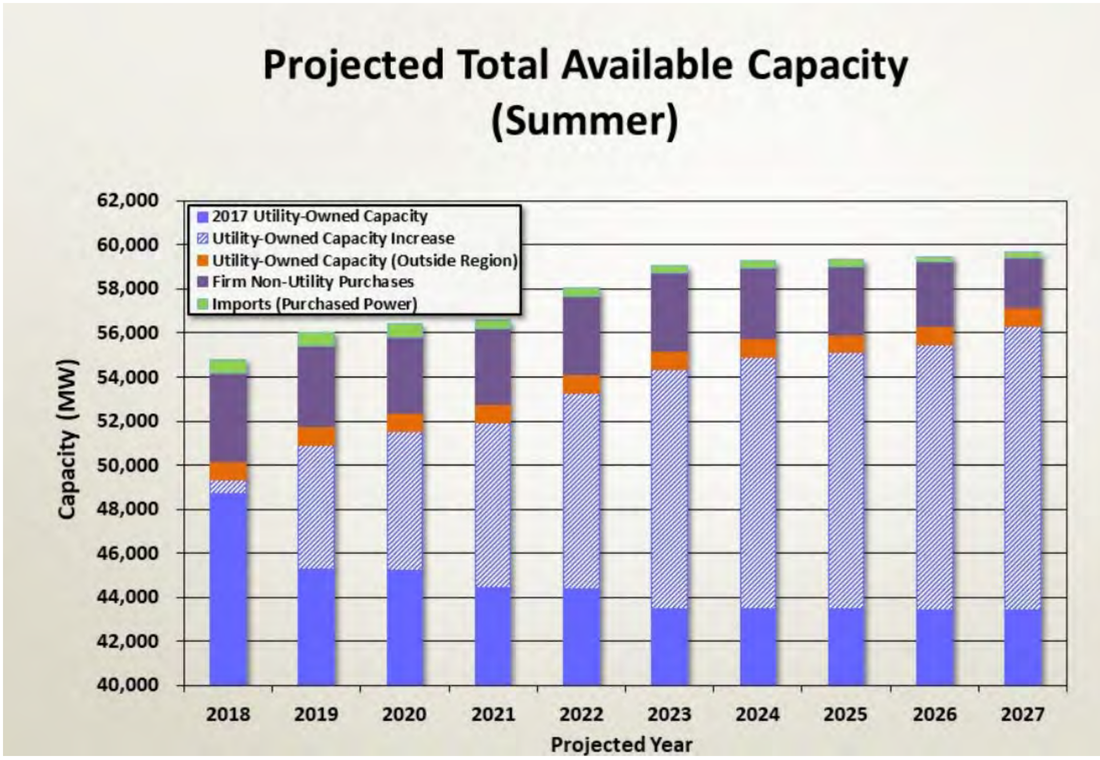
Source: Florida Reliability Coordinating Council, Inc.[15]

It is important to note in the above chart that reserve margins in Florida exceed the minimum planning reserve margin of 15% in both the summer and winter months. Under the current regulated market structure, Florida IOUs are required to plan their generation portfolio to meet firm load, which does not include interruptible industrial customers and other demand-side reduction programs for commercial and residential customers. These programs provide important demand reductions that displace generating capacity. Currently, these programs are funded through the IOUs and costs are recovered in rates. In a restructured market, these programs are subject to competitive market forces. To the extent that the competitive market does not adequately compensate these resources, the benefits of these resources will not be realized, and resource adequacy and system reliability will be at risk.

In addition, the ability of Florida to develop generation resources is illustrated in the following figure from the FRCC. As this shows, the Florida IOUs are well positioned to reliably develop needed generation sources, in a manner that is fully regulated by the FPSC, to the benefit of customers.

[15] Florida Public Service Commission 2018 Ten-Year Site Plan Workshop, FRCC Presentation. Oct. 11, 2018. Slide 23.

FIGURE AP8- 7: FLORIDA PROJECTED AVAILABLE CAPACITY



Source: FRCC[16]

This comparison of Texas and Florida highlights the risks that are inherent in replacing coordinated resource planning with competitive market forces in ensuring the reliability of electric service. The ballot measure reflects "a solution without a problem," and is not designed to address challenges in Florida or improve the provision of reliable and low-cost electric service to Floridians. This is not to the benefit of Florida or Floridians.

In addition, over three decades ago, the FPSC created the Generation Performance Incentive Factor ("GPIF") as a financial incentive and penalty framework that would encourage the IOUs to "operate their generating units as efficiently as possible and minimize fuel costs borne by their customers."[17] Under the GPIF, the FPSC sets individual annual performance targets for each IOU base load generating resource. The GPIF mechanism is designed to reward efficiency improvements, which translate into fuel cost savings and reduced costs to ratepayers. Restructured markets do not have these types of mechanisms, and customers will not necessarily receive the benefits of efficiency improvements.

Reliability of the Bulk Power System

The reliability of the bulk power system is a significant concern posed by the ballot measure. The bulk power system is overseen by the North American Electric Reliability Corporation ("NERC"). Under the Energy Policy Act of 2005, the FERC was given the authority to select an "electric reliability organization" to develop and

16 Florida Public Service Commission 2018 Ten-Year Site Plan Workshop, FRCC Presentation. Oct. 11, 2018. Slide 25.

17 In re: Investigation of Fuel Cost Recovery Clause Application to Investor-owned Electric Utilities, Order No. 9558, issued September 19, 1980, in Docket No. 800400-CI.

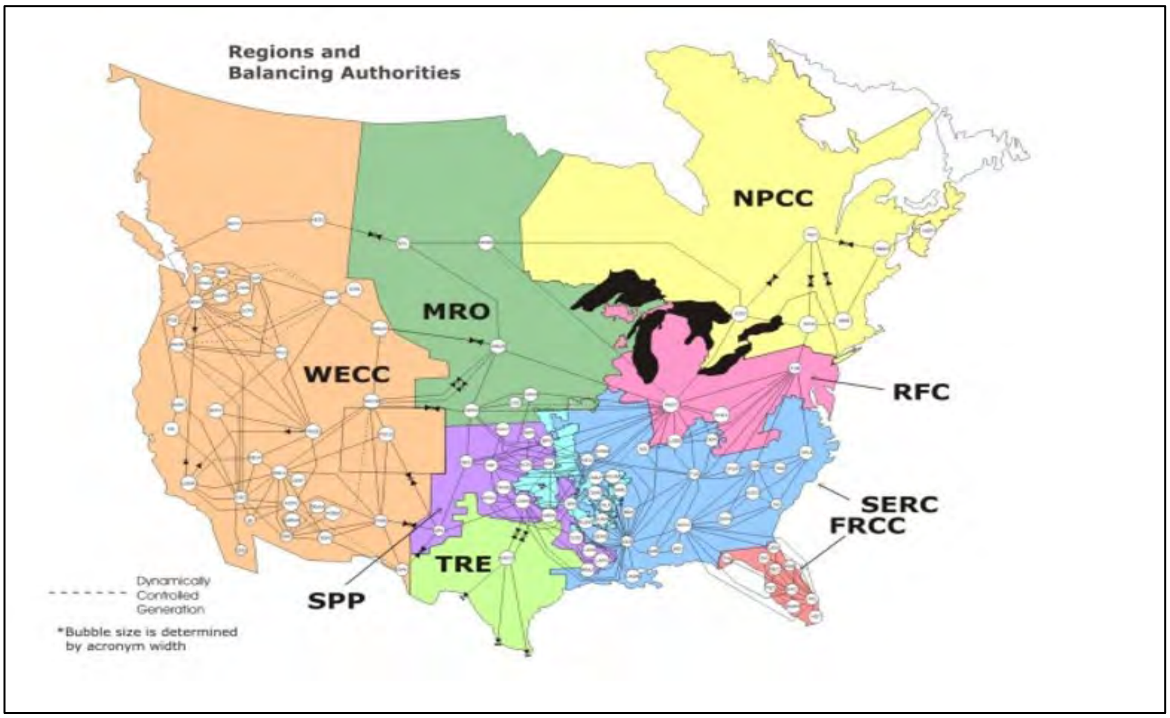
enforce standards to ensure the reliability of the nation's electric grid. In 2006, FERC certified NERC as the national electric reliability organization.

NERC was established as a not-for-profit entity with responsibility for ensuring the reliability of the electricity system in North America. NERC is an organization of lawyers, engineers, and analysts that is dedicated to setting mandatory and enforceable industry standards for the provision of electric energy.

NERC continuously develops, justifies, enforces, and seeks approval of bulk power system reliability standards. NERC has broad jurisdiction over all bulk power system owners, operators, and users. As an industry-led organization, NERC experts work to develop and enforce transmission planning and operational standards that include but are not limited to: i) resource and demand balancing; ii) critical infrastructure protection; iii) personnel performance, training, and qualifications; iv) protection and control; v) transmission operations; vi) transmission planning; and vii) interchange scheduling and coordination. NERC's authority allows them to assess penalties on electric utilities and service providers that fall out of compliance with relevant standards.

NERC oversees eight regional reliability entities that encompass all of the interconnected power systems of the contiguous United States and Canada, as shown in Figure AP8- 8.

FIGURE AP8- 8: NERC RELIABILITY REGIONS[18]



The FRCC was established in 1996 as a not-for-profit company incorporated in the State of Florida. FRCC's mission is to identify, prioritize, and assure the effective and cost-efficient mitigation of risks to the reliability and security of the peninsular Florida bulk power system. The FRCC serves as a regional entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the FRCC Region. The area of the state of Florida that is within the FRCC Region is peninsular Florida east of the Apalachicola

[18] A Primer on NERC, January 30, 2014.

River. Areas west of the Apalachicola River are within the Southeastern Electric Reliability Council ("SERC") Region. The FRCC includes all utility systems within the state's border, with the exception of the northwestern Panhandle, which is partially operated by Gulf Power Company and remains part of SERC.

A key responsibility of the FRCC is to annually assess the reliability of the bulk power system in peninsular Florida, and to ensure resource adequacy as required by the FPSC. As part of this annual assessment, the FRCC aggregates and reviews forecasted load and resource data reflecting expected conditions over the next ten years. The FRCC receives data annually from its members to develop its Regional Load & Resource Plan ("RLRP"). Based on the information contained in the RLRP, a Load & Resource Reliability Assessment Report (Reliability Assessment Report) is developed and submitted to the FPSC along with the RLRP. The Reliability Assessment Report evaluates the projected reliability for peninsular Florida by analyzing projections of resource adequacy, loss of load probability, generation availability, and generation forced outage rates.

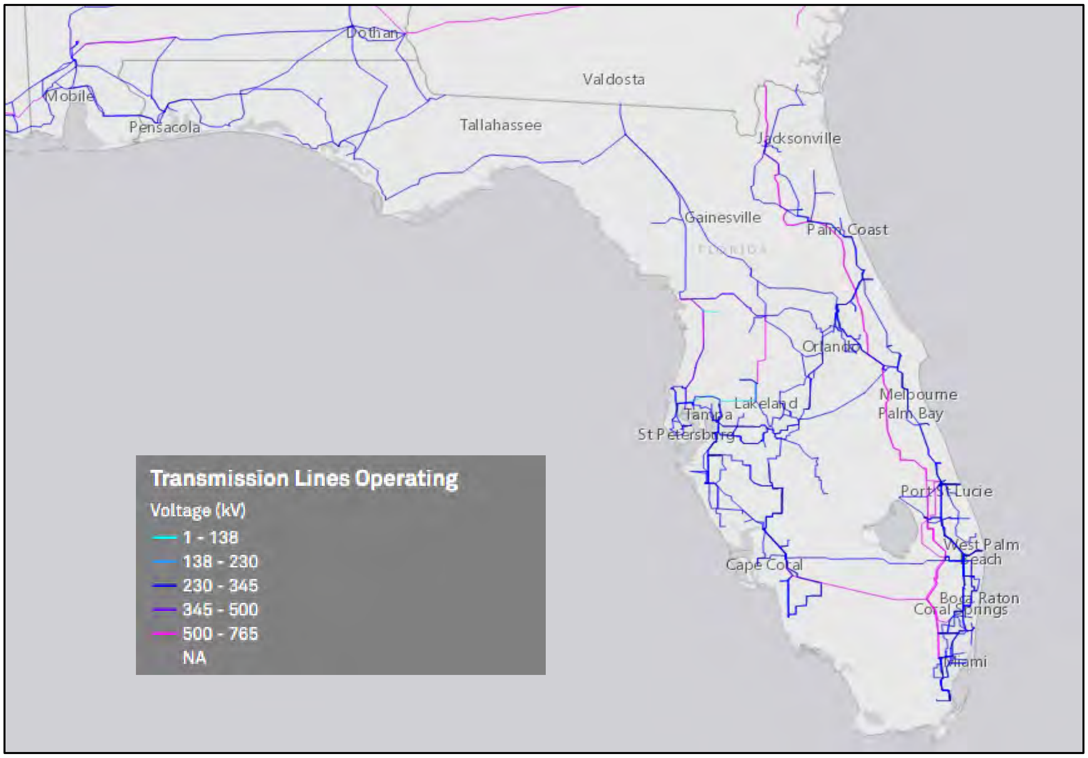
The FRCC Region participants perform various transmission planning studies addressing NERC reliability standards. These studies include near-term and longer-term transmission studies and seasonal assessments as well as additional sensitivity studies as needed to address specific issues (e.g., extreme summer weather), interconnection and integration studies, and interregional assessments. The studies analyze short term and longer-term bulk power system reliability to identify potential emerging concerns, monitor known concerns, monitor the effects of planned projects and identify major projects that may require long lead-times.

Peninsular Florida is relatively isolated in terms of its electric power interconnections. Its only link with another bulk power system is with SERC at the Florida/Georgia border and in the Florida panhandle through interconnections with Georgia Power. This makes FRCC among the regions in the US with the lowest potential to import or export power. Only the ERCOT region in Texas is more electrically isolated from its neighbors. In fact, Florida can import approximately 3,600 MW of generating capacity, compared to a peak load of approximately 46,000 MW, or less than 8% of peak load.[19] This means that Florida relies on its own internal generation to serve 92% of its customer needs. By comparison, New England has the ability to import over 20% of its peak energy needs.

In contrast to external connectivity, there is significant interconnectivity within Florida. The utilities within Peninsular Florida are interconnected via a high-voltage system made up of 500 kV and 230 kV lines. Double circuit 500 kV lines run the length of the state's eastern seaboard and enable significant power flows from the north to load centers in the southeast and around Miami.[20] Florida's transmission system is shown in Figure AP8-9.

[19] FRCC Load and Resource Plan 2018
[20] Ibid., pg. 24.

FIGURE AP8- 9: MAP OF FLORIDA ELECTRIC TRANSMISSION SYSTEM[21]



The impact of proposed electric restructuring on reliability and governance in Florida is complex and unclear at this time. First, as discussed above, there are currently two reliability entities in Florida – FRCC and SERC. It could be more efficient for the entire State of Florida to operate under a single regional reliability entity with a uniform set of transmission planning and operational procedures, especially given the unique geographic characteristics of the state. However, this would require Gulf Power Company to move from SERC to FRCC, which would be an expensive and time-consuming change. In addition, because of limited interconnectivity between the panhandle and peninsular Florida, any efforts to integrate these two regions for reliability purposes would be costly and time consuming.

Regarding the likely impact of the existing transmission configuration on the design and operation of a wholesale energy market, it is likely that the wholesale market design would require a unique load zone for the panhandle region of Florida that would be recognized as a transmission constrained region within the wholesale energy market footprint. This would result in higher wholesale electricity prices than the rest of the state since there would be limited ability for more efficient generating units located outside of the transmission constrained region to serve load within the transmission constrained region. The premium that customers in the panhandle region would pay is unknown at this time. Alternatively, the wholesale market could be designed such that the wholesale market was comprised of two entirely separate energy zones. This would require that the panhandle and peninsular Florida regions be effectively operated separately, with very limited ability to capture all the operational and economic benefits of the entire portfolio of generation resources in the state. This would introduce inefficiencies in the wholesale market that, while they cannot be quantified at this time, would certainly limit the region's ability to capture all the benefits of wholesale competition. To maximize the opportunity to

[21] Ibid., pg. 22.

capture the promised benefits of restructuring, a significant amount of transmission capacity would need to be constructed to increase the connectivity between the peninsula and panhandle.

Jurisdictional Considerations

Restructuring would severely restrict the FPSC's jurisdiction over the process of selecting resources to power Florida's energy future: with a move to retail choice comes a loss of the utility's obligation to build and a corresponding loss of PSC jurisdiction over power prices. Instead, jurisdiction over regulatory policies that drive electricity prices will be transferred from elected Florida policymakers to the FERC, a federal agency whose broad agenda may not always align with Florida customers' best interests from both a cost and reliability standpoint. Under competition, energy marketers and independent power producers under FERC-jurisdictional RTO tariff rules, rather than state-regulated utilities, decide whether, when, and how to enter the market and what supply and demand-side resources to develop.

Because Texas restructured only the ERCOT region, the limited direct current interconnections with neighboring regions allowed the state to avoid FERC jurisdiction. As a result, the state regulatory commission and Texas law had final oversight over how electric service would be provided within ERCOT. Florida will likely not enjoy this same level of autonomy. The entire state is electrically interconnected to the other states in the eastern US interconnection and thus FERC will have jurisdiction over wholesale power sales and wheeling across the state.

In addition, the FPSC has developed several programs to enhance the efficiency of service at lowest cost. In addition to the GPIF, there is the Environmental Cost Recovery Clause, and Conservation Programs that all fall under FPSC jurisdiction. These programs promote a portfolio of resources that is low cost, efficient and environmentally conscious. Restructuring may undermine the FPSC's influence in all these areas causing higher cost, less efficiency, and less reliability to Florida's citizens.

State Efforts to Re-Regulate

Because new generation resources were not being constructed in sufficient quantities or at locations sufficient to meet system needs, at least five restructured states have taken actions to partially re-regulate their electricity markets by requiring incumbent utilities to enter into long-term contracts for new resources and/or are taking other actions to incent new generation: Connecticut, Maryland, New Jersey, Delaware, and Illinois. In each state, policymakers were motivated by concerns that reliability of service was being threatened by a failure of wholesale market design to spur investment in new generation. Although the response differed by state, the basic elements of the legislative and regulatory responses included a focus at the state level on resource planning (which was no longer being performed by the utilities) and the development of new generation resources (which can take three to five years) at locations necessary to meet system reliability needs or remedy transmission constraints.

The experiences of Maryland, New Jersey, and Delaware indicate that, while generation resources may be adequate from an RTO/ISO-wide basis, reliability must be achieved for each defined load area. Ultimately, the failure of PJM capacity markets to incent new generation within these transmission-constrained areas contributed to state actions to re-regulate their electricity markets. The fact that RTO/ISO rules require each load-serving entity (both regulated utilities and energy marketers, as applicable) to acquire sufficient resources to meet their load serving obligation does not ensure that sufficient resources will be available at the right time, in the right quantities, or at the right locations to satisfy those requirements.

Risk Related Impacts of Restructuring

Advocates of restructuring argue that competitive markets shift risk from customers to independent generators and retailers. In fact, restructuring creates a new set of risks for customers. Likely in response to an early-restructuring wave of bankruptcies, the more recent data on independent power producers' investments in generation capacity show that they actually take on little risk, focusing their investments almost exclusively on natural gas and renewable generation backed by PPAs. This dramatic departure from a balanced portfolio approach to fuel diversity and long-term resource adequacy in generation increases the risk of reliability challenges, price volatility, and supply disruption for customers. In addition, restructuring introduces the risk of market manipulation and energy marketer abuses and business failures.

Under a traditional regulatory model, utilities recover their prudently incurred operating costs and earn a regulated return on prudently invested capital. This cost recovery model provides regulated utilities with a lower cost of capital than merchant generators and energy marketers who must compensate their investors for the greater risks inherent in restructured markets. It is electricity customers, though, who ultimately pay this higher cost of capital embedded in energy marketers' prices.

A recent analysis of new generation capacity additions highlights the extent to which merchant generators' investments have been dominated by natural gas and renewables and the much greater fuel diversity shown by regulated generation additions in the past two years. This study concluded that: "Utility-developed new capacity shows a much greater diversity than the merchant projects, with roughly one-third natural gas, one-third solar, and another quarter wind. In contrast, new merchant capacity is 86 percent natural gas and 12 percent wind, with a small amount of storage and solar."[22] Currently, the FPSC oversees resource selection to meet customer needs, including the development of renewable resources to meet public policy goals. Under a competitive market structure, the FPSC would no longer have any input into resource selection, which would be subject to market forces. Competitive markets are not designed to ensure important fuel diversity benefits or to meet public policy goals, and the loss of FPSC oversight on resource selection introduces material risk to system reliability and the cost of energy in Florida.

Restructured markets undervalue baseload plants' contribution to resource adequacy.[23] Moreover, because large baseload plants have high fixed costs and low operating costs, their owners' cost recovery is highly exposed to risk of fluctuations in dispatch by regional markets. In contrast, natural gas-fired generators have relatively low fixed costs and higher variable costs, which makes gas-fired generation less risky to build and to own. The higher risks faced by baseload plants makes it difficult for generators in a restructured market to justify investing shareholder capital in upgrading existing coal plants where such investments would otherwise be economically justified.

Under the current regulatory model, Florida utilities conduct long-term planning under the oversight of the Commission and invest in adequate generation resources to meet their customers' demands. The current model ensures that Florida utilities have "steel in the ground" with a diverse portfolio of resources sufficient to keep the lights and air conditioning on for their customers. Municipal electric utilities and cooperatives in Florida are part of the integrated Florida generation and delivery system. These citizen-owned utilities have enjoyed the system stability provided by FPSC-directed resource adequacy for the IOUs. While municipalities and cooperatives are excluded from the deregulation initiative, it is very likely that their costs are also going to go

---

22 Caplan, Elisa, "Financial Arrangements Behind New Generating Capacity and Implications for Wholesale Market Reform" American Public Power Association (July 2018), p. 1.

23 Baseload plants are generally understood to be plants that provide a continuous supply of energy to the system on a 24/7 basis, except for maintenance and forced outages.

up as the generation assets previously owned by IOUs no longer provide a stable and reliable statewide system that municipalities and cooperatives can rely upon. In contrast, restructured states make no such requirements of their energy marketers who need not own a single megawatt of generation capacity to make promises to deliver power to customers.[24]

Furthermore, the security of fuel supply under a competitive market structure has the potential to be at risk, resulting in higher costs to the region. Many competitive markets across North America do not require generators to have firm fuel supply in the form of either firm gas supply or fuel oil back up. These jurisdictions have experienced severe fuel shortages at times when system reliability was at risk due to lack of firm fuel supply. For example, in the winter of 2014 alone, the cost of electricity at the wholesale level in New England totaled approximately $5 billion dollars due to high prices as a result of gas shortages.[25] A deliberate approach to resource diversity, which is absent in a restructured market, provides important protections against high costs, particularly as regions become more dependent on gas resources.

Finally, restructured states often find that their residential—particularly low-income and elderly—customers are the victims of unsavory marketing practices by financially unstable retailers who have defaulted on their supply obligations, raising costs for all customers.

[24] See, e.g., the requirements for energy suppliers in Maryland (available at http://goo.gl/S14NoZ) and for retail energy providers in Texas (available at http://goo.gl/S2nMbx).

[25] Winter Reliability Program Updated, Restructuring Roundtable, September 25, 2015.

APPENDIX 9: TEXAS AS AN EXAMPLE OF COMPETITIVE MARKETS

Purpose of Report

This report was prepared by Concentric to provide information and insights on the potential impact of ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment") based on the Texas experience with restructured markets. Advocates of competition in Florida point to Texas as the appropriate point of comparison.

Background

Texas deregulated its electricity market on January 1, 2002. Senate Bill 7 ("SB7") dismantled the state's investor-owned utilities ("IOUs") and fundamentally transformed the way Texans purchased their power. The IOUs were each were "unbundled" and broken into three companies: generation (power plants), transmission (power lines) and retail (customer service and billing). The law allowed municipally-owned utilities and cooperatives to opt out of restructuring.

Over the 15 years since deregulation was introduced in Texas, the market has experienced several unexpected challenges, and the benefits of this market transformation continue to be debated. A recent Rice University study called the results of retail choice into question:

> "The Texas experience is not universally accepted as a success. Notably, a recent study commissioned by the Texas Coalition for Affordable Power (TCAP 2016) claims that electricity deregulation in Texas has not delivered the intended outcome. In particular, the study notes among its major findings that Texans paid average residential rates that were 6.4% below the national average in the 10 years prior to deregulation but 8.5% higher in the 10 years following deregulation."
>
> And:
>
> "A recent study conducted by the Texas Coalition for Affordable Power (TCAP 2016) shows that customers in areas exempt from deregulation have on average enjoyed lower residential rates compared to those in deregulated areas."[1]

In addition to unexpectedly higher retail prices in Texas post-deregulation, the energy market also has experienced volatile prices, serious system reliability threats, and historically high customer complaints. The experience in Texas should give Floridians pause when considering the promised benefits of restructuring.

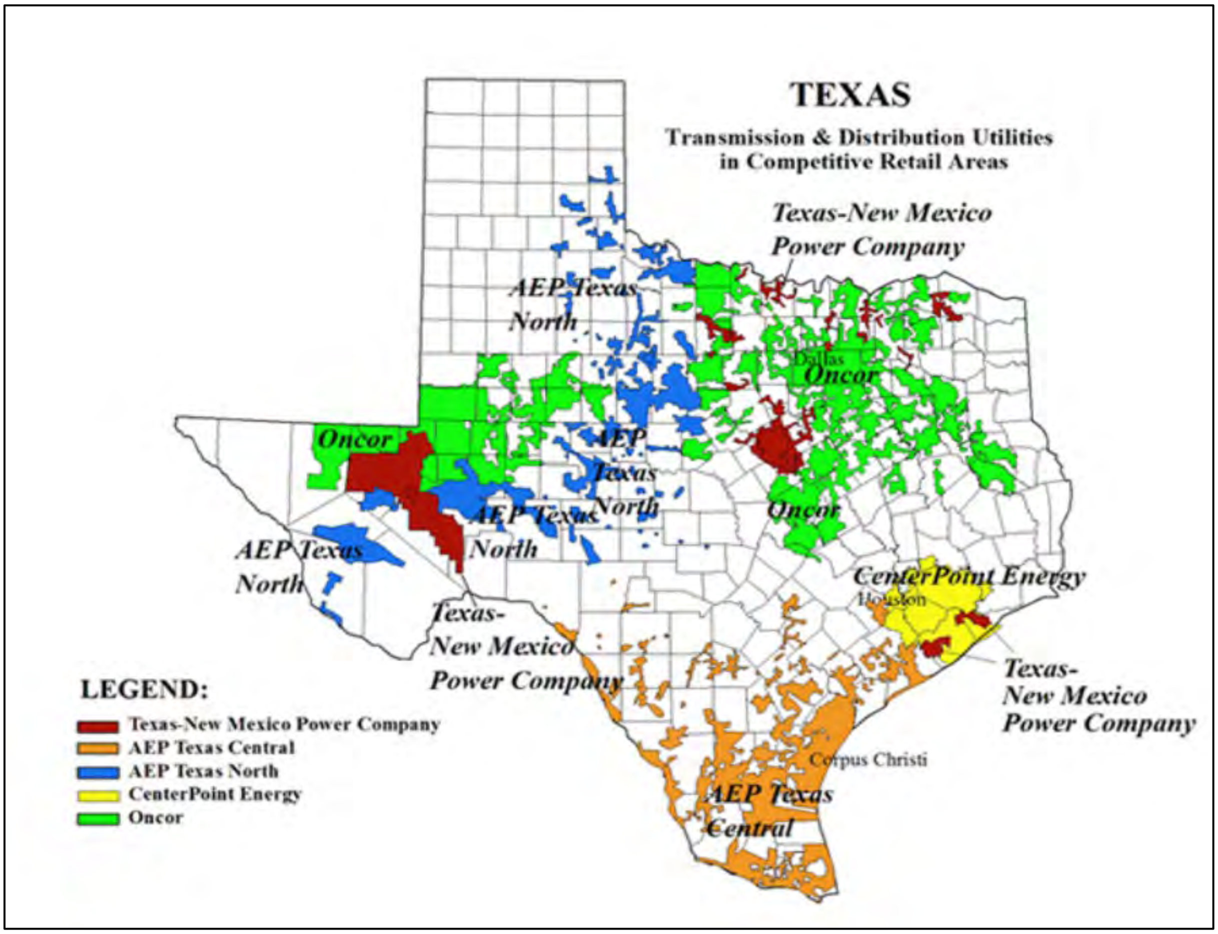
Comparison – Texas v. Florida

While the sponsors of the Amendment assert that the Amendment is modeled after Texas' restructuring there are a number of clear and important differences. Under SB7, vertically-integrated utilities operating within the ERCOT region were required to split into three discrete entities: generation companies, the still regulated transmission and distribution utilities, and retail electric providers. Under this "unbundling" provision, these entities were required to function separately — even if they remained under the same corporate ownership. As noted earlier, Texas did not prohibit the IOU ownership of transmission and distribution facilities, while the

[1] Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Rice University, Hartley et. al, June 2017, pp.3 and 7.

Amendment specifically restricts IOUs to the construction, operation, and repair of electrical transmission and distribution systems. Further, SB7 did not codify a customer's right to generate and sell power, while the Amendment specifically allows for customers to produce their energy themselves or in association with others. Finally, SB7 did not require a single state-wide competitive market, and did not result in a complete restructuring across the state, as shown in Figure AP9- 1. This was due to the fact that approximately 30% of the state was served by rural electric cooperatives and municipal utilities, both of which were allowed to remain vertically integrated under SB7. The Amendment, however, would restructure all areas within the state served by IOUs, including remote areas where transmission interconnections are limited.

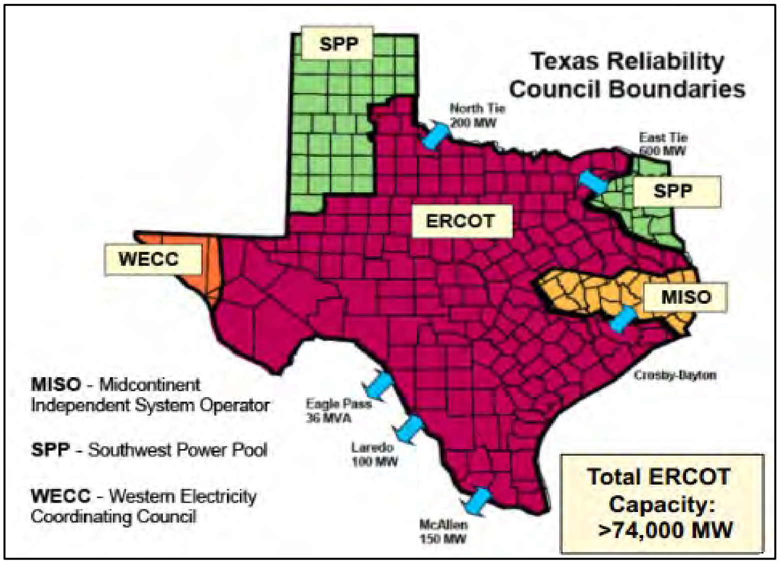
FIGURE AP9- 1: COMPETITIVE RETAIL AREAS IN TEXAS[2]



2 Public Utilities Commission of Texas.

Furthermore, Texas was not required to operate within a single wholesale market under restructuring, as shown in Figure AP9- 2.

FIGURE AP9- 2: WHOLESALE MARKET STRUCTURE IN TEXAS[3]



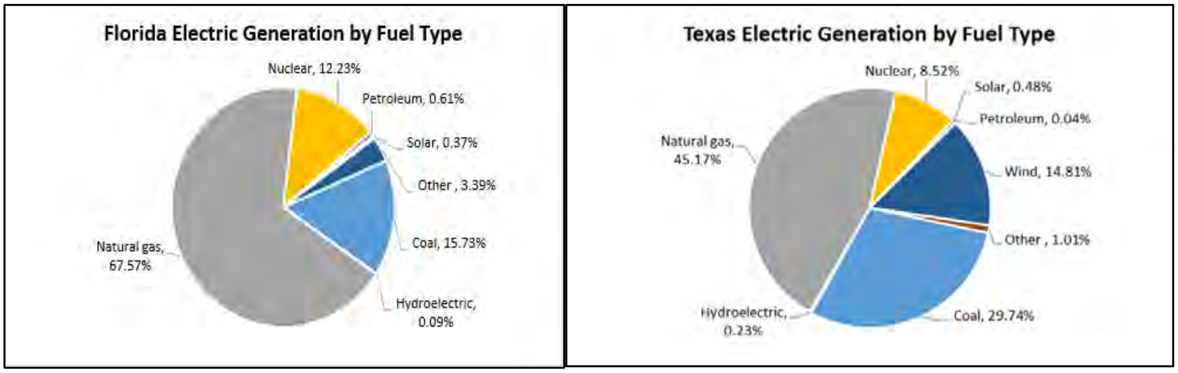
Importantly, because Texas restructured only the ERCOT region, the limited direct current interconnections with neighboring regions allowed the state to avoid FERC jurisdiction. As a result, the state regulatory commission and Texas law had final oversight over how electric service would be provided within ERCOT. Florida will likely not enjoy this same level of autonomy. The entire state is electrically interconnected to the other states in the eastern US interconnection and thus FERC will have jurisdiction over wholesale power sales and wheeling across the state.

In addition to jurisdictional concerns, the Amendment calls for a single state-wide wholesale market, which will create challenges with transmission constraints and efficient and economic market operation. Transmission systems were not built with deregulation in mind, but rather were built by each utility to serve their own customers with relatively few links to one another that existed for reliability purposes. As a result, there are areas of Florida, specifically the Florida Panhandle with limited interconnectivity that will hamper the free exchange of electricity under restructuring.

In addition to the fundamental differences in approach between Texas and Florida, there are important structural differences between the two states that do not lend themselves to a direct comparison between the two states. Importantly, Florida is far more dependent on natural gas, as shown in Figure AP9- 3.

3 Public Utilities Commission of Texas.

FIGURE AP9- 3: FUEL MIX – TEXAS VS FLORIDA[4]



In addition, governance under Texas restructuring will likely be very different from governance that would be expected in a restructured Florida energy market. Texas was able to avoid federal jurisdiction due to its direct current ("DC") ties, which are asynchronous transmission links that allow ERCOT to pass electrons externally in a controlled fashion. The Federal Power Act holds that federal jurisdiction follows the flow of electricity and since electrons do not "freely" flow across DC ties, ERCOT remains free from FERC oversight and maintains jurisdictional autonomy. It has been argued that the legal autonomy enjoyed by ERCOT has allowed for much more nimble policymaking in Texas, especially after restructuring. It is doubtful that Florida will enjoy this autonomy and will more than likely cede jurisdictional oversight to the FERC.

Experience with Restructuring in Texas

Bankruptcies

In 2014, roughly twelve years after the introduction of electric competition in Texas, Energy Future Holdings, the then-parent of Luminant Generation Company and Oncor Electric Delivery, filed for bankruptcy, representing of the largest Chapter 11 bankruptcy filings in corporate history. The filing also marked the colossal collapse of a heavily-leveraged $45 billion bet taken by private equity firms, who borrowed enormous amounts of money on the wager that natural gas prices would continue rising and, in the process, elevate wholesale electricity prices. Instead, new natural gas exploration technology led to a fall in natural gas prices, and electricity prices were driven down to historic lows.

According to reports, EFH owned more than $36 billion in assets when it filed for Chapter 11 protections. But it also owed more than $49 billion to creditors and had no way to keep up with its debt payments. Most of the losses were accrued by the generation side of the company — Luminant — which operated in the wholesale power market. Warren Buffet, who invested $2 billion in EFH, described his involvement in the debacle as a "major unforced error."

In addition to the cost of the restructuring, which was estimated at $42 billion, law firms, banks and consultants continue to work on the bankruptcy case, almost five years later, receiving over $600 million, making it one of the most complex and expensive corporate bankruptcies in US history.[5] The total fees for all the professionals

4 SNL
5 Energy company's bankruptcy generating Enron-sized legal fees, The Texas Lawbook, March 29, 2018.

– for the lawyers, bankers, accountants, restructuring experts for all the companies involved – will probably hit $1 billion, according to the company's General Counsel.

Price volatility also caused the bankruptcy of some retail electric providers. Texas Commercial Energy ("TCE") filed for bankruptcy protection in 2003 following a sudden and dramatic rise in the price of wholesale electricity. Because TCE did not own generating assets, it acquired the acquired electricity in the wholesale market and then resold it on a retail basis to its customers. When the wholesale price of power exceeded the price TCE was charging its retail customers, TCE was unable to pay its bills as they came due.

Retail electric providers continue to churn in Texas. In 2018, Breeze Energy, a Dallas retail electric company with thousands of customers in Houston, was shut down by Texas regulators after the company defaulted on its financial obligations, leaving industry analysts to speculate that the anticipation of higher wholesale electricity prices this summer may have put the retail electric provider in a financial squeeze.

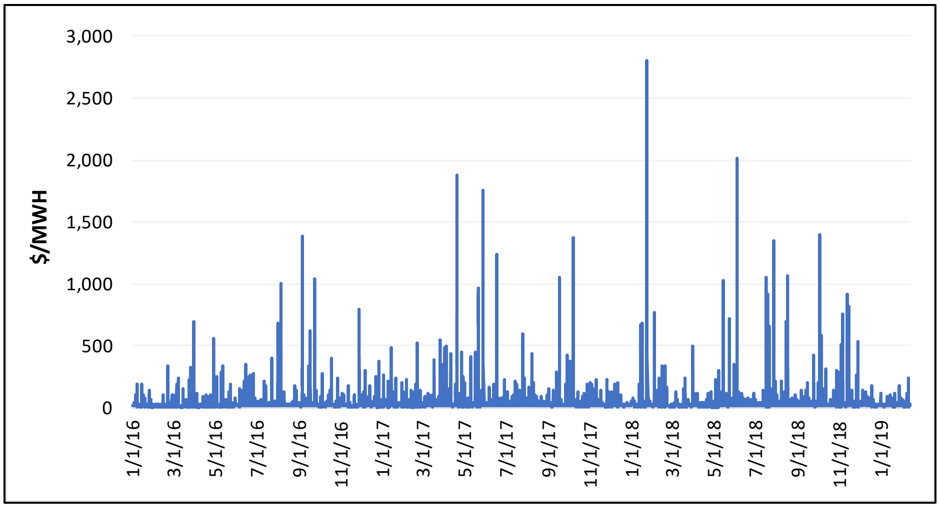
Wholesale Prices

Industry restructuring in Texas was touted as a path to lower energy prices for customers. However, studies and data show that the success of industry restructuring in Texas is a hotly debated issue. As early as 2001, when the electric choice pilot program was introduced, wholesale energy prices began spiking. The magnitude of the price spikes —100 times typical price levels — were similar to spikes seen during the California crisis. The first occurred on July 31, the very first day of the pilot project, when power that had been selling for between $10 and $45 per megawatt-hour ("MWH") suddenly shot up to $1,000 per MWH.[6] The Texas system operator blamed the first spike on an anomaly. However, on August 5, the market experienced another series of price spikes, with power prices surging to over 100 times its regular price. On August 8, wholesale prices spiked again — from a relatively typical level of less than $60 per MWH to $999 per MWH. An hour later, the energy price skyrocketed to $10,000 — but was adjusted downwards to $1,000 because of the price caps.[7] Although the spikes impacted a relatively small segment of the wholesale market (the pilot program was capped at 5% of the market), it foreshadowed some troubling market power issues and potential abuses. In the competitive energy market, the cost of the highest acceptable bid for power dictates the price to all successful bidders. For example, market participants may submit bids ranging from $50 per MWH to $1,000 per MWH. If the grid operator needs 100% of that power to meet demand, then all bidders get the last price submitted that meets system demand, or $1,000 per MWH — even those who submit bids offering to accept payment of $50 per MWH.

As is shown in below, competitive energy markets can be quite volatile. This has become the new norm in Texas and has important implications in a restructured market. Price volatility creates uncertainty that generators and suppliers will reflect in their pricing structures, driving up costs to customers. In addition, price uncertainly creates an investment disincentive, which drives down the ability of the system to reliability meet customer demand.

6 Deregulated Electricity in Texas, A Market Annual, 2018, pg.19.
7 Ibid.

FIGURE AP9- 4: ERCOT HOURLY REAL-TIME PRICES – HOUSTON ZONE[8]

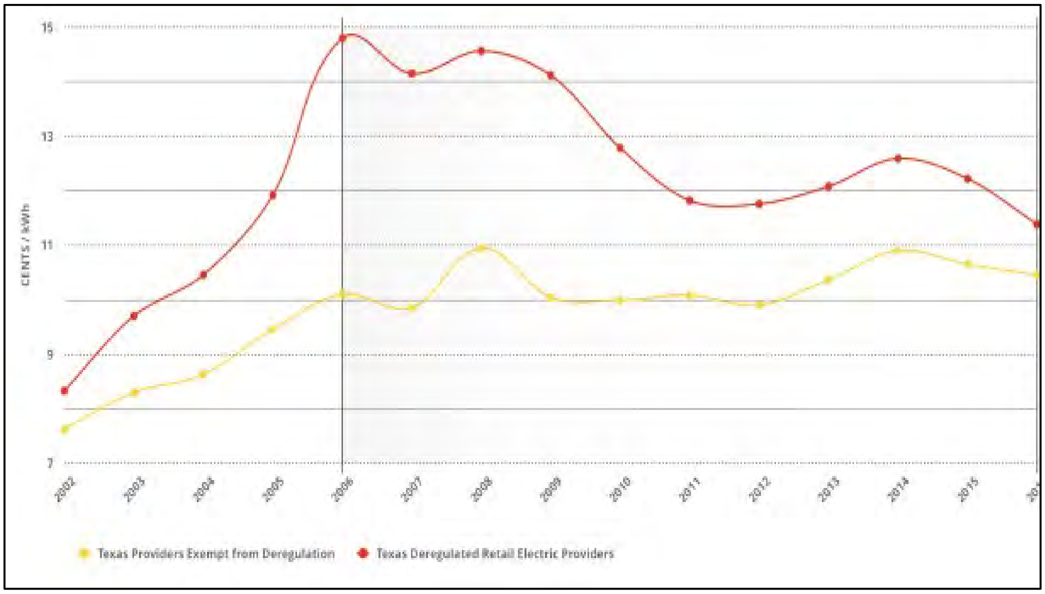


Retail Prices in Texas

Texas has experienced unexpected price increases since it opened its markets to competition. The Texas Coalition for Affordable Power ("TCAP") produces annual analyses that assess the competitive market and the impact on retail prices. In its 2014 study, TCAP found that restructuring has cost Texas customer $22 billion from 2002 – 2012.[9] In its most recent 2018 report, TCAP found that Texans have consistently paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation. This annual trend began during the very first year of the retail electric deregulation in Texas and has continued through 2016, as shown in Figure AP9- 5.

[8] SNL Financial.
[9] TCAP 2014 Electric Restructuring Report.

FIGURE AP9- 5: AVERAGE RESIDENTIAL ELECTRICITY PRICES IN TEXAS[10]



In Texas, electricity providers affiliated with the incumbent utility were required to charge a "price to beat" until the incumbent utility lost sufficient market share to alternative providers. This price was designed as a price floor to prevent the incumbent from offering artificially low rates to stifle competition and undercut new market players. When the price to beat was set, it included a 6% discount off the utility's base rates. However, prices in the deregulated areas steadily climbed as natural gas prices rose in the mid-2000s. From 2002 to 2006, the price to beat rose 88% and the competitive offers rose 62%. In contrast, rates in regulated areas of Texas rose only 24% during this period.

System Reliability Concerns

Electric competition in Texas has negatively impacted the amount of generation available to meet customer demand. Resource planning in competitive markets is replaced by market forces that are relied upon to send investment signals to incent new entry and retain existing generation. One way to measure the ability of the system to meet expected customer demand is by calculating the system "reserve margin." The system reserve margin measures the relationship between how much electricity generators theoretically can produce in a single instant and the forecasted peak demand for electricity by consumers. Because power shortfalls can put a system at risk for blackouts — especially during extreme weather events — the reserve margin measurement is a good indicator of system reliability. During the transition into deregulation, back in 2001, Texas enjoyed the highest reserve margin in the nation. This helped to calm the anxieties about deregulation after California's market began collapsing during that state's transition to deregulation. The public was assured in 2001 that Texas would not face reliability issues.

But such a claim could not be made in 2011. The National Electric Reliability Corporation ("NERC") reported ERCOT's reserve margin ratio in 2011 at about 14%, which marked a nearly 40% decline from pre-deregulation levels and far below the national average in 2011 of around 25%.[11] In fact, after 10 years of

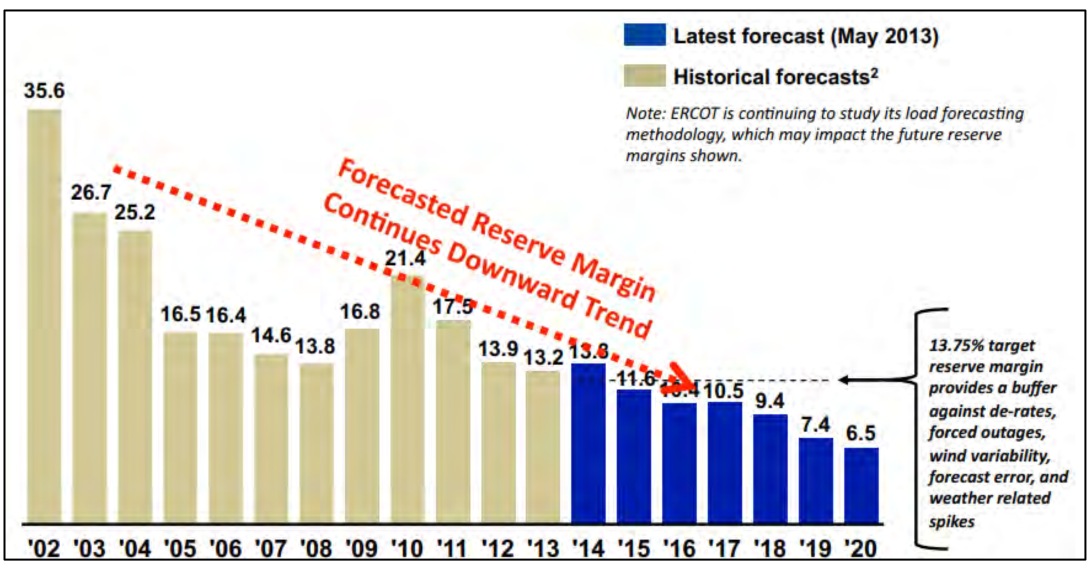
[10] TCAP Report on Electricity Prices in Texas, April 2018.
[11] NERC Long Term Reliability Assessment 2011.

deregulation, Texas possessed the lowest reserve margin in the nation, according to NERC. This was especially alarming, since electricity prices increased over this same time period. In 2012, NERC forwarded a letter to the grid operator expressing its concern about system reliability in Texas:

> "At its November 26, 2012 meeting, the NERC Board of Trustees (Board) discussed its concerns for the situation in Electric Reliability Council of Texas (ERCOT). While it was noted that NERC cannot order the construction of new generation or transmission, NERC is accountable for assessing the current and future reliability of the BPS and informing decision-makers. Therefore, the Board requested that NERC take follow-on actions with the organizations that are responsible for resource adequacy to ensure the parties are taking timely action.
>
> As identified in the assessment, one area of concern requiring immediate attention is the projected Planning Reserve Margin levels in the ERCOT assessment area. Capacity resources in ERCOT have drifted to a level below the Planning Reserve Margin target and are projected to further diminish through the ten-year period covered in the assessment. It is clear to me that these levels imply higher reliability risks especially the potential for firm load shed, and ERCOT will need more resources as early as summer 2013 in order to maintain a sufficient reserve margin."[12]

The reserve margin in Texas has continued to dwindle since the introduction of competition, as shown in Figure AP9- 6.

FIGURE AP9- 6: ERCOT SUMMER RESERVE MARGIN 2002-2020[13]



Competitive markets have introduced added system reliability risks in Texas in the form of blackouts. In early 2006, rolling blackouts in Texas left more than 200,000 people unexpectedly without power, including about 78,000 customers in the CenterPoint Energy service territory (around Houston) and about 80,000 customers in the North Texas service territory of TXU Electric Delivery. The crisis began when the grid operator saw usage begin to peak and concluded that it might not have enough generation online to meet demand. All available

---

12 NERC Letter to ERCOT President and CEO, January 7, 2013.

13 Association of Electric Companies of Texas, Inc. Update on the Texas Electric Industry, January 23, 2014.

generation was called to operate at its highest output. However, demand continued to spike, and the grid operator was forced to cut power to various industrial customers. A subsequent loss of four generators representing over 900 MW was too large of a contingency for the system to handle, and rolling blackouts were called. These rolling blackouts were the first in more than a decade.

ERCOT blamed a confluence of events, including the planned outage of about 14,000 megawatts of capacity for plant maintenance, a spate of unseasonably hot weather that went unpredicted by ERCOT's computers, and some unexpected last-minute plant shutdowns.[14] Officials pledged to make course corrections to better handle such events in the future.

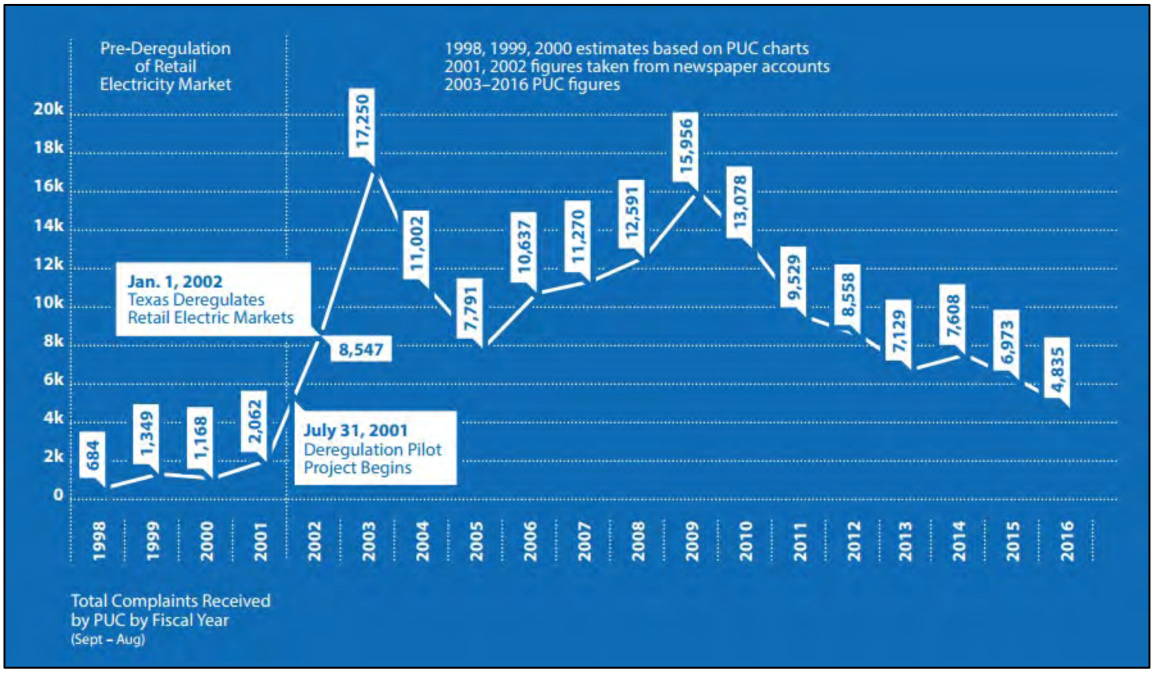
However, approximately two years later, on February 26, 2008, ERCOT officials took emergency action to avoid blackouts. A sudden loss in wind power, coupled with other factors, sent grid operators taking emergency actions once again to avoid a catastrophic system collapse. It was a serious emergency for the grid operator, and one that illustrated the inherent challenges associated with wind power. The inherent challenges with wind operation mean that generators have to remain on standby and ready to ramp up quickly. This represents reliability risks and added costs to the system, which are ultimately borne by customers.

CUSTOMER COMPLAINTS

The number of complaints regarding electric service filed at the Texas Public Utility Commission has increased steadily since the market opening and peaked in July and August of 2003, as shown in Figure AP9- 7.

[14] Deregulated Electricity in Texas, A Market Annual, 2018, pg.19.

FIGURE AP9- 7: ANNUAL ELECTRICITY-RELATED COMPLAINTS IN TEXAS[15]



Over the course of the fiscal year, the Texas Public Utility Commission Customer Service Division received about 17,000 electricity complaints — about half relating to billing, although many consumers also complained about service disconnections and faulty service. This would mark an all-time high for the number of annual complaints under the Texas deregulation law.[16] According to recent report on the history of deregulation in Texas, customer complaints quadrupled with the transition to deregulation in 2002 and have not returned to pre-deregulation levels. Although some of this increase can be explained by population growth and the use of the internet to facilitate the complaint process, the magnitude of the increase cannot realistically be explained by these two factors alone.

15 TCAP History of Deregulation 2018, pg. 86.
16 TCAP History of Deregulation 2018, pg. 32.

APPENDIX 10: IMPACT OF ELECTRIC RESTRUCTURING ON RETAIL ENERGY COSTS

Purpose

This report was prepared by Concentric to provide information and analysis regarding the impact of electric industry restructuring on retail electricity costs as Florida assesses the ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment"). This report provides background considerations related to retail energy costs that are affected by electric industry restructuring. It discusses the nature and limitations of comparisons of electricity costs across states and summarizes the cost-related customer experiences in restructured states.

Background and Key Conclusions

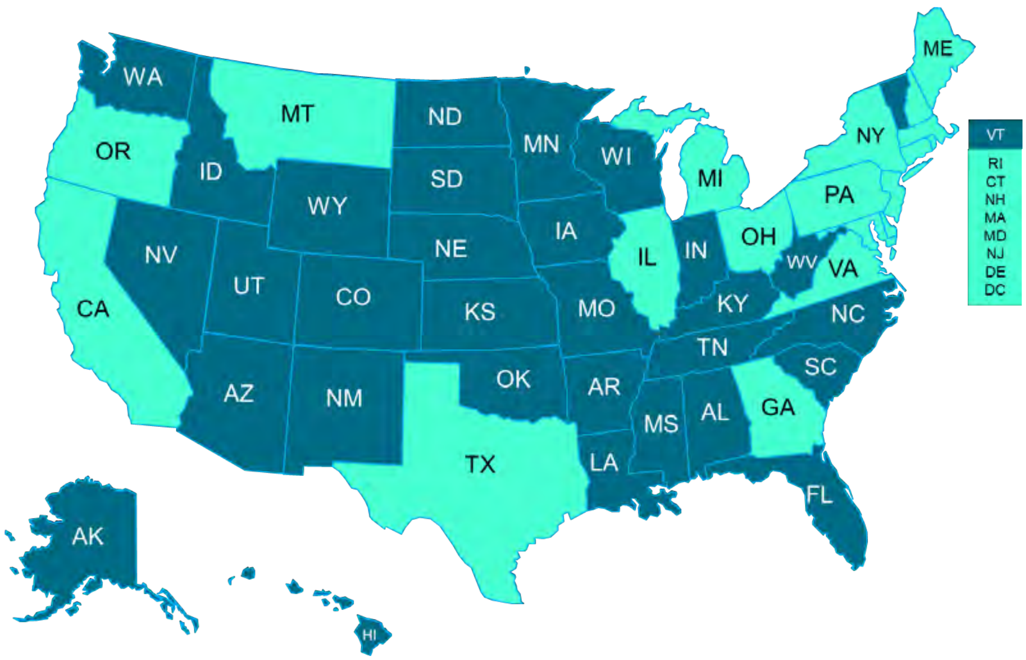
Debates concerning electric industry restructuring often center around the likely impact on electricity costs and prices, the prices paid by retail customers (including industrial, commercial, and residential customers as well as government facilities and other essential service buildings). A key driver for restructuring states in the late 1990s was high retail electric rates compared to other states. More recently, states that have contemplated restructuring but chosen to retain their traditionally regulated electric markets have cited a lack of clear price advantages, and other significant questions and concerns that have remained unresolved.[1] As discussed in more detail below, there is no conclusive evidence of a price advantage for customers in restructured states compared to those in regulated states. However, there is evidence that rates in restructured states are more closely tied to natural gas commodity prices than are rates in traditionally regulated states. Finally, there is evidence that the cost/price advantages that have accrued to customers in restructured states principally apply to larger commercial and industrial customers.

1 A recent example is Nevada, which considered a form of restructuring beginning in 2016, but voted against pursuing that path in a 2018 statewide ballot initiative.

State-to-State Comparisons

States that have enacted a form of electric market restructuring are shaded light green in Figure AP10- 1, below.

FIGURE AP10- 1: STATUS OF ELECTRIC RESTRUCTURING IN THE CONTINENTAL UNITED STATES[2]



It is challenging to compare electricity prices across states due to substantive differences in the structure, regulation, and economic conditions affecting the power industry.[3] For example, a state's electricity rates reflect fuel prices, weather, regulatory costs, tax policy, and other factors that vary state-to-state. In restructured states, these prices also typically reflect state-specific rate caps or other mechanisms that are designed to protect customers from the forces of unbridled competition on at least a transitional basis. Further, retail electricity rates used in comparisons typically include many other components (e.g., transmission and distribution) in addition to the cost of generation. This does not eliminate the instructive value of an examination of other states' electricity rates and experiences with restructuring. It does, however, suggest that this examination be considered in a broader context and be used directionally or anecdotally rather than as an absolute.

Data provided by the Energy Information Administration ("EIA") and shown in the tables below are often used in academic literature to quantify the effects of restructuring. However, recent studies have backed away from EIA data because it "provides an incomplete assessment of total bills that residential, industrial and commercial customers receive"[4] Nevertheless, the figures below, based on EIA data are illustrative in that they show directionally how average electric prices have changed over time.

2 Electric Choice, Map of Deregulated Energy States & Markets (Updated 2018). Accessed 1/24/19, https://www.electricchoice.com/map-deregulated-energy-markets/

3 This limitation in state-to-state comparisons is noted in many academic studies of the effects of restructuring. See, for example, Borenstein and Bushnell (2018).

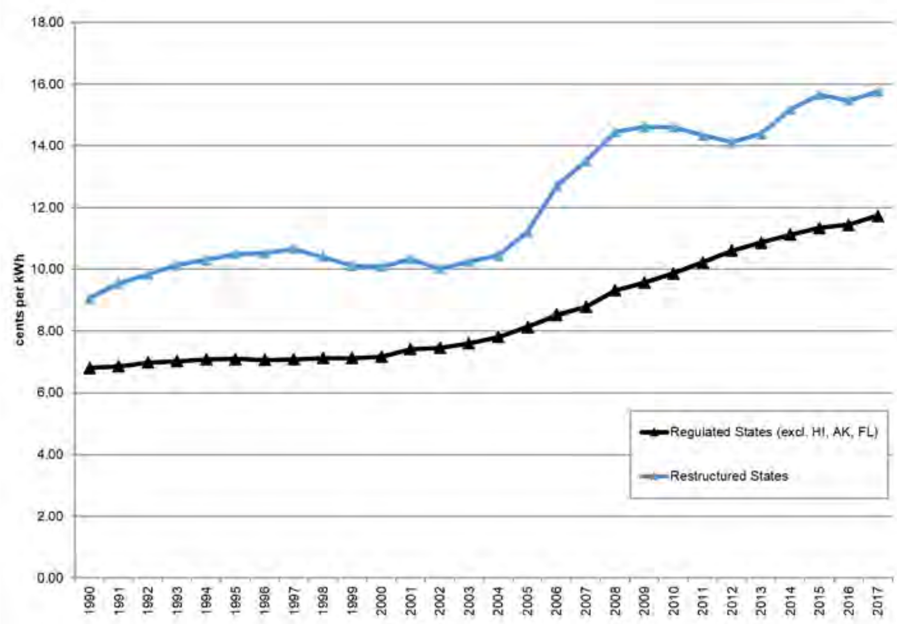
4 Dormady, N., Hoyt, M. Roa-Henriquez, A. & Welch, W. 2019. Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, at 4. See also: Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, at 28.

Concentric' s assessments of restructuring's impact on electricity prices and related effects of restructuring described in this paper are based a review of publicly available studies, reports and industry publications.

Impact of Restructuring on Rates

Figure AP10- 2, below, uses EIA data to compare prices in restructured and non-restructured states. This figure suggests that restructured states have significantly higher rates than traditionally regulated states. According to the data, from 1990 to 2017, rates in restructured markets have been on average 42% percent higher than rates in regulated markets.[5] Over the same period, rates in restructured markets have been approximately 26% higher than rates in Florida.

FIGURE AP10- 2: AVERAGE RESIDENTIAL RATE OF RESTRUCTURED AND REGULATED STATES (BEFORE AND AFTER RESTRUCTURING)

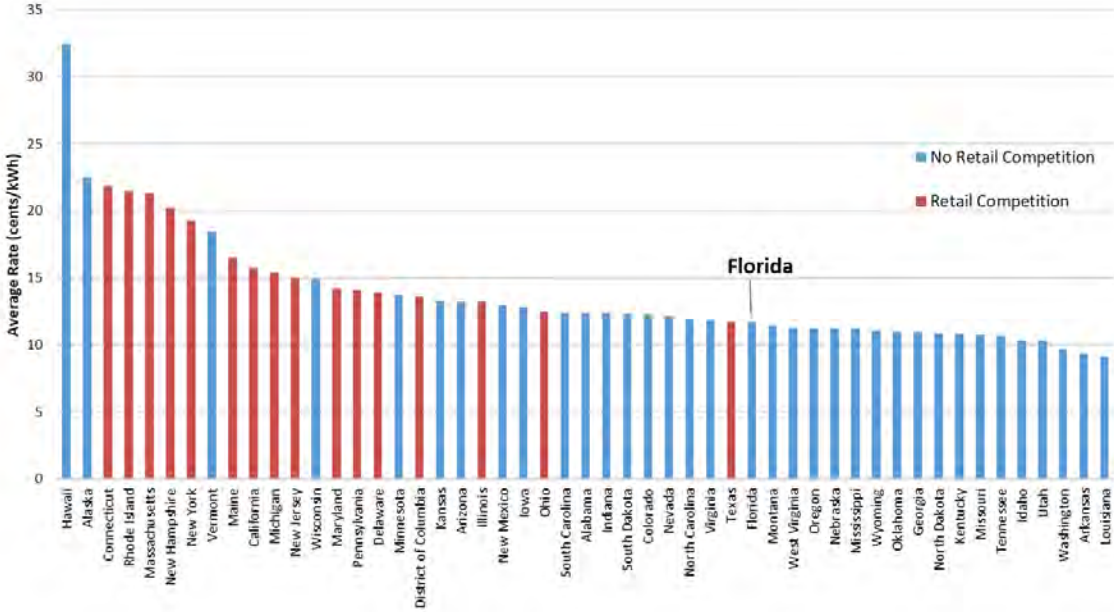


Data source: EIA Electric Power Monthly, October 12, 2018[6,7]

High electricity prices were a major driver of deregulation in states that have restructured. Unlike those states, Floridians enjoy electricity costs that are below national averages as shown in Figure AP10- 3 and Figure AP10- 4, below.

FIGURE AP10- 3: AVERAGE RESIDENTIAL RATES, STATUS OF COMPETITION

5 Regulated markets exclude Alaska, Hawaii, and Florida.
6 Rate calculations do not include fuel costs.
7 Restructured states include: CA, CT, DC, DE, IL, MA, MD, ME, MI, NH, NJ, NY, OH, PA, RI, and TX.



Source: EIA, Electric Power Monthly, October 2018

FIGURE AP10- 4: AVERAGE RATES BY CUSTOMER SEGMENT (UNITED STATES, FLORIDA)

	Residential	Commercial	Industrial	All Sectors
Florida - IOU	11.61	9.20	7.67	10.37
Restructured Average	16.24	12.71	9.53	13.32
U.S. Average	12.87	10.74	6.91	10.46

Source: EIA, Electric Power Monthly, October 2018

Many states have recently completed evaluations of whether residential and small commercial customers are better off with retail restructuring. The Massachusetts AG ("AG") developed a paper in March, 2018 to determine "whether residential consumers in Massachusetts pay more or less for their electric supply when they buy it from the competitive marketplace rather than their electric company (such as National Grid, Eversource, and Unitil); and (2) identify remedies if warranted."[8] The final analysis showed that "Massachusetts consumers in the competitive supply market paid $176.8 million more than they would have paid if they had received electric supply from their electric company during the two-year period from July 2015 to June 2017. A third year of data shows residential customers lost another $76.2 million, for a three-year total of $253 million."[9] This report looked only at residential electric supply and not the commercial or industrial market. The AG's recommendation was to eliminate the electric supply market for individual residential customers because the cost of retail supply was higher by far than the basic service provided by the utilities. The report also noted

8 Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, p. viii.

9 Ibid., p. viii

that "Unlike the commercial and industrial market, where sophisticated buyers with demands for large volumes are likely able to negotiate more favorable rates, individual residential consumers are not getting a bargain."[10]

Other states have conducted similar studies. A Rhode Island evaluation conducted over four years found that customers who switched from their utility to retail providers had paid $56 million over the default service costs.[11] In Connecticut a study completed by the Office of the Consumer Counsel concluded that in 2015 customers who switched to a competitive supplier paid almost $58 million more than remaining with their default supplier.[12] A 30-month study conducted by the New York Public Service Commission found that customers who switched electric and gas suppliers paid nearly $820 million more than if they had remained with their default suppliers.[13]

A technical report written by the Guinn Center in 2018 to examine the Nevada Retail Choice Ballot Initiative debated whether retail choice would lower or raise electric bills. The study was ultimately inconclusive for many of the reasons discussed above, but it did find that the "….analysis of the experiences of other choice states does suggest that restructuring exposes ratepayers to the imperfections and challenges of the wholesale electric market, leading to heightened uncertainty around rate behavior."[14] The conclusion from the Guinn Center study is that there are not clear price benefits to electric restructuring and that it could create volatile rates.

Impacts of Price Caps

How states implement restructuring is a key consideration for comparisons of electricity prices across states. Some states imposed regulatory price caps on incumbent utilities' supply rates. This was done to protect customers from rapidly increasing market prices during the transition to a restructured market. In some circumstances, these regulatory constraints helped create short-run benefits by establishing the "price to beat" for merchant power providers, who then "beat" those prices for a period as the market developed. However, as these artificial price caps began to expire, the average price of electricity increased. When Illinois retail price freezes expired in 2007 "bills soared up to 55% for Ameren customers and 26% for those of Commonwealth Edison."[15] Maryland froze prices to customers who continued to rely on utility sales service at levels that were approximately five percent below pre-restructuring levels only to have them increase by over 70 percent as soon as the caps were removed.[16]

Cross-Subsidization Between Rate Classes

The promise of new pricing options and other services has not materialized for the vast majority of residential and small commercial customers. The substitution of cost-based utility generation (supported by resource planning) with market-based wholesale rates has added to the upward cost pressure for this large group of customers. In states like Ohio, where the electric restructuring law allowed utilities to either divest their

---

10 Ibid., p. 15.

11 National Grid: The Narragansett Electric Company, Standard Offer Supply Procurement Plan / 2019 Renewable Energy Standard Procurement Plan. March 1, 2018, p. 9.

12 Gregory B. Hladky, Study: Consumers Pay Extra for Retail Electricity. Hartford Courant. April 20, 2016. http://www.courant.com/news/connecticut/hc-retail-electricity-costs-above-state-standard-20160420-story.html.

13 Jeff Platsky, AT RISK: NY Reviews Electric, Gas Free-Choice Program; Consumers Ended Up Paying More. Press Connects. February 9, 2018. https://www.pressconnects.com/story/news/2018/02/09/risk-ny-groundbreaking-program-allowing-customers-select-electric-gas-suppliers/302146002/

14 Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, at 24.

15 Davidson, Paul. "Shocking Electricity Prices Follow Deregulation." ABC News and USA Today, August 12, 2007. Article accessed January 30, 2019.

16 Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, at 41.

generation or transfer their generation to a corporate affiliate, residential and commercial customers have seen different outcomes. As noted in a study by Dormady *et al*:

> While enabling legislation required 100 percent divestiture of generation assets, utilities were permitted to corporately rather than functionally divest those assets. By selling those generation assets (almost entirely legacy coal plants) to deregulated arms-length companies, they created a perverse cost recovery incentive. When those coal assets performed poorly in the shale boom era, utilities sought riders through their regulated distribution businesses to compensate for losses of their deregulated generation businesses. The largest share of this burden was passed to households. [17]

The study notes that rates are somewhat lower for residential and commercial customers of utilities in Ohio that have fully divested their assets, but higher for residential and commercial customers of utilities that have only transferred their assets to an affiliate. This indicates that the outcomes of restructuring depend on how the policy is implemented and how the market develops, the latter of which is beyond the control of regulators.

Rate reductions even to large commercial and industrial customers have not been consistent or sustained. One study showed that the difference in prices paid by industrial customers in restructured market states nearly tripled from 1999 to July 2007 compared to similar customers in regulated states. The same study concluded that, in one year alone, industrial customers paid $7.2 billion more for electricity in restructured states than if they had paid the average electricity price of regulated states. While this example is dated, it nonetheless relays the experience in markets shortly after restructuring.[18]

The Dormady study noted above developed by using bill data in Ohio to estimate intra-firm cross subsidization concluded that:

> …retail restructuring has reduced or had no effect on price disparities between customer classes, with several notable exceptions. First, the findings suggest that, where customers observed savings associated with retail choice, the greatest savings have been observed by industrial customers and, where customers have observed cost increases, the greatest increases have been observed by residential customers (Type I cross-subsidization). Second, the findings suggest that, while customers have generally observed some savings associated with the implementation of competition (i.e., the deregulated component of their bill), savings have generally been more than offset by cross subsidies to arms-length deregulated generation affiliates ("gencos") (Type II cross-subsidization). [19]

Finally, the Dormady study concludes with the following:

> Regulators and legislators interested in understanding the differential effects of retail restructuring might, therefore, be better served looking inwards – at political and regulatory processes that affect these markets – before adjudicating the theory of deregulation. Similarly, researchers might finally settle the ambiguity about the impact of electric deregulation with better specification of the additional, non-market determinants of deregulation outcomes.

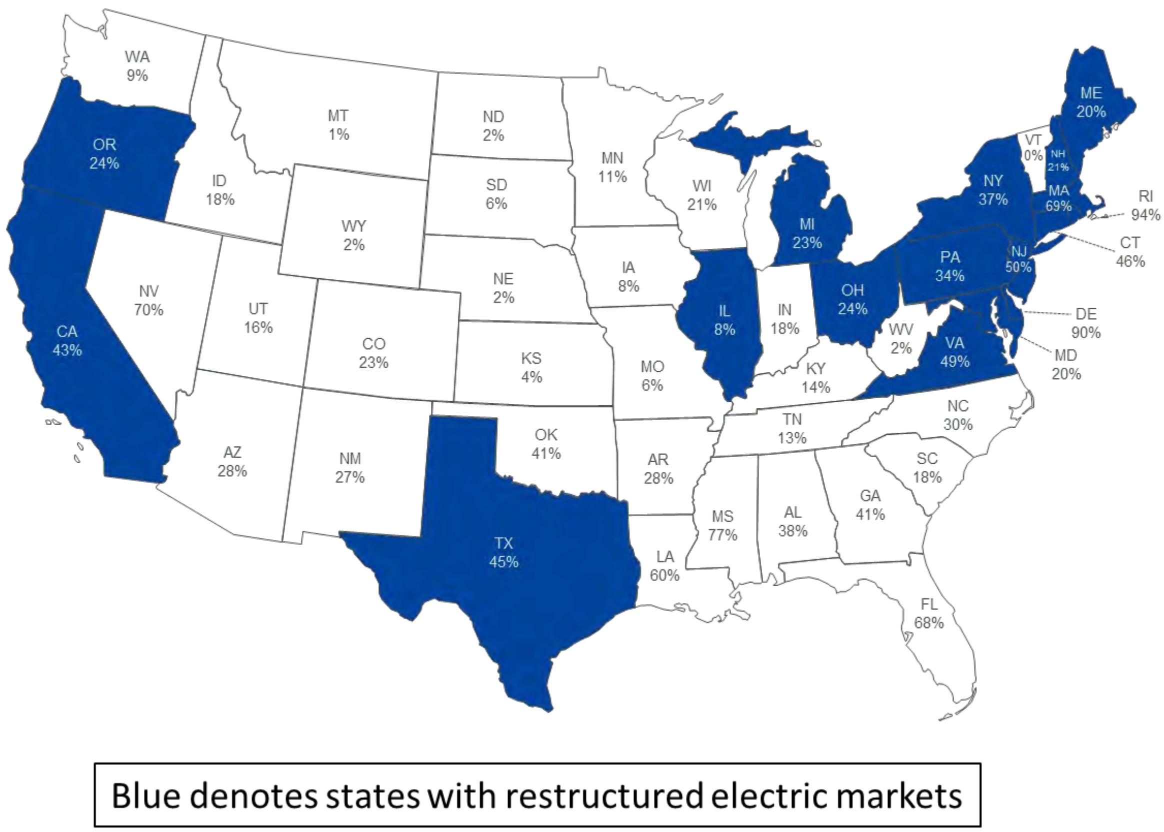
[17] Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, Dormady, Hoyt, Roa-Henriquez, Welch, December 2018, at 33-34.
[18] Competitively Priced Electricity Costs More, Studies Show, David Cay Johnston, The New York Times, November 6, 2007
[19] Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, Dormady, Hoyt, Roa-Henriquez, Welch, December 2018, at 2.

Likewise, these findings have potentially significant implications for the efficiency of wholesale markets. Regulatory subsidization of generation units can have both short run and long run adverse efficiency consequences for wholesale markets.

Impact of Natural Gas on Restructuring

Many restructured states rely more on natural gas-fired electric generation than traditionally regulated states. See Figure AP10- 5, below.

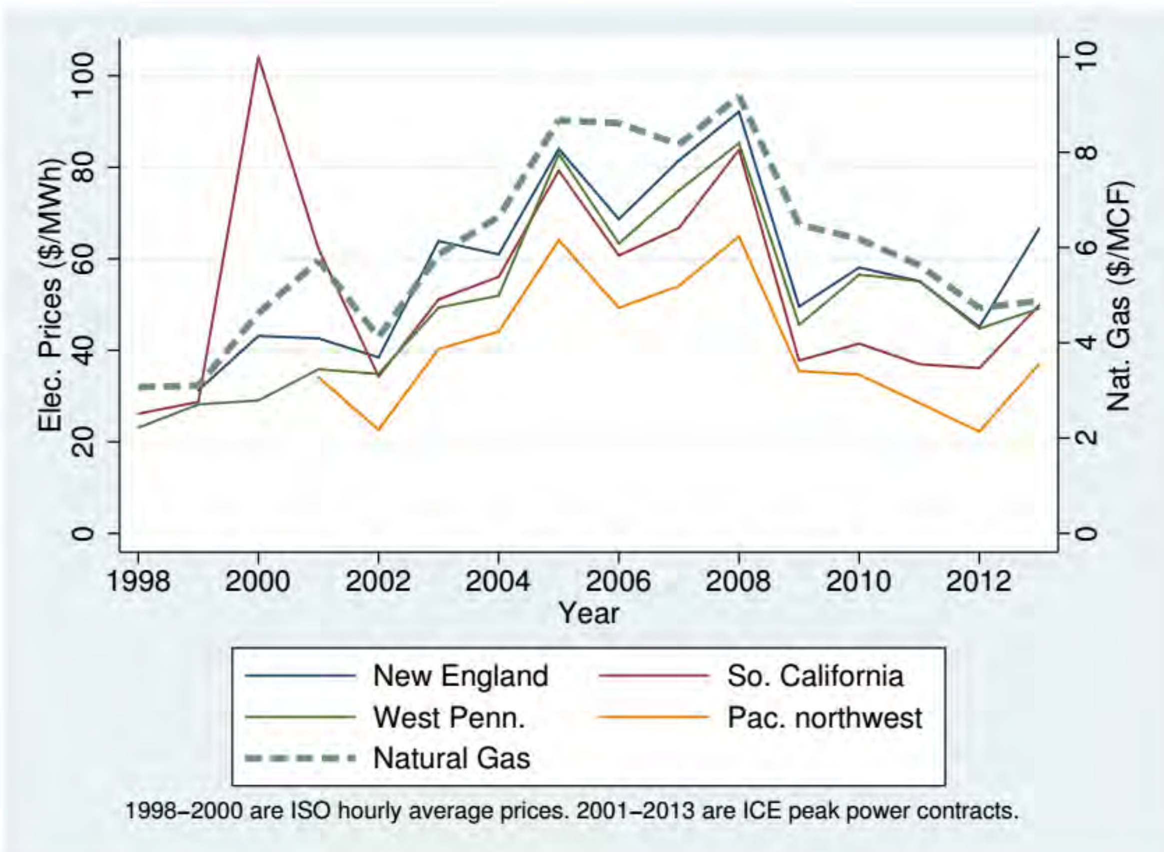
FIGURE AP10- 5: PROPORTION OF GENERATION CAPACITY SERVED BY NATURAL GAS (2017)



This reliance developed because as gas commodity costs fell around the 2008 timeframe, independent power producers in restructured markets began building more efficient, less costly gas plants to replace older, more expensive coal and oil generation. In regulated states, utilities typically maintain existing units until the economics of new units are established through approved, long-term resource plans. Prices for deregulated generation are driven by the marginal producer, which is now commonly natural gas generation. Therefore, "restructuring of generation greatly increased the exposure of electricity rates to natural gas costs, even if a fairly small share of electricity was sourced from gas-fired plants. As natural gas prices nearly tripled during the first half of the 2000s, the impact on retail rates and the rents created for infra-marginal generation were far greater than they would have been under regulation."[20] As a result, electricity prices in restructured states are much more heavily influenced by natural gas prices.

It has also been noted that "Much of the dissatisfaction with high retail prices in restructured states during the period of 2006-2008 was due to a combination of dramatically higher gas prices combined with the expiration of rate freezes…"[21] See Figure AP10- 6, below, which illustrates this link.

FIGURE AP10- 6: WHOLESALE ELECTRICITY AND CITYGATE NATURAL GAS PRICES[22]



The Guinn Center report notes that the uncertainty around rates in restructured markets could be a result of natural gas price fluctuations.

> Therefore, it is impossible to isolate the effects of restructuring on electricity rates. We have already documented such confounding factors as weather variations, timing, congestion issues, and more, but perhaps nothing is more intertwined with retail electric choice than wholesale costs, specifically, natural gas. The preceding discussion should not be misconstrued to suggest that electric prices in restructured states will increase necessarily because of natural gas's pronounced contribution to costs. On the contrary, natural gas prices have been volatile, historically; when they are low, consumers in restructured states—by virtue of their increased

20 The U.S. Electricity Industry after 20 Years of Restructuring, Severin Borenstein and James Bushnell, Revised May 2015, at 14.
21 Bushnell, Mansur, and Novan. Review of Economics Literature on US Electricity Restructuring. February 2017.
22 Ibid., at 14.

exposure to the wholesale market— realize benefits from lower fuel costs. But when they rise, consumers may pay higher electricity bills as a result of pass-through from IPPs to competitive suppliers.[23]

Conclusions

Academic and industry research consistently finds that there is no conclusive link between pricing advantages for retail customers and electric industry restructuring. The conclusions from the Guinn analysis are echoed consistently throughout the research: "This report has found that some people in restructured states have enjoyed the benefits of retail electric choice, while others have confronted unfavorable outcomes. The impact of restructuring turns largely on market design and policy decisions rendered before and during the implementation phase. But even those states that proceeded with caution and careful consideration were not invulnerable to unintended consequences."

In considering the impacts of restructuring on the costs for Florida's electric consumers, several factors require careful examination. These include: the existing generation fleet; the likely evolution of the generation fleet in a restructured market; consistency of changes in the generation fleet with Florida's environmental goals; and the ability of Florida's electric and fuel infrastructure to support a functionally competitive wholesale market. All of these factors must be considered along with the practical experience gained elsewhere before a legitimate case for consumer benefits can be established.

[23] Ibid., at 37.

TAB 9

eia U.S. Energy Information Administration

U.S. States

State Profiles and Energy Estimates

Rankings: Average Retail Price of Electricity to Residential Sector, December 2018 (cents/kWh)

Download Table Data as CSV

Rank	State	Average Retail Price of Electricity to Residential Sector (cents/kWh)
1	Hawaii	34.43
2	Rhode Island	22.51
3	Alaska	21.99
3	Massachusetts	21.99
5	Connecticut	20.84
6	New Hampshire	19.78
7	California	19.44
8	Vermont	18.06
9	New York	17.34
10	Maine	16.11
11	New Jersey	15.45
12	Michigan	15.10
13	Wisconsin	14.06
14	Pennsylvania	13.58
15	Maryland	13.24
16	District of Columbia	13.15
17	Minnesota	12.87
18	Illinois	12.30
19	Delaware	12.27
20	Arizona	12.26
21	New Mexico	12.04
22	Ohio	12.00
23	Kansas	11.96
24	Colorado	11.90
25	Indiana	11.89
26	Florida	11.86
27	South Carolina	11.77
28	Nevada	11.72
29	Alabama	11.62
30	Texas	11.22
31	Mississippi	11.12

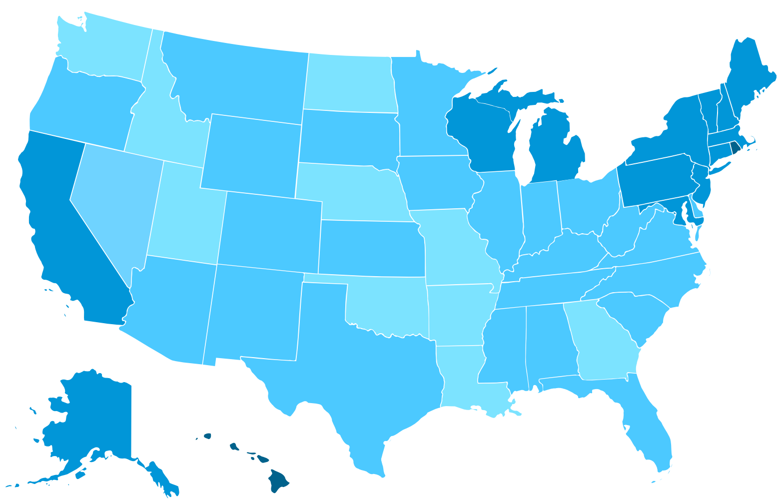
Nevada
11.72 cents/kWh
Rank: 28

Note: Rankings are based on the full source data values.

A. 327

Rank	State	Average Retail Price of Electricity to Residential Sector (cents/kWh)
32	Iowa	11.08
33	South Dakota	11.05
34	Virginia	11.01
35	Montana	10.93
36	Wyoming	10.84
37	North Carolina	10.78
38	Tennessee	10.72
39	Oregon	10.68
40	West Virginia	10.41
41	Kentucky	10.36
42	Utah	9.97
43	Idaho	9.83
44	Nebraska	9.81
45	Missouri	9.54
45	North Dakota	9.54
47	Washington	9.35
48	Georgia	9.29
49	Oklahoma	9.02
50	Arkansas	9.01
50	Louisiana	9.01

Note: Rankings are based on the full source data values.



<= 10.00 cents/kWh

10.00 to < 13.00 cents/kWh

13.00 to < 22.00 cents/kWh

>= 22.00 cents/kWh

Value is not available

Notes & Sources

Consumption

A. 328

- Total Energy per Capita: EIA, State Energy Data System, Total Consumption Per Capita

Expenditures

- Total Energy per Capita: EIA, State Energy Data System, Total Expenditures Per Capita

Production

- Total Energy: EIA, State Energy Data System, Total Energy Production
- Crude Oil: EIA, Petroleum Supply Annual, Crude Oil Production
- Natural Gas: EIA, Natural Gas Annual, Natural Gas Gross Withdrawals and Production
- Coal: EIA, Annual Coal Report, Coal Production and Number of Mines by State
- Electricity: EIA, Electric Power Monthly, Net Generation by State

Prices

- Natural Gas: EIA, Natural Gas Monthly, Natural Gas Prices
- Electricity: EIA, Electric Power Monthly, Residential Electricity Prices

Environment

- Carbon Dioxide Emissions: State CO_2 Emissions

COMPETITIVE ENERGY MARKET FOR CUSTOMERS OF INVESTOR-OWNED UTILITIES

SUPPORT FOR FIEC FINANCIAL IMPACT STATEMENT

Contents

Tables:

Figures:

Appendices:

GLOSSARY OF TERMS

Amendment – Ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*".

Franchise Agreements – Agreements with the local communities the IOUs serves. In general, these agreements provide the IOU with the exclusive right, and obligation, to serve the community's customers as well as access to rights of way.

Independent System Operator ("ISO") or Regional Transmission Organization ("RTO") – ISOs and RTOs are not-for-profit entities that are formed to perform three basic functions: (1) operate the bulk electric power system, (2) develop, oversee, and administer the wholesale electric market, and (3) manage the power system planning processes to address transmission needs. Florida, like many traditionally regulated states, does not currently have an ISO, RTO, or similar organization.

Price to Beat – In Texas, a price that was designed as a price floor to prevent the incumbent providers from offering artificially low rates to stifle competition and undercut new market players.

Provider of Last Resort – A company who is required to provide service to customers who for some reason (e.g., their chosen supplier goes out of business) do not have a competitive service provider.

Retail Energy Supplier, Retail Electric Provider, Retail Marketer, or Energy Service Company ("ESCO") – A company that serves as a middleman or an intermediary between the electricity buyer (residential, commercial and industrial customers) and the wholesale electric market. Retail marketers purchase electricity through wholesale electricity markets and resell it to consumers.

Slamming – Unauthorized switching of customers to a competitive supplier without proper authorization from customers.

Stranded Costs – Costs that are created when the market value of utility assets in a restructured market is less than the net book value on the utilities' books.

Vertically-Integrated Utilities – Utilities that own all levels of the supply chain (generation and transmission and distribution).

LIST OF ABBREVIATIONS

AG	Attorney General
CAISO	California ISO
EDR	The Office of Economic and Demographic Research
ERCOT	Electric Reliability Council of Texas
ESCO	Energy Service Company
FERC	Federal Energy Regulatory Commission
FIEC	Financial Impact Estimating Conference

FMPA	Florida Municipal Power Agency
FPC	Florida Power Corporation
FPL	Florida Power & Light Company
IOU	Investor Owned Utility
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	ISO New England
LNG	Liquefied Natural Gas
MISO	Midwest ISO
NERC	National Electric Reliability Corporation
NYISO	New York ISO
NY PSC	New York Public Service Commission
OUC	Orlando Utilities Commission
PJM	Pennsylvania-New Jersey-Maryland Interconnection
POLR	Provider Of Last Resort
PPA	Power Purchase Agreement
PUCN	Public Utilities Commission of Nevada
PUCT	Texas Public Utility Commission
ROE	Return on Equity
RTO	Regional Transmission Organization
SB7	Texas Senate Bill 7
SPP	Southwest Power Pool
T&D	Transmission and Distribution Systems
TCAP	Texas Coalition for Affordable Power
TCE	Texas Commercial Energy
TECO	Tampa Electric Corporation

I. INTRODUCTION

Purpose of Report

This report was prepared and is submitted on behalf of Florida's four major investor-owned utilities ("IOUs"): Duke Energy Florida, Florida Power & Light Company ("FPL"), Gulf Power Company, and Tampa Electric Company ("TECO"). The purpose of this report is to provide information and analysis for the consideration of the Financial Impact Estimating Conference ("FIEC") in its development of a Financial Impact Statement for the Florida ballot measure entitled "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" ("Energy Market Amendment" or "Amendment").

If approved, the Amendment would "destructure" not "restructure" the state's electricity markets and cost state and local government $1.3 to $1.7 billion in upfront or one-time costs, and in excess of $825 million in annual, ongoing costs, and would dramatically increase the risk and volatility of the state's energy markets. Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone.

Proposed Constitutional Amendment

The proponents of this constitutional Amendment summarize their proposal as follows:

> "Grants customers of investor-owned utilities the right to choose their electricity provider and to generate and sell electricity. Requires the Legislature to adopt laws providing for competitive wholesale and retail markets for electricity generation and supply, and consumer protections, by June 1, 2025, and repeals inconsistent statutes, regulations, and orders. Limits investor-owned utilities to construction, operation, and repair of electrical transmission and distribution systems. Municipal and cooperative utilities may opt into competitive markets."

What does this Amendment mean? The plain language of the Amendment is clear: Florida's IOUs would be limited to the construction, operation and repair of transmission and distribution ("T&D") systems, and would be precluded from owning generation, T&D and other electric infrastructure.

Regardless of any hope, wish or alleged intent of the proponents of the Amendment, the provisions of a state Constitution do not merely serve as "guidance" to legislators or citizens. Neither the Legislature nor the Executive Branch will have the ability to supply additional terms to the core provisions of the Amendment. Courts will not interpret the Constitution as a "guide;" on the contrary, presumptively the Amendment will be given the meaning that the words convey. As noted later in this report, citizens may sue the state for any perceived failure to comply with the Constitution and any of its amendments. The proposed Amendment was drafted differently than key elements of the Texas legislation and, as written, will create a risky and costly electricity system in Florida. Indeed, as written, the Amendment could not even hope to achieve the less than ideal outcomes that continue to worry Texas lawmakers and regulators. But, at least in Texas as in other states that have attempted to repair market failures or other deficiencies in their restructured markets, they have the ability to amend Texas Senate Bill 7 ("SB7") that enacted restructuring or agency rules through normal legislative and administrative processes without being constrained by a set of constitutionally enshrined "rights" that instead would impose serious limitations on the State of Florida's efforts to ensure the development of adequate electric infrastructure, the institution of consumer price protections, and the implementation of good public policy in general.

While the sponsors of the Amendment assert that the Amendment is modeled after Texas' restructuring and does not preclude the IOUs from owning T&D, that is not the case. As discussed in more detail later in this report, SB7, which mandated the manner in which restructuring would be carried out, required each electric utility to separate its business activities from one another into the following units: (i) a power generation company; (ii) a retail electric provider; and (iii) a T&D utility. The electric utility could accomplish the separation required by either through the creation of separate non-affiliated companies or separate affiliated companies owned by a common holding company or through the sale of assets to a third party. SB7 specifically provided that T&D utilities would own and operate T&D infrastructure. To the contrary, the Amendment, and the ballot measure voters would be asked to vote on, does not contemplate IOU ownership of any electric infrastructure.

Instead, the Amendment would forcibly expel from Florida's electric energy market IOUs that currently supply electricity to approximately 70% of Floridians. IOUs would be forced to dispose of their ownership of more than $60 billion of current investment in generation, T&D and other electric infrastructure. This enormous void would ostensibly be filled by yet-to-be determined and qualified providers of electric service in a so-called "competitive" market with none of the price oversight or other protections currently provided through regulation by the Florida Public Service Commission. The Legislature and Executive Branch agencies would be required to design and implement a complex series of laws and regulations in an effort to comply with the Amendment, as written, and would be faced with significant risk exposure ensuring the efficacy of the Amendment if the "competitive" market does not materialize for all customers or otherwise falters or fails.

The Amendment is poorly drafted and unclear. It does not say what its Sponsors say it means. They casually assert that IOUs would continue to own T&D and that generation may "simply" be transferred to non-regulated affiliates of IOUs, but in doing so, the Sponsors read more into the Amendment than its plain language states. For the Sponsors to state or imply that the Legislature will embrace the Sponsor's view of the Amendment, rather than its plain meaning, is naïve and irresponsible and should be rejected by the conference. Despite its poor drafting, ambiguities and uncertainties, the Legislature and the citizens of Florida will be forced to live with its language and its consequences in perpetuity – if it makes it on to the ballot and is approved by the voters. As discussed in more detail below, those consequences are enormously negative for state and local government, to say nothing of the almost certainly catastrophic impact this would have on Florida's energy markets for years to come.

Key Conclusions

Proposals to restructure a state's energy markets are not new. A proposal was considered and rejected in Florida at the turn of the century, as well as more recently when a very similar Amendment was rejected by the Constitutional Revision Committee. No proposal to restructure a state's electricity market, however, has been adopted in the United States in over 18 years.[1] This is because the experience of other jurisdictions, including Texas, demonstrates the costs and risks to state and local government and to all customers are just too great.

Based on the information and analysis described in detail in the remainder of this report, it is very clear that the proposed Energy Market Amendment at a minimum would:

- Eliminate the state's IOUs from Florida's electric energy market and force the sale or "divestiture" of their nearly 50 power plants, more than 150,000 miles of T&D, and other electric infrastructure, creating ***billions of dollars*** in "stranded" costs, which will need to be paid for by or through government action to avoid an unconstitutional "taking;"

[1] The most recent restructuring proposals were adopted in 2000 by the District of Columbia and Michigan. (See, DC Bill 13-284 and PSC Order 11796 (September 19, 2000) and Michigan Public Acts 141 and 142 of 2000).

- Require the formation of an independent system operator ("ISO"), costing customers, including state and local government, ***hundreds of millions of dollars*** in start-up costs and on-going administrative costs;
- Force the state legislature and executive branch of government and other agencies and organizations to expend an ***enormous amount of time, resources and money*** to comply with the Amendment, implement "competitive" electric markets, defend their decisions in litigation, be the ultimate back-stop for market failures and be exposed to substantial new risks;
- ***Put at risk billions of dollars*** in annual franchise fees and other taxes paid by the state's IOUs, resulting in significantly lower revenues to local, municipal and state government;
- ***Put at risk the billions of dollars*** the IOUs have committed in Power Purchase Agreements ("PPA") and natural gas supply and transportation contracts;
- Prohibit municipal and cooperative utilities from purchasing their power from IOUs, abrogating the contracts that are in place and requiring these utilities to find new suppliers of their electricity;
- As a replacement, a new market would be created for companies such as the main proponent (Infinite Energy) with no obligation to provide essential electric service to all customers on a non-discriminatory basis and whose rates are not regulated by the state or any other entity;
- Threaten electric reliability and expose Floridians to consumer fraud and market manipulation as has been the experience in states that have restructured their electric markets; and
- Put the state in the position of having to organizationally and financially backstop any aspect of the supply and delivery of electricity if the new market fails in any respect.

Financial Impact

The financial impact of the Amendment is best summarized as:

- Significantly increasing energy costs to state and local government by $1.3 billion to $1.7 billion in upfront or one-time costs and more than $825 million in ongoing annual costs by eliminating low cost providers from the marketplace and by forcing uneconomic divestitures of electric system infrastructure by the IOUs, the costs of which would be paid by to all customers, including state and local governments;
- Imposing extensive implementation and litigation costs on state government and Florida taxpayers; and
- Resulting in significantly lower revenues to local government through reduced eligible franchise fees and other taxes.

Table 1, below, summarizes the financial impacts of the proposed Energy Market Amendment on state and local government. For those costs that would be borne by all Florida electricity customers, state and local governments would only a bear a portion of the costs based on their proportionate share of electricity purchases (approximately 11%). The assumptions and support underlying this table are provided in APPENDIX 1 Analysis of Financial Impact.

TABLE 1: SUMMARY OF RESULTS

Cost Category	Quantification/Total Impact on Florida Customers	State and Local Government Portion	
		Low Estimate	High Estimate
	Upfront or One-Time Costs		
Generation Stranded Costs[2]	• $10 billion to $12.3 billion • These costs will be experienced even under the proponent's interpretation of the Amendment since all these assets must be transferred to new entities	• $1.1 billion	• $1.4 billion
T&D and Electric Infrastructure Stranded Costs	• The net book value investment in IOUs' T&D assets is $24.3 billion • A substantial portion of this investment could be stranded when IOUs divest their T&D ownership • No other state that has restructured prohibited IOU ownership of T&D • Stranded costs for T&D and other electric infrastructure have not been specifically quantified because there is no precedent for restructuring of this type	• Unknown	• Unknown
Creation of a Wholesale Market and ISO Start-up/RTO Integration Costs	• Start-up costs range from $100 to $500 million • Other costs (e.g., customer education) approximately $20 million • These costs will occur even under the proponent's interpretation of the Amendment since the Amendment specifically calls for the establishment of a market monitor	• Start-up costs of $11.0 million • Other costs (e.g., consumer education) of $20 million	• Start-up costs of $55.0 million • Other costs (e.g., consumer education) of $20 million

2 Note, stranded costs are typically recovered from electricity customers over a period of years through a "competitive transition charge." For purposes on this analysis they are presented as upfront, one-time costs.

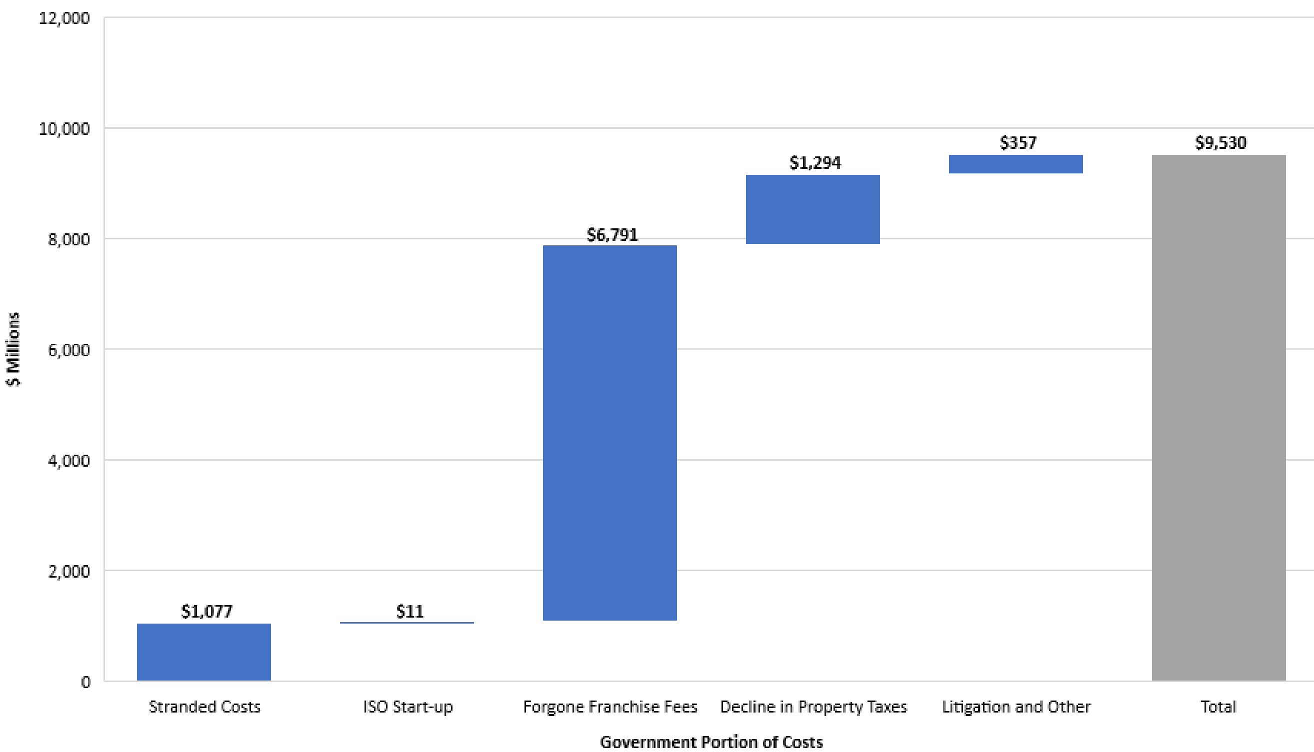
Cost Category	**Quantification/Total Impact on Florida Customers**	**State and Local Government Portion**	
		Low Estimate	**High Estimate**
Litigation Costs	• Litigation costs to implement the Constitutional Amendment range from $150 million to $300 million	• $150 million	• $300 million
Total Upfront or One-Time Costs	• $10.1 billion to $13.2 billion	• $1.3 billion	• $1.7 billion
	On-Going Annual Costs or Lost Revenues		
Franchise Fees	• $679.1 million in *annual* local municipality revenues would be eliminated • These costs will occur under the proponent's interpretation of the Amendment since franchises will be eliminated	• $679.1 million per year	• $679.1 million per year
Tax Revenues	• Decrease in *annual* property tax revenues by approximately $129.4 million to $173.8 million • Numerous additional risks related to declines in other state and local taxes, such as gross receipts tax and municipal public service tax • These costs will occur even under the proponent's interpretation of the Amendment since the taxable value of generation-related property will be lower	• $129.4 million per year	• $173.8 million per year
ISO Management and Administrative Costs	• Annual operating costs of $170.0 to $228.0 million • These costs will occur even under the proponent's interpretation of the Amendment since the Amendment specifically calls for the establishment of a market monitor	• $18.7 million per year	• $25.1 million per year
Total On-going Annual Costs or Lost Revenues	• $978.5 million to $1.1 billion per year	• $827.2 million per year	• $878.0 million per year

Cost Category	Quantification/Total Impact on Florida Customers	State and Local Government Portion	
		Low Estimate	High Estimate
	Other Costs		
	While not quantified herein, there are numerous other costs that would occur post-restructuring, meaning the results above are the minimum impact to Florida and state and local governments. Those costs include: • Additional costs to state and local governments related to implementation and ongoing administrative costs under restructuring. • Stranded costs beyond those quantified above, including those related to natural gas pipeline contracts, PPAs, regulatory assets, and other stranded assets. • Costs to the IOUs for the early retirement of debt related to their infrastructure. • The costs associated with any additional degree of state involvement as an operational or financial backstop to ensure the constitutionally guaranteed rights of this Amendment or to address the political or practical realities of any market failures. • Costs to the state economy due to lost productivity and disruption caused by the dismantling of the state's reliable and low-cost electricity system during the uncertain transition to the new competitive market, including lost economic development opportunities.		

As detailed in the table above, the financial impact of the Amendment on state and local government is estimated to be no less than $1.3 billion and as much as $1.7 billion in one-time costs and more than $825 million in on-going annual costs and lost revenues. Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone. As noted in the table above, there are numerous other costs that would be incurred post-restructuring. As such, the cost impact described above is the minimum level that would be incurred by state and local governments. ***The eventual cost to Florida and its governmental agencies would be much larger***.

Figure 1, below, illustrates the building blocks of the cost impact, based on the minimum cost impacts provided in the table above.

FIGURE 1: STATE & LOCAL GOVERNMENT COSTS OF RESTRUCTURING OVER 10 YEARS ($MILLIONS)[3]



3 "Other" includes costs such as ongoing wholesale market operations costs and customer education costs.

II. THE AMENDMENT IS UNPRECEDENTED IN THE ENERGY INDUSTRY

The ballot initiative is not a "simple" proposal to restructure Florida's energy markets and is clearly not similar to restructuring proposals implemented in Texas and some other states as its proponents would have the FIEC believe. The many problems with the Amendment are addressed here at length so that the reader understands the extent of disruption and negative financial consequences associated with the Amendment, which exacerbates the costs to all customers including state and local governments. Among many things, the proposed Amendment would:

- Irrevocably amend the state Constitution creating a constitutional right for "***every person or entity*** that receives electricity service from an investor owned utility… the right to choose their electricity provider, including, but not limited to, ***selecting from multiple providers in competitive wholesale and retail electricity markets***, or by producing electricity themselves or in association with others, and ***shall not be forced to purchase electricity from one provider;***"
- Provide that "any citizen shall have standing to ***seek judicial relief*** to compel the Legislature to comply with its constitutional duty to enact such legislation…;"
- Constitutionally mandate that "wholesale and retail markets be fully competitive so that electricity customers are ***afforded meaningful choices among a wide variety of competing electricity providers***.;" and
- "[L]imit the activity of investor-owned utilities to the construction, operation, and repair of electrical transmission and distribution systems."

The Amendment Would Change the State Constitution

No other U.S. state has ever implemented electric market restructuring through a constitutional Amendment. This is a very important distinction that has significant and potentially costly implications for all customers and for state and municipal governments in particular. The Amendment would catastrophically disrupt the electric market in Florida and create hardships for customers and state and local government, as illustrated below.

No other state provides citizens a constitutional right to select their electricity provider "from multiple providers in competitive wholesale and retail markets" and grants citizens standing to seek judicial relief if enacting legislation does not yield the desired results. The state will be legally responsible if "multiple competitive providers in competitive wholesale and retail electricity markets" do not present themselves to citizens or entities that receive electricity. How can a Provider of Last Resort ("POLR") be mandated where the costs of that service could not be socialized without offending the constitutional right to a "fully competitive market?" What happens if the market produces inadequate electric infrastructure as has been seen in other states such that "black outs" occur or reliability deteriorates? In short, customers, either citizens or entities, who currently purchase electricity from the state's IOUs may seek judicial relief from the state. In addition to guaranteeing certain constitutional rights, this Amendment guarantees years of litigation with potentially enormous financial consequences for the state.

The Amendment Eliminates Any Obligation to Provide Essential Electric Service

By eliminating the state's IOUs as electric providers, the Amendment eliminates any obligation to provide essential electric service on a non-discriminatory basis to all customers and eliminates the Florida Public Service Commission's regulation of the electricity rates charged to retail customers for this service. What does this mean? "Competitive providers" may charge whatever rates the market will bear and may discount rates for certain customers while overcharging other customers or entire customer classes. As discussed later in this report, vulnerable customers, in particular low income and elderly customers, have been the victims of fraud and exorbitant prices in many restructured states. In fact, these market abuses have been so bad that some states have responded by suspending retail choice.

The Amendment specifically prohibits "forcing" a Floridian to purchase electricity from one provider (*e.g.*, customers could not remain with their existing provider). States that have legislatively restructured energy markets and allowed customers to choose their electricity suppliers, have also established a POLR that provides service to ensure that customers receive electric supply if they do not choose a retail marketer (or in the event that their retail supplier exits the market). The Amendment makes no provision for a POLR and by specifically prohibiting "forcing" a customer to purchase electricity from a single provider appears to provide no backstop for customers who are unable to secure this essential service. Indeed, the legislature may be constitutionally precluded from establishing such a regime (or at least precluded from creating a regime that socializes the higher costs of providing rural service in favor of ensuring that all Floridians enjoy affordable access to quality electric service) if it is found to offend the concept of a "fully competitive market" under this Amendment.

The Amendment Would Constitutionally Prohibit IOUs From Owning Electric Infrastructure

By explicitly limiting Florida's IOUs "to the construction, operation, and repair of electrical transmission and distribution systems," and omitting the words "own" and "generation," it constitutionally prohibits IOUs from owning generation and selling electricity, and from owning T&D and other electric infrastructure. No other U.S. state, including Texas, has placed this breadth of limitations on its IOUs. Prohibiting IOU ownership of generation and T&D amounts to nothing less than a government taking of the vast majority of assets held by investor-owned companies. As noted earlier, while the sponsors of the Amendment may suggest that what they meant was that IOUs would continue to own T&D, that is not what the Amendment says and the FIEC, the state Supreme Court, voters, the legislature and the executive branch would be limited by the specific Amendment language.

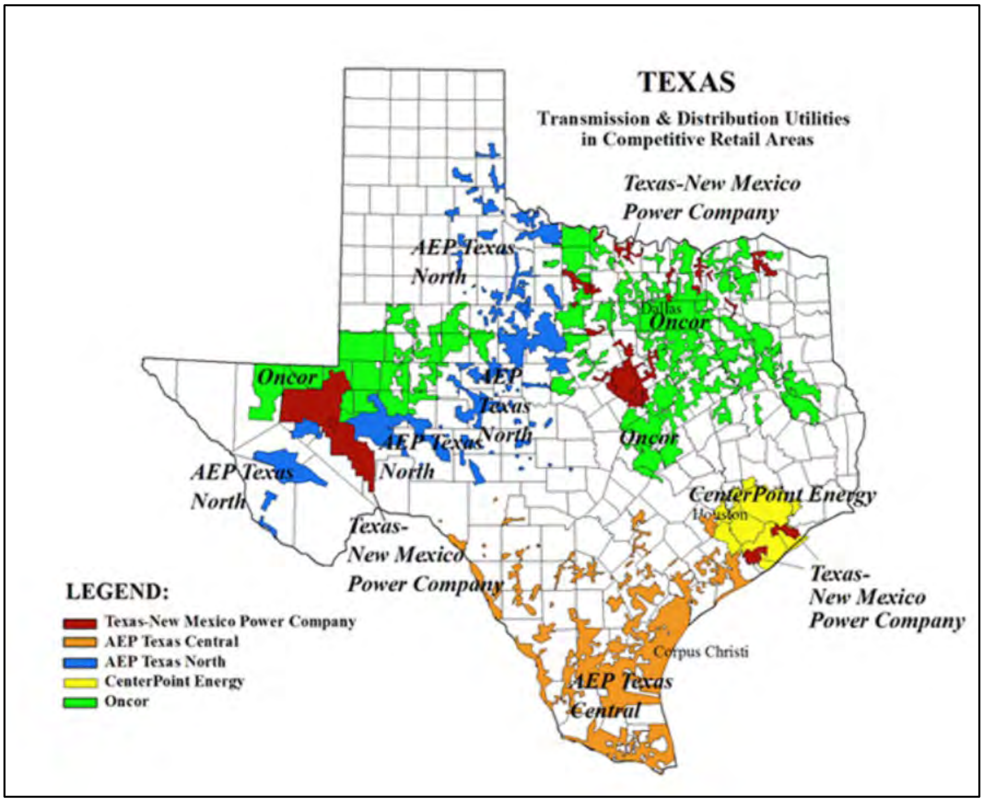
Prohibiting IOU ownership of generation and T&D leaves the state's entire electric system in the hands of yet-to-be identified entities, reducing the current IOU T&D operations to potential subcontractor status for the yet-to-be-identified T&D owner (assuming the IOUs even choose to enter this business). It also creates uncertainty around many important functions, including who is responsible for the restoration of service after a major storm. During the February 11, 2019 FIEC meeting, the sponsors of the Amendment "explained" that customers would receive their bills from their new competitive electricity supplier and would call them with any issues, but that it would be the responsibility of the IOUs to address service interruptions. There are two issues with this statement: 1) the explanation by the sponsors of the Amendment regarding what competitive electricity suppliers do amounts to acting as nothing more than a "middle man" buying power, marking it up and reselling it to customers, and 2) the IOUs are limited to T&D subcontractors, at best, and such subcontractors do not typically also provide customer service functions.

The Amendment Differs from Texas Restructuring

While the sponsors of the Amendment assert that the Amendment is modeled after Texas' restructuring there are a number of clear and important differences. Under SB7, which governed restructuring in Texas, vertically-integrated utilities operating within the Electric Reliability Council of Texas ("ERCOT") region were required to split into three discrete entities: generation companies, the still regulated transmission and distribution utilities, and retail electric providers. The entities could remain under the same corporate owners, even IOUs, but each entity had to function separately. SB7 allowed for continued ownership of transmission and distribution systems by IOUs under the definition of a transmission and distribution utility, defined as "a person or river authority that owns or operates for compensation in this state equipment or facilities to transmit or distribute electricity…"[4]

As noted earlier, Texas specifically provides for IOU ownership of transmission and distribution facilities, while the Amendment expressly restricts IOUs to the construction, operation, and repair of electrical transmission and distribution systems. Further, SB7 did not codify a customer's right to generate and sell power, while the Amendment specifically allows for customers to produce their energy themselves or in association with others. Finally, SB7 did not require a single state-wide competitive market, and did not result in a complete restructuring across the state, as shown in Figure 2.

FIGURE 2: COMPETITIVE RETAIL AREAS IN TEXAS[5]



The Amendment, however, would restructure all areas within the state served by IOUs, including remote areas where transmission interconnections are limited. Transmission systems were not built with a restructured market in mind, but rather were built by each utility to serve their own customers with relatively few links to one another that existed for reliability purposes. As a result, there are areas of Florida, specifically the Florida Panhandle, with limited interconnectivity that will hamper the free exchange of electricity under restructuring. These regions currently operate as separate reliability regions. While it could be more efficient for the entire State of Florida

4 Senate Bill 7, Section 31.002, Utilities Code.
5 Public Utilities Commission of Texas.

to operate under a single regional reliability entity with a uniform set of transmission planning and operational procedures, this would be a costly and time-consuming undertaking.

This Amendment, and its implications, are unprecedented in the industry. It would completely dismantle Florida's electric industry, establish constitutional rights and requirements (some of which may not be within the authority of the legislature and executive branch), and essentially direct the legislature to "work out the details."

III. TEXAS IS NOT A "SHINING STAR" IN ELECTRICITY RESTRUCTURING

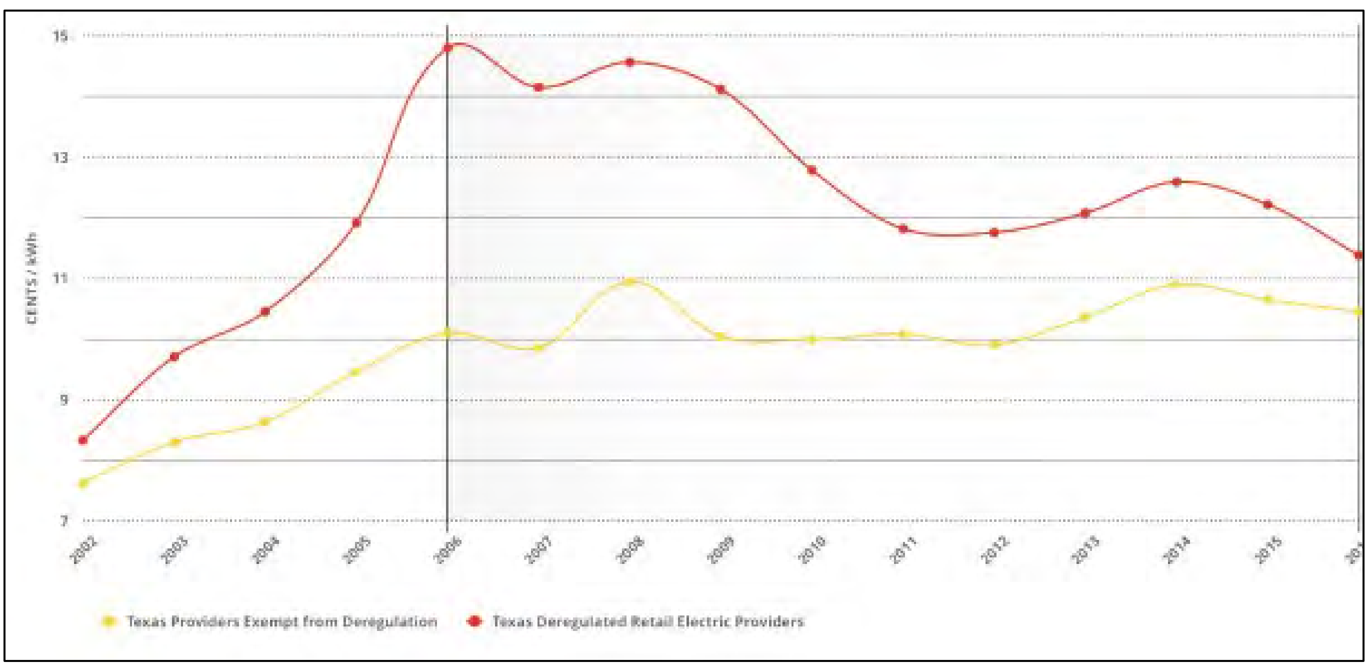
The sponsors of the Amendment point to Texas as the shining example of the success of electric restructuring.

The differences between Texas and Florida make the adoption of the Texas model risky and costly for Florida customers and governments. Further, the experience with electric competition in Texas has been fraught with challenges, including price increases, decreasing reserve margins, blackouts, bankruptcies, and unprecedented levels of customer complaints.

Texas Competitive Energy Prices Exceed Its Regulated Prices

Texas has experienced unexpected price increases since it opened its markets to competition. The Texas Coalition for Affordable Power ("TCAP") produces annual analyses that assess the competitive market and the impact on retail prices. In its 2014 study, TCAP found that restructuring had cost Texas customers $22 billion from 2002 – 2012.[6] This annual trend began during the very first year of the retail electric deregulation in Texas and has continued through 2016, as shown in Figure 3.

FIGURE 3: AVERAGE RESIDENTIAL ELECTRICITY PRICES IN TEXAS



[6] TCAP 2014 Electric Restructuring Report.

In its most recent 2018 report, TCAP found that Texans have consistently paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation.

In Texas, electricity providers affiliated with the incumbent utility were required to charge a "price to beat" until the incumbent utility lost sufficient market share to alternative providers. This price was designed as a price floor to prevent the incumbent from offering artificially low rates to stifle competition and undercut new market players. When the price to beat was set, it included a 6% discount off the utility's base rates, as adjusted for fuel costs. However, prices in the deregulated areas steadily climbed as natural gas prices rose in the mid-2000s. From 2002 to 2006, the price to beat rose 88% and the price of competitive offers rose 62%. In contrast, rates in regulated areas of Texas rose only 24% during this period.

Rolling Blackouts and Shrinking Reserve Margins Threaten Texas

Competitive markets have introduced added system reliability risks in Texas. In early 2006, rolling blackouts in Texas left more than 200,000 people unexpectedly without power, including about 78,000 customers in the CenterPoint Energy service territory (around Houston) and about 80,000 customers in the North Texas service territory of TXU Electric Delivery. The crisis began when the grid operator saw usage begin to peak and concluded that it might not have enough generation online to meet demand. All available generation was called to operate at its highest output. However, demand continued to spike, and ***the grid operator was forced to cut power to various industrial customers***. A subsequent loss of four generators representing over 900 MW was too large of a contingency for the system to handle, and ***rolling blackouts were called. These rolling blackouts were the first in more than a decade.***

ERCOT blamed a confluence of events, including the planned outage of about 14,000 megawatts of capacity for plant maintenance, a spate of unseasonably hot weather that went unpredicted by ERCOT's computers, and some unexpected last-minute plant shutdowns.[7] Officials pledged to make corrections to better handle such events in the future. However, approximately two years later, on February 26, 2008, ERCOT officials took emergency action to avoid blackouts. A sudden loss in wind power, coupled with other factors, caused grid operators to take emergency actions once again to avoid a catastrophic system collapse. Additional operator actions to avoid blackouts have been necessary in subsequent years. This represents reliability risks and added costs to the system, which are ultimately borne by customers.

Electric competition in Texas has also resulted in shrinking reserve margins, which poses a serious threat to system reliability. Reserve margins are a measure of the generating capacity available to serve customer demand, which poses a serious threat to system reliability. Because power shortfalls can put a system at risk for blackouts, the reserve margin measurement is a good indicator of system reliability. ***In 2001, prior to deregulation, Texas had the highest reserve margin in the nation[8]. By 2011, these reserve margins had shrunk to alarmingly low levels.*** The National Electric Reliability Corporation ("NERC") reported ERCOT's reserve margin ratio in 2011 at about 14 percent, which marked a nearly 40 percent decline from pre-deregulation levels and far below the national average in 2011 of around 25 percent.[9] In fact, ***after 10 years of deregulation, Texas possessed the lowest reserve margin in the nation***, according to NERC. This was especially alarming, since electricity prices increased over this same time period. The reserve margin in Texas continues to dwindle, with the grid operator projecting reserve margins in the summer of 2019 to be 7.4%, while ERCOT's target reserve margin is 13.75%[10]. Just

7 Deregulated Electricity in Texas, A Market Annual, 2018, pg.19.
8 Jim Forsyth, "Texas Launches Electric Power Deregulation," United Press International, June 1, 2001.
9 NERC Long Term Reliability Assessment 2011.
10 ERCOT Capacity, Demand and Reserves Report, December 2018.

prior to the summer of 2018, ERCOT warned of the risk of rotating blackouts due to expected reserve margins in the range of 6%. It is likely that with the projected summer 2019 reserve margins, ERCOT will issue a similar warning.

Bankruptcies Followed Restructuring

In 2014, roughly twelve years after the introduction of electric competition in Texas, Energy Future Holdings, the then-parent of Luminant Generation Company and Oncor Electric Delivery, filed for bankruptcy, representing one of the biggest Chapter 11 bankruptcy filings in corporate history. The filing also marked the colossal collapse of a heavily-leveraged $45 billion bet taken by private equity firms, who borrowed enormous amounts of money on the wager that natural gas prices would continue rising compared to coal and, in the process, elevate wholesale electricity prices. Instead, new natural gas exploration technology led to a fall in natural gas prices, and electricity prices were driven down to historic lows.

Price volatility has also caused the bankruptcy of some retail electric providers. Texas Commercial Energy ("TCE") filed for bankruptcy protection in 2003 following a sudden and dramatic rise in the price of wholesale electricity. Because TCE did not own generating assets, it acquired the electricity in the wholesale market and then resold it on a retail basis to its customers. When the wholesale price of power exceeded the price TCE was charging its retail customers, TCE was unable to pay its bills as they came due.

Retail electric providers continue to face headwinds in Texas. In 2018, Breeze Energy, a Dallas retail electric company with thousands of customers in Houston, was shut down by Texas regulators after the company defaulted on its financial obligations, leaving industry analysts to speculate that the anticipation of higher wholesale electricity prices this summer may have put the retail electric provider in a financial squeeze.

Customer Complaints Skyrocketed

The number of complaints regarding electric service filed at the Texas Public Utility Commission increased steadily since the market opening and peaked in July and August of 2003. Over the course of the fiscal year, the Texas Public Utility Commission ("PUCT") Customer Service Division received about 17,000 electricity complaints — about half relating to billing, although many consumers also complained about service disconnections and faulty service. This was a more than 1,200% increase over the average number of annual electricity complaints received by the PUCT in the years prior to restructuring and would mark an all-time high for the number of annual complaints under the Texas deregulation law.[11]

IV. WHAT WOULD THE PROPOSAL DO TO FLORIDA'S ENERGY MARKETS?

Florida's Energy Markets Today

As in most U.S. states, incumbent IOUs supply electricity to the majority of Florida's residents, more than 70%, at retail rates regulated by the Florida Public Service Commission. Municipal electric companies or rural electric cooperatives serve the remainder of the state's electricity consumers, as shown in Table 2, but are not subject to this Amendment.

---

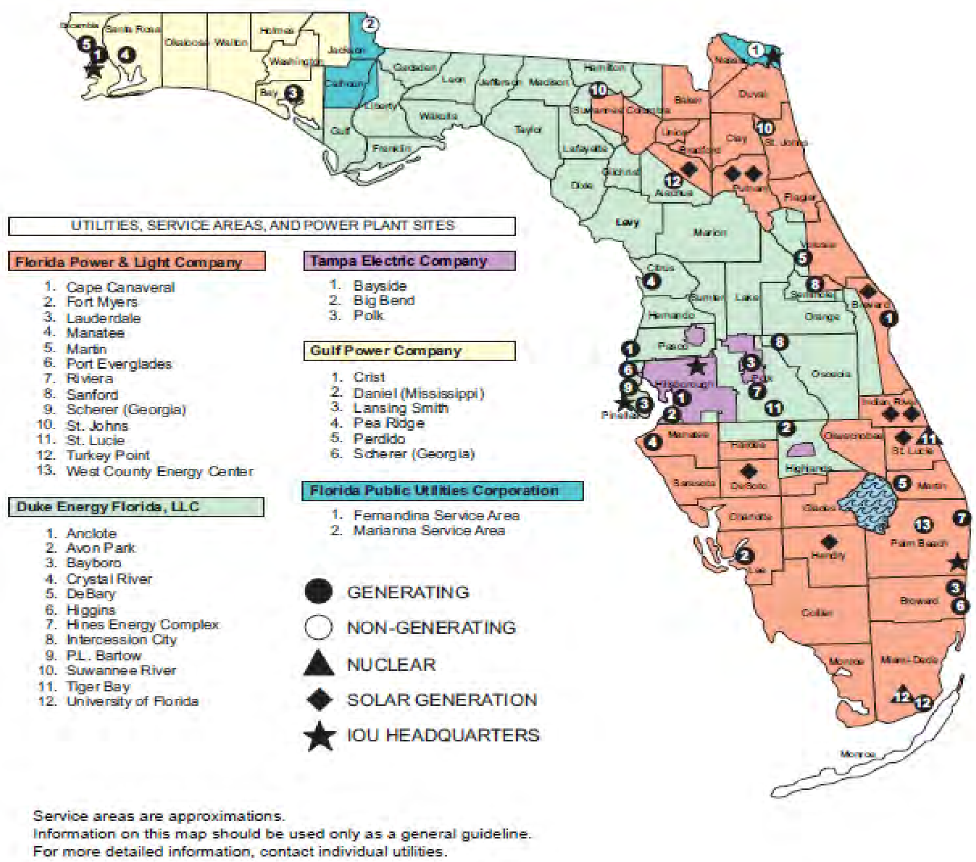
[11] TCAP History of Deregulation 2018, pg. 32.

TABLE 2: FLORIDA CUSTOMERS BY PROVIDER, CUSTOMER CLASS

	No. of Providers	Total	% Total	Residential Customers	Commercial Customers	Industrial Customers
IOU	5	7,912,950	75%	6,997,244	900,050	15,656
Municipal	33	1,447,183	14%	1,248,540	196,257	2,386
Cooperative	16	1,144,913	11%	1,025,506	116,294	3,133
Total:	**54**	**10,505,066**		**9,271,290**	**1,212,601**	**21,175**

Each IOU has a specific service territory, as shown in Figure 4, within which it provides non-discriminatory electric service to all residents, businesses, schools, hospitals, houses of worship and state and local government facilities. The IOUs cannot pick and choose their customers, charge two different customers who are purchasing the same service different prices, or otherwise discriminate in the ways that they serve the public. All customers, including remotely-located customers and low income, elderly, and other vulnerable customers, are provided non-discriminatory access to essential electric service. As discussed later in the report, in many states which have restructured their electricity markets, vulnerable customers, in particular low-income and elderly customers, have been the victims of fraud.

FIGURE 4: ELECTRIC IOU SERVICE TERRITORIES AND IOU-OWNED GENERATION RESOURCES[12]



Source:
Florida Public Service Commission

Many municipal and cooperative electric companies also purchase a portion of their electricity for their customers from the IOUs. For example, Lee County Electric Cooperative, one of the largest electric cooperatives in the country with nearly 200,000 customers, purchases 100% of its electricity under a long-term contract with FPL. The Amendment would prohibit municipal and cooperative utilities from purchasing their power from IOUs, abrogating the contracts that are in place creating both legal issues and electricity supply and cost issues. Municipal and cooperative utilities would have to find new suppliers of their electricity if the Amendment passes.

The IOUs supply electricity by making substantial investments on behalf of their customers, including owning and operating electric generating plants, purchasing electric power from others, and owning and operating T&D systems necessary to deliver power to their customers. As of December 31, 2018, the IOUs have currently invested $60 billion in electric infrastructure investments.[13]

In addition, Florida IOUs are responding to customer demand for affordable and reliable clean energy by investing in substantial amounts of solar energy. In addition to the plants listed in Figure 4 above, FPL owns 18 other currently operating solar power plant sites throughout Florida (totaling over 1,250 MW of capacity),

[12] As discussed later in this report, there are additional solar generating facilities that are not reflected in this map.
[13] IOU Earnings Surveillance Reports.

Duke owns four other solar plants (totaling over 92 MW) and TECO has five additional solar plants (totaling over 318 MWs).[14] The IOUs will also be adding significant amounts of solar generation in the near future. In 2019, Duke will add 74.9 MW and TECO will add 282 MW.[15] Further, earlier this year, FPL announced its "30-by-30" program that has as its goal the installation of 30 million solar panels by the year 2030 and Duke will add an additional 551Mws by 2021. As FPL and other utilities continue to expand their solar fleets, enhancing economies of scale, customers will benefit from increasingly carbon-free electricity sources while maintaining low prices and reliability.

When a storm hits, the IOUs work diligently to restore service. Despite being the "lightning capital" of the U.S., Florida has achieved a level of reliability in electric service that has won national awards and industry recognition. Florida's IOUs and their parent companies have been recognized for outstanding performance in many categories:

- Reliability
- Storm restoration and emergency response
- Innovation
- Customer service
- Employer

APPENDIX 4 IOU Awards provides additional detail regarding awards received by the IOUs and their parent companies.

In many cases, an IOU has franchise agreements with the local communities it serves. In general, these agreements provide the IOU with the exclusive right, and obligation, to serve the community's customers as well as access to rights of way. Franchise agreements include a franchise fee paid by the IOU to the community for those rights. The Florida IOUs pay almost $670 million per year in franchise fees, as discussed in more detail later in this report. IOUs also pay substantial sales, property and other taxes. Most taxes paid by IOUs are based on their revenues. Finally, Florida's IOUs play other important roles in their communities including as employers and charitable givers (both in terms of the IOUs' millions of dollars in charitable contributions each year to causes like STEM education and environmental sustainability, and their employees donating thousands of hours of time to community endeavors).

[14] Source: S&P Financial and Company Site Plans and news releases.
[15] Company Site Plans.

Florida's IOUs do all of this at electricity rates well-below national averages and the average rates charged in states that have restructured their electricity markets as shown in Table 3, below.

TABLE 3: AVERAGE ELECTRIC RATES IN FLORIDA, OTHER STATES

	Residential	Commercial	Industrial	All Sectors
Florida IOU	11.61	9.20	7.67	10.37
Restructured Average	16.24	12.71	9.53	13.32
U.S. Average	12.87	10.74	6.91	10.46

Source: EIA, Electric Power Monthly, October 2018

The proposed Amendment would radically change this favorable situation, increasing energy costs to state and local governments and all customers and adding unnecessary risk and uncertainty to Florida's heretofore stable and reliable electric markets.

Florida's Energy Market if the Amendment is Implemented

If the Amendment is implemented, Florida's energy market would be radically and forever changed. IOUs would be limited to only the "construction, operation, and repair of electrical transmission and distribution systems," thus prohibiting IOUs from owning the generation, transmission and distribution that they have successfully built, operated and maintained on behalf of their customers for more than 100 years.[16] To comply with the policies put forth in the Amendment, IOUs would be forced to sell their generating plants for a market price. While the sponsors of the Amendment suggest that the assets could simply be transferred to non-regulated affiliates of the IOUs, the Amendment does not address this, there is nothing simple about such a transfer, and it would still require establishing the current market value of the assets transferred. Based on the experience in states that have restructured and on the current market for generating plants, it is clear the market value of the IOUs' generating plants would be less than the current book value of the plants, and, for certain types of generating plants (*e.g.*, coal and nuclear plants), there may be no market value at all. And, while IOUs could construct, operate and repair T&D systems, the plain language of the Amendment also prohibits IOU ownership of those systems. As discussed in more detail later in this report, massive amounts of IOU investment would be rendered uneconomic or "stranded" and customers would be required to foot the bill for those costs.

The Amendment posits "a wide variety of competing electricity providers" would own the generation and provide electricity service to Floridians. The Amendment, however, is either vague or completely silent on the innumerable facts and details critical to state and local government and Florida's other energy consumers. Those facts and details include the following, each of which creates the likelihood of litigation, increased costs in administration of the market, or risks to reliability issues:

- The elimination of any obligation to provide electric service to all customers means that customers would not be assured non-discriminatory access to this essential service. Low-income customers, medically essential services, and customers in sparsely populated and remotely located communities that are currently served by IOUs would be particularly at risk.
- If competing electricity providers are not willing to take on all customers or if providers materialize but they charge rates that are much higher and are not guaranteed because that is what the market will

16 Florida Keys Electric Cooperative, Jerry Wilkinson. Accessed February 9, 2019, http://www.keyshistory.org/fkec.html.

bear for this essential service with no substitute, there is no backstop for customers. In particular, the Florida Public Service Commission, which currently regulates the price of electricity in Florida, would not be able to intervene as it would not have jurisdiction over new entrants.

- Who would a customer call if their lights go out? Who would restore electric service after a hurricane? The Amendment is silent on these key questions.
- The Amendment would grant all customers the constitutional right to generate their own electricity, which means that potentially millions of customers could each have their own power plant. Customers would have the constitutional right to connect these plants to the electric grid. Such an unplanned approach could create significant reliability, predictability and stability issues for Florida's electric system.
- The Amendment requires the implementation of a competitive wholesale market. Florida, unlike many states, is not part of a regional transmission organization ("RTO") or similar organization that is necessary for the state to have a competitive wholesale electricity market. All of this would have to be formed in only a few years.
- The Amendment states that electricity customers would be protected against certain abusive practices retail marketers might employ. Yet a competitive retail electric market, whose participants are not regulated by the state, cannot provide these protections, as has been demonstrated in other restructured states including Texas.
- The Amendment carves out cooperatives and municipally-owned electric utilities but does not address the fact that the IOUs supply a substantial portion of the electricity that these organizations sell to their end-use customers. The state's cooperative and municipal providers would be required to replace this electricity and keep the lights on for governmental and other customers.
- The Amendment would eliminate comprehensive resource planning to ensure the adequacy, diversity, and environmental sustainability of energy resources. The Amendment's statement that it does not limit or expand the State's public policies on energy is misleading and ignores the fact that competitive energy market participants would not be regulated by the State.
- Franchise agreements are specific contracts between IOUs and municipalities. If these IOUs go away, so do the franchise agreements and franchise fees. This risk was exposed by the League of Cities at the February 11, 2019 FIEC meeting.
- Many taxes paid by the state's IOUs would be substantially reduced. The Amendment's statement that the authority to levy and collect taxes, fees and other charges would be unchanged ignores the fact that state and local government revenues would decrease as a result of this Amendment unless state and local government increases taxes. The recently passed Amendment requiring a supermajority vote of the legislature to impose new taxes or to increase current taxes would make it more difficult for the legislature to mitigate tax losses resulting from restructuring the state's electric industry.

State and Local Governments would be Harmed by the Amendment

The Amendment would increase costs and reduce revenues to state and local governments. As discussed in this report, there is no reasonable scenario under which costs would not increase and revenues would not decrease. ***State and local governments, both as energy consumers and through forgone revenues, would be responsible for approximately $1.3 billion to $1.7 billion in one-time costs and more than $825 million in on-going annual costs and lost revenues. Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone.*** What do state and local government and the state's energy consumers get in return for this multi-billion-dollar price tag? They will get a middleman inserted into their energy transaction, by way of a marketer or competitive generator. They would get the right to choose their electricity provider (just not an IOU, and not if they are served by a municipal or co-operative utility) and to purchase competitively-priced electricity (which, importantly, does not mean lower price or better). They would also be faced with all the unanswered questions and risks that this Amendment would create. As other parties commented at the FIEC's February 11, 2019 meeting, Florida's electricity markets work well, service is reliable, and energy costs are competitive. There is no reason to dismantle or "destructure" Florida's electricity market.

V. THE AMENDMENT WOULD IMPOSE IMPLEMENTATION AND OTHER COSTS

Implementing full retail choice for all customers of Florida's IOUs as required by the proposed Amendment necessitates the design, implementation, and ongoing administration and monitoring of functioning competitive energy markets in the state. The legislature and executive branch would be required to commit substantial time, resources and money to design and implement a complex set of laws and regulations in an effort to create these markets and comply with the plain language of the Amendment as written. This would be complicated and contentious, would take many years and would result in extensive implementation costs, litigation and other administrative costs. These costs would be borne by all electric customers and would negatively impact state and local government.

Forming a Functioning Wholesale Market is Costly

It is not possible to introduce full retail choice in Florida as put forth in the Amendment without establishing a functioning wholesale market. A functioning wholesale electricity market is necessary to facilitate the buying and selling of electricity for all retail customers. All states that have restructured their electricity markets to provide full retail choice (commercial, industrial and residential) are part of either an ISO or a RTO.[17] ISOs and RTOs are not-for-profit entities that are formed to perform three basic functions: (1) operate the bulk electric power system, (2) develop, oversee, and administer the wholesale electric market, and (3) manage the power system planning processes to address transmission needs. Florida, like many traditionally regulated states, does not currently have an ISO, RTO, or similar organization. See also APPENDIX 6: *Wholesale Market Implementation*.

States that have implemented ISOs or RTOs have spent years and hundreds of millions of dollars to do so. States that have recently considered an ISO or RTO formation have estimated that implementation could take up to 10 years and cost between $100 million and $500 million. There is no reason to believe Florida would be any different. In fact, given the unique nature of Florida as a peninsula with limitations on inter-state infrastructure, implementation of a wholesale market could cost even more.

It is also worth remembering that Florida previously considered, and rejected, forming an RTO in part due to the extensive implementation costs.[18] In 2006, Florida Power Corporation ("FPC"), FPL, and TECO developed a proposal referred to as "GridFlorida" in response to the U.S. Federal Energy Regulatory Commission ("FERC"), which required all public utilities that own, operate or control interstate transmission facilities to file a proposal to form or participate in an RTO. GridFlorida engaged the ICF consulting firm to conduct a study to determine the costs and benefits of developing and operating an RTO for Florida. The study found:

> … the prospect of a basic Day-1 RTO operation as proposed are "bleak," with the Peninsula Florida costs exceeding the Peninsula Florida benefits by over $700 million over the three-year operating period. Under a more advanced Day-2 RTO operation ICF concludes that the total

[17] RTOs and ISOs have similar (virtually indistinguishable) functions. The primary difference lies in the governance structure.

[18] Before the Public Service Commission of Florida, Docket No. 020233-EI, Order No. PSC-06-0388-FOF-EI, May 9, 2006.

project benefits are a negative $285 million in Peninsular Florida over the ten-year operating period.[19]

As a result of the GridFlorida study, FPC, FPL and TECO withdrew their proposal. The Florida Public Service Commission and the FERC approved the withdrawal. In 2018 dollars, the estimate of costs relied on by the Florida Public Service Commission and the FERC would exceed the benefits by ***$1 billion for basic Day-1 RTO operations and over $400 million over the ten-year operating period.***

Other Annual Costs Would Rise

In addition to the upfront implementation costs, there are on-going annual costs to administer an ISO or RTO. Those costs include, but are not limited to, salaries and benefits for employees, IT costs, hardware and software maintenance costs, consultant costs, marketing monitoring costs and training and travel costs. ISOs and RTOs are sophisticated organizations with substantial organizational infrastructure and employees. Annual costs to administer the ISO/RTO would be in the range of $170 to $228 million based on other single state ISO/RTOs like New York ISO and ERCOT, respectively.

In addition to annual administrative costs, there are various ongoing costs that would be incurred if the Amendment proceeds. Those costs include consumer outreach and education, software and other information technology upgrades, and monitoring and oversight costs. For example, Texas had a budget of $24 million to educate customers during the first two years after retail choice was implemented.[20] In addition to customer education, Texas hired additional customer service representatives to deal with skyrocketing complaints and bill resolutions pertaining to issues with implementing a restructured market. Estimated education costs for Florida would be approximately $18 million.[21] The staff of the Public Utilities Commission of Nevada ("PUCN") noted additional specific software and computer system technology costs, increased costs to maintain electric grid reliability, and costs associated with maintaining the new systems that would need to be created to implement Nevada's failed restructuring ballot initiative, including approximately $2.2 million for increased PUCN regulatory and workload costs. The PUCN staff's paper also noted that "regulatory uncertainty is generally bad for business" and concluded that it was likely that all of these costs would have been added to Nevadan's monthly electric bills in an open and competitive electric market.[22]

An additional approximately $170 to $228 million in annual administrative costs and $20 million in other costs that are passed onto Floridian electricity customers is clearly bad for business.

The Florida Legislature and Executive Branch Would be Required to Commit Extensive Time, Resources and Money to Implement the Amendment

The Florida legislature and executive branch would be required to design and implement a complex series of laws and regulations in an effort to comply with the Amendment. In so doing, they would be faced with answering many questions that are unaddressed in the Amendment, including but not limited to determining:

- How to fill the market void left by IOUs;

---

19 Before the Public Service Commission of Florida, Docket No. 20020233-EI, Order No. PSC-06-0388-FOF-EI, May 9, 2006.
20 PUCN, Energy Choice Initiative Final Draft Report, Docket No. 17-10001, April 2018, at 62-63.
21 Estimated education costs were based on a ratio of Texas education costs and its population and applied to Florida's current population.
22 Ibid., at 65-67.

- How to implement, oversee and administer a new restructured market through which service would be provided but without the overarching price protection currently provided by the Florida Public Service Commission;
- How to provide for competitive wholesale electric markets as required by the Amendment without infringing upon the jurisdiction of the FERC;
- The constitutionally permissible role of the "market monitor" required by the Amendment, its structure and who would bear the costs of this new agency;
- How the forced divestiture requirements can be effectuated without running afoul of either the U.S. or Florida constitutions;
- Which of the existing laws and extensive regulations would be struck to ensure the "purposes" of the Amendment are met;
- How to reconcile public policy mandates such as renewables and conservation with the competitive market required by the constitutional Amendment;
- The myriad of rules and regulations necessary to address, for a potentially unwieldy number of individual service providers, issues such as: licensing requirements; unwarranted service disconnections; deceptive or unfair practices; consumer safety and education; and complaint resolutions;
- Whether the state can compel a private entity (and if so who) to:
    - Serve customers who otherwise would go unserved in a "competitive" market because they are unable to pay the "market" price for service or are not cost-effectively servable, or cannot meet credit check requirements;
    - Repair electric infrastructure (power plants, transmission structures and/or distribution poles) following a hurricane or other natural disaster and who would bear the costs of those repairs or rebuilds.
- Whether and how to address public policies on renewable energy, energy efficiency, fuel diversity and environmental protection (all of which exist in current Florida law and may be stricken);
- What entity or bureaucracy would have responsibility for the reliability of the operation and coordination of the state's electric grid, to ensure the system remains properly balanced and maintained minute by minute, 24 hours a day, 7 days a week, 365 days a year; and
- How to ensure that there continues to be adequate electric infrastructure such that the needs of Florida's expanding economy and population continue to be reliably and cost-effectively met.

In attempting to implement the Amendment, the legislature and the executive branch would also have to determine what role the state might have to play (and at what cost) to ensure that:

- Adequate infrastructure is built and maintained in the event that the legislature's effort to design a new "market" structure results in an inadequacy of energy supply or reliable infrastructure;
- <u>All</u> residents and businesses in Florida continue to have the right to affordable and reliable electric service;
- Florida's electric infrastructure is promptly repaired or rebuilt following a hurricane or natural disaster and how those costs would be funded; and

- Florida's electric grid continues to be properly operated and coordinated minute by minute, 24 hours a day / 7 days a week, although much of the regulatory responsibility would be shifted to the Federal government (which has been challenged in meeting this responsibility).

The state of Florida would have the ultimate responsibility to ensure that any new system works properly. Whether due to political realities or the newly enshrined constitutional rights, the state would face significant financial exposure for market failures.

Litigation is Inevitable

Because the Amendment leaves many important questions unanswered, hundreds of millions of state dollars could be spent on lawyers and consultants alone.[23] The Amendment is expected to create substantially more litigation costs than any other energy-related litigation in the state in recent years. Finally, as noted earlier, the Amendment constitutionally grants Floridians standing to seek judicial relief if, among other things, "meaningful choices among a wider variety of competing electricity providers" do not present themselves.

VI. PROHIBITING IOUS FROM OWNING GENERATION AND T&D WOULD INCREASE COSTS

IOUs currently have approximately $60 billion in current investment (i.e., net book value) in electric system infrastructure to serve the state's energy consumers.[24] IOUs also have significant commitments and obligations under purchase power agreements, fuel contracts, and collective bargaining agreements with union labor. The forced sale, or divestiture, of electricity infrastructure puts those investments and commitments at risk and would result in substantial costs for Florida electricity customers in the form of "stranded costs."

Stranded costs are created when the market value of utility assets in a restructured market is less than the value on the utilities' books. There are three primary drivers of this devaluation: (1) the forced sale of assets creates uneven bargaining power for asset purchases, leading to low (i.e., "fire sale) valuations; (2) assets would be heavily discounted due to the risks and uncertainty of operating in an unproven merchant market; and (3) the market does not value the same factors that have led to certain prudent IOU investments. Those factors include fuel diversity, environmental goals, and long-term planning considerations. As described below, the forced divestiture (or even the forced spinoff to an unregulated affiliate) of the IOUs electricity infrastructure would generate significant stranded costs. These stranded costs for generation assets alone can reasonably be expected to exceed $10 billion and could range much higher. The state of Florida would have to either fund the compensation for the billions of dollars of this property "taken" as a result of the Amendment or pass those costs on to current customers (including state and local government customers) through a non-bypassable recovery charge on electric bills as other states have elected to do.

Estimating the Generation Stranded Costs Created by the Amendment

There is a wealth of experience with stranded costs in the states that have restructured their electricity markets. There is also market data on generating plant sales in the U.S. Using these two data sets, one can reasonably

23 In a well-known case between Florida and Georgia over upstream water rights, litigation has cost the state $57 million in just the past four years. Since the ballot initiative could result in multiple litigation cases, that $57 million could be three times as much at the low end and six times as much at the high end. Tampa Bay Times, "Supreme Court Finally Rules on Florida's 30-year Water War with Georgia. And it's not over," June 28, 2018.

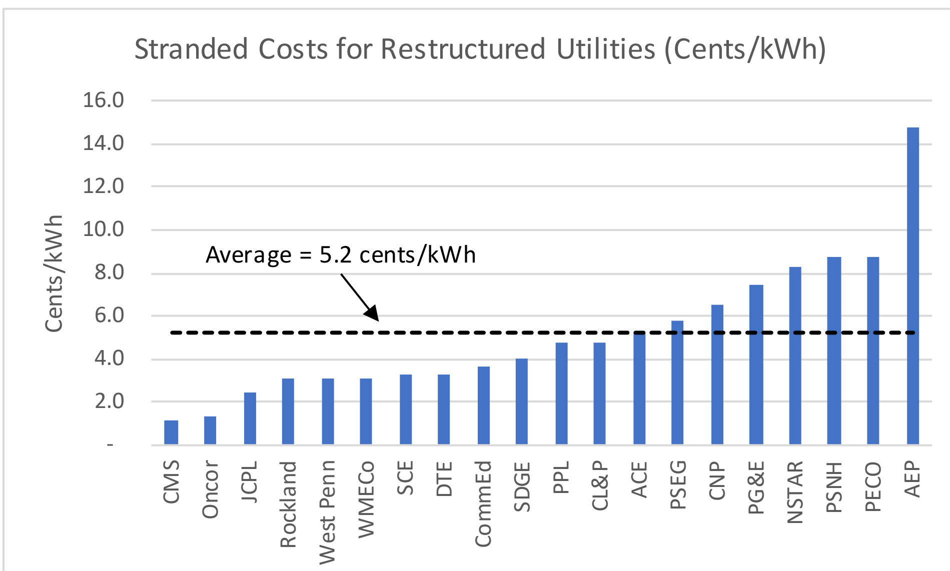
24 IOU Earnings Surveillance Reports.

estimate the amount of generation stranded costs that the Amendment would create. Based on an analysis of stranded costs in other states that have restructured and other current market data, the forced "divestiture" caused by the Amendment would create stranded costs for the generation assets that can reasonably be expected to exceed $10 billion. Lost value during generation asset sales has been an experienced feature of all prior market restructuring in other states. Even if the Amendment and associated legislation allow for the spinning off some or all the IOUs generation into unregulated affiliates, those spin-offs would be recorded at fair market value, generating the same level of stranded costs as if the utilities sold those assets on the open market. As electricity consumers, state and local governments can expect to bear over $1 billion of the $10 billion amount.[25] In addition, if any portion of the IOUs' investments in their $24.3 billion in T&D assets, in addition to hundreds of millions of commitments under power and fuel purchase agreements, become stranded, that would add significantly to stranded costs.

Stranded Cost Experience in Restructured States

In states that have restructured, including California, Connecticut, Illinois, Massachusetts, Michigan, New Hampshire, New Jersey, Pennsylvania, and Texas, utilities have been authorized to recover over $40 billion in stranded costs.[26] Figure 5, below, shows those stranded costs, on a cents-per-kWh basis. To arrive at the ¢/kWh of delivered energy, the total amounts of electric restructuring-related stranded costs, by company, were divided by the five-year average annual kWh sales for that utility beginning with and prior to the initial stranded cost authorization date. Expressing stranded costs on a ¢/kWh basis makes it possible to apply this metric to kWh sales in Florida to impute a level of stranded costs for Florida.

FIGURE 5: STRANDED COSTS FOR RESTRUCTURED UTILITIES (¢/KWH)



Applying this experience to Florida's IOUs would result in a range of stranded costs from $2.2 billion to $27.9 billion, with an average of $9.8 billion, which is 36.9% of 2017 net book value.[27]

---

25 Based on the proportion of IOU sales of electricity to governmental agencies.
26 Regulatory Research Associates, "Utility Asset Securitization in the U.S.," March 4, 2013. Supplemented by Concentric research.
27 $9.80 billion divided by $26.50 billion in generation net book value.

How are these data best interpreted? A few key conclusions can be drawn from them: (1) stranded costs would be significant in Florida; (2) even if Florida were to experience the minimum level of stranded costs experienced among other restructured utilities, that would result in 1.2¢/kWh, or $2.2 billion total; and (3) stranded costs can reasonably be expected to exceed $10 billion. Furthermore, the restructuring embodied in the Amendment goes further than restructuring in other states (e.g., through the prohibition on IOU ownership of T&D assets), meaning that the above stranded costs estimates are conservative.

Stranded costs will be passed on to electricity customers, including state and local governments. State and local government, as electric customers, could pay more than $1 billion in stranded costs, in addition to the costs of procuring their electricity from a new "competitive" supplier. *See* APPENDIX 1 Analysis of Financial Impact for details on those calculations.

Recent Power Plant Sales

Data from over 60 recent power plant sales was also analyzed to estimate the value of the IOUs generation fleet. This analysis, based on median sales prices for power plants in the U.S. over the last five years, indicates that the Florida IOUs generating assets would be valued at between approximately 10% and 100% below their net book value (depending on fuel type, as discussed below nuclear generation, which is a significant portion of FPL's generation fleet, is particularly at risk), with an average discount of approximately 49.6%. Applying that approximately 49.6% average discount to the Florida IOUs generation net book value (excluding certain plants that are planned to be retired in the near term), results in a stranded cost estimate of $12.3 billion. That analysis, by fuel type, is provided in the table below, and is further discussed in APPENDIX 1 Analysis of Financial Impact. Market values for generation in particular are also highly dependent on the structure of the market the plants serve. If the Amendment is implemented, the electricity market structure in Florida would be new and uncertain, further negatively influencing the value of the divested plants.

TABLE 4: ESTIMATE OF STRANDED COSTS IN FLORIDA BASED ON RECENT ASSET SALES – BY FUEL TYPE

Fuel Type	IOU Plant Count	IOU 2017 Capacity (MW)	2017 Net Book Value ($/KW)	Median Market Comp. Sale ($/KW)[28]	Discount/ (Premium) of Market Value to Net Book Value ($/KW)	% Discount/ (Premium)
	[A]	**[B]**	**[C]**	**[D]**	**[E] = [C] – [D]**	**[F] = [E]/[C]**
Coal	6	5,332	1,046	0	1,046	100.0%
Natural Gas	30	28,801	468	420	47	10.2%
Nuclear	2	3,502	1,468	0	1,468	100.0%
Residual Fuel Oil	6	1,051	87	67	21	23.8%
Solar	9	285	2,094	1,252	842	40.2%
MW-weighted Average % Discount/(Premium)						**49.6%**
Total Net Book Value of IOU Generation (ex. near-term retirements) ($billions)						**$24.9**
Estimated Stranded Generation Costs ($billions)						**$12.3**

[28] Note: includes sales across the U.S. for the period 2014 through 2018. Nuclear and coal generation are assumed to have no available market for the sale of those types of plants. As such, the market value is assumed to be $0.

Nuclear Divestiture Alone Will Create Billions of Dollars in Stranded Costs

Florida has benefited from emission-free nuclear generation for decades. Currently there are a total of four operating nuclear units at two sites in Florida: the St. Lucie Nuclear and Turkey Point sites, which are both owned and operated by FPL. The Florida Municipal Power Agency ("FMPA") and the Orlando Utilities Commission ("OUC") also own minority interests in St. Lucie Unit 2 (of 8.81% and 6.09% respectively). FPL has invested in and is maintaining an option to construct and operate two new nuclear units at the Turkey Point Nuclear Plant. The net book value of FPL's investment in the nuclear plants is currently $5.68 billion.

While there may be some market for other types of generation (*e.g.*, natural gas, solar), there is currently no active market for nuclear plants as operating concerns in the U.S. There have been no plant-level transactions involving majority ownership stakes in any operating nuclear plant in the U.S. since 2007. There have been attempts: Dominion attempted to sell the Kewaunee Nuclear Power Plant and Entergy attempted to sell Vermont Yankee[1] – but both failed to sell and both plants were subsequently shut down by their owners. If the Amendment passes and FPL is forced to divest its nuclear plants there is no reason to believe that its experience will be any different than Dominion's or Entergy's, rendering 100% of its $5.68 billion current investment stranded. FPL would continue to be responsible for the future decommissioning of these facilities, including any costs above the balances in the existing nuclear decommissioning trust funds. Customers would be liable for both stranded costs and decommissioning costs.

The stranded cost challenges would not be isolated to the IOUs. The Amendment would also force a sale of the St. Lucie plant on FMPA and the OUC. FMPA and OUC will be forced to write-down the value of their investments in the station. Depending on how the FMPA and OUC municipalities have financed their investment in St. Lucie, it may be necessary to raise revenue through taxes or through rate adjustments to pay off bonds related to the nuclear ownership. It is likely that FMPA and the OUC would seek judicial relief.

Further, the impact of nuclear divestiture on local economies would be substantial. These effects were seen in Florida following Duke Energy Florida's closure of the Crystal River nuclear power plant in 2013. When Crystal River's closure was announced in 2013, the plant had 585 full-time employees, not including security personnel and contractors.[2] By early 2018 that number had fallen to 70.[3] In 2008, the county's appraiser assessed the tax on two parcels at the Crystal River site at $10.5 million. In 2016 this decreased to $413,990, according to county records. Duke Energy Florida, as a regulated utility with deep roots in the region, was able to mitigate the impact to the community and employees from the plant's closure by, for example, making every effort to transfer the plant's employees to other generating stations in Duke's fleet as well as siting a new natural gas combined cycle generating station in the same city and county. In a restructured market, it is unlikely that new generation providers would feel or act on the same responsibility.

Substantial Stranded Costs Would be Created

The analyses of stranded costs described above indicate an average range of $9.8 billion to $12.3 billion of potential stranded costs in Florida, as shown in the table below. In addition, if any portion of the IOUs investments in their $24.3 billion in T&D assets, in addition to hundreds of millions of commitments under power and fuel purchase agreements, becomes stranded, that would add significantly to stranded costs.

TABLE 5: STRANDED COSTS SUMMARY

Stranded Cost Measure	Mean Result ($billions)	Middle 50% ($billions)
Stranded costs based on experiences in other U.S. states	$9.8	$5.9 to $12.8
Stranded costs estimated based on sales of power plants	$12.3	

VII. THE AMENDMENT WOULD LOWER REVENUES TO STATE AND LOCAL GOVERNMENT

Florida's IOUs contribute significantly to the revenues that support the budgets of state and local government. In 2017, Florida's IOUs paid nearly $3 billion in taxes and fees to state and local government. The Amendment would significantly reduce these taxes and fees. While there is a potential that some of these decreases could be made up through a combination of taxes paid by new entrants and changes to statutes and local ordinances, there is significant uncertainty regarding that outcome and a likelihood of increased legal and other costs. The recently passed Amendment requiring a supermajority vote of the legislature to impost new taxes or to increase current taxes would make it more difficult for the legislature to mitigate tax losses resulting from the Amendment.

Taxes Paid by IOUs Would Decrease

Florida IOUs and their customers are assessed a number of state and local taxes related to the ownership of utility assets and the purchase and sale of electricity. The reduction in utility-owned assets and electricity sales caused by the Amendment would result in significantly less taxes and fees being paid by IOUs and their customers to state and local governments. Table 6 and Table 7, below, summarize the types of taxes that are assessed, as well as the annual rate of each tax paid by each IOU.

TABLE 6: TYPES OF TAXES PAID BY FLORIDA IOUS

Tax	Percentage	Tax Basis	Applies to	Assessed by
Sales Tax	6.95%[29]	Sales price of electricity	Commercial customers (exemptions apply)	State
Local Option Tax (Discretionary Sales Tax)	0.5% - 2.5%	Sales price of electricity	Commercial customers (exemptions apply)	Counties
Gross Receipts Tax	2.5%	Gross receipts of utility	Utility	State
Corporate Income Tax	5.5%	Taxable Income	Utility	State

[29] The tax percentage varies by county across Florida.

Tax	Percentage	Tax Basis	Applies to	Assessed by
Property Taxes	Up to 10 mills	Net book value of assets	Utility	Cities/Counties
Municipal Utility Tax (Public Service Tax)	Up to 10%	Purchase of electricity	All customers	Cities/Counties

In 2018, IOUs paid $2.9 billion in state and local taxes. Over $350 million of annual property taxes alone are jeopardized by the proposed Amendment because of the projected decline in the value of the generation-related tax base. Sales, Gross Receipts, Local Option and Municipal Utility tax revenues are also at risk of declines if these taxes are interpreted as not applicable to the T&D portion of customers' bills, or as customers become able to purchase electricity from suppliers outside the state of Florida. Florida cities and counties have expressed particular concern over the loss of Municipal Utility Tax revenues, of which IOUs paid over $780 million in 2017,[30] and over $860 million in 2018. In addition to lost revenues, local governments would have to contend with the administrative challenges of collecting these taxes from multiple providers in a context in which it is unclear at what point the actual taxable purchase of electricity occurs. All else being equal, if the proposed Amendment renders these taxes not applicable to unbundled electricity sales, then the impact on state and local government tax revenues would be substantial.

TABLE 7: STATE AND LOCAL TAXES PAID BY FLORIDA IOUS IN 2018 ($MILLIONS)[31]

	State		Local		
	Sales Tax & Use Tax	**Gross Receipts Tax**	**Property Taxes**	**Local Option Tax**	**Municipal Utility Tax**
Florida Power & Light	$289.3	$268.7	$716.4	$14.1	$576.8
Gulf Power Company	$27.9	$32.7	$12.5	$2.9	$26.8
Tampa Electric Company	$36.0	$48.5	$107.0	$3.8	$58.6
Duke Energy Florida	$105.0	$112.1	$251.5	$6.9	$206.0
Total	**$458.2**	**$462.0**	**$1,087.4**[32]	**$27.6**	**$868.2**

Property Tax Revenues Would be Dramatically Reduced

Florida's IOUs paid more than $1 billion in property taxes in 2018. The impact of the forced sale of generating assets on property taxes is immense. If Florida IOU-owned power plants are sold at a discount to net book value (*i.e.*, stranded costs are created), the property tax basis would be impaired. As discussed earlier, the IOUs generating facilities would face value impairments of between 36.9% and 49.6%. Those new, lower valuations would then flow through to the taxable base, leading to a decline in annual property tax revenues. The table below provides a summary of the associated forgone annual property tax revenues earned by Florida municipalities.

30 Florida League of Cities presentation given at the FIEC Public Workshop, February 11, 2019.
31 Source: IOU provided data.
32 Approximately $350.2 million of this amount is paid for Florida IOUs for generation property.

TABLE 8: PROPERTY TAX IMPACT OF RESTRUCTURING

Impaired Value %	Total Property Taxes Paid by Florida IOUs for Generation Property ($ millions)[33]	Estimated Annual Property Impact of Restructuring ($ millions)
36.9% - 49.6%	$350.2	$129.4 to $173.8

The impact on property tax revenues could be especially disastrous for communities that currently host nuclear generating facilities. As discussed above, the closure of the Crystal River nuclear generating unit in Citrus County, Florida mitigated by the construction of a new natural gas combined cycle still led to a major budget shortfall for the county after Duke Energy Florida's local tax liability fell by approximately 63%.[34] Similar circumstances have prevailed in other areas of the U.S. following restructuring.

- Following the upcoming closure of Entergy's Pilgrim nuclear plant in Plymouth Massachusetts, the town of Plymouth Massachusetts will lose $9.3 million annually in payments from Entergy, representing 7% of the town's tax base. In addition, the property taxes paid by the plant's 190 employees who reside in Plymouth – approximately $950,000 – are also in jeopardy.[35]
- When the Zion nuclear station in Illinois closed, its annual property taxes to the community in which it resided fell from nearly $20 million to $1.6 million. To fill the gap created by this loss, property taxes on a $300,000 home surged from $8,000 to $20,000 per year, which has made it extremely difficult to attract new businesses to the region according to local officials.
- Similar effects are expected in New York following the closure of the Indian Point nuclear plant. Municipalities in the surrounding areas anticipate $32 million in annual losses to their budgets as a result of the plant's closure. The village of Buchanan will face a $2.6 million hole in a $6.2 million annual budget from the loss of property-tax revenue. The Hendrick Hudson school district faces annual losses of more than $26 million after its payment-in-lieu-of-taxes agreement with Entergy expires. From 2021, when Indian Point closes, through 2025, municipal property tax revenue will plunge dramatically from $24.8 million to $1.3 million. Officials estimate that an *average* annual tax increases of 13 percent would be required to make up for such a loss.

Franchise Fees are at Risk

Prohibiting IOUs from owning generation and providing generation-related services, prohibiting IOUs from owning T&D, and prohibiting exclusive franchises would impact municipality's franchise agreements with the IOUs and put franchise fee revenues earned by municipalities from IOUs (currently approximately $679.1 million) at risk. Simply stated, with no franchise there can be no franchise fees.

This same concern was voiced by the League of Cities during the FIEC public workshop on February 11, 2019. At the public workshop, the League of Cities discussed how franchise fees: (1) provide compensation to cities for fair rent for the utility's use of public rights of way and the cities' agreement not to compete with electric providers within their jurisdictions; and (2) offset the costs associated with maintenance of rights of way. The

33 Source: IOU provided data.
34 Behrendt, B., "Crystal River Nuclear Plant Closure Devastates Citrus County," Tampa Bay Times, https://www.tampabay.com/news/business/energy/fallout-from-crystal-river-nuclear-plants-closure-devastates-citrus-county/1273833.
35 Spillane, G., "Plymouth braces for economic blow," Cape Cod Times, https://www.capecodtimes.com/article/20151014/news/151019748.

League of Cities expressed concern that franchise fees are at risk of being eliminated entirely. The proposed Amendment specifically provides that future legislation must "prohibit any granting of either monopolies or exclusive franchises for the generation and sale of electricity." This language introduces uncertainty over the continued purpose of franchise agreements with utilities. It also increases the likelihood that IOUs would be incentivized to either exit or not renew existing franchise fee agreements as a result of losing exclusivity within a municipality.[36]

VIII. ELECTRIC SYSTEM RELIABILITY WOULD BE JEOPARDIZED

Four elements of the proposed restructuring combine to give Florida reason to be concerned about the impacts on reliability and resource adequacy. These are: (1) the abandonment of integrated resource planning processes and Florida Public Service Commission requirement that regulated utilities build infrastructure to accommodate growth, efficiency and environmental policy; (2) the failure of competitive markets to ensure fuel diversity and fuel supply; (3) the threat to system reliability; and (4) the transfer of jurisdiction from the Florida Public Service Commission to the FERC. The unique nature and isolation of peninsular Florida introduces additional complexities that must be considered and included in the analysis of the costs and benefits of energy market reforms in Florida. The challenges imposed by restructured markets on resource adequacy and related issues are more fully described in APPENDIX 8 Resource Adequacy.

Integrated Resource Planning Would be Abandoned

Municipal electric utilities and cooperatives in Florida are part of the integrated Florida resources and reliability planning. These citizen-owned utilities enjoy the benefits of system stability provided by the Florida Public Service Commission-directed resource adequacy for the IOUs. Under the current regulatory model, Florida utilities conduct long-term planning under the oversight of the Florida Public Service Commission and invest in adequate generation resources to meet a specified reserve margin (or back-up power) for their customers' demands. The current model ensures that Florida utilities have "steel in the ground" with a diverse portfolio of resources sufficient to keep the lights and air conditioning on for their customers. While municipalities and cooperatives are excluded from the deregulation initiative, it is very likely that their costs are also going to go up as the generation assets previously owned by IOUs no longer provide a stable and reliable statewide system that municipalities and cooperatives rely upon. In contrast, restructured states make no such requirements of their energy marketers, such as Infinite Energy, who need not own a single megawatt of generation capacity to make promises to deliver power to customers.[37]

The State's Fuel Diversity and Fuel Supply Would be at Risk

Due to factors such as low natural gas prices, environmental restrictions on coal generation, and other economic factors, restructured states have seen their reliance on natural gas steadily increase. In the Mid-Atlantic region,

---

[36] For example, several franchise agreements between FPL and Florida municipalities contain clauses allowing FPL (the "Grantee") to terminate the agreement early (see, e.g., Palm Beach County Franchise Agreement, Section 8: "If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the unincorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the unincorporated areas of the Grantor in which the Grantee may lawfully serve, and determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter.").

[37] See, e.g., the requirements for energy suppliers in Maryland (available at http://goo.gl/S14NoZ) and for retail energy providers in Texas (available at http://goo.gl/S2nMbx).

coal and natural gas have reversed roles as fuel sources for electric power. Coal is expected to decline from 42 percent in 2007 to 27 percent in 2020, while the share for natural gas is expected to increase from 33 percent to 43 percent over this same time period. While the grid operator has taken steps to ensure the reliability of the system while accommodating more gas-fired generating capacity, they continue to introduce mechanisms to ensure the resiliency of the grid.

Similarly, in New England, natural gas generation made up over 60 percent of generation to serve load in 2017. ISO New England ("ISO-NE") has struggled with how to address this increasing reliance on natural gas-fired generation citing the "fuel-security risks to system reliability." An ISO-NE report discussed the causes of this risk, including: heavy reliance on natural-gas-fired capacity; reliability issues due to limited natural gas transmission infrastructure into the region, as well as limited fuel storage; lack of firm fuel contracts by natural gas generators; retirement of non-gas-fired generation (nuclear, coal, etc.); exposure to winter electricity price spikes; and higher variable cost peaking units (e.g., Liquefied Natural Gas ("LNG")).[38]

Under a competitive market structure fuel supply has the potential to be at risk, resulting in higher costs to the region. Many competitive markets across North America do not require generators to have firm fuel supply in the form of either firm gas supply or fuel oil back up. Restructured jurisdictions have experienced severe fuel shortages at times when system reliability was at risk due to lack of firm fuel supply. For example, in the winter of 2014, the cost of electricity at the wholesale level totaled approximately $3.2 billion dollars for December, January and February alone due to high prices as a result of gas shortages.[39] To put this in context, in a typical year, wholesale energy costs total $5 billion for the entire twelve-month period. A deliberate approach to resource diversity, which is absent in a restructured market, provides important protections against high costs, particularly as regions become more dependent on natural gas resources.

System Reliability Would be Threatened

As discussed above, competitive markets can introduce system reliability risks, as has been the case in Texas and California. Electric competition in Texas has resulted in shrinking reserve margins. Over the first decade of electric restructuring, reserve margins in Texas declined almost forty percent. The reserve margin for the upcoming summer period is expected to be 7.4%, far below the target reserve margin of 13.75%.

These shrinking reserve margins have very real consequences, notably in the form of blackouts. Blackouts have occurred in Texas on three separate occasions since the introduction of competition. California has experienced similar system emergencies. In June of 2000, a series of localized, rolling blackouts affected 97,000 Pacific, Gas & Electric consumers in the Bay Area.[40] The grid operator ordered the cuts because supplies were low due to the closure of several plants for maintenance purposes. The rolling blackouts were declared in hopes of avoiding a major statewide, uncontrolled blackout. Since that time, California has instituted rolling blackouts on no less than three separate occasions, the most recent occurring in 2011 that resulted in the loss of power to approximately 1.4 million people in the San Diego area.

Decision-Making Power Would be Transferred to the FERC

Restructuring would also severely restrict the Florida Public Service Commission's jurisdiction over generation. With a move to retail choice comes a loss of the utility's obligation to build and a corresponding loss of Florida

38 Source: ISO-NE 2017 Regional System Plan.
39 Winter Reliability Program Updated, Restructuring Roundtable, September 25, 2015.
40 Frontline, The California Crisis.

Public Service Commission jurisdiction over power prices. Instead, jurisdiction over regulatory policies that drive electricity prices would be transferred from the Florida Public Service Commission to the FERC, a federal agency whose broad agenda may not always align with Florida customers' best interests from both a cost and reliability standpoint. Under competition, energy marketers and Independent Power Producers ("IPP") are subject to FERC-jurisdictional RTO tariff rules, rather than state-regulated utilities, decide whether, when, and how to enter the market and what supply and demand side resources to develop, and at what price.

IX. RETAIL RESTRUCTURING EXPOSES CUSTOMERS TO INCREASED COST AND RISK

While the Amendment language promises consumer protections, states with restructured electricity markets have struggled to protect customers from deceptive marketing practices of competitive retail energy suppliers. Customers, in particular vulnerable customers including low income and elderly customers, have suffered the most. This has prompted a number of states to suspend retail choice.

What is a Retail Energy Supplier?

In states that have adopted electric restructuring, "retail energy supplier," "retail electric provider", "retail marketer," or "energy service company ("ESCO")" refers to a company that serves as a middleman or an intermediary between the electricity buyer (residential, commercial and industrial customers) and the wholesale electric market. Retail marketers purchase electricity through wholesale electricity markets and resell it to consumers. Today, in most restructured states, customers that do not choose a retail marketer remain on electricity supply service provided by the utility, which is referred to by terms such as "default service," "standard offer service," "basic service," or POLR. Notably, in Texas, utilities are not allowed to provide electricity supply service, and so select retail electric providers supply POLR service. The Amendment would preclude the Florida IOUs from providing POLR service, as such customers would only be able to receive retail service from marketers.

Adding ESCOs Will Add Costs

Like other competitive businesses, retail marketers develop and sell products, pay their costs, and seek to earn a profit in doing so. They must buy electricity, hire staff, market to customers, sell their services and deliver these services to their customers. In addition, retail marketers must also perform a supply management function in which customer supply obligations are matched with wholesale supply purchases. Retail marketers incur costs for the products they supply (cost of goods sold) and a variety of operating expenses. ESCOs are not obligated to serve other than what they contract for with customers. If their rates are out of market, they can leave the service area and the customer has no real recourse.

Adding ESCOs to Florida's energy markets would create additional, and duplicative, costs including:

- Acquisition costs – Retail supplier service costs include customer acquisition expenses which the utility does not incur. Costs for an ESCO to market its services and "acquire" customers, including sales commissions, branding and marketing expenses, average approximately $121/customer, based on analysis of publicly available information of financial reports of ESCOs.[41] If these

[41] Sources: Crius Energy Trust, Management Discussion and Analysis ("MD&A"), March 8, 2018, pages 10 and 12; Just Energy MD&A, May 16, 2018, pages 4 and 30; Genie Energy Ltd, 2017 Form 10-K, pages 27 and 28; Spark Energy Inc., 2017 Form10-K; pages 52 and 93. Calculated as average

costs were to be incurred in Florida, the state's nearly 6.3 million residential electricity consumers served by the IOUs can expect to pay an additional $1.1 billion as retailers seek to recover these costs in their fees.

- Billing, customer care and other corporate functions - In most restructured markets, utilities and retailers both provide customer care and billing functions. Utilities maintain billing systems for determining transmission and distributes rates and retailers calculate supply charges. These redundant billing requirements mean that each consumer served by a retailer is supporting two billing platforms. The average "cost to serve" for competitive retailers was $112/customer/year. The impact of these higher operating costs could be considerable for Florida consumers. Based on this estimated retailer "costs to serve" Florida consumers would pay an additional $1.0 billion per year assuming all consumers were to switch to a retail supplier.[42]

Consumer Fraud and Deceptive Marketing, Billing, and Pricing are Risks

States with restructured electricity markets have experienced extensive problems in retail supplier marketing, customer acquisition, billing, and pricing practices. There are numerous cases in which state regulators and attorneys general have undertaken punitive action against energy marketers for practices ranging from illegal bait and switch schemes, to fraudulent claims about savings, to "slamming" (unauthorized switching of customers to a competitive supplier without proper authorization from customers). APPENDIX 6: Impact of Electric Restructuring on Retail Energy Costs and Service provides an illustrative list of punitive actions and fines against retail marketers for violations including: forged signatures on contracts; promising savings that did not materialize; inaccurately communicating and displaying rates on bills; fraudulent marketing under the guise of the local utility; and not communicating fees and contract lengths. Such deceptive and fraudulent practices are often targeted at low-income, elderly, and non-English speaking customers. Beyond such one-time actions, several states have undertaken broader studies and actions to try to end the retail supplier industry for residential customers, including the following:

- After reporting aggressive sales tactics, false promises and the targeting of low-income, elderly, and minority residents, Massachusetts has proposed legislation to end electricity choice for individual residential customers;[43]
- Illinois' Attorney General ("AG") has also called for an end to residential choice, based on similar deceptive marketing practices;[44] and
- This month, Consumer Counsel, in collaboration with AARP, other consumer advocates, and a U.S. senator, called for the end of residential choice that "economically harms consumers" in Connecticut.[45]

While decision-making of the Florida Public Service Commission over generation and transmission would transfer to the FERC under restructuring, the job of the Florida Public Service Commission would become more complex regarding oversight of retail prices and service in Florida. First, the Florida Public Service Commission would no

of Crius, Just Energy, Genie, and Spark total acquisition costs and cost to serve, divided by acquired new customers and total customers, respectively. See APPENDIX 6: Impact of Electric Restructuring on Retail Energy Costs and Service for details.

42 Ibid.

43 "AG Healey Calls for Shut Down of Individual Residential Competitive Supply Industry to Protect Electric Customers" Press Release, March 29, 2018. https://www.mass.gov/news/ag-healey-calls-for-shut-down-of-individual-residential-competitive-supply-industry-to-protect.

44 "[Attorney General] Madigan Sues Another Alternative Retail Electric Supplier & Reaches $3 Million Settlement for Defrauded Customers" Press Release, November 19, 2018. http://illinoisattorneygeneral.gov/pressroom/2018_11/20181119b.html.

45 "Time to End the Third-Party Residential Electric Supply Market" AARP Connecticut. February 2, 2019. https://states.aarp.org/time-to-end-the-third-party-residential-electric-supply-market/.

longer have regulatory jurisdiction over retail electric prices and service, as it does now over the IOUs. Nonetheless, it would likely undertake efforts to try to address aggressive and deceptive pricing, marketing, and billing practices for residential customers in particular. Florida's large population of elderly, low-income, and non-native-English speaking residents, as compared to the rest of the country,[46] would be especially vulnerable to deceptive marketing practices, and state agencies would need to incur additional expenses to ensure they are protected. For example, after restructuring was implemented in Texas, there was a significant jump in customer complaints, slamming of customers, marketers going bankrupt, and massive telemarketing campaigns. Complaints to the Texas Public Utilities Commission averaged 1,300/year prior to restructuring; after restructuring, complaints rose to as much as 17,250 in a given year.[47] This burden imposes costs on state government and leads to far lower customer satisfaction. The Florida Public Service Commission would need to undertake significant effort to shift from regulation to restructured markets and establish and monitor the competitive electric retail market.

X. THERE IS NO CLEAR ADVANTAGE TO RESTRUCTURING

High electricity prices were a major driver in states that have restructured. Florida's electricity prices are already below both the national average and the average of restructured states. And while the sponsors of the Amendment have suggested that Florida's energy prices could be reduced by restructuring, there is no conclusive evidence to support such a conclusion. As discussed below, this is the same conclusion that was reached by the Office of Economic and Demographic Research ("EDR") during the FIEC meeting on February 11, 2019.

Restructuring has been used as a method to attempt to address inefficiencies or high energy prices in particular states. However, as discussed below, Florida does not face the challenges that other states have felt the need to address. The proposed Amendment is a solution in search of a problem.

Florida's Energy Prices are Already Competitive

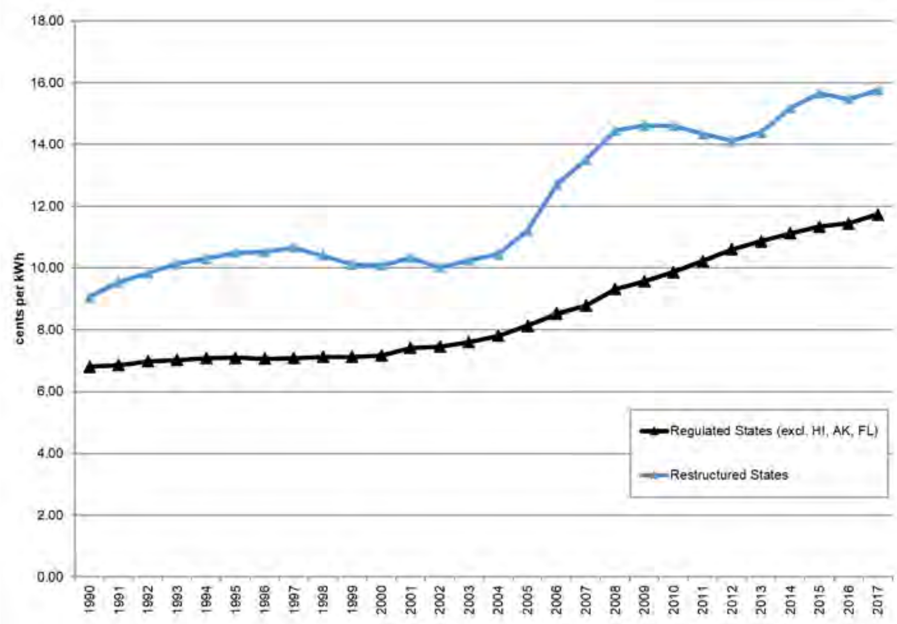
From 1990 to 2017, rates in restructured markets have been on average 42% percent higher than rates in regulated markets, as shown below.[48] Over the same period, rates in restructured markets have been approximately 26% higher than rates in Florida.

46 20.1% of Floridians are over the age of 65, as of July 1, 2018, as compared to the national average of 15.6%; 28.7% of Floridians speak a language other than English at home (from 2013-2017), as compared to the national average 21.3%, and 14% of Floridians live below the poverty line (from 2013-2017), as compared to the national average of 12.3%.
Source: https://www.census.gov/quickfacts/fl; https://www.census.gov/quickfacts/fact/table/US/PST045218

47 Deregulated Electricity in Texas, A History of Retail Competition – The First 10 Years, Appendix C: Electricity Complaints Under Deregulation, Texas Coalition for Affordable Power, found at hhttp://historyofderegulation.tcaptx.com/chapter/appendix-c-electricity-complaints-increase-under-deregulation/, accessed 6/26/2013.

48 Regulated markets exclude Alaska, Hawaii, and Florida.

FIGURE 6: AVERAGE RESIDENTIAL RATE OF RESTRUCTURED AND REGULATED STATES (BEFORE AND AFTER RESTRUCTURING)



Source: EIA Electric Power Monthly, October 12, 2018[49,50]

In the Literature: Assessments of Restructuring

EDR reviewed a wide array of academic and industry literature on the impact of restructuring and provided a summary of its research and findings during the FIEC meeting on Monday February 11, 2019. In particular, EDR reviewed five evaluations of the restructuring experience in the state of Texas, [51] which is described by proponents as the model environment for the Amendment's intent. Each of these resources found that restructuring led to negative or neutral outcomes in terms of cost, customer experience, and other qualitative measures of the benefits promised by advocates of restructuring.

A dissenting report, by the Perryman Group[52] was also mentioned at the FIEC February 11 meetings. The report estimated annual savings to Florida customers if electric restructuring had been implemented. The Study presents two analyses that are based on fundamentally flawed assumptions, and the results do not produce credible indications of changes in electric rates resulting from retail choice. The first Perryman Group analysis examines the changes in retail prices in Texas, adjusted for inflation, prior to and after the introduction of retail choice.

49 Rate calculations do not include fuel costs.
50 Restructured states include: CA, CT, DC, DE, IL, MA, MD, ME, MI, NH, NJ, NY, OH, PA, RI, and TX.
51 Texas Coalition for Affordable Power. "Deregulated Electricity in Texas: A Market Annual 2018 Edition" (2018).
Texas Coalition for Affordable Power. "Electricity Prices in Texas: A Snapshot Report, 2018 Edition" (April 2018).
Public Utilities Commission of Texas. "Scope of Competition in Electric Markets in Texas: Report to the 86th Texas Legislature" (January 15, 2019).
Hunter, Tom, Public Utility Commission of Texas. "History of Electric Deregulation in ERCOT" (April 17, 2012).
Public Sector Consultants Inc. "Electric Industry Deregulation: A Look at the Experiences of Three States" (2016)
52 The Perryman Group. "Potential Economic Benefits of Statewide Competition in the Florida Electric Power Market: A Preliminary Assessment" (December 2017).

The second Perryman Group analysis examines changes in retail electric prices for areas in Texas that were restructured and those that were not.

There are several problems with these analyses. First, the changes estimated in Texas occurred over a period when the fundamental economics of the utility industry were changing. The single largest driver of changing electricity costs was the sharp decline in natural gas prices. These lower gas prices flowed through wholesale electric costs for both regulated and retail choice states, but not equally, depending on the degree of reliance on gas for generation. Second, electric rates are the result of many cost drivers that changed over time, and it is not possible to reliably estimate the path of rates absent retail choice over such a dynamic period. Third, even if such results were achieved in Texas, one cannot say such results would apply in Florida with a completely different utility cost structure and generation mix.

Simply comparing electricity prices in Texas that existed prior to 2002 with electricity prices today does not sufficiently account for changes in technology, load, generation mix and fuel costs. Similarly, a comparison of electricity rates in Texas today with those that currently exist in Florida, provides little insight into the rates that would exist in Florida if retail competition was enacted. To suggest an implied reduction in Florida's electric rates is simply not realistic or reliable.

The IOUs have reviewed the reports that were included EDR's review and agree with its conclusion that there is no conclusive evidence of a retail price benefit to restructuring. Therefore, there is no offsetting cost savings to help with the significant cost increases and revenue losses that state the local governments are certain to experience.

State Evaluations of Restructuring Experience

Many states have recently completed evaluations of whether residential and small commercial customers are better or worse off by switching to retail providers. For example, the Massachusetts AG delivered a paper in March 2018 to determine "whether residential consumers in Massachusetts pay more or less for their electric supply when they buy it from the competitive marketplace rather than their electric company."[53] The final analysis showed that:

> "Massachusetts consumers in the competitive supply market paid $176.8 million more than they would have paid if they had received electric supply from their electric company during the two-year period from July 2015 to June 2017. A third year of data shows residential customers lost another $76.2 million, for a three-year total of $253 million."

The Massachusetts AG's recommendation was to eliminate the electric supply market for individual residential customers because the cost of retail supply was higher by far than the basic service provided by the utilities.

Similarly, in New York, the Public Service Commission ("NY PSC") ordered competitive electric suppliers to cease signing up new customers due to customers paying more for electricity provided by competitive suppliers than what they would have paid based on utility rates. The NY PSC order demonstrates the market's poor performance and frustration the commission had in overseeing the competitive retail market for the public's benefit. In particular, the NY PSC wrote:

---

53 Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, p. viii.

> "experience shows that, with regard to mass market customers, [energy service companies or "ESCOs"] cannot effectively compete with commodity prices offered by utilities. This may be for a number of reasons, including customer acquisition costs, the greater economies of scale of utilities, and the fact that utilities do not profit from the sale of energy commodity. In addition, the Department of Public Service continues to receive a large number of complaints from ESCO customers about unexpectedly high bills."[54]

Other states have reached similar conclusions after similar reviews. A Rhode Island evaluation conducted over four years found that customers who switched from their utility to retail providers had paid $56 million more than the default service costs.[55] In Connecticut a study completed by the Office of the Consumer Counsel concluded that in 2015 customers who switched to a competitive supplier paid almost $58 million more than they would have if they had remained with their default supplier.[56] A 30-month study conducted by the NY PSC found that customers who switched electric and gas suppliers paid nearly $820 million more than if they had remained with their default suppliers.[57]

The Amendment Would Expose Floridians to More Volatile Energy Prices

If the Amendment is enacted, Florida ratepayers would be exposed to electricity prices for energy and capacity that could be subject to extreme market risks. Due to its unique nature, electricity is the most volatile energy commodity. Moreover, because wholesale electricity markets are an unusual combination of market-driven participants and regulated utilities that are for the most part indifferent to market prices, they harbor higher risk than other commodity markets. This can be seen in the recent history of spot prices of various energy commodities in the U.S. (See Figure 7, below).

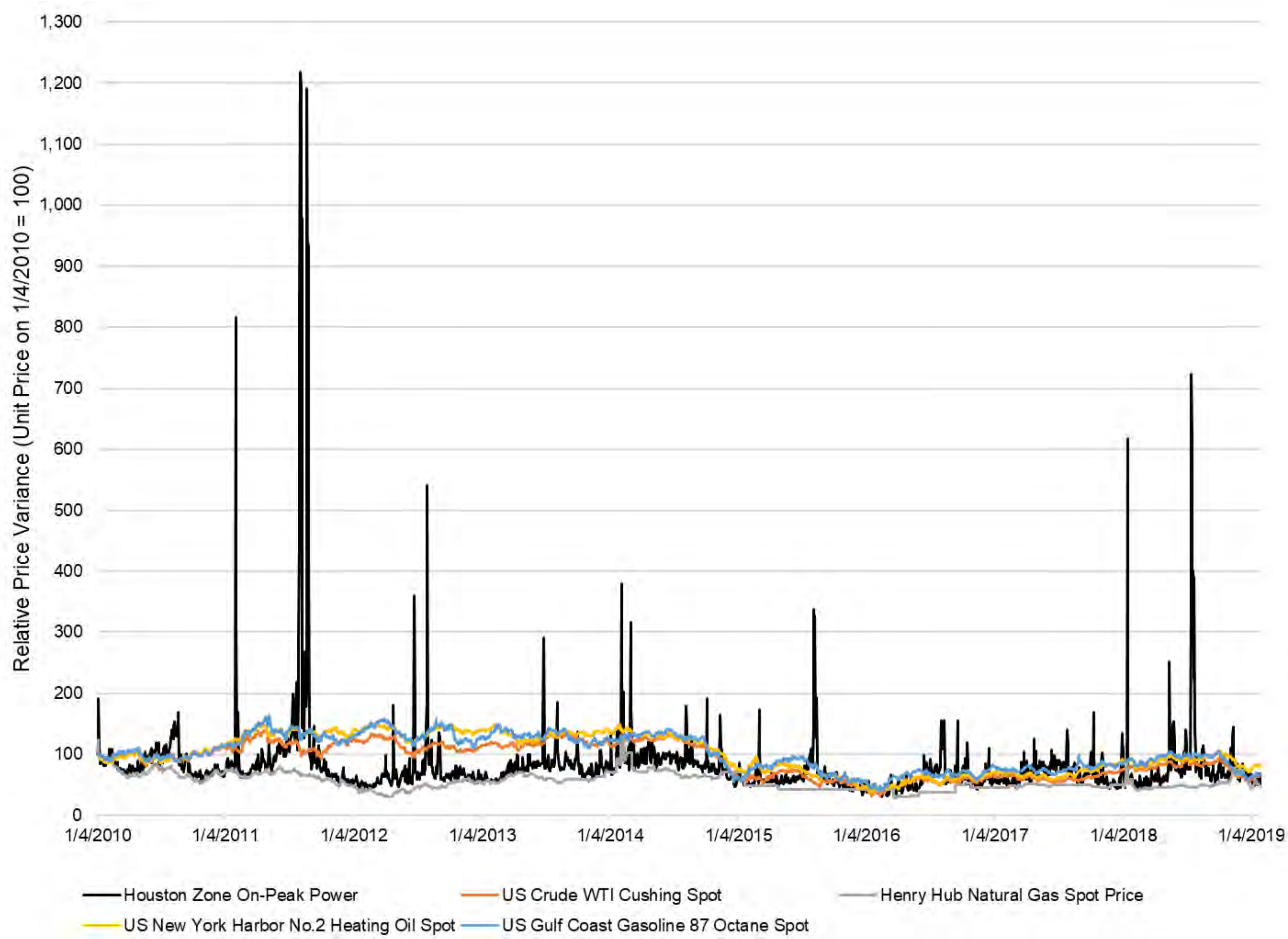
54 New York Public Service Commission Order Resetting Retail Energy Markets and Establishing Further Process, CASE 15-M-0127, (2/23/2016), p. 2. This Order was challenged in the New York court system, and subsequent process is ongoing.

55 National Grid: The Narragansett Electric Company, Standard Offer Supply Procurement Plan / 2019 Renewable Energy Standard Procurement Plan. March 1, 2018, p. 9.

56 Gregory B. Hladky, Study: Consumers Pay Extra for Retail Electricity. Hartford Courant. April 20, 2016. http://www.courant.com/news/connecticut/hc-retail-electricity-costs-above-state-standard-20160420-story.html.

57 Jeff Platsky, AT RISK: NY Reviews Electric, Gas Free-Choice Program; Consumers Ended Up Paying More. Press Connects. February 9, 2018. https://www.pressconnects.com/story/news/2018/02/09/risk-ny-groundbreaking-program-allowing-customers-select-electric-gas-suppliers/302146002/

FIGURE 7: SPOT PRICES FOR POWER AND FUELS (2010-2019)



To the extent the Florida market would embody these risky attributes, as IOUs are removed from the generation marketplace and municipal electric utilities are not, generators in the state would be exposed to more market price volatility than in other regional markets. Layer on top of that Florida's unique geography – a peninsula with more limited transmission access than other parts of the U. S. – and a high degree of reliance on one type of fuel (natural gas) for much of its electric generation, the risk profile of competitive electric generators in Florida would be quite high. Competitive generation risk is generally very high among all industries,[58] and in Florida would almost certainly be even higher.

The Amendment Would Turn the State's Power Plants and Energy Markets Over to Unregulated Companies at the Expense of Floridians

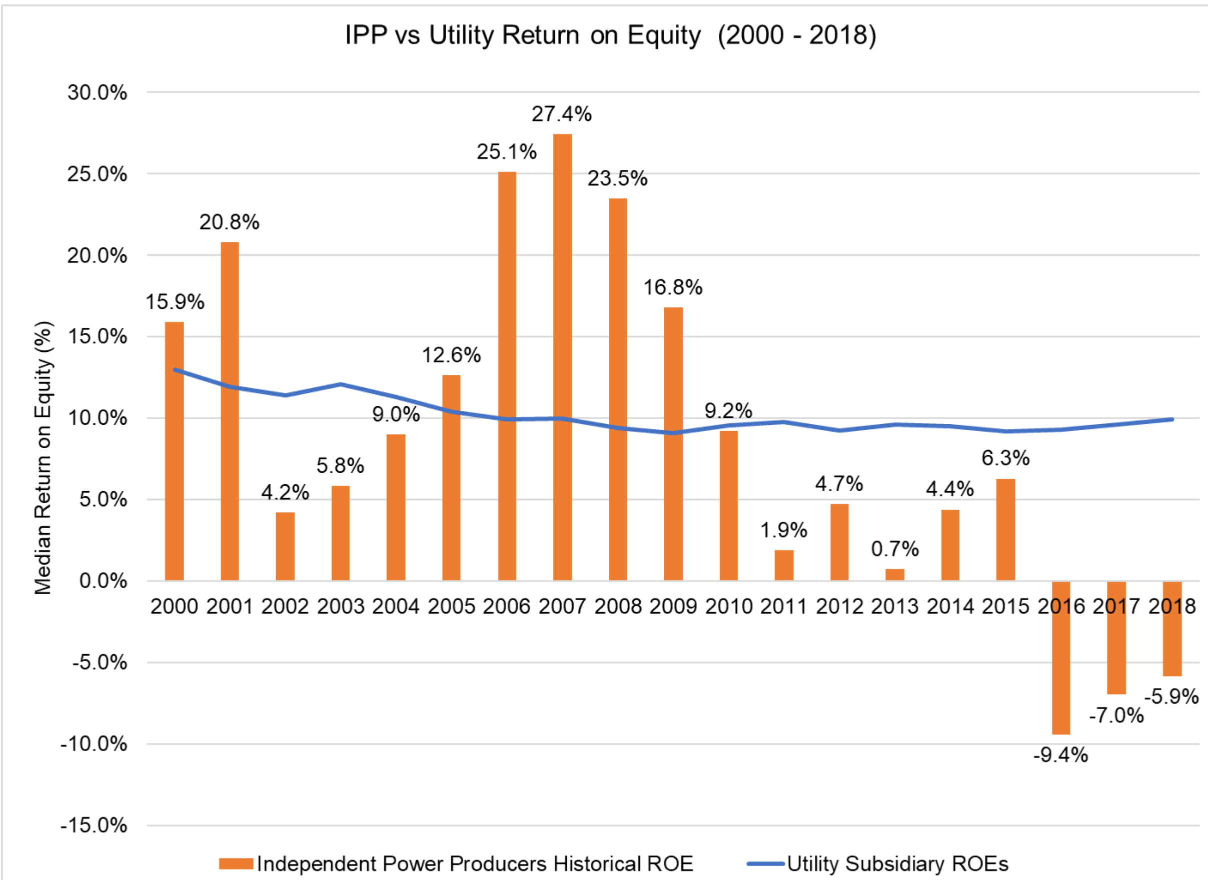
Under the Amendment, IOUs (whose rates are regulated by the Florida Public Service Commission and who currently supply more than 76%[59] of Florida's electric energy at below national average prices) would be

58 See, for instance, S&P Global Ratings, *Criteria: Key Credit Factors for The Unregulated Power & Gas Industry*, March 26, 2018, where the industry is portrayed as "moderately high risk" compared to the "very low risk" regulated utilities industry.

59 EIA Table 6, 7, 8, 10 https://www.eia.gov/electricity/sales_revenue_price/

replaced by as yet unidentified electricity providers' whose rates would not be regulated. While the average return on equity ("ROE") allowed by the Florida Public Service Commission for IOUs is approximately 10.3%, some merchant generators have ROEs as high as 19% reflecting the additional risk associated with their business model. Because the risk for merchant generators is so high, tied to the extreme volatility of electricity commodity markets, returns would also underperform at times. The earnings record (see Figure 8) shows this as well, especially in the most recent years following the shock of the 2008 financial crisis and severe recession that followed in the U.S.

FIGURE 8: COMPARISON OF REQUIRED RETURNS FOR INDEPENDENT POWER PRODUCERS, REGULATED UTILITIES[60]



The collapse of industry profitability has important consequences for grid stability and has led to questions about the ability of competitive markets to provide the necessary support for electric system reliability. Florida customers, including municipalities and cooperatives, would consequently be highly reliant on a riskier group of companies for their electricity. Merchant energy companies have experienced much greater periods of financial distress than utilities during the course of electricity restructuring, have had issues with market manipulation and are riskier than regulated electric companies. From the very beginning, the risks of the merchant model became evident as bankruptcies and near-bankruptcies proliferated as early market participants learned to manage the new energy market landscape. The most well-known bankruptcy was that of Enron Corp. in 2001, but there were numerous merchant failures that came in its wake, including high-profile companies NRG Energy in 2002,

60 IPPs in the chart include Allegheny Energy Supply, Calpine, Exelon Generation, FirstEnergy Solution, NRG Energy, PSEG Power and Vistra Energy.

Atlanta-based Mirant Corp. in 2003, and Calpine Corp. in 2005. Another prominent generator, Dynegy Corp., experienced considerable distress at that time but managed to stay afloat until new stresses in merchant generation led to a default in 2012. The merchant energy industry's travails continue to this day, with a 2017 report led by respected Wall Street analyst Hugh Wynne describing the industry as undergoing a "breakdown".[61] The latest industry leaders to fail were Texas-based Energy Future Holdings in 2014 and Mirant-successor GenOn Energy in 2017.

There are numerous examples of market abuses by profit-motivated competitive generators. Since 2007, $332 million in civil penalties for market manipulation actions in electric restructured markets have been imposed by FERC.

Many States have Not Restructured for Good Reason

Currently, 30 states remain fully regulated, while some form of electric retail choice is available in 20 states nationwide. Retail choice in these states varies from full retail choice for commercial, industrial and residential customers to partial retail choice for large industrial customers capped at a percentage of total retail sales. The success of these restructuring efforts in terms of cost to consumer has varied widely. In states that have claimed victory in terms of lower costs to consumers, this is largely due to lower gas prices, and not directly correlated to restructuring. In other states, retail competition has largely been stagnant, and regulators have decided that the risks posed by restructured markets outweigh the potential benefits. As a result, many states that embarked on restructuring efforts have decided to halt or roll back competition.

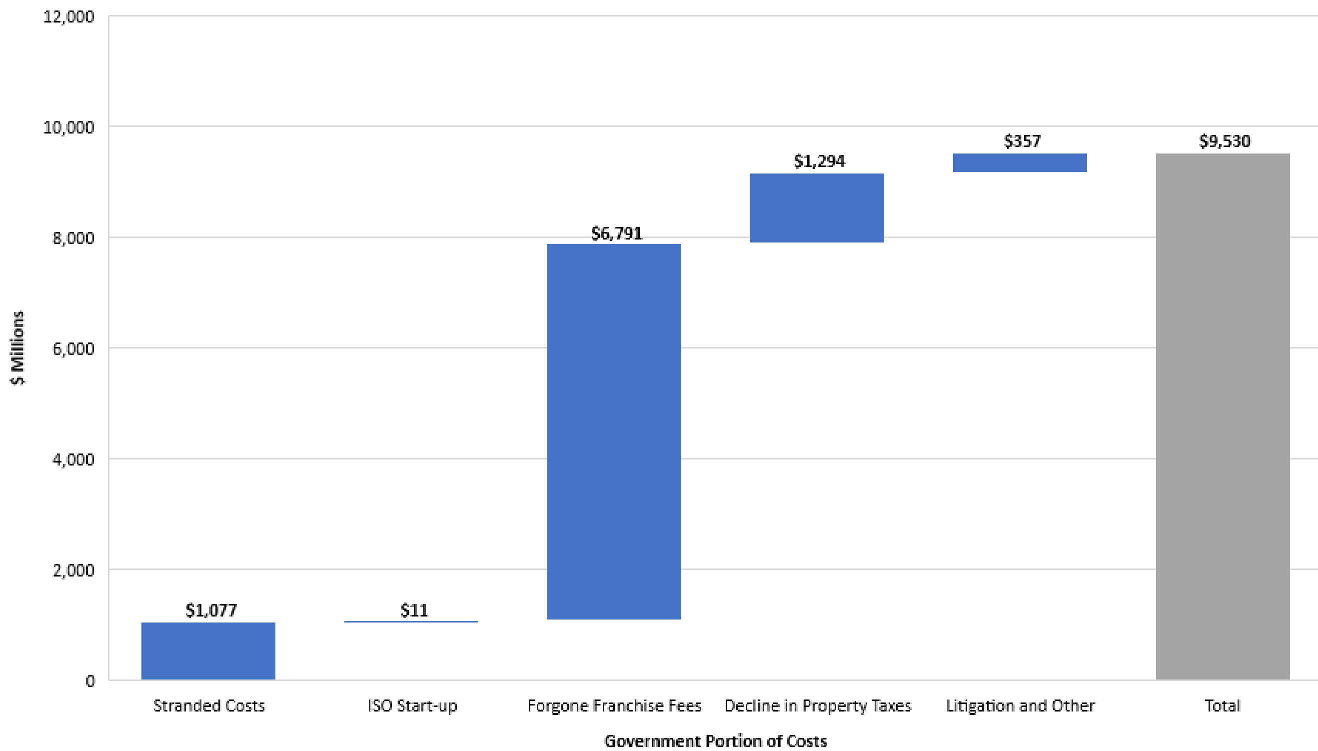
XI. CONCLUSION

The Amendment would negatively impact state and local governments

The financial impact of the Amendment on state and local government is estimated to be no less than $1.3 billion and as much as $1.7 billion in one-time costs and more than $825 million in on-going annual costs and lost revenues. ***Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone, as shown in* Figure 9 *below*.** There are numerous other costs that would be incurred post-restructuring. As such, the cost impact described above is the minimum level that would be incurred by state and local governments. ***The eventual cost to Florida and its governmental agencies would be much larger*.**

[61] The Breakdown of the Merchant Generation Business Model: A clear-eyed view of risks and realities facing merchants, June 2017.

FIGURE 9: IMPACT TO STATE & LOCAL GOVERNMENTS (10 YEARS, $MILLIONS)



The Amendment would:

- Eliminate the state's IOUs from Florida's electric energy market and force the sale or "divestiture" of their 50 power plants, more than 150,000 miles of T&D, and other electric infrastructure, creating ***billions of dollars*** in "stranded" costs which are necessarily compensated by or through government action to avoid an unconstitutional "taking;"
- Require the formation of an ISO, costing customers, including state and local government, ***hundreds of millions of dollars*** in start-up costs and on-going administrative costs;
- Force the state legislature and executive branch of government and other agencies and organizations to expend an ***enormous amount of time, resources and money*** to comply with the Amendment, implement "competitive" electric markets, defend their decisions in litigation, be the ultimate back-stop for market failures and be exposed to substantial new risks;
- ***Put at risk the billions of dollars*** in annual franchise fees and taxes paid by the state's IOUs, resulting in significantly lower revenues to local, municipal and state government;
- ***Put at risk the billions of dollars*** the IOUs have committed in power purchase agreements and natural gas supply and transportation contracts;
- Prohibit municipal and cooperative utilities from purchasing their power from IOUs, abrogating the contracts that are in place and requiring these utilities to find new supplies of their electricity;
- As a replacement, a new market would be created for companies such as the main proponent (Infinite Energy) with no obligation to provide essential electric service to all customers on a non-discriminatory basis and whose rates are not regulated by the state or any other entity;

- Threaten electric reliability and expose Floridians to consumer fraud and market manipulation as has been the experience in states that have restructured their electric markets; and
- Put the state in the position of having to organizationally and financially backstop any aspect of the supply and delivery of electricity if the new market fails in any respect.

If approved, the Amendment would "destructure" not "restructure" the state's electricity markets and cost state and local government $1.3 to $1.7 billion in one-time costs, and in excess of $825 million in annual, ongoing costs, and would dramatically increase the risk and volatility of the state's energy markets. Over ten years, those costs and lost revenues would exceed $9.5 billion for state and local governments alone.

APPENDICES

APPENDIX 1: ANALYSIS OF FINANCIAL IMPACT

Purpose

This report was prepared by Concentric Energy Advisors, Inc. ("Concentric") to provide the results of Concentric's analysis of the costs associated with the Florida ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*."

The following costs were considered:

TABLE AP1- 1 RESTRUCTURING COST CATEGORIES

Cost Category	Description
Stranded Costs	Stranded costs are a utility's existing costs that are rendered unrecoverable by restructuring. Examples include: the costs associated with generation assets divested by IOUs where those assets sell for less than the value on the books of the utilities; "out of the money" PPAs and fuel contracts; and regulatory assets on the books of the utilities associated with the generation function.
Franchise Fees and Tax Revenue	A franchise fee is paid for use by utilities of public rights of way and for the right to provide service free from competition by the local government. In those municipalities in which utilities have franchise agreements, the utilities currently pay franchise fees and other taxes in exchange for franchise rights. The loss of this franchise poses a risk to franchise payments to cities in Florida. IOUs also make substantial tax payments related to their generation assets and the sale of electricity, which will be materially reduced if, as has occurred in other states, the utilities' tax bases (*i.e.*, property values and electricity sales) decline.
Creation of a Wholesale Market and ISO Start-up/RTO Integration Costs	Deregulated states have implemented wholesale markets in order to provide transparency regarding generation and transmission costs. Implementation of a wholesale market would have its own costs and would also require a grid operator such as an ISO or RTO, which would lead to additional start-up and ongoing operating costs.
Other Implementation, Litigation and Administrative Costs	Restructuring will increase the burden on state and local governments, including government agencies such as the Florida Public Service Commission. Such costs will be the most significant in the years leading up to and immediately following restructuring.
Impact on Electricity Prices	Many of the costs discussed above, such as stranded costs and reliability costs, will have an impact on the all-in cost of electricity in Florida.

Status Quo

Quantifying the status quo, where applicable, serves two purposes. First, it provides context for the overall scope of the Florida IOUs' generation functions. Second, for many of the components of the cost analysis, the status quo provides the foundation for the cost quantification. The following tables provide the status quo related to key value components that will be impacted by restructuring.

TABLE AP1- 2; TOTAL OPERATING AND PLANNED GENERATING CAPACITY – BY IOU[1]

	Generating Plant Count	Current Capacity (MW)	Planned Capacity (MW)
Florida Power & Light	40	27,848	6,149
Gulf Power Company	8	2,249	3
Tampa Electric Company	20	5,358	2,989
Duke Energy Florida	22	11,466	505
	90	**46,921**	**9,645**

TABLE AP1- 3: TOTAL OPERATING AND PLANNED IOU GENERATING CAPACITY – BY FUEL TYPE[2]

Fuel Type	Generating Plant Count	Current Capacity (MW)	Planned Capacity (MW)
Coal	7	5,699	-
Coal-Derived Syn Gas	1	294	630
Distillate Fuel Oil	3	990	-
Landfill Gas	1	3	2
Natural Gas	33	31,989	5,745
Nuclear	2	3,515	2,200
Oil	-	-	-
Residual Fuel Oil	2	3,308	-
Solar	41	1,123	1,069
Total	**90**	**46,921**	**9,645**

TABLE AP1- 4: NET BOOK VALUE OF FLORIDA IOU GENERATING ASSETS – BY IOU ($000S)[3]

	2013	2014	2015	2016	2017
Florida Power & Light	$13,524,650	$14,773,358	$15,010,672	$17,055,889	$17,094,789
Gulf Power Company	1,732,738	1,684,087	2,091,510	1,996,410	1,998,932
Tampa Electric Company	2,651,400	2,722,089	2,796,700	2,755,288	3,302,925
Duke Energy Florida	3,693,143	3,721,109	3,717,683	3,808,705	4,101,091
Total	**$21,601,931**	**$22,900,644**	**$23,616,565**	**$25,616,292**	**$26,497,737**

1 Source: SNL Financial.
2 Source: SNL Financial.
3 Source: IOU Annual Status Reports.

TABLE AP1- 5: NET BOOK VALUE OF FLORIDA IOU GENERATING ASSETS – BY FUEL TYPE ($000S)[4]

	2013	2014	2015	2016	2017
Net Steam Plant	$6,693,140	$6,872,206	$7,339,182	$7,108,165	$6,940,042
Net Nuclear Plant	5,104,116	5,072,758	5,232,235	5,210,157	5,087,020
Net Hydro Plant	-	-	-	-	-
Net Other Prod. Plant	9,804,675	10,955,679	11,045,149	13,297,970	14,470,674
Total	**$21,601,931**	**$22,900,644**	**$23,616,565**	**$25,616,292**	**$26,497,737**

TABLE AP1- 6: NET BOOK VALUE OF FLORIDA IOU T&D ASSETS ($000S)[5]

	2013	2014	2015	2016	2017
Florida Power & Light	$10,183,209	$10,794,364	$11,706,248	$12,770,622	$14,246,769
Gulf Power Company	1,073,824	1,140,411	1,327,046	1,345,851	1,372,919
Tampa Electric Company	1,647,849	1,698,529	1,779,964	1,981,844	2,878,889
Duke Energy Florida	4,403,026	4,629,665	4,965,051	5,319,531	5,816,800
Total	**$17,307,908**	**$18,262,969**	**$19,778,309**	**$21,417,849**	**$24,315,378**

Note, the net book value data above are as of December 31, 2017. As of the IOUs November 2018 Earnings Surveillance Reports, total net book value of the IOUs assets was over $60 billion.

TABLE AP1- 7: STATE AND LOCAL TAXES AND FRANCHISE FEES PAID BY FLORIDA IOUS IN 2018 ($MILLIONS)[6]

	State		Local			
	Sales Tax & Use Tax	Gross Receipts Tax	Franchise Fees	Property Taxes	Local Option tax	Municipal Utility Tax
Florida Power & Light	$289.3	$268.7	476.4	$716.4	$14.1	$576.8
Gulf Power Company	$27.9	$32.7	42.8	12.5	2.9	$26.8
Tampa Electric Company	36.0[7]	48.5	46.6	107.0	3.8	58.6
Duke Energy Florida	105.0	112.1	113.3	251.5	6.9	206.0
Total	**$458.2**	**$462.0**	**$679.1**	**$1,087.5**[8]	**$27.6**	**$868.2**

4 Source: IOU Annual Status Reports.
5 Source: IOU Annual Status Reports.
6 Source: IOU provided data.
7 Includes sales tax only.
8 Approximately $350.20 million of this amount is paid for Florida IOUs for generation property.

TABLE AP1- 8: TOTAL SALES OF ELECTRICITY (TWH)[9]

	2013	2014	2015	2016	2017	5-Year Average
Florida Power & Light	107.37	112.93	119.41	119.28	117.87	**115.37**
Gulf Power Company	14.91	16.03	14.03	14.62	15.45	**15.01**
Tampa Electric Company	18.64	18.78	19.12	19.44	19.43	**19.08**
Duke Energy Florida	38.16	38.73	39.99	40.66	40.29	**39.57**
Total	**179.08**	**186.47**	**192.55**	**194.00**	**193.04**	**189.03**

Stranded Costs

Concentric's stranded costs analysis uses two sets of market-related data to estimate the level of stranded costs in Florida after restructuring. First, Concentric analyzed data related to stranded costs approved for recovery from electricity customers in other U.S. states that restructured. Second, Concentric reviewed data from recent sales of power plants in the U.S. to estimate generation-related stranded costs in Florida, post-restructuring. The evaluation of recent sales of power plants results in a conservative estimate of stranded costs, as it specifically estimates generation asset-related stranded costs only. In other words, it excludes other sources of stranded costs, such as "out of the money" PPAs and regulatory assets. Appendix 4 Stranded Costs provides background on the other categories of stranded costs.

Concentric's analysis is focused on the generation function. The ballot measure, however, also states that utilities will be limited to the "construction, operation, and repair of electrical transmission and distribution systems." If the IOUs are no longer able to own transmission and distribution assets, that will be another source of potential stranded costs. As provided earlier in this report, as of December 31, 2017 the IOUs had a total of over $24.3 billion in net book value of transmission and distribution assets. Those assets would be at risk if IOU ownership was no longer authorized under the state Constitution.

Stranded Costs Approved for Recovery from Electricity Customers

As discussed above, Concentric analyzed data related to stranded costs approved for recovery from electricity customers in other U.S. states that restructured. Stranded costs analyzed by Concentric were expressed in total and on a dollars-per-kilowatt hour ("¢/kWh") of delivered energy. To arrive at the ¢/kWh of delivered energy, Concentric divided the total amounts of electric restructuring-related stranded costs, by company, by the five-year average annual kWh sales for that utility beginning with and prior to the initial stranded cost authorization date. Expressing stranded costs on a ¢/kWh basis makes it possible to apply this metric to kWh sales in Florida to impute a level of stranded costs for Florida. The tables below provide the results of that analysis.

9 Source: SNL Financial. Includes sales for resale.

TABLE AP1- 9: STRANDED COSTS AUTHORIZED FOR RECOVERY FROM ELECTRICITY CUSTOMERS IN OTHER RESTRUCTURED U.S. STATES[10]

State	Utility	Total Stranded Costs ($ billions)	¢/kWh[11]	Details on Stranded Costs
California	Pacific Gas & Electric	$5.64	7.4	• 1997—$2.9 billion authorized • 2005—$1.9 billion authorized (part of settlement resolving bankruptcy proceeding) • 2005—$844 million authorized
California	San Diego Gas & Electric	$0.70	4.0	• Authorized in 1997
California	Southern California Edison	$2.50	3.3	• Authorized in 1997
Connecticut	Connecticut Light and Power	$1.44	4.8	• Authorized in 2000
Illinois	Commonwealth Edison	$3.40	3.7	• Authorized in 1998
Massachusetts	Boston Edison (NSTAR Electric)	$1.40	8.3	• 1999—$725 million authorized • 2005—$675 million authorized
Massachusetts	Western Mass Electric	$0.150	3.1	• Authorized in 2001
Michigan	Consumers Energy	$0.470	1.2	• Authorized in 2001
Michigan	Detroit Edison	$1.75	3.3	• Authorized in 2000
New Hampshire	Public Service Co. of New Hampshire	$1.21	8.7	• 2000—$575 million authorized • 2018—$636 million authorized

10 Source: Regulatory Research Associates, "Utility Asset Securitization in the U.S.," March 4, 2013.
11 The kWh equals the five-year average of the utility's sales prior to the first year of authorized stranded costs. For utilities for which stranded costs authorization was provided in multiple proceedings, Concentric used the five-year kWh average from the first authorization date.

State	Utility	Total Stranded Costs ($ billions)	¢/kWh[11]	Details on Stranded Costs
New Jersey	Public Service Gas & Electric (PSEG)	$2.65	5.8	• 1999—$2.5 billion authorized • 2005—$150 million authorized
New Jersey	Atlantic City Electric (ACE)	$0.47	5.2	• 2002—$320 million authorized • 2003—$152 million authorized
New Jersey	Jersey Central Power & Light	$0.502	2.4	• 2001—$320 million authorized • 2003—$182 million authorized
New Jersey	Rockland Electric	$.046	3.1	• Authorized in 2004
Pennsylvania	PECO Energy	$5.00	8.8	• 1998—$4 billion authorized • 2000—$1billion authorized
Pennsylvania	PPL Electric	$2.40	6.5	• 1998—$2.4 billion authorized • 2001—$900 million authorized
Pennsylvania	West Penn Power	$0.70	3.1	• 1998—$600 million authorized • 2005—$100 million authorized
Texas	CenterPoint Energy Houston Electric	$4.78	6.5	• 2000—$749 million authorized • 2005—$1.85 billion million authorized • 2006—$488 million authorized • 2011—$1.70 billion authorized

State	Utility	Total Stranded Costs ($ billions)	¢/kWh[11]	Details on Stranded Costs
Texas	AEP Texas Central Co.	$3.38	14.8	• 2000—$797 million authorized • 2006—$1.74 billion million authorized • 2012—$800 million authorized
Texas	Oncor	$1.29	1.3	• 2002—$500 million authorized • 2002—$790 million authorized
Range		**$.05-$5.6 billion**	**1.2¢ - $14.8¢/kWh (average 5.2¢/kWh)**	

As shown in the table above, this measure of stranded costs ranges from 1.2¢/kWh to 14.8¢/kWh. The table below applies that range to IOU sales of electricity in Florida to provide a range of stranded cost estimates.

TABLE AP1- 10: ESTIMATE OF STRANDED COSTS IN FLORIDA BASED ON AMOUNTS AUTHORIZED FOR RECOVERY IN OTHER U.S. STATES

	TWh Sales (5-Year Average)	Stranded Costs (¢/kWh)	Total Stranded Costs
Florida IOUs (based on range of results from the table above)	189.03	1.2¢ - 14.8¢/kwh	$2.2 - $27.9 billion
Florida IOUs (based on average result from the table above)		5.2¢/kWh	$9.8 billion

Stranded Costs Estimated Based on Power Plant Sales

Concentric also reviewed data from recent sales of power plants in the U.S. as a proxy for the values that Florida power plants might sell for as part of restructuring-driven divestitures. By comparing those proxies of value to the Florida IOU's net book value for generation assets, Concentric estimated generation-related stranded costs in Florida as a result of restructuring, as shown below. This analysis was performed by fuel type. A summary of the transactions analyzed is provided in Appendix A to this report. In performing this analysis, Concentric excluded certain of the IOUs generation plants that were nearing retirement.

TABLE AP1- 11: ESTIMATE OF STRANDED COSTS IN FLORIDA BASED ON RECENT ASSET SALES – BY FUEL TYPE[12]

Fuel Type	IOU Plant Count	IOU 2017 Capacity (MW)	2017 Net Book Value ($/KW)	Median Market Comp. Sale ($/KW)[13]	Discount/ (Premium) of Market Value to Net Book Value ($/KW)	% Discount/ (Premium)
	[A]	**[B]**	**[C]**	**[D]**	**[E] = [C] – [D]**	**[F] = [E]/[C]**
Coal	6	5,332	1,046	0	1,046	100.0%
Natural Gas	30	28,801	468	420	47	10.2%
Nuclear	2	3,502	1,468	0	1,468	100.0%
Residual Fuel Oil	6	1,051	87	67	21	23.8%
Solar	9	285	2,094	1,252	842	40.2%
MW-weighted Average % Discount/(Premium)						**49.6%**
Total Net Book Value of IOU Generation (ex. near-term retirements) ($billions)						**$24.9**
Estimated Stranded Generation Costs ($billions)						**$12.3**

Based on the analysis above, the estimated market value of the Florida generation fleet is approximately 49.6% less than net book value, on average. Applying that result to the entirety of the Florida IOU generation net book value included in the analysis of $24.9 billion results in a stranded cost estimate (*for generation only*, i.e., before consideration of PPAs, fuel contracts, and other stranded assets) of approximately $12.3 billion, with an impairment (*i.e.*, the difference between market value and book value) range of approximately 10% to 100%, depending on the fuel type.

Stranded Costs Conclusion and Impact on Florida State and Local Governments

Concentric's analyses indicates a range from $9.80 billion to $12.3 billion of potential stranded costs in Florida, based on the average results from stranded cost data in other U.S. states and recent generating plant sales. Looking more broadly at the results (*i.e.*, at the middle 50% of the stranded costs data) provides a range of results from $5.9 billion to $12.8 billion. Those results indicate that stranded costs will be significant, and likely to exceed $10 billion. The results of Concentric's analysis are summarized in the table below.

TABLE AP1- 12: STRANDED COSTS SUMMARY

Stranded Cost Measure	Mean Result ($billions)	Middle 50% of Results ($billions)
Estimate based on stranded costs experience in other U.S. states	$9.8	$5.9 to $12.8
Stranded costs estimated based on sales of power plants	$12.3	

12 As noted above, this analysis excluded certain of the IOUs generation plants. As such, the plant count and capacity figures listed in this table are less than the actual plant count and capacity totals for the IOUs.

13 Note: includes sales across the U.S. for the period 2014 through 2018. Nuclear and coal generation are assumed to have no available market for the sale of those types of plants. As such, the market value is assumed to be $0.

Florida's government agencies currently purchase approximately 11% of the Florida IOU's sales of electricity, based on kWh. Since stranded costs will be recovered from electricity customers, government agencies can expect to bear 11% of those costs. The table below provides those figures.

TABLE AP1- 13: ESTIMATE OF STRANDED COSTS APPLICABLE TO FLORIDA GOVERNMENT AGENCIES

Stranded Costs Borne by Government Agencies (11% of Total)	Mean Result ($billions)	Middle 50% of Results ($billions)
Estimate based on stranded costs experience in other U.S. states	$1.1	$0.6 to $1.4
Stranded costs estimated based on sales of power plants	$1.4	

Franchise Fees and Tax Revenue

As discussed in Concentric's separate report regarding franchise fees and tax revenues, restructuring in Florida puts a significant amount of state and local tax and franchise fee revenue at risk of significant declines. Furthermore, the "Status Quo" section of this report summarizes the current annual tax and franchise fee payments made by the IOUs. The following table provides brief summaries of the specific risks to those taxes.

TABLE AP1- 14: STATE AND LOCAL TAX RISK FACTORS

Tax/Fee	Description	Risk Factors from Restructuring
Sales Tax/Use Tax	6.95% sales tax levied on all sales of bundled electricity to commercial customers. Use tax imposed on utilities for purchases. (certain exemptions apply).	• If sales tax does not apply to unbundled sales of electricity, then customers will not pay sales tax on the transmission and distribution portions of electricity purchases. • Likely loss in revenues from large electricity consumers deciding to purchase electricity from non-Florida suppliers, thereby avoiding the sales tax.
Gross Receipts Tax	2.5% tax on gross receipts of utility companies. These taxes are passed through to customers.	• Applicable sales of electricity could diminish under restructuring as consumers can purchase electricity from suppliers outside of Florida and avoid the gross receipts taxes. • Based on the current phrasing of statute, it is unclear whether the gross receipts tax would continue to apply at all.
Franchise Fees	Typically, 6% fee levied on all electricity sales within municipal boundaries. Specific rates negotiated by municipality and utility.	• At a minimum, franchise fee revenues will decline as electric services are unbundled and generation service is no longer provided by the IOU. Moreover, there is the risk that, in addition to or even superseding the decline in franchise fees attributable to a decline in IOU revenues, franchise fees may no longer be assessable at all depending on the impact that the ballot initiative has on the current laws that allow for franchise agreements, the continued existence of franchises as currently defined by law, and the continued enforceability of franchise agreements.

Tax/Fee	Description	Risk Factors from Restructuring
Property Tax	Up to 10 mills levied by municipalities, counties, school districts and water management districts.	• If regulated utilities divest their generation assets pursuant to industry restructuring, and the sales prices for those assets are at less than net book value, there will be a decrease in the property base and an associated decrease in property taxes, all else being equal.
Local Option Tax	0.5%-2.5% tax levied by counties. Functions as an additional sales tax.	• Like with the sales tax, if local option tax does not apply to unbundled sales of electricity, then customers will not pay the tax on the transmission and distribution portion of electricity purchases. • Likely loss in revenues from large electricity consumers that purchase electricity from suppliers in other parts of the state with less or no local option taxes.
Municipal Utility Tax	Up to 10% tax levied by municipalities and counties on sales of bundled electricity.	• Possible decrease in municipal utility revenues if relevant statutes are interpreted to no longer apply to unbundled sales of electricity.

The most directly quantifiable components of state and local taxes that will be impacted by restructuring are franchise fees and property taxes. Specifically, if franchise fees are eliminated by the ballot measure, that will result in a decline in county and municipal revenue of $679.1 million in franchise fees. In addition, if Florida IOU-owned power plants are sold at a discount to net book value (*i.e.*, stranded costs are created), the property tax basis related to Florida generation will be impaired. Concentric's analysis of stranded costs in other U.S. states indicates that generating property values could be impaired by approximately 36.94% (*i.e.*, $9.80 billion divided by $26.50 billion in generation net book value). Concentric's analysis of U.S. power plant transactions indicate that Florida power plants would sell at a discount of between 10.2% and 100% of net book value, with a weighted average discount of 49.6%. Those new, lower valuations would then flow through to the taxable base, leading to a decline in annual property taxes. The table below provides a summary of the associated forgone annual tax revenues earned by Florida municipalities.

TABLE AP1- 15: PROPERTY TAX IMPACT OF RESTRUCTURING

Valuation Method	Impaired Value %	Total Property Taxes Paid by Florida IOUs for Generation Property ($ millions)[14]	Estimated Annual Property Impact of Restructuring ($ millions)
Stranded costs in other U.S. states	36.9%	$350.2	$129.4
Sales of Power Plant	49.6%		$173.8

Creation of a Wholesale Market and ISO Start-up/RTO Integration Costs

As discussed in Concentric's report titled "Implementation, Litigation and Other Costs," it could take Florida up to five years to implement electric restructuring and then another five to ten years to appropriately implement a working ISO/RTO. The start-up costs could range anywhere between $100 to $500 million with annual revenue requirements in the range of $178 to $228 million.

[14] Source: IOU provided data.

Implementation, Litigation and Administrative Costs

In addition to wholesale market and ISO/RTO start-up and operations costs, there will be litigation, customer education, regulatory and grid reliability costs. While not directly quantified by Concentric, cost estimates from other restructured states for customer education alone have been in the range of $10-$25 million for initial outreach and education, with additional ongoing annual costs. These types of costs are discussed further in Concentric's report titled "Implementation, Litigation and Other Costs."

Other Costs

While not quantified as part of Concentric's initial analysis, there are likely to be other costs borne by the state of Florida and its local municipalities following restructuring. Those include costs related to:

- State and local government administrative expenses to negotiate/procure electricity;
- Loss of Florida jobs;
- Grid reliability measures; and
- Loss of IOU economies of scale.

These costs should be considered as part of the evaluation of the impacts of the ballot measure. Because their quantification is not provided in this report, the estimates of the cost of restructuring that are provided herein likely understate the total cost of the ballot measure.

Impact on Electricity Prices

Many of the costs discussed herein, such as stranded costs and reliability costs, will have an impact on the all-in cost of electricity in Florida. This relative increase in the cost of electricity will directly impact state and local government agencies through their electricity bills. Concentric has not estimated a customer bill impact directly, due to the significant number of assumptions required regarding cost recovery timelines, the financing of stranded costs, and other issues. The customer bill impact of restructuring, however, is likely to be significant, and customers could be paying transition charges for decades.

Conclusions

The following table summarizes Concentric's analytical results related to the costs discussed herein. State and local governments currently purchase approximately 11% of total IOU kWh sales. For those costs that will borne by all Florida electricity customers, the following table also provides the state and local government impact based on their 11% share. For state and local government costs related to forgone fees and revenues, the state and local government impact is equal to the entirety of restructuring's costs.

TABLE AP1- 16: SUMMARY OF RESULTS

Cost Category	Total Quantification/Impact	State and Local Government Impact
Stranded Costs	• $10 billion - $12.3 billion	• $1.1 to $1.4 billion
Franchise Fees and Tax Revenue	• Decrease in *annual* property tax revenues of $129.4 million to $173.8 million	• Property taxes: $129.4 million to $173.8 million

Cost Category	Total Quantification/Impact	State and Local Government Impact
	• Risk of elimination of $679.1 million in franchise fees • Numerous additional risks related to declines in state and local taxes	• Franchise fees: $679.1 million
Creation of a Wholesale Market and ISO Start-up/RTO Integration Costs	• Start-up costs $100 to $500 million • Other costs (e.g., consumer education) of $20 million	• Start-up costs $11.0 million to $55.0 million • Other costs (e.g., consumer education) of $20 million
Annual ongoing ISO costs	• $170 million -$228 million	• $18.7 million to $25.1 million
Litigation Costs	• $150 million to $300 million	• $150 million to $300 million
Other implementation, litigation and administrative costs	• Additional costs to state and local governments related to implementation, litigation, and ongoing administrative costs under restructuring.	
State and local government administrative expenses to negotiate/procure electricity	• Additional costs to state and local governments to procure electricity from new suppliers.	
Florida Jobs	• Job loss due to plant sales and closures.	
Grid Reliability Measures	• Increased electricity costs due to needed infrastructure investments and other costs to mitigate reliability concerns under restructuring.	
Loss of IOU economies of scale	• Increased costs due to lack of scale in decentralized market.	
Impact on Electricity Prices	• Many of the costs discussed above, such as stranded costs and reliability costs, will have an impact on the all-in cost of electricity in Florida.	

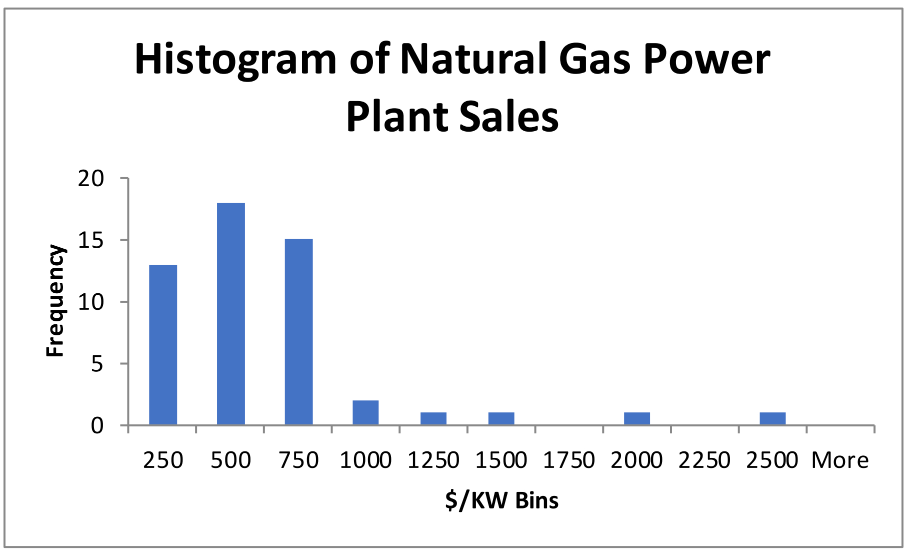
As shown in the table above, significant costs borne by state and local governments can be expected from restructuring. Those costs include both one-time costs (*e.g.*, hundreds of millions of dollars to establish an ISO/RTO) and on-going costs (*e.g.*, stranded costs recovered through electricity rates and declines in taxes and fees).

Attachment A: US Power Plant Sale Summary

U.S. power plant sales data was obtained for the period 2014 through 2018. The analysis focused on power plants transactions that involved only one fuel type (*i.e.*, fleet sales that involved multiple fuel types were excluded).

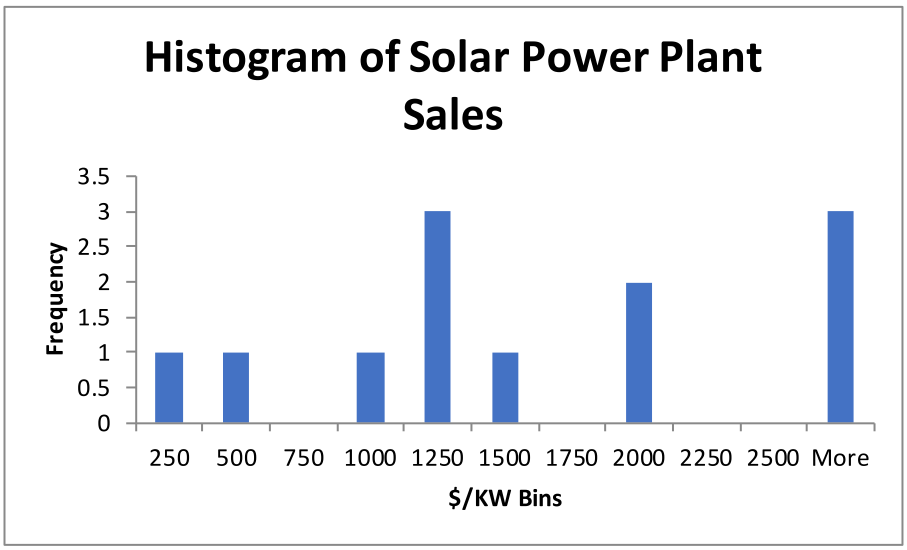
Natural Gas

Average Transaction Value ($/KW)		$494.60
Median Transaction Value ($/KW)		$420.36
Transaction Value Frequency	*Frequency*	*Cumulative %*
$0 - $250	12	23.53%
$250 - $500	18	58.82%
$500 - $750	15	88.24%
$750 - $1,000	2	92.16%
$1,000 - $1,250	1	94.12%
$1,250 - $1,500	1	96.08%
$1,500 - $1,750	0	96.08%
$1,750 - $2,000	1	98.04%
$2,000 - $2,250	0	98.04%
$2,250 - $2,500	1	100.00%
Total	**52**	



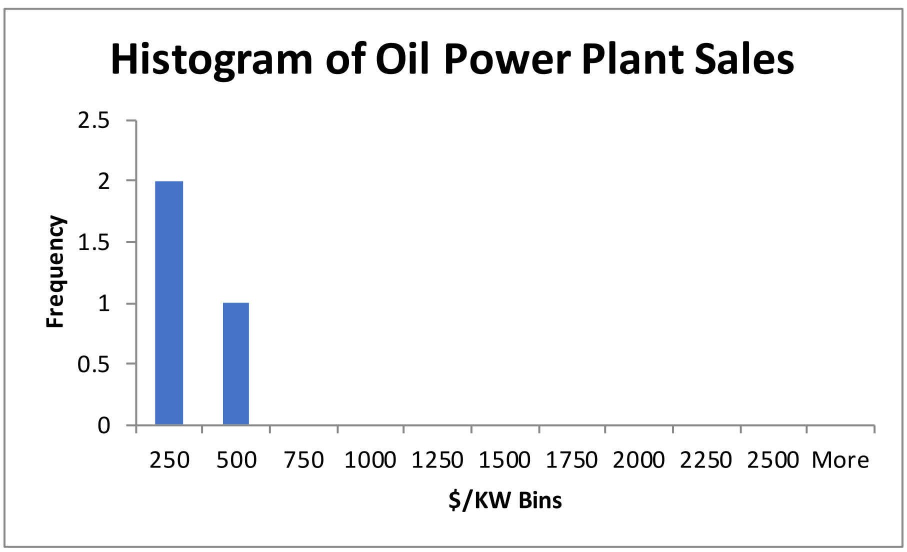
Solar

Average Transaction Value ($/KW)		$1,655.20
Median Transaction Value ($/KW)		$1,251.76
Transaction Value Frequency	*Frequency*	*Cumulative %*
$0 - $250	1	8.33%
$250 - $500	1	16.67%
$500 - $750	0	16.67%
$750 - $1,000	1	25.00%
$1,000 - $1,250	3	50.00%
$1,250 - $1,500	1	58.33%
$1,500 - $1,750	0	58.33%
$1,750 - $2,000	2	75.00%
$2,000 - $2,250	0	75.00%
$2,250 - $2,500	0	75.00%
$2,500 +	3	100.00%
Total	**12**	



Oil

Average Transaction Value ($/KW)		$1,655.20
Median Transaction Value ($/KW)		$1,251.76
Transaction Value Frequency	*Frequency*	*Cumulative %*
$0 - $250	2	66.67%
$250 - $500	1	100.00%
$500 - $750	0	100.00%
$750 - $1,000	0	100.00%
$1,000 - $1,250	0	100.00%
$1,250 - $1,500	0	100.00%
$1,500 - $1,750	0	100.00%
$1,750 - $2,000	0	100.00%
$2,000 - $2,250	0	100.00%
$2,250 - $2,500	0	100.00%
$2,500 +	0	100.00%
Total	**3**	



APPENDIX 2: IMPLEMENTATION AND OTHER COSTS

Purpose of Report

This report was prepared by Concentric to provide information and analysis of the potential implementation, litigation and other costs associated with implementing the ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment").

Background and Key Conclusions

Currently, Floridian's purchase their electricity from either rural electric cooperatives, municipal electric companies or investor-owned utilities ("IOUs"). The state's IOUs are vertically integrated and are regulated by the Florida Public Service Commission and other state and federal regulatory bodies. The Amendment would provide all customers of Florida's IOUs the right to choose their electricity provider. Implementing full retail choice necessitates the design, implementation, and ongoing administration and monitoring of functioning competitive energy markets. The legislature and executive branch will be required to commit time, resources and money to design and implement laws and regulations in an effort to create these markets.

As discussed in more detail below, forming and maintaining a functioning wholesale market is a very lengthy process, which can be litigious, and requires substantial investment in both development and ongoing administrative costs. Initial implementation will take years and is likely to require ongoing refinement extending the timeframe to full implementation of a functioning independent system operator. One-time implementation costs will be no less than $100 million and as much as $500 million or more. On-going, annual costs of administering and monitoring the newly formed competitive markets will be between $200 million and $300 million per year. In addition to these on-going costs, there will be tens of millions of dollars of litigation, customer education, regulatory and grid reliability costs. These costs would be fully borne by the state's electric customers, including state and local government. Finally, if the proposed Amendment is approved, it would be the first time a state restructured its energy markets by amending its Constitution. This is expected to increase the complexity, time, and cost of implementation.

Timeframe – State Restructuring

Through the 1990s and early 2000s a number of state legislators and regulators passed legislation and implemented regulations to provide for retail choice and competitive energy markets. This process took approximately four to five years in most states, but up to ten years or more in some cases.[1] The table below provides a summary of the number of years it took to implement state-level restructuring.

[1] See Pennsylvania and New Hampshire in the table. In Pennsylvania, Legislation was passed in 1996 and price caps for POLR customers were still in place until 2011. In New Hampshire in 2018, Eversource completed the sale of its hydroelectric facilities completing the final milestone in the restructuring of the electric industry in NH after 20 years.

TABLE AP2 - 1:

State	Legislation/ Regulation	Years	# of Years	Restructured Market (Yes/No/ Partial)	Summary
Arizona	Regulation	1999-2003	4	No	Ultimately did not restructure due in part to insufficient competitive suppliers in state. Restructuring was considered again in 2013 but not pursued due to a variety of issues/costs/risks.
California	Legislation	1998-2001	3	Partial	Direct access for all customers was suspended in 2001 because of significant issues and litigation. Currently, there is limited access to competitive electricity for non-residential customers only.
Connecticut	Legislation	1998-2003	5	Yes	All IOU customers have retail choice.
Delaware	Legislation	1999-2006	7	Yes	All IOU customers have retail choice. Rate caps were in place through 2006.
District of Columbia	Regulation, Legislation	1999 -2005	6	Yes	All IOU customers have retail choice. Rate caps were in place through 2005.
Georgia	Legislation	1973	N/A	Partial	Choice for commercial and industrial customers with load of 900 kW or more only.
Illinois	Legislation	2002-2007	5	Yes	All IOU customers have retail choice. Rates were frozen through 2007.
Maine	Legislation	1997-2000	3	Yes	All IOU customers have retail choice.
Maryland	Legislation	2000-2008	8	Yes	All IOU customers have retail choice. Rate stabilization plans (rate caps) were in place through 2008.
Massachusetts	Legislation	1997-1999	2	Yes	All IOU customers have retail choice. Rate were frozen for specified periods of time for each utility.
Michigan	Legislation	2000-2006	6	Partial	Currently under state law, no more than 10% of an electric utility's average weather-adjusted retail sales for the preceding calendar year may take electric choice service from an alternative electric supplier at any time. If your utility's 10% cap is fully subscribed, you will be placed in its queue. Residential rates were initially capped until 2006.
Montana	Legislation	1997-2000	3	No	In 2007 Legislation repealed competition entirely.
Nevada	Legislation	1997-2002	5	Partial	Failure of CA restructuring effort led to a repeal of retail access for residential customers in 2001. Retail law enacted in 2002 allows choice for commercial/industrial/governmental end users with load of 1 MW or more. Ballot initiative to introduce retail energy choice for all customers failed in 2018.
New Hampshire	Legislation	1998-2018	20	Yes	All IOU customers have retail choice. Significant litigation followed the NH PUC's 1997 approval of a restructuring plan. PSNH finally divested its generation assets in 2018.

State	Legislation/ Regulation	Years	# of Years	Restructured Market (Yes/No/ Partial)	Summary
New Jersey	Legislation	1999-2003	4	Yes	All IOU customers have retail choice. Rate reductions and rate caps were implemented through 2003.
New Mexico	Legislation	1999-2002	3	No	Retail competition law repealed in 2003.
New York	Regulation	1996-1998	2	Yes	All IOU customers have retail choice.
Ohio	Legislation	1999-2008	9	Yes	All IOU customers have retail choice. Rates were frozen through 2005 and rate stabilization plans were in place through 2008.
Oregon	Legislation	1999-2002	3	Partial	Commercial and industrial IOU customers using at least 30 kW per month have retail choice
Pennsylvania	Legislation	1996-2011	15	Yes	All IOU customers have retail choice. Rates were frozen in some instances through 2011.
Rhode Island	Legislation	1996-1998	2	Yes	All IOU customers have retail choice.
Texas	Legislation	1999-2006	7	Yes	All IOU customers have retail choice. Customers that did not select a generation provider were serviced under a price to beat (rate cap) through 2006.
Virginia	Legislation	1999-2004	5	Partial	Non-residential customers (customer with annual demand greater than 5 MW) have retail choice. 2007 legislation repealed 1999 restructuring statutes and limited retail access to large non-residential customers.

Source: SNL, American Coalition of Competitive Energy Suppliers

A technical report written by the Guinn Center regarding the 2018 Nevada Retail Choice Ballot Initiative provides additional information on the implementation of electric restructuring in several states in the U.S. For instance, the study notes that:

> New Jersey produced one investigative study, three pieces of legislation, and seven regulatory orders by 2000. New York had three investigative studies, three pieces of legislation, and six regulatory orders through 2001. Ohio conducted one investigative study, enacted one piece of enabling legislation, and issued twelve regulatory orders through 2002. Texas released six investigative studies, enacted four pieces of legislation, and implemented nineteen regulatory orders by 2002. As one report notes, though, the state did not anticipate certain issues in its enabling legislation; they only came into full view during the implementation phase and include information technology struggles, setup of the POLR (i.e., the safety [net] for those instances in which the retail supplier cannot continue service), costly market redesign (related to issues regarding market manipulation and a need to redesign the wholesale market), and stranded costs.
>
> Michigan perhaps best exemplifies the challenges surrounding implementation of retail electric choice, as its plans were considered carefully yet thwarted through the process. In 2000 two companion pieces of legislation—Public Act 141 and Public Act 142—were enacted to enable restructuring. Five regulatory orders had been issued through August 1999 to lay the groundwork for a retail electric choice market. By 2002, the Michigan Public Service Commission implemented 25 additional regulatory orders. Michigan requires annual reports on the status

of electric competition in the state. Its report for 2006 states that "the Commission issued 40 orders to further establish and implement the framework for Michigan's electric customer choice programs and the provisions of 2000 PA 141.[2]

The struggles discussed above were very common during the 1990s and early 2000 as states proceeded with energy restructuring implementation. Given the fact that the proposal is a constitutional Amendment, the complexity of implementation in Florida is expected to be even higher than that experienced in other states. No state has imposed retail choice and competitive wholesale and retail electric markets through a constitutional Amendment.

Timeframe – ISO/RTO Implementation

At the same time that states began restructuring their retail electric markets, FERC issued Orders 888 and 889 establishing and promoting competition in the wholesale market by ensuring fair access and market treatment to customers. Order No. 888 introduced the concept of ISOs as a way as a way of administering the transmission grid non-discriminately on a regional basis. In FERC Order No. 2000, the Commission encouraged the voluntary formation of RTOs. The Order required an RTO to have four basic characteristics: 1) it must be independent of market participants; 2) it must service an appropriate region of sufficient scope and configuration to permit it to maintain reliability; 3) it must have operational authority overall transmission facilities under its control; and 4) it must have exclusive authority for maintaining the short-term reliability of the grid that it operates. As shown in the table below, the establishment of the ISOs/RTOs was an evolutionary process and, in some cases, it took many years to complete.

TABLE AP2 - 2: ISO/RTO DEVELOPMENT OVER TIME

ISO/RTO	Timeline
CAISO[3] (CA)	The California ISO was created in September 1996 as a nonprofit public benefit corporation with the passage of California Assembly Bill 1890 that restructured the state's power market. It incorporated in May 1997 and in March 1998 began serving 80 percent of the state, or 30 million people, with the purpose of managing the state's transmission grid, facilitating the spot market for power and performing transmission planning functions. The California Power Exchange operated the state's competitive wholesale power market and customer choice program until the 2000-2001 energy crisis forced it into bankruptcy in January 2001. The exchange ultimately ceased operation leaving the state without a day-ahead energy market until spring 2009 when the ISO opened a nodal market.
ERCOT[4] (TX)	Formed in 1970, established as an ISO in 1996, with certain market protocols established by 2000. In 2001, wholesale power sales between electric utilities began as the existing 10 control areas in ERCOT consolidated into one. In 2002, retail electric markets opened. A nodal market, featuring locational marginal pricing for generation at more than 8,000 nodes was finally launched in 2010 after over six years of planning.

2 Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, at 68.
3 California Independent System Operator Corporation, 2010 ISO/RTO Metrics Report, Appendix D, at 28.
4 History of ERCOT, http://www.ercot.com/about/profile/history.

ISO/RTO	Timeline
SPP[5] (AR, IO, KS, LA, MN, MT, MO, NM, ND, OK, SD, TX, WY)	Formed in 1941, SPP joined NERC in the 1960s. SPP implemented a regional open-access tariff in 1998. The tariff provided non-firm and short-term firm, point-to-point transmission service across the systems of 14 members. Long-term firm service followed in 1999 and network service in 2001. It took SPP several attempts before the FERC gave it RTO status in 2004. In 2007, SPP implemented the Energy Imbalance Service, which took two years to put in place at a cost of $33 million.
MISO[6] (AR, IL, IN, IO, KY, LA, MI, MN, MS, MO, MT, TX, WI)	MISO was initially established in 1998. FERC accepted MISO's organizational plan and initial transmission tariff on Sept. 16, 1998, then approved the MISO as an RTO in December 2001. On April 1, 2005, MISO launched the Energy Markets and began centrally dispatching generating units throughout much of the central United States based on bids and offers cleared in the market.
PJM[7] (DE, IL, IN, KY, MD, MI, NJ, NC, OH, PA, TN, VA, WV, DC)	Founded in 1927 as a power pool, PJM opened its first bid-based energy market on April 1, 1997. Later that year, the FERC approved PJM as an ISO. In 2000, PJM launched both a market for regulation service, its first ancillary services market, and the Day-Ahead Energy Market. PJM became an RTO in 2001. From 2002 through 2005, PJM integrated several utility transmission systems into its operations. They included: Allegheny Power in 2002; Commonwealth Edison, American Electric Power and Dayton Power & Light in 2004; and Duquesne Light and Dominion in 2005. These integrations expanded the number and diversity of resources available to meet consumer demand for electricity and increased the benefits of PJM's wholesale electricity market. In 2007, PJM completed its first capacity auction under the Reliability Pricing Model which secures power supply resources for the future.
NYISO[8] (NY)	The creation of the NYISO was authorized by the FERC in 1998. In November 1999, New York State's competitive wholesale electricity markets were opened to utility and non-utility suppliers and consumers as the NYISO began its management of the bulk electricity grid. The formal transfer of the grid operation responsibilities from the New York Power Pool to the NYISO took place on December 1, 1999. NYISO studied the implementation of a forward capacity market but did not implement this market change.
ISO-NE[9] (CT, MA, ME, NH, RI, VT)	The New England Power Pool was established in 1971. In 1997, ISO New England ("ISO-NE") was created to operate the regional power system, implement wholesale markets, and ensure open access to transmission in New England. In 1999 ISO-NE launched a regional wholesale electricity markets to expand its competitive market to regional generation and sales of wholesale electricity. In 2003 ISO-NE added locational pricing, day-ahead and real-time markets to more accurately reflect the cost of wholesale power and provide clearer economic signals for infrastructure investment. In 2005, ISO-NE began operation as an RTO assuming broader authority over day-to-day operation of region's transmission system. In 2006, ISO-NE launched locational a forward reserve market for better valuation of reserves. In 2008, ISO-NE launched a new Forward Capacity Market to replace the old ICAP market.

As shown above, there are numerous steps required to form an RTO, with many regulatory approvals along the way, including:[10]

5 The Power of Relationships, 75 Years of Southwest Power Pool, Nathania Sawyer and Les Dillahunty, 2016.
6 Midwest Independent Transmission System Operator, 2010 ISO/RTO Metrics Report, Appendix E, at 144. MISO History, https://www.misoenergy.org/stakeholder-engagement/learning-center/miso-history.
7 PJM Interconnection, 2010 ISO/RTO Metrics Report, Appendix H, at 260.
8 New York Independent System Operator, 2010 ISO/RTO Metrics Report, Appendix G, at 196.
9 New England Independent System Operator, Our History, https://www.iso-ne.com/about/what-we-do/history.
10 For the most part these steps are dependent on the previous approval.

- Negotiations among the various stakeholders on operating protocols and RTO structure (a year or longer);
- Filing and approval with the FERC (six to eighteen months);
- Additional FERC filings to transfer operational control of transmission assets (at least six months);
- Modifications to existing transmission Open Access Transmission Tariffs (twelve months or longer);
- Additional approvals from other reliability governing bodies (six months or longer);
- Once approved, developing operating systems, policies and staffing (a year or longer); and
- Development of an internal market monitoring function and retention of a qualified independent market monitor to identify and report market violations, market design flaws and market power abuses.

In addition, all the following must be addressed when designing the market and determining competition rules. This process also could take several years.

- <u>Capacity, ancillary and energy markets</u>: Rules and rates must be established to set up each of these markets and trading policies.
- <u>POLR:</u> Rates and rules must be set for the POLR, the provider who must serve a customer when another provider defaults or drops a customer. This includes determining who the POLR would be.
- <u>Generation divestiture</u>: Existing utilities may be required by restructuring rules to sell off or spin off their power generation business.
- <u>Stranded costs</u>: A process must be put in place for existing utilities to recover investments made in power plants.
- <u>Systems and Processes</u>: Computer information systems and cybersecurity protocols must be established and procedures for switching customers to and from retail suppliers must be revisited.[11]

Overall, the initial formation of an ISO/RTO and establishment of energy, ancillary and potentially capacity markets and related financial hedging tools should be expected to take at least five years and an investment in the hundreds of millions of dollars. Further, the issues and effort to operate in the resulting new environment, regulated by FERC, must be considered. Considerable investments will be required to develop information systems to operate new markets and to form a new legal entity that will have hundreds of employees.

As discussed in APPENDIX 9 Wholesale Market Implementation, markets that have long since restructured are still struggling with updating existing rules and writing new rules as they learn from their experiences. Almost twenty years after the initial market transition restructured markets are still "changing." For example, in New England, there is a large emphasis on state policies for clean energy. Wholesale energy markets were not designed to address public policy mandates, and the influx of state-sponsored clean energy resources have challenged the wholesale market design. As a result, the New England ISO must continually make changes to the market structure to address the unintended consequences of these resources on the market. If Florida pursues retail restructuring it should expect to spend years participating at the FERC developing the market model and rules and then participating at the FERC in perpetuity as the model evolves.

[11] The Commission approved Statewide Standards and processes established by the Process Standardization Working Group must be reevaluated.

Implementation Costs

Estimates

Estimates of the cost to form an RTO/ISO range from $100 million to upwards of $500 million and could take up to ten years to fully implement. Concentric has reviewed several papers that have estimated the cost to implement an ISO/RTO like structure.

Most recently, the Public Utilities Commission of Nevada ("PUCN") was asked by the Nevada Governor's Committee on Energy Choice to open an investigatory docket to examine issues related to Nevada's Energy Choice Initiative. The PUCN finalized the Energy Choice Initiative Final Draft Report ("PUCN Report") in April 2018. The PUCN Report noted the following:

> NV Energy states that a Nevada-only ISO would have new operational and administrative costs that would be paid by all Nevadans NV Energy estimates that it would cost approximately 100 million dollars in new investment for NV Energy to set up a Nevada-only ISO wholesale market. This estimate does not include ongoing annual costs to operate the wholesale market.
>
> ***
>
> NV Energy estimates it will take 6 to 10 years to fully establish a Nevada-only ISO. This estimate is based on Nevada stakeholders needing one year or more to establish governance and a process to identify a market operator. This step could be shortened if the Nevada State Legislature designates NV Energy to perform the system and market operator functions. Thereafter, two to three years would be needed for a stakeholder process to establish the complex tariff for rules, price formation, and settlement formulas needed for the wholesale market operation systems. Like Nevada joining CAISO, FERC approval would be necessary.[12]

In addition, the PUCN Report noted, there would be ongoing costs associated with operating and maintaining the new ISO/RTO. Specifically, the PUCN Report stated that a key finding was "Adding up these yearly maintenance costs totals approximately 45.7 million dollars…"

In 2017, the California ISO formed the "Committee on Energy Choice Technical Working Group on Open Energy Market Design & Policy". The President and CEO, Steve Berberich, presented findings from the Committee that concluded that "creating a new ISO could cost upwards of $500 million." He also noted that when the CAISO nodal market went live in 2009, it cost approximately $200 million and the Texas nodal market cost $600 million.[13]

In 2004, FERC studied the cost of developing an ISO/RTO. The Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization ("FERC RTO Cost Report") was written to:

> …inform the Commission and facilitate discussions with the industry and the states regarding Regional Transmission Organization (RTO) formation. Specifically, the purpose of this Study is to estimate the cost of developing a Day One RTO that provides independent and non-discriminatory transmission service and satisfies the minimum requirements of Order No. 2000

[12] Energy Choice Initiative Final Draft Report, Public Service Commission of Nevada, April 2018, at 79-80.

[13] California ISO, Committee on Energy Choice Technical Working Group in Open Energy Market Design & Policy, July 10, 2017. Nodal ERCOT Program Update from November 2010, noted cumulative actual and forecast costs for the nodal program of $526.1 million.

to operate as an RTO. Further, the Study estimates the annual operating expenses necessary to run such an organization. Estimates of the costs of RTO formation vary widely and market participants cite the cost of RTO development as a significant barrier to RTO formation.

FERC concluded that the Day-1 RTOs required investments of between $38 million to $117 million, which converts to 2018 dollars of $54 to $167 million. The information included in this report came from PJM, MISO, ERCOT and SPP and only included implementation and estimates of revenue requirement costs through 2000, therefore missing any costs added after that time. It should be noted that Day-1 RTO costs (as shown in the table below) only include the following: 1) administration of open access transmission tariffs; 2) performance of reliability functions and transmission planning; and 3) management of transmission through traditional methods, such as redispatch and transmission loading relief. On the other hand, Day-2 RTO costs include the administration of the same functions as Day-1 RTOs but also include costs associated with market operations for day-ahead and real-time energy, and for transmission congestion. In addition, many Day-2 RTOs operate ancillary services markets and capacity markets. The cost to implement a Day-2 RTO is much higher since there are additional systems that must be added for day-ahead and capacity and ancillary services markets. In order to achieve the promised benefits of full retail reform in Florida, a functioning day-2 electricity market is necessary to facilitate the buying and selling of electricity for all retail customers.

GridFlorida

FERC Order 2000 required all public utilities that own, operate or control interstate transmission facilities to file a proposal to form or participate in an RTO. In response to the FERC, FPC now Duke Energy Florida, FPL and TECO engaged the consulting Firm ICF to develop a proposal referred to as "GridFlorida." GridFlorida conducted a study to determine the costs and benefits of developing and operating an RTO for Florida. The study found the following:

> The ICF Cost-Benefit Final Report concludes that the prospect of a basic Day-1 RTO operation as proposed are "bleak," with the Peninsula Florida costs exceeding the Peninsula Florida benefits by over $700 million over the three-year operating period. Under a more advanced Day-2 RTO operation ICF concludes that the total project benefits are a negative $285 million in Peninsular Florida over the ten-year operating period.[14]

In 2018 dollars the costs would exceed the benefits by $1 billion for basic Day-1 RTO operations and over $400 million over the ten-year operating period. As a result of the ICF study, FPC, FPL and TECO withdrew their proposal for GridFlorida. The Florida Commission and the FERC granted an approval of the withdrawal.

Actual Costs

The actual implementation costs for the development of the ISOs/RTOs noted above is difficult to calculate since they were developed, in some cases over several years or decades through many different iterations. Concentric has researched background cost information for ISOs/RTOS and found the following:

[14] Before the Public Service Commission of Florida, Docket No. 020233-EI, Order No. PSC-06-0388-FOF-EI, May 9, 2006.

TABLE AP2 - 3: ESTIMATE OF COSTS TO IMPLEMENT EXISTING ISO/RTOS

ISO/RTO	Implementation Cost
CAISO	No publicly available data found
ERCOT	Day 1 estimates of $179 million with 188 employees, with an estimated annual budget of $101 million.[15]
SPP	Day 1 estimate of $60 million with 140 employees, with an estimated annual budget of $56 million.[16]
MISO	Day 1 estimates of $184 million with 187 employees, with an estimated annual budget of $115 million.[17]
PJM	Day 1 estimates of $110 million with 263 employees, with an estimated annual budget of $122 million.[18] Day-2 estimate of capital investment of additional $332.6 million
NYISO	No publicly available data found
ISO-NE	No publicly available data found

Further, once an ISO/RTO is established, it must evolve. For example, PJM opened a new control room in 2001. That control room took five years to construct and cost approximately $215 million to place in service.[19] Those costs are not included in the table above.

GDS Associates, Inc. ("GDS") produced a report in 2007 that compared the 2001-2005 actual annual costs of all U.S. RTOs excluding ERCOT. That study found the following:

> Over the five-year study period 2001-2005, total aggregate costs increased for ISO-NE by 98 percent, for MISO by 228 percent, for NYISO by 66 percent, and for PJM by 94 percent. Costs for CAISO declined.[20]

GDS noted that the main reason for the 228% increase in MISO costs was because of the start-up of the MISO energy market in 2005. This cost was not included in the Day-1 costs noted in the table above since that is a Day-2 market operation. Prior to implementing the energy market, MISO had to invest in new systems and additional staff to support the energy market.[21]

Designing markets is certainly not a "one and done" activity, nor is it limited to state-wide issues. In fact, states with retail electricity competition have continually shifted their policies with respect to retail access and retail rates, to address obvious flaws in the initial market design. Wholesale electric markets that have long since restructured are still struggling with updating existing rules and writing new rules as they learn from their experiences, especially in the area of providing sufficient incentives to encourage necessary investment in infrastructure. In addition, IOUs have to continually evolve to address state policies and priorities, such as

---

15 Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization, Docket No PL04-16-000, October 2004, Exhibit 3, page 1. Converted to 2018 dollars.
16 Ibid. Converted to 2018 dollars.
17 Ibid. Converted to 2018 dollars.
18 Ibid. Converted to 2018 dollars.
19 PJM prepare to open 2nd control center, SNL Financial, October 24, 2001.
20 American Public Power Association, Electric Market Reform Initiative, Task 2, Analysis of Operational and Administrative Cost of RTOs, February 5, 2007, Prepared by GDS Associates, Inc. This study analyzed annual costs, not implementation costs.
21 Ibid., at 22.

legislation requiring utilities to solicit and enter into long term contracts for renewable energy (e.g., Massachusetts).[22]

The interplay between competitive wholesale electricity markets and state-level retail access has also caused conflict. As shown by the examples of Maryland and New Jersey, state regulatory bodies have found it necessary to actively participate in FERC-regulated wholesale markets by passing legislation that allows customers of investor-owned utilities to help finance new power plant construction in an effort to address serious reliability concerns after the market consistently failed to result in new projects within their higher-priced PJM zones. The cost for these kinds of legal battles has been significant.

On-Going Administrative Costs

In addition to the upfront implementation costs, there are on-going annual costs to administer an ISO/RTO. Those costs include, but are not limited to, salaries and benefits for employees, IT costs, hardware and software maintenance costs, consultant costs, marketing monitoring costs and training and travel costs. ISOs/RTOs are sophisticated organizations with substantial organizational infrastructure and employees. The table below provides information on the 2019 Budgets for U.S. ISOs/RTOs.

TABLE AP2 - 4: ANNUAL BUDGETS FOR EXISTING ISO/RTOS (2019)

ISO/RTO	2019 Budget ($000,000s)	Employees
CAISO[23]	$193.5 ($0.807/Mwh)	643
ERCOT[24]	$228.01 ($0.555/Mwh)	749
SPP[25]	$193.8	~605
MISO[26]	$339.8	~900
PJM[27]	$363.08	~920
NYISO[28]	$168.2 ($1.071$/Mwh)	~570
ISO-NE[29]	$196.90 ($1.310/Mwh)	~584

The FERC RTO Cost Report discussed above noted that annual revenue requirement estimates for 2004 were between $35 million to $78 million, which converts to 2018 dollars of $50 million to $111.5 million. As one can see from the table above those past estimates are considerably lower than the current 2019 budgets for an ISO/RTO. NYISO's 2019 Budget of $168.2 million is one of the lowest, yet considerably higher than what was

22 These types of policies essentially provide out of market revenue that distorts the price formation of the market for non-renewable resources (i.e., essentially suppresses the price because these resources can bid in at a very low price, because they get their revenues elsewhere).
23 CAISO Briefing on Draft FY2019 Revenue Requirement, November 13, 2018.
24 ERCOT's 2018/2019 Biennial Budget Submission.
25 SPP 2019 Budget Preliminary Draft, Prepared by Accounting Department, 10/8/2018.
26 2019 Budget, Board of Director Meeting, December 6, 2018. Budget of $339.8 includes both operating and capital budgets.
27 Finance Committee Letter to the PJM Board, September 21, 2018.
28 NYISO 2019 Budget Overview, October 31, 2018.
29 ISO New England Proposed 2019 Operating and Capital Budgets, August 10, 2018.

estimated by the FERC. The FERC RTO Cost Report estimated 2004 PJM staff of 263, increasing to 328 in 2005. As shown above, PJM has total staff in 2018 of approximately 920, over three times as many staff members as estimated in 2004.

Other Costs

There are various ongoing costs that will be incurred by Florida utilities and ultimately ratepayers if the ballot initiative proceeds. Since Nevada most recently went through an energy choice ballot initiative the information that was revealed throughout that process is very informative. For instance, the PUCN Staff studied the cost for consumer education and outreach and received information from the Texas Commission personnel that noted that Texas had a budget of $24 million dollars to educate customers during the first two years after retail choice was implemented. The annual budget in Texas for consumer outreach is $750,000. PUCN Staff also found that Pennsylvania spent $15.5 million dollars for customer education and outreach. With that information as a backdrop, the PUCN determined that given Nevada's size and based on what other states have spent that, Nevada would need to spend at least $10 million for its initial consumer education and outreach.[30] Other costs not quantified included hiring additional customer service representatives to deal with complaint and bill resolution pertaining to issues with implementing a restructured market.

The PUCN Staff report discussed various other costs including, specific software and computer system technology costs for NV Energy for both wholesale and retail markets, potential increased costs to maintain electric grid reliability, new costs associated with maintaining the new systems created to implement the Energy Choice Initiative, including approximately $2.2 million for increased PUCN regulatory and increased workload costs. Finally, and maybe most importantly, the PUCN paper notes that "regulatory uncertainty is generally bad for business". A review of all the possible costs ended with a conclusion by the PUCN Staff that it is reasonably likely that these costs will be added to Nevadan's monthly electric bills in an open and competitive electric market.[31] The prospect of multi-year implementation of energy choice in Florida could be stalling development since its unknown outcome could be financially disruptive.

Some of the costs discussed above will be borne by regulatory agencies, others by market participants, but in the end, all will be borne by ratepayers.

Potential Litigation

The implementation of certain states' retail restructuring plans in the late 1990's and early 2000s were fraught with litigation, including California, Montana, Nevada and New Hampshire. This same type of litigation could occur in Florida, which could add significant expense, time and headache to the electric restructuring process. The PUCN Staff study notes that:

> If history is a guide to the future, then the future will likely hold significant state and federal court litigation for Nevada if the Energy Choice Initiative passes. Nevada's exploration into deregulation in the 1990s resulted in state and federal lawsuits. Litigation was commenced in state court before the First Judicial District Court, State of Nevada in Carson City Case No. 00-00416A in the year 2000. Litigation was also commenced in federal court in the United States District Court, District of Nevada Case No.CV-N-00-0157- DWH-VPC, in the year 2000,

30 PUCN, Energy Choice Initiative Final Draft Report, Docket No. 17-10001, April 2018, at 62-63.
31 Ibid., at 65-67.

whereby Nevada Power Company and Sierra Pacific Power Company (NV Energy) sued the PUCN for injunctive and declaratory relief.

In federal court, NV Energy raised, among other things, federal claims that Nevada violated NV Energy's rights under the United States Constitution and that actions to deregulate were superseded by federal laws and violated the Supremacy Clause, interfered with NV Energy's contracts and violated the Contracts Clause, failed to adequately consider evidence and violated the Due Process Clause, violated NV Energy's Civil Rights, and constituted a taking of property without just compensation and violated the Takings Clause. Deregulation caused NV Energy's stock value to fall and resulted in a loss of its revenue. The lawsuit was eventually settled. If the Energy Choice Initiative is approved by voters in 2018, state and federal litigation involving Nevada is reasonably foreseeable.[32]

Other litigation related to the ISO/RTOs could be very lengthy. Capacity design cases at ISO-NE and NYISO have taken years and involved more than a dozen litigants. Litigation at the FERC surrounding market manipulation is likely to occur. The so-called "competitive markets" are characterized by protracted litigation at the FERC and in the courts and a number of regulatory initiatives to protect against adverse outcomes. The states and regions that implemented restructuring—a path from which return is costly and difficult—are still, almost 20 years later, trying to figure out how to design a "competitive" electricity industry that can deliver the same benefits already enjoyed by Floridians under the present regulatory framework. ISO/RTO market participants have a profit incentive to exert market power up to the edge set by rules and the law. Market manipulation is an important issue; since 2007 the FERC has levied significant fines and penalties for these abuses. For instance, in February 2017, GDF Suez Energy Marketing, Inc. was fined $41 million by the FERC for "inflating their receipt of lost opportunity cost credits paid to combustion turbines that cleared the day-ahead market, however, the turbines were not dispatched in the real-time market"[33].

State commissions in restructured states have effectively been transformed from the decision-maker in state proceedings to simply another party in FERC proceedings. State commissions have banded together and formed organizations that can participate as a bloc in certain ISO discussions and FERC litigation matters but states do not always share the same interests. The FERC certainly does not defer to the states in its decision-making. This presents an enormous resource challenge for states to simply keep up with issues before the FERC that have an impact on customers within their jurisdictions, particularly if those customer interests are not effectively represented by other parties, as is often the case. Of course, keeping up with issues is one challenge; participating as a litigant in FERC proceedings is also a resource-intensive and expensive proposition.

Litigation Related to the Ballot Measure

The basic construct of the ballot proposal increases the likelihood of costly litigation in Florida. No state has ever initiated electric restructuring via a state constitutional Amendment; the states that have restructured did so via the legislative process.

Although the Florida Proposal contemplates a significant implementation role for the Florida Legislature, the framework for restructuring in the Proposal is so sparse, vague and open to different interpretations that Florida can expect an additional level or type of litigation, namely state court litigation over whether implementing

[32] Ibid., at 58-59.

[33] Source: http://www.ferc.gov/enforcement/civil-penalties/civil-penalty-action.asp

legislation and regulatory decisions are constitutional or unconstitutional under the Amendment. This type of litigation could add years and millions of dollars of costs to the implementation process.

Moreover, because the ballot proposal would to create a constitutional right for individuals to select from multiple energy suppliers, the state can expect litigation from individuals claiming violation of a constitutional right if the retail market established during implementation does not actually give consumers in some areas of the state a choice among multiple providers. It's easy to imagine – in the third largest state in America and one that is as geographically diverse as Florida - that customers in remote and rural areas of Florida could find themselves without multiple offers to supply electricity and then seek damages from the state for failing to properly implement the Amendment.

Conclusion

Based on the information in this appendix, the estimated range of costs for the implementation of an ISO/RTO would be between $100 to $500 million. Annual costs to administer the ISO/RTO would be in the range of $170 to $228 million based on other single state ISO/RTOs like New York ISO and ERCOT, respectively. In addition, other costs for education and Commission costs would be incurred. In addition, there will be litigation costs. Please see the table below for a summary of the information provided in this appendix.

TABLE AP2 - 5: ESTIMATED IMPLEMENTATION COSTS FOR A NEW ISO/RTO

	Low ($000,000)	**High ($000,000)**
Implementation Costs	$100	$500
Administrative costs	$170	$228
Other Costs	$20	$20

APPENDIX 3: IOU AWARDS

Florida Power & Light and Gulf Power

Customer & Community

PA Consulting Group ReliabilityOne™ National Reliability Excellence Award: Florida Power and Light (FPL) was named the winner of the 2018 ReliabilityOne™ National Reliability Excellence Award presented by PA Consulting Group, demonstrating its continued efforts to improve reliability. This marked the third time in four years that FPL has received the national award.

EEI Emergency Recovery and Emergency Assistance Awards: Both FPL and Gulf Power have been awarded Emergency Recovery and Emergency Assistance Awards by the Edison Electric Institute (EEI) on numerous occasions; most recently in January 2019 for Gulf's outstanding power restoration efforts after Hurricane Michael and for FPL's contributions in restoring power to hard-hit North Carolina communities following Hurricane Florence. Both utilities were presented with the special 2018 Emergency Assistance Award for Puerto Rico Power Restoration for their contributions to the unprecedented emergency power restoration mission in Puerto Rico following Hurricane Maria. The utilities have also received awards in recent years for restoration efforts following Hurricanes Irma, Hermine and Matthew and other severe weather, including tornadoes.

J.D. Power Residential Customer Satisfaction: FPL received the top ranking for residential customer satisfaction among large electric providers in the southern U.S., according to the J.D. Power 2016 Electric Utility Residential Customer Satisfaction Study. FPL also ranked second-highest in the nation among all large electric providers.

Benchmark Portal Center of Excellence: In 2016, FPL's Customer Care Center was certified as a Center of Excellence for the third time by Benchmark Portal. The prestigious recognition is awarded to call centers that rank in the top 10 percent of call centers surveyed for efficiency and effectiveness.

Chartwell Best Practices Awards: FPL's outage prediction technology earned national recognition as Chartwell's 12th Annual Best Practices Awards Gold Outage Communications winner in 2016.

International Smart Grid Action Network Award of Excellence: FPL's Automated Fault Mapping Prediction System was recognized with an Award of Excellence by the International Smart Grid Action Network in 2016.

Environmental

Market Strategies Environmental Champion: FPL was recognized as an Environmental Champion in 2017 among the nation's largest electric and gas utilities in a nationwide study of utility customers by Market Strategies International.

Southeastern Electric Exchange Industry Excellence Award: FPL was recognized by the Southeastern Electric Exchange with its Chairman's Award for the company's response to numerous environmental challenges encountered during an important transmission line project.

EI New Energy Top 100 Green Utilities: In 2017, NextEra Energy was ranked as the top green utility in the United States and No. 2 in the world based on carbon emissions and renewable energy capacity by EI Energy Intelligence

U.S. Green Building Council Recertification: NextEra Energy's headquarters in Juno Beach, Florida, achieved the prestigious Leadership in Energy and Environmental Design (LEED) Gold recertification for existing buildings in 2015. LEED is the U.S. Green Building Council's leading rating system for designating the world's greenest, most energy-efficient and high-performing buildings.

Economic & Governance

Fortune World's Most Admired Companies: In 2019, NextEra Energy was ranked No. 1 in the electric and gas utilities industry on Fortune's list of "Most Admired Companies" for the 12th time in 13 years. We were also named one of the top 25 companies in the world, across all industries, for innovation, use of corporate assets, social responsibility and long-term investment value.

Fortune Change the World: NextEra Energy was ranked No. 21 among the top 57 companies globally that "Change the World" by Fortune. This annual list recognizes companies that have a positive social impact, and NextEra Energy was the only energy company from the Americas and one of only two electric companies in the world to be included in 2018.

Ethisphere Institute World's Most Ethical Companies: In 2018, NextEra Energy was named one of the World's Most Ethical Companies® by the Ethisphere Institute, the global leader in defining and advancing the standards of ethical business practices. NextEra Energy is one of only 20 companies in the world to achieve this honor 11 or more times.

Nuclear Energy Institute Top Innovative Practice Award: NextEra Energy's nuclear energy fleet received the Nuclear Energy Institute 2016 top innovation award for pioneering a unique program that significantly improves plant performance.

Forbes' America's Best Employers: For the third consecutive year, NextEra Energy was named by Forbes as one of America's Best Employers. Working with research firm Statista, Forbes asked thousands of U.S. workers employed by large companies whether they would recommend their employer.

Forbes' Best Employers for Diversity: NextEra Energy was named to Forbes' first-ever list of America's Best Employers for Diversity in 2018. In partnership with research firm Statista, Forbes ranked 250 employers across all industries in the U.S. according to results from employee surveys, examination of diversity policies, and analysis of diversity in executive boards and management teams.

OSHA Voluntary Protection Program: Numerous NextEra Energy locations have received the prestigious U.S. Occupational Safety and Health Administration Voluntary Protection Program Star status. The honor is awarded to worksites with exemplary occupational safety and health.

National Business Group on Health Best Employers for Healthy Lifestyles: NextEra has been honored 10 times by the National Business Group on Health for its ongoing commitment to promoting a healthy work environment and encouraging its workers to live healthier lifestyles.

Duke Energy Florida

Reliability

Electric Energy Institute (EEI) 2018 Advocacy Excellence Award: EEI recognized Duke Energy for its leadership in developing solar power and bringing customer-focused smart grid technology to its customers in Florida.

The company received an EEI Advocacy Excellence Award honorable mention for developing Florida's smart grid, additional renewable resources and enhanced services to customers. The award recognizes companies that use a range of advocacy and engagement activities to achieve company goals and effect change. Under the terms of a settlement with the state, the company will invest $6 billion in the state over the next four years, including $1.2 billion for modernizing the electric grid to make it more customer-focused, resilient, reliable and amenable to emerging technologies including renewable energy. The company also plans to develop or acquire up to 700 megawatts (MW) of solar energy through 2022. Duke Energy is also involved in a pilot program to enable "community" solar programs that allow customers without solar panels to subscribe to "blocks" (50 kilowatt-hours) of solar energy that come from arrays owned and operated by Duke Energy in Florida.

2016 Greentech Media's Grid Edge 20: Duke Energy is always innovating and embracing new technologies and forward-thinking strategies to power the communities we serve. Greentech Media named Duke Energy to the Grid Edge 20, honoring companies that are shaping the electrical power sector's transformation.

Storm Restoration and Emergency Response

Duke Energy earns EEI's 'Emergency Recovery Award' for power restoration efforts in Carolinas after Hurricane Florence: In September 2018, Duke Energy received the Edison Electric Institute's "Emergency Recovery Award" for the company's outstanding power restoration efforts after Hurricane Florence hit North Carolina and South Carolina.

Duke Energy wins award for its successful restoration effort after Winter Storm Jonas: In June 2016, the Edison Electric Institute (EEI) presented Duke Energy with the association's Emergency Recovery Award for its outstanding power restoration efforts after Winter Storm Jonas assaulted the Carolinas. The award is presented twice annually to EEI member companies in recognition of their extraordinary efforts to restore power to customers after service disruptions caused by severe weather conditions or other natural events. Duke Energy has earned the award 12 times since EEI began presenting it in 1998.

Innovation

2018 Wind Technician Team of the Year Award: Duke Energy Renewable Services' technicians received the 2018 Wind Technician Team of the Year Award at the 10th Annual Wind Operations forum in Dallas. This team is operating and maintaining DTE Energy's wind fleet in Michigan and was recognized for its accomplishments in safety performance, innovation, environmental stewardship and customer service.

Top performing solar assets by the Solar Finance Council: Duke Energy Renewables' Highlander I, Seville I and Seville II solar power projects in California were recognized by the Solar Finance Council as three of the top 100 performing solar assets in the country. The Solar Finance Council, which launched in May of this year, partnered with kWh Analytics to present their findings on solar project output in the U.S.

Blue Diamond Award for Data Efficiency Project: Duke Energy Renewables also has won the prestigious Blue Diamond Award for its Data Efficiency Project. The 2018 Blue Diamond Awards is an annual event recognizing technology as an economic driver for innovation in the Charlotte, N.C., region and has been in place for more than 25 years.

Top sustainable companies: Duke Energy makes it 13 years in a row: Building on its long-running record of sustainability leadership, Duke Energy was recently named to the Dow Jones Sustainability Index for North America for the 13th consecutive year in 2018.

Duke Energy economic development team honored by Site Selection magazine for 14 years straight: For the 14th consecutive year, Duke Energy has been named to Site Selection magazine's annual list of "Top Utilities in Economic Development" in 2018.

Newsweek's 2017 Green Rankings: Duke Energy ranked in the top 15% of Newsweek's 2017 Green Rankings. One of the most recognized environmental performance assessments of the world's largest publicly traded companies, the Green Rankings rate the top 500 U.S. companies, top 500 Global, and best in industry. Duke Energy received high marks for waste productivity. In 2016, Duke Energy recycled about 75 percent of the coal combustion byproducts (coal ash and gypsum) produced in North Carolina.

2017 Energy for Wildlife National Achievement Award: Presented by the National Wild Turkey Federation (NWTF), the Energy for Wildlife National Achievement Award recognized Duke Energy for our commitment to protect and restore wildlife and natural resources in the communities we serve. Duke Energy has teamed up with NWTF to help conserve or enhance more than 6,000 acres of critical habitat across Florida, the Carolinas and Indiana.

2017 Governor's Business Ambassador Award: Florida Gov. Rick Scott presented Duke Energy Florida with the state's Business Ambassador Award for its contributions to the state's economic vitality. The award is presented to Florida companies and individuals for their efforts in creating jobs and opportunities for families across the state.

Make it an even dozen: Duke Energy economic development team honored by Site Selection magazine for 12th consecutive year: For the 12th consecutive year, Duke Energy has been named to Site Selection magazine's annual list of "Top Utilities in Economic Development" in 2016.

2016 Outstanding Stewards of America's Waters Award: Maintaining water quality and shoreline management is essential to protect our communities. The National Hydropower Association recognized Duke Energy with the 2016 Outstanding Stewards of America's Waters Award for successfully developing the Pines Recreation Area and High Falls Trail as part of the West Fork Hydroelectric Project in North Carolina.

2016 Circle of Excellence Award: At Duke Energy, we believe sustainability is the key to our success, and so we incorporate that belief in all that we do. In recognition of our sustained commitment to corporate responsibility, the Distribution Business Management Association honored Duke Energy with the 2016 Circle of Excellence Award.

Tree Line USA Utility: The Arbor Day Foundation highlighted Duke Energy efforts in quality tree care by recognizing Duke Energy Florida as a Tree Line USA utility for the 10th consecutive year. The Tree Line USA Program demonstrates how trees and utilities can co-exist for the benefit of communities and citizens by highlighting best management practices in public and private utility arboriculture.

Customer Service

2017 CS Week's Best Mobility Implementation Award: CS Week presented Duke Energy with its Best Mobility Implementation Award for the company's proactive customer outage notification program, which automatically provides registered customers with information about their power outage. Duke Energy is committed to meeting our customers' needs by providing them with real-time information about outages so they can make decisions.

Duke Energy recognized for mobile app that shares power outage information: In 2016, CS Week presented Duke Energy with its Best Mobility Implementation Award for the company's proactive customer outage notification program, which automatically provides registered customers with information about their power outage.

Light shines on Duke Energy's customer service: Duke Energy was recognized for its superior customer service to its large commercial, industrial and government business accounts during the Edison Electric Institute's (EEI) fall National Key Accounts Workshop in 2015.

Employer

Duke Energy receives highest honor from the U.S. Department of Defense for its support of National Guard and Reserve employees: Duke Energy has received the 2018 Secretary of Defense Employer Support Freedom Award, the highest honor the U.S. Department of Defense gives to companies for their outstanding support for employees who serve in the National Guard and Reserve. Duke Energy was one of only 15 companies nationwide to be selected out of more than 2,300 nominations.

Pro Patria Award presented by the North Carolina Employer Support of the Guard and Reserve: Duke Energy received the ESGR award for large employer in North Carolina. The award is in recognition of the company's support of employees who serve in the National Guard and Reserve. The award is the highest level awarded by the ESGR State Committee.

Duke Energy named one of America's Best Employers by Forbes: Duke Energy has been named to Forbes magazine's 2018 list of America's Best Employers. Out of 500 companies ranked, Duke Energy moved up 38 spots to #106.

Duke Energy named one of Fortune's "World's Most Admired Companies": Duke Energy has been named to Fortune magazine's 2018 list of the World's Most Admired Companies. Duke Energy was ranked 5th among gas and electric utilities, up from 9th last year.

Duke Energy earns perfect score in 2018 Corporate Equality Index: Duke Energy received a perfect score of 100 percent in Human Rights Campaign's national benchmarking study that annually ranks companies on LGBT-friendly corporate practices and policies.

Duke Energy receives top award for supplier diversity: The Edison Electric Institute (EEI) has awarded Duke Energy the top honor in the electric utility association's 2017 Business Diversity Awards program.

2017 Above and Beyond Award: Piedmont Natural Gas, a subsidiary of Duke Energy, was honored with the prestigious "Above and Beyond Award" by the North Carolina Committee for Employer Support of the Guard and Reserve. The award recognizes employers who provide job security for employees while they are on active duty.

2016 United Way North Carolina's Power of Commitment Award: Duke Energy has a long-standing commitment to addressing the needs of the communities where our customers live and work. The United Way of North Carolina recognized Duke Energy with the Power of Commitment Award for our investment to expand the North Carolina 2-1-1 system, which helps people find health and human services resources in their community, to all 100 counties in the state.

2015 Enable America ADA Award: For several decades, Duke Energy has made it a corporate priority to offer employment opportunities to those with disabilities. Enable America Raleigh recently honored those efforts by presenting us with their ADA Award. We are delighted to partner with Enable America to advance its mission to help veterans and people with disabilities find employment and live independently.

2015 North Carolina Business Leadership Employer of the Year: Duke Energy was named "Employer of the Year" at the fall conference of the North Carolina Business Leadership Network. The organization is dedicated to showing businesses how they can gain a competitive edge by including the disabled in their workforce.

DailyWorth's 25 Best Companies for Women: In 2014, financial website DailyWorth ranked Duke Energy #16 on its list of "The 25 Best Companies for Women." The site considered factors such as upward mobility opportunities and leadership development programs, as well as a culture of support for women and their families.

2013 100 Best Corporate Citizens: Duke Energy's dedication to balancing the diverse interests of customers, communities, employees and shareholders was recognized for the fifth consecutive year by Corporate Responsibility (CR) magazine through placement on their 100 Best Corporate Citizens list. Duke Energy was ranked 26th on the 2013 list after being independently assessed in seven key areas: environment, climate change, human rights, philanthropy, employee relations, financial and governance.

Tampa Electric Awards / Recognition

2017 SAP Excellence in Customer Experience Award SAP, the market leader in enterprise application software, honored TECO with the Excellence in Customer Experience award in recognition of our hard work to modernize our systems and business processes to improve how we serve our more than 1.1 million valued customers.

2017 EPA Energy Star Certified Homes Market Leader Award ENERGY STAR named Tampa Electric among the winners of its 2017 Certified Homes Market Leader Award. The award goes to organizations that are leaders in "promoting energy-efficient construction and helping homebuyers experience the peace of mind, quality, comfort, and value that come with living in an ENERGY STAR-certified home."

2015 Edison Award the Edison Electric Institute (EEI) today named Tampa Electric Co. as the winner of the 2015 Edison Award, the electric industry's most prestigious honor. The award was given for Tampa Electric's innovative partnership to create a reclaimed water project at its Polk Power Station, near Mulberry.

2014 Sustainable Florida Award Tampa Electric wins award for LEGOLAND partnership solar array from Sustainable Florida, an organization that "promotes sustainable best management practices through collaborative educational efforts throughout Florida".

2013 National Assistance Award for Hurricane Sandy efforts Tampa Electric has won the Edison Electric Institute (EEI) Emergency Assistance Award for 2012, in recognition for the utility's outstanding support to restore power and natural gas service after last year's devastating Hurricane Sandy.

2012 Industry Excellence Award the Southeastern Electric Exchange (SEE), a non-profit, non-political trade association of investor-owned electric utilities, named Tampa Electric the winner of its 2012 Industry Excellence Award in the Transmission Line category.

2009-2018 Tree Line USA The National Arbor Day Foundation™ has certified Tampa Electric a Tree Line USA ® utility for its efforts to protect the health of trees the company must trim near power lines.

2004 U.S. EPA's Gulf Guardian the Manatee Viewing Center was recognized by the U.S. Environmental Protection Agency's Gulf of Mexico program offices during the annual Gulf Guardian Awards Program. The Gulf of Mexico Program is dedicated to finding and applying environmental solutions that work in concert with sound economic development.

APPENDIX 4: STRANDED COSTS

Purpose

This report was prepared by Concentric to provide information and analysis regarding Investor Owned Utility ("IOU") generation stranded costs that may be created by implementing the ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment"). This report provides background information on types of stranded costs, identifies how such costs are typically recovered by IOUs (including associated calculations), and provides data and analysis from several other jurisdictions that have restructured their electric industries.

Background

Currently, Florida residents purchase their electricity from either municipal electric companies, rural electric cooperatives, IOUs, and/or they may generate electricity for their own consumption. The state's IOUs are vertically integrated and are regulated by the Florida Public Service Commission and other state and federal regulatory bodies. The Amendment would limit IOUs to the "construction, operation, and repair of electrical transmission and distribution systems." While the ballot measure is silent on many key issues, its implementation would, at a minimum, prohibit the IOUs from owning generation and selling electricity. Furthermore, a straightforward reading of the ballot language indicates that IOUs also would be prohibited from owning transmission and distribution ("T&D") assets, and would instead be limited to their construction, operation, and repair. To comply, the IOUs would need to dispose of their generation assets and other electric infrastructure assets. This disposal would most likely occur through the sale or "divestiture" of those assets, although there is the potential that the ballot measure and associated legislation would allow for the assets to spun out to unregulated affiliates of the IOUs. If electricity infrastructure is spun out to unregulated affiliates, accounting rules would require those assets to be recorded on the affiliates' books at fair market value.

Stranded costs are the differences between the market value of a utility's assets in a restructured, competitive market and the value of those assets on the books of the utility. There are two primary drivers of this devaluation: (1) the forced sale of assets creates uneven bargaining power for asset purchases, leading to low (i.e., "fire sale) valuations; and (2) the market does not value the same factors that have led to certain prudent IOU investments. Those factors include fuel diversity, environmental goals, and long-term planning considerations. Examples of generation-related stranded costs include the costs associated with generation assets divested by IOUs where those assets sell for less than the value on the books of the utilities, "out of the money" PPAs, and fuel contracts, long-term pipeline transportation contracts that are unlikely to be attractive to merchant generators, and stranded costs and regulatory assets on the books of the utilities that are associated with the generation function (or other "stranded" functions). Utilities are compensated for these stranded costs, typically through a recovery charge or non-bypassable wires charge on electric bills.

Categories of Stranded Costs

General categories of stranded costs are provided in Table AP4- 1, below. This table is non-exhaustive but provides the major categories of stranded costs that have historically been authorized for recovery by IOUs from electricity customers.

TABLE AP4- 1: TYPES OF STRANDED COSTS

Cost Type	Description
Unrecoverable Costs of Generation Assets and Infrastructure	If a plant is sold, shut down, or spun off to an unregulated affiliate, its potential stranded costs are measured as the unrecovered capital costs, or "net book value," offset by its market value or salvage value. Generation assets include power plants, solar facilities, substations, land associated with future generation sites that no longer can be constructed by the utility, and other associated infrastructure.
Uneconomic PPAs and Fuel Purchase Contracts	Uneconomic (or "out of the money") PPAs and fuel purchase contracts are contracts that cost more than the utility's incremental cost of producing or procuring the same generation or fuel. This category also refers to renewable contracts that were agreed to in order to comply with state mandated Renewable Portfolio Standards requirements, and can further include transmission contracts, service contracts, and other contracts. Experience in other regions demonstrates that merchant generators are unwilling to sign firm transportation contracts on pipelines, and prefer short term, or city gate contracts. This has a very significant adverse effect on reliability and creates an inability to underpin gas transportation infrastructure in the state. For a state such as Florida that is reliant on gas for electric generation, this is likely to be one of the biggest adverse impacts arising out of the Amendment.
Regulatory Assets/Liabilities	A regulatory asset is a specific cost that a regulator permits an IOU to defer on its balance sheet because it is probable the cost will be recovered in future periods. Regulatory assets may become stranded under restructuring if they no longer meet the accounting requirements for deferral, and thus would need separate treatment from regulators to ensure recovery. The same is true for regulatory liabilities, which are revenue items that are deferred on the balance sheet.
Investments in Programs Mandated by Regulators [1]	These investments include demand-side management programs, low-income programs, pollution control, and provisions of universal service. Demand-side management ("DSM") programs are often capitalized, included in rate base, and amortized over time.[2]
Intangibles	Intangibles include early retirement and severance packages, job retraining, computer data, and IT systems. Legislators or regulators in California, Michigan, New Jersey, Maine, Pennsylvania, and

[1] Regulators in restructured states often include this category in general "regulatory-related" stranded costs.

[2] The treatment of DSM costs under restructuring would likely depend on the means by which the utility recovers DSM costs. A 1998 from the Congressional Budget Office titled "Electric Utilities: Deregulation and Stranded Costs" (at 14) argues that because the utility provides rebates for customers that use energy efficient appliances/light bulbs, though the utility no longer owns the generation that benefits from the greater efficiency, the DSM programs are a stranded cost: "Since those costs [*i.e.*, for DSM rebates] are not part of generating power, the market price for electricity will not reflect spending on DSM programs, and utilities will not be able to recover un-expensed DSM costs."

Cost Type	Description
	Massachusetts have included such expenditures as stranded costs that can be recovered from electricity customers.[3]
Costs to Retire Debt and Capital	These costs include the costs associated with paying down the principle and interest of the existing loans.

Stranded Costs Created by Industry Restructuring

APPENDIX 1 Analysis of Financial Impact provides information regarding stranded costs that was compiled by Regulatory Research Associates, supplemented by Concentric research. In addition, Concentric has performed independent research of stranded cost recovery authorized in other U.S. states. This data is largely consistent with the stranded costs information provided by Regulatory Research Associates. In addition, restructuring was recently considered in Nevada in 2017-2018 in the context of a ballot initiative.[4] During the Public Utility Commission of Nevada's investigation into the proposal, NV Energy submitted several reports and comments that outlined the risks involved with restructuring, including stranded costs. NV Energy estimated that stranded costs would range from $5.18 billion to $6.13 billion, the majority of which related to retiring baseload generation.[5]

Stranded Cost Recovery

The most common stranded cost recovery mechanism is a "transition charge," which may be referred to as competition transition charge ("CTC") or a market transition charge ("MTC"). Approved stranded costs are then passed on to customers through transition surcharges.

Transition Charges

A transition charge is an additional charge added to customer's bills that provides for the payment of the stranded costs incurred as a result of restructuring. Typically, the charges are based on actual energy use as a per kWh or kilowatt ("kW") charge, rather than applied as a flat rate to all customers.

Table AP4- 2, below, provides a summary of several states' stranded costs recovery mechanisms.

TABLE AP4- 2: EXAMPLES OF STRANDED COST RECOVERY MECHANISMS[6]

State	Name	Recovery Adjustment Mechanism Description
Connecticut	Competitive Transition Assessment ("CTA")	IOUs were permitted to recover, through a CTA (1) above-market generating plants recognized in rates before the restructuring bill passed, (2) regulatory assets recognized a year after the restructuring bill was passed; and, (3) non-utility generation contracts entered into before the stranded costs proceeding began.

3 Congressional Budget Office Paper, Electric Utilities: Deregulation and Stranded Costs, October 1998, page 11.
4 Energy Choice Initiative Final Report, Investigatory Docket No.17-10001, PUC of Nevada.
5 Final Comments, Nevada Power Company NV Energy and Sierra Pacific Power Company, Docket No.17-10001, at 1.
6 SNL Research; and Concentric research of state utility dockets.

State	Name	Recovery Adjustment Mechanism Description
Delaware	Non-residential Wire Charge	Delmarva Power divested most of its generation assets, and the Delaware Commission authorized the recovery of $16 million of stranded costs through a non-residential surcharge.[7]
Illinois	CTC	Commonwealth Edison recovered stranded costs through a non-bypassable CTC that varied periodically with the market price of power.
Maine	CTC	The stranded costs were re-set every two-to-three years with periodic "true-ups" until the stranded costs were fully recovered.
Massachusetts	Transition Charge	The Massachusetts Department of Public Utilities approved company-specific transition plans, and virtually all generation assets were divested. The utilities were permitted to recover stranded costs through a transition charge.
Michigan	N.A.	The 2000 and 2008 legislation provided for full recovery of PSC-approved stranded costs.
Montana	CTC	Northwestern has a CTC adjustment mechanism in place in its rates. This rider allows the company to recover restructuring-related out-of-market costs for certain power purchase contracts.
New Hampshire	Stranded Cost Recovery Charge ("SCRC")	The PSNH Proposed Restructuring Settlement allowed for recovery through the SCRC.
New Jersey	Market Transition Charge ("MTA")	New Jersey utilities recover stranded costs through a market transition charge. This MTC is a four-to-eight-year adjustment mechanism that allows the utility to recover stranded costs, though the amount changes based on market prices and customer demand. [8]
New York	N.A.	The New York Public Service Commission did not adopt a generic adjustment mechanism for cost recovery; instead, they approved plans on a company-by-company basis.
Ohio	N.A.	Stranded cost recovery extended to at least year-end 2005 for generation-related assets, and to year-end 2010 for regulatory assets.
Pennsylvania	CTC	The law permitted stranded cost recovery through competition transition charges, or CTCs. The CTC is now expired.

7 Delmarva was permitted to recover a maximum of $50 million on a system-wide basis but only $16 million through the non-residential wire charge (Docket 99-163, Order, August 31, 1999, at 5).

8 2013 New Jersey Revised Statutes, Section 48:3-61 – Market transition charge for stranded costs.

State	Name	Recovery Adjustment Mechanism Description
Rhode Island	Transition Charge	A non-bypassable transition charge for the recovery of generation-related stranded costs is to be collected from all distribution customers through Dec. ember 31, 2029.
Texas	CTC	As part of the 1997 legislation, Texas established a "true-up" mechanism whereby the restructured utilities would recover stranded costs through a CTC.

Conclusion

Stranded costs are a utility's existing costs that are rendered unrecoverable by restructuring. Examples include the costs associated with generation assets divested by IOUs where those assets sell for less than the value on the books of the utilities, "out of the money" PPAs and fuel contracts, and regulatory assets on the books of the utilities that are associated with the generation function. Significant stranded costs are a common outcome of electric industry restructuring, and, depending on the market value for restructured assets, are often billions of dollars, depending on the size of the restructured utility. Stranded costs are important to consider in any assessment of the restructuring being proposed by the Amendment.

APPENDIX 5: WHOLESALE MARKET IMPLEMENTATION

Purpose of Report

This report was prepared by Concentric to provide information and insights on the potential impact of ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment"). The design and implementation of a competitive wholesale market is a complicated and resource intensive effort that continues long after competition has been introduced. Wholesale markets require constant monitoring and frequent redesign to ensure that the outcomes are competitive and system costs are minimized. Florida is required to provide non-discriminatory access to its transmission system, with a wholesale market consisting of bilateral contracts and tariffs to access the transmission system and sell power, but this is a far simpler "market" than what is required to accommodate full retail restructuring.

Goals of Wholesale Competition

A well-functioning wholesale market is vital to capturing the promised benefits of retail competition. An effective wholesale market is necessary to provide the region with reliable wholesale electricity at competitive prices. This is accomplished by providing appropriate incentives for investment in and retirement of generating capacity, evaluating transmission investments, and providing generators a reasonable opportunity to recover their fixed and variable costs. In addition, a wholesale market is an effective means of supporting the lowest possible retail energy prices that reflect marginal production cost including the costs of congestion, losses, and scarcity of energy.

Designing and Implementing Wholesale Markets

Wholesale electricity markets are complicated and resource intensive. The basic standard wholesale market design in operation in the U.S. is effective in minimizing system costs and maintaining reliability. Wholesale electricity markets generally consist of an organized day-ahead and real-time market for energy. The day-ahead market allows for market participants to submit bids and offers for energy for next day delivery. These bids and offers reflect financial positions that generation and load serving entities "lock-in" prior to the operating day. The real-time market is a physical market in the operating day where the grid operator dispatches generation based on offers to supply energy and bids to consume energy. Prices paid by load and paid to generating resources are known as locational marginal prices ("LMPs"). LMPs reflect the value of electric energy at hundreds and sometimes thousands of different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. LMPs consist of an energy component (the price for energy), a congestion component (the marginal cost of congestion at a given location), and a loss component (the costs of system losses at a given location). The market is settled at the location-based LMP based on deviations between bids and offers in the day-ahead and real-time markets.

In addition to the markets for energy, there are markets for: i) capacity which represents an insurance policy for "steel in the ground" when needed; ii) ancillary services to ensure the system can reliably meet demand during unexpected system conditions; iii) transmission congestion and loss management tools; and iv) other financial mechanisms that allow for efficient market outcomes and risk management.

Implementing a competitive wholesale market entails massive efforts that require multiple years and numerous resources, with start-up costs ranging anywhere between $100 to $500 million and annual revenue requirements in the range of $200 to $300 million. First, the region must form an ISO or a RTO. ISOs/RTOs are non-profit entities that were created as a part of electricity restructuring in the U.S., beginning in the 1990s. The history of the ISO/RTO dates back to FERC Orders 888 and 889, which suggested the concept of the independent system operator to ensure non-discriminatory access to transmission systems. FERC Order 2000 encouraged, but did not quite require, all transmission-owning entities to form or join such an organization to promote the regional administration of high-voltage transmission systems. FERC Order 2000 contains a set of technical requirements for any system operator to be considered a FERC-approved RTO, since RTOs are regulated by FERC, not by the states (i.e., RTO rules are determined by a FERC-approved tariff and not by state Public Utility Commissions) Each RTO establishes its own rules and market structures, but there are many commonalities. Broadly, the RTO performs the following functions: i) management of the bulk power transmission system within its footprint; ii) ensuring non-discriminatory access to the transmission grid by customers and suppliers; iii) dispatch of generation assets within its footprint to keep supply and demand in balance and administration of the entirety of the wholesale markets; and iv) regional planning for generation and transmission. In many ways, ISOs/RTOs perform the same functions as the vertically-integrated utilities that were supplanted by electricity restructuring. There are, however, a number of important distinctions between ISOs/RTOs and utilities: i) ISOs/RTOs do not sell electricity to retail customers; ii) ISOs/RTOs purchase power from generators, resell it to electric distribution utilities, who then resell it again to end-use customers; iii) ISOs/RTOs may not earn profits; iv) ISOs/RTOs do not own any physical assets – they do not own generators, power lines or any other equipment; v) ISO/RTO decision-making is governed by a "stakeholder board" consisting of various electric sector constituencies. In some cases, the RTO can implement policy unilaterally without approval by the stakeholder board, but this is generally rare. Generally, however, policies must be approved by the FERC; and vi) ISOs/RTOs monitor activity in their markets to avoid manipulation by individual generators or groups of generators.

Wholesale Market challenges

Shrinking Reserve Margins

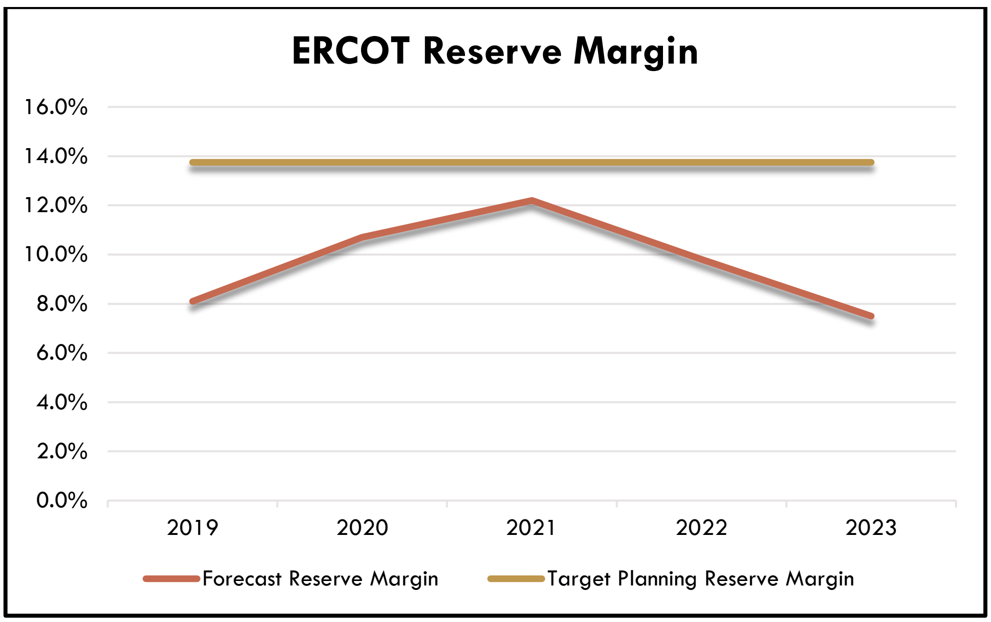
Wholesale energy markets are designed to send price signals to incent new entry and retain existing generation when needed for bulk power system reliability. New entry, as well as existing generation, has been challenged in their ability to recover their fixed and variable operating costs, including fuel, fixed and variable operating and maintenance expenses, and a return on and of investment. The percentage of recovered operating costs for new gas-fired resources is shown in Table AP5- 1.

TABLE AP5- 1: PERCENTAGE OF RECOVERED COSTS FOR NEW RESOURCES– 2016[1]

	ISO-NE	NYISO	PJM	Midwest ISO
Combined Cycle	45%	53%	92%	44%
Simple Cycle	66%	92%	79%	38%

The inability of generating resources to recover their operating costs has the potential to threaten the reliability of supply. For example, the development of adequate supply resources in a restructured market continues to be an issue in Texas. This is illustrated in the figure below from the Electric Reliability Council of Texas ("ERCOT"), which provides information on ERCOT's projected reserve margin, which is a measure of the percentage by which available capacity is expected to exceed forecasted peak demand across the region. As the figure below shows, ERCOT's own projections for its reserve margin in the coming years illustrate a persistent shortfall relative to the target, highlighting the magnitude of the resource adequacy challenges currently being faced by ERCOT.

FIGURE AP5- 1: ERCOT RESERVE MARGINS 2019-2023[2]



Fuel Diversity

A related issue regarding restructuring is the resulting impact on fuel diversity. With restructuring, the planning of generation is largely removed from the jurisdiction of the public utility commission and the state in general. The state would presumably retain siting and environmental oversight, but the state would be constrained

[1] Values are from the 2016 State of the Market Reports and are approximate. The values reflect an unconstrained zone (NY West/ISO-NE West/Michigan/Dominion (PJM).

[2] ERCOT

regarding other elements of planning. This has been illustrated recently by the efforts of Maryland, New Jersey, and other states to contract for certain generation resources that these states deemed would be advantageous for customers and the system. However, due to the legal changes associated with restructuring, these efforts were negated by the US Supreme Court. Details for several of these states is provided in the table below.

TABLE AP5- 2: EXAMPLES OF RESTRUCTURED STATE EFFORTS TO ACHIEVE RESOURCE PLANNING GOALS

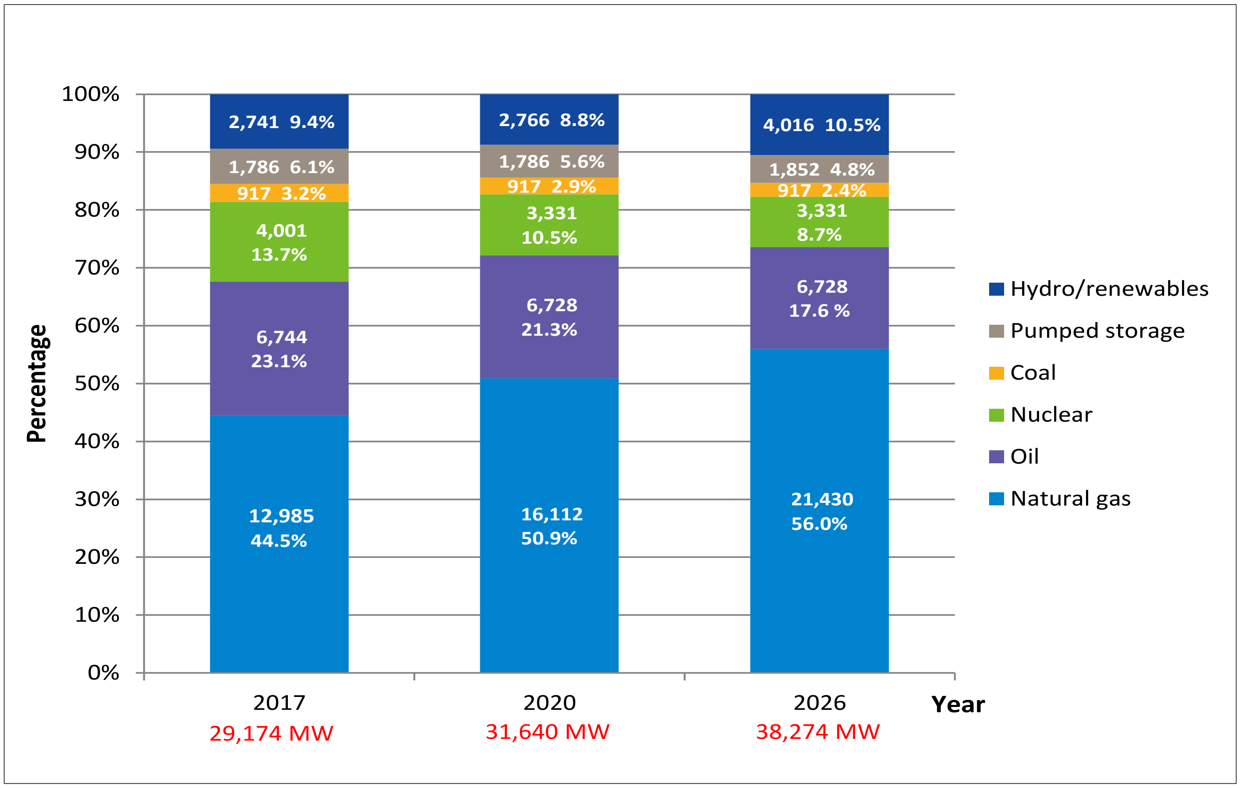
Maryland[3]	On April 19, 2016 the US Supreme Court overturned a Maryland Public Service Commission approval of a compensation arrangement for a new in-state power plant, ruling that, in approving the plan/PPAs, the PSC encroached on FERC authority over PJM.
New Jersey[4]	On April 25, the US Supreme Court declined to hear an appeal of a lower court decision that overturned New Jersey's Long-term Capacity Agreement Pilot Program law, which required the NJ Board of Public Utilities to develop a program under which the state's electric utilities would enter into long term contracts for 2,000 MW of generation.
Ohio[5]	The Ohio Public Utilities Commission Order of March 31, 2016 approved Ohio Edison, Toledo Edison and Cleveland Electric Illuminating to enter into PPAs with unregulated generating affiliate, FirstEnergy Solutions, for a portion of output of plants, i.e., "contract for differences" from revenues from PJM markets. The plants subject to the PPA have all been adversely impacted in recent years by weak wholesale power prices and would likely be uneconomic to operate if the current market environment persists. A FERC ruling negated that decision, and the utilities changed the mechanism to a rider.
NY & Illinois[6]	In light of the recent and potential retirement of nuclear generation plants, several states have developed programs to ensure the continued operation of such units for clean energy and reliability purposes. New York[7] and Illinois[8] have zero emission credit ("ZECs") programs, which provide subsidies for nuclear generation, as part of the NY Clean Energy Standard (finalized by the NY Public Service Commission in August 2016) and Illinois statute (passed in December 2016). These programs are currently being challenged in state and federal courts by competitive market proponents.

Massachusetts and New England more broadly provide another example of the impacts of restructuring on resource and fuel diversity. Due to factors such as low natural gas prices, environmental restrictions on coal generation, and various economic factors, New England has seen its generation fleet becoming increasingly comprised of natural gas units, which provided over 60 percent of generation to serve load in 2017. This presents potential cost and reliability risks for the region, and planners at ISO New England ("ISO-NE") have struggled with how to address this increasing reliance on natural gas-fired generation. ISO-NE, as the market operator, has struggled to find fuel and technology neutral mechanisms to increase the fuel diversity and reliability of the generation fleet, as shown below.

---

3 Lillian Federico, S&P Global; "As a follow up to Maryland PPA decision, U.S. Supreme Court declines to review nullification of NJ's LCAPP law" (April 25, 2016).
4 Ibid.
5 Russell Ernst, S&P Global; "Ohio PUC to consider FirstEnergy's latest proposal in controversial PPA affair" May 11, 2016).
6 S&P Global; State Power Project: "Examining State Authority in Interstate Electricity Markets – Illinois".
7 "Why Court Victories for New York, Illinois Nuclear Subsidies are a Big Win for Renewables." Julia Pyper, Greentech Media. July 31, 2017.
8 State Power Project: "Examining State Authority in Interstate Electricity Markets – Illinois"

FIGURE AP5- 2: NEW ENGLAND'S SUMMER CAPACITY BY FUEL TYPE



Source: ISO-NE 2017 Regional System Plan

ISO-NE has outlined the challenges, citing the "fuel-security risks to system reliability." An ISO-NE report discusses the causes of this risk, including heavy reliance on natural-gas-fired capacity; reliability issues due to limited natural gas transmission infrastructure into the region, as well as limited fuel storage; lack of firm fuel contracts by natural gas generators; retirement of non-gas-fired generation (nuclear, coal, etc.); exposure to winter electricity price spikes; and higher variable cost peaking units (e.g., LNG).[9]

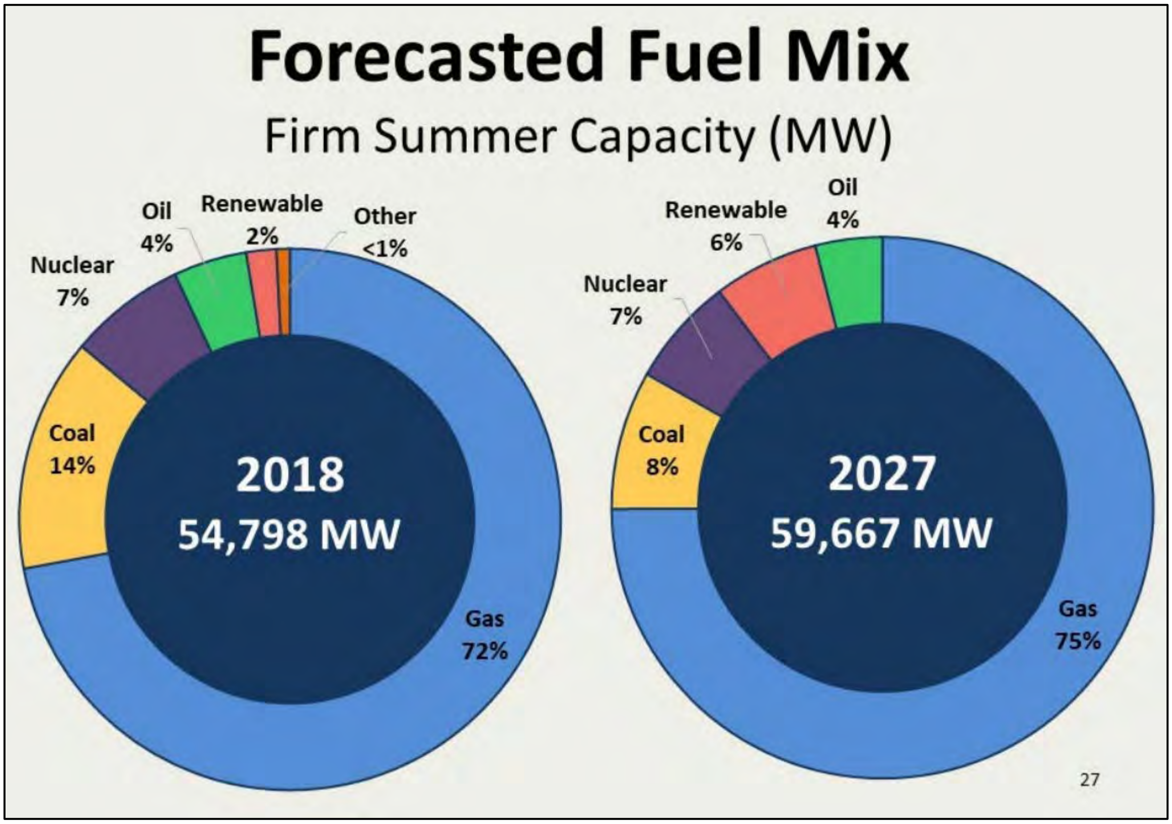
Under a competitive market structure, fuel supply has the potential to be at risk, resulting in higher costs to the region. Many competitive markets across North America do not require generators to have firm fuel supply in the form of either firm gas supply or fuel oil back up. Restructured jurisdictions have experienced severe fuel shortages at times when system reliability was at risk due to lack of firm fuel supply. For example, in the winter of 2014, the cost of electricity at the wholesale level totaled approximately $3.2 billion dollars for December, January and February alone due to high prices as a result of gas shortages.[10] To put this in context, in a typical year, wholesale energy costs total $5 billion for the entire twelve-month period. A deliberate approach to resource diversity, which is absent in a restructured market, provides important protections against high costs, particularly as regions become more dependent on natural gas resources.

9 Source: ISO-NE 2017 Regional System Plan.

10 Winter Reliability Program Updated, Restructuring Roundtable, September 25, 2015.

With its increasing reliance on natural gas generation, Florida faces its own challenges. As shown in Figure AP5- 4, below, Florida has even higher percentage of its capacity met by natural gas resources.

FIGURE AP5- 3: FLORIDA FORECASTED FUEL MIX

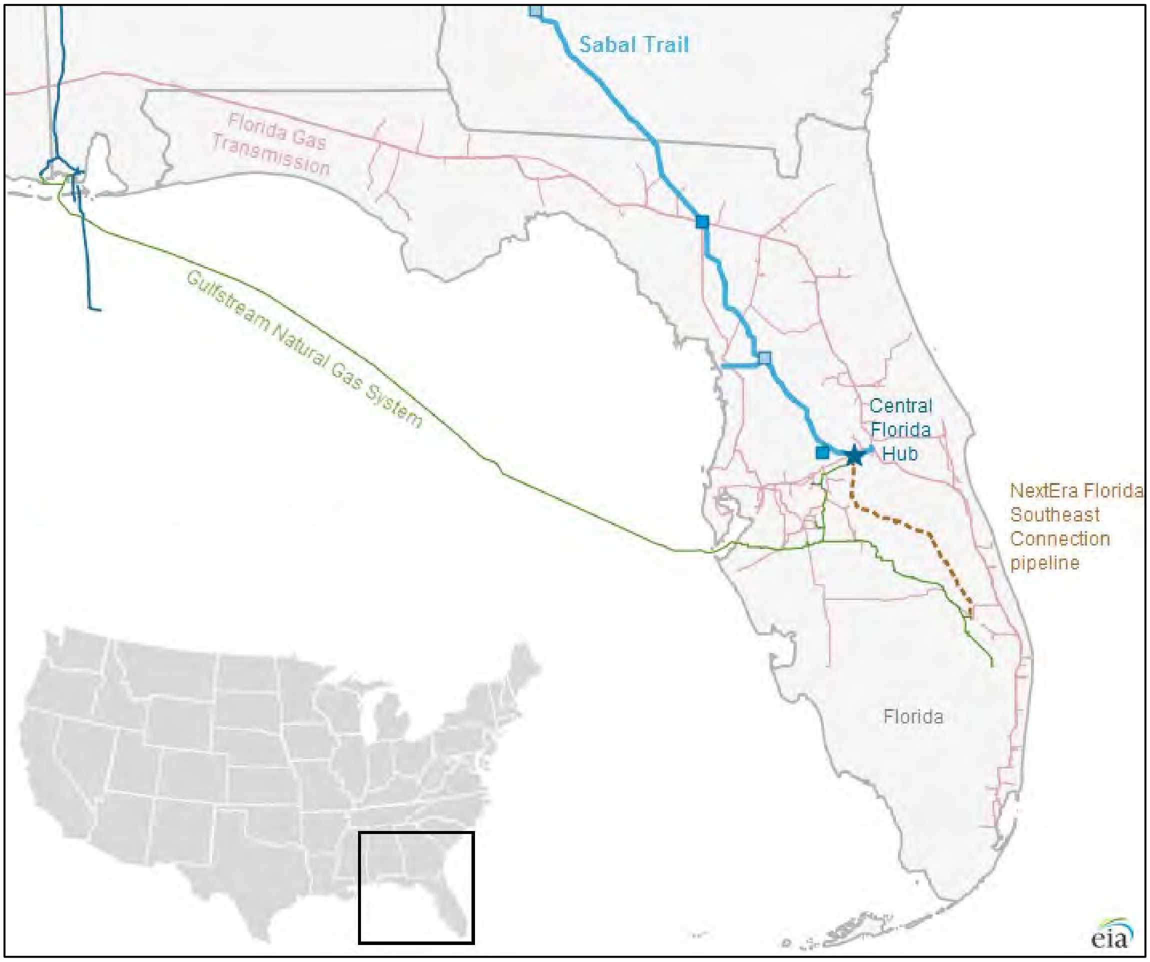


Source: FRCC[11]

Further, just as New England has limited pipeline transmission capacity into the region, Florida, as a peninsula, faces similar challenges. Florida currently receives natural gas supplies from several interstate pipelines: Gulf South Pipeline Company, Southern Natural Gas Company, Florida Gas Transmission and Gulfstream Natural Gas System. The completion of the Southeast Market Pipelines Project, composed of three separate, but related, interstate natural gas transmission pipeline projects subject to FERC jurisdiction, including: 1) the Transcontinental Gas Pipe Line Company, LLC's (Transco) Hillabee Expansion Project; 2) the recently completed Sabal Trail Transmission, LLC's (Sabal Trail) Sabal Trail Project; and 3) the Florida Southeast Connection, LLC's (FSC) Florida Southeast Connection Project provides additional natural gas supplies for Florida. The figure below illustrates the location of Florida's Natural Gas Pipelines.

[11] FRCC, Slide 27.

FIGURE AP5- 4: FLORIDA NATURAL GAS PIPELINES



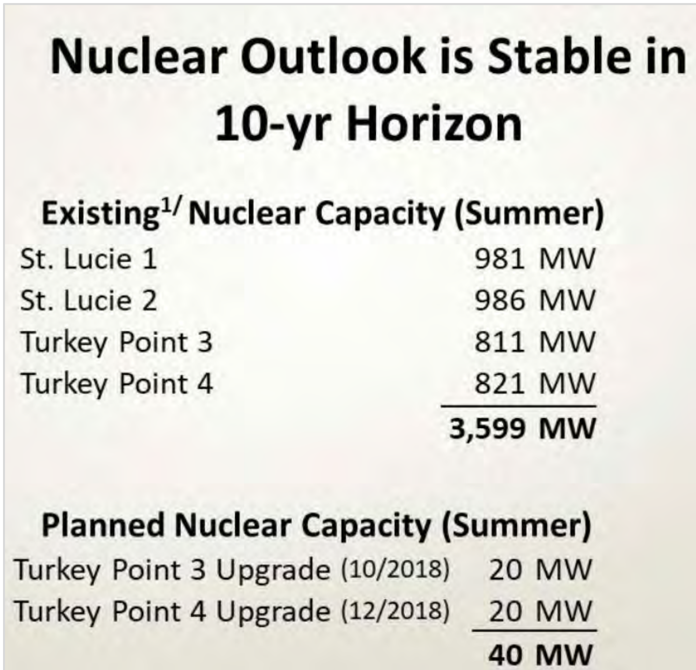
Source: Energy Information Administration

Massachusetts, which is a fully restructured competitive electric market, provides an instructive example of a restructured state struggling with reliance on natural gas in a transmission constrained area. As a potential measure to address this in recent years, the Massachusetts State Energy Office put forth, and the Department of Public Utilities ("DPU") supported, a measure allowing the electric distribution utilities to contract for capacity to support new natural gas pipeline infrastructure, even though the distribution utilities own no generation. This effort was eventually defeated by a Massachusetts Supreme Judicial Court decision, due to a restructuring related statute.

Additional examples may be seen in states such as Ohio, New York, and Illinois, as they have sought to create mechanisms to support the continued operation of baseload power plants. In the case of nuclear plants, policy makers see them as an important source of electricity with no greenhouse gas emissions, which is vital in a carbon-constrained future. This is informed by the closure of many nuclear units throughout the country, which have closed, or are slated to close, due to the inability to survive in restructured wholesale electric markets.

An important issue for Florida in assessing restructuring is the impact on Florida's nuclear fleet. A recent FRCC presentation noted the steadfast footing of Florida's nuclear reactors.[12] If Florida were to restructure, the continued operation of these nuclear units would be highly in doubt, as is evidenced by the many nuclear retirements in restructured markets throughout the U.S. If these units were to retire, customers would be saddled with massive stranded costs, and reliance on natural gas would be significantly exacerbated. Further, retirement of Florida's nuclear generation would represent a loss of carbon-free baseload resources, an invaluable resource in addressing climate change. Florida's nuclear plants are shown in Figure AP5- 6, below.

FIGURE AP5- 5: EXISTING AND PLANNED NUCLEAR CAPACITY IN FLORIDA[13]



Source: FRCC[14]

Market Manipulation

One of the most important functions of an ISO/RTO is to ensure that wholesale markets are competitive. Electricity markets are especially vulnerable to market power challenges, even in the absence of intentional abuse. Market monitoring is essential to control potential market abuses by market participants but is also important simply to monitor how the markets are working, and to look for ways to improve market rules and practices for better overall performance over time. Market monitoring requires the exercise of considerable judgment, as well as the use of advanced tracking and modeling techniques.

To deliver any of the potential benefits of market competition, the market must be structured to minimize the potential for the exercise of generator market power. By tracking market data such as prices, loading, and congestion, market monitors can assess the extent to which a market is operating in a competitive manner. When

[12] FRCC, Slide 22.
[13] Ibid.
[14] Ibid.

departures from competitive conditions are found, the ISO/RTO conducts detailed studies to identify underlying causes and problems and allows system operators to take mitigating actions. Long-term market monitoring also serves to illuminate deficiencies in market design and operation and leads to enhancements to improve market structure.

Even with well-designed market abuse screening mechanisms, abuses still occur, driving up system costs. For example, in 2012, Constellation Energy Group Inc's ("CEG") agreed to a $245 million settlement with regulators over charges of power market manipulation, which at the time was the largest fine handed out by the FERC since 2005. A unit of CEG agreed to pay a civil penalty of $135 million, return $110 million in unjust profits and reassign four traders following a FERC investigation into manipulation of the New York wholesale power market from September 2007 to December 2008.[15]

In July of 2013, the FERC ordered Barclays Bank PLC ("Barclays") and four of its traders to pay $453 million in civil penalties for manipulating electric energy prices in California and other western markets between November 2006 and December 2008. FERC also ordered Barclays to disgorge $34.9 million, plus interest, in unjust profits to the Low-Income Home Energy Assistance Programs of Arizona, California, Oregon, and Washington. In the order, FERC found that Barclays' actions demonstrated an affirmative, coordinated and intentional effort to carry out a manipulative scheme, in violation of the Federal Power Act and FERC's Anti-Manipulation Rule.[16]

[15] Reuters Business News, March 12, 2012.
[16] https://www.ferc.gov/media/news-releases/2013/2013-3/07-16-13.asp#.XGgZe-hKiUk.

APPENDIX 6: ELECTRIC RESTRUCTURING AND RETAIL MARKET CONSIDERATIONS

Purpose of Report

This paper was prepared by Concentric to provide information and insights on the potential impact of ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment") on retail energy costs and service. In particular, this paper addresses: (1) the implications of electric restructuring and retail choice on the Florida Public Service Commission ("FPSC"); (2) experiences of residential customers served by competitive suppliers ; (3) actions taken against retail marketers; (4) analysis of costs incurred by competitive suppliers to provide retail service; and (5) the relatively low participation in competitive retail markets by residential consumers.

Background

Implementing retail choice as contemplated by the Amendment would require the design, implementation, ongoing administration and monitoring of functioning wholesale and retail electricity markets. Establishing, maintaining, and providing oversight over a functioning retail market is a lengthy and complex process, which would require substantial investment. In addition, shifting to a fully restructured market for retail electric service could subject Floridians, particularly residential customers, and especially low-income, elderly, and non-native English-speaking customers, to aggressive marketing practices, billing and customer service issues, and higher cost for services as compared to regulated utility services. Finally, there is relatively low participation rates among residential customers in most restructured states and low levels of satisfaction with competitive supply.

What is a Retail Marketer?

In states that have adopted electric restructuring, "retail energy supplier," "retail marketer," or "energy service company ("ESCO")" refers to a company that serves as an intermediary between the electricity buyer (residential, commercial and industrial customers) and the wholesale electric market. Retailer marketers purchase electricity through wholesale electricity markets and resell it to consumers. Like other competitive businesses, retail marketers develop and sell products, pay their costs, and seek to earn a profit in doing so. They must buy electricity, hire staff, market to customers, sell their services and deliver these services to their customers. In addition, retail marketers must also perform a supply management function in which customer supply obligations are matched with wholesale supply purchases. Retail marketers incur costs for the products they supply (cost of goods sold) and a variety of operating expenses.

Today, in most restructured states, customers that do not choose a retail marketer remain on electricity supply service provide by the utility, which is referred to by terms such as "default service," "standard offer service," "basic service," of POLR service. The term "POLR" reflects that the supply service is provided to ensure that customers receive electric supply if they do not choose a retail marketer or in the event that their retail supplier goes out of business or exits the market. The Amendment does not address POLR service.

Impact of Restructuring on FPSC and State Regulation

Moving from a traditionally regulated retail market to full retail choice has implications for the activity, role, and jurisdiction of the FPSC. One main impact is that the FPSC, or another agency, would need to undertake significant work to shift from regulation to restructuring and establish and monitor the restructured electric retail market. For example, the FPSC would need to:

- Implement rules and regulations for the restructured retail electricity market;
- Implement and administer licensure or certification requirements for retail providers;
- Set protocols for customer enrollment, de-enrollments, shut-offs, late fees, billing formats, contract language, third-party sales verification and consumer protections;
- Establish data exchange protocols for communications between the utilities, marketers and independent system operator ("ISO");
- Initiate an unbundling proceeding;
- Take enforcement actions against providers that do not comply with these rules;
- Review applications for licensure and issue certificates;
- Review applications from retail providers to cease providing service;
- Oversee transition of customers from retail providers that exit the market;
- Oversee customer education regarding the competitive market;
- Address additional questions/complaints from customers to the FPSC.

The FPSC may require additional staff with additional expertise to fulfill these functions and should expect to spend significant time, particularly in the early years of restructuring, with implementation issues. This additional administrative burden may lead to cost increases for the FPSC as it needs to add economic, technical and legal staff to conduct and administer these functions.

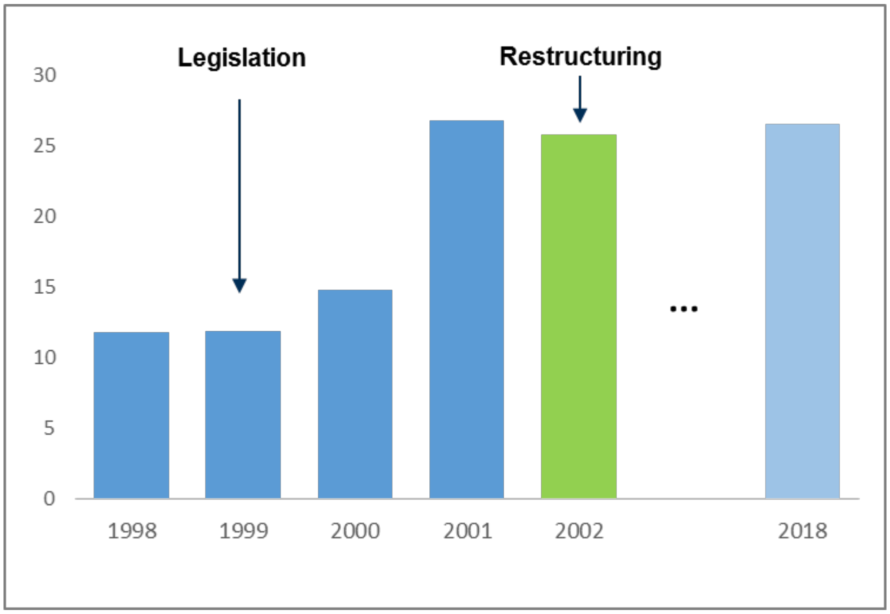
Texas Public Utility Commission Cost Increases due to Restructuring[1]

In order to establish the new deregulated market, the Texas Public Utilities Commission ("Texas PUC") had to significantly expand resources in order to prepare for the new market, ensure execution, and oversee the new market structure. Although some oversight costs were shifted to the regional transmission organization that was created in Texas (i.e., the Electric Reliability Coordinating Council of Texas or "ERCOT"), the new Texas PUC responsibilities more than offset any cost reductions associated with this shift – as can be seen in Figure AP6- 1 below.[2]

There was a significant ramp-up in costs in the years immediately preceding restructuring following the enactment of restructuring legislation, and Texas PUC costs have remained at considerably higher levels ever since. There was an 81% increase in costs between 2000 and 2001 alone.[3] Some of the additional costs included professional fees to contractors / consultants to address the various challenges as highlighted in the previous section. One particular program worth noting in 2001 was a large increase in costs to develop, implement, and manage consumer education across the state.

1 Charles River Associates conducted research and analysis on public utility commission costs due to restructuring on behalf of the Florida Chamber of Commerce. This section summarizes the results of that work.
2 Legislative Appropriations Request for Fiscal Years 2018 and 2019; Governor's Office of Budget, Planning and Policy
3 Legislative Summary Document Regarding PUC Texas – January 2003; State Auditor's Office (SAO 03-377)

FIGURE AP6- 1: TEXAS PUBLIC UTILITY COMMISSION COSTS ($ MILLIONS)



Customer Rates and Marketing Practices

Reduction in FPSC jurisdiction over retail electric service in a restructured market structure could impact customers, particularly residential customers, through increased bills and deceptive marketing, billing, and pricing practices. Many states have recently performed evaluations of their restructured market including whether residential customers are better or worse off than with retail providers.

The Massachusetts AG developed a study in March, 2018 to determine "whether residential consumers in Massachusetts pay more or less for their electric supply when they buy it from the competitive marketplace rather than their electric utility (such as National Grid, Eversource, and Unitil); and (2) identify remedies if warranted."[4] The final analysis showed that "Massachusetts consumers in the competitive supply market paid $176.8 million more than they would have paid if they had received electric supply from their electric company during the two-year period from July 2015 to June 2017. A third year of data shows residential customers lost another $76.2 million, for a three-year total of $253 million."[5] This report looked only at residential electric supply and not the commercial or industrial market, and noted that "Unlike the commercial and industrial market, where sophisticated buyers with demands for large volumes are likely able to negotiate more favorable rates, individual residential consumers are not getting a bargain."[6] Following the publication of this study, the AG issued a press release citing aggressive sales tactics, false promises, higher costs, and the targeting of low-income, elderly, and minority residents, and proposed legislation to end electricity choice for individual residential customers.[7]

4 Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, p. viii.

5 Rebecca Tepper, Massachusetts Attorney General's Office, "Suppliers Are Not Providing Value to Individual, Residential Customers" Presentation to the New England Restructuring Roundtable, *October 12, 2018*, slide 4.

6 Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, p. viii., p. 15.

7 "AG Healey Calls for Shut Down of Individual Residential Competitive Supply Industry to Protect Electric Customers" Press Release, March 29, 2018. https://www.mass.gov/news/ag-healey-calls-for-shut-down-of-individual-residential-competitive-supply-industry-to-protect

- A Rhode Island evaluation conducted over four years found that customers who switched from their utility to retail providers had paid $56 million over the default service costs.[8] In Connecticut a study completed by the Office of the Consumer Counsel concluded that in 2015 customers who switched to a competitive supplier paid almost $58 million more than remaining with their default supplier.[9] A 30-month study conducted by the New York Public Service Commission found that customers who switched electric and gas suppliers paid nearly $820 million more than if they had remained with their default suppliers.[10] Illinois AG Lisa Madigan reported that residential and small commercial customers enrolled with competitive suppliers paid over $600 million more for electricity in the last four years than if they continued to purchase their electricity from the regulated utility. [11]

Following the filing of a lawsuit against a retail provider in Illinois for violations of that state's consumer fraud laws, Illinois' AG Madigan also called for an end to residential choice, due to deceptive marketing practices.[12] This month, Connecticut Consumer Counsel, in collaboration with AARP, other consumer advocates, and a U.S. senator, called for the end of residential choice that "economically harms consumers" in Connecticut.[13]

In New York, the Department of Public Service Commission ("NY DPS") ordered competitive electric suppliers to cease signing up new customers, due to customers paying more for electricity provided by competitive suppliers than what they would have paid based on utility rates. The NY DPS order demonstrates the market's poor performance and frustration the commission had in overseeing the competitive retail market for the public's benefit. In particular, the New York Commission wrote:

> "experience shows that, with regard to mass market customers, ESCOs cannot effectively compete with commodity prices offered by utilities. This may be for a number of reasons, including customer acquisition costs, the greater economies of scale of utilities, and the fact that utilities do not profit from the sale of energy commodity. In addition, the Department of Public Service continues to receive a large number of complaints from ESCO customers about unexpectedly high bills."[14]

The NY DPS reported that it received over 5,000 initial complaints against ESCOs in 2015, with 1,076 "escalated complaints," (i.e., not initially resolved by ESCOs) which fall into the following categories:

- 30% - "questionable marketing practices"
- 25% - "dissatisfaction with prices charged – no savings realized"
- 22% - "slamming – enrollment without authorization."[15]

---

8 National Grid: The Narragansett Electric Company, Standard Offer Supply Procurement Plan / 2019 Renewable Energy Standard Procurement Plan. March 1, 2018, Testimony of Stephen A. McCauley, p. 9.

9 Gregory B. Hladky, Study: Consumers Pay Extra for Retail Electricity. Hartford Courant. April 20, 2016. http://www.courant.com/news/connecticut/hc-retail-electricity-costs-above-state-standard-20160420-story.html.

10 Jeff Platsky, AT RISK: NY Reviews Electric, Gas Free-Choice Program; Consumers Ended Up Paying More. Press Connects. February 9, 2018. https://www.pressconnects.com/story/news/2018/02/09/risk-ny-groundbreaking-program-allowing-customers-select-electric-gas-suppliers/302146002/

11 "[Attorney General] Madigan Sues Another Alternative Retail Electric Supplier & Reaches $3 Million Settlement for Defrauded Customers" Press Release, November 19, 2018. http://illinoisattorneygeneral.gov/pressroom/2018_11/20181119b.html

12 Ibid.

13 "Time to End the Third-Party Residential Electric Supply Market" AARP Connecticut. February 2, 2019. https://states.aarp.org/time-to-end-the-third-party-residential-electric-supply-market/

14 New York Public Service Commission Order Resetting Retail Energy Markets and Establishing Further Process, CASE 15-M-0127, (2/23/2016), p. 2.

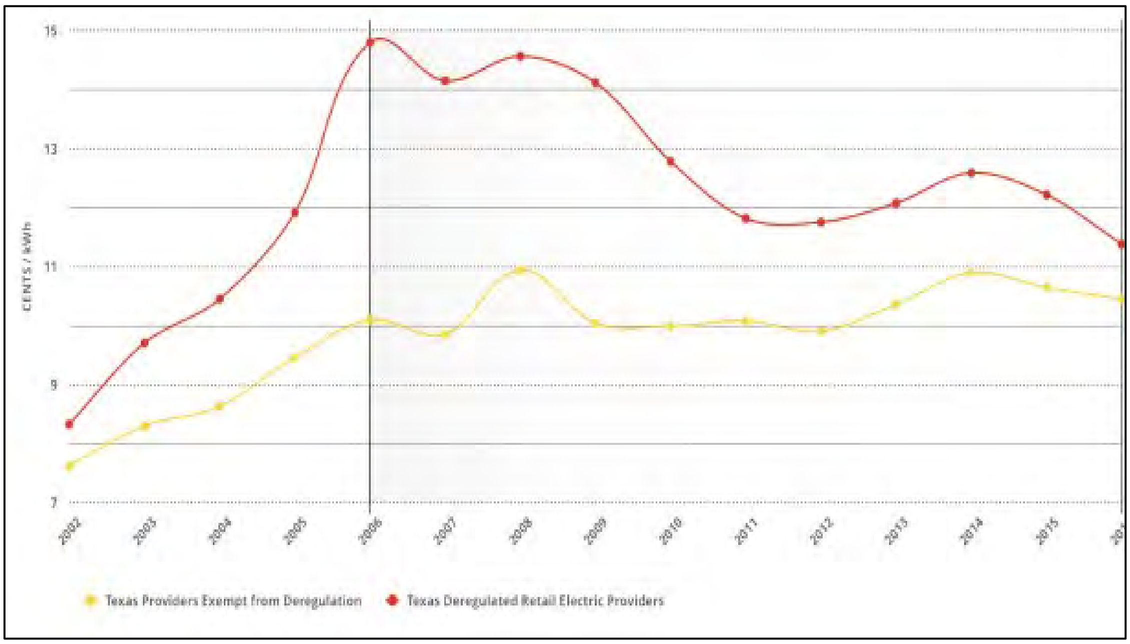
15 Ibid., pp. 12-13.

The NY Commission ordered that ESCOs may only enroll/ renew retail customers based on contracts that: (1) guarantee savings in comparison to what the customer would have paid as a full-service utility customer, or (2) provide at least 30% renewable electricity. Ultimately this order was challenged, and the process is ongoing.

Texas provides another example of an increase of customer complaints following restructuring. After restructuring was implemented in that state, there was a significant increase in customer complaints, as complaints to the Texas Public Utilities Commission, which averaged 1,300/year prior to restructuring rose to as much as 17,250 in a given year.[16] While recent years have shown some decline in these numbers, they are still far above pre-restructuring levels.

Texas has experienced price increases since it opened its markets to competition. According to a 2014 report from the Texas Coalition for Affordable Power ("TCAP"), restructuring has cost Texas customers $22 billion from 2002 – 2012.[17] In its most recent 2018 report, TCAP found that Texans have consistently paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation. This annual trend began during the very first year of the retail electric deregulation in Texas and has continued through 2016, as shown in Figure AP6- 2.

FIGURE AP6- 2: AVERAGE RESIDENTIAL ELECTRICITY PRICES IN TEXAS[18]



Restructured states often find that their residential—particularly low-income, non-native English speaking, and elderly—customers are the victims of aggressive and misleading marketing practices. As Florida has a large population of low-income, elderly, and non-native English-speaking customers, this represents a considerable risk of restructuring in the state.[19]

[16] Texas Coalition for Affordable Power, "Deregulated Electricity in Texas 2017 Edition" p. 84.
[17] Ibid., citing to TCAP's 2014 report. p. 74.
[18] TCAP Report on Electricity Prices in Texas, April 2018.
[19] 20.1% of Floridians are over the age of 65, as of July 1, 2018, as compared to the national average of 15.6%; 28.7% of Floridians speak a language other than English at home (from 2013-2017), as compared to the national average of 21.3%, and 14% of Floridians live below the poverty line (from 2013-2017), as compared to the national average of 12.3%. Source: https://www.census.gov/quickfacts/fl; https://www.census.gov/quickfacts/fact/table/US/PST045218

These case studies demonstrate the significant risk of retail price increases, particularly for residential customers, from retail restructuring. These case studies also demonstrate that a decision to rely on markets to set prices can lead to customers suffering higher prices than those offered under regulated utility service. Put another way, it is impossible to have both market and regulation setting the prices at the same time. Particularly because the Amendment would preclude Florida's regulated utilities from offering retail service, a decision to rely on market prices means abandoning a safety net for customers and results in a significant loss of control for the Commission over retail pricing and associated practices.

Actions Against Marketers

There are numerous cases in which regulators and attorneys general have undertaken punitive action against energy marketers for an array of violations. Table AP6- 1, below, summarizes a selection of such actions.

TABLE AP6- 1: ILLUSTRATIVE REGULATOR AND ATTORNEY GENERAL ACTIONS AGAINST ENERGY MARKETERS

State/ Province	Illustrative Complaints, Enforcement Actions, Settlements, etc.
Connecticut	In 2018 Spark Energy was fined twice by the Connecticut Public Utility Regulatory Authority. They were first fined in $900,000 in August for displaying inaccurate rates on their bills. The second fine for $750,000 was issued on September 5, 2018 in response to Spark sending automated calls to customers under the guise of Eversource.[20] Connecticut AG and Consumer Counsel petitioned the Public Utilities Regulatory Authority to investigate the marketing practices of Energy Plus, after customers claimed the company failed to adequately disclose energy rates, culminating in a $4.5 million settlement paid by the company.[21]
Illinois	In October 2018, Sperian Energy settled a lawsuit issued by AG Lisa Madigan for deceptive market practices like failing to notify customers of contract lengths and fees. Sperian was required to refund $2.65 million to 60,000 Illinois customers and was banned from marketing to customers in Illinois for the next two years.[22] Illinois Commerce Commission fined Just Energy in relation to deceptive sales and marketing practices and ordered an independent audit of the company's sales program.[23] Illinois AG reached settlement with U.S. Energy Savings Corp. (now Just Energy) allowing hundreds of customers to terminate contracts and receive $1 million in restitution for misleading sales tactics.[24]

20 Matt Pilon, "Spark Energy Hit with Second Fine", September 11, 2018.
21 Dowling, Brian, "Settlement with NRG Energy Subsidiary Nets State $4.5M For Enforcement," *The Hartford Courant*, May 22, 2014.
22 "Attorney General Lisa Madigan: Secures $2.6 Million in Refunds for Illinois Residents Defrauded by Sperian Energy", Press Release, October 21, 2018.
23 Illinois Commerce Commission, "Illinois Commerce Commission Fines Just Energy for Deceptive Sales and Marketing Practices, Orders Audit," Press Release, April 15, 2010.
24 "Madigan Secures $1 Million in Consumer Restitution from Alternative Gas Supplier for Deceptive Claims," Press Release, May 14, 2009.

State/ Province	Illustrative Complaints, Enforcement Actions, Settlements, etc.
Maryland	Maryland Public Service Commission fined North American Power $100,000 for misleading advertisements and ordered the suspension of telemarketing activities in the state.[25] The Maryland Public Service Commission fined TES Energy for brokering electric service without a license.[26]
New Jersey	Energy Plus was the target of a class action lawsuit for allegedly perpetrating an illegal bait-and-switch scheme and defrauding thousands of New Jersey consumers of millions of dollars.[27]
New York	Liberty Power was required to pay $550,000 in refunds to New York customers in April 2018, due to tricking customers into signing contracts by impersonating utility representatives and disguising contracts as billing corrections.[28] In 2017 Energy Plus was ordered to reimburse $800,000 to customers in a lawsuit filed by New York AG Schneiderman. The AG's office found that Energy Plus had wrongly promised savings and had misrepresented their cancellation policy.[29] New York AG reached a settlement with U.S. Energy Savings Corp. (now Just Energy) requiring the company to waive hundreds of thousands of dollars in customer termination fees and pay $200,000 to the state.[30]
Ohio	In 2016 Just Energy was fined $125,000 by the Ohio Public Utilities Commission for deceptive marketing practices. Customers complained to the PUC that they had received bills from Just Energy without ever signing up for their service.[31]
Ontario	Ontario Energy Board fined Direct Energy for a string of forged signatures on energy contracts. Ontario Energy Board fined Ontario Energy Savings Corp. (now Just Energy) for a string of forged signatures on energy contracts.[32]

Retail Marketers' Cost Structure

Retail marketers incur many of the same types of costs as utilities for billing and customer care. A result of retail restructuring is that instead of a single IOU providing these functions, as many ESCOs as function in the market provide these functions, creating duplicative and additive costs. Finally, retail providers incur significant costs to establish their brand and market and sell their product to consumers. Ultimately, retail providers seek to recoup these costs from retail customers through rates.

---

25 Cho, Hanah, "Electric Choice: Know Your Rights," *Baltimore Sun*, January 7, 2012.
26 "License Briefs," EnergyChoiceMatters.com, April 14, 2011.
27 "Sanford Wittels & Heisler File Class Action Against Energy Plus," Press Release, May 2, 2012.
28 Bill Heitzel, "Liberty Power Agrees to Fund Customers for Unscrupulous Tactics," April 12, 2018
29 "A.G. Schneiderman Announces $800K Settlement with Energy Service Company That Falsely Advertised Lower Utility Bills", Press Release, August 30, 2017.
30 "Attorney General Cuomo Reaches Agreement with WNY Natural Gas Provider After Consumer Complaints," Press Release, November 10, 2009.
31 Dan Gearino, "Electricity Marketer Just Energy Fined Over Complaints", November 5, 2016.
32 Ibid.

Acquisition Costs

Retail supplier service costs include customer acquisition expenses which the utility does not incur. These costs can vary widely depending on the sales channel used by the retailer. A review of certain retailers that report acquisition costs suggests that these costs average approximately $121/customer including costs for door-to-door sales commissions, branding and marketing expenses.[33] If the Amendment is approved, an additional $850 million of costs may be incurred as retailers seek to acquire customers and then recover these costs in their rates.[34] This cost estimate does not include customer acquisitions costs for commercial and industrial accounts of which there are over 915,000 in Florida.

Duplicative Systems

In most restructured markets, utilities and retailers both provide customer care and billing functions. Utilities maintain billing systems for determining transmission and distributes rates and retailers calculate supply charges. These redundant billing requirements mean that each consumer served by a retailer is supporting two billing platforms.

Further, under cost of service regulation, electric utilities enjoy significant back-office economies of scale which benefits consumers in the form of lower and more stable monthly electricity bills. Given the relative lack of scale of retailers operating within a single service territory, it is reasonable to expect that actual supplier costs are far higher than what utilities incur for these services on a unit basis. (In this case the comparable utility service costs would include only billing, customer care and some corporate allocation and would not include transmission and distribution system operating costs and associated depreciations expenses.)

The average "cost to serve" for competitive retailers in a review of publicly available information was $112/customer/year. [35] The impact of these higher operating costs could be considerable for Florida customers. As Florida has nearly 7 million residential electricity customers served by IOUs, estimated retailer "costs to serve" alone would cost Florida customers an additional $784 million per year assuming all customers were to switch to a retail supplier.

Limited Residential Customer Uptake of Competitive Retail Service

Residential customers have not demonstrated a strong desire for retail choice. This is demonstrated in a recent US Energy Information Administration ("EIA") report that showed that electricity residential retail choice participation has declined since its peak in 2014 and includes the following table.[36]

---

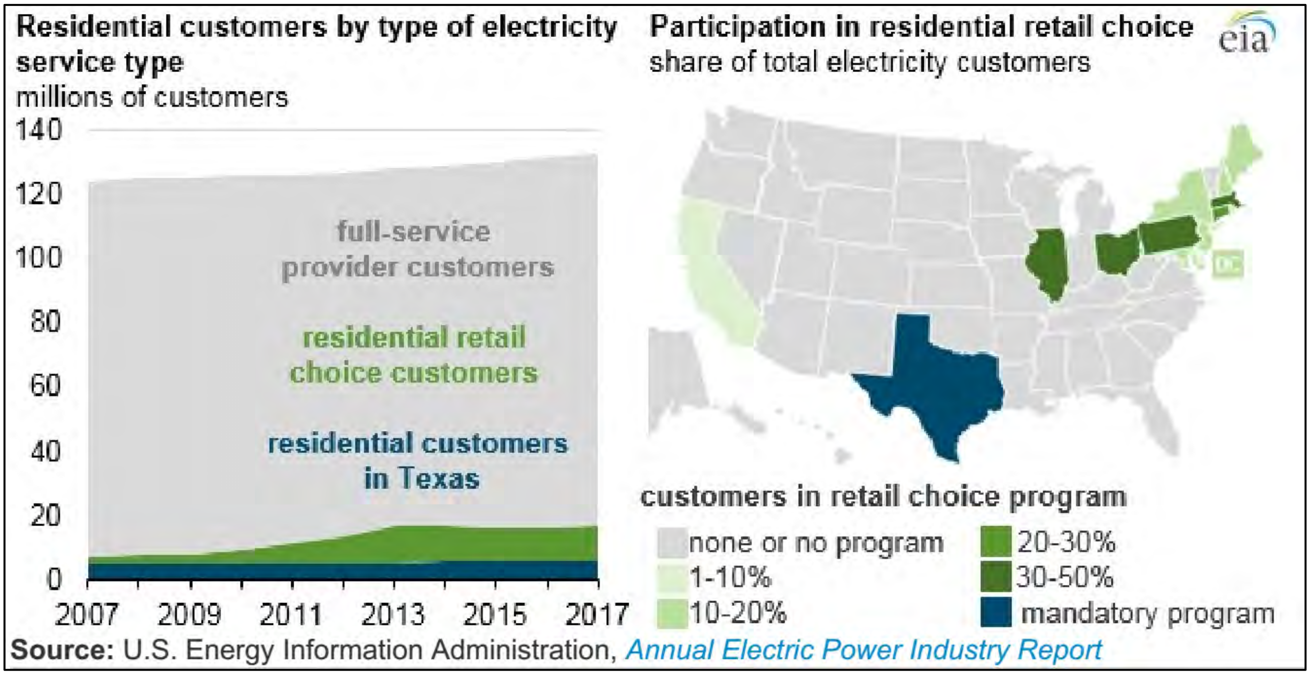
33 Sources: Crius Energy Trust, Management Discussion and Analysis ("MD&A"), March 8, 2018, pages 10 and 12; Just Energy MD&A, May 16, 2018, pages 4 and 30; Genie Energy Ltd, 2017 Form 10-K, pages 27 and 28; Spark Energy Inc., 2017 Form10-K; pages 52 and 93. Calculated as average of Crius, Just Energy, Genie, and Spark total acquisition costs, divided by acquired new customers.

34 $850 million is calculated as the product of the cost of $121.48 per customer multiplied by the number of residential customers served by Florida's IOUs, 6,997,244, rounded from $850,053,527.

35 Sources: Crius Energy Trust, Management Discussion and Analysis ("MD&A"), March 8, 2018, pages 10 and 12; Just Energy MD&A, May 16, 2018, pages 4 and 30; Genie Energy Ltd, 2017 Form 10-K, pages 27 and 28; Spark Energy Inc., 2017 Form10-K; pages 52 and 93. Calculated as average of Crius, Just Energy, Genie, and Spark total cost to serve, divided by total customers.

36 US EIA, "Today in Energy: Electricity residential retail choice participation has declined since 2014 peak." (Nov. 8, 2018).

FIGURE AP6- 3: RESIDENTIAL PARTICIPATION IN RETAIL CHOICE IN U.S.



It is observed that residential customers exhibit "stickiness," meaning that when they are presented with retail choice, many customers either do not switch providers and take service from the POLR, or switch and then return to their original provider or the POLR.

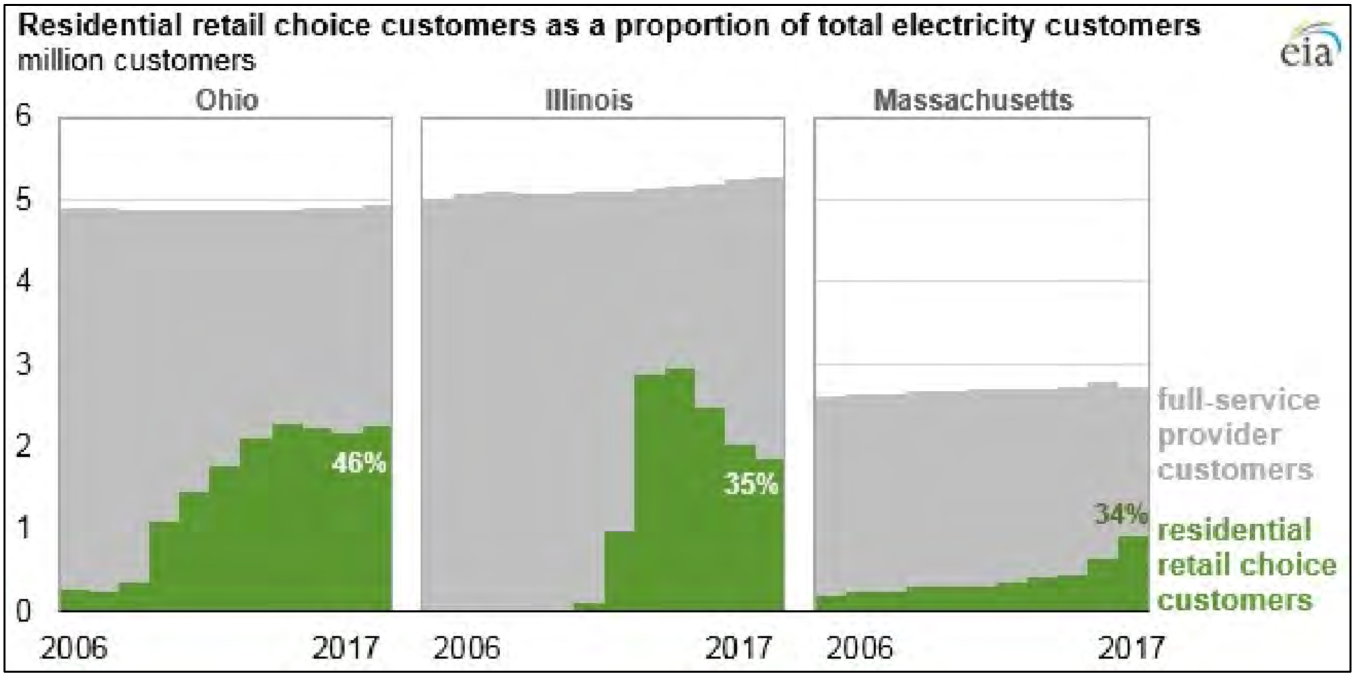
One factor impacting residential participation in competitive retail markets that also have utility provided service is "community choice aggregation" ("CCA") or "municipal aggregation." CCA legislation enables local governments to enter into contracts whereby customers participate in competitive retail supply arrangements, unless they individually opt-out. This has driven increases in residential participation in states like Massachusetts, where the vast majority of residential customers served by competitive supply are part of CCAs. In 2014 in Massachusetts, which implemented restructuring in 1999, approximately 18% of residential customers. This number has grown in the last four years to approximately 42% of customers in 2018, due largely to numerous new CCAs.[37] This is reflected in Figure AP6-4, below.

CCAs are not immune, however, to negative potential outcomes associated with competitive electric supply service. Illinois saw an increase in residential customer participation in competitive retail electric service as CCAs were introduced in that state from 2009-2013. However, following extreme cold weather in January 2014, FirstEnergy Solutions, a major retail power marketer in Illinois, announced it would impose a one-time surcharge of $5 to $15 on its customers, including in Illinois, to cover extra costs. (FirstEnergy Solutions also applied this surcharge to its Ohio customers, which led to a broad investigation by the Public Utilities Commission of Ohio; ultimately, FirstEnergy Solutions decided to exclude its almost three million residential customers from the charge.) After this event, residential customers in Illinois switched back to their default providers at a rate of 16% in 2015 and 18% in 2016. As of 2017, retail choice providers serviced 35% of total residential customers

[37] Electric Customer Migration Data, Mass.gov. https://www.mass.gov/service-details/electric-customer-migration-data. 2014 data is annual; 2018 data is for Sept. 2018, the most recent month available.

in Illinois, down from the peak of 57% in 2014.[38] Figure AP6- 4 below shows recent increase in Massachusetts, as well as declines in Illinois and Ohio.

FIGURE AP6- 4: CHANGE IN RESIDENTIAL CUSTOMERS PARTICIPATING IN RETAIL ELECTRIC SUPPLY IN THREE STATES

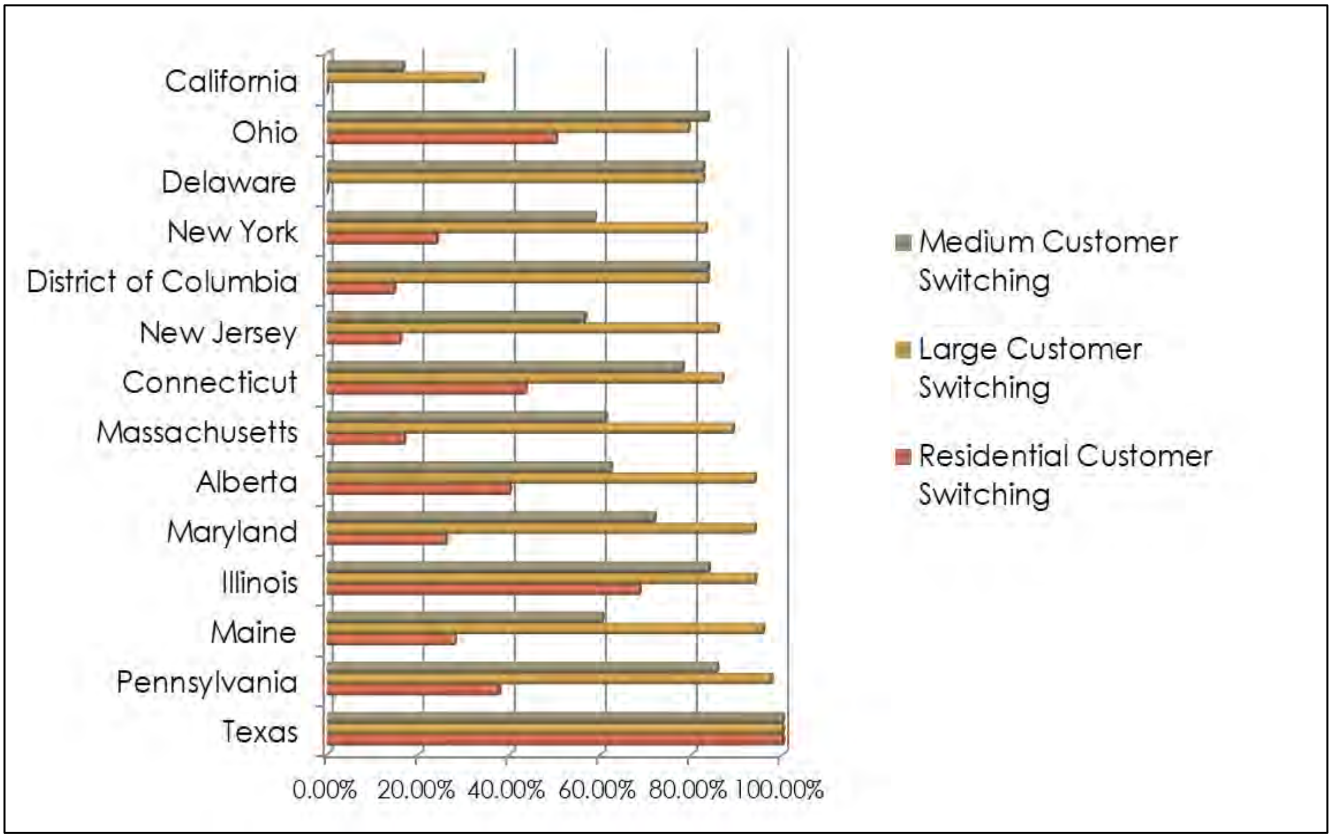


In contrast to residential customers, the migration to retail suppliers by industrial customers has been much greater. In Massachusetts in 2014, 73% of large commercial and industrial customers used retail supply and this grew to 85% in 2018.

Figure AP6- 5: below, illustrates that retail access has been popular with commercial and industrial customers; but less popular with residential customers.

38 US EIA, "Today in Energy: Electricity residential retail choice participation has declined since 2014 peak." (Nov. 8, 2018).

FIGURE AP6- 5: PERCENT OF CUSTOMERS ON RETAIL ELECTRIC SUPPLY BY STATE AND RATE CLASS[39]



39 "Annual Baseline Assessment of Choice in Canada and the United States" January 2014, pages 14, 26.

APPENDIX 7: RE-REGULATION EFFORTS

Purpose of Report

This report was prepared by Concentric to provide information and insights on the experience of those states that began efforts to restructure their electricity markets only to decide to halt electric restructuring or re-regulate. This report discusses the experiences of California as the first state to introduce competitive electricity markets, as well as other states that started and then reversed restructuring efforts, largely impacted by the experience of California.

Background

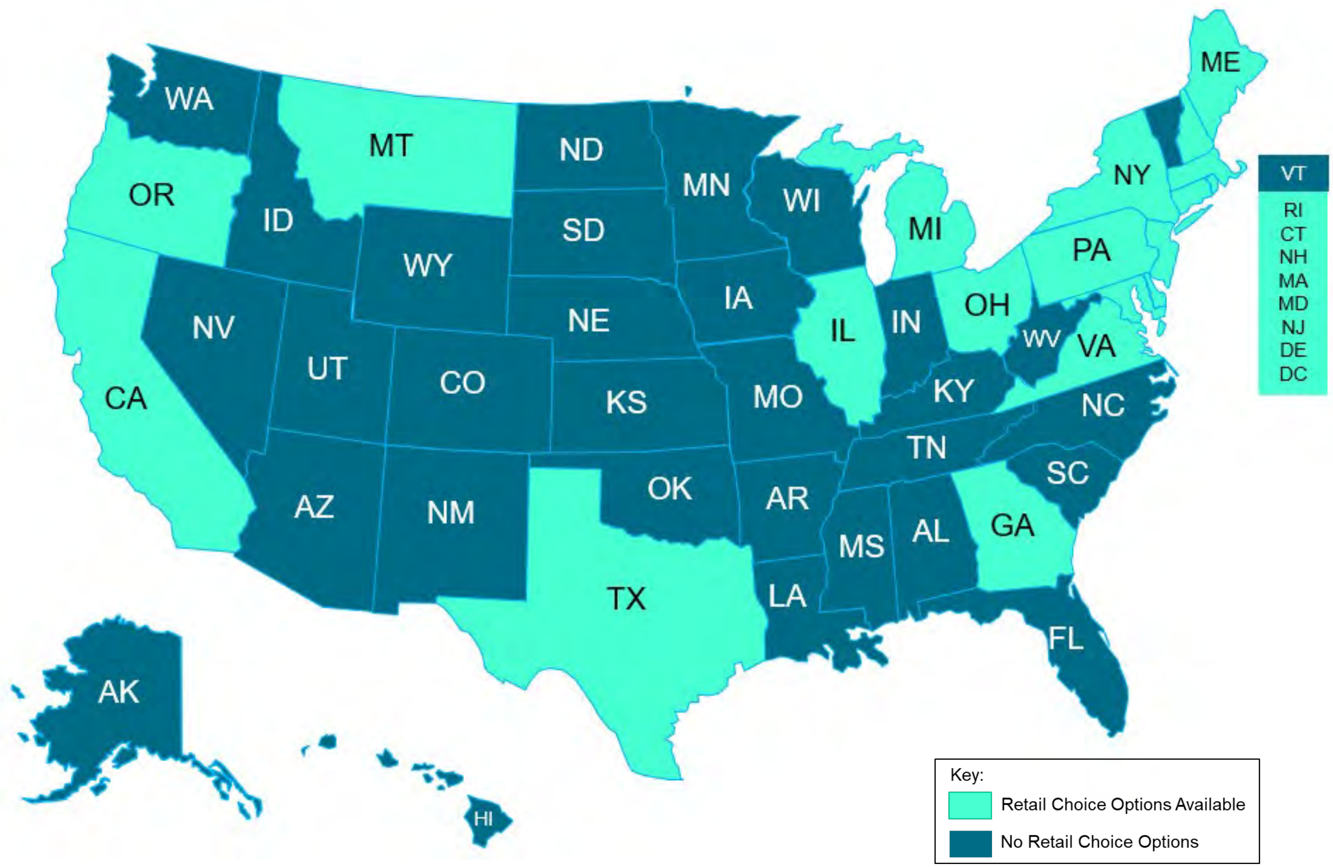
Currently, Floridians' electricity service is provided either by municipal electric companies, electric cooperatives or investor owned utilities ("IOUs"). The state's IOUs are vertically integrated and are regulated by the Florida Public Service Commission ("FPSC") and other state and federal regulatory bodies. Ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" would provide all customers of Florida's IOUs the right to choose their electricity provider, and the right to generate electricity either alone or in association with others. IOUs would be limited to the "construction, operation, and repair of electrical transmission and distribution systems." IOUs would no longer own generation, and the existence of sufficient generation and other supply resources, as well as transmission investment, would be shifted to competitive market forces under the jurisdiction of federal regulatory bodies.

The realities of competitive electricity markets have been experienced in several states across the country. Florida should consider these lessons learned as it considers the costs, benefits, and risks of introducing competition in the state of Florida.

Retail Choice Today

Currently, some form of electric retail choice is available in 20 states nationwide. Retail choice in these states varies from full retail choice for commercial, industrial and residential customers to partial retail choice for large industrial customers capped at a percentage of total retail sales. The states that have implemented electric restructuring in some form is show in Figure AP7- 1.

FIGURE AP7- 1: STATUS OF ELECTRIC RESTRUCTURING BY STATE[1]



Re-Regulation Efforts

California

California was one of the first states to restructure its energy market. The 1996 law that restructured California's electricity industry was intended to be the first step toward lower electricity prices for 70 percent of the state's population. The restructuring plan was enacted to change the sources and pricing of electricity for customers of the state's three large investor-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. Together, those utilities served almost three-quarters of the state's electricity users. California's restructuring plan was based on the assumption that greater competition among independent power generators would cause wholesale prices for electricity to fall. By the summer of 2000, however, demand for electricity had outpaced the generating capacity available to supply the market. Wholesale prices per megawatt hour in California, which were near $30 in April of 2000 rose significantly to more than $100 by

[1] American Coalition of Competitive Energy Suppliers

June 2000.[2] By November, prices had increased to between $250 MWh and $450 MWh.[3] The first five months of 2001 were characterized by soaring wholesale prices, energy emergencies, and a small number of rolling blackouts. The pain was severe. The California grid operator was forced to institute statewide rolling blackouts to prevent the whole grid from collapsing. Emergency rate hikes were ordered since utility retail price caps had been instituted when the market was first established. However, these rate hikes were insufficient in protecting the financial assets and the borrowing power of the big electric utilities. With their monetary resources depleted, the utilities were no longer credit worthy, and Pacific Gas & Electric eventually filed for bankruptcy. By December of 2000, under orders of the FERC, purchase price controls were replaced by a "soft cap" on wholesale markets. The FERC ordered the soft price cap to limit price changes while allowing cost-based price increases above the wholesale price-controlled levels. But these soft caps were not effective and encouraged gaming of the system by generators and marketers. Eventually, the FERC ordered refunds of large sums from retail marketers to California, as massive market abuses by Enron and other marketers were proven. As a result of the California crisis, states that had been moving towards electric restructuring suspended further action, or even repealed restructuring schemes on the books. The FERC continued to press for a standard market design and regional transmission organizations.

The California Public Utilities Commission ("CPUC") suspended retail choice on September 20, 2001, in Decision 01-09-060. At the time, the CPUC estimated that about 5% of the state's peak load of 46,000 MW was under direct access contracts, mostly with large industrial customers. Contracts in place were allowed to continue until their expiration. Efforts to restore choice have not been successful to date.

Arizona

Arizona opened its energy market to retail competition on January 1, 2001. Customers could remain with their distribution utility, choose a competitive supplier or aggregate together to receive service. With the California market experiencing rolling blackouts and escalated electric bills, Arizona became concerned about electric restructuring. In 2002, the Arizona Corporation Commission ("ACC") stated, "The wholesale market is not currently workably competitive; therefore, reliance on that market will not result in just and reasonable rates."[4] In 2004 in a case before the Arizona Supreme Court, the court decided that the Arizona state constitution allocated the authority to prescribe just and reasonable rates solely to the ACC. Electric restructuring would lead to rates being set by participants in a competitive market. This decision held that rates set by a competitive market would imply that the ACC was neglecting its constitutional responsibility. Efforts to revisit electric restructuring have not been successful.

Arkansas

The Electric Consumer Choice Act of 1999 mandated electric competition by January 1, 2002. As the California energy crisis unfolded, energy traders poised to compete in the newly opened markets in Arkansas saw their stocks plummet, and Arkansas legislators, alarmed by the disastrous consequences of electric restructuring in California, postponed open access. Shortly thereafter Enron Corporation collapsed, with its market cap dropping from $77 billion to $500 million in a matter of a few weeks. As a result, Arkansas regulators determined that continued movement toward retail competition was not in the public interest.

2 ASU Energy Policy Innovation Council, October 2013.
3 Ibid.
4 Ibid.

Montana

In 1997, the Montana legislature voted to pass an electric restructuring bill. Montana Power then sold its electric generating assets as well as a portion of its distribution assets for $2.5 billion, funneling the profits into a telecommunications company, Touch America, which then went bankrupt and dissolved within 19 months, taking the pensions of Montana Power workers and stockholders' investments with it.[5] By the summer of 2003, electricity prices in Montana had risen by 15%.[6] Consequently, politicians began to agree that electric restructuring had been a huge mistake. The state's power companies were allowed to purchase generation, and retail competition was suspended. There are not currently plans to re-introduce a competitive electricity market.

Nevada

Nevada flirted with, but never consummated, a transition away from a regulated monopoly structure to a competitive, retail electric market in the late 1990's and early 2000's. The first official legislative steps towards a restructured energy market came from a 1995 resolution. That resolution kickstarted a process that dominated the next six years of legislative sessions and regulatory proceedings. One of the first products of that resolution was a 360-plus page report produced by the state's regulatory commission, which after years of research, countless hearing and tens of thousands of pages in docket filings summed up their findings with the statement that "Implementation would be complicated, but achievable."[7] Despite thousands of man-hours and countless hearings in front of the legislators and regulators, state leaders ultimately backed away from the effort after watching California's energy market implode and lead to mass rolling blackouts across the state.

Recently, a statewide ballot initiative was introduced to open up the electricity market to competition. The statewide ballot initiative went before voters in the November 2016 and 2018 general elections. After significant time and expense, the initiative failed.

New Mexico

New Mexico began on its path toward electric restructuring in January of 1998 with a call for legislative adoption of electric restructuring standards by the autumn of 1999 and full retail competition by January of 2001. In March 1999, however, electric restructuring hit a road block. The State Supreme Court ruled that the energy commission had exceeded its authority when it ordered Public Service of New Mexico to open its power lines to a competitor.

In April of 2000, New Mexico's investor-owned utilities sought a delay of the start of competition for a year. They claimed to be unprepared to implement new billing and computer systems. In August, even before the delayed date could come into play, New Mexico's AG, the New Mexico Industrial Energy Consumers, and the New Mexico Rural Electric Cooperative Association cited California's crisis and asked for a postponement of the decision to authorize the unbundling. New Mexico's energy market continues to be fully regulated.

Michigan

Michigan opened its retail electric market to competition in 2001. Public Act 141, commonly known as the "Customer Choice and Electric Reliability Act" mandated choice for all retail customers of investor-owned utilities

5 Great Falls Tribune, December 6, 2014.
6 Ibid.
7 What Nevada Can Learn from its Attempt (and Failure) to deregulate the energy market in the 1990s, November 17, 2017

by January 1, 2002. In anticipation of the introduction of competitive suppliers to the Michigan utility system, and to allow them to functionally participate in the retail electric market, the law directed the three largest utilities in the state (Consumers Energy, Detroit Edison, and Indiana Michigan Power Company) to file a joint plan by January 1, 2002 to permanently expand available transmission capacity by at least 2,000 MW by 2004, and directed all utilities serving the state to immediately take "all necessary steps" to connect merchant power plants with more than 100 KW to their transmission and distribution systems. In addition, existing utilities were required to relinquish commercial control over any generation exceeding 30% of relevant market capacity.

With regard to residential customers of Consumers Energy and Detroit Edison, Public Act 141 called for an immediate 5 percent rate reduction, and for a rate freeze until at least January 1, 2006. Under the implementation rules filed by these utilities and approved by the Michigan Public Service Commission, customers that failed to choose an alternative supplier, or that were not offered service from another supplier, would retain total service from their existing utility company. In addition, Public Act 141 imposed certain protections for residential customers, including increased winter shut-off protection for senior citizens and low-income customers.

For a variety of reasons related to high wholesale prices and low retail price caps, and competitive choice of suppliers, few consumers switched electricity suppliers. As a result, in 2008, the governor of Michigan agreed to cap participation in electric choice programs, guaranteeing utilities a 90 percent market share, in exchange for a commitment to deploy more renewable energy. Michigan has since debated fully opening its energy market to competition but has not done so to date.

Virginia

In 1999, the Virginia General Assembly passed a law that was intended to restructure Virginia's energy market and bring competition for electric generation to the Commonwealth. After several years, however, the General Assembly determined that sufficient competition had not developed, primarily due to high gas prices and low retail rates, and that retail electric restructuring of electric generation should not go forward. Therefore, in 2007, the General Assembly passed a comprehensive re-regulation law. The Re-Regulation Act established new procedures for reviewing each utility's rates and earnings. The law also allowed utilities to recover certain costs, including money spent on new power plants and renewable energy programs, outside of their base rates and through new single-issue rate riders called rate adjustment clauses. Currently, customers using at least 5 megawatts a year or any customer that will use 100 percent renewable energy can buy electricity from a company other than the regulated utility. There has been no progress to date in moving forward with full retail competition.

APPENDIX 8: RESOURCE ADEQUACY, SYSTEM PLANNING, AND RELIABILITY

Purpose of Report

This report was prepared by Concentric to provide information and insights on the potential impact of ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment") on resource adequacy and bulk power system reliability in the state of Florida. This report discusses potential impacts on resource adequacy in terms of the generation resources to meet customer demand, the unique nature and isolation of peninsular Florida and potential impacts of jurisdictional changes on system reliability.

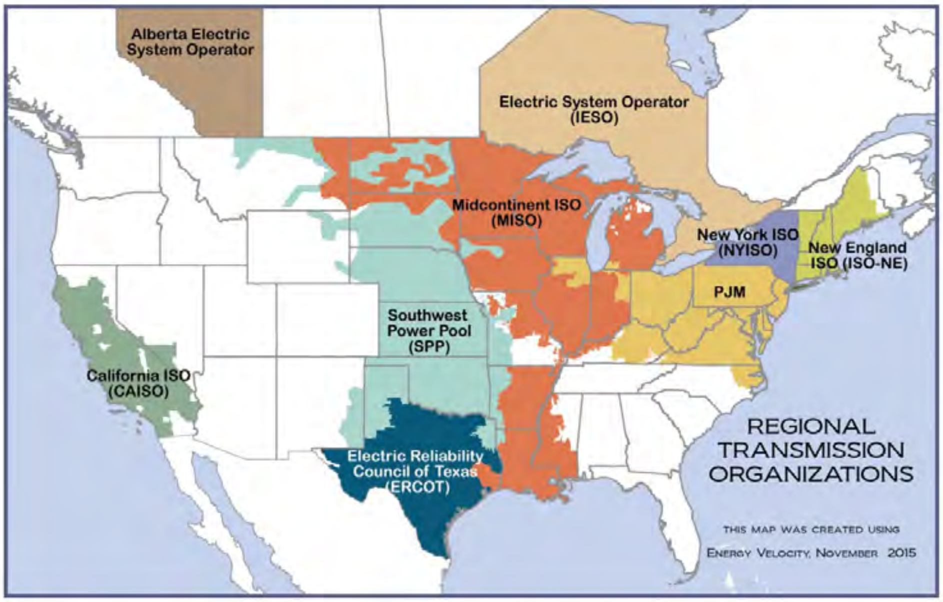
Background

Currently, electricity service is provided either by rural electric cooperatives, municipal electric companies or investor owned utilities ("IOUs"). The state's IOUs are vertically integrated and are regulated by the Florida Public Service Commission ("FPSC") and other state and federal regulatory bodies. The Amendment would provide all customers of Florida's IOUs the right to choose their electricity provider, and the right to generate electricity either alone or in association with others. IOUs would be limited to the "construction, operation, and repair of electrical transmission and distribution systems." IOUs would no longer own generation or transmission and distribution, and the existence of sufficient generation and other supply resources, as well as transmission investment, would be shifted to competitive market forces under the jurisdiction of federal regulatory bodies.

Implementing full retail choice as proposed in the ballot measure, and the right to engage in electric generation, would require the design, implementation, ongoing administration and monitoring of functioning wholesale and retail electricity markets. While there are a very small number of states where retail choice is available without a competitive wholesale market (e.g. Georgia), the ability to choose a retail provider in these states is limited to large commercial and industrial customers. In order to achieve the promised benefits of full retail reform, a functioning wholesale electricity market is necessary to facilitate the buying and selling of electricity for all retail customers. All states that have restructured their electricity markets to provide full retail choice (commercial, industrial and residential) are part of either an ISO (Independent System Operator) or an RTO (Regional Transmission Organization). ISOs/RTOs are not-for-profit entities that were formed to perform three basic functions: (1) operate the bulk electric power system, (2) develop, oversee, and administer the wholesale electric market, and (3) manage the power system planning processes to address transmission needs. Florida, like many traditionally regulated states, does not currently have an ISO/RTO or like organization.

A number of traditionally regulated states are part of an ISO/RTO but do not have a competitive retail electric market/retail choice. The current configuration of ISOs/RTOs is shown in the figure below.

FIGURE AP8- 1: MAP OF CONTINENTAL ISO/RTO FOOTPRINTS[1]



Florida is geographically isolated from existing ISO/RTOs, meaning that it would likely need to establish its own wholesale power market to manage the services that would be required to support the form of restructuring contemplated in the ballot initiative, which would restructure the electric market at both the retail and wholesale levels. As discussed in more detail below, forming and maintaining a functioning wholesale market is a very lengthy process, and will require substantial investment in the development and on-going administration of the competitive market, including the establishment of an ISO/RTO.

Key Conclusions

Three elements of restructuring combine to give Florida reason to be concerned about the impacts of restructuring on reliability and resource adequacy. These are: (1) the transfer of jurisdiction from the FPSC to the FERC; (2) the abandonment of integrated resource planning processes and recourse to regulated utilities to build infrastructure to accommodate growth, efficiency and environmental policy; and (3) the ongoing challenges of incenting new entry in competitive markets. It is precisely these three factors that have caused several states (e.g., Connecticut, Illinois, Maryland, and New Jersey) to take belated "re-regulation" actions in an attempt to address reliability concerns that restructuring theorists, led by Enron and academicians, had successfully argued would be taken care of by "the market."[2,3] Further, the unique nature and isolation of peninsular Florida introduces additional complexities that must be considered and included in the analysis of the costs and benefits of retail energy market reforms in Florida.

1 Federal Energy Regulatory Commission, Regional Transmission Organizations (RTO)/Independent System Operators (ISO), October 18, 2018, https://www.ferc.gov/industries/electric/indus-act/rto.asp

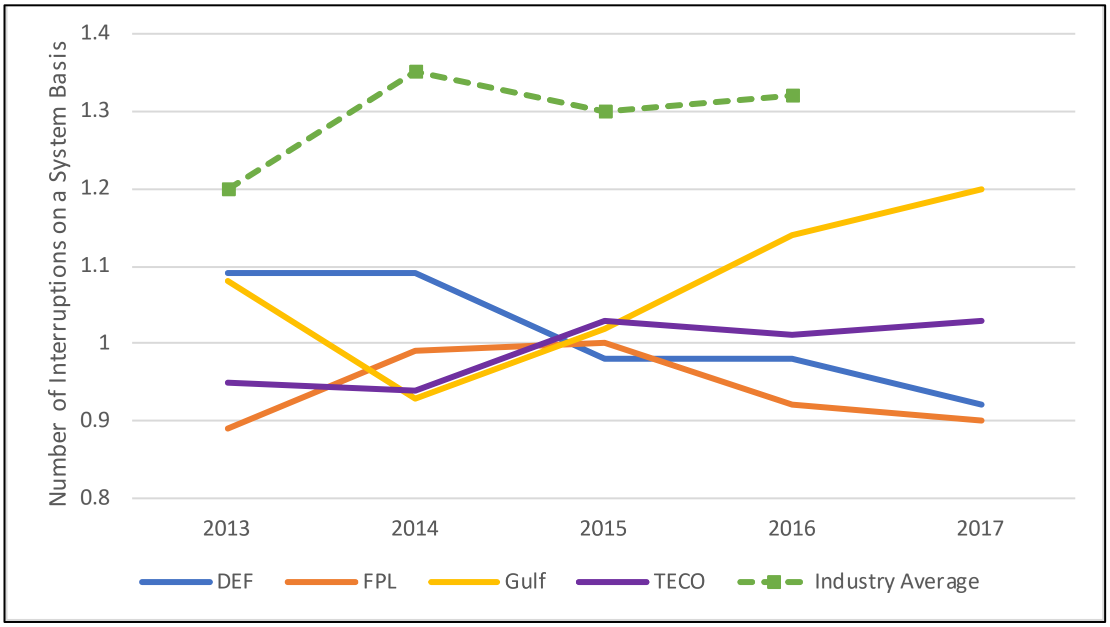
2 Wayne, Leslie, "Enron's Many Strands: The Politics; Enron, Preaching Deregulation, Worked the Statehouse Circuit," *New York Times*, February 9, 2002.

3 Hogan, William, "Restructuring the Electricity Market: Institutions for Network Systems," Harvard University, April 1999.

Resource Adequacy

One of the most significant concerns with the proposed ballot measure is the potential threat to resource adequacy in Florida. Currently, IOUs are responsible for the planning of, investment in, and maintenance of the electric grid, including ensuring sufficient generation and other resources (such as demand side management and demand response programs) to meet customer demand. The FPSC provides regulatory oversight of these functions. Over time, this has resulted in Florida having a high degree of reliability. For example, a review of recent system reliability data shows that the major Florida IOUs demonstrate considerably higher system reliability than the industry wide averages based on widely accepted measures, as shown in the tables below. This exceptional performance is the result of not only the proper planning and maintenance of the electric delivery system, but also a deliberate approach to generation resource planning to ensure that generating resources are available to meet customer demand.

FIGURE AP8- 2: SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX[4]



[4] Review of Florida's Investor-Owned Electric Utilities 2017 Service Reliability Reports; 2016 Distribution Reliability Study 2017 IEEE PES General Meeting.

FIGURE AP8- 3: SYSTEM AVERAGE INTERRUPTION DURATION INDEX[5]

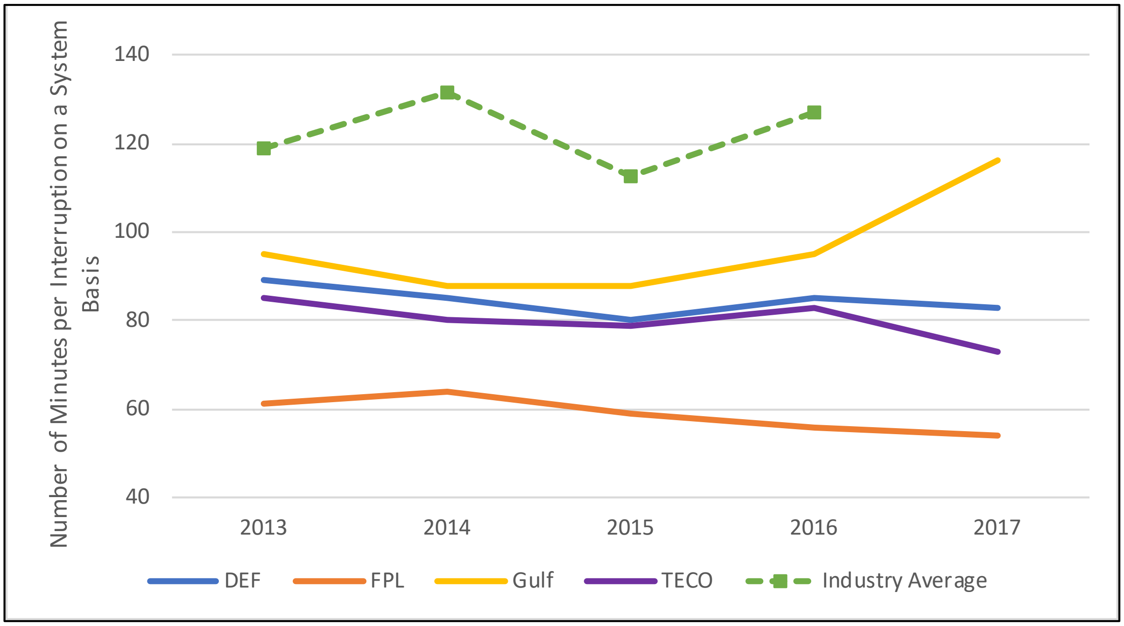
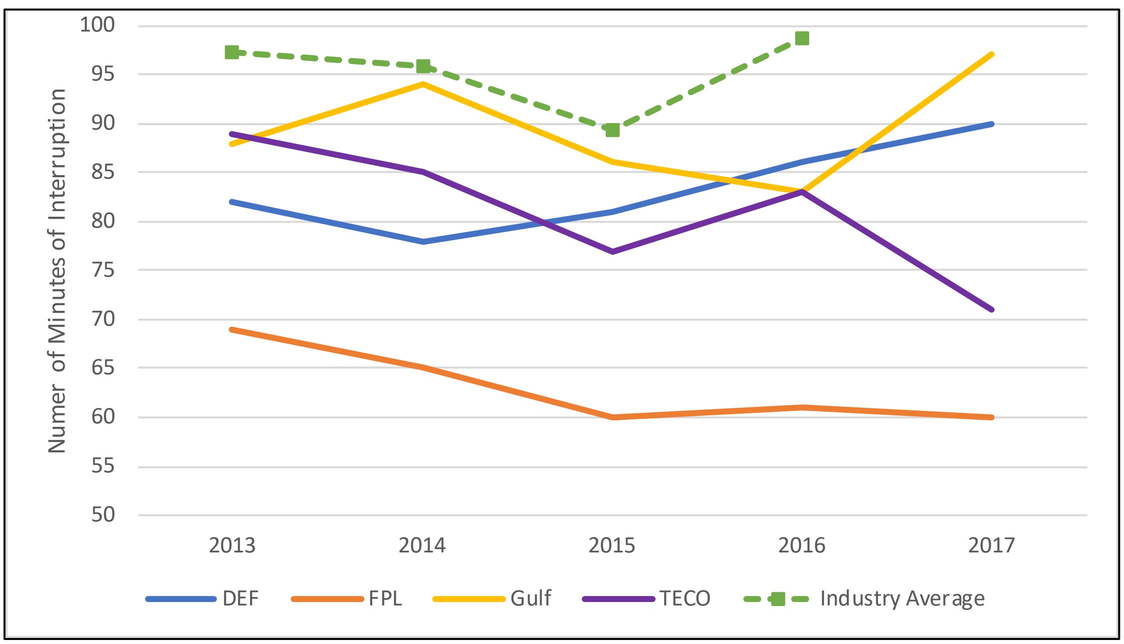


FIGURE AP8- 4: CUSTOMER AVERAGE INTERRUPTION DURATION INDEX [6]

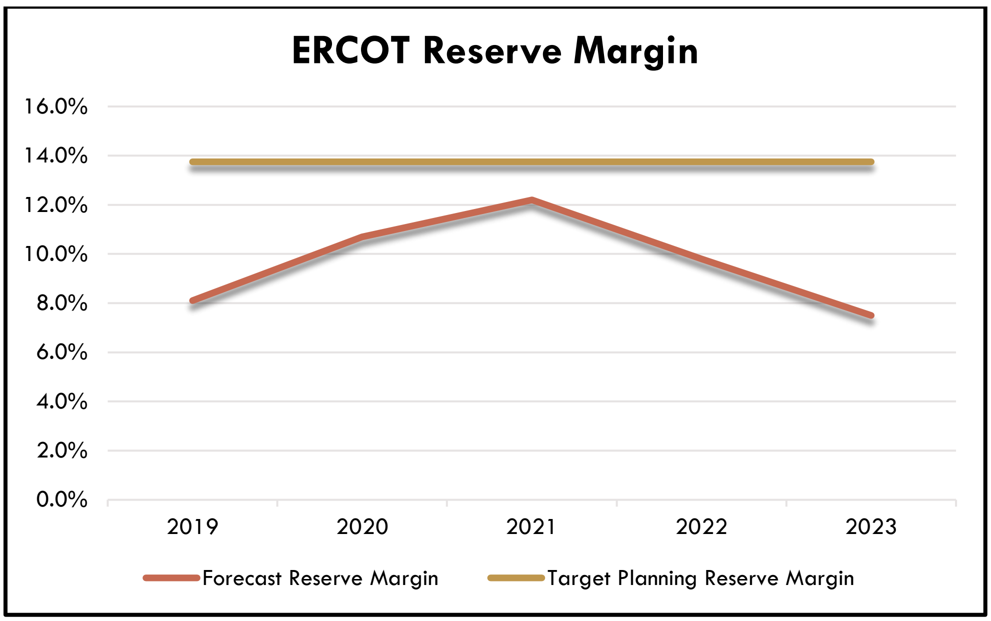


5 Ibid.
6 Ibid.

This planning of generation resources that is so critical to the provision of reliable service is a casualty of restructured markets, under which the amount and type of new generation is left to market forces. In the case of Florida, this resource planning void would happen at precisely the time when fuel price, technology, and environmental regulation uncertainties necessitate constructive, long-term resource planning among regulators, utilities, and the broad group of stakeholders that depend on a reliable, affordable, environmentally responsible portfolio of resources.

Experience has shown that restructured electricity markets struggle with the how to provide the incentives necessary to encourage generation when and where it is needed. In markets where electric utilities are prevented from owning generation, there is no longer any utility responsibility for generation resource planning to ensure reliable service. Merchant generators' short-run, profit-driven decisions to construct and retire generation capacity replace the vital role served by integrated resource planning. In Texas, this has resulted in shrinking reserve margins, as shown in Figure AP8- 5 below.

FIGURE AP8- 5: ERCOT RESERVE MARGINS 2019-2023



Source: ERCOT.[7]

When this information was released by ERCOT in December 2018, Texas Public Utility Commission Chair DeAnn Walker referred to the report as "pretty scary." A few weeks later, ERCOT announced that a 470 MW plant was being mothballed, which further reduced ERCOT's projected 2019 reserve margin from 8.1% to 7.4%, far below its target planning reserve margin of 13.75%.[8] With this announcement, PUC Chair Walker stated, "I was already concerned, and with [this plant] coming out, it's heightened my concerns."[9] It should be noted that part of the reason for this shortfall is cancelation of projects that had been planned. In particular, three

7 2019-2023 reserve margins from ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT Region, 2019-2028, December 4, 2018, p.9. As noted below, some industry participants are advocating for a capacity market that would alleviate these issues, but after almost 20 years, nothing has been implemented.

8 On Dec. 26, 2018, it was announced that the Texas Municipal Power Agency's 470 MW Gibbons Creek coal plant would be mothballed indefinitely, which reduces the forecast planning reserve margin for summer 2019 to 7.4%. Watson, Mark, S&P Global Market Intelligence, "Texas PUC directs ERCOT to implement price adder, market efficiency reforms" January 18, 2019.

9 Kleckner, Tom, RTO Insider, "Texas PUC Responds to Shrinking Reserve Margin" January 17, 2019.

proposed gas-fired projects totaling 1.8 GW of capacity and five wind projects totaling 1.1 GW have been canceled since May, and another 2.5 GW of gas, wind and solar projects have been delayed.[10]

Some economists have argued that the answer to the current Texas electricity crisis is to allow more price volatility and price spikes to promote incremental electricity production from existing facilities, as well as new facilities, to alleviate the threat of brownouts. In addition, several Texas electricity industry stakeholders have advocated for creation of a capacity market in the state, including the former Texas PUC Chairman.[11][12] ERCOT's own independent market monitor issued a report in June 2013 that concluded that "it is our view that if the planning reserve margin is viewed as a minimum requirement, implementation of a capacity market is the most efficient mechanism to achieve this objective."[13] Unfortunately, as the PJM experience indicates, it is not yet evident how to construct a capacity market that works as well as traditional regulation.[14]

In stark contrast to the plight of Texas under deregulation, Florida has robust reserve margins, due in large part to resource planning requirements as mandated by the FPSC. Pursuant to Florida Statutes, each IOU must submit a Ten-Year Site Plan to the FPSC which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. This plan is based on an integrated resource planning process that includes load forecast assumptions, a reliability analysis to determine when resources may be needed to meet expected load, and a screening of demand-side and supply-side resources to meet the expected resource need in the most cost-effective manner. This provides a solid framework for flexible, cost-effective utility resource planning to ensure resource adequacy and system reliability. The following figure shows Florida's reserve margins, which far exceed those of Texas and meet or exceed Florida Reliability Coordinating Council ("FRCC") criteria.

10 Kleckner, Tom, RTO Insider, "ERCOT Predicts Tight Reserve Margin for 2019" Dec. 4, 2018.

11 SNL Energy, "PUCT Votes Unanimously to Raise ERCOT Price Caps to $9,000/MWh," October 26, 2012.

12 Energy markets are designed to allow generators to recover their variable operating costs and utilize caps on offer prices to protect against extreme price levels. Many wholesale energy market designs include a capacity market which is designed to provide generators with the opportunity to recover their fixed operating costs. Energy only markets similar to ERCOT allow energy pricing to reach levels that are high enough to allow a generator the opportunity to recover its fixed costs in the energy market.

13 SNL Energy, "Market Monitor Sees Capacity Market as Most Efficient Route to ERCOT Reliability Goals," June 24, 2013.

14 As noted in the Implementation, Litigation and Other Costs White Paper, the implementation of the ISO/RTOs and new market structures within these markets are difficult and costly to implement. For example, PJM has a 2019 annual budget of $360 million. *Finance Committee Letter to the PJM Board, September 21, 2018.*

FIGURE AP8- 6: FLORIDA PLANNED RESERVE MARGIN

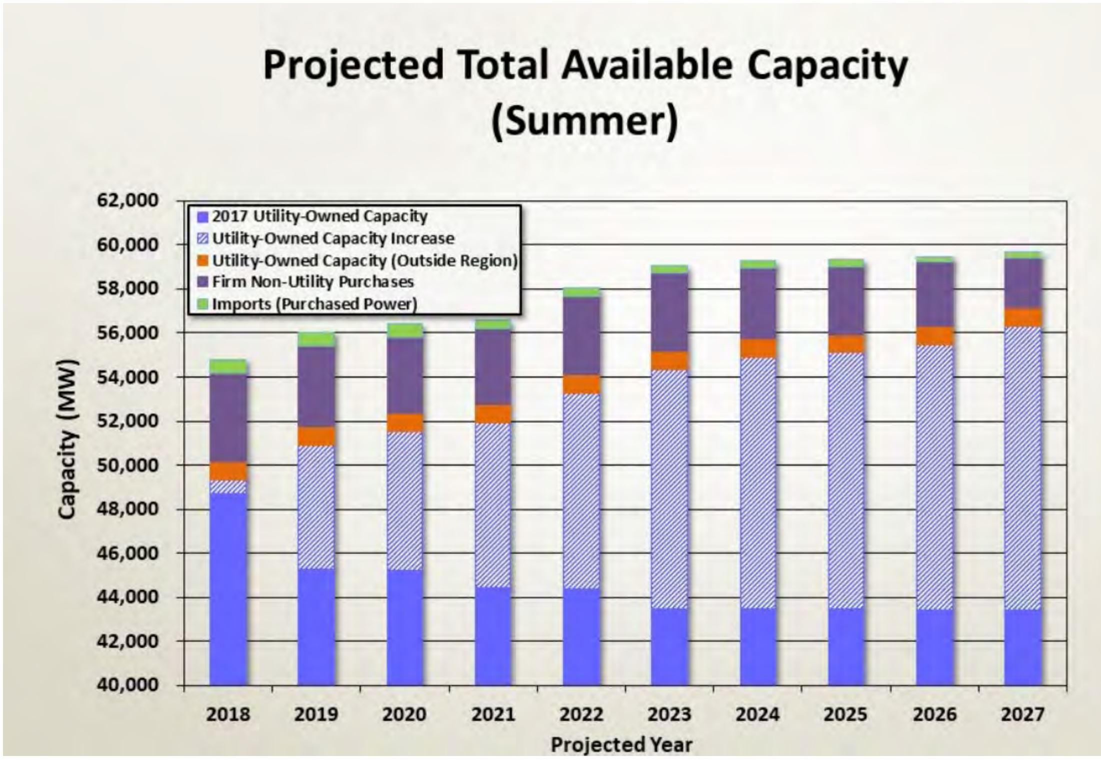
Source: Florida Reliability Coordinating Council, Inc.[15]

It is important to note in the above chart that reserve margins in Florida exceed the minimum planning reserve margin of 15% in both the summer and winter months. Under the current regulated market structure, Florida IOUs are required to plan their generation portfolio to meet firm load, which does not include interruptible industrial customers and other demand-side reduction programs for commercial and residential customers. These programs provide important demand reductions that displace generating capacity. Currently, these programs are funded through the IOUs and costs are recovered in rates. In a restructured market, these programs are subject to competitive market forces. To the extent that the competitive market does not adequately compensate these resources, the benefits of these resources will not be realized, and resource adequacy and system reliability will be at risk.

In addition, the ability of Florida to develop generation resources is illustrated in the following figure from the FRCC. As this shows, the Florida IOUs are well positioned to reliably develop needed generation sources, in a manner that is fully regulated by the FPSC, to the benefit of customers.

15 Florida Public Service Commission 2018 Ten-Year Site Plan Workshop, FRCC Presentation. Oct. 11, 2018. Slide 23.

FIGURE AP8- 7: FLORIDA PROJECTED AVAILABLE CAPACITY



Source: FRCC[16]

This comparison of Texas and Florida highlights the risks that are inherent in replacing coordinated resource planning with competitive market forces in ensuring the reliability of electric service. The ballot measure reflects "a solution without a problem," and is not designed to address challenges in Florida or improve the provision of reliable and low-cost electric service to Floridians. This is not to the benefit of Florida or Floridians.

In addition, over three decades ago, the FPSC created the Generation Performance Incentive Factor ("GPIF") as a financial incentive and penalty framework that would encourage the IOUs to "operate their generating units as efficiently as possible and minimize fuel costs borne by their customers."[17] Under the GPIF, the FPSC sets individual annual performance targets for each IOU base load generating resource. The GPIF mechanism is designed to reward efficiency improvements, which translate into fuel cost savings and reduced costs to ratepayers. Restructured markets do not have these types of mechanisms, and customers will not necessarily receive the benefits of efficiency improvements.

Reliability of the Bulk Power System

The reliability of the bulk power system is a significant concern posed by the ballot measure. The bulk power system is overseen by the North American Electric Reliability Corporation ("NERC"). Under the Energy Policy Act of 2005, the FERC was given the authority to select an "electric reliability organization" to develop and

16 Florida Public Service Commission 2018 Ten-Year Site Plan Workshop, FRCC Presentation. Oct. 11, 2018. Slide 25.
17 In re: Investigation of Fuel Cost Recovery Clause Application to Investor-owned Electric Utilities, Order No. 9558, issued September 19, 1980, in Docket No. 800400-CI.

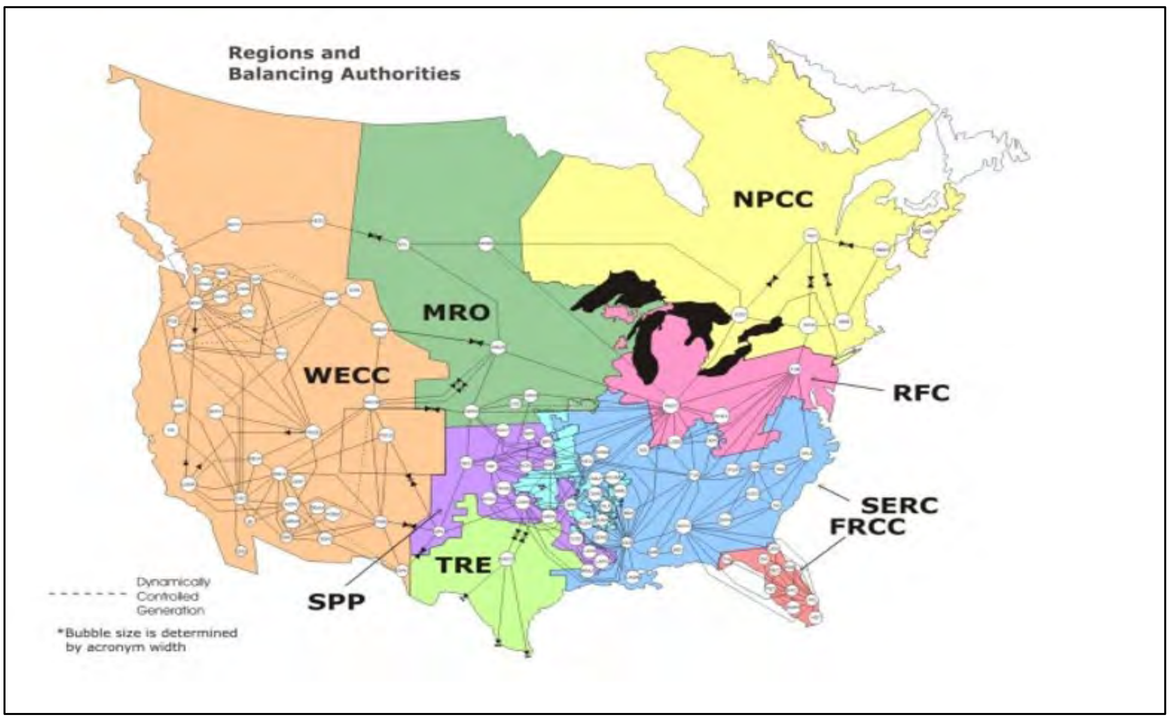
enforce standards to ensure the reliability of the nation's electric grid. In 2006, FERC certified NERC as the national electric reliability organization.

NERC was established as a not-for-profit entity with responsibility for ensuring the reliability of the electricity system in North America. NERC is an organization of lawyers, engineers, and analysts that is dedicated to setting mandatory and enforceable industry standards for the provision of electric energy.

NERC continuously develops, justifies, enforces, and seeks approval of bulk power system reliability standards. NERC has broad jurisdiction over all bulk power system owners, operators, and users. As an industry-led organization, NERC experts work to develop and enforce transmission planning and operational standards that include but are not limited to: i) resource and demand balancing; ii) critical infrastructure protection; iii) personnel performance, training, and qualifications; iv) protection and control; v) transmission operations; vi) transmission planning; and vii) interchange scheduling and coordination. NERC's authority allows them to assess penalties on electric utilities and service providers that fall out of compliance with relevant standards.

NERC oversees eight regional reliability entities that encompass all of the interconnected power systems of the contiguous United States and Canada, as shown in Figure AP8- 8.

FIGURE AP8- 8: NERC RELIABILITY REGIONS[18]



The FRCC was established in 1996 as a not-for-profit company incorporated in the State of Florida. FRCC's mission is to identify, prioritize, and assure the effective and cost-efficient mitigation of risks to the reliability and security of the peninsular Florida bulk power system. The FRCC serves as a regional entity with delegated authority from NERC for the purpose of proposing and enforcing reliability standards within the FRCC Region. The area of the state of Florida that is within the FRCC Region is peninsular Florida east of the Apalachicola

[18] A Primer on NERC, January 30, 2014.

River. Areas west of the Apalachicola River are within the Southeastern Electric Reliability Council ("SERC") Region. The FRCC includes all utility systems within the state's border, with the exception of the northwestern Panhandle, which is partially operated by Gulf Power Company and remains part of SERC.

A key responsibility of the FRCC is to annually assess the reliability of the bulk power system in peninsular Florida, and to ensure resource adequacy as required by the FPSC. As part of this annual assessment, the FRCC aggregates and reviews forecasted load and resource data reflecting expected conditions over the next ten years. The FRCC receives data annually from its members to develop its Regional Load & Resource Plan ("RLRP"). Based on the information contained in the RLRP, a Load & Resource Reliability Assessment Report (Reliability Assessment Report) is developed and submitted to the FPSC along with the RLRP. The Reliability Assessment Report evaluates the projected reliability for peninsular Florida by analyzing projections of resource adequacy, loss of load probability, generation availability, and generation forced outage rates.

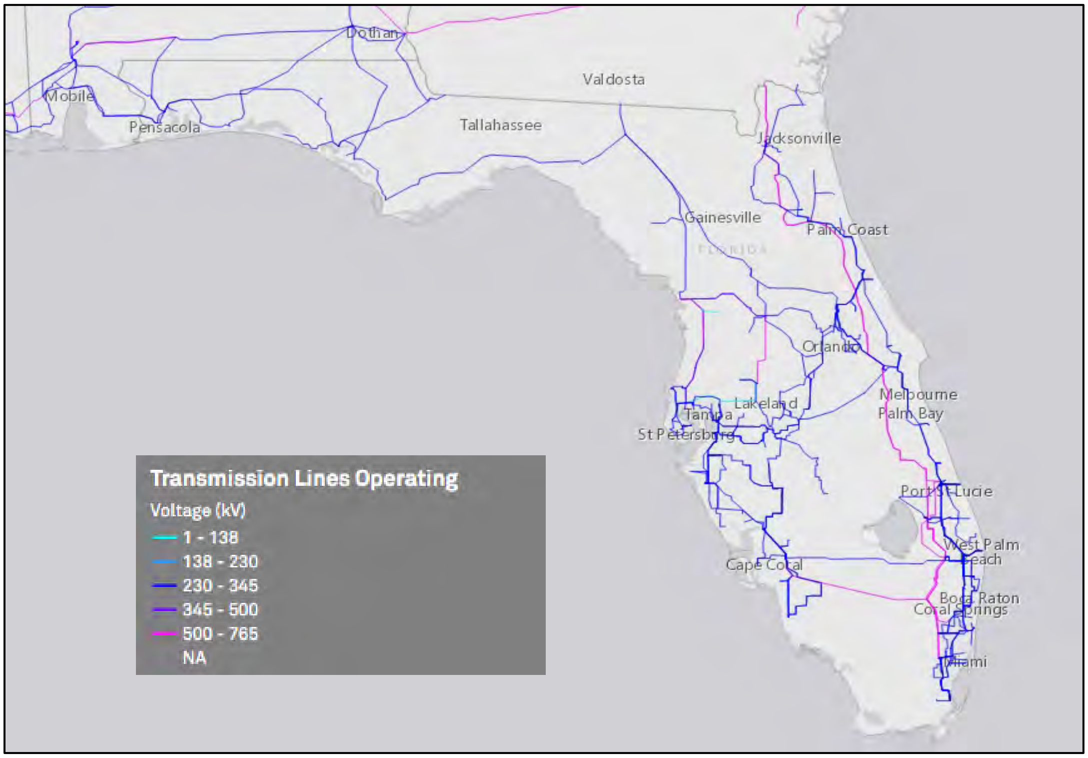
The FRCC Region participants perform various transmission planning studies addressing NERC reliability standards. These studies include near-term and longer-term transmission studies and seasonal assessments as well as additional sensitivity studies as needed to address specific issues (e.g., extreme summer weather), interconnection and integration studies, and interregional assessments. The studies analyze short term and longer-term bulk power system reliability to identify potential emerging concerns, monitor known concerns, monitor the effects of planned projects and identify major projects that may require long lead-times.

Peninsular Florida is relatively isolated in terms of its electric power interconnections. Its only link with another bulk power system is with SERC at the Florida/Georgia border and in the Florida panhandle through interconnections with Georgia Power. This makes FRCC among the regions in the US with the lowest potential to import or export power. Only the ERCOT region in Texas is more electrically isolated from its neighbors. In fact, Florida can import approximately 3,600 MW of generating capacity, compared to a peak load of approximately 46,000 MW, or less than 8% of peak load.[19] This means that Florida relies on its own internal generation to serve 92% of its customer needs. By comparison, New England has the ability to import over 20% of its peak energy needs.

In contrast to external connectivity, there is significant interconnectivity within Florida. The utilities within Peninsular Florida are interconnected via a high-voltage system made up of 500 kV and 230 kV lines. Double circuit 500 kV lines run the length of the state's eastern seaboard and enable significant power flows from the north to load centers in the southeast and around Miami.[20] Florida's transmission system is shown in Figure AP8-9.

[19] FRCC Load and Resource Plan 2018
[20] Ibid., pg. 24.

FIGURE AP8- 9: MAP OF FLORIDA ELECTRIC TRANSMISSION SYSTEM[21]



The impact of proposed electric restructuring on reliability and governance in Florida is complex and unclear at this time. First, as discussed above, there are currently two reliability entities in Florida – FRCC and SERC. It could be more efficient for the entire State of Florida to operate under a single regional reliability entity with a uniform set of transmission planning and operational procedures, especially given the unique geographic characteristics of the state. However, this would require Gulf Power Company to move from SERC to FRCC, which would be an expensive and time-consuming change. In addition, because of limited interconnectivity between the panhandle and peninsular Florida, any efforts to integrate these two regions for reliability purposes would be costly and time consuming.

Regarding the likely impact of the existing transmission configuration on the design and operation of a wholesale energy market, it is likely that the wholesale market design would require a unique load zone for the panhandle region of Florida that would be recognized as a transmission constrained region within the wholesale energy market footprint. This would result in higher wholesale electricity prices than the rest of the state since there would be limited ability for more efficient generating units located outside of the transmission constrained region to serve load within the transmission constrained region. The premium that customers in the panhandle region would pay is unknown at this time. Alternatively, the wholesale market could be designed such that the wholesale market was comprised of two entirely separate energy zones. This would require that the panhandle and peninsular Florida regions be effectively operated separately, with very limited ability to capture all the operational and economic benefits of the entire portfolio of generation resources in the state. This would introduce inefficiencies in the wholesale market that, while they cannot be quantified at this time, would certainly limit the region's ability to capture all the benefits of wholesale competition. To maximize the opportunity to

21 Ibid., pg. 22.

capture the promised benefits of restructuring, a significant amount of transmission capacity would need to be constructed to increase the connectivity between the peninsula and panhandle.

Jurisdictional Considerations

Restructuring would severely restrict the FPSC's jurisdiction over the process of selecting resources to power Florida's energy future: with a move to retail choice comes a loss of the utility's obligation to build and a corresponding loss of PSC jurisdiction over power prices. Instead, jurisdiction over regulatory policies that drive electricity prices will be transferred from elected Florida policymakers to the FERC, a federal agency whose broad agenda may not always align with Florida customers' best interests from both a cost and reliability standpoint. Under competition, energy marketers and independent power producers under FERC-jurisdictional RTO tariff rules, rather than state-regulated utilities, decide whether, when, and how to enter the market and what supply and demand-side resources to develop.

Because Texas restructured only the ERCOT region, the limited direct current interconnections with neighboring regions allowed the state to avoid FERC jurisdiction. As a result, the state regulatory commission and Texas law had final oversight over how electric service would be provided within ERCOT. Florida will likely not enjoy this same level of autonomy. The entire state is electrically interconnected to the other states in the eastern US interconnection and thus FERC will have jurisdiction over wholesale power sales and wheeling across the state.

In addition, the FPSC has developed several programs to enhance the efficiency of service at lowest cost. In addition to the GPIF, there is the Environmental Cost Recovery Clause, and Conservation Programs that all fall under FPSC jurisdiction. These programs promote a portfolio of resources that is low cost, efficient and environmentally conscious. Restructuring may undermine the FPSC's influence in all these areas causing higher cost, less efficiency, and less reliability to Florida's citizens.

State Efforts to Re-Regulate

Because new generation resources were not being constructed in sufficient quantities or at locations sufficient to meet system needs, at least five restructured states have taken actions to partially re-regulate their electricity markets by requiring incumbent utilities to enter into long-term contracts for new resources and/or are taking other actions to incent new generation: Connecticut, Maryland, New Jersey, Delaware, and Illinois. In each state, policymakers were motivated by concerns that reliability of service was being threatened by a failure of wholesale market design to spur investment in new generation. Although the response differed by state, the basic elements of the legislative and regulatory responses included a focus at the state level on resource planning (which was no longer being performed by the utilities) and the development of new generation resources (which can take three to five years) at locations necessary to meet system reliability needs or remedy transmission constraints.

The experiences of Maryland, New Jersey, and Delaware indicate that, while generation resources may be adequate from an RTO/ISO-wide basis, reliability must be achieved for each defined load area. Ultimately, the failure of PJM capacity markets to incent new generation within these transmission-constrained areas contributed to state actions to re-regulate their electricity markets. The fact that RTO/ISO rules require each load-serving entity (both regulated utilities and energy marketers, as applicable) to acquire sufficient resources to meet their load serving obligation does not ensure that sufficient resources will be available at the right time, in the right quantities, or at the right locations to satisfy those requirements.

Risk Related Impacts of Restructuring

Advocates of restructuring argue that competitive markets shift risk from customers to independent generators and retailers. In fact, restructuring creates a new set of risks for customers. Likely in response to an early-restructuring wave of bankruptcies, the more recent data on independent power producers' investments in generation capacity show that they actually take on little risk, focusing their investments almost exclusively on natural gas and renewable generation backed by PPAs. This dramatic departure from a balanced portfolio approach to fuel diversity and long-term resource adequacy in generation increases the risk of reliability challenges, price volatility, and supply disruption for customers. In addition, restructuring introduces the risk of market manipulation and energy marketer abuses and business failures.

Under a traditional regulatory model, utilities recover their prudently incurred operating costs and earn a regulated return on prudently invested capital. This cost recovery model provides regulated utilities with a lower cost of capital than merchant generators and energy marketers who must compensate their investors for the greater risks inherent in restructured markets. It is electricity customers, though, who ultimately pay this higher cost of capital embedded in energy marketers' prices.

A recent analysis of new generation capacity additions highlights the extent to which merchant generators' investments have been dominated by natural gas and renewables and the much greater fuel diversity shown by regulated generation additions in the past two years. This study concluded that: "Utility-developed new capacity shows a much greater diversity than the merchant projects, with roughly one-third natural gas, one-third solar, and another quarter wind. In contrast, new merchant capacity is 86 percent natural gas and 12 percent wind, with a small amount of storage and solar."[22] Currently, the FPSC oversees resource selection to meet customer needs, including the development of renewable resources to meet public policy goals. Under a competitive market structure, the FPSC would no longer have any input into resource selection, which would be subject to market forces. Competitive markets are not designed to ensure important fuel diversity benefits or to meet public policy goals, and the loss of FPSC oversight on resource selection introduces material risk to system reliability and the cost of energy in Florida.

Restructured markets undervalue baseload plants' contribution to resource adequacy.[23] Moreover, because large baseload plants have high fixed costs and low operating costs, their owners' cost recovery is highly exposed to risk of fluctuations in dispatch by regional markets. In contrast, natural gas-fired generators have relatively low fixed costs and higher variable costs, which makes gas-fired generation less risky to build and to own. The higher risks faced by baseload plants makes it difficult for generators in a restructured market to justify investing shareholder capital in upgrading existing coal plants where such investments would otherwise be economically justified.

Under the current regulatory model, Florida utilities conduct long-term planning under the oversight of the Commission and invest in adequate generation resources to meet their customers' demands. The current model ensures that Florida utilities have "steel in the ground" with a diverse portfolio of resources sufficient to keep the lights and air conditioning on for their customers. Municipal electric utilities and cooperatives in Florida are part of the integrated Florida generation and delivery system. These citizen-owned utilities have enjoyed the system stability provided by FPSC-directed resource adequacy for the IOUs. While municipalities and cooperatives are excluded from the deregulation initiative, it is very likely that their costs are also going to go

22 Caplan, Elisa, "Financial Arrangements Behind New Generating Capacity and Implications for Wholesale Market Reform" American Public Power Association (July 2018), p. 1.

23 Baseload plants are generally understood to be plants that provide a continuous supply of energy to the system on a 24/7 basis, except for maintenance and forced outages.

up as the generation assets previously owned by IOUs no longer provide a stable and reliable statewide system that municipalities and cooperatives can rely upon. In contrast, restructured states make no such requirements of their energy marketers who need not own a single megawatt of generation capacity to make promises to deliver power to customers.[24]

Furthermore, the security of fuel supply under a competitive market structure has the potential to be at risk, resulting in higher costs to the region. Many competitive markets across North America do not require generators to have firm fuel supply in the form of either firm gas supply or fuel oil back up. These jurisdictions have experienced severe fuel shortages at times when system reliability was at risk due to lack of firm fuel supply. For example, in the winter of 2014 alone, the cost of electricity at the wholesale level in New England totaled approximately $5 billion dollars due to high prices as a result of gas shortages.[25] A deliberate approach to resource diversity, which is absent in a restructured market, provides important protections against high costs, particularly as regions become more dependent on gas resources.

Finally, restructured states often find that their residential—particularly low-income and elderly—customers are the victims of unsavory marketing practices by financially unstable retailers who have defaulted on their supply obligations, raising costs for all customers.

24 See, e.g., the requirements for energy suppliers in Maryland (available at http://goo.gl/S14NoZ) and for retail energy providers in Texas (available at http://goo.gl/S2nMbx).

25 Winter Reliability Program Updated, Restructuring Roundtable, September 25, 2015.

APPENDIX 9: TEXAS AS AN EXAMPLE OF COMPETITIVE MARKETS

Purpose of Report

This report was prepared by Concentric to provide information and insights on the potential impact of ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment") based on the Texas experience with restructured markets. Advocates of competition in Florida point to Texas as the appropriate point of comparison.

Background

Texas deregulated its electricity market on January 1, 2002. Senate Bill 7 ("SB7") dismantled the state's investor-owned utilities ("IOUs") and fundamentally transformed the way Texans purchased their power. The IOUs were each were "unbundled" and broken into three companies: generation (power plants), transmission (power lines) and retail (customer service and billing). The law allowed municipally-owned utilities and cooperatives to opt out of restructuring.

Over the 15 years since deregulation was introduced in Texas, the market has experienced several unexpected challenges, and the benefits of this market transformation continue to be debated. A recent Rice University study called the results of retail choice into question:

> "The Texas experience is not universally accepted as a success. Notably, a recent study commissioned by the Texas Coalition for Affordable Power (TCAP 2016) claims that electricity deregulation in Texas has not delivered the intended outcome. In particular, the study notes among its major findings that Texans paid average residential rates that were 6.4% below the national average in the 10 years prior to deregulation but 8.5% higher in the 10 years following deregulation."
>
> And:
>
> "A recent study conducted by the Texas Coalition for Affordable Power (TCAP 2016) shows that customers in areas exempt from deregulation have on average enjoyed lower residential rates compared to those in deregulated areas."[1]

In addition to unexpectedly higher retail prices in Texas post-deregulation, the energy market also has experienced volatile prices, serious system reliability threats, and historically high customer complaints. The experience in Texas should give Floridians pause when considering the promised benefits of restructuring.

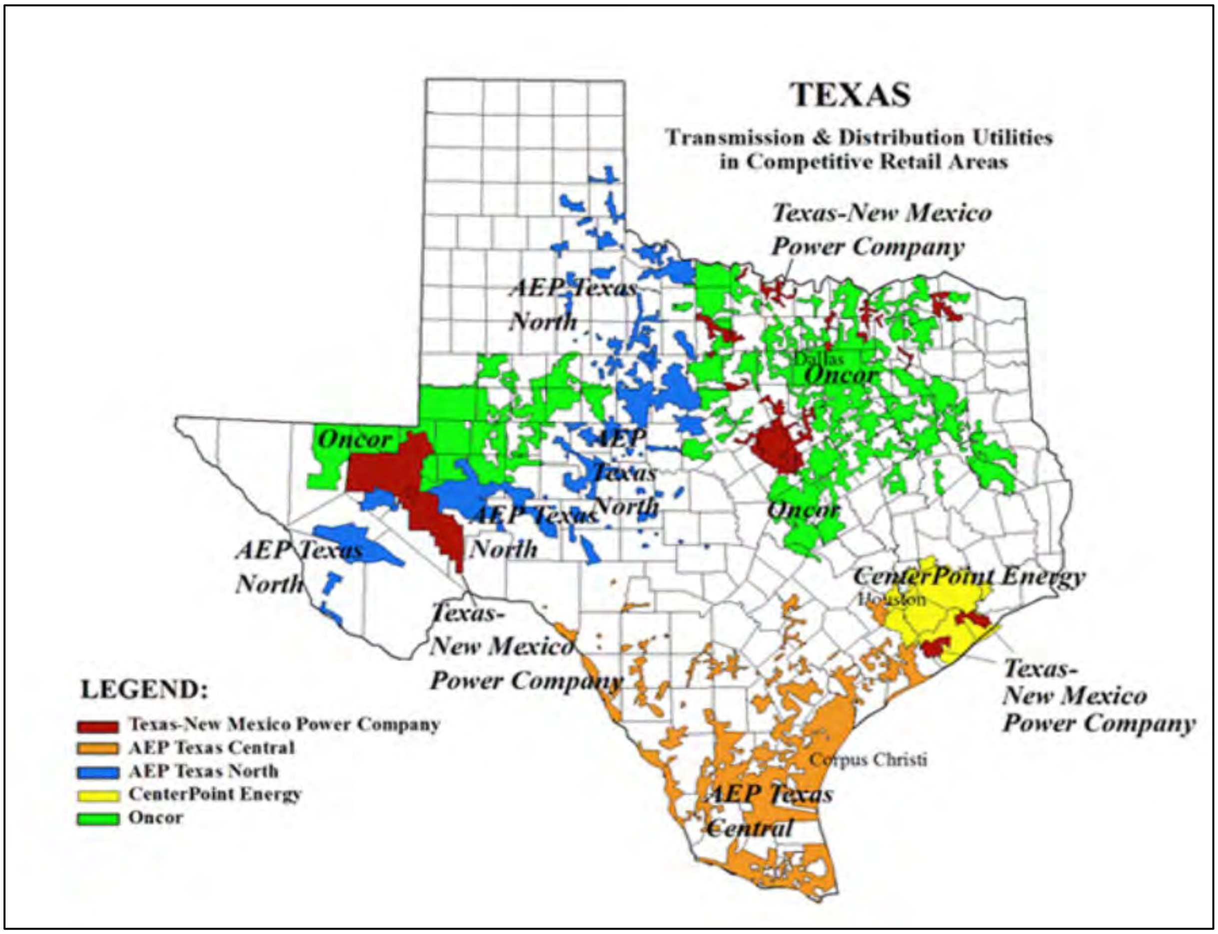
Comparison – Texas v. Florida

While the sponsors of the Amendment assert that the Amendment is modeled after Texas' restructuring there are a number of clear and important differences. Under SB7, vertically-integrated utilities operating within the ERCOT region were required to split into three discrete entities: generation companies, the still regulated transmission and distribution utilities, and retail electric providers. Under this "unbundling" provision, these entities were required to function separately — even if they remained under the same corporate ownership. As noted earlier, Texas did not prohibit the IOU ownership of transmission and distribution facilities, while the

1 Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Rice University, Hartley et. al, June 2017, pp.3 and 7.

Amendment specifically restricts IOUs to the construction, operation, and repair of electrical transmission and distribution systems. Further, SB7 did not codify a customer's right to generate and sell power, while the Amendment specifically allows for customers to produce their energy themselves or in association with others. Finally, SB7 did not require a single state-wide competitive market, and did not result in a complete restructuring across the state, as shown in Figure AP9- 1. This was due to the fact that approximately 30% of the state was served by rural electric cooperatives and municipal utilities, both of which were allowed to remain vertically integrated under SB7. The Amendment, however, would restructure all areas within the state served by IOUs, including remote areas where transmission interconnections are limited.

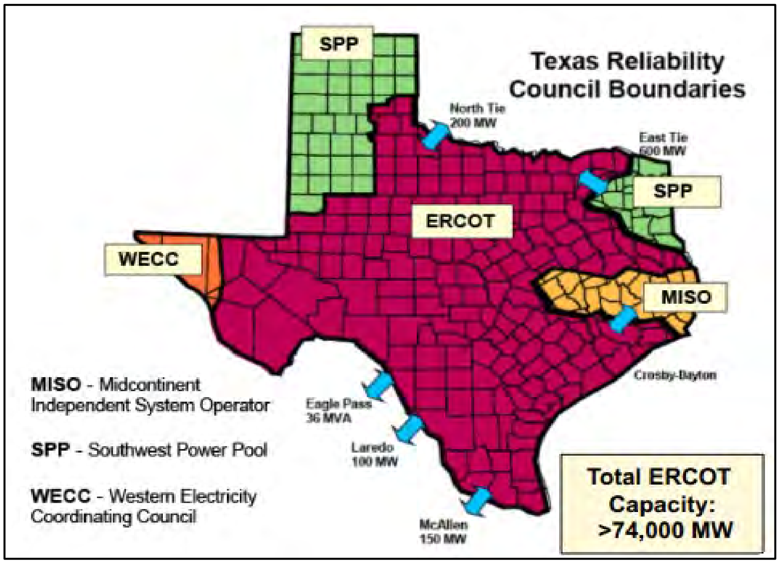
FIGURE AP9- 1: COMPETITIVE RETAIL AREAS IN TEXAS[2]



2 Public Utilities Commission of Texas.

Furthermore, Texas was not required to operate within a single wholesale market under restructuring, as shown in Figure AP9- 2.

FIGURE AP9- 2: WHOLESALE MARKET STRUCTURE IN TEXAS[3]



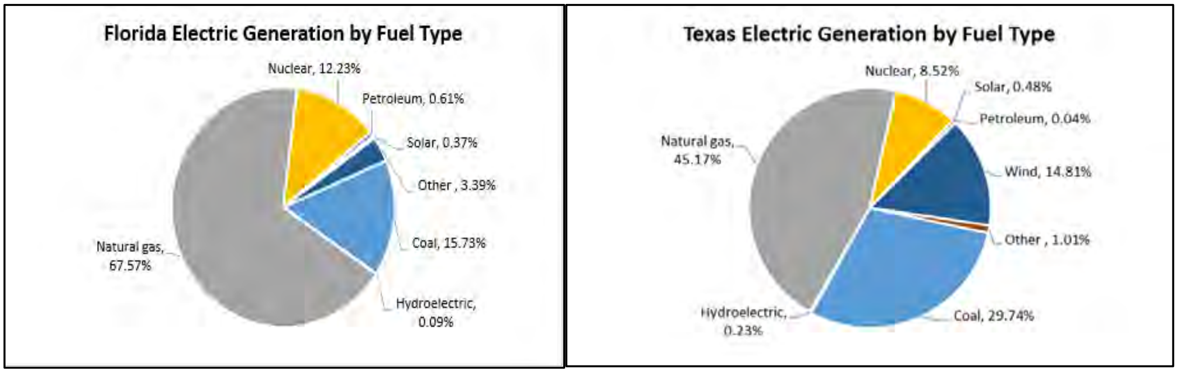
Importantly, because Texas restructured only the ERCOT region, the limited direct current interconnections with neighboring regions allowed the state to avoid FERC jurisdiction. As a result, the state regulatory commission and Texas law had final oversight over how electric service would be provided within ERCOT. Florida will likely not enjoy this same level of autonomy. The entire state is electrically interconnected to the other states in the eastern US interconnection and thus FERC will have jurisdiction over wholesale power sales and wheeling across the state.

In addition to jurisdictional concerns, the Amendment calls for a single state-wide wholesale market, which will create challenges with transmission constraints and efficient and economic market operation. Transmission systems were not built with deregulation in mind, but rather were built by each utility to serve their own customers with relatively few links to one another that existed for reliability purposes. As a result, there are areas of Florida, specifically the Florida Panhandle with limited interconnectivity that will hamper the free exchange of electricity under restructuring.

In addition to the fundamental differences in approach between Texas and Florida, there are important structural differences between the two states that do not lend themselves to a direct comparison between the two states. Importantly, Florida is far more dependent on natural gas, as shown in Figure AP9- 3.

3 Public Utilities Commission of Texas.

FIGURE AP9- 3: FUEL MIX – TEXAS VS FLORIDA[4]



In addition, governance under Texas restructuring will likely be very different from governance that would be expected in a restructured Florida energy market. Texas was able to avoid federal jurisdiction due to its direct current ("DC") ties, which are asynchronous transmission links that allow ERCOT to pass electrons externally in a controlled fashion. The Federal Power Act holds that federal jurisdiction follows the flow of electricity and since electrons do not "freely" flow across DC ties, ERCOT remains free from FERC oversight and maintains jurisdictional autonomy. It has been argued that the legal autonomy enjoyed by ERCOT has allowed for much more nimble policymaking in Texas, especially after restructuring. It is doubtful that Florida will enjoy this autonomy and will more than likely cede jurisdictional oversight to the FERC.

Experience with Restructuring in Texas

Bankruptcies

In 2014, roughly twelve years after the introduction of electric competition in Texas, Energy Future Holdings, the then-parent of Luminant Generation Company and Oncor Electric Delivery, filed for bankruptcy, representing of the largest Chapter 11 bankruptcy filings in corporate history. The filing also marked the colossal collapse of a heavily-leveraged $45 billion bet taken by private equity firms, who borrowed enormous amounts of money on the wager that natural gas prices would continue rising and, in the process, elevate wholesale electricity prices. Instead, new natural gas exploration technology led to a fall in natural gas prices, and electricity prices were driven down to historic lows.

According to reports, EFH owned more than $36 billion in assets when it filed for Chapter 11 protections. But it also owed more than $49 billion to creditors and had no way to keep up with its debt payments. Most of the losses were accrued by the generation side of the company — Luminant — which operated in the wholesale power market. Warren Buffet, who invested $2 billion in EFH, described his involvement in the debacle as a "major unforced error."

In addition to the cost of the restructuring, which was estimated at $42 billion, law firms, banks and consultants continue to work on the bankruptcy case, almost five years later, receiving over $600 million, making it one of the most complex and expensive corporate bankruptcies in US history.[5] The total fees for all the professionals

[4] SNL
[5] Energy company's bankruptcy generating Enron-sized legal fees, The Texas Lawbook, March 29, 2018.

– for the lawyers, bankers, accountants, restructuring experts for all the companies involved – will probably hit $1 billion, according to the company's General Counsel.

Price volatility also caused the bankruptcy of some retail electric providers. Texas Commercial Energy ("TCE") filed for bankruptcy protection in 2003 following a sudden and dramatic rise in the price of wholesale electricity. Because TCE did not own generating assets, it acquired the acquired electricity in the wholesale market and then resold it on a retail basis to its customers. When the wholesale price of power exceeded the price TCE was charging its retail customers, TCE was unable to pay its bills as they came due.

Retail electric providers continue to churn in Texas. In 2018, Breeze Energy, a Dallas retail electric company with thousands of customers in Houston, was shut down by Texas regulators after the company defaulted on its financial obligations, leaving industry analysts to speculate that the anticipation of higher wholesale electricity prices this summer may have put the retail electric provider in a financial squeeze.

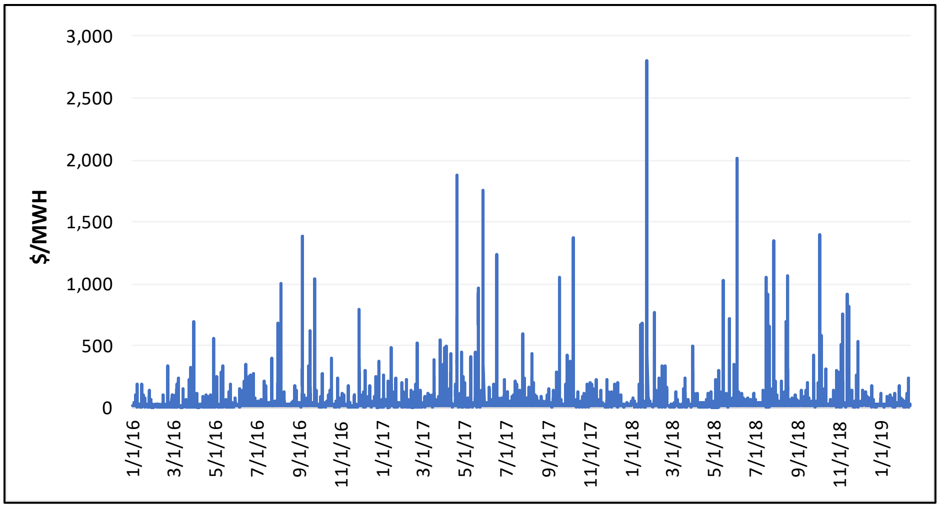
Wholesale Prices

Industry restructuring in Texas was touted as a path to lower energy prices for customers. However, studies and data show that the success of industry restructuring in Texas is a hotly debated issue. As early as 2001, when the electric choice pilot program was introduced, wholesale energy prices began spiking. The magnitude of the price spikes —100 times typical price levels — were similar to spikes seen during the California crisis. The first occurred on July 31, the very first day of the pilot project, when power that had been selling for between $10 and $45 per megawatt-hour ("MWH") suddenly shot up to $1,000 per MWH.[6] The Texas system operator blamed the first spike on an anomaly. However, on August 5, the market experienced another series of price spikes, with power prices surging to over 100 times its regular price. On August 8, wholesale prices spiked again — from a relatively typical level of less than $60 per MWH to $999 per MWH. An hour later, the energy price skyrocketed to $10,000 — but was adjusted downwards to $1,000 because of the price caps.[7] Although the spikes impacted a relatively small segment of the wholesale market (the pilot program was capped at 5% of the market), it foreshadowed some troubling market power issues and potential abuses. In the competitive energy market, the cost of the highest acceptable bid for power dictates the price to all successful bidders. For example, market participants may submit bids ranging from $50 per MWH to $1,000 per MWH. If the grid operator needs 100% of that power to meet demand, then all bidders get the last price submitted that meets system demand, or $1,000 per MWH — even those who submit bids offering to accept payment of $50 per MWH.

As is shown in below, competitive energy markets can be quite volatile. This has become the new norm in Texas and has important implications in a restructured market. Price volatility creates uncertainty that generators and suppliers will reflect in their pricing structures, driving up costs to customers. In addition, price uncertainly creates an investment disincentive, which drives down the ability of the system to reliability meet customer demand.

6 Deregulated Electricity in Texas, A Market Annual, 2018, pg.19.
7 Ibid.

FIGURE AP9- 4: ERCOT HOURLY REAL-TIME PRICES – HOUSTON ZONE[8]

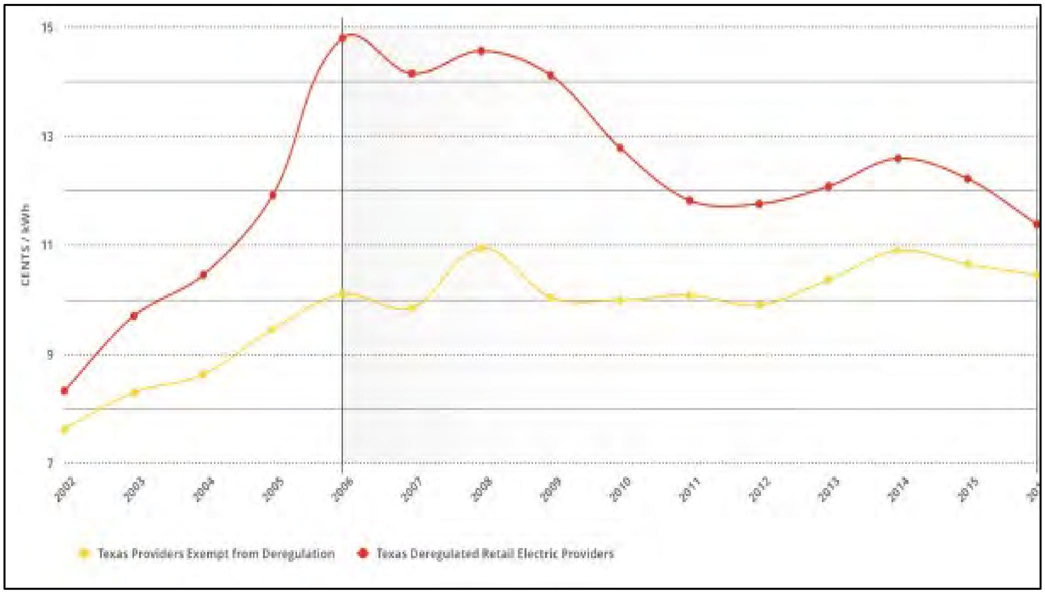


Retail Prices in Texas

Texas has experienced unexpected price increases since it opened its markets to competition. The Texas Coalition for Affordable Power ("TCAP") produces annual analyses that assess the competitive market and the impact on retail prices. In its 2014 study, TCAP found that restructuring has cost Texas customer $22 billion from 2002 – 2012.[9] In its most recent 2018 report, TCAP found that Texans have consistently paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation. This annual trend began during the very first year of the retail electric deregulation in Texas and has continued through 2016, as shown in Figure AP9- 5.

8 SNL Financial.
9 TCAP 2014 Electric Restructuring Report.

FIGURE AP9- 5: AVERAGE RESIDENTIAL ELECTRICITY PRICES IN TEXAS[10]



In Texas, electricity providers affiliated with the incumbent utility were required to charge a "price to beat" until the incumbent utility lost sufficient market share to alternative providers. This price was designed as a price floor to prevent the incumbent from offering artificially low rates to stifle competition and undercut new market players. When the price to beat was set, it included a 6% discount off the utility's base rates. However, prices in the deregulated areas steadily climbed as natural gas prices rose in the mid-2000s. From 2002 to 2006, the price to beat rose 88% and the competitive offers rose 62%. In contrast, rates in regulated areas of Texas rose only 24% during this period.

System Reliability Concerns

Electric competition in Texas has negatively impacted the amount of generation available to meet customer demand. Resource planning in competitive markets is replaced by market forces that are relied upon to send investment signals to incent new entry and retain existing generation. One way to measure the ability of the system to meet expected customer demand is by calculating the system "reserve margin." The system reserve margin measures the relationship between how much electricity generators theoretically can produce in a single instant and the forecasted peak demand for electricity by consumers. Because power shortfalls can put a system at risk for blackouts — especially during extreme weather events — the reserve margin measurement is a good indicator of system reliability. During the transition into deregulation, back in 2001, Texas enjoyed the highest reserve margin in the nation. This helped to calm the anxieties about deregulation after California's market began collapsing during that state's transition to deregulation. The public was assured in 2001 that Texas would not face reliability issues.

But such a claim could not be made in 2011. The National Electric Reliability Corporation ("NERC") reported ERCOT's reserve margin ratio in 2011 at about 14%, which marked a nearly 40% decline from pre-deregulation levels and far below the national average in 2011 of around 25%.[11] In fact, after 10 years of

---

[10] TCAP Report on Electricity Prices in Texas, April 2018.

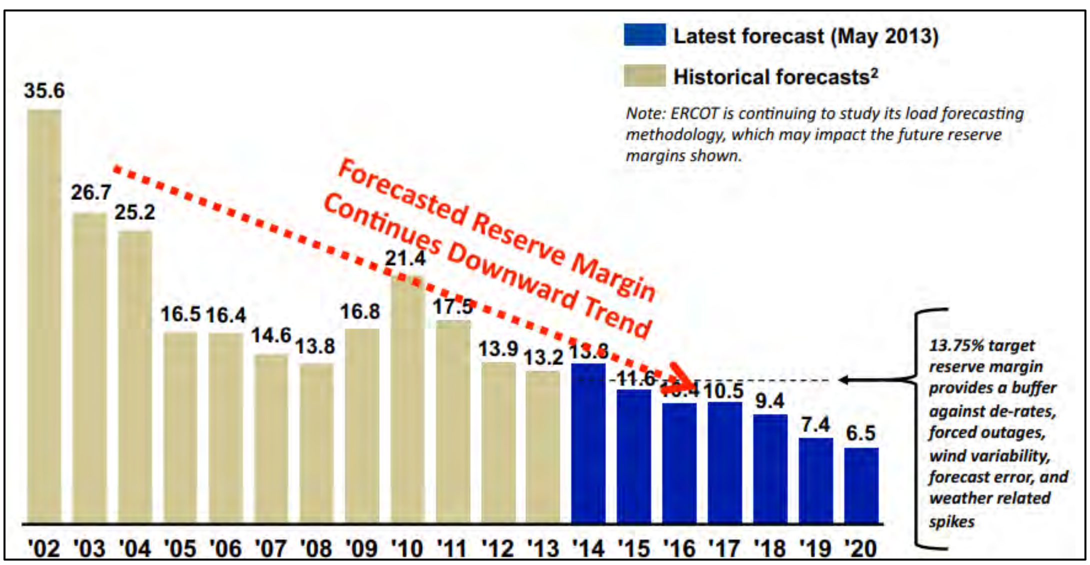
[11] NERC Long Term Reliability Assessment 2011.

deregulation, Texas possessed the lowest reserve margin in the nation, according to NERC. This was especially alarming, since electricity prices increased over this same time period. In 2012, NERC forwarded a letter to the grid operator expressing its concern about system reliability in Texas:

> "At its November 26, 2012 meeting, the NERC Board of Trustees (Board) discussed its concerns for the situation in Electric Reliability Council of Texas (ERCOT). While it was noted that NERC cannot order the construction of new generation or transmission, NERC is accountable for assessing the current and future reliability of the BPS and informing decision-makers. Therefore, the Board requested that NERC take follow-on actions with the organizations that are responsible for resource adequacy to ensure the parties are taking timely action.
>
> As identified in the assessment, one area of concern requiring immediate attention is the projected Planning Reserve Margin levels in the ERCOT assessment area. Capacity resources in ERCOT have drifted to a level below the Planning Reserve Margin target and are projected to further diminish through the ten-year period covered in the assessment. It is clear to me that these levels imply higher reliability risks especially the potential for firm load shed, and ERCOT will need more resources as early as summer 2013 in order to maintain a sufficient reserve margin."[12]

The reserve margin in Texas has continued to dwindle since the introduction of competition, as shown in Figure AP9- 6.

FIGURE AP9- 6: ERCOT SUMMER RESERVE MARGIN 2002-2020[13]



Competitive markets have introduced added system reliability risks in Texas in the form of blackouts. In early 2006, rolling blackouts in Texas left more than 200,000 people unexpectedly without power, including about 78,000 customers in the CenterPoint Energy service territory (around Houston) and about 80,000 customers in the North Texas service territory of TXU Electric Delivery. The crisis began when the grid operator saw usage begin to peak and concluded that it might not have enough generation online to meet demand. All available

12 NERC Letter to ERCOT President and CEO, January 7, 2013.
13 Association of Electric Companies of Texas, Inc. Update on the Texas Electric Industry, January 23, 2014.

generation was called to operate at its highest output. However, demand continued to spike, and the grid operator was forced to cut power to various industrial customers. A subsequent loss of four generators representing over 900 MW was too large of a contingency for the system to handle, and rolling blackouts were called. These rolling blackouts were the first in more than a decade.

ERCOT blamed a confluence of events, including the planned outage of about 14,000 megawatts of capacity for plant maintenance, a spate of unseasonably hot weather that went unpredicted by ERCOT's computers, and some unexpected last-minute plant shutdowns.[14] Officials pledged to make course corrections to better handle such events in the future.

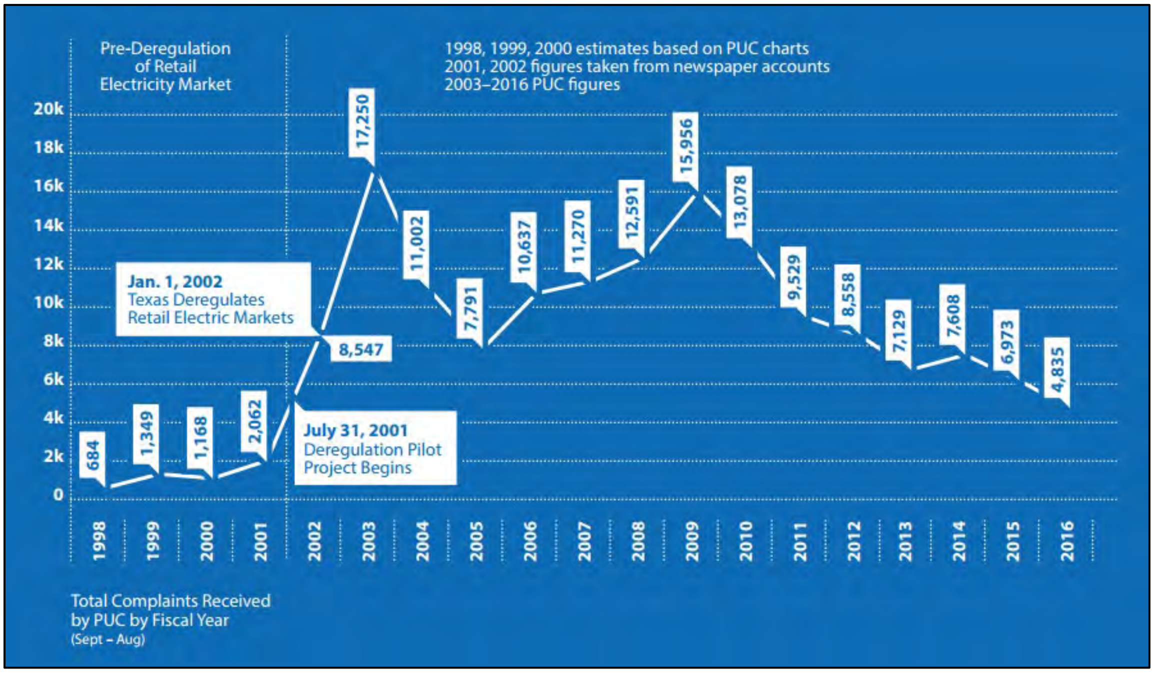
However, approximately two years later, on February 26, 2008, ERCOT officials took emergency action to avoid blackouts. A sudden loss in wind power, coupled with other factors, sent grid operators taking emergency actions once again to avoid a catastrophic system collapse. It was a serious emergency for the grid operator, and one that illustrated the inherent challenges associated with wind power. The inherent challenges with wind operation mean that generators have to remain on standby and ready to ramp up quickly. This represents reliability risks and added costs to the system, which are ultimately borne by customers.

CUSTOMER COMPLAINTS

The number of complaints regarding electric service filed at the Texas Public Utility Commission has increased steadily since the market opening and peaked in July and August of 2003, as shown in Figure AP9- 7.

[14] Deregulated Electricity in Texas, A Market Annual, 2018, pg.19.

FIGURE AP9- 7: ANNUAL ELECTRICITY-RELATED COMPLAINTS IN TEXAS[15]



Over the course of the fiscal year, the Texas Public Utility Commission Customer Service Division received about 17,000 electricity complaints — about half relating to billing, although many consumers also complained about service disconnections and faulty service. This would mark an all-time high for the number of annual complaints under the Texas deregulation law.[16] According to recent report on the history of deregulation in Texas, customer complaints quadrupled with the transition to deregulation in 2002 and have not returned to pre-deregulation levels. Although some of this increase can be explained by population growth and the use of the internet to facilitate the complaint process, the magnitude of the increase cannot realistically be explained by these two factors alone.

---

[15] TCAP History of Deregulation 2018, pg. 86.
[16] TCAP History of Deregulation 2018, pg. 32.

APPENDIX 10: IMPACT OF ELECTRIC RESTRUCTURING ON RETAIL ENERGY COSTS

Purpose

This report was prepared by Concentric to provide information and analysis regarding the impact of electric industry restructuring on retail electricity costs as Florida assesses the ballot measure "*Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*" (the "Amendment"). This report provides background considerations related to retail energy costs that are affected by electric industry restructuring. It discusses the nature and limitations of comparisons of electricity costs across states and summarizes the cost-related customer experiences in restructured states.

Background and Key Conclusions

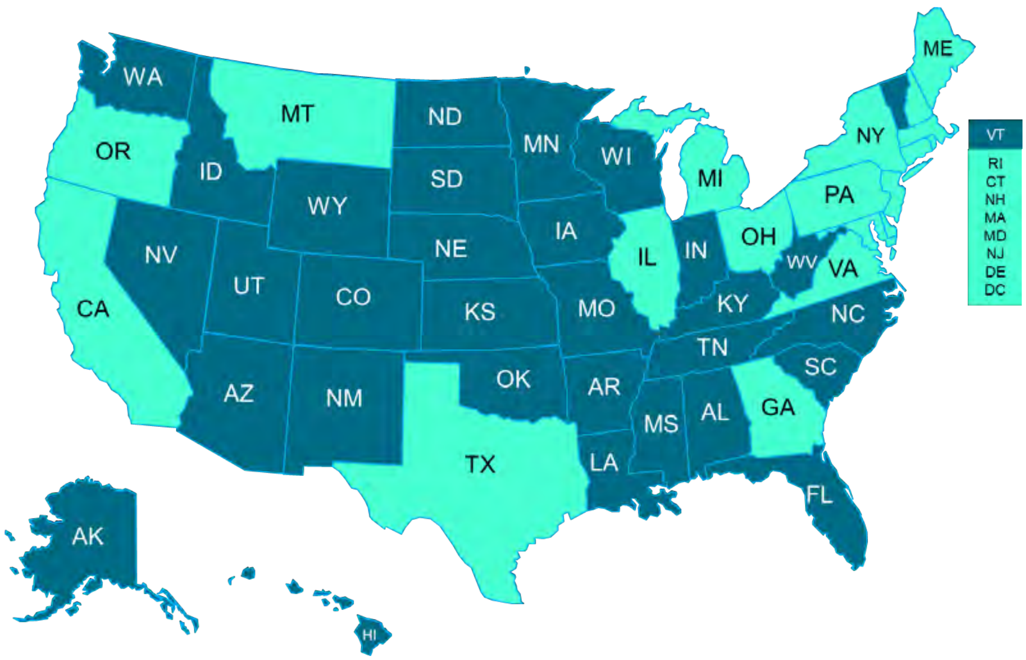
Debates concerning electric industry restructuring often center around the likely impact on electricity costs and prices, the prices paid by retail customers (including industrial, commercial, and residential customers as well as government facilities and other essential service buildings). A key driver for restructuring states in the late 1990s was high retail electric rates compared to other states. More recently, states that have contemplated restructuring but chosen to retain their traditionally regulated electric markets have cited a lack of clear price advantages, and other significant questions and concerns that have remained unresolved.[1] As discussed in more detail below, there is no conclusive evidence of a price advantage for customers in restructured states compared to those in regulated states. However, there is evidence that rates in restructured states are more closely tied to natural gas commodity prices than are rates in traditionally regulated states. Finally, there is evidence that the cost/price advantages that have accrued to customers in restructured states principally apply to larger commercial and industrial customers.

[1] A recent example is Nevada, which considered a form of restructuring beginning in 2016, but voted against pursuing that path in a 2018 statewide ballot initiative.

State-to-State Comparisons

States that have enacted a form of electric market restructuring are shaded light green in Figure AP10- 1, below.

FIGURE AP10- 1: STATUS OF ELECTRIC RESTRUCTURING IN THE CONTINENTAL UNITED STATES[2]



It is challenging to compare electricity prices across states due to substantive differences in the structure, regulation, and economic conditions affecting the power industry.[3] For example, a state's electricity rates reflect fuel prices, weather, regulatory costs, tax policy, and other factors that vary state-to-state. In restructured states, these prices also typically reflect state-specific rate caps or other mechanisms that are designed to protect customers from the forces of unbridled competition on at least a transitional basis. Further, retail electricity rates used in comparisons typically include many other components (e.g., transmission and distribution) in addition to the cost of generation. This does not eliminate the instructive value of an examination of other states' electricity rates and experiences with restructuring. It does, however, suggest that this examination be considered in a broader context and be used directionally or anecdotally rather than as an absolute.

Data provided by the Energy Information Administration ("EIA") and shown in the tables below are often used in academic literature to quantify the effects of restructuring. However, recent studies have backed away from EIA data because it "provides an incomplete assessment of total bills that residential, industrial and commercial customers receive"[4] Nevertheless, the figures below, based on EIA data are illustrative in that they show directionally how average electric prices have changed over time.

---

2 Electric Choice, Map of Deregulated Energy States & Markets (Updated 2018). Accessed 1/24/19, https://www.electricchoice.com/map-deregulated-energy-markets/

3 This limitation in state-to-state comparisons is noted in many academic studies of the effects of restructuring. See, for example, Borenstein and Bushnell (2018).

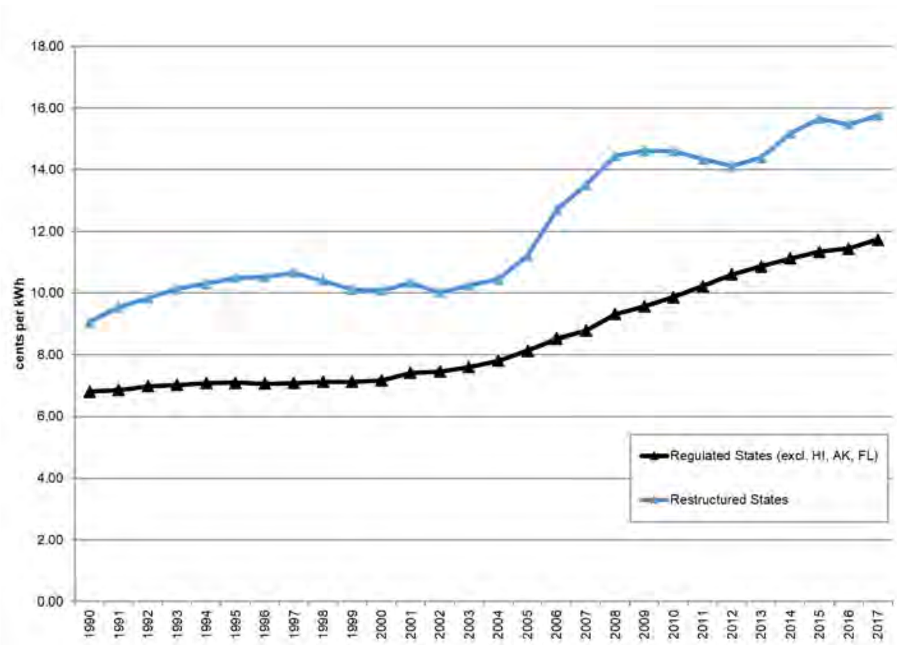
4 Dormady, N., Hoyt, M. Roa-Henriquez, A. & Welch, W. 2019. Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, at 4. See also: Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, at 28.

Concentric' s assessments of restructuring's impact on electricity prices and related effects of restructuring described in this paper are based a review of publicly available studies, reports and industry publications.

Impact of Restructuring on Rates

Figure AP10- 2, below, uses EIA data to compare prices in restructured and non-restructured states. This figure suggests that restructured states have significantly higher rates than traditionally regulated states. According to the data, from 1990 to 2017, rates in restructured markets have been on average 42% percent higher than rates in regulated markets.[5] Over the same period, rates in restructured markets have been approximately 26% higher than rates in Florida.

FIGURE AP10- 2: AVERAGE RESIDENTIAL RATE OF RESTRUCTURED AND REGULATED STATES (BEFORE AND AFTER RESTRUCTURING)

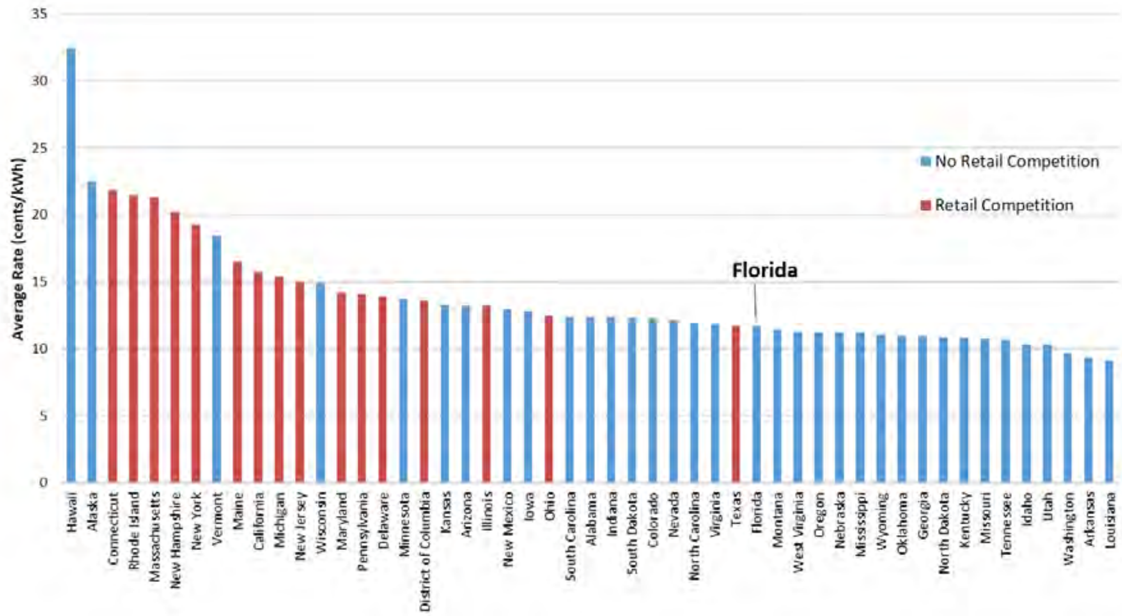


Data source: EIA Electric Power Monthly, October 12, 2018[6,7]

High electricity prices were a major driver of deregulation in states that have restructured. Unlike those states, Floridians enjoy electricity costs that are below national averages as shown in Figure AP10- 3 and Figure AP10- 4, below.

FIGURE AP10- 3: AVERAGE RESIDENTIAL RATES, STATUS OF COMPETITION

5 Regulated markets exclude Alaska, Hawaii, and Florida.
6 Rate calculations do not include fuel costs.
7 Restructured states include: CA, CT, DC, DE, IL, MA, MD, ME, MI, NH, NJ, NY, OH, PA, RI, and TX.



Source: EIA, Electric Power Monthly, October 2018

FIGURE AP10- 4: AVERAGE RATES BY CUSTOMER SEGMENT (UNITED STATES, FLORIDA)

	Residential	Commercial	Industrial	All Sectors
Florida - IOU	11.61	9.20	7.67	10.37
Restructured Average	16.24	12.71	9.53	13.32
U.S. Average	12.87	10.74	6.91	10.46

Source: EIA, Electric Power Monthly, October 2018

Many states have recently completed evaluations of whether residential and small commercial customers are better off with retail restructuring. The Massachusetts AG ("AG") developed a paper in March, 2018 to determine "whether residential consumers in Massachusetts pay more or less for their electric supply when they buy it from the competitive marketplace rather than their electric company (such as National Grid, Eversource, and Unitil); and (2) identify remedies if warranted."[8] The final analysis showed that "Massachusetts consumers in the competitive supply market paid $176.8 million more than they would have paid if they had received electric supply from their electric company during the two-year period from July 2015 to June 2017. A third year of data shows residential customers lost another $76.2 million, for a three-year total of $253 million."[9] This report looked only at residential electric supply and not the commercial or industrial market. The AG's recommendation was to eliminate the electric supply market for individual residential customers because the cost of retail supply was higher by far than the basic service provided by the utilities. The report also noted

[8] Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts, Massachusetts Attorney General's Office. March 2018, p. viii.

[9] Ibid., p. viii

that "Unlike the commercial and industrial market, where sophisticated buyers with demands for large volumes are likely able to negotiate more favorable rates, individual residential consumers are not getting a bargain."[10]

Other states have conducted similar studies. A Rhode Island evaluation conducted over four years found that customers who switched from their utility to retail providers had paid $56 million over the default service costs.[11] In Connecticut a study completed by the Office of the Consumer Counsel concluded that in 2015 customers who switched to a competitive supplier paid almost $58 million more than remaining with their default supplier.[12] A 30-month study conducted by the New York Public Service Commission found that customers who switched electric and gas suppliers paid nearly $820 million more than if they had remained with their default suppliers.[13]

A technical report written by the Guinn Center in 2018 to examine the Nevada Retail Choice Ballot Initiative debated whether retail choice would lower or raise electric bills. The study was ultimately inconclusive for many of the reasons discussed above, but it did find that the "….analysis of the experiences of other choice states does suggest that restructuring exposes ratepayers to the imperfections and challenges of the wholesale electric market, leading to heightened uncertainty around rate behavior."[14] The conclusion from the Guinn Center study is that there are not clear price benefits to electric restructuring and that it could create volatile rates.

Impacts of Price Caps

How states implement restructuring is a key consideration for comparisons of electricity prices across states. Some states imposed regulatory price caps on incumbent utilities' supply rates. This was done to protect customers from rapidly increasing market prices during the transition to a restructured market. In some circumstances, these regulatory constraints helped create short-run benefits by establishing the "price to beat" for merchant power providers, who then "beat" those prices for a period as the market developed. However, as these artificial price caps began to expire, the average price of electricity increased. When Illinois retail price freezes expired in 2007 "bills soared up to 55% for Ameren customers and 26% for those of Commonwealth Edison."[15] Maryland froze prices to customers who continued to rely on utility sales service at levels that were approximately five percent below pre-restructuring levels only to have them increase by over 70 percent as soon as the caps were removed.[16]

Cross-Subsidization Between Rate Classes

The promise of new pricing options and other services has not materialized for the vast majority of residential and small commercial customers. The substitution of cost-based utility generation (supported by resource planning) with market-based wholesale rates has added to the upward cost pressure for this large group of customers. In states like Ohio, where the electric restructuring law allowed utilities to either divest their

---

10 Ibid., p. 15.
11 National Grid: The Narragansett Electric Company, Standard Offer Supply Procurement Plan / 2019 Renewable Energy Standard Procurement Plan. March 1, 2018, p. 9.
12 Gregory B. Hladky, Study: Consumers Pay Extra for Retail Electricity. Hartford Courant. April 20, 2016. http://www.courant.com/news/connecticut/hc-retail-electricity-costs-above-state-standard-20160420-story.html.
13 Jeff Platsky, AT RISK: NY Reviews Electric, Gas Free-Choice Program; Consumers Ended Up Paying More. Press Connects. February 9, 2018. https://www.pressconnects.com/story/news/2018/02/09/risk-ny-groundbreaking-program-allowing-customers-select-electric-gas-suppliers/302146002/
14 Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, at 24.
15 Davidson, Paul. "Shocking Electricity Prices Follow Deregulation." ABC News and USA Today, August 12, 2007. Article accessed January 30, 2019.
16 Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, at 41.

generation or transfer their generation to a corporate affiliate, residential and commercial customers have seen different outcomes. As noted in a study by Dormady *et al*:

> While enabling legislation required 100 percent divestiture of generation assets, utilities were permitted to corporately rather than functionally divest those assets. By selling those generation assets (almost entirely legacy coal plants) to deregulated arms-length companies, they created a perverse cost recovery incentive. When those coal assets performed poorly in the shale boom era, utilities sought riders through their regulated distribution businesses to compensate for losses of their deregulated generation businesses. The largest share of this burden was passed to households. [17]

The study notes that rates are somewhat lower for residential and commercial customers of utilities in Ohio that have fully divested their assets, but higher for residential and commercial customers of utilities that have only transferred their assets to an affiliate. This indicates that the outcomes of restructuring depend on how the policy is implemented and how the market develops, the latter of which is beyond the control of regulators.

Rate reductions even to large commercial and industrial customers have not been consistent or sustained. One study showed that the difference in prices paid by industrial customers in restructured market states nearly tripled from 1999 to July 2007 compared to similar customers in regulated states. The same study concluded that, in one year alone, industrial customers paid $7.2 billion more for electricity in restructured states than if they had paid the average electricity price of regulated states. While this example is dated, it nonetheless relays the experience in markets shortly after restructuring.[18]

The Dormady study noted above developed by using bill data in Ohio to estimate intra-firm cross subsidization concluded that:

> …retail restructuring has reduced or had no effect on price disparities between customer classes, with several notable exceptions. First, the findings suggest that, where customers observed savings associated with retail choice, the greatest savings have been observed by industrial customers and, where customers have observed cost increases, the greatest increases have been observed by residential customers (Type I cross-subsidization). Second, the findings suggest that, while customers have generally observed some savings associated with the implementation of competition (i.e., the deregulated component of their bill), savings have generally been more than offset by cross subsidies to arms-length deregulated generation affiliates ("gencos") (Type II cross-subsidization). [19]

Finally, the Dormady study concludes with the following:

> Regulators and legislators interested in understanding the differential effects of retail restructuring might, therefore, be better served looking inwards – at political and regulatory processes that affect these markets – before adjudicating the theory of deregulation. Similarly, researchers might finally settle the ambiguity about the impact of electric deregulation with better specification of the additional, non-market determinants of deregulation outcomes.

---

17 Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, Dormady, Hoyt, Roa-Henriquez, Welch, December 2018, at 33-34.

18 Competitively Priced Electricity Costs More, Studies Show, David Cay Johnston, The New York Times, November 6, 2007

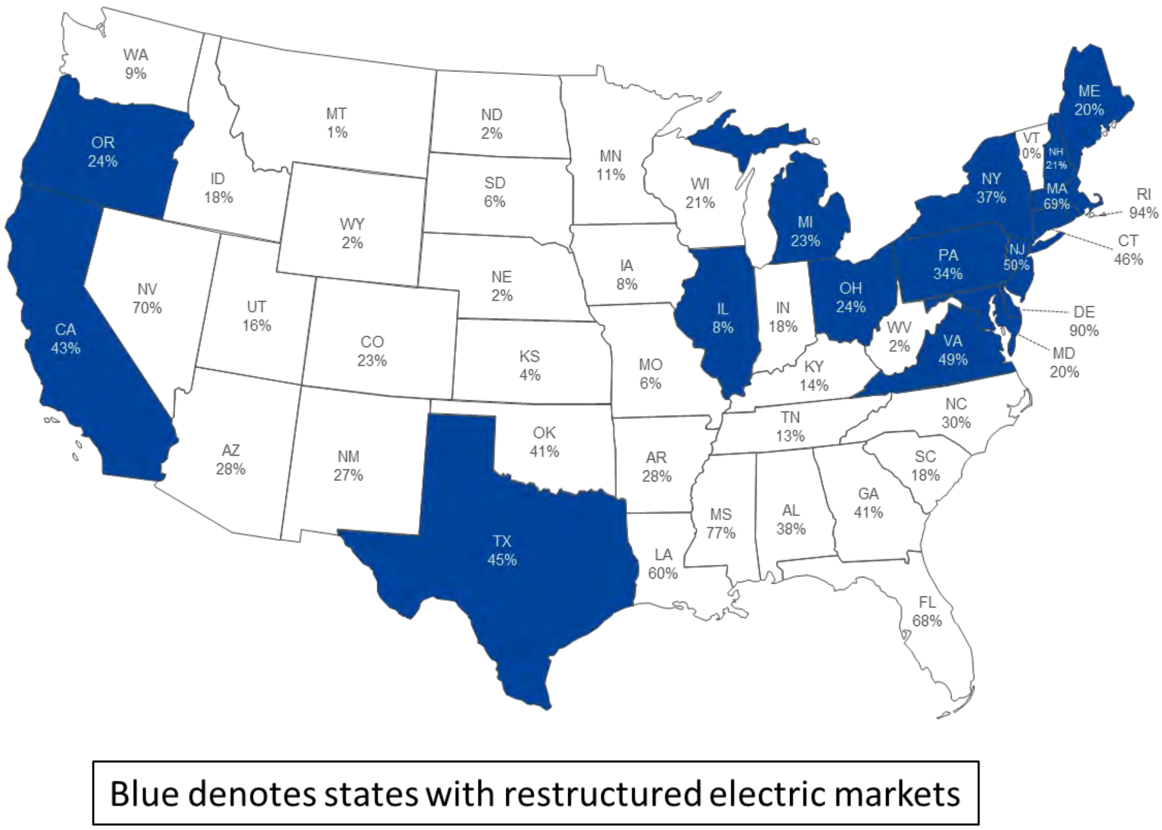
19 Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, Dormady, Hoyt, Roa-Henriquez, Welch, December 2018, at 2.

Likewise, these findings have potentially significant implications for the efficiency of wholesale markets. Regulatory subsidization of generation units can have both short run and long run adverse efficiency consequences for wholesale markets.

Impact of Natural Gas on Restructuring

Many restructured states rely more on natural gas-fired electric generation than traditionally regulated states. See Figure AP10- 5, below.

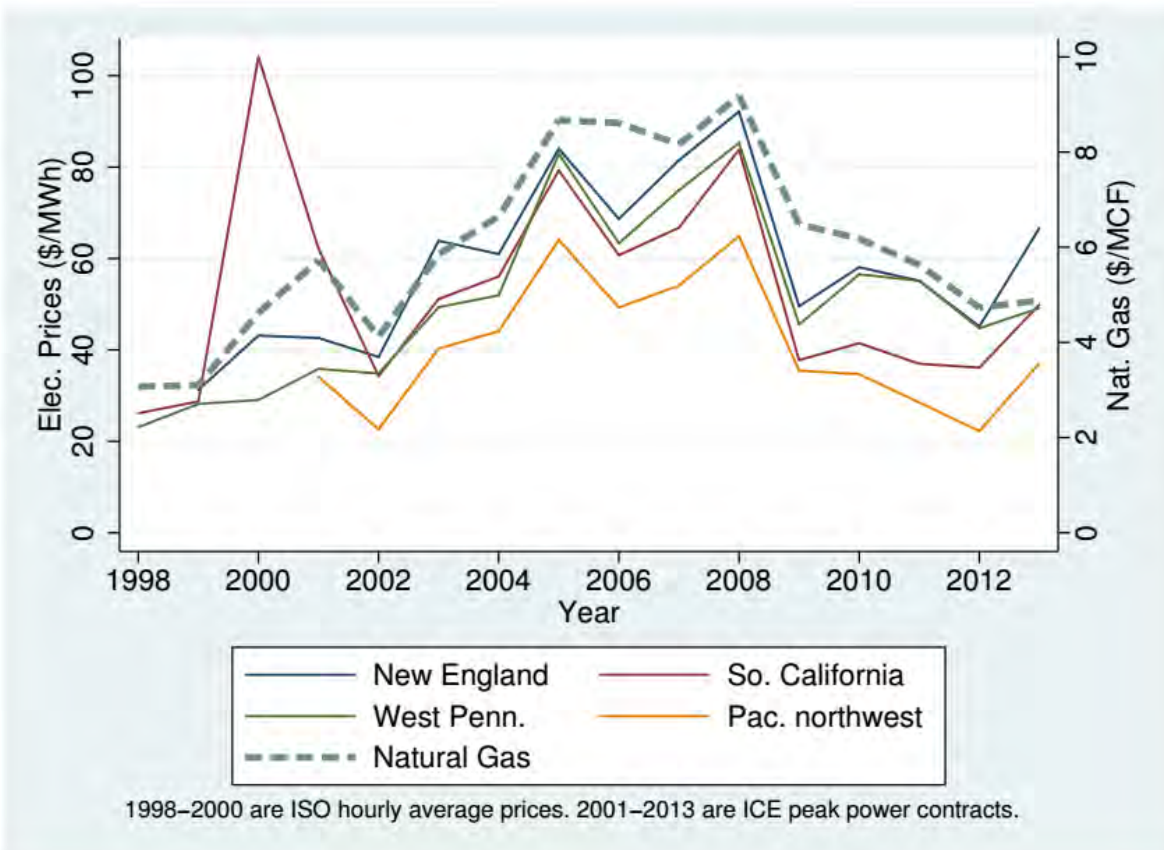
FIGURE AP10- 5: PROPORTION OF GENERATION CAPACITY SERVED BY NATURAL GAS (2017)



This reliance developed because as gas commodity costs fell around the 2008 timeframe, independent power producers in restructured markets began building more efficient, less costly gas plants to replace older, more expensive coal and oil generation. In regulated states, utilities typically maintain existing units until the economics of new units are established through approved, long-term resource plans. Prices for deregulated generation are driven by the marginal producer, which is now commonly natural gas generation. Therefore, "restructuring of generation greatly increased the exposure of electricity rates to natural gas costs, even if a fairly small share of electricity was sourced from gas-fired plants. As natural gas prices nearly tripled during the first half of the 2000s, the impact on retail rates and the rents created for infra-marginal generation were far greater than they would have been under regulation."[20] As a result, electricity prices in restructured states are much more heavily influenced by natural gas prices.

It has also been noted that "Much of the dissatisfaction with high retail prices in restructured states during the period of 2006-2008 was due to a combination of dramatically higher gas prices combined with the expiration of rate freezes…"[21] See Figure AP10- 6, below, which illustrates this link.

FIGURE AP10- 6: WHOLESALE ELECTRICITY AND CITYGATE NATURAL GAS PRICES[22]



The Guinn Center report notes that the uncertainty around rates in restructured markets could be a result of natural gas price fluctuations.

> Therefore, it is impossible to isolate the effects of restructuring on electricity rates. We have already documented such confounding factors as weather variations, timing, congestion issues, and more, but perhaps nothing is more intertwined with retail electric choice than wholesale costs, specifically, natural gas. The preceding discussion should not be misconstrued to suggest that electric prices in restructured states will increase necessarily because of natural gas's pronounced contribution to costs. On the contrary, natural gas prices have been volatile, historically; when they are low, consumers in restructured states—by virtue of their increased

20 The U.S. Electricity Industry after 20 Years of Restructuring, Severin Borenstein and James Bushnell, Revised May 2015, at 14.
21 Bushnell, Mansur, and Novan. Review of Economics Literature on US Electricity Restructuring. February 2017.
22 Ibid., at 14.

exposure to the wholesale market— realize benefits from lower fuel costs. But when they rise, consumers may pay higher electricity bills as a result of pass-through from IPPs to competitive suppliers.[23]

Conclusions

Academic and industry research consistently finds that there is no conclusive link between pricing advantages for retail customers and electric industry restructuring. The conclusions from the Guinn analysis are echoed consistently throughout the research: “This report has found that some people in restructured states have enjoyed the benefits of retail electric choice, while others have confronted unfavorable outcomes. The impact of restructuring turns largely on market design and policy decisions rendered before and during the implementation phase. But even those states that proceeded with caution and careful consideration were not invulnerable to unintended consequences.”

In considering the impacts of restructuring on the costs for Florida’s electric consumers, several factors require careful examination. These include: the existing generation fleet; the likely evolution of the generation fleet in a restructured market; consistency of changes in the generation fleet with Florida’s environmental goals; and the ability of Florida’s electric and fuel infrastructure to support a functionally competitive wholesale market. All of these factors must be considered along with the practical experience gained elsewhere before a legitimate case for consumer benefits can be established.

23 Ibid., at 37.

TAB 10

Review of Florida's Investor-Owned Electric Utilities

2 0 1 7

Service Reliability Reports

December 2 0 1 8

State of Florida
Florida Public Service Commission
Division of Engineering

Review of Florida's Investor-Owned Electric Utilities 2 0 1 7 Service Reliability Reports

December 2 0 1 8

State of Florida
Florida Public Service Commission
Division of Engineering

Table of Contents

List of Tables and Figures

Terms and Acronyms

AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
CAIDI	Customer Average Interruption Duration Index
CEMI5	Customers Experiencing More Than Five Interruptions
CI	Customer Interruption
CME	Customer Momentary Events
CMI	Customer Minutes of Interruption
DSM	Demand Side Management
DEF	Duke Energy Florida, LLC
EOC	Emergency Operation Center
F.A.C.	Florida Administrative Code
FEMA	Federal Emergency Management Agency
FPL	Florida Power & Light Company
FPUC	Florida Public Utilities Company
GIS	Geographic Information System
Gulf	Gulf Power Company
IEEE	Institute of Electrical and Electronics Engineers, Inc.
IOU	The Five Investor-Owned Electric Utilities: FPL, DEF, TECO, Gulf, and FPUC
L-Bar	Average of Customer Service Outage Events Lasting A Minute or Longer
MAIFIe	Momentary Average Interruption Event Frequency Index
N	Number of Outages
NWS	National Weather Service
OMS	Outage Management System
RDUP	Rural Development Utility Program
SCADA	Supervisory Control and Data Acquisition
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TECO	Tampa Electric Company
VMP	Vegetation Management Program

Reliability Metrics

Average Duration of Outage Events (L-Bar) is the sum of each outage event duration for all outage events during a given time period, divided by the number of outage events over the same time within a specific area of service.

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

Customers Experiencing More Than Five Interruptions (CEMI5) is the number of retail customers that have experienced more than five service interruptions. (CEMI5 in this review is a customer count shown as a percentage of total customers.)

Customer Interruptions (CI) is the number of customer service interruptions, which lasted one minute or longer.

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

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

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

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

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

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

Executive Summary

The Florida Public Service Commission (FPSC or Commission) has jurisdiction to monitor the reliability of electric service provided by Florida's investor-owned electric utilities (IOUs) for maintenance, operational, and emergency purposes.[1] This report is a compilation of the 2017 electric distribution reliability data filed by Florida's IOUs. The data is presented using tables and figures so that trends in each IOU's service reliability may be easily observed. In addition, the scope of the IOUs' Annual Distribution Service Reliability Report was expanded to include status reports on the various storm hardening and preparedness initiatives required by the Commission.[2] This data may be used during rate cases, show cause dockets, and is helpful in resolving customer complaints.

Monitoring service reliability is achieved through a review of service reliability metrics provided by the IOUs pursuant to Rule 25-6.0455, Florida Administrative Code (F.A.C.).[3] Service reliability metrics are intended to reflect changes over time in system average performance, regional performance, and sub-regional performance. For a given system, increases in the value of a given reliability metric denote declining reliability in the service provided. Comparison of the year-to-year levels of the reliability metrics may reveal changes in performance, which indicates the need for additional investigation, or work in one or more areas. Rule 25-6.0455, F.A.C., requires the IOUs to file distribution reliability reports to track adjusted performance that excludes events such as planned outages for maintenance, generation disturbances, transmission disturbances, wildfires, and extreme acts of nature such as tornadoes and hurricanes. This "adjusted" data provides an indication of the distribution system performance on a normal day-to-day basis.

The active hurricane seasons of 2004 and 2005 revealed the importance of collecting reliability data that reflects the total reliability experience from the customer perspective. In June 2006, Rule 25-6.0455, F.A.C., was revised to require each IOU to provide both "actual" and "adjusted" performance data for the prior year. This data provides insight concerning the overall reliability performance of each utility.

The March 2018 Distribution Reliability Reports of Duke Energy Florida, LLC (DEF), Florida Power & Light Company (FPL), Florida Public Utilities Company (FPUC), Gulf Power Company (Gulf), and Tampa Electric Company (TECO) and responses to staff's data requests were sufficient to perform the 2017 review.

The following company specific summaries provide highlights of the observed patterns.

---

[1] Sections 366.04(2)c and 366.05, Florida Statutes.

[2] Wooden Pole Inspection Orders: FPSC Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, in Docket No. 20060078-EI; and FPSC Order Nos. PSC-06-0778-PAA-EU, issued September 18, 2006, PSC-07-0078-PAA-EU, issued January 29, 2007, in Docket No. 20060531-EU.
Storm Preparedness Initiative Orders: FPSC Order Nos. PSC-06-0351-PAA-EI, issued April 25, 2006, PSC-06-0781-PAA- EI, issued September 19, 2006, PSC-06-0947-PAA-EI, issued November 13, 2006, and PSC-07-0468-FOF-EI, issued May 30, 2007, in Docket No. 20060198-EI.

[3] The Commission does not have rules or statutory authority requiring municipal electric utilities and rural electric cooperative utilities to file service reliability metrics.

Service Reliability of Duke Energy Florida, LLC

The unadjusted data for DEF indicates that its 2017 allowable exclusions accounted for approximately 97 percent of all Customer Minutes of Interruption (CMI) excluded. The "Named Storms" category accounted for approximately 96 percent of the CMI excluded. DEF experienced one tornado, Tropical Storm Emily, and Hurricane Irma.

On an adjusted basis, DEF's 2017 System Average Interruption Duration Index (SAIDI) was 83 minutes, decreasing its adjusted SAIDI by 2 minutes from the 2016 results. The trend for the SAIDI over the five-year period of 2013 to 2017 is trending slightly downward. The System Average Interruption Frequency Index (SAIFI) in 2017 was 0.92 interruptions, indicating a 6 percent decrease from 2016. The Customer Average Interruption Duration Index (CAIDI) increased for 2017 compared to 2016. Over the five-year period, the SAIFI is trending downward as the CAIDI is trending upward.

In **Figure 3-8**, DEF's Top Five Outage Categories, the category "Defective Equipment" is in the top spot representing 26 percent of the top 10 outage categories. The next two highest categories were "Vegetation" (20 percent) and "Other Causes" (20 percent). "Other Weather" (13 percent) and "Animals" (14 percent) are the next two causes of outages. Commission staff requested that, beginning with 2014 data, all IOU's use the same outage categories for comparison purposes. As such, the "Vegetation," "Defective Equipment," and "Other Weather" now include outage categories that in the past were separately identified. The "Vegetation" and "Other Weather" outage categories are trending downward for the five-year period of 2013 to 2017 even though the "Other Weather" category had a 10 percent increase in 2017 and the "Vegetation" category had a 3 percent increase. The "Defective Equipment" category had an increase between 2016 and 2017 and continues to trend upward for the five-year period. The "Other Causes" category had an increase in 2017 compared to 2016 and continues to trend upward for the five-year period. The "Animals" category had a decrease in 2017 and is relatively flat for the five-year period.

The percentage of reliability complaints compared to the total number of complaints filed with the Commission for DEF increased to 4.2 percent in 2017 from 4.0 percent in 2016. Over the five-year period from 2013-2017, DEF's reliability related complaints have been trending downward.

In 2017, DEF completed 985 hardening projects for existing transmission structures. The projects included maintenance pole change-outs, insulator replacements, Department of Transportation/customer relocations, line rebuilds, and system planning additions. The transmission structures are designed to withstand the current the National Electrical Safety Code (NESC) wind requirements and are built utilizing steel or concrete structures. At the end of 2017, DEF reported it had 21,285 transmission structures left to harden then in 2018, DEF plans to harden 1,002 transmission structures.

Service Reliability of Florida Power & Light Company

The unadjusted data for FPL indicates that its 2017 allowable exclusions accounted for approximately 99 percent of the total CMI. The "Names Storms" category accounted for approximately 98 percent of the CMI excluded. In addition, FPL's service area was affected by 13 tornadoes and 2 fire events, Tropical Storm Emily, Tropical Storm Philippe, Hurricane Irma, and Hurricane Nate.

FPL's 2017 metrics on an adjusted basis include SAIDI which was reported as 54 minutes and represents a 2 minute decrease from last year's reported 56 minutes. The SAIFI and CAIDI both improved in 2017. The SAIFI decreased from 0.92 interruptions in 2016 to 0.90 interruptions in 2017 and the CAIDI decreased from 61 minutes in 2016 to 60 minutes in 2017.

"Defective Equipment" (38 percent) and "Vegetation" (18 percent) outages were the leading causes of outage events per customer for 2017. Starting in 2014, "Defective Equipment" includes "Equipment failure," "Equipment Connect," and "Dig-in," which were all separate categories, in prior years. The next three outage causes are "Unknown Causes" (11 percent), "Animals" (10 percent) and "Other Causes" (10 percent). **Figure 3-16** shows an increasing trend in the number of outage events attributed to "Defective Equipment," which had increased by 12 percent from 2016 to 2017. The analysis shows a decrease in the number of outage events caused by "Vegetation," "Unknown Causes," and "Animals." The number of outages decreased by 15 percent for "Vegetation" and increased for "Unknown Causes" by 3 percent from 2016 to 2017. The analysis shows that the "Animals" category is trending downward with a decrease in outages of 3 percent and the "Other Causes" category experienced an increase in outages of 28 percent.

Complaints related to FPL's reliability decreased by .01 percent from 2016 to 2017. FPL's reliability related complaints continue trending upward as shown in **Figure 4-10**, even with the decrease in 2017.

In 2017, FPL replaced 1,934 wood transmission structures with spun concrete poles. FPL completed the replacement of ceramic post insulator with polymer insulators in 2014. Also, in 2014, FPL completed the installation of water-level monitoring systems and communication equipment in 223 substations. In 2018, FPL plans on replacing approximately 1,400 to 1,800 wood transmission structures. FPL has 5,991 wood transmission structures remaining to be replaced.

Service Reliability of Florida Public Utilities Company

The unadjusted data for FPUC indicate that its 2017 allowable exclusions accounted for approximately 93 percent of the total CMI. The "Named Storms" category accounted for approximately 84 percent of the CMI excluded. FPUC reported that neither the Northeast nor the Northwest divisions were impacted by tornadoes during 2017. The Northeast division was affected by Hurricane Irma. The Northwest division was impacted by Tropical Storm Cindy, Hurricane Harvey, and Hurricane Irma.

The 2017 adjusted data for FPUC's SAIDI was 139 minutes, a 25 percent decrease from 185 minutes reported in the previous year. The SAIFI also decreased from 1.95 interruptions in 2016 to 1.64 interruptions in 2017. The CAIDI value in 2017 was 85 minutes, a decrease from the 95 minutes in 2016.

FPUC's top five causes of outages included "Vegetation," "Animals," "Other Weather," "Lightning," and "Defective Equipment" events. As shown in **Figure 3-21**, "Vegetation" (31 percent) was the number one cause of outages in 2017 followed by "Animals" (23 percent), "Defective Equipment" (14 percent), "Other Weather" (13 percent), and "Lightning" (7 percent). "Vegetation," "Animals," and "Lightning" attributed outages decreased in 2017, as "Defective

Equipment" and "Other Weather" caused outages increased. Beginning in 2014, the "Defective Equipment" category now includes outage categories that in the past were separately identified.

FPUC's reliability related complaints are minimal. In 2017, the Utility had two reliability related complaints filed with the Commission. The volatility in FPUC's results can be attributed to its small customer base that averages 28,000 or fewer customers. For the last five years, the percentage of reliability related complaints against FPUC have been trending upward.

All of the Northeast division's 138kV poles are constructed of concrete and steel. The Northeast division's 69kV transmission system consists of 217 poles of which 105 are concrete. The Northwest division does not have transmission structures. In 2017, FPUC did not harden any of its transmission structures. However, FPUC does plan to harden five structures in 2018. FPUC has 112 transmission structures left to be hardened.

Service Reliability of Gulf Power Company

The adjusted data for Gulf indicates that its 2017 allowable exclusions accounted for 28 percent of exclusion its CMI. The "Named Storms" category accounted for approximately 14 percent of the total CMI excluded. Gulf explained Hurricanes Irma and Nate, and Tropical Storm Cindy affected its service area. In 2017, five tornadoes also affected its service area accounting for 4 percent of the total CMI.

The 2017 SAIDI for Gulf was reported to be 116 minutes, which is higher than the 95 minutes reported in 2016. The SAIFI increased to 1.20 interruptions from 1.14 interruptions the previous year. The CAIDI increased to 97 minutes from 83 minutes in 2016. Gulf stated that it continues to collect outage data which extends to the customer meter level. The Utility reviews outage data and the resulting reliability indices at the system level and at its three regions. Gulf is analyzing 2017 data to determine the need for any specific improvement opportunities beyond the current programs and storm hardening initiatives.

Gulf's top five causes of outages were listed as "Animals," "Defective Equipment," "Vegetation," "Lightning," and "Unknown Causes." "Animals" (28 percent) caused outages was the number one cause of outages followed by "Defective Equipment" (23 percent), "Vegetation" (20 percent), "Lightning" (13 percent), and "Unknown Causes" (7 percent). The number of outages decreased for "Animals" and "Lightning" in 2017 when compared to 2016, as shown in **Figure 3-29**. The "Defective Equipment" and "Vegetation" categories now include outage categories that in the past were separately identified.

There were no complaints reported to the Commission against Gulf that were reliability related in 2017, improving the 0.2 percent recorded last year. Gulf's percentage of total complaints for the five-year period of 2013 to 2017 is trending downward. Overall, Gulf has the lowest percentage of total complaints related to reliability as shown in **Figure 4-10**.

Gulf had two priority goals for hardening its transmission structures: installation of guys on H-frame structures and replacement of wooden cross arms with steel cross arms. The installation of guys on H-frame structures was completed in 2012. The replacement of wooden cross arms was due to be completed in 2017; however, Gulf experienced lengthy environmental permitting delays. In 2017, 54 wooden cross arms were replaced and the 3 remaining will be replaced in 2018.

Service Reliability of Tampa Electric Company

The adjusted data for TECO indicates that its 2017 allowable exclusions accounted for approximately 77 percent of the CMI. The "Named Storms" category accounted for approximately 71 percent of the CMI excluded. Hurricane Irma affected TECO's entire service area in 2017.

The adjusted SAIDI decreased from 83 minutes in 2016 to 73 minutes in 2017 and represents a 12 percent improvement in performance. The SAIFI increased to 1.03 interruptions from 1.01 interruptions in the previous year. The CAIDI decreased 14 percent from 83 minutes reported in 2016 to 71 minutes. TECO reported the improvements in SAIDI and CAIDI were attributed to less severe weather events combined with quicker restoration times. The increase in SAIFI was contributed to an increased number of outages experienced in 2017 as compared to 2016.

"Defective Equipment" (26 percent) and "Vegetation" (22 percent) were the largest contributors to TECO's causes of outage events followed by "Animals" (17 percent), "Lightning" (13 percent), and "Unknown Causes" (10 percent). **Figure 3-37** illustrates the top five outage causes. "Defective Equipment," the leading cause of outages, has been trending downward since 2014. "Defective Equipment" had a 3 percent decrease in outages when compared to the previous year. Beginning in 2014, the "Defective Equipment" category now includes outage categories that in the past were separately identified. "Animal" and "Lightning" related causes are also trending downward. "Vegetation" and "Unknown Causes" related causes are remaining relatively flat even though there were increases of 8 percent and 4 percent, respectively, in 2017.

TECO's percentage of total service reliability related complaints decreased from 11.3 percent in 2016 to 8.0 percent in 2017. TECO's percentage of service reliability complaints is trending upward over the period of 2013 to 2017. TECO continues to focus on vegetation management, circuit review activity, line improvements, and other maintenance activities to minimize service-related complaints in 2018. Working through and responding to complaints at a regional level affords TECO an opportunity to be aware of any trends that may occur for a given feeder or lateral.

TECO's transmission system is hardened by utilizing its inspections and maintenance program to systematically replace wood structures with non-wood structures. In 2017, TECO hardened 407 structures including 389 pole replacements utilizing steel or concrete poles and replaced 18 sets of insulators with polymer insulators. TECO's goal for 2018 is to harden 58 transmission structures. TECO has approximately 7,262 wooden poles left to be replaced.

Review Outline

This review primarily relies on the March 2018 Reliability Reports filed by the IOUs for the 2017 reliability performance data and storm hardening and preparedness initiatives. A section addressing trends in reliability related complaints is also included. Staff's review consists of five sections.

- **Section I:** Storm hardening activities, which include each IOU's Eight-Year Wooden Pole Inspection Program and the Ten Storm Preparedness Initiatives.
- **Section II:** Each utility's actual 2017 distribution service reliability data and support for each of its adjustments to the actual service reliability data.
- **Section III:** Each utility's 2017 distribution service reliability based on adjusted service reliability data and staff's observations of overall service reliability performance.
- **Section IV:** Inter-utility comparisons and the volume of reliability related customer complaints for 2013 to 2017.
- **Section V:** Appendices containing detailed utility specific data of the IOUs and summaries of the municipal and rural cooperative utilities.

Section I: Storm Hardening Activities

Each IOU, pursuant to Rule 25-6.0342(2), F.A.C., must file a storm hardening plan which is required to be updated every three years. The IOU's third updated storm hardening plans were filed on May 2 and 3, 2016, except for FPL who filed its plan on March 15, 2016.[4] The following subsections provide a summary of each IOU's programs addressing an on-going Eight-Year Wooden Pole Inspection Program and the Ten Storm Preparedness Initiatives as directed by the Commission.

Eight-Year Wooden Pole Inspection Program

FPSC Order Nos. PSC-06-0144-PAA-EI, issued February 27, 2006, in Docket No. 20060078-EI and PSC-07-0078-PAA-EU, issued January 29, 2007, in Docket No. 20060531-EU, require each IOU to inspect 100 percent of their installed wooden poles within an eight-year inspection cycle. The National Electrical Safety Code (NESC) serves as a basis for the design of replacement poles for wood poles failing inspection. Additionally, Rule 25-6.0342(3)(b), F.A.C., requires that each utility's storm hardening plan address the extent to which the plan adopts extreme wind loading standards as specified in Figure 250-2(d) of the 2007 edition of the NESC. Staff notes that DEF determined the extreme wind loading requirements, as specified in Figure 250-2(d) of the NESC did not apply to poles less than 60 feet in height that are typically found within the electrical distribution system. DEF stated in its 2009 Storm Hardening Report that extreme wind loading requirements have not been adopted for all new distribution construction since poles less than 60 feet in height are more likely to be damaged by fallen trees and other wind borne debris.[5]

---

[4] Docket Nos. 20160061-EI (FPL), 160105-EI (TECO), 20160106-EI (FPUC), 20160107-EI (DEF), and 20160108-EI (Gulf), *In re: Petition for approval of 2016-2018 storm hardening plan, pursuant to Rule 25-6.0342, F.A.C.*
[5] DEF Storm Hardening Plan 2007-2009, Appendix J, pp. 4-5.

Table 1-1 shows a summary of the quantities of wooden poles inspected by all IOUs in 2017.

Table 1-1
2017 Wooden Pole Inspection Summary

Utility	Total Poles	Poles Planned 2017	Poles Inspected 2017	Poles Failed Inspection	% Failed Inspection	Years Complete in 8-Year Inspection Cycle
DEF	795,260	100,000	100,038	1,727	1.73%	3
FPL	1,075,419	133,630	123,279	6,225	5.05%	4
FPUC	26,548	3,439	4,105	205	4.99%	2
GULF	206,474	26,000	25,889	910	3.52%	4
TECO	285,000	0	0	0	0.00%	4

Source: The IOUs 2017 distribution service reliability reports.

Table 1-2 indicates the projected wooden pole inspection requirements for the IOUs.

Table 1-2
Projected 2018 Wooden Pole Inspection Summary

Utility	Total Poles	Total Number of Wood Poles Inspected in current cycle	Number of Wood Pole Inspections Planned for 2018	Percent of Wood Poles Planned 2018	Percent of Wood Pole Inspections Completed in 8-Year Cycle	Years Remaining in 8-Year Cycle After 2017
DEF	795,260	395,296	100,000	12.57%	50%	5
FPL	1,075,419	511,387	124,915	11.62%	48%	4
FPUC	26,548	6,583	3,328	12.54%	25%	6
GULF	206,474	104,236	26,000	12.59%	50%	4
TECO	285,000	161,672	36,000	12.63%	57%	4

Source: The IOUs 2017 distribution service reliability reports.

The annual variances shown in Tables 1-1 and 1-2 are allowable so long as each utility achieves 100 percent inspection within an eight-year period. Staff continues to monitor each utility's performance.

Ten Initiatives for Storm Preparedness

On April 25, 2006, the Commission issued FPSC Order No. PSC-06-0351-PAA-EI, in Docket No. 20060198-EI. This Order required that the IOUs file plans for Ten Storm Preparedness Initiatives (Ten Initiatives).[6] Storm hardening activities and associated programs are on-going parts of the annual reliability reports required from each IOU since rule changes in 2006. The status of these initiatives is discussed in each IOU's report for 2017. Separate from the Ten Initiatives, and not included in this review, the Commission established rules addressing storm hardening of transmission and distribution facilities for all of Florida's electric utilities.[7,8,9]

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

Each IOU continues to maintain the commitment to complete three-year trim cycles for overhead feeder circuits, except for TECO, which is on a four-year cycle, since feeder circuits are the main arteries from the substations to the local communities. The approved plans of all the IOUs also require a maximum of a six-year trim cycle for lateral circuits. In addition to the planned trimming cycles, each IOU performs hot-spot tree trimming[10] and mid-cycle trimming to address rapid growth problems.

---

[6] Docket No. 20060198-EI, *In re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates.*

[7] FPSC Order No. PSC-06-0556-NOR-EU, issued June 28, 2006, in Docket No. 20060172-EU, *In re: Proposed rules governing placement of new electric distribution facilities underground, and conversion of existing overhead distribution facilities to underground facilities, to address effects of extreme weather events*, and Docket No. 20060173-EU, *In re: Proposed amendments to rules regarding overhead electric facilities to allow more stringent construction standards than required by National Electric Safety Code*.

[8] FPSC Order Nos. PSC-07-0043-FOF-EU, issued January 16, 2007, and PSC-07-0043A-FOF-EU, issued January 17, 2007, both in Docket Nos. 20060173-EU and 20060172-EU.

[9] FPSC Order No. PSC-06-0969-FOF-EU, issued November 21, 2006, in Docket No. 20060512-EU, *In re: Proposed adoption of new Rule 25-6.0343, F.A.C., Standards of Construction - Municipal Electric Utilities and Rural Electric Cooperatives*.

[10] Hot-spot tree trimming occurs when an unscheduled tree trimming crew is dispatched or other prompt tree trimming action is taken at one specific location along the circuit. For example, a fast growing tree requires hot-spot tree trimming in addition to the cyclical tree trimming activities. TECO defines hot-spot trimming as any internal or external customer driven request for tree trimming. Therefore, all tree trim requests outside of full circuit trimming activities are categorized as hot-spot trims.

Table 1-3 is a summary of feeder vegetation management activities by each company's cycle.

Table 1-3
Vegetation Clearing from Feeder Circuits

IOU	# of Years in Cycle	1st Year of Cycle	Total Feeder Miles	Miles Trimmed				Total Miles Trimmed	% of Miles Trimmed
				1st Year	2nd Year	3rd Year	4th Year		
DEF	3	2015	4,106	1,024	1,016	2,106		4,146	101.0%
FPL	3	2016	12,850	4,418	4,381			8,799	68.5%
FPUC	3	2017	159	29				29	18.4%
GULF	3	2016	723	241	241			482	66.7%
TECO	4	2017	1,739	198.9				199	11.4%

Note: In 2012, the Commission approved TECO's request to modify its trim cycle for feeders to four years.[11]
Source: The IOUs 2017 distribution service reliability reports.

Based on the data in Table 1-3, it appears that both FPL and Gulf are on schedule with their feeder vegetation cycles. DEF has completed its three-year feeder trim cycle with over 100 percent feeders trimmed. FPUC appears to be behind schedule for the three-year feeder trim cycle with 18.4 percent competed. FPUC suggests that its vegetation management would be more efficient if it trimmed all of the laterals associated with the feeders at the same time. This would allow FPUC to keep the trim crews in the same general area instead of moving them to different feeders or laterals. This vegetation management schedule has been started in several locations. TECO indicates that it is behind schedule with its vegetation management cycles due to recent storm activity and labor shortfalls. TECO explained that over the past two years, storms have impacted its service area. Due to the storms, there has been a higher demand for qualified vegetation management personnel, which has far exceeded the supply.

[11] FPSC Order No. PSC-12-0303-PAA-EI, issued June 12, 2012, in Docket No. 20120038-EI, *In re: Petition to modify vegetation management plan by Tampa Electric Company*.

Table 1-4 is a summary of the lateral vegetation management activities by company.

Table 1-4
Vegetation Clearing from Lateral Circuits

IOU	# of Years in Cycle	1st Year of Cycle	Total Lateral Miles	Miles Trimmed 1st Year	2nd Year	3rd Year	4th Year	5th Year	6th Year	Total Lateral Miles Trimmed	% of Lateral Miles Trimmed
DEF	5	2016	14,118	2,173	1,909					4,082	28.9%
FPL	6	2013	22,788	4,124	3,685	3,817	3,745	3,560		18,931	83.1%
FPUC	6	2014	571	145	134	188	86			554	97.0%
GULF	4	2014	5,148	1,294	913	331	446			2,984	58.0%
TECO	4	2017	4,524	627						627	13.9%

Note: In 2006, the Commission approved DEF's request to modify its lateral trim cycle to five years.[12] In the same docket, the Commission approved FPL's modified trim cycle for laterals to six years.[13] FPUC's lateral trim cycle was modified to six years in 2010.[14] The Commission approved Gulf's modified lateral trim cycle to four years in 2010.[15] In 2012, the Commission approved TECO's request to modify its trim cycle for laterals to four years.[16]

Source: The IOUs 2017 distribution service reliability reports.

From the data in Table 1-4, it appears that FPL and FPUC are on schedule with lateral vegetation cycles. DEF is in the second year of its five-year lateral trim cycle with 28.7 percent laterals trimmed indicating that DEF is behind schedule. DEF plans to increase the number of lateral miles to be trimmed in 2018. Gulf reported that its goal is to trim one-fourth of its lateral lines each year. Gulf uses outage data to identify specific locations for trimming to improve reliability to its customers; therefore, the actual line miles trimmed may vary from year to year. Gulf has also invested in the removal of ground floor vegetation and herbicide programs that enhance the overall vegetation management program but may not be apparent in lateral mile tracking. As previously discussed, TECO is behind schedule with its vegetation management cycles due to the strong storm activity, which caused a higher demand for qualified vegetation management personnel.

---

[12] FPSC Order No. PSC-06-0947-PAA-EI, issued November 13, 2006, in Docket No. 20060198-EI, *In re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates*.

[13] FPSC Order No. PSC-07-0468-FOF-EI, issued May 30, 2007, in Docket No. 20060198-EI, *In re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates*.

[14] FPSC Order No. PSC-10-0687-PAA-EI, issued November 15, 2010, in Docket No. 20100264-EI, *In re: Review of 2010 Electric Infrastructure Storm Hardening Plan filed pursuant to Rule 25-6.0342, F.A.C., submitted by Florida Public Utilities Company*.

[15] FPSC Order No. PSC-10-0688-PAA-EI, issued November 15, 2010, in Docket No. 20100265-EI, *In re: Review of 2010 Electric Infrastructure Storm Hardening Plan filed pursuant to Rule 25-6.0342, F.A.C., submitted by Gulf Power Company*.

[16] FPSC Order No. PSC-12-0303-PAA-EI, issued June 12, 2012, in Docket No. 20120038-EI, *In re: Petition to modify vegetation management plan by Tampa Electric Company*.

Tables 1-3 and **1-4** do not reflect hot-spot trimming and mid-cycle trimming activities. An additional factor to consider is that not all miles of overhead distribution circuits require vegetation clearing. Factors such as hot-spot trimming and open areas contribute to the apparent variances from the approved plans. Annual variances as seen in Tables 1-3 and 1-4 are allowable as long as each utility achieves 100 percent completion within the cycle-period stated in its approved plan for feeder and lateral circuits.

Initiative 2 - Audit of Joint-Use Agreements

For hardening purposes, the benefits of fewer attachments are reflected in the extreme wind loading rating of the overall design of pole loading considerations. Each IOU monitors the impact of attachments by other parties to ensure the attachments conform to the utility's strength and loading requirements without compromising storm performance. Each IOU's plan for performing pole strength assessments includes the stress impacts of all pole attachments as an integral part of its eight-year wood pole inspection program. In addition, these assessments are also conducted on concrete and steel poles. The following are some 2017 highlights:

- DEF performs its joint-use audit on an eight-year cycle with 2017 being the third year in the current cycle. In 2017, DEF audited one-eighth of its joint-use attachments. Of the 57,605 distribution poles that were strength tested 145 failed the test. DEF added guy wires to 30 poles and replaced 113 of the failed poles. The two remaining poles will be addressed in 2018 because the final design solution has not been completed. However, potential solutions include installing larger, stronger poles or installing additional guying. DEF found no unauthorized attachments on the poles. Of its 5,761 joint-use transmission poles, 277 poles were strength tested with 52 poles failing the test. These transmission poles will be replaced.

- FPL audited approximately 20 percent of its service territory through its joint-use survey in order to determine the number and ownership of jointly used poles and associated attachments in 2017. Pole strength and loading tests were also performed on the joint-use poles. The results show that 13 (0.02 percent) poles failed the strength test due to overloading. The results also show that 2,166 (3.12 percent) poles failed the strength test due to other reasons, which could include pole decay or damage caused by woodpeckers. The 2017 survey and inspection results show that no unauthorized attachments were found.

- In 2014, FPUC added language to its Joint-Use Agreements to clarify joint-use safety audit instructions. The additional language included a provision for an initial joint-use pole attachment audit to take place 12 months after the effective date of the agreement, and on a five-year recurring cycle after the first audit. Currently, four Joint-Use Agreements have been executed. The other agreements are being negotiated. FPUC completed the joint-use pole attachment audit in 2016 and discovered discrepancies in the total number of attachments. However, it cannot identify which attachments were unauthorized due to insufficient initial data. The next audit should take place in 2021 and will provide more detail. FPUC will be able to refer to the 2016 audit as a benchmark since it was the first audit conducted after the effective date of the Joint-Use Agreements.

- Gulf performs its joint-use inventory audits every five years. The last audit was completed in October 2016 and the next audit will be conducted in 2021. As of 2017, Gulf has 202,706 distribution poles with 312,149 third-party attachers (148,202 Telecom and 163,947 cable TV and other). Gulf is attached to 62,686 foreign poles (poles not owned by Gulf). Gulf's mapping system has been updated to reflect the third-party attachments.

- In 2017, TECO conducted comprehensive loading analysis and continued to streamline its processes to better manage attachment requests from attaching entities. A comprehensive loading analysis was performed on 1,179 poles. TECO identified 8 distribution poles that were overloaded due to joint-use attachments and 35 poles were overloaded due to TECO's attachments. These overloaded poles were corrected by being re-guyed, re-configured, or reinforced with trusses.

Initiative 3 - Six-Year Transmission Inspections

The IOUs are required by the Commission to inspect all transmission structures and substations, and all hardware associated with these facilities. Approval of any alternative to a six-year cycle must be shown to be equivalent or better than a six-year cycle, in terms of cost and reliability in preparing for future storms. The approved plans for DEF, FPL, FPUC, Gulf, and TECO require full inspection of all transmission facilities within a six-year cycle. DEF, which already had a program indexed to a five-year cycle, continues with its five-year program. Such variances are allowed so long as each utility achieves 100 percent completion within a six-year period, as outlined in FPSC Order No. PSC-06-0781-PAA-EI, issued September 19, 2006, in Docket No. 20060198-EI.

- DEF inspected 822 transmission circuits (26 percent), 501 transmission substations (100 percent), 514 transmission tower structures (15 percent), and 12,699 transmission poles (25 percent) in 2017. DEF plans to inspect 32 percent of the transmission system in 2018. DEF performs ground patrol of transmission line structure associated hardware, and conductors on a routine basis to identify potential problems. DEF is on target for its five-year transmission inspections.

- In 2014, FPL began a new six-year cycle, performing climbing inspections on all 500 kV structures. Climbing inspections for all other steel and concrete structures are on a ten-year cycle. In 2017, FPL inspected approximately 83.8 percent of transmission circuits, 100 percent of transmission substations, 100 percent of non-wood transmission tower structures, and 36.3 percent of wood transmission poles. In addition, FPL inspects 100 percent of its wood poles and structures by performing a visual inspection at ground level each year. It appears that FPL is on target for its six-year transmission inspections.

- In 2012, FPUC inspected 100 percent of transmission circuits, transmission substations, tower structures, and transmission poles. The transmission inspections included climbing patrols of 95 138kV and 217 69kV structures. Transmission inspections will be conducted at a minimum every six years on all transmission facilities. FPUC is on schedule for its transmission facilities inspections, with the next inspection scheduled to be completed by the end of 2018.

- ♦ Gulf inspected 56 transmission substations in 2017 and conducted 428 inspections of its 2,467 metal poles and towers as well as 3,475 wood and concrete transmission poles. Gulf also performed four aerial inspections and inspected approximately 1,000 more poles than planned. The Utility replaced 123 of its wood transmission poles. Gulf's transmission line inspections include a ground line treatment inspection, a comprehensive walking inspection, and aerial inspections. The transmission inspections are based on two alternating 12-year cycles, which results in the structures being inspected at least once every six years. It appears that Gulf is on schedule for its transmission inspections.

- ♦ TECO's transmission system inspection program includes ground patrol, aerial infrared patrol, substation inspections, which are on a one-year cycle, above ground inspection and ground line inspection, which is on an eight-year cycle. The above ground inspection was shifted from a six-year cycle to an eight-year cycle in 2015 per FPSC Order No. PSC-14-0684-PAA-EI, issued December 10, 2014, in Docket No. 20140122-EI. Additionally, pre-climb inspections are performed prior to commencing work on any structure. In 2017, TECO inspected 72 (100 percent) of its transmission substations and completed 204 (100 percent) of its planned transmission equipment inspections. TECO did not complete any ground patrol or aerial infrared patrols because these inspections were completed in 2016. It appears that TECO is on target for its transmission inspection schedule.

Initiative 4 - Hardening of Existing Transmission Structures

Hardening transmission infrastructure for severe storms is important in order to continue providing transmission of electricity to high priority customers and key economic centers. IOUs are required by the Commission to show the extent of the utility's efforts in hardening of existing transmission structures. No specific activity was ordered other than developing a plan and reporting on storm hardening of existing transmission structures. In general, all of the IOU's plans continued pre-existing programs that focus on upgrading older wooden transmission poles. Highlights of 2017 and projected 2018 activities for each IOU are explained below.

- ♦ DEF planned 1,199 transmission structures for hardening and completed hardening of 985 transmission structures, which includes maintenance pole change-outs, insulator replacements, Department of Transportation/customer relocations, line rebuilds, and system planning additions. The transmission structures are designed to withstand the current NESC wind requirements and are built utilizing steel or concrete structures. In 2018, DEF plans to harden 1,002 transmission structures. DEF reported 53,476 transmission poles, with 21,285 wood poles (40 percent) left to be hardened.

- ♦ FPL completed all replacements of its ceramic post insulators with polymer insulators in 2014. Also, in 2014, FPL completed the installation of water-level monitoring systems and communication equipment in its 223 substations. FPL replaced 1,934 wood transmission structures with spun concrete poles in 2017. In 2017, FPL has 5,991 (9 percent) wood transmission structures remaining to be replaced.

- ♦ In 2017, FPUC did not harden any of its transmission structures. However, FPUC does plan to harden five structures in 2018. All of the Northeast division's 138kV poles are constructed of concrete and steel and meet NESC standards. The Northeast division's 69kV transmission system consists of 217 poles of which 105 are concrete poles. FPUC has 112 (51 percent) transmission structures left to be hardened. This includes seven wood span guy poles. FPUC indicated that during the hardening replacements, it designed and installed self-supporting structures, which in most cases eliminates the need to use span guys. The Northwest division does not have transmission structures.

- Gulf has two priority goals for hardening its transmission structures: installation of guys on H-frame structures and replacement of wooden cross arms with steel cross arms. The installation of guys on H-frame structures was completed in 2012. In 2017, 54 transmission structures were hardened. The replacement of wooden cross arms with steel cross arms was due to be completed in 2017; however, Gulf experienced lengthy environmental permitting delays. Gulf has three wooden cross arms left to be replaced.

- TECO is hardening the existing transmission system by utilizing its inspections and maintenance program to systematically replace wood structures with non-wood structures. In 2017, TECO hardened 407 structures including 389 structure replacements utilizing steel or concrete poles and replaced 18 sets of insulators with polymer insulators. TECO's goal for 2018 is to harden 58 transmission structures. TECO has approximately 7,262 (30 percent) wood poles left to be replaced.

Initiative 5 - Transmission and Distribution Geographic Information System

Initiative 6 - Post-Storm Data Collection and Forensic Analysis

Initiative 7 - Collection of Detailed Outage Data Differentiating Between the Reliability Performance of Overhead and Underground Systems

These three initiatives are addressed together because effective implementation of any one initiative is dependent upon effective implementation of the other two initiatives. The five IOUs have Geographic Information System (GIS) and other programs to collect post-storm data on competing technologies, perform forensic analysis, and assess the reliability of overhead and underground systems on an ongoing basis. Differentiating between overhead and underground reliability performance and costs is still difficult because underground facilities are typically connected to overhead facilities and the interconnected systems of the IOUs address reliability on an overall basis. The electric utility companies have implemented an Outage Management System (OMS). The collection of information for the OMS is being utilized in the form of a database for emergency preparedness. This will help utilities identify and restore outages sooner and more efficiently. The OMS also fills a need for systems and methods to facilitate the dispatching of maintenance crews during outages, and for providing an estimated time to restore power to customers. Effective restoration will also yield improved customer service and increased electric utility reliability. The year 2017 highlights and projected 2018 activities for each IOU are listed below:

- DEF's forensics teams will participate in DEF's 2018 Storm Drill. During field observations, the forensics team collects various information regarding poles damaged during storm events and collects sufficient data at failure sites to determine the nature and cause of the failure. In collaboration with University of Florida's Public Utility Research

Center (PURC), DEF and the other IOUs developed a common format to collect and track data related to damage discovered during forensics investigation. Weather stations were installed across Florida as part of the collaboration with PURC and the other IOUs. As a result, DEF is now able to correlate experienced outages with nearby wind speeds. This type of information is augmented with on-site forensics data following a major storm event. DEF collects information to determine the percentage of storm caused outages on overhead and underground systems.

DEF's GIS provides several sets of data and information points regarding DEF's assets. DEF uses OMS, Customer Service System, and GIS to help analyze the performance of its overhead and underground facilities. DEF collects available performance information as part of the storm restoration process. DEF implemented a new GIS, Work Management System, and Asset Management System in 2017. These systems allow DEF to facilitate the compliance tracking, maintenance, planning, and risk management of the major distribution and transmission assets. One hundred percent of the overhead and underground distribution and transmission systems are in the GIS. In addition, in 2017, DEF installed approximately 227 circuit miles of new underground cable. DEF indicated that its distribution system consists of 44 percent underground circuit miles.

- ♦ FPL completed its five approved Key Distribution GIS improvement initiatives in 2012. The initiatives include post-hurricane forensic analyses, the addition of poles, streetlights, joint-use survey, and hardening level data to the GIS. Data collection and updates to the GIS will continue through inspection cycles and other normal daily work activities. FPL has post-storm data collection and forensic analysis plans, systems and processes in place and ready for use. The plans, systems and processes capture overhead and underground storm performance based on an alternative metric of analyzing performance of laterals.

  FPL utilized its alternative plan to develop metrics to demonstrate the performance of, damage to, and causes of damage to overhead and underground facilities. This includes the population of overhead and underground feeders and laterals experiencing an outage versus the respective total population of feeders and laterals, the performance of overhead hardened versus non-hardened feeders, failure rates for overhead and underground transformers, failure rates for underground facilities by type, major causes of system damage, and overhead pole performance.

- ♦ FPUC uses GIS mapping for all of its deployed equipment and uses it to identify distribution and transmission facilities. The system interfaces with the Customer Information System to function as a Customer OMS. The implementation of the OMS has resulted in significant improvement in data collection and retrieval capability for analyzing and reporting reliability indices. The migration of the data began in 2012 and was completed in 2013. In 2014, FPUC began using the new OMS. The enhancements, which include providing outage data via smart mobile phones, have proven beneficial for managing outages. The plan to enable customer outage calls to be automatically logged into the system has been postponed to 2017 and 2018 due to the need to upgrade internal phone systems. FPUC purchased an application in 2015 that will enhance the current OMS by enabling crews to electronically receive and close outages in the field. The implementation of this application was completed in 2016. Field data will be collected, analyzed, and entered into the OMS. The process is triggered 72 hours prior to a storm. FPUC collects outage data attributed to overhead and underground equipment failure in order to evaluate the associated reliability indices. During 2017, there were no projects to convert overhead facilities to underground on FPUC's system. In 2018, FPUC successfully implemented an OMS enhancement in which customers are able to leave a voice message.

- Gulf completed its distribution facilities mapping transition to its new Distribution GIS in 2009. The transmission system has been completely captured in the transmission GIS database. The Distribution GIS and Transmission GIS are continually updated with any additions and changes as the associated work orders for maintenance, system improvements, and new business are completed. This ongoing process provides Gulf sufficient information to use with collected forensic data to assess performance of its overhead and underground systems in the event of a major storm. The forensic data collection process was tested prior to storm season. This process was activated as part of Gulf's pre-storm preparation for Hurricane Nate. Even though there was minimal damage to Gulf's facilities, Gulf and its contractors tested the transfer of data. Using aerial patrol, Gulf will be able to capture an initial assessment of the level of damage to the transmission system and record the GPS coordinates and failures with the Transmission Line Inspection System. Gulf's existing Common Transmission Database will be utilized to capture all forensic information. Gulf did experience outages and damage from transmission outages, planned outages, and all other outages in 2017, but these outage events did not produce major storm related data. Gulf will continue its record keeping and analysis of data associated with overhead and underground outages.

- TECO's GIS continues to serve as the foundational database for all transmission, substation and distribution facilities. Development and improvement of the GIS continues on an ongoing basis. In 2017, over 35 changes and enhancements to the system were made including: data updates, and functionality changes to better conform to business processes and improve the user experience. TECO uses an outside contractor to execute the process that includes the establishment of a field asset database, forensic measurement protocol, integration of forensics activity with overall system restoration, forensics data sampling and reporting format. TECO incurs costs based on the category of storm and level of activation of the outside contractor depending upon the number of storm events in 2018. The data collected following a significant storm will be used to determine the root cause of damage. An established process is in place for collecting post-storm data, forensic analysis and outage performance data for both overhead and underground systems.

Initiative 8 - Increased Utility Coordination with Local Governments

The Commission's goal with this program is to promote an ongoing dialogue between IOUs and local governments on matters such as vegetation management and underground construction, in addition to the general need to increase pre- and post-storm coordination. The increased coordination and communication is intended to promote IOU collection and analysis of more detailed information on the operational characteristics of underground and overhead systems.

This additional data is also necessary to inform customers and communities that are considering converting existing overhead facilities to underground facilities (undergrounding), as well as to assess the most cost-effective storm hardening options.

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

♦ DEF's storm planning and response program is operational year-round to respond to catastrophic events at anytime. There are approximately 70 employees assigned full-time, year-round to coordinate with local governments on issues such as emergency planning, vegetation management, undergrounding, and service related issues. In 2017, DEF visited several EOCs in different counties to review storm procedures and participated in several different storm drills including Florida's state wide annual storm drill. For 2018, DEF plans to continue to participate in county storm drills and Florida's state wide annual storm drill. Also in 2017, DEF held 11 individual live line demonstration sessions across its service territory. These events addressed emergency response, general safety awareness, a utility's perspective on hurricane preparedness, and safety issues. Representatives from the sheriff's departments, public schools, and fire/rescue departments attended these sessions.

  When Hurricane Irma made landfall in Florida, DEF provided around the clock support for the State EOC and 35 county EOCs within its service territory. DEF executed its "Make It Safe" road-clearing program and modified it to provide support to counties well beyond 24-48 hours. In an effort to keep local governments and the public informed during the restoration process, DEF sent outbound customer messages, used social media sites, conducted print and broadcast interviews, participated in daily round table calls with the State, produced update videos, and distributed news releases.

♦ FPL, in 2017, continued efforts to improve local government coordination. The company conducted meetings with county emergency operations managers to discuss critical infrastructure locations in each jurisdiction. FPL also invited federal and state emergency management personnel to participate in FPL's annual storm preparedness drill. In 2017, FPL conducted over 1,000 community presentations providing information on storm readiness and other topics of community interest. FPL's dedicated government portal website has information that government leaders rely on to help during storm recovery. The site contains media alerts and releases, customer outage information and maps, critical infrastructure facility information, estimated time of restoration information, FPL staging site locations and available personnel resources. In addition, FPL meets with all counties and municipalities that request information on line clearing and underground conversions. The meetings also include discussions on vegetation management and planting the "right tree in the right place."

- ♦ FPUC has continued its involvement with local governments regarding reliability issues with emphasis on vegetation management. FPUC's current practice is to have its personnel located at the county EOCs on a 24-hour basis during emergency situations to ensure good communication. FPUC also has a dedicated Manager of Government Relations in each division. The manager's role is to maintain relationships with local and state government officials and staff, and business and community leaders. The manager is also responsible for responding to customer issues referred by governmental officials.

- ♦ Gulf meets with governmental entities for all major projects, as appropriate, to discuss the scope of the projects and coordinate activities involved with project implementation. Gulf maintains year-round contact with city and county officials to ensure cooperation in planning, good communications, and coordination of activities. In 2017, Gulf participated in hurricane drills, EOC training, and statewide exercises. Gulf assigns employees to county EOCs throughout Northwest Florida to assist during emergencies. Gulf also conducts a storm drill each year. In 2017, Gulf's service area was not significantly affected by any "Named Storms" and received minimal damage from Hurricanes Irma and Nate. However, Gulf activated its mutual assistance plan and additional offsite crews responded during these events.

- ♦ TECO's communication efforts, in 2017, focused on maintaining existing vital governmental contacts and continued participation on standing disaster recovery planning committees. TECO participated in joint storm workshops, training involving governmental officials and exercises with Hillsborough, Polk, and Pinellas Counties and municipal agencies. TECO continues to work with local, state, and federal governments to streamline the flow of information to help efforts to restore all service as quickly as possible. Hurricane Irma triggered all county and municipal agencies to activate their EOCs. TECO had a representative in the EOCs for Oldsmar, Plant City, Tampa, Temple Terrace, Hillsborough County, Pasco County, Pinellas County, and Polk County.

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

PURC assisted Florida's electric utilities by coordinating a three-year research effort, from 2006 to 2009, in the area of hardening the electric infrastructure to better withstand and recover from hurricanes. Hurricane winds, undergrounding, and vegetation management research are key areas explored in these efforts by all of the research sponsors involved with PURC. Since that time, PURC compiles a research report every year to provide the utilities with results from its research. The latest report was issued February 2018.

Current projects in this effort include: (1) research on undergrounding existing electric distribution facilities by surveying the current literature including case analyses of Florida underground projects, and developing a model for projecting the benefits and costs of converting overhead facilities to underground; (2) data gathering and analysis of hurricane winds in Florida and the possible expansion of a hurricane simulator that can be used to test hardening approaches; and (3) an initiative to increase public outreach to address storm preparedness in the wake of Hurricane Sandy. This included reaching out to affected states for further data and a print debate surrounding overhead vs. underground installation of power lines.

The effort is the result of FPSC Order No. PSC-06-0351-PAA-EI, issued April 25, 2006, in Docket No. 20060198-EI, directing each investor-owned electric utility to establish a plan that increases collaborative research to further the development of storm resilient electric utility infrastructure and technologies that reduce storm restoration costs and outages to customers. The order directed them to solicit participation from municipal electric utilities and rural electric cooperatives in addition to available educational and research organizations.

The IOUs joined with the municipal electric utilities and rural electric cooperatives in the state (collectively referred to as the Project Sponsors) to form a steering committee of representatives from each utility and entered into a Memorandum of Understanding (MOU) with PURC. In serving as the research coordinator for the project outlined by the MOU, PURC manages the workflow and communications, develops work plans, serves as a subject matter expert and conducts research, facilitates the hiring of experts, coordinates with research vendors, advise the project sponsors, and provides reports for project activities.

In 2017, PURC and the Steering Committee organized a web-based workshop for over 40 participants from the Project Sponsors. The workshop was held to orient new members on the model, (that is described in the undergrounding section below), of the costs and benefits of storm hardening strategies and to discuss the integration of data from recent storm activities. Following the demonstration of the model, participants discussed strategies for adding data from recent storm experiences to the model. The utilities agreed to update the model with their data from the most recent storm (Hurricane Irma). This effort should be completed in 2018.

Undergrounding Of Electric Utility Infrastructure: All five IOUs participate with PURC, along with the other cooperative and municipal electric utilities, in order to perform beneficial research regarding hurricane winds and storm surge within the state. The group's research shows that while underground systems on average have fewer outages than overhead systems, they can sometimes take longer to repair. Analyses of hurricane damage in Florida found that underground systems might be particularly susceptible to storm surge. The research on undergrounding has been the focus for understanding the economics and effects of hardening strategies, including undergrounding. As a result, Quanta Technologies was contracted to conduct a three-phase project to understand the economics and effect of hardening policies in order to make informed decisions regarding hardening of underground facilities.

Phase I of the project was a meta-analysis of existing research, reports, methodologies, and case studies. Phase II examined specific undergrounding project case studies in Florida and included an evaluation of relevant case studies from other hurricane prone states and other parts of the world. Phase III developed a methodology to identify and evaluate the costs and benefits of undergrounding specific facilities in Florida. The primary focus is the impact of undergrounding on hurricane performance. This study also considered benefits and drawbacks of undergrounding during non-hurricane conditions. The collaborative refined the computer model developed by Quanta Technologies. The reports for Phase I, Phase II, and Phase III are available at http://warrington.ufl.edu/purc/research/energy.asp.

PURC and the utilities have worked to fill information gaps for model inputs; however, there are still information gaps. There have also been significant investments and efforts in the area of forensic data collection, which includes the utilities' responses and plans to meet the FPSC's storm preparedness initiative. As discussed above, discussions between the project sponsors and the PURC, regarding model updates, are in the process of being scheduled. These discussions are expected to include impacts associated with Hurricanes Hermine, Matthew, and Irma.

PURC has worked with doctoral and master's candidates at the University of Florida to assess the inter-relationships between wind speed and other environmental factors on utility damage. PURC was contacted by the University of Wisconsin and North Carolina State University, who showed interest in the model, but no additional relationships have been established. Researchers at the Argonne National Laboratory also contacted PURC. The researchers were interested in modeling the effects of storm damage and developed a deterministic model, rather than a probabilistic model, themselves. The researchers did use many of the factors that the collaborative attempted to quantify. The researchers that contacted PURC cite the model as the only non-proprietary model of its kind.

The PURC report noted that the research discussed in previous years' reports on the relationship between wind speed and rainfall is still under review. Further results of the relationship and related research can likely be used to supplement and refine the model.

Hurricane Wind Effects: The collaborative group is trying to determine the appropriate level of hardening required for the electric utility infrastructure against wind damage from hurricanes. The project's focus was divided into two categories: (1) accurate characterization of severe dynamic wind loading; and (2) understanding the likely failure modes for different wind conditions. An agreement with WeatherFlow, Inc., to study the effects of dynamic wind conditions upon hurricane landfall includes 50 permanent wind-monitoring stations around the coast of Florida. This agreement expired in 2012; however, it was renewed in April 2017 and will automatically renew annually on the effective date for an additional one-year period, unless terminated by the parties to the agreement. In addition, PURC has developed a uniform forensics data gathering system for use by the utilities and a database that will allow for data sharing that will match the forensics data with the wind monitoring and "Other Weather" data.

Public Outreach: PURC researchers continue to discuss the collaborative effort in Florida with the engineering departments of the state regulators in Connecticut, New York, and New Jersey, Pennsylvania, and regulators in Jamaica, Grenada, Curacao, Samoa, and the Philippines. The regulators and policymakers showed interest in the collaborative effort and its results, but have shown no further interest in participating in the research effort. In addition, PURC researchers also engaged with popular media in preparation for, and in the wake of Hurricane Irma. This included 13 online articles, three radio broadcasts, and a TV broadcast.

Initiative 10 - A Natural Disaster Preparedness and Recovery Program

Each IOU is required to maintain a copy of its current formal disaster preparedness and recovery plan with the Commission. A formal disaster plan provides an effective means to document lessons learned, improve disaster recovery training, pre-storm staging activities and post-storm recovery, collect facility performance data, and improve forensic analysis. In addition, participation in the Commission's annual pre-storm preparedness briefing is required which focuses on the extent to which all Florida electric utilities are prepared for potential hurricane events. The following are some 2017 highlights for each IOU.

- DEF's Storm Recovery Plan is reviewed and updated annually based on lessons learned from the previous storm season and organizational needs. The Distribution System Storm Operational Plan and the Transmission Storm Plan incorporates organizational redesign at DEF, internal feedback, suggestions, and customer survey responses. DEF uses the Extreme Wind Loading standards in accordance with the National Electrical Safety Code, Rule 250C in all planning for transmission upgrades, rebuilds and expansions of existing facilities.

- FPL's Storm Emergency Plan identifies emergency conditions associated with natural disasters and responsibilities and duties of FPL's Emergency Response Organization. The plan provides a summary of overall emergency process, systems, accounting, safe work practices, etc. The plan also provides information on the Emergency Response Organization conducting damage assessment, restoration response, supporting organizations for external agency support, such as regulatory bodies, EOC's, local governments, etc., and support to major commercial and industrial customers. The plan is reviewed annually and revised as necessary.

- FPUC utilizes its Disaster Preparedness and Recovery Plan to prepare for storms annually and will ensure all employees are aware of their responsibilities. The objectives included in the plan to ensure orderly and efficient service restoration are: the safety of employees, contractors, and the general public; early damage assessment in order to develop manpower requirements; request additional manpower as soon as conditions and information indicate the need; provide for orderly restoration activities; provide all logistical needs for employees and contractors; provide ongoing preparation of FPUC's employee buildings, equipment and support functions; and provide support and additional resources for employees and their families. The plan was updated in 2017 and included: the organizational chart to reflect employee changes, telephone contact lists, and the transmission provider was changed from JEA to FPL.

- Gulf's 2018 Storm Restoration Procedures Manual is currently being revised and reviewed and all changes were incorporated by April 1, 2018. Gulf continues to provide annual refresher training in the area of storm preparedness for various storm roles at minimal cost. A mock hurricane drill was completed on May 16, 2017. The drill involved testing the readiness to deal with an unexpected event during a restoration effort. Gulf uses the strategy described in its Storm Restoration Procedures Manual to respond to any natural disaster that may occur. Annually, Gulf develops and refines its planning and preparations for the possibility of a natural disaster. Gulf's restoration procedures establish a plan of action to be utilized for the operation and restoration of generation, transmission, and distribution facilities during major disasters.

- TECO's Emergency Management Plans address all hazards, including extreme weather events. TECO continues to use the policy labeled Emergency Management and Business Continuity. This policy delineates the responsibility at employee, company, and community levels. TECO continues to participate in internal and external preparedness exercises, collaborating with government emergency management agencies, at local, State and Federal levels. Prior to June 1, 2017, all emergency support functions were reviewed, personnel trained, and Incident Command System Logistics and Planning

Section Plans were tested. TECO continues to participate in internal and external preparedness exercises, and collaborates with local, state, and federal government emergency management agencies. During the state's mock hurricane exercise, TECO tested its response and communications plans.

Section II: Actual Distribution Service Reliability

Electric utility customers are affected by all outage and momentary events, regardless of where problems originate. For example, generation events and transmission events, while remote from the distribution system serving a customer, affect the distribution service experience. Actual reliability data is the accumulation of these events.

The actual reliability data includes two subsets of outage data: (1) data on excludable events; and (2) data pertaining to normal day-to-day activities. Rule 25-6.0455(4), F.A.C., explicitly lists outage events that may be excluded:

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

This section provides an overview of each IOU's actual 2017 performance data and focuses on the exclusions allowed by the rule.

Duke Energy Florida, LLC: Actual Data

Table 2-1 provides an overview of key DEF metrics: Customer Minutes of Interruption (CMI) and Customer Interruptions (CI) for 2017. Excludable outage events accounted for approximately 97 percent of the minutes of interruption experienced by DEF's customers. In 2017, DEF experienced a tornado that impacted its service area on January 22, 2017, Tropical Storm Emily on July 31, 2017, and Hurricane Irma on September 9-20, 2017.

The biggest impact on CMI were the "Named Storm" events, which accounted for approximately 96 percent of the excludable minutes of interruptions. DEF stated that the transmission events accounted for 0.40 percent of the minutes of interruptions. DEF stated that the initiating causes varied from equipment failures to weather, but were predominantly weather causes. The sustained causes also varied from major storm weather to vegetation. DEF stated that there were 340 major transmission events resulting in exclusion in 2017.

Table 2-1
DEF's 2017 Customer Minutes of Interruptions and Customer Interruptions

2017	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	% of Actual	Value	% of Actual
Reported Actual Data	**4,572,731,881**		**4,056,764**	
Documented Exclusions				
Planned Service Interruptions	19,532,821	0.43%	439,486	10.83%
Named Storms	4,381,736,056	95.82%	1,552,555	38.27%
Tornadoes	6,300,041	0.14%	25,021	0.62%
Ice on Lines		0.00%		0.00%
Planned Load Management Events		0.00%		0.00%
Generation/Transmission Events	18,148,483	0.40%	397,194	9.79%
Extreme Weather (EOC Activation/Fire)		0.00%		0.00%
Reported Adjusted Data	**147,014,480**	**3.22%**	**1,642,508**	**40.49%**

Source: DEF's 2017 distribution service reliability report.

Florida Power & Light Company: Actual Data

Table 2-2 provides an overview of FPL's CMI and CI figures for 2017. Excludable outage events accounted for approximately 99 percent of the minutes of interruption experienced by FPL's customers. FPL reported thirteen tornadoes, two fire events, Hurricane Irma, Hurricane Nate, Tropical Storm Emily, and Tropical Storm Philippe in 2017. FPL reports that even though Hurricane Nate did not make landfall in its service territory, seven of FPL's territories were impacted. Tropical Storm Emily impacted FPL's service territories on July 31, 2017, through August 1, 2017, Hurricane Irma on September 7-24, 2017, Hurricane Nate on October 8, 2017, and Tropical Storm Philippe on October 28-29, 2017. The two fire events impacted the Naples region on March 5-6, 2017, and April 22-23, 2017. The tornadoes affected the following regions:

- West Dade and West Palm regions on January 22-23, 2017
- North Florida region on February 7-8, 2017
- Toledo Blade region on March 13, 2017
- Toledo Blade and Wingate regions on March 14, 2017
- Treasure Coast region on March 23, 2017
- Naples and Treasure Coast regions on April 6, 2017
- Boca Raton region on May 2, 2017
- North Florida region on May 24, 2017
- Gulfstream region on June 5, 2017
- North Florida region on June 6, 2017
- Treasure Coast and Brevard regions on August 18, 2017
- Manasota region on August 26-27, 2017
- Gulfstream region on October 24, 2017

The biggest impact on CMI was the "Named Storm" events, which accounted for approximately 98 percent of the minutes of interruption. FPL explained that after each extreme weather event, it gathers relevant information to critique its processes and performance. FPL continues to further develop new technology to strengthen its emergency response. Two examples of FPL's new technology are: (1) a mobile application which combines outage tickets, weather information, electrical network information, customer energy consumption and voltage, restoration crew locations and meter status; and (2) another new technology uses smart meter information to confirm power status of all smart meters in an area before the restoration crews leave that area. These new technologies will assist with diagnosing problems accurately.

Table 2-2
FPL's 2017 Customer Minutes of Interruptions and Customer Interruptions

2017	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	% of Actual	Value	% of Actual
Reported Actual Data (1)	**19,490,525,605**		**11,582,664**	
Documented Exclusions				
Planned Service Interruptions	24,053,437	0.12%	279,467	2.41%
Named Storms	19,172,871,947	98.37%	6580299	56.81%
Tornadoes	25,985,521	0.13%	269314	2.33%
Ice on Lines	0	0.00%	0	0.00%
Planned Load Management Events	0	0.00%	0	0.00%
Generation/Transmission Events (2)	10,302,765	0.05%	769,414	6.64%
Extreme Weather (EOC Activation/Fire)	1,052,790	0.01%	7,495	0.06%
Reported Adjusted Data	**266,561,910**	**1.37%**	**4,446,089**	**38.39%**

Notes: (1) Excludes Generation/Transmission Events per Rule 25-6.0455(2), .F.A.C.; and (2) Information Only, as reported actual data already excludes Generation/Transmission Events.
Source: FPL's 2017 distribution service reliability report.

Florida Public Utilities Company: Actual Data

Table 2-3 provides an overview of FPUC's CMI and CI figures for 2017. Excludable outage events accounted for approximately 93 percent of the minutes of interruption experienced by FPUC's customers. The biggest impact on CMI was the "Named Storms" events, which accounted for approximately 84 percent of the minutes of interruption. FPUC reported that neither the Northeast nor the Northwest divisions were impacted by tornadoes during 2017. FPUC reported that the following weather events impacted its service areas: Tropical Storm Cindy on June 19-22, 2017, and Hurricane Harvey on August 29-31, 2017, affected the Northwest division, and Hurricane Irma on September 9-13, 2017, affected both divisions.

FPUC reported the Northeast division experienced major transmission events on January 21, 2017, May 31, 2017, and July 10, 2017. The Northeast division experienced a substation outage on December 12, 2017. The Northwest division experienced one substation event on September 15, 2017. Both divisions had several planned outages that allowed FPUC to perform maintenance to different sections of the distribution system.

Table 2-3
FPUC's 2017 Customer Minutes of Interruptions and Customer Interruptions

2017	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	% of Actual	Value	% of Actual
Reported Actual Data	**55,971,247**		**149,430**	
Documented Exclusions				
Planned Service Interruptions	182,313	0.33%	2,735	1.83%
Named Storms	47,228,463	84.38%	31,851	21.31%
Tornadoes	0	0.00%	0	0.00%
Ice on Lines	0	0.00%	0	0.00%
Planned Load Management Events	0	0.00%	0	0.00%
Generation/Transmission Events	2,345,212	4.19%	57,583	38.54%
Extreme Weather (EOC Activation/Fire)	2,182,893	3.90%	9,541	6.38%
Reported Adjusted Data	**4,032,366**	**7.20%**	**47,720**	**31.93%**

Source: FPUC's 2017 distribution service reliability report.

Gulf Power Company: Actual Data

Table 2-4 provides an overview of Gulf's CMI and CI figures for 2017. Excludable outage events accounted for approximately 28 percent of the minutes of interruption experienced by Gulf's customers. The biggest impact on CMI was "Named Storms," which accounted for approximately 14 percent of the minutes of interruption. Hurricanes Irma on September 11, 2017, Hurricane Nate on October 7, 2017, and Tropical Storm Cindy on June 19, 2017, affected all three regions of Gulf's service area. Gulf reported five tornadoes, which accounted for approximately 4 percent of the minutes of interruption. The tornadoes affected the following regions:

- ♦ Eastern region on January 21, January 22, and June 21, 2017
- ♦ Central region on January 21, January 22, May 21, and June 21, 2017
- ♦ Western region on January 2, January 21, January 22, and June 21, 2017

Gulf reported that all of its regions were affected by transmission events, which accounted for 7 percent of the minutes of interruptions. The causes for the transmission events include erroneous operations, external utility trouble, severe weather, deterioration, failed equipment, animal, lightning, vegetation, relay misoperation, and planned outages. Gulf explained that external utility trouble is defined as an outage occurring on another utility's system that affects Gulf's facilities or its customers. When this outage occurs, Gulf will sectionalize from the other utility if possible and restore the system after the utility has made its repairs. Gulf reported the cause of the external utility trouble was due to lightning and vegetation and affected the Central region. Gulf further explained the relay misoperation was due to a lightning strike causing two breakers to open simultaneously.

Table 2-4
Gulf's 2017 Customer Minutes of Interruption and Customer Interruptions

2017	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	**% of Actual**	**Value**	**% of Actual**
Reported Actual Data	**74,779,078**		**792,046**	
Documented Exclusions				
Planned Service Interruptions	3,140,466	4.20%	58,073	7.33%
Named Storms	10,292,926	13.76%	60,376	7.62%
Tornadoes	2,766,751	3.70%	13,088	1.65%
Ice on Lines		0.00%		0.00%
Planned Load Management Events		0.00%		0.00%
Generation/Transmission Events	4,947,579	6.62%	107,793	13.61%
Extreme Weather (EOC Activation/Fire)		0.00%		0.00%
Reported Adjusted Data	**53,631,356**	**71.72%**	**552,716**	**69.78%**

Source: Gulf's 2017 distribution service reliability report.

Tampa Electric Company: Actual Data

Table 2-5 provides an overview of TECO's CMI and CI figures for 2017. Excludable outage events accounted for approximately 77 percent of the minutes of interruption experienced by TECO's customers. TECO reported that all regions were impacted by Hurricane Irma from September 10-18, 2017. The "Named Storms" account for approximately 71 percent of the minutes of interruption.

The Generation/Transmission events accounted for approximately 3 percent of the minutes of interruption. TECO reported 13 transmission outages in 2017. The causes listed included equipment failure, vehicle collision, vegetation related, and other weather. TECO reported that all equipment failures were repaired, structures replaced, overgrown vegetation were trimmed, and poles were repaired.

Table 2-5
TECO's 2017 Customer Minutes of Interruptions and Customer Interruptions

2017	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	% of Actual	Value	% of Actual
Reported Actual Data	**244,456,219**		**1,441,901**	
Documented Exclusions				
Planned Service Interruptions	7,020,124	2.87%	156,999	10.89%
Named Storms	173,523,001	70.98%	300,668	20.85%
Tornadoes		0.00%		0.00%
Ice on Lines		0.00%		0.00%
Planned Load Management Events		0.00%		0.00%
Generation/Transmission Events	8,469,160	3.46%	202,686	14.06%
Extreme Weather (EOC Activation/Fire)		0.00%		0.00%
Reported Adjusted Data	**55,443,934**	**22.68%**	**781,548**	**54.20%**

Source: TECO's 2017 distribution service reliability report.

Section III: Adjusted Distribution Service Reliability Review of Individual Utilities

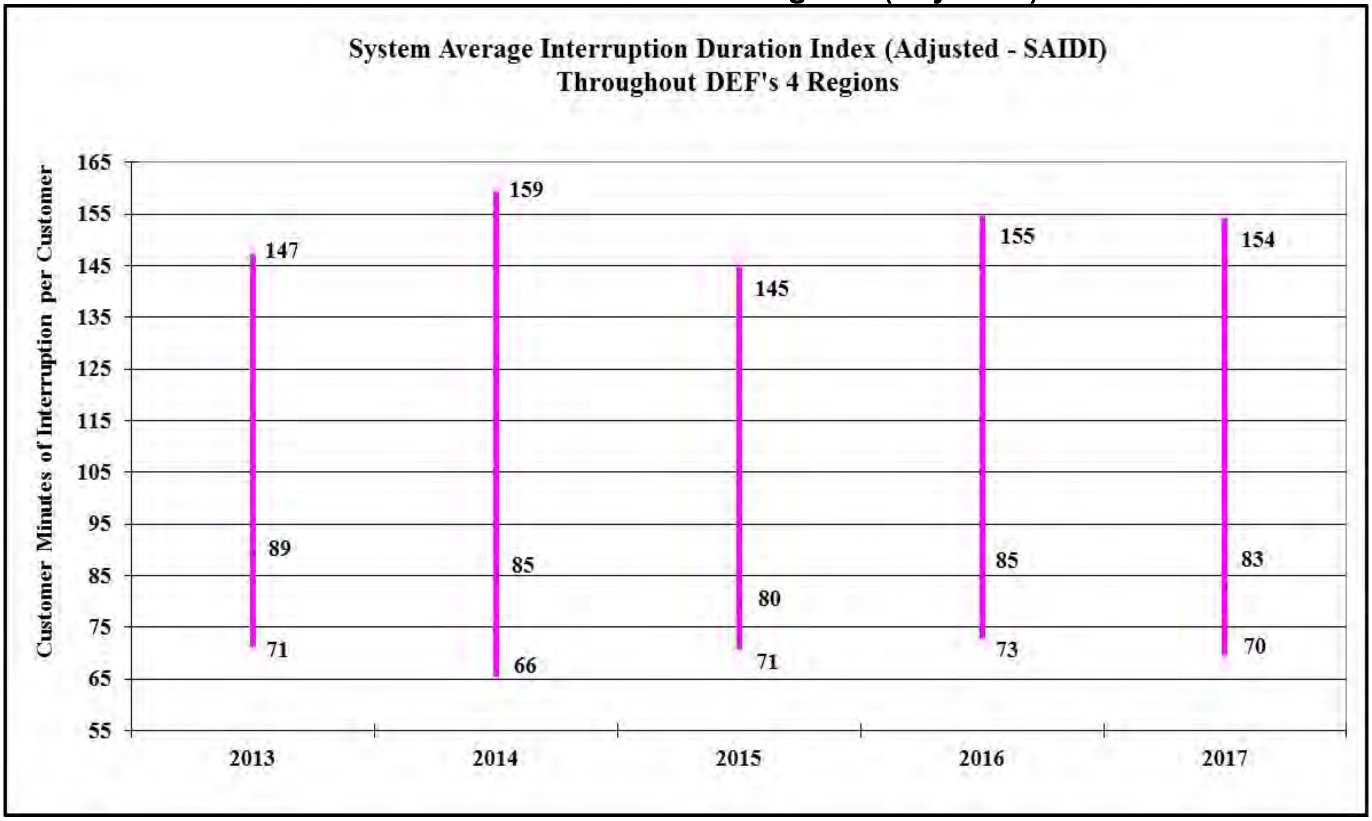
The adjusted distribution reliability metrics or indices provide insight into potential trends in a utility's daily practices and maintenance of its distribution facilities. This section of the review is based on each utility's reported adjusted data.

Duke Energy Florida, LLC: Adjusted Data

Figure 3-1 charts the adjusted SAIDI recorded across DEF's system and depicts decreases in the lowest, the average and highest values for 2017. DEF reported that 2017 presented the Utility with the most challenging weather related year. DEF notes that there were seven days in 2017 that had weather-related outages from afternoon thunderstorms, which caused more than 50 percent of customer outages on those days.

DEF's service territory is comprised of four regions: North Coastal, South Coastal, North Central, and South Central. **Figure 3-1** illustrates that the North Coastal region continues to report the poorest SAIDI over the last five years, fluctuating between 147 minutes and 154 minutes. While the South Coastal and South Central regions have the best or lowest SAIDI for the same period. The North Coastal region is rural and has more square miles when compared to the other regions. This region is also served by predominantly long circuits with approximately 7,700 miles of overhead and underground main circuits. DEF explained that these factors result in higher exposure to outage causes and higher reliability indices.

Figure 3-1
SAIDI across DEF's Four Regions (Adjusted)



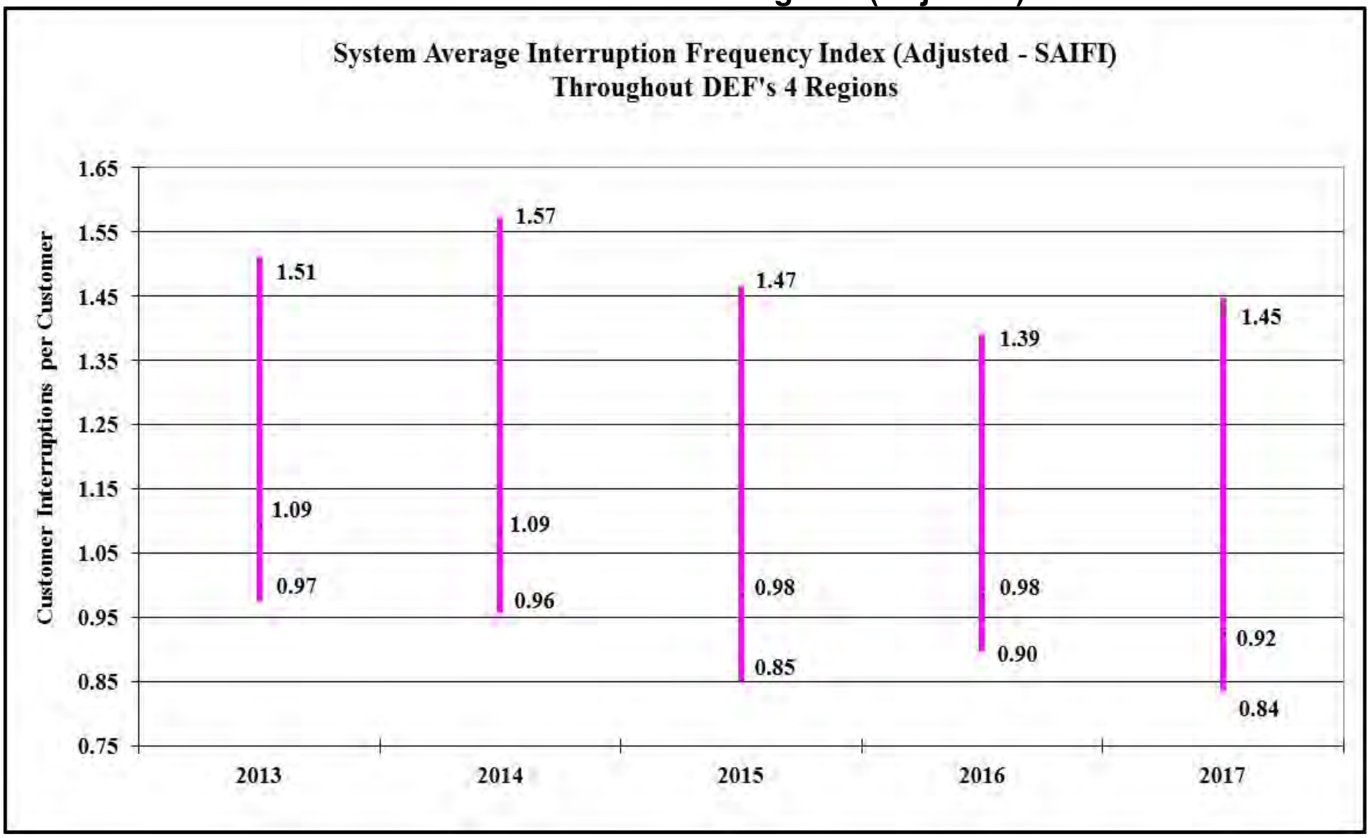
DEF's Regions with the Highest and Lowest Adjusted SAIDI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIDI	North Coastal	North Coastal	North Coastal	North Coastal	North Coastal
Lowest SAIDI	South Coastal	South Coastal	South Central	South Coastal	South Central

Source: DEF's 2013-2017 distribution service reliability reports.

Figure 3-2 shows the adjusted SAIFI across DEF's system. The minimum, maximum, and average SAIFI indexes are trending downward. There were decreases of 6 percent for the minimum value, and 6 percent for the average value, and an increase of 9 percent for the maximum value, in 2017. The South Central region had the lowest number of interruptions, while the North Coastal region continues to have the highest number of interruptions.

Figure 3-2
SAIFI across DEF's Four Regions (Adjusted)



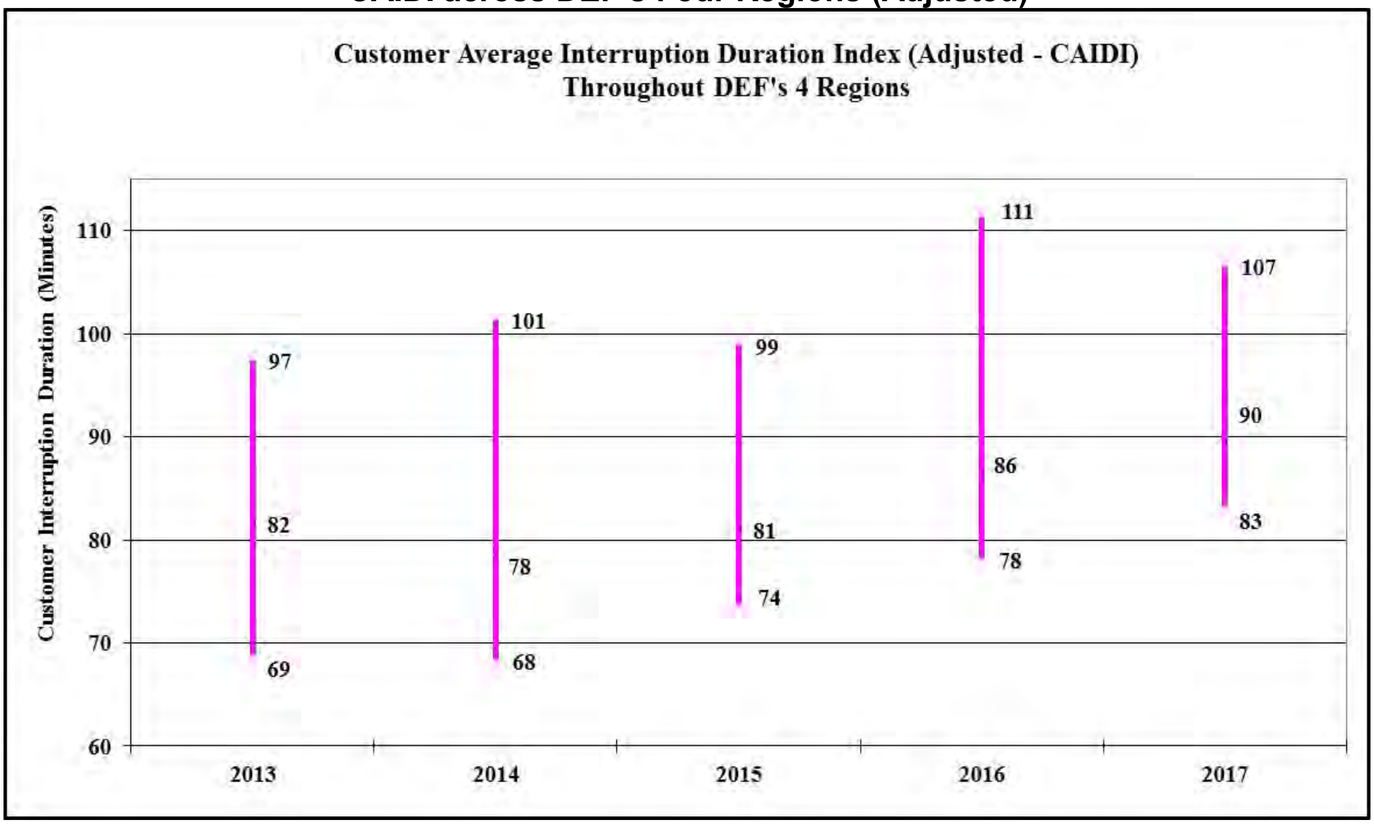
DEF's Regions with the Highest and Lowest Adjusted SAIFI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIFI	North Coastal	North Coastal	North Coastal	North Coastal	North Coastal
Lowest SAIFI	South Central	South Coastal	North Central	South Coastal	South Central

Source: DEF's 2013-2017 distribution service reliability reports.

Figure 3-3 illustrates the CAIDI, or the average number of minutes a customer is without power when a service interruption occurs, for DEF's four regions. DEF's adjusted CAIDI is increasing for a five-year period from 82 minutes in 2013 to 90 minutes in 2017. The North Coastal region has continued to have the highest CAIDI level for the past five years with the maximum CAIDI trending upward. The South Central region had the lowest CAIDI level during the same period with the minimum CAIDI trending upward.

Figure 3-3
CAIDI across DEF's Four Regions (Adjusted)



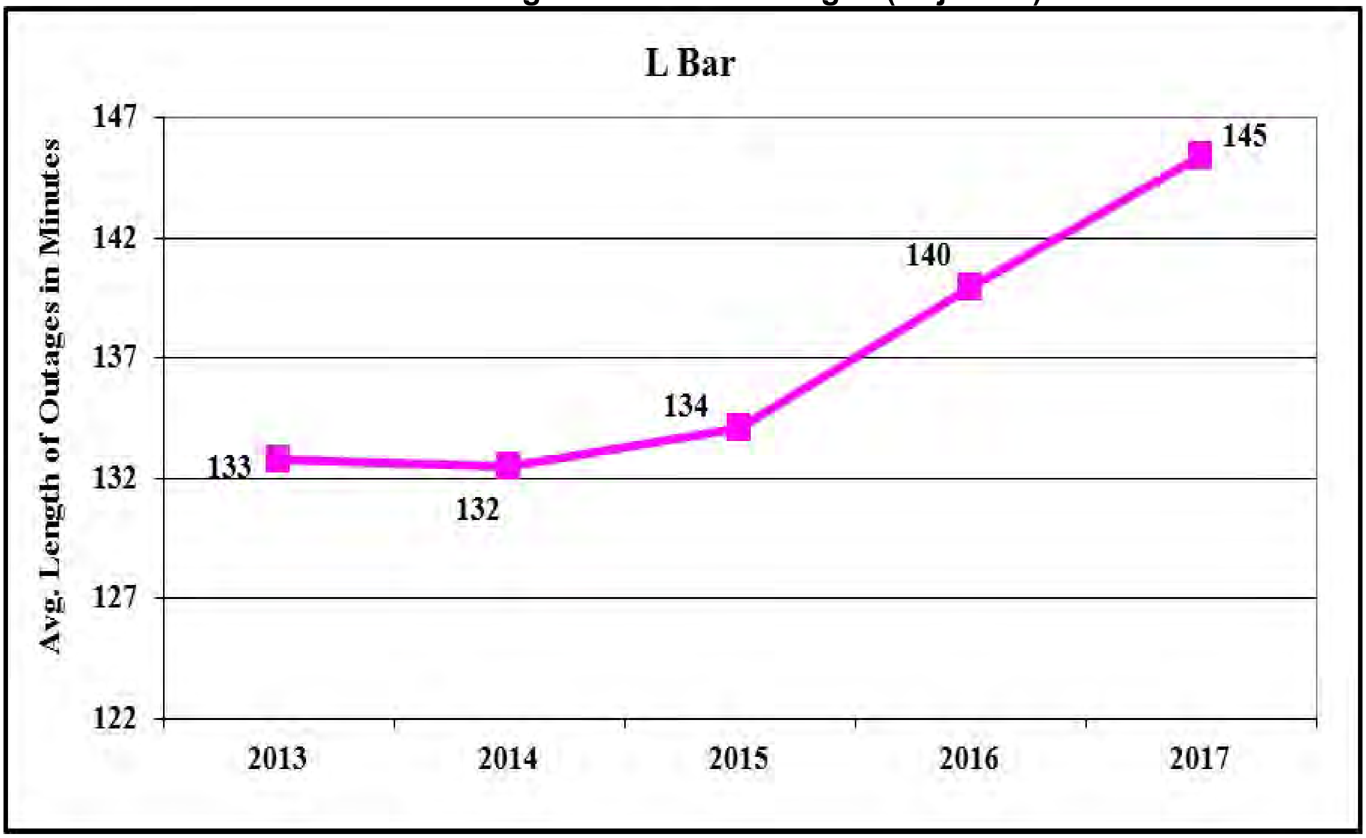
DEF's Regions with the Highest and Lowest Adjusted CAIDI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest CAIDI	North Coastal	North Coastal	North Coastal	North Coastal	North Coastal
Lowest CAIDI	South Coastal	South Coastal	South Coastal	South Central	South Central

Source: DEF's 2013-2017 distribution service reliability reports.

Figure 3-4 is the average length of time DEF spends restoring customers affected by outage events, excluding hurricanes and certain other outage events. This is displayed by the index L-Bar in the graph below. The data demonstrates an overall 8 percent increase of outage durations since 2013, and a 3 percent increase from 2016 to 2017. DEF's overall L-Bar index is trending upward, indicating that DEF is spending more time restoring service from outage events.

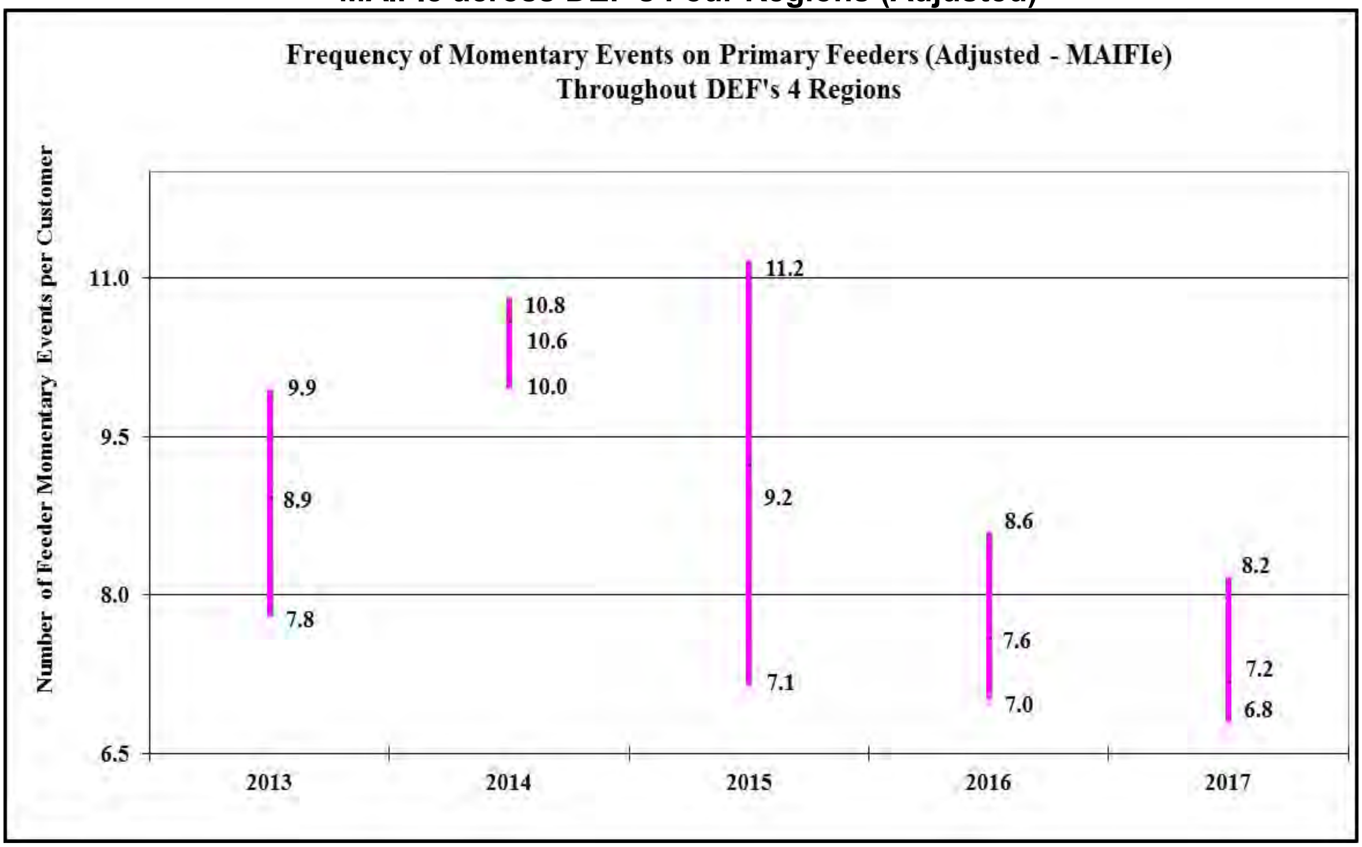
Figure 3-4
DEF's Average Duration of Outages (Adjusted)



Source: DEF's 2013-2017 distribution service reliability reports.

Figure 3-5 illustrates the frequency of momentary events on primary circuits for DEF's customers recorded across its system. These momentary events often affect a small group of customers. A review of the supporting data suggests that the MAIFIe results between 2013 and 2017 appear to be trending downward showing improvement and there was a decrease in the average MAIFIe of 5 percent from 2016 to 2017. The North Coastal, South Central, and South Coastal regions appear to have the best (lowest) results for the last five years. There was a 3 percent decrease for the lowest MAIFIe from 2016 to 2017. The South Coastal, North Central, and North Coastal regions appear to have the worst (highest) results for the last five years. There was a 5 percent decrease from 2016 to 2017.

Figure 3-5
MAIFIe across DEF's Four Regions (Adjusted)



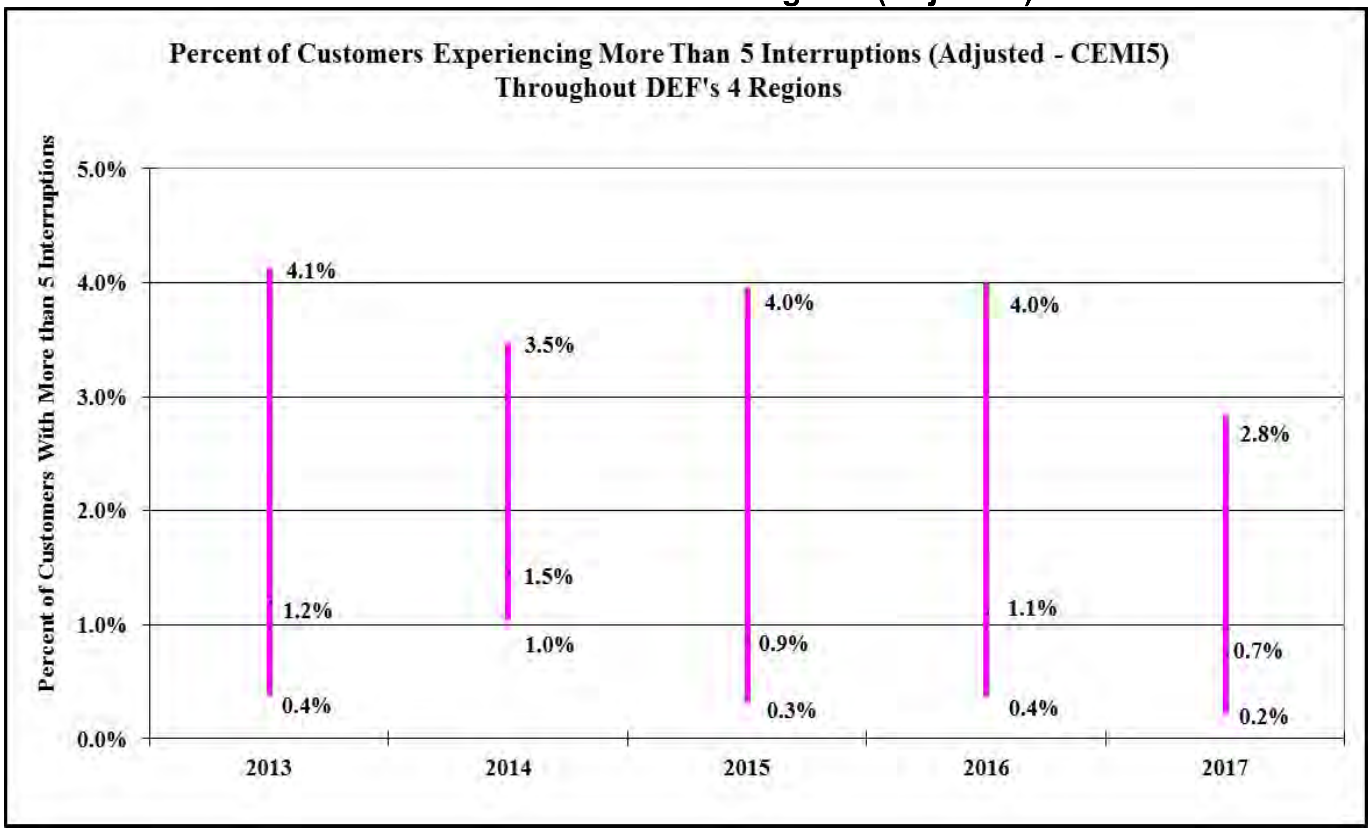
DEF's Regions with the Highest and Lowest Adjusted MAIFIe Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest MAIFIe	South Coastal	North Central	South Coastal	North Central	North Coastal
Lowest MAIFIe	South Central	North Coastal	North Coastal	South Central	South Coastal

Source: DEF's 2013-2017 distribution service reliability reports.

Figure 3-6 charts the percentage of DEF's customers experiencing more than five interruptions over the last five years. DEF reported a decrease in the average CEMI5 performance from 1.1 percent in 2016 to 0.7 percent in 2017. The average CEMI5 is trending downward over the past five years. The South Coastal region has the lowest reported percentage for all of DEF's regions and the North Coastal region continues to have the highest reported percentage.

Figure 3-6
CEMI5 across DEF's Four Regions (Adjusted)



DEF's Regions with the Highest and Lowest Adjusted CEMI5 Distribution Reliability Performance by Year

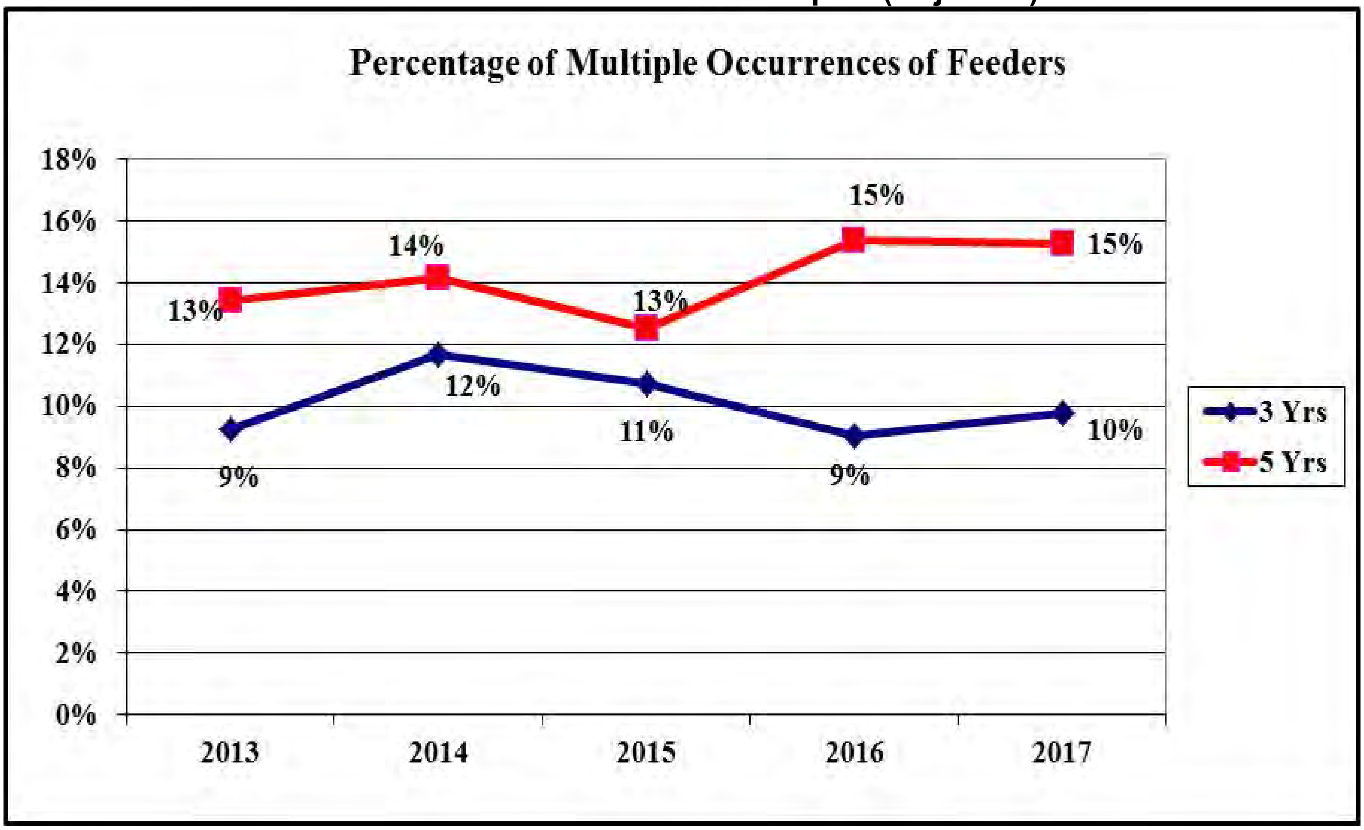
	2013	2014	2015	2016	2017
Highest CEMI5	North Coastal	North Coastal	North Coastal	North Coastal	North Coastal
Lowest CEMI5	South Coastal	South Central	North Central	North Central	South Coastal

Source: DEF's 2013-2017 distribution service reliability reports.

Figure 3-7 shows the fraction of multiple occurrences of feeders using a three-year and five-year basis. During the period of 2013 to 2017, the five-year fraction of multiple occurrences is trending upward as the three-year fraction of multiple occurrences is trending downward. The Three Percent Feeder Report lists the top 3 percent of feeders with the most feeder outage events. The fraction of multiple occurrences is calculated from the number of recurrences divided by the number of feeders reported.

Five of DEF's feeders have been on the Three Percent Feeder Report for the last two years consecutively, for totals of three or more years. The outages varied from equipment failure, public dig-ins into an underground cable, vehicular accident, vegetation, thunderstorms, and contractor error. DEF explained that the outage due to contractor error was because the feeder had a hot-line tag, which prevents the reclosing device from going through its normal operations to clear a temporary fault, while the contractors were performing work on the feeder. When the outage occurred, the breaker opened after the first operation creating a permanent fault. DEF replaced the failing equipment, trimmed trees, and performed infrared scans on the feeders. All issues found during the infrared scans were corrected.

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

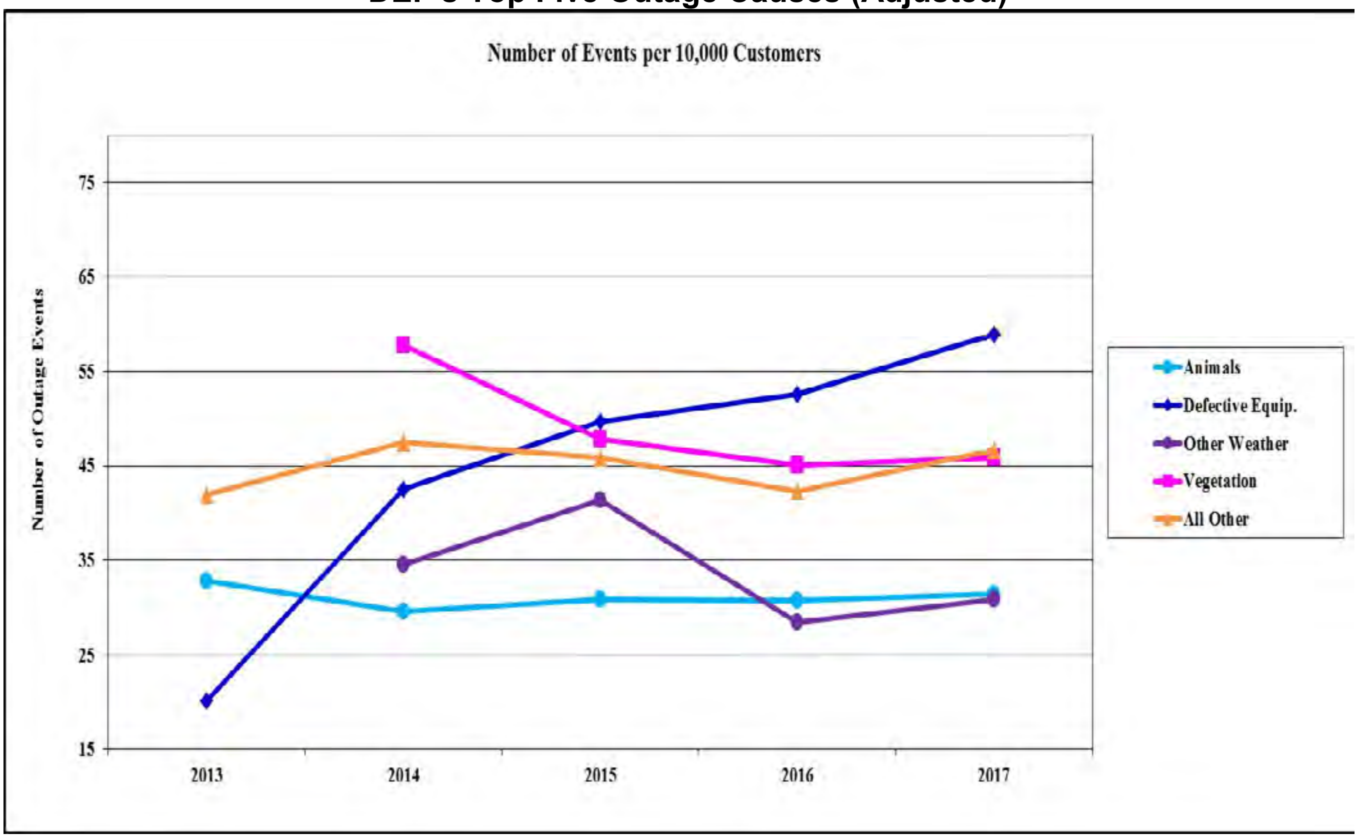


Source: DEF's 2013-2017 distribution service reliability reports.

Figure 3-8 shows the top five causes of outage events on DEF's distribution system normalized to a 10,000-customer base. The figure is based on DEF's adjusted data and represents approximately 93 percent of the top 10 causes of outage events that occurred during 2017. For the five-year period, the top five causes of outage events were "Defective Equipment" (26 percent), "Vegetation" (20 percent), "Other Causes" (20 percent), "Animals" (14 percent), and "Other Weather" (13 percent) on a cumulative basis. Commission staff requested that, beginning with 2014 data, all IOU's use the same outage categories for comparison purposes. As such, the "Vegetation," "Defective Equipment," and "Other Weather" now include outage categories that in the past were separately identified. The outage events caused by "Vegetation" and "Other Weather" are trending downward even though the "Other Weather" category had an increase of 10 percent in 2017. DEF reported that it prioritizes the reliability improvements action plan by balancing historical and current year performance. In addition, current year performance is monitored monthly to identify emergent and seasonal issues including load balancing for cold weather and the need for foot patrols of devices experiencing multiple interruptions.

To address outages related to "Defective Equipment," DEF is continuing to invest in proactive system maintenance activities, such as pole replacements, pad-mounted transformer replacements, and underground cable replacements. In 2018, DEF plans to invest in proactive switchgear replacements, overhead transformer retrofits, and other reliability programs.

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



Source: DEF's 2013-2017 distribution service reliability reports.

Observations: DEF's Adjusted Data

DEF's SAIDI, SAIFI, MAIFIe, CEMI5 and the Three-Year Percent of Multiple Feeder Outage Events are trending downward over the past five years. The CAIDI, L-Bar, and the Five-Year Percent of Multiple Feeder Outage Events are all trending upward over the five-year period. All of the reliability indices, except for CAIDI, L-Bar, and the Three-Year Percent of Multiple Feeder Outage Events, had decreases from 2016 to 2017. The results for the North Coastal Region have continually demonstrated the highest (poorest) service reliability indices of the four regions within DEF for the past five years. The North Coastal region is rural and has more square miles compared to DEF's other service territories.

DEF reported that 2017 presented the Utility with the most challenging weather related year. DEF also reported that there were seven days in 2017 that had weather-related outages from afternoon thunderstorms, which caused more than 50 percent of customer outages on those days.

In 2017, DEF continued its multi-year program to install new electronic reclosers by installing 182 reclosers. The electronic reclosers are designed to reduce the overall number and duration of outages by increased sectionalization on distribution feeders. This project will also improve the communication between the devices. This is an on-going project and work has continued in 2018.

DEF has also installed "self-healing teams" throughout its service territory. This is designed to mitigate the number of customers impacted by outages. DEF will continue to invest in small wire reconductor projects in areas of concerns and will be deploying self-optimizing grid projects beginning in 2018. The self-optimizing grid projects working with the "self-healing teams" will further limit the loss of power to customers and provide automatic fault isolation for multiple concurrent faults. Additionally, in 2018, DEF began work as part of its Grid Investment Plan, which includes proactive switchgear replacements, overhead transformers retrofits and other reliability programs, targeting the North Coastal region. This work is planned to increase in 2019.

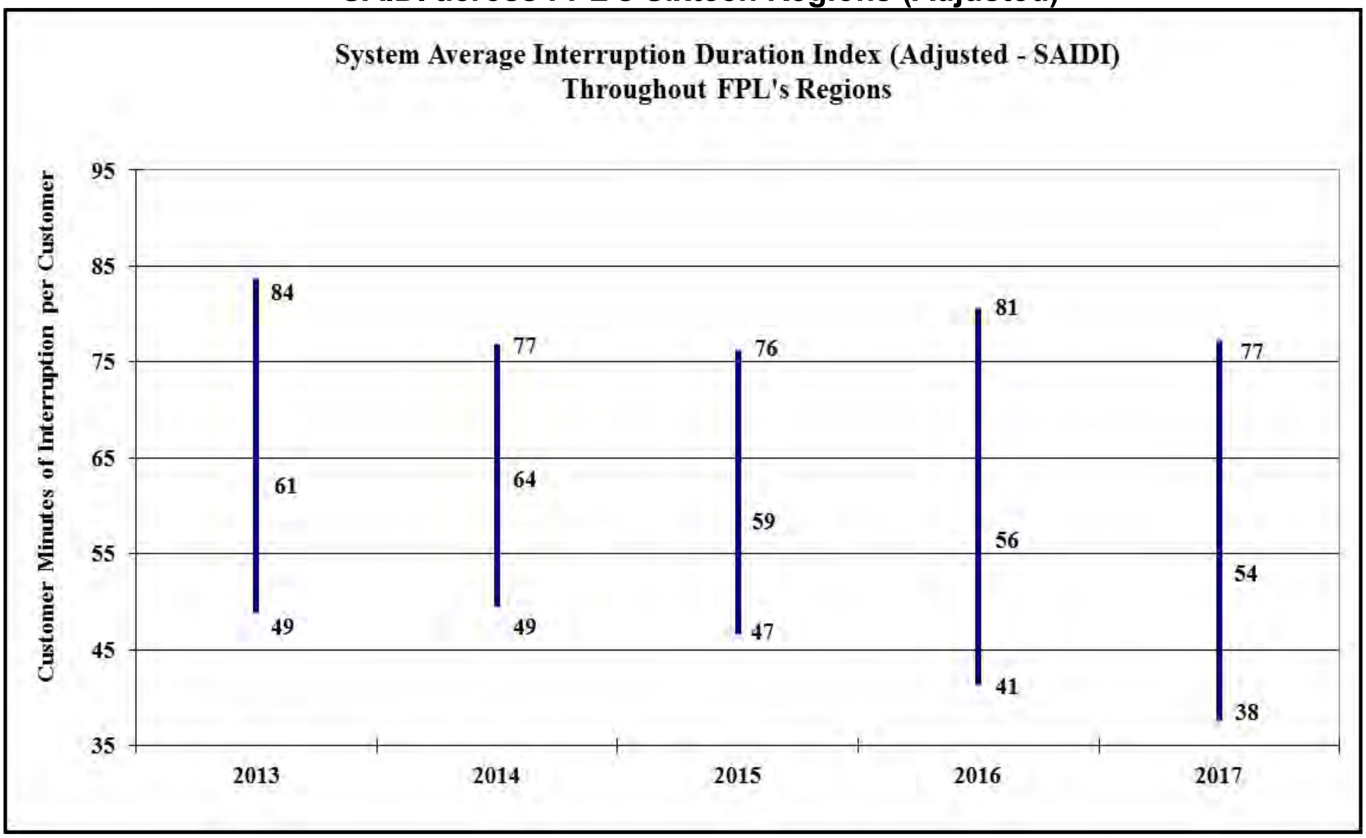
In order to help reduce outage times, DEF implemented nighttime on-duty coverage with its Line Techs in the South Coastal and Central regions. This will drive faster response during the overnight hours by having resources on site and ready to respond. In addition, during periods of increased outage events, DEF engages its contract resources and has vegetation management resources on call to aid in outage response.

To help improve reliability to its customers, DEF has initiated a targeted undergrounding program. This program focuses on historically poor performing overhead lateral circuits and is scheduled to begin in 2018, ending in 10 years. DEF estimates it will convert approximately 1,200 lateral circuits in 30 counties. DEF will start with simple tap line and extended tap line scenarios in order to test its methods, processes and tools, and to incorporate lessons learned before starting on more complex neighborhood and community scenarios. DEF provided an overview of its targeted undergrounding program during the Commission's Internal Affairs meeting on August 7, 2018. Staff will continue to monitor the targeted underground program and report on the progress.

Florida Power & Light Company: Adjusted Data

Figure 3-9 shows the highest, average, and lowest adjusted SAIDI recorded across FPL's system that encompasses four management regions with 16 service areas. The highest and lowest SAIDI values are the values reported for a particular service area. FPL had an overall decrease of 2 minutes (4 percent) to its average SAIDI results for 2017 compared to 2016. The average SAIDI appears to be trending downward over the five-year period of 2013 to 2017. The Pompano region has the best SAIDI results for two out of the five years.

Figure 3-9
SAIDI across FPL's Sixteen Regions (Adjusted)



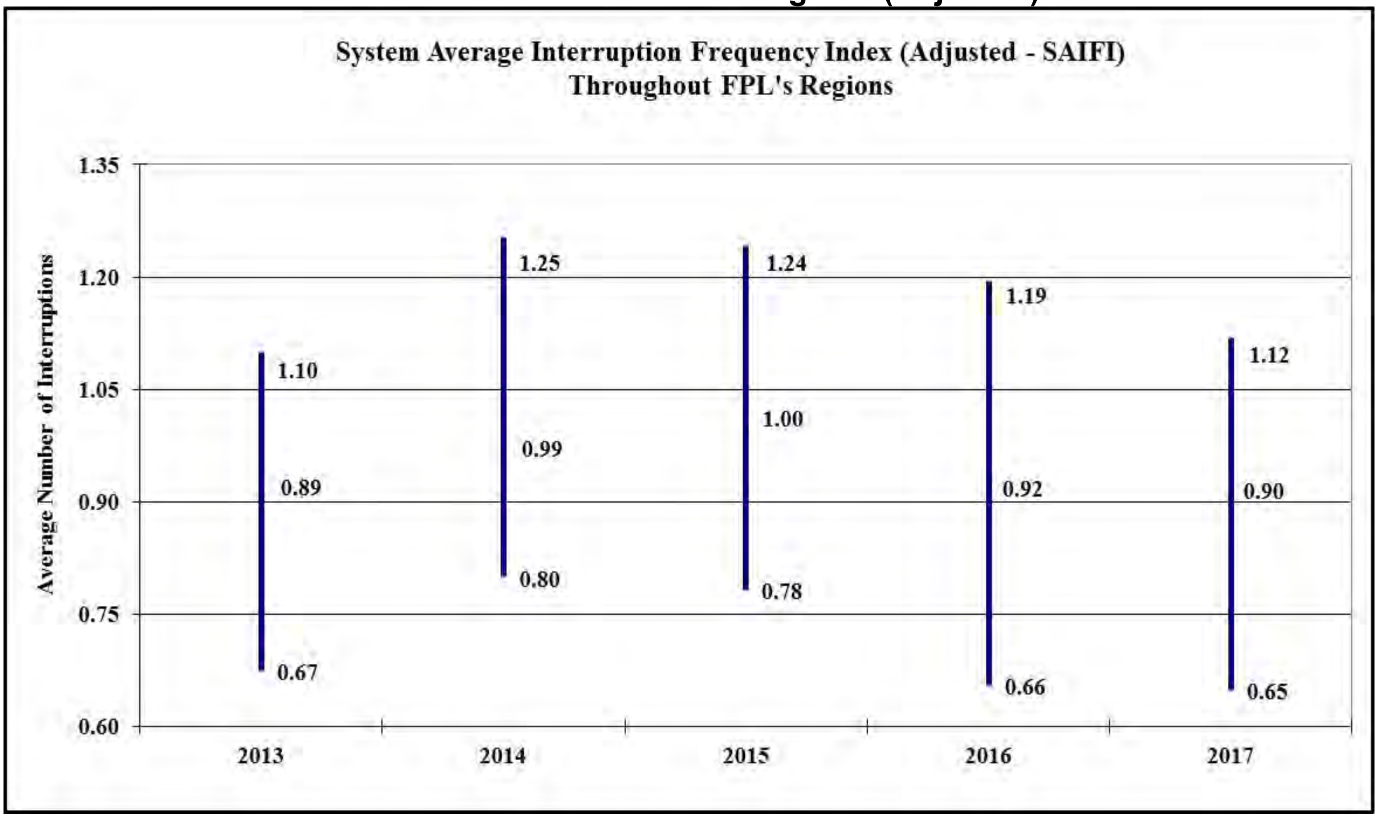
FPL's Regions with the Highest and Lowest Adjusted SAIDI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIDI	North Florida	North Dade	South Dade	Treasure Coast	Toledo Blade
Lowest SAIDI	Pompano	West Palm	Central Dade	Central Dade	Pompano

Source: FPL's 2013-2017 distribution service reliability reports.

Figure 3-10 is a chart of the highest, average, and lowest adjusted SAIFI across FPL's system. FPL had a decrease in the system average results to 0.90 outages in 2017, compared to 0.92 outages in 2016, which is a 2 percent decrease. FPL reported a decrease in the highest SAIFI of 1.12 interruptions in 2017 compared to 1.19 interruptions in 2016. The region reporting the lowest adjusted SAIFI for 2017 was Pompano at 0.65 interruptions compared to 0.66 interruptions in the Central Dade region in 2016. The highest, average and lowest SAIFI appear to be trending downward during the period of 2013 to 2017.

Figure 3-10
SAIFI across FPL's Sixteen regions (Adjusted)



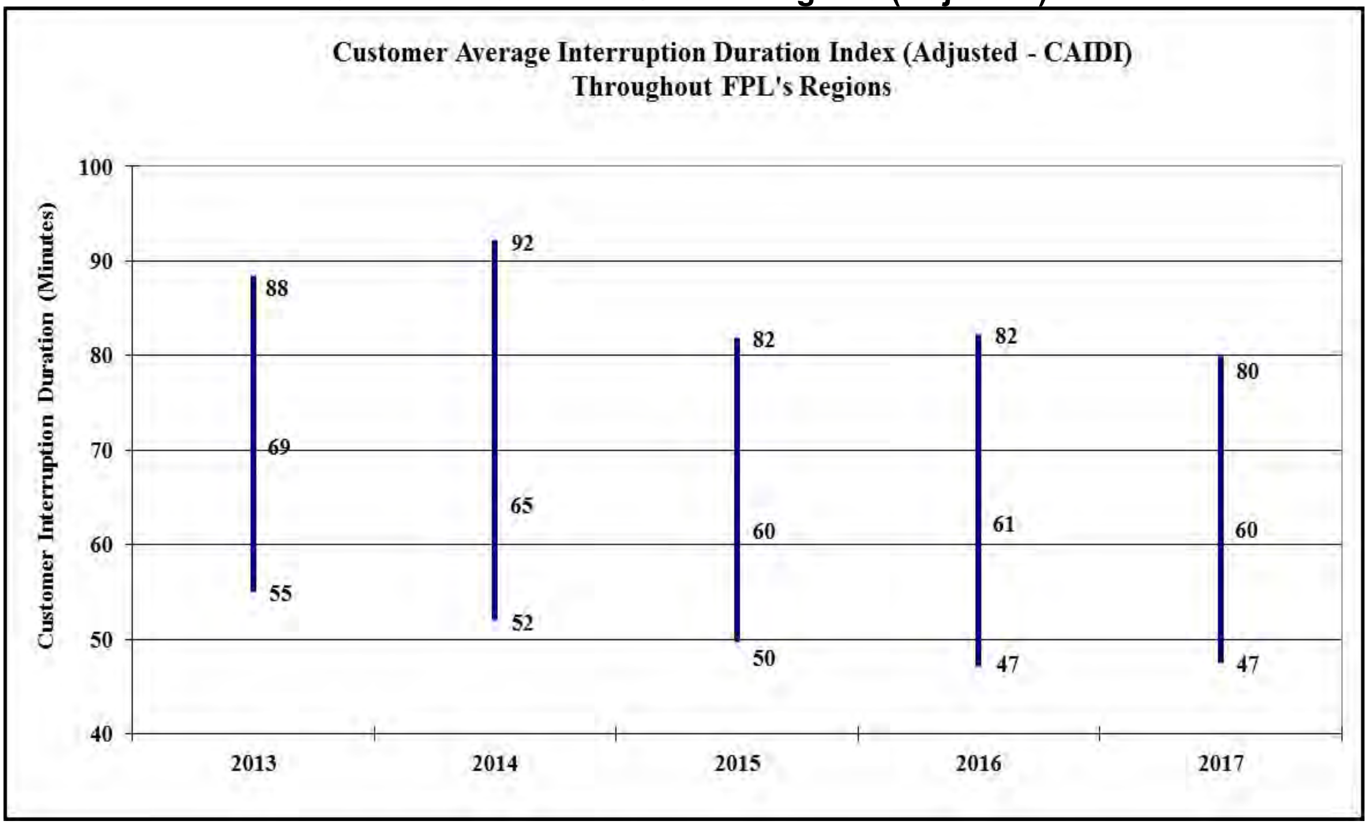
FPL's Regions with the Highest and Lowest Adjusted SAIFI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIFI	Boca Raton	Wingate	West Dade	Treasure Coast	Toledo Blade
Lowest SAIFI	Central Dade	Central Dade	Central Dade	Central Dade	Pompano

Source: FPL's 2013-2017 distribution service reliability reports.

Figure 3-11 depicts FPL's highest, average, and lowest CAIDI expressed in minutes. FPL's adjusted average CAIDI has decreased approximately 2 percent from 61 minutes in 2016 to 60 minutes in 2017. The average duration of CAIDI is trending downward. For 2016 and 2017, the West Palm service area reported the lowest duration of CAIDI at 47 minutes. The highest duration of CAIDI was 80 minutes for the South Dade service area for 2017, which is a decrease from the recorded 82 minutes in 2016.

Figure 3-11
CAIDI across FPL's Sixteen Regions (Adjusted)



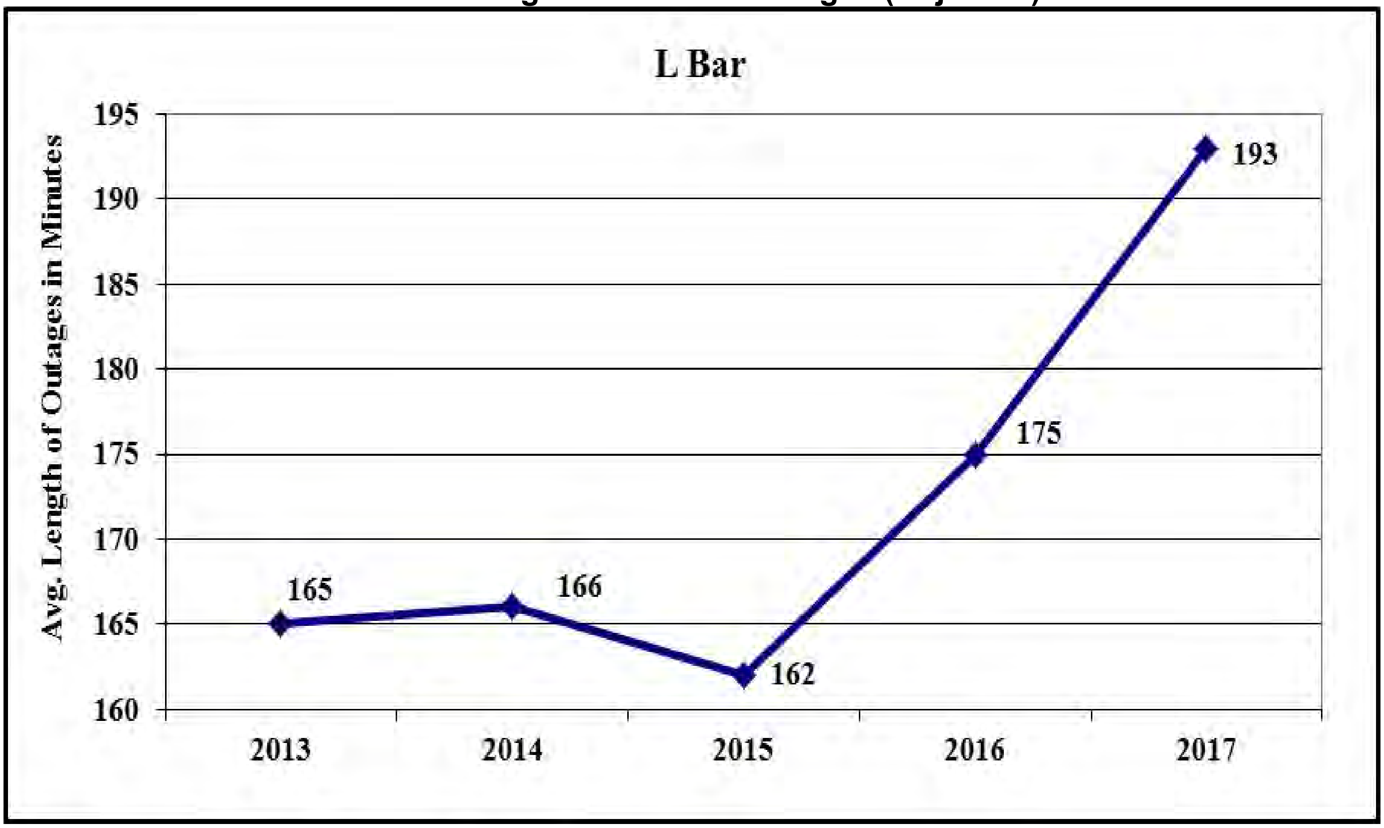
FPL's Regions with the Highest and Lowest Adjusted CAIDI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest CAIDI	North Dade	North Dade	North Dade	North Dade	South Dade
Lowest CAIDI	Boca Raton	Boca Raton	Boca Raton	Boca Raton	West Palm

Source: FPL's 2013-2017 distribution service reliability reports.

Figure 3-12 depicts the average length of time that FPL spends recovering from outage events, excluding hurricanes and other extreme outage events and is the index known as L-Bar (Average Service Restoration Time). FPL had a 9 percent increase in L-Bar from 175 minutes in 2016 to 193 minutes in 2017. There is a 14.5 percent overall increase since 2013 and the L-Bar is trending upward, indicating FPL is spending more time restoring service.

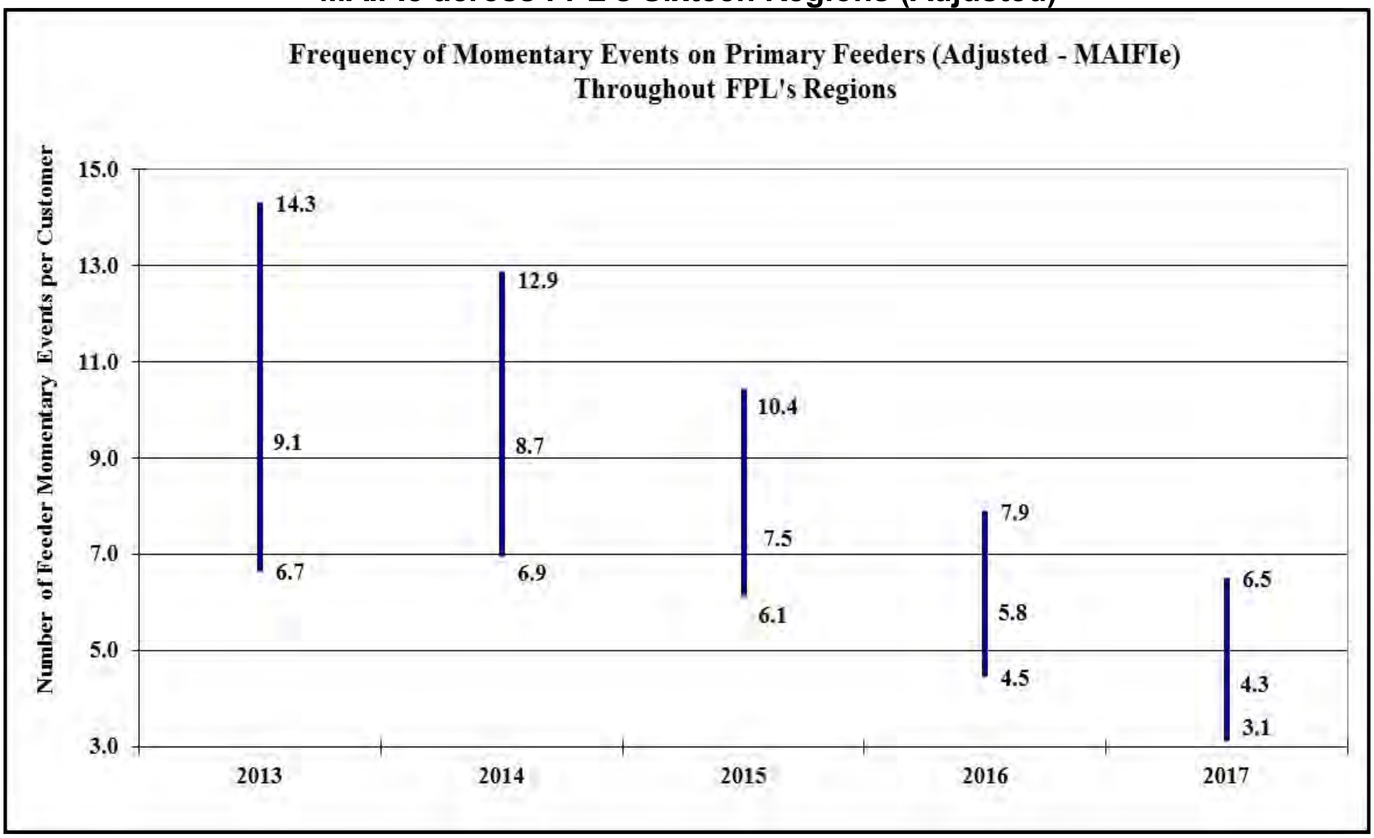
Figure 3-12
FPL's Average Duration of Outages (Adjusted)



Source: FPL's 2013-2017 distribution service reliability reports.

Figure 3-13 is the highest, average, and lowest adjusted MAIFIe recorded across FPL's system. FPL's Treasure Coast and Wingate service areas have experienced the least reliable MAIFIe results of the 16 service areas of FPL since 2013. The Pompano, Central Dade, and Manasota service areas had the fewest momentary events since 2013. The results have been trending downward (improving) over the last five years. There is a 26 percent decrease in the average MAIFIe results from 2016 to 2017. As a note, FPL calculates MAIFIe differently. Specifically, if a feeder begins in one region and crosses another region, all customers on that feeder are impacted by the MAIFIe event and are counted in the starting region. Therefore, the number of customers per region will be different.

Figure 3-13
MAIFIe across FPL's Sixteen Regions (Adjusted)



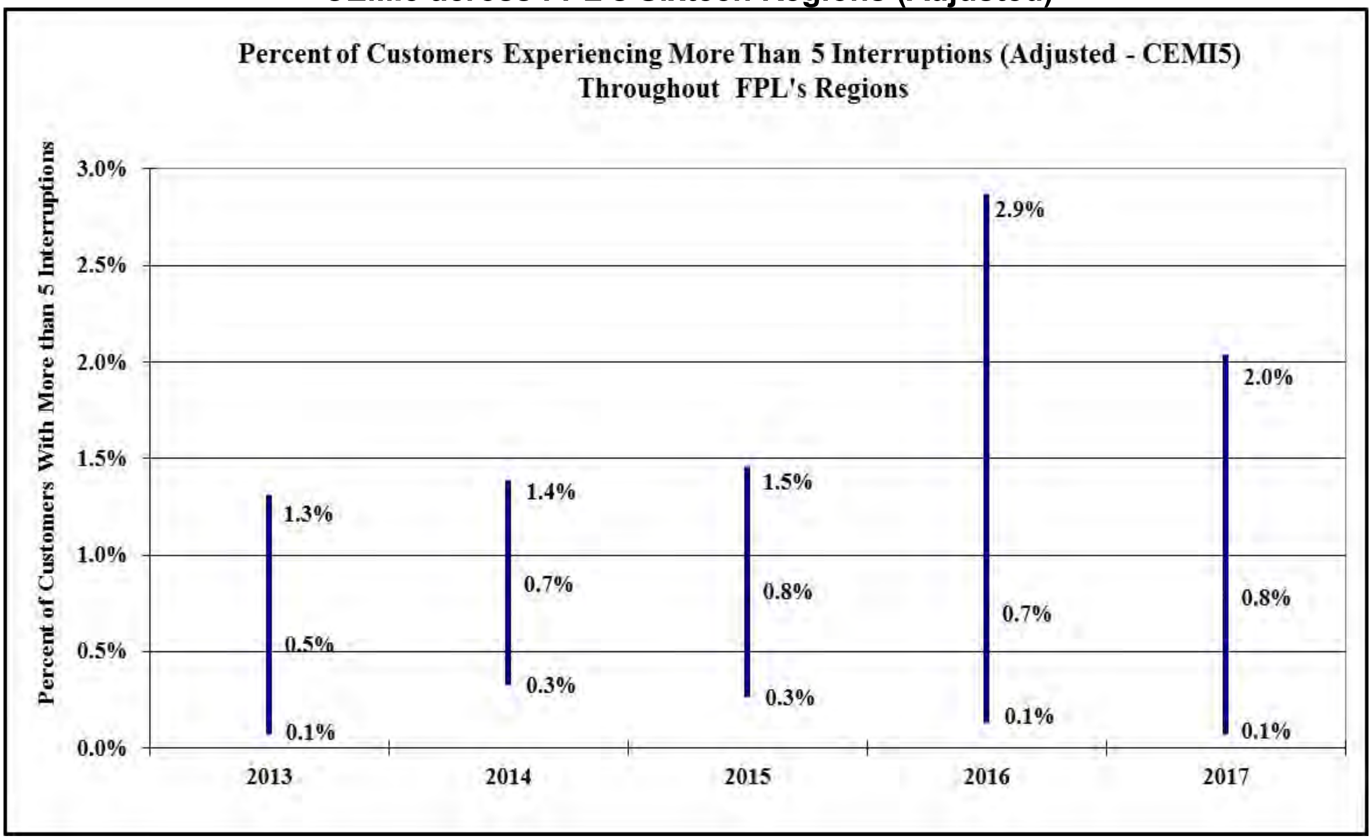
FPL's Regions with the Highest and Lowest Adjusted MAIFIe Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest MAIFIe	Treasure Coast	Wingate	Wingate	Wingate	Wingate
Lowest MAIFIe	Central Dade	Pompano	Manasota	Pompano	Pompano

Source: FPL's 2013-2017 distribution service reliability reports.

Figure 3-14 shows the highest, average, and lowest adjusted CEMI5. FPL's customers with more than five interruptions per year appear to be increasing and trending upward. The service areas experiencing the highest CEMI5 over the five-year period appear to fluctuate among West Dade, Boca Raton, Treasure Coast, and West Palm. Pompano, Gulf Stream, and Brevard are reported as having the lowest percentages in the last five years. The average CEMI5 result for 2017 was 0.8 percent compared to 0.7 percent in 2016.

Figure 3-14
CEMI5 across FPL's Sixteen Regions (Adjusted)



FPL's Regions with the Highest and Lowest Adjusted CEMI5 Distribution Reliability Performance by Year

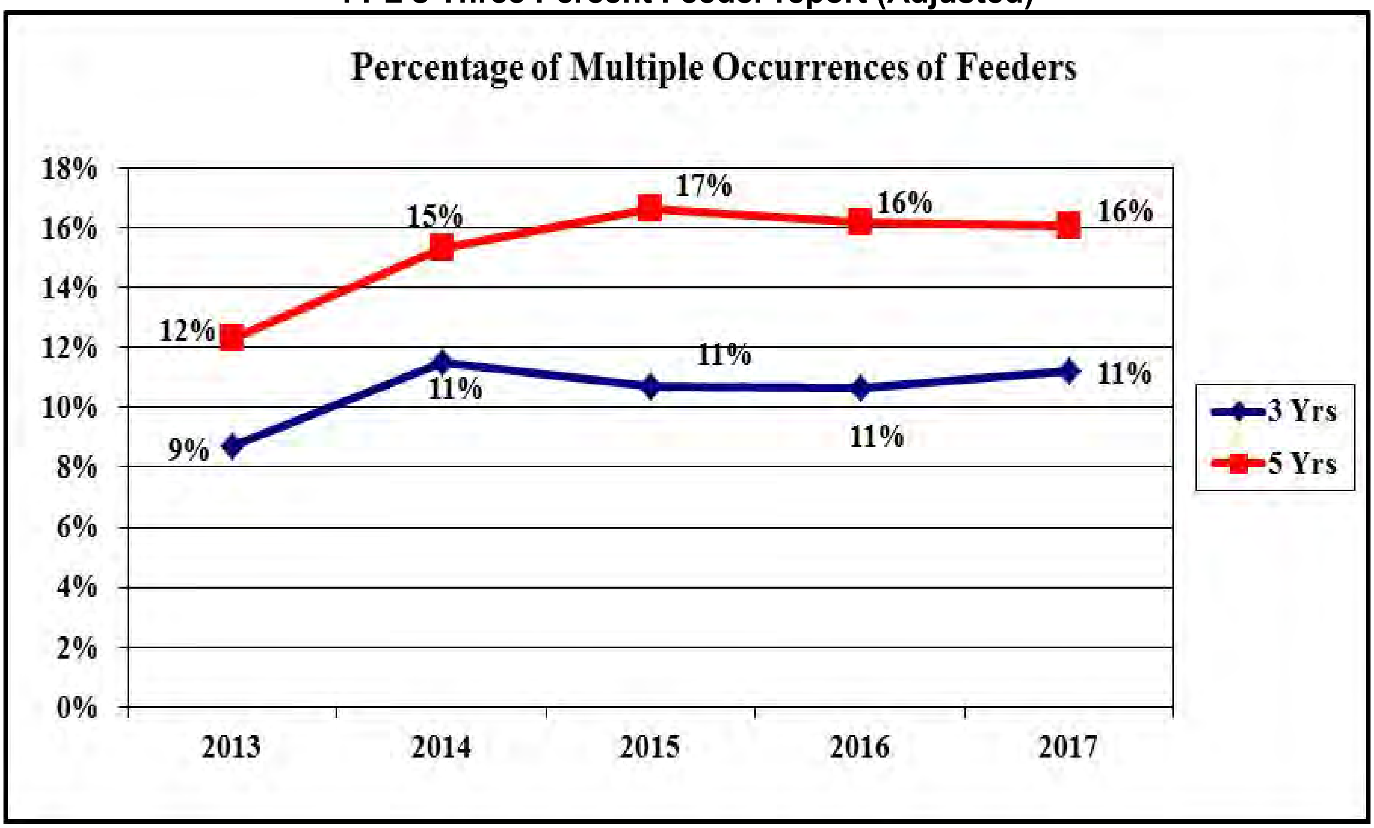
	2013	2014	2015	2016	2017
Highest CEMI5	Boca Raton	West Palm	West Dade	Treasure Coast	West Palm
Lowest CEMI5	Pompano	Brevard	Brevard	Gulf Stream	Pompano

Source: FPL's 2013-2017 distribution service reliability reports.

Figure 3-15 is a graphical representation of the percentage of multiple occurrences of FPL's feeders and is derived from The Three Percent Feeder Report, which is a listing of the top three percent of problem feeders reported by the utility. The fraction of multiple occurrences is calculated from the number of recurrences divided by the number of feeders reported. The three-year percentage had no change with 11 percent in 2016 and 2017. The five-year percentage was 16 percent in 2016 and 2017. Both the five-year percentage and the three-year percentage appear to be trending upward.

Staff notes six feeders were on the Three Percent Feeder Report the last two years. FPL reported that recently completed and future efforts to improve performance on the six feeders include equipment repairs (cross arms, lightning arrestors, insulators, and splices), vegetation management, and tree trimming. FPL also reported that four of these feeders are scheduled to be storm hardened in 2018.

Figure 3-15
FPL's Three Percent Feeder report (Adjusted)

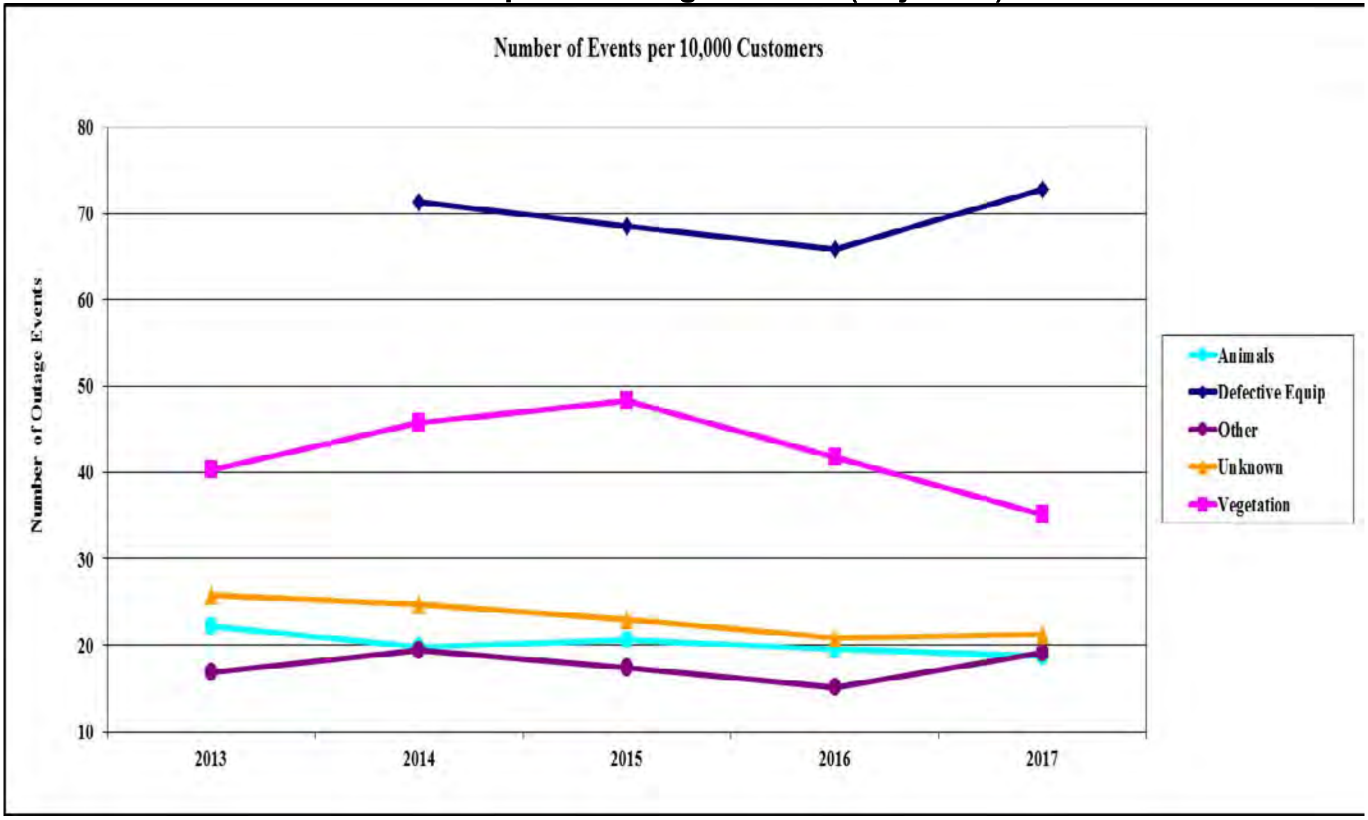


Source: FPL's 2013-2017 distribution service reliability reports.

Figure 3-16 depicts the top five causes of outage events on FPL's distribution system normalized to a 10,000-customer base. The graph is based on FPL's adjusted data of the top 10 causes of outage events. For the five-year period, the five top causes of outage events included "Defective Equipment" (38 percent), "Vegetation" (18 percent), "Unknown Causes" (11 percent), "Animals" (10 percent), and "Other Causes" (10 percent) on a cumulative basis. The outage events due to "Vegetation," "Animals," and "Unknown Causes" are trending downward as the "Other Causes" category is relatively flat. The "Defective Equipment" category dominates the highest percentage of outage causes throughout the FPL regions. The data shows an increasing trend in outage events caused by "Defective Equipment." The number of outages increased for the "Defective Equipment" category from 2016 to 2017. Starting in 2014, "Defective Equipment" includes "Equipment Failure," "Equipment Connect" and "Dig-in," which were all separate categories, in prior years.

Annually, FPL evaluates its current reliability remediation programs and verifies the program's need and/or existence. In addition, FPL proposes new reliability remediation programs to improve its reliability performance concentrating on the highest cause codes and those cause codes that have shown trends needing attention. FPL has 15 reliability programs listed for its 2018 budget. The programs include: priority feeder inspection, reduce the number of direct buried feeder and lateral cables, installing, relocating, and maintaining distribution capacitor banks, and replacing oil circuit reclosers with electronic reclosers. Eleven programs are designed to help improve the "Defective Equipment" cause code, which had an increase in 2017. Six programs will help to improve the "Unknown Causes" and "Other Causes" cause codes, which also had an increase in 2017. In addition to the reliability programs identified by FPL in its report, the Utility is planning to inspect and repair or replace auto transformers, as necessary. This program will also help address the "Defective Equipment" and "Animals" cause codes.

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



Source: FPL's 2013-2017 distribution service reliability reports.

Observations: FPL's Adjusted Data

The least reliable overall results seem to fluctuate between FPL's different service areas, as do the best service reliability results. The 2017 report shows the system indices for SAIDI, SAIFI, CAIDI, and MAIFe, are lower or better than the 2016 results. The system index for CEMI5 and L-Bar are higher than the 2016 results. There was no change in the Three-Year Percentages of Multiple Feeder Outage events and the Five-Year Percentages of Multiple Feeder Outage events results. FPL explains that it evaluates its current reliability programs annually to verify the program's need and/or existence. In addition, FPL proposes new reliability programs to improve its reliability performance concentrating on the highest cause codes and those cause codes that have shown trends needing attention. The cause codes that FPL will be concentrating on to improve are "Equipment Failures," "Unknown Causes," and "Other Causes" of outages. FPL is also continuing to increase the utilization of automation to address feeder interruptions.

The Wingate region has had the highest MAIFIe for four years consecutively. However, the MAIFIe value for the Wingate region did improve by 18 percent in 2017. FPL is performing targeted vegetation trimming, increasing the number of investigative feeder patrols, and installing automated lateral switches to improve reliability in the Wingate region. FPL also reported that some reliability programs (i.e., priority feeder program and overhead line inspections) addressing momentary issues would also address some of the Wingate feeders.

To address the declining performance of FPL's overall system CEMI5, the Utility has completed 439 visual assessments and 283 thermal inspections of the CEMI5 risk feeders and addressed issues found with 373 feeders. In addition, FPL initiated reliability assessments prior to starting any hardening project to proactively identify potential reliability issues, which resulted in follow-up work on 193 feeders. All follow-up work has been completed. The Utility initiated quality control patrols to identify temporary construction issues (e.g., insufficient cover, improper use of a jumper) on all active feeder hardening projects.

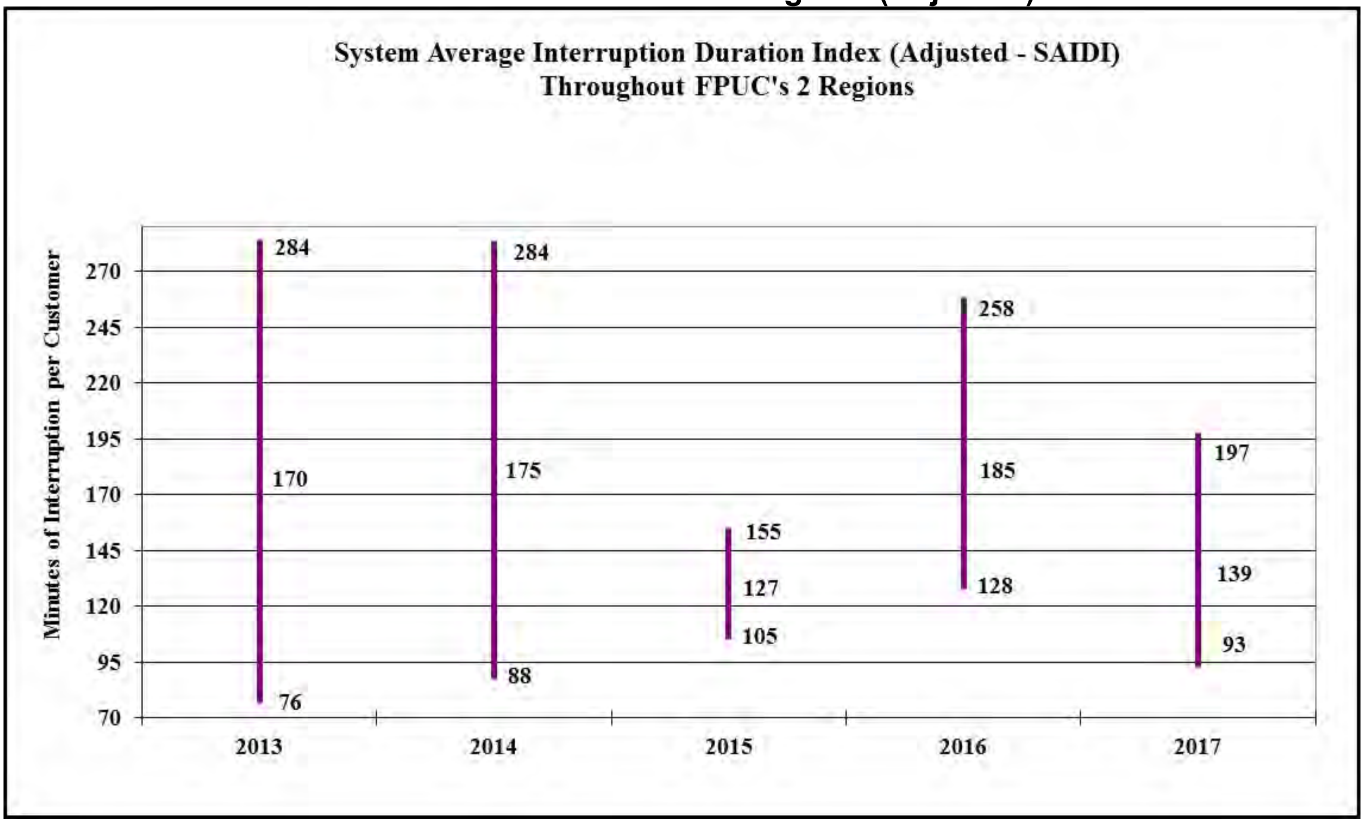
FPL has initiated a targeted undergrounding program to help improve reliability on its system. This program is a three-year pilot, converting the worst performing lateral circuits to underground laterals, and is scheduled to begin in 2018. As the pilot program continues, FPL will test assumptions and obtain experience. FPL estimates it will convert 280 overhead laterals throughout its service territory. FPL provided an overview of its targeted undergrounding program at the Commission's Internal Affairs meeting held on August 7, 2018. Staff will continue to monitor FPL's targeted underground program and report on its progress.

Florida Public Utilities Company: Adjusted Data

FPUC has two electric divisions, the Northwest division, referred to as Marianna and the Northeast division, referred to as Fernandina Beach. Each division's results is reported separately because the two divisions are 250 miles apart and not directly interconnected. Although the divisions may supply resources to support one another during emergencies, each division has diverse situations to contend with, making it difficult to compare the division's results and form a conclusion as to response and restoration time.

Figure 3-17 shows the highest, average, and lowest adjusted SAIDI values recorded by FPUC's system. The data shows the average SAIDI index is trending downward for the five-year period of 2013 to 2017 and there was a 25 percent decrease from 2016 to 2017.

Figure 3-17
SAIDI across FPUC's Two Regions (Adjusted)



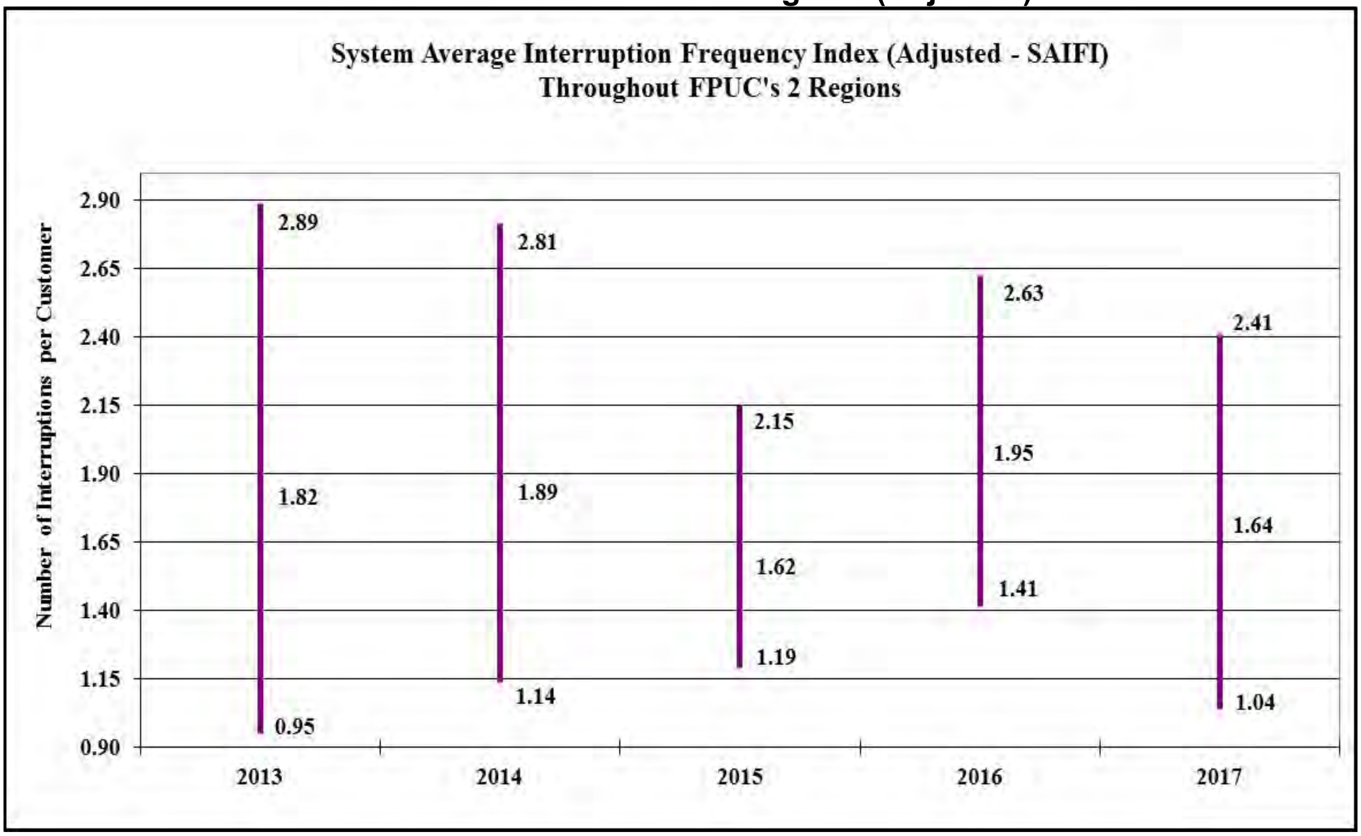
FPUC's Regions with the Highest and Lowest Adjusted SAIDI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIDI	Marianna (NW)	Marianna (NW)	Marianna (NW)	Marianna (NW)	Marianna (NW)
Lowest SAIDI	Fernandina(NE)	Fernandina(NE)	Fernandina(NE)	Fernandina(NE)	Fernandina(NE)

Source: FPUC's 2013-2017 distribution service reliability reports.

Figure 3-18 shows the adjusted SAIFI across FPUC's two divisions. The data depicts a 16 percent decrease in the 2017 average SAIFI reliability index from 2016. The data for the average and maximum SAIFI values are trending downward as the minimum SAIFI value is trending upward over the five-year period of 2013 to 2017.

Figure 3-18
SAIFI across FPUC's Two Regions (Adjusted)



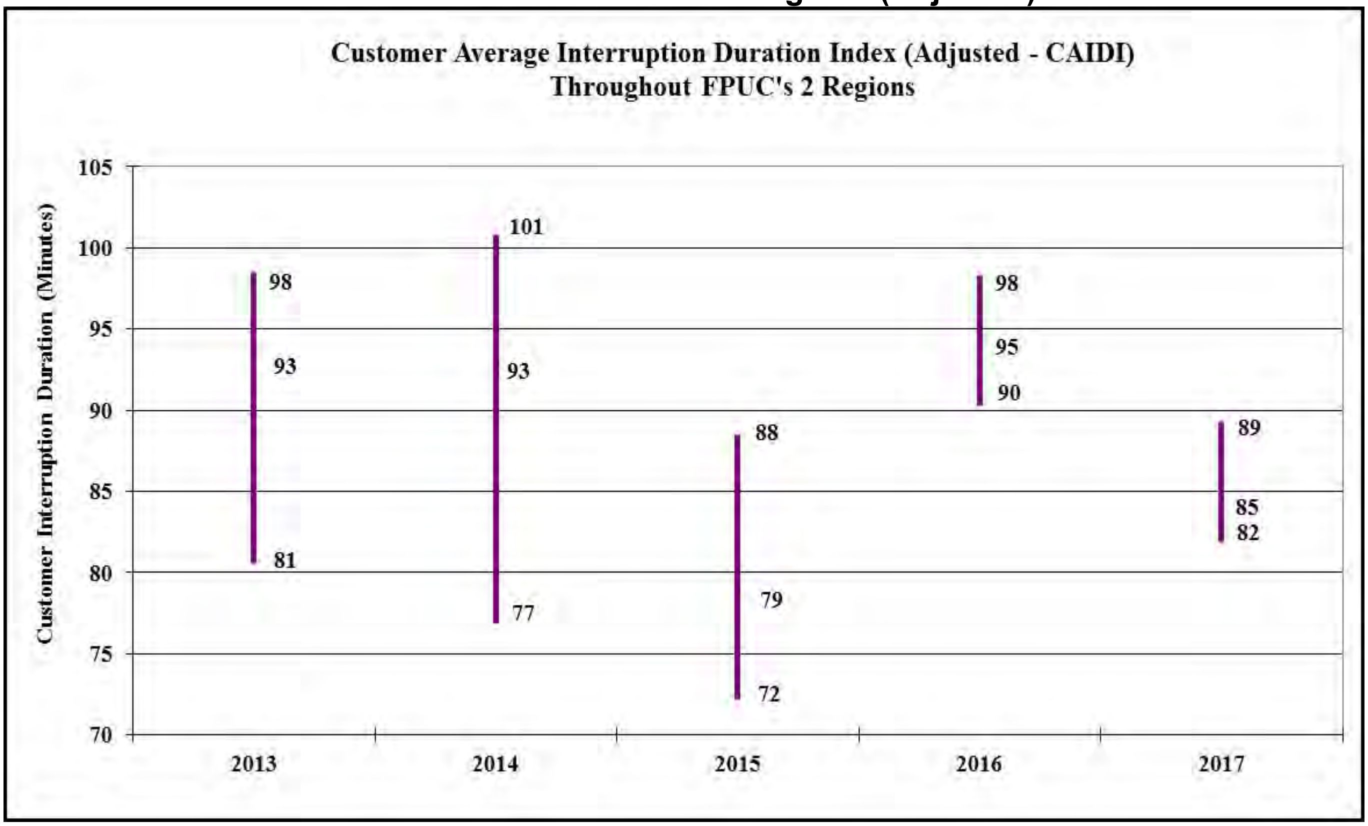
FPUC's Regions with the Highest and Lowest Adjusted SAIFI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIFI	Marianna (NW)	Marianna (NW)	Marianna (NW)	Marianna (NW)	Marianna (NW)
Lowest SAIFI	Fernandina(NE)	Fernandina(NE)	Fernandina(NE)	Fernandina(NE)	Fernandina(NE)

Source: FPUC's 2013-2017 distribution service reliability reports.

Figure 3-19 shows the highest, average, and lowest adjusted CAIDI values across FPUC's system. FPUC's data shows the average CAIDI value decreased by 11 percent for 2017 (85 minutes) when compared to 2016 (95 minutes). For the past five years, the maximum, the minimum, and the average CAIDI values are trending downward.

Figure 3-19
CAIDI across FPUC's Two Regions (Adjusted)



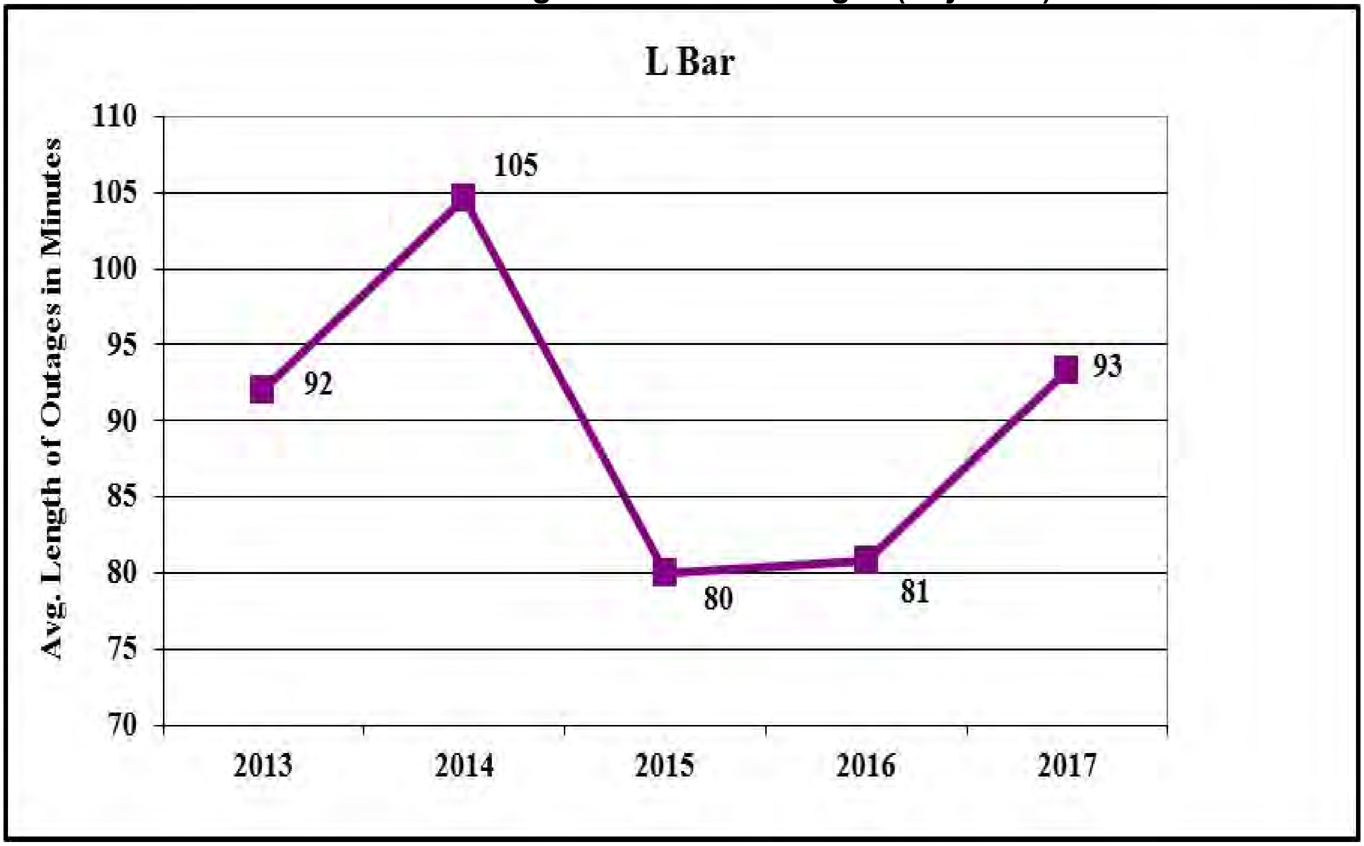
FPUC's Regions with the Highest and Lowest Adjusted CAIDI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest CAIDI	Marianna (NW)	Marianna (NW)	Fernandina(NE)	Marianna (NW)	Fernandina(NE)
Lowest CAIDI	Fernandina(NE)	Fernandina(NE)	Marianna (NW)	Fernandina(NE)	Marianna (NW)

Source: FPUC's 2013-2017 distribution service reliability reports.

Figure 3-20 is the average length of time FPUC spends recovering from outage events (adjusted L-Bar). There was a 13 percent increase in the L-Bar value from 2016 to 2017. The data for the five-year period of 2013 to 2017 suggests that the L-Bar index is trending downward indicating FPUC is taking less time to restore service after an outage event.

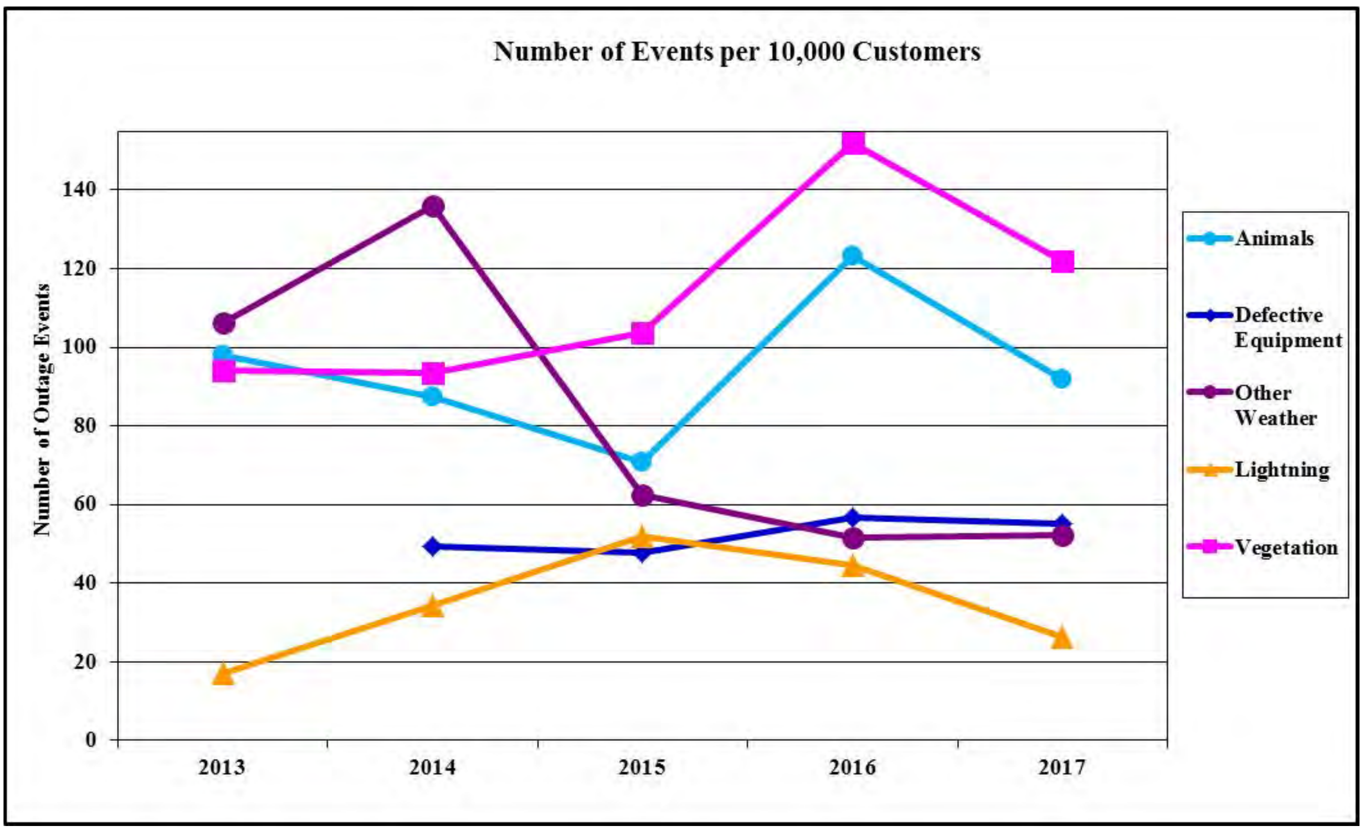
Figure 3-20
FPUC's Average Duration of Outages (Adjusted)



Source: FPUC's 2013-2017 distribution service reliability reports.

Figure 3-21 shows the top five causes of outage events on FPUC's distribution system normalized to a 10,000-customer base. The figure is based on FPUC's adjusted data of the top 10 causes of outages. For 2017, the top five causes of outage events were "Vegetation" (31 percent), "Animals" (23 percent), "Defective Equipment" (14 percent), "Other Weather" (13 percent), and "Lightning" (7 percent). These five factors represent 88 percent of the total adjusted outage causes in 2017. The "Lightning" category is trending upward even though there was a 40 percent decrease from 2016 to 2017. The causes by "Defective Equipment," "Animals," and "Vegetation" are also trending upward. "Defective Equipment" decreased 2 percent from 2016 to 2017. The "Animals" and "Vegetation" category decreased 25 percent and 19 percent during the same time period, respectively. The "Other Weather" category caused outages is trending downward over the five-year period of 2013 to 2017, even though there was a 3 percent increase from 2016 to 2017. Beginning with 2014, the "Defective Equipment" category now includes outage categories that in the past were separately identified.

Figure 3-21
FPUC's Top Five Outage Causes (Adjusted)



Source: FPUC's 2013-2017 distribution service reliability reports.

FPUC filed a Three Percent Feeder Report listing the top 3 percent of feeders with the outage events for 2017. FPUC has so few feeders that the data in the report has not been statistically significant. There were two feeders on the Three Percent Feeder Report, one in each division. Neither of these feeders was listed on the report for the last five years.

Observations: FPUC's Adjusted Data

The SAIDI, SAIFI, and CAIDI average indices have all decreased compared to 2016. For the five-year period of 2013 to 2017, the average indices for SAIDI, SAIFI, CAIDI and L-Bar are trending downward. FPUC reported that it continues to invest in its storm hardening initiatives, infrastructure improvements, and system upgrades in both divisions. FPUC believes this will generate reliability improvements in the future. The Utility reviewed its five-year reliability indicator trends, averages and outage causes, and determined the reliability indexes continue to be significantly influenced by weather.

To improve its reliability, in 2018, FPUC is planning to implement a new lateral protection strategy by installing cutout-mounted recloser units. This program deploys TripSaver cutout mounted reclosers on the worst performing laterals over the last three years. The TripSaver recloser works the same as an electronic recloser but for a smaller number of customers. The reclosers offer protection to upstream customers by giving a utility the ability to isolate faults and shorten the outage time experienced by customers.

In addition, to help mitigate the situation with vegetation caused outages, FPUC suggests that its vegetation management would be more efficient if it trimmed all of the laterals associated with the feeders at the same time. This would allow FPUC to keep the trim crews in the same general area instead of moving them to a different feeder or lateral. This vegetation management schedule has been started in several locations. To help mitigate the situation with animal caused outages, FPUC plans to continue to implement the standard practice of installing animal guards and covering riser wire between the cutout, arrester, and transformer. In addition, if metal brackets are in use, they will be replaced with fiberglass brackets to help control animal related outages. FPUC reported that the deployment of the TripSavers should also help with animal related outages.

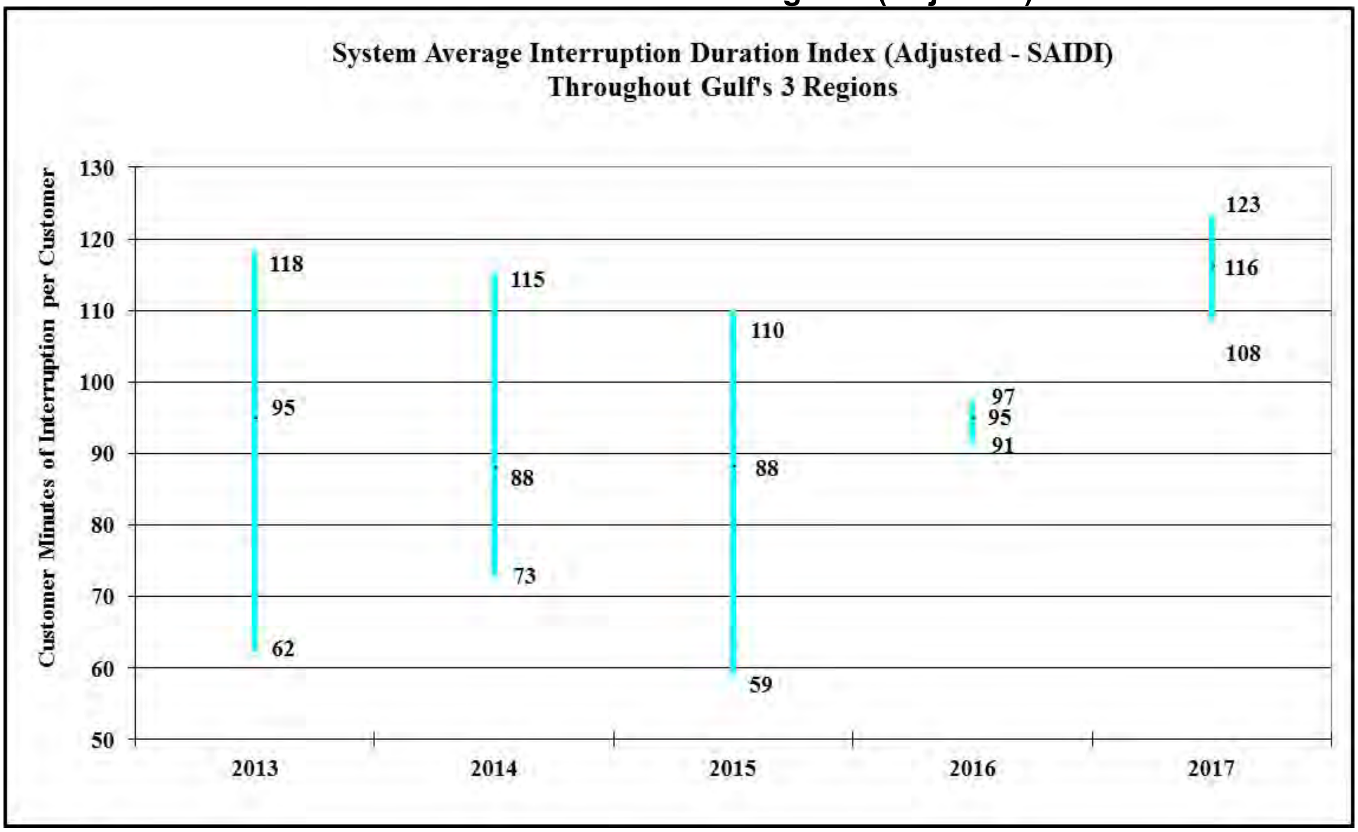
FPUC does not have to report MAIFIe or CEMI5 because Rule 25-6.0455, F.A.C., waives the requirement. The cost for the information systems necessary to measure MAIFIe and CEMI5 has a higher impact on small utilities compared to large utilities on a per customer basis.

Gulf Power Company: Adjusted Data

Gulf's service area includes much of the Florida panhandle and covers approximately 7,550 square miles in eight Florida counties – Bay, Escambia, Holmes, Jackson, Okaloosa, Santa Rosa, Walton, and Washington. This geographic area is divided into three regions known as the Western, Central, and Eastern. The region distribution metrics and overall distribution system metrics are presented in the following figures.

Figure 3-22 illustrates Gulf's SAIDI minutes, or the interruption duration minutes on a system basis. The chart depicts an 18 percent increase in the average SAIDI in Gulf's combined regions when compared to the 2016 results. Gulf's 2017 average performance was 116 minutes compared to 95 minutes in 2016. The highest SAIDI value for the past three years has been in the Western region as the Central and Eastern regions have the best or lowest SAIDI values. The maximum SAIDI index is continuing to trend downward even with an increase in 2017, as the minimum and average SAIDI indices are trending upward.

Figure 3-22
SAIDI across Gulf's Three Regions (Adjusted)



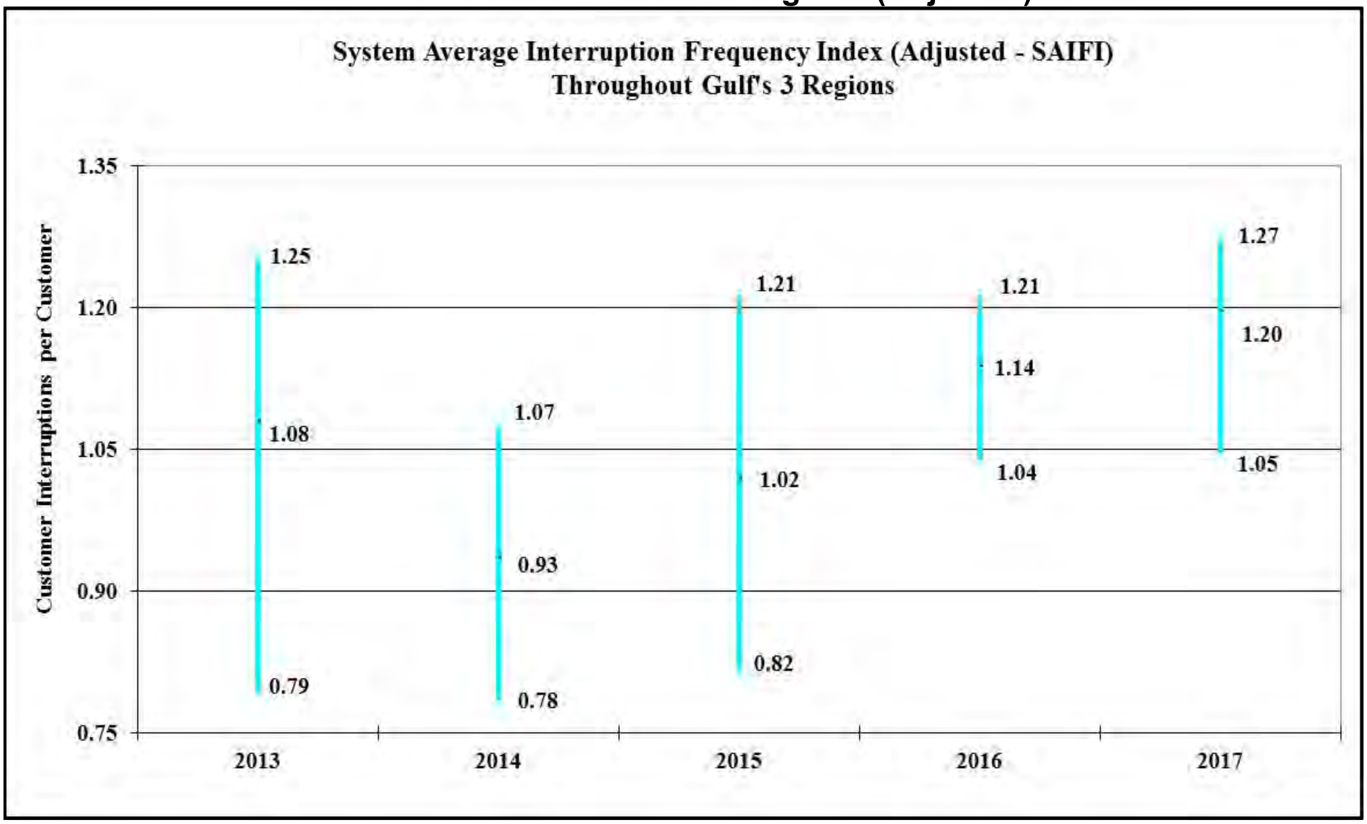
Gulf's Regions with the Highest and Lowest Adjusted SAIDI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIDI	Eastern	Central	Western	Western	Western
Lowest SAIDI	Central	Eastern	Eastern	Central	Eastern

Source: Gulf's 2013-2017 distribution service reliability reports.

Figure 3-23 illustrates that Gulf's SAIFI had a 5 percent increase in 2017 when compared to 2016. The highest SAIFI value for the past five years has fluctuated between the three regions. The lowest values appear to fluctuate between the Central region and the Eastern region. The maximum, average, and minimum SAIFI values appear to be trending upward.

Figure 3-23
SAIFI across Gulf's Three Regions (Adjusted)



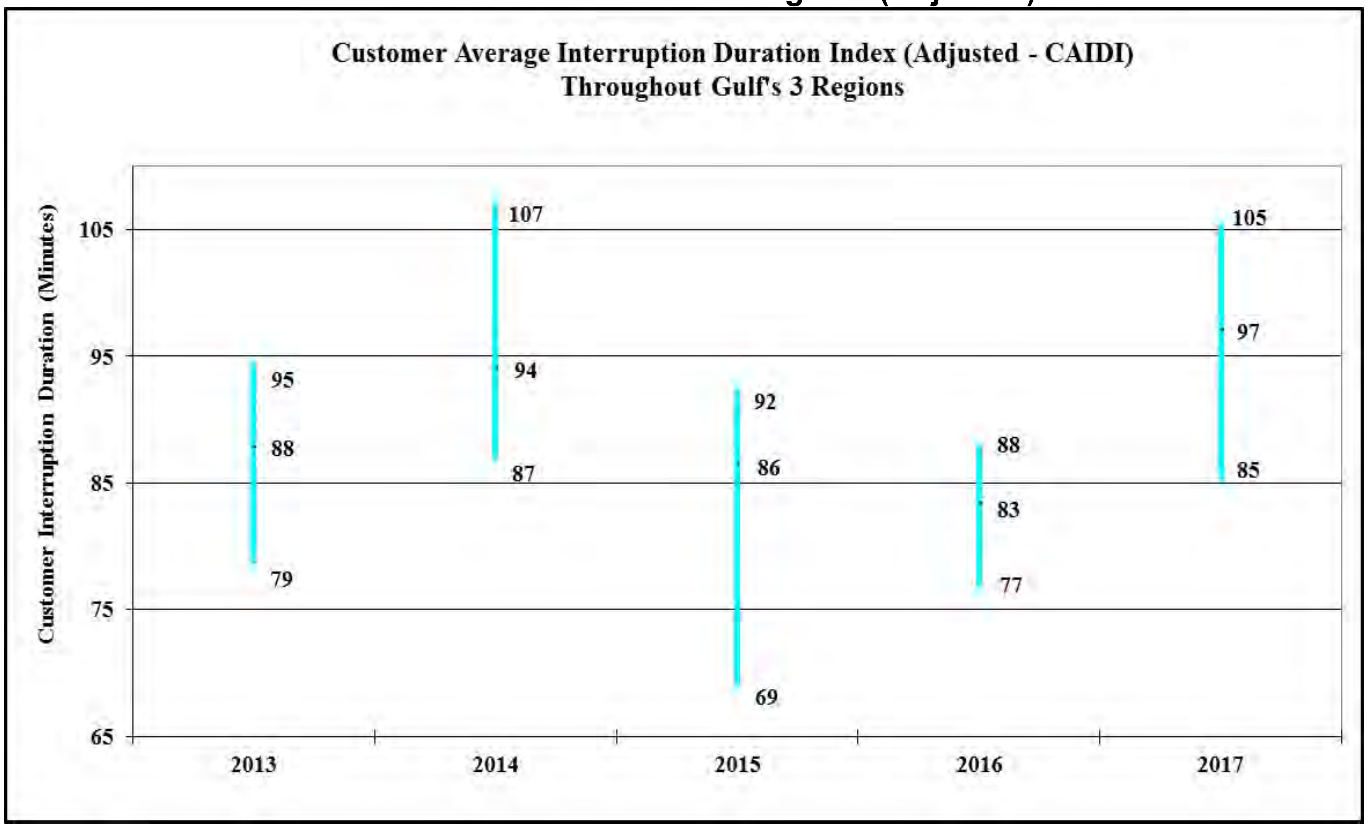
Gulf's Regions with the Highest and Lowest Adjusted SAIFI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIFI	Eastern	Central	Western	Eastern	Eastern
Lowest SAIFI	Central	Eastern	Central	Central	Central

Source: Gulf's 2013-2017 distribution service reliability reports.

Figure 3-24 is Gulf's adjusted CAIDI. For 2017, the average CAIDI is 97 minutes and represents a 14 percent increase from the 2016 value of 83 minutes. In 2017, the Central region had the highest CAIDI value, as the Eastern region had the lowest CAIDI. Staff notes that the average, the maximum and the minimum CAIDI values are trending upward.

Figure 3-24
CAIDI across Gulf's Three Regions (Adjusted)



Gulf's Regions with the Highest and Lowest Adjusted CAIDI Distribution Reliability Performance by Year

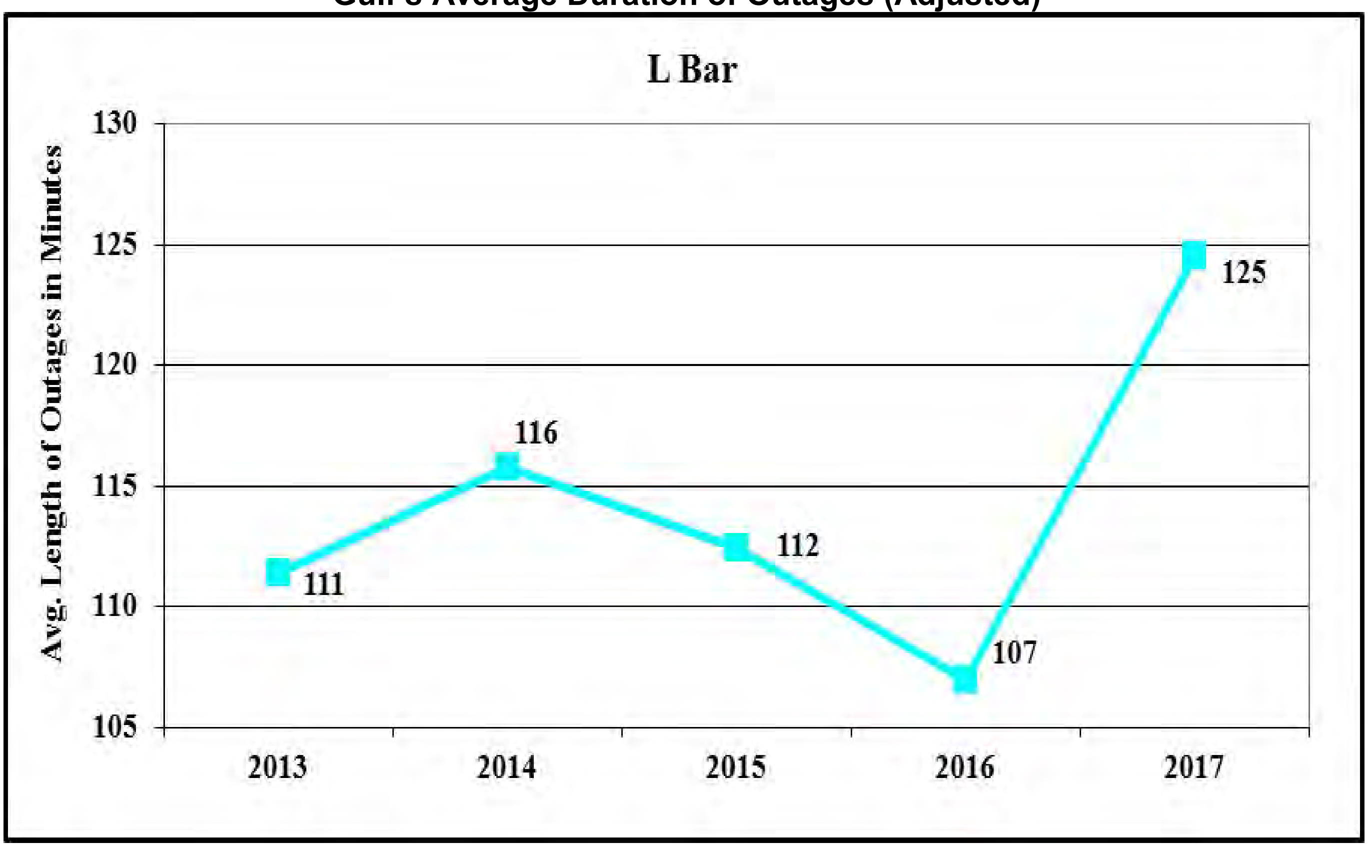
	2013	2014	2015	2016	2017
Highest CAIDI	Eastern	Central	Central	Central	Central
Lowest CAIDI	Central	Western	Eastern	Eastern	Eastern

Source: Gulf's 2013-2017 distribution service reliability reports.

Figure 3-25 illustrates Gulf's L-Bar or the average length of time Gulf spends recovering from outage events, excluding hurricanes and other allowable excluded outage events. Gulf's L-Bar showed a 14 percent increase from 2016 to 2017. The data for the five-year period of 2013 to 2017 shows an upward trend.

Gulf reported that all three of its regions experienced outages due to three non-excludable severe thunderstorms. These severe thunderstorms occurred on January 1 and 2, 2017, February 7, 2017, and May 1, 2017. During these events, a combined 59,414 customers lost power, primarily due to high wind speeds. Regarding the January 1 and 2, 2017 event, Gulf reported: the average outage for the Central region lasted 228 minutes; the Eastern region, the average outage lasted 45 minutes; and, in the Western region the average outage lasted 113 minutes. Gulf reported for the February 7, 2017 event that the average customer outage for the Central region was 248 minutes, for the Eastern region was 164 minutes, and for the Western region was 103 minutes. Regarding the May 1, 2017, event in the Central region, the average customer outage was 107 minutes, in the Eastern region the average outage was 264 minutes, and in the Western region the average outage was 241 minutes. Excluding these three events, Gulf did not find that the time to restore power had increased for events associated with normal weather days.

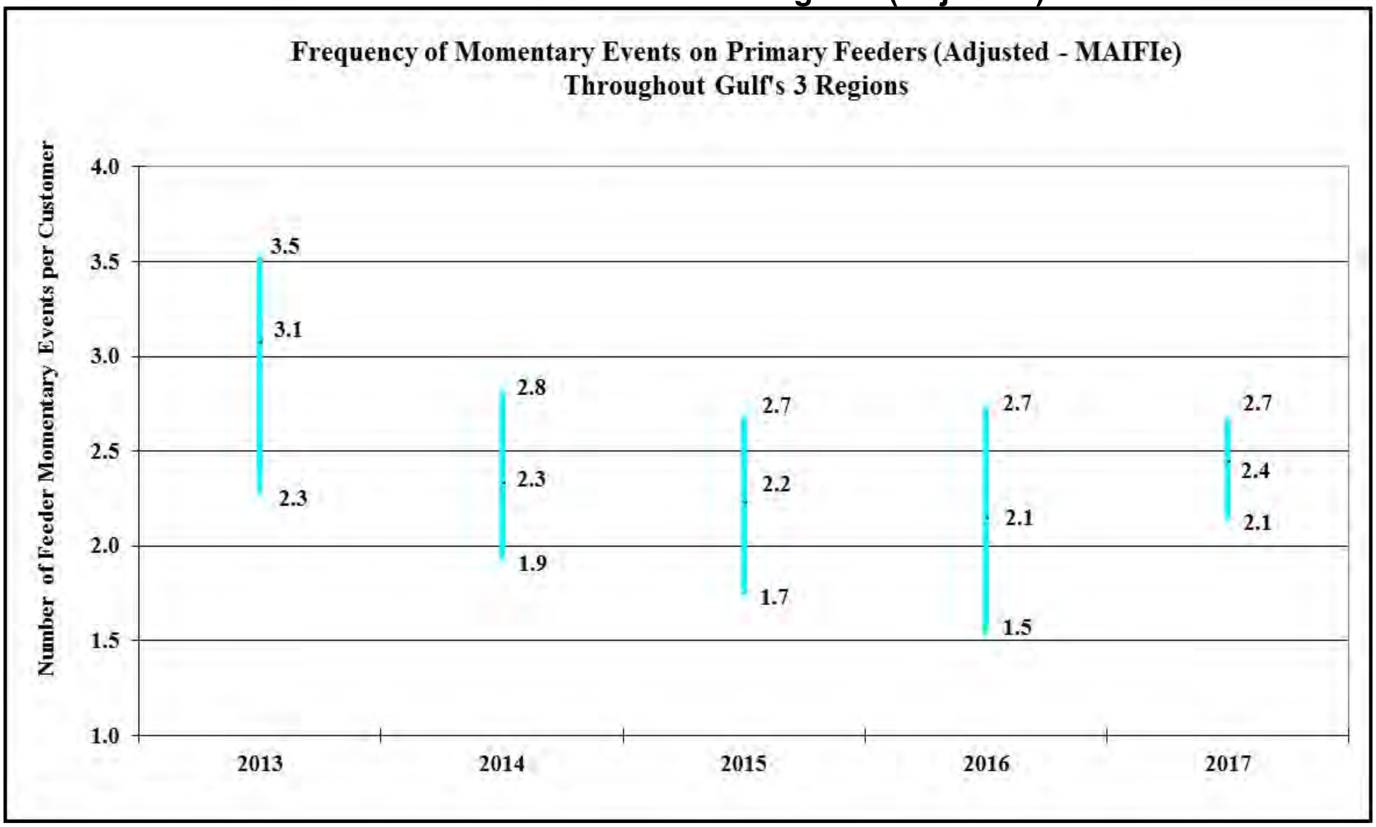
Figure 3-25
Gulf's Average Duration of Outages (Adjusted)



Source: Gulf's 2013-2017 distribution service reliability reports.

Figure 3-26 is the adjusted MAIFIe recorded across Gulf's system. The adjusted MAIFIe results by region show that the Central region had the lowest frequency of momentary events on primary feeders. The Western region has the highest MAIFIe index in 2017. The average MAIFIe showed a 13 percent decline when compared to 2016. The data suggest that the highest, average, and lowest MAIFIe are all continuing to trend downward, suggesting improvement.

Figure 3-26
MAIFIe across Gulf's Three Regions (Adjusted)



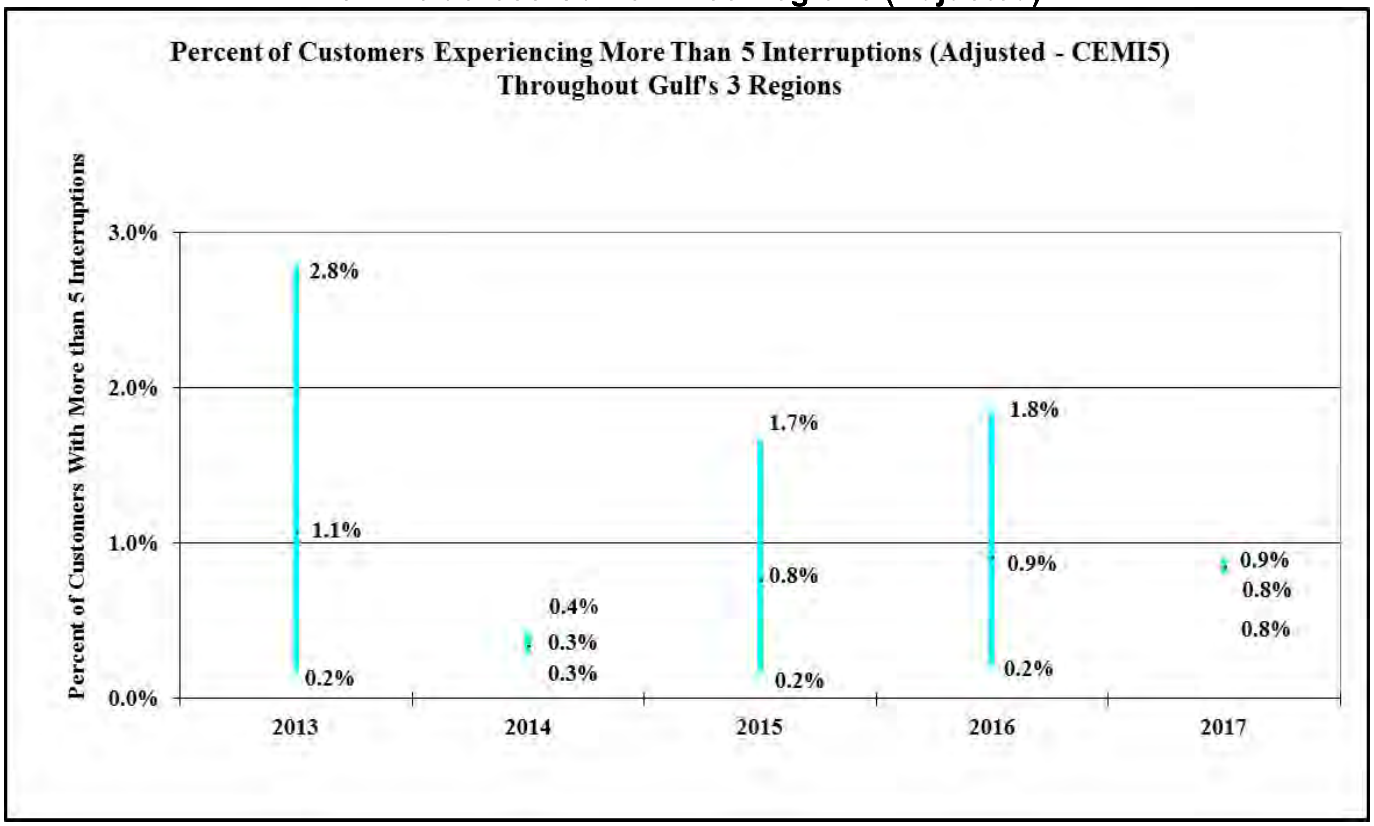
Gulf's Regions with the Highest and Lowest Adjusted MAIFIe Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest MAIFIe	Western	Central	Western	Western	Western
Lowest MAIFIe	Eastern	Eastern	Eastern	Central	Central

Source: Gulf's 2013-2017 distribution service reliability reports.

Figure 3-27 shows the highest, average, and lowest adjusted CEMI5 across Gulf's Western, Central, and Eastern regions. Gulf's 2017 results illustrate an 11 percent decrease in the average CEMI5 percentage when compared to 2016. The maximum CEMI5 appears to be trending downward over the five-year period of 2013 to 2017, as the average CEMI5 appears to be relatively flat, suggesting that the percentage of Gulf's customers experiencing more than five interruptions is decreasing and improving. The minimum CEMI5 appears to be trending upward for the same period.

Figure 3-27
CEMI5 across Gulf's Three Regions (Adjusted)



Gulf's Regions with the Highest and Lowest Adjusted CEMI5 Distribution Reliability Performance by Year

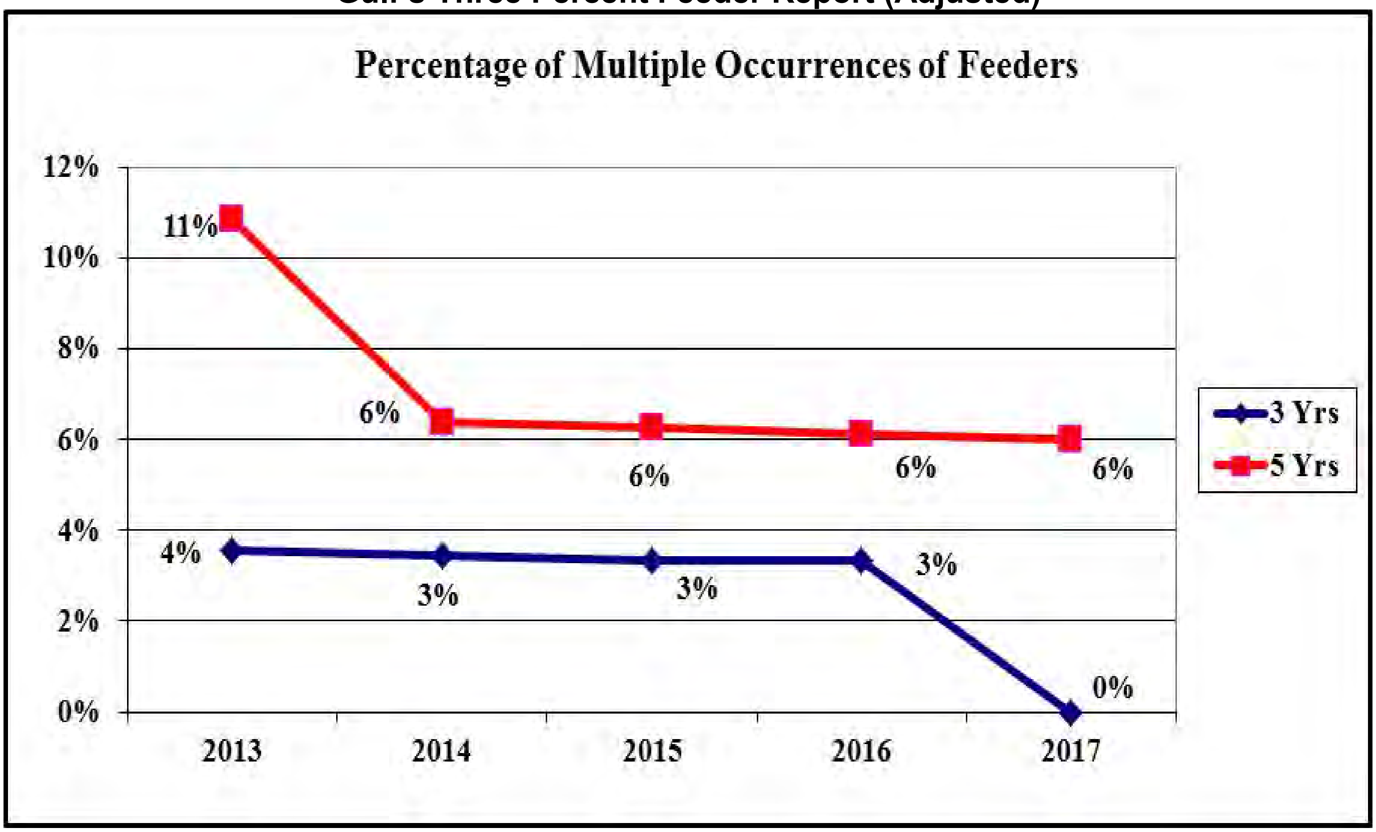
	2013	2014	2015	2016	2017
Highest CEMI5	Eastern	Eastern	Eastern	Eastern	Central
Lowest CEMI5	Central	Western	Central	Central	Western

Source: Gulf's 2013-2017 distribution service reliability reports.

Figure 3-28 shows the multiple occurrences of feeders using the Utility's Three Percent Feeder Report and is analyzed on a three- and five-year basis. The Three Percent Feeder Report is a listing of the top 3 percent of feeders that have the most feeder outage events. The supporting data illustrates that the five-year multiple occurrences did not change from 2016 to 2017 as the three-year multiple occurrences decreased. The five-year period of 2013 to 2017 indicates overall that the five-year index is trending downward, as is the three-year multiple occurrences index.

There were 10 feeders on the Three Percent Feeder Report. Gulf reported that the three top causes of the outages associated with the 10 feeders listed were manual operations, deterioration, and trees. Gulf explained manual operation cause is when Gulf purposefully opens breakers for line crews to work safely during an emergency. Often these outages are created to isolate a dangerous condition or to operate a manual device that could potentially pose a safety hazard to personnel if opened while energized. Gulf has several inspection programs and conductor replacement efforts in place to mitigate deterioration outages. Deterioration includes equipment inside the substation and on the distribution feeder. To mitigate the outages due to vegetation, Gulf is expanding its tree trimming rights with the Right-of-Way Acquisition Pilot in addition to tree trimming and other vegetation management efforts.

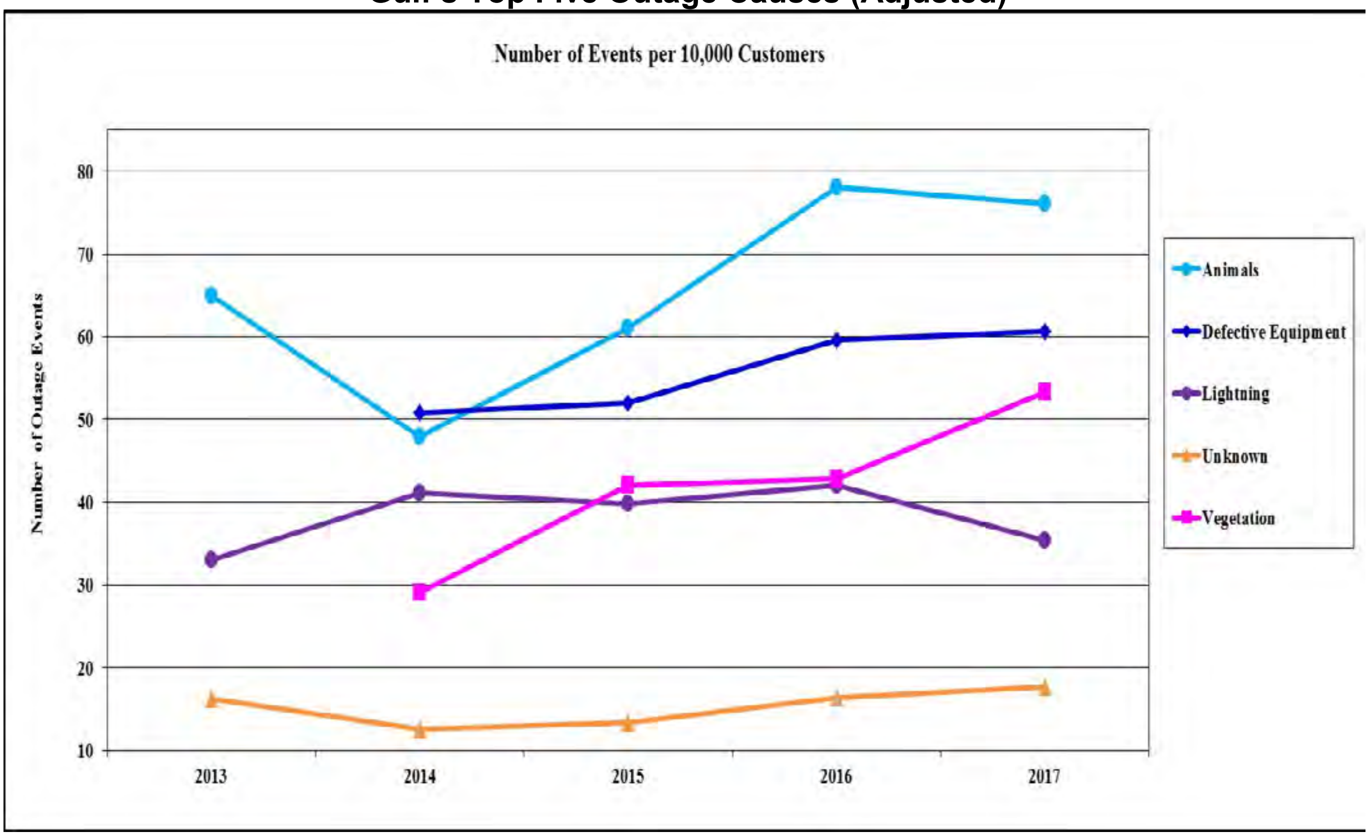
Figure 3-28
Gulf's Three Percent Feeder Report (Adjusted)



Source: Gulf's 2013-2017 distribution service reliability reports.

Figure 3-29 is a graph of the top five causes of outage events on Gulf's distribution system normalized to a 10,000-customer base. The figure is based on Gulf's adjusted data of the top 10 causes of outage events and represents 91 percent of the total adjusted outage events that occurred during 2017. The top five causes of outage events were "Animals" (28 percent), "Defective Equipment" (23 percent), "Vegetation" (20 percent), "Lightning" (13 percent), and "Unknown Causes" (7 percent). The percentage of outages due to "Animals" was the highest cause of outages. The number of outage events due to "Animals" is trending upward even though there was a 1 percent decrease in 2017. The numbers of outage events due to "Lightning" and "Unknown Causes" are slightly trending upward. The number of outages due to "Defective Equipment" and "Vegetation" are both trending upward. The "Defective Equipment" and "Vegetation" categories now include outage categories that in the past were separately identified. Gulf continues to focus its process improvement efforts on the system wide top outage causes through its existing programs and storm hardening efforts.

Figure 3-29
Gulf's Top Five Outage Causes (Adjusted)



Source: Gulf's 2013-2017 distribution service reliability reports.

Observations: Gulf's Adjusted Data

There were improvements seen in Gulf's CEMI5 and the Three-Year Percentages of Multiple Feeder Outage events indices in 2017 as the SAIDI, SAIFI, CAIDI, MAIFIe and L-Bar declined. The Five-Year Percentages of Multiple Feeder Outage events were unchanged. Overall it appears that the trend lines of the reliability indices for the five-year period of 2013 to 2017 are primarily trending upward.

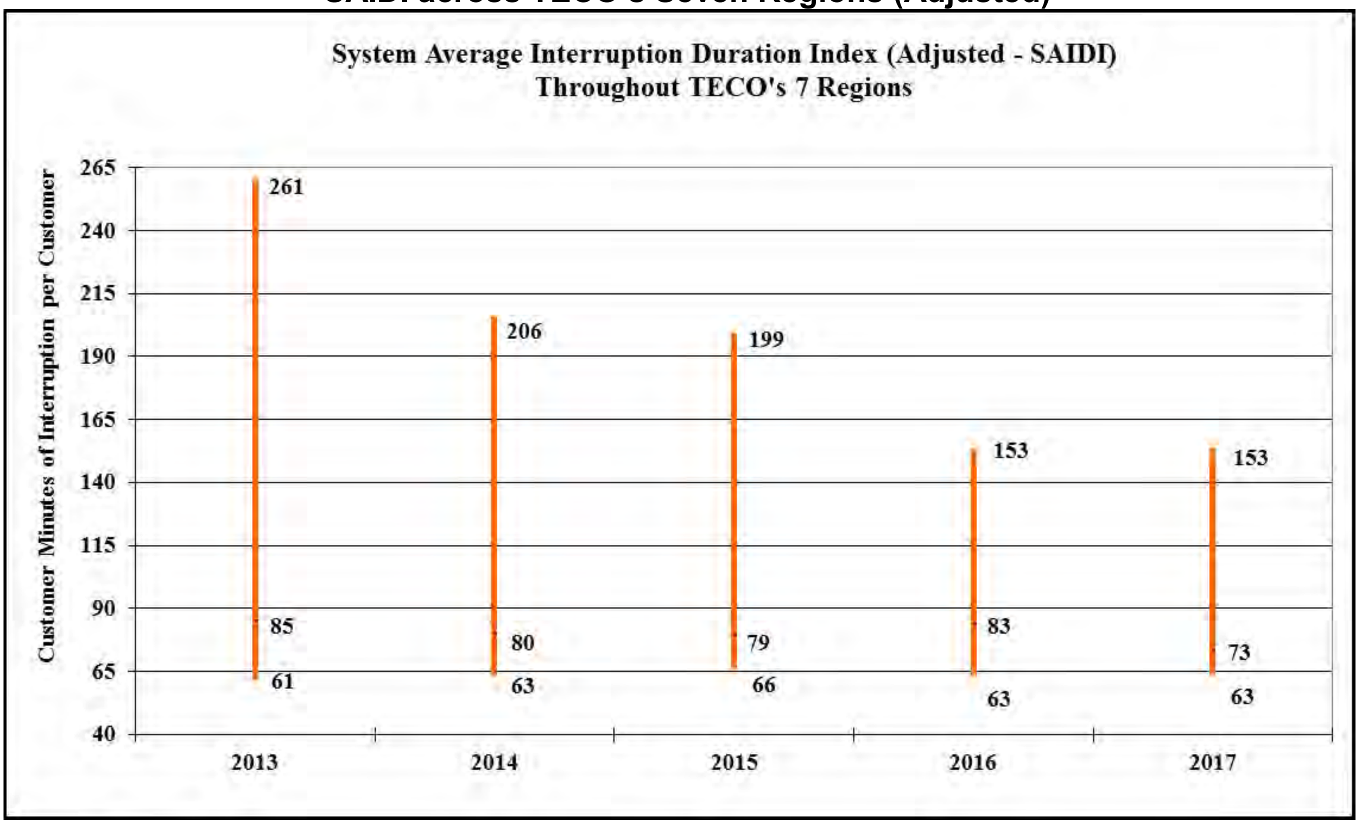
Gulf continues to collect outage data at the customer meter level. The Utility reviews outage data and the resulting reliability indices at the system level and by its three regions. Gulf is analyzing 2017 data to determine the need for any specific improvement opportunities beyond the current programs and storm hardening initiatives. Gulf reported that it continues to seek opportunities to improve system reliability. In 2018, Gulf expanded its conductor replacement program. This program identifies aged or undersized sections of the distribution system and rebuilds them to the latest construction specifications.

Gulf will continue to install additional distribution automation devices to further segment the feeder for outage restoration. These devices protect customers by limiting those affected by temporary faults and sustained outages.

Tampa Electric Company: Adjusted Data

Figure 3-30 shows the adjusted SAIDI values recorded by TECO's system. Five of the seven TECO regions had improvements in SAIDI performance during 2017, with the Eastern region having the lowest SAIDI performance results. The Dade City region continues to have the poorest SAIDI performance results for the five-year period of 2013 to 2017. The lowest SAIDI index for the seven regions appears to be slightly trending upward. The average SAIDI index decreased 12 percent from 2016 to 2017. This index appears to be slightly trending downward. The Central, Eastern, and Winter Haven regions recorded the lowest SAIDI indices for the five-year period. Dade City, Plant City, and South Hillsborough regions have the fewest customers and represent the most rural, lowest customer density per line mile in comparison to the other four TECO divisions.

Figure 3-30
SAIDI across TECO's Seven Regions (Adjusted)



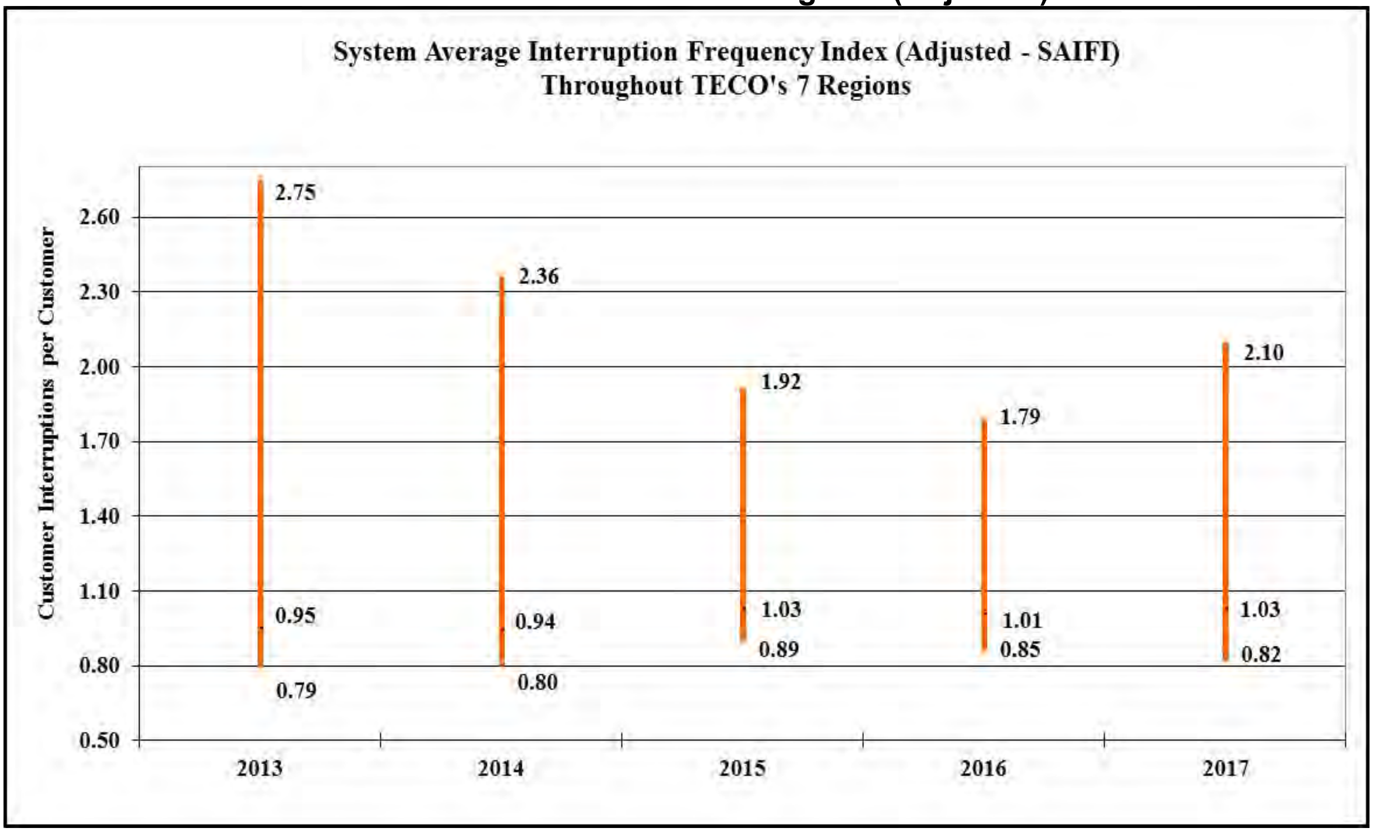
TECO's Regions with the Highest and Lowest Adjusted SAIDI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIDI	Dade City	Dade City	Dade City	Dade City	Dade City
Lowest SAIDI	Winter Haven	Central	Winter Haven	Central	Eastern

Source: TECO's 2013-2017 distribution service reliability reports.

Figures 3-31 illustrates TECO's adjusted frequency of interruptions per customer reported by the system. TECO's data represent a 2 percent increase in the SAIFI average from 1.01 interruptions in 2016 to 1.03 interruptions in 2017. TECO's Dade City region continues to have the highest frequency of service interruptions when compared to TECO's other regions. The minimum and average SAIFI are trending upward while the maximum SAIFI is trending downward.

Figure 3-31
SAIFI across TECO's Seven Regions (Adjusted)



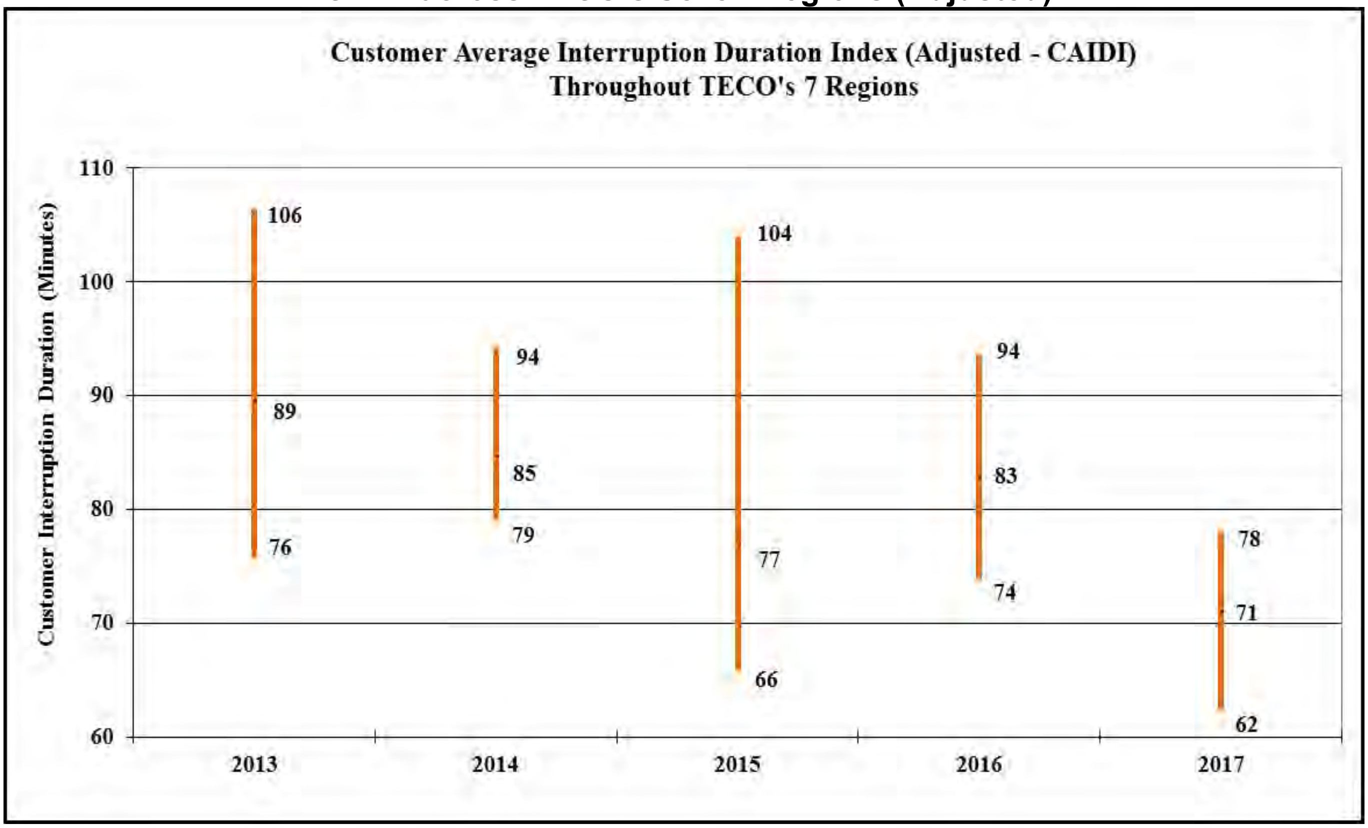
TECO's Regions with the Highest and Lowest Adjusted SAIFI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest SAIFI	Dade City	Dade City	Dade City	Dade City	Dade City
Lowest SAIFI	Central	Central	Western	Central	Central

Source: TECO's 2013-2017 distribution service reliability reports.

Figure 3-32 charts the length of time that a typical TECO customer experiences an outage, which is known as CAIDI. The highest CAIDI minutes appear to be confined to the Dade City, Eastern, Plant City, and Western regions. Winter Haven and Central regions have had the lowest (best) results for the last five years. The average CAIDI is trending downward at this time suggesting TECO's customers are experiencing shorter outages and there was a 14 percent decrease in the average CAIDI when comparing 2016 to 2017.

Figure 3-32
CAIDI across TECO's Seven Regions (Adjusted)



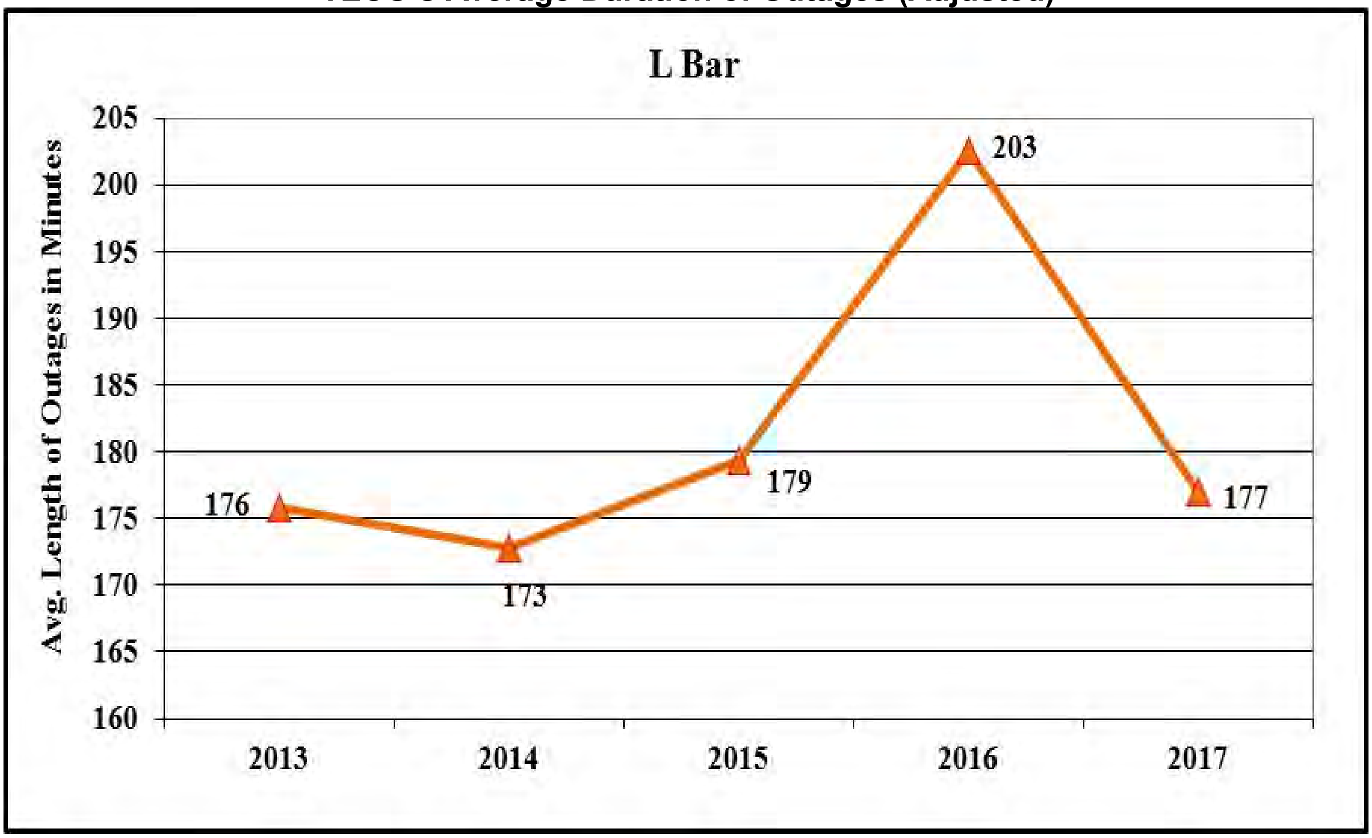
TECO's Regions with the Highest and Lowest Adjusted CAIDI Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest CAIDI	Eastern	Western	Dade City	Plant City	Central
Lowest CAIDI	Winter Haven	Central	Central	Central	Winter Haven

Source: TECO's 2013-2017 distribution service reliability reports.

Figure 3-33 denotes a 13 percent decrease in outage durations for the period from 2016 to 2017 for TECO. The average length of time TECO spends restoring service to its customers affected by outage events, excluding hurricanes and other allowable excluded outage events is shown in the L-Bar index. The L-Bar index continues to be trending upward for the five-year period of 2013 to 2017, suggesting longer restoral times.

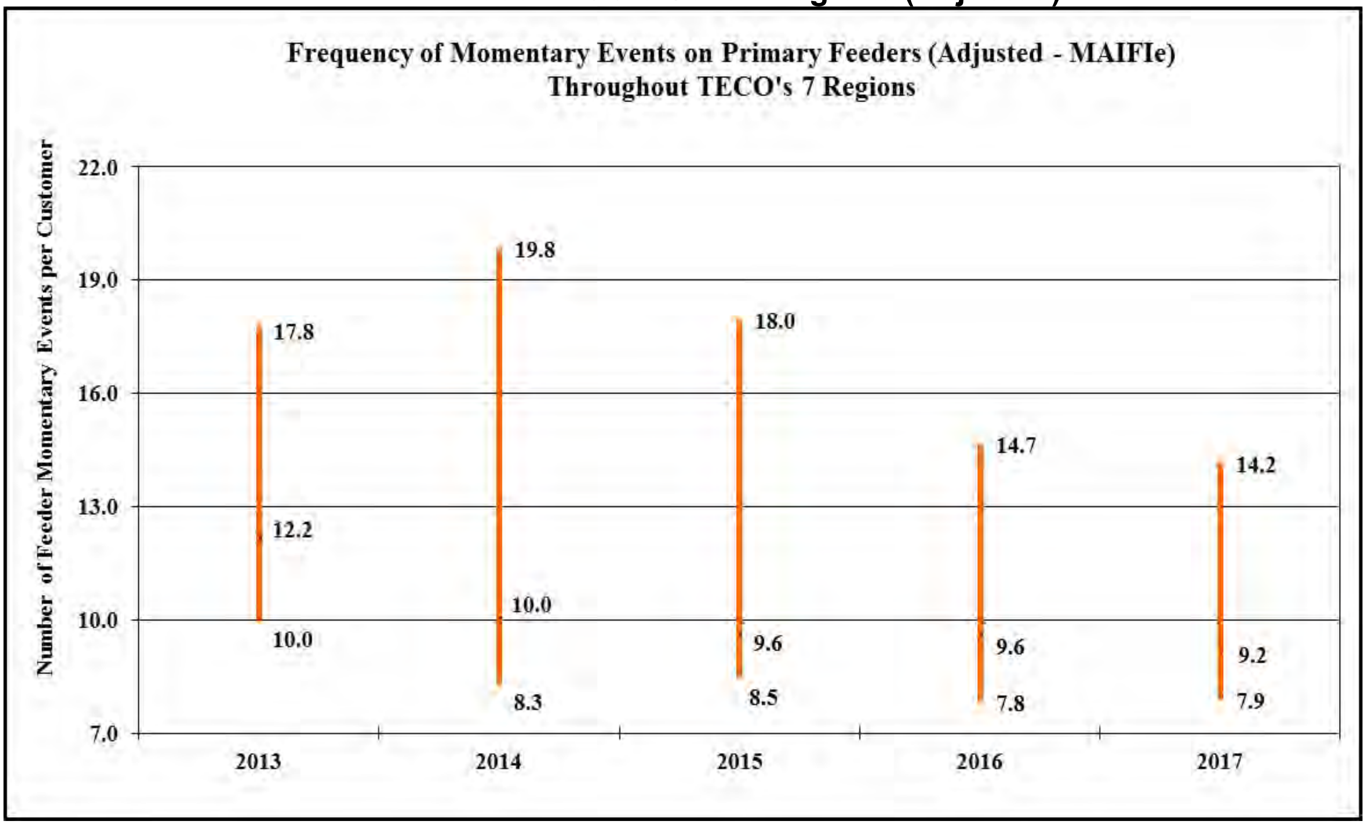
Figure 3-33
TECO's Average Duration of Outages (Adjusted)



Source: TECO's 2013-2017 distribution service reliability reports.

Figure 3-34 illustrates TECO's number of momentary events on primary circuits per customer recorded across its system. In 2017, the MAIFIe performance improved over the 2016 results in all regions except Central and Winter Haven. The average MAIFIe decreased by 4 percent from 2016 to 2017. **Figure 3-34** shows that the average MAIFIe is trending downward, which suggest an improvement in performance over the five-year period of 2013 to 2017.

Figure 3-34
MAIFIe across TECO's Seven Regions (Adjusted)



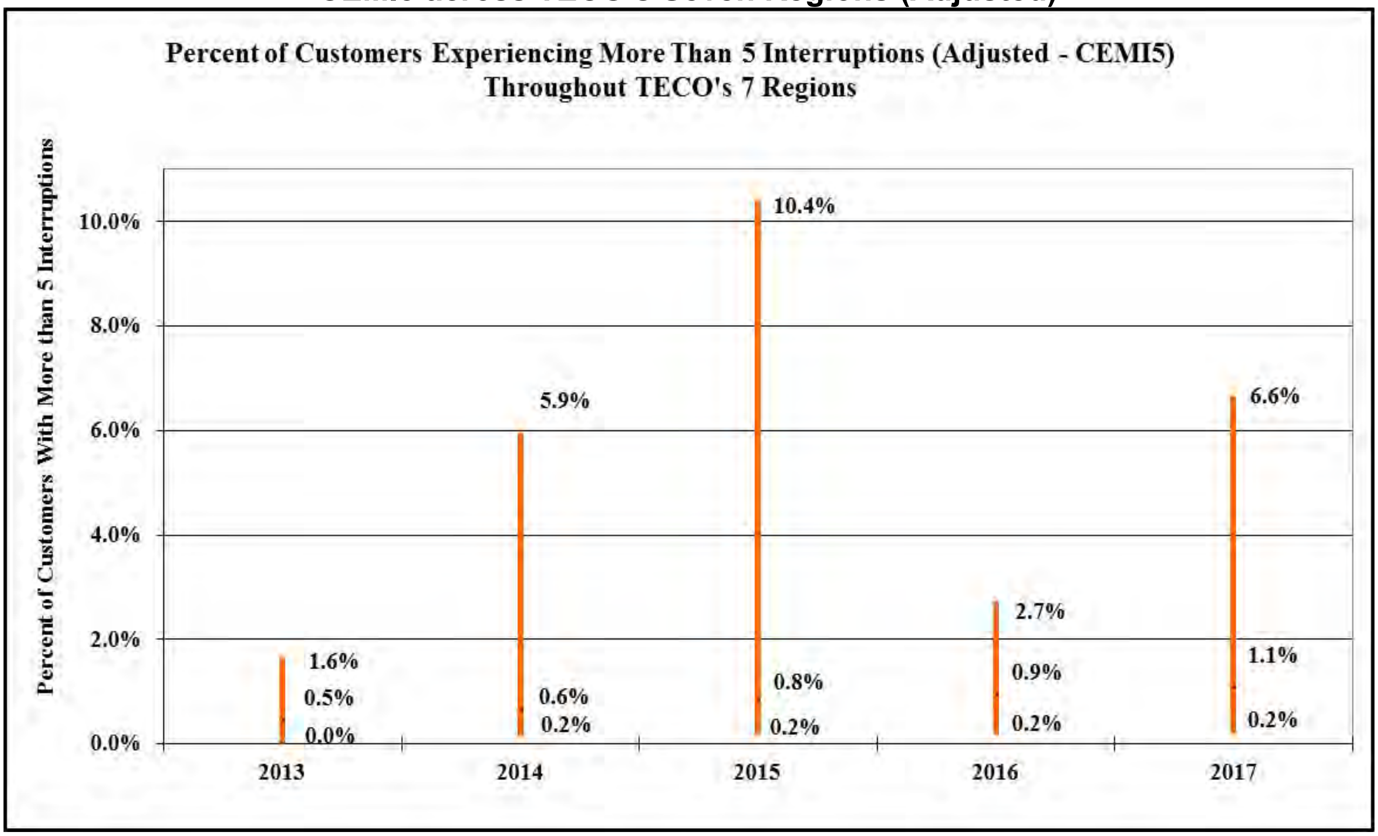
TECO's Regions with the Highest and Lowest Adjusted MAIFIe Distribution Reliability Performance by Year

	2013	2014	2015	2016	2017
Highest MAIFIe	Plant City	Dade City	Dade City	Dade City	Dade City
Lowest MAIFIe	Central	Central	Central	Central	Central

Source: TECO's 2013-2017 distribution service reliability reports.

Figure 3-35 shows the percent of TECO's customers experiencing more than five interruptions. Three regions in TECO's territory experienced a decrease in the CEMI5 results for 2017. The Dade City, Eastern, Plant City, and South Hillsborough regions experienced an increase in the CEMI5 index. Dade City reported the highest CEMI5 percentage for 2017. With TECO's results for this index varying for the past five years, the average CEMI5 index appears to be trending upward indicating a decline in performance. There was a 16 percent increase in the average CEMI5 index from 2016 to 2017.

Figure 3-35
CEMI5 across TECO's Seven Regions (Adjusted)



TECO's Regions with the Highest and Lowest Adjusted CEMI5 Distribution Reliability Performance by Year

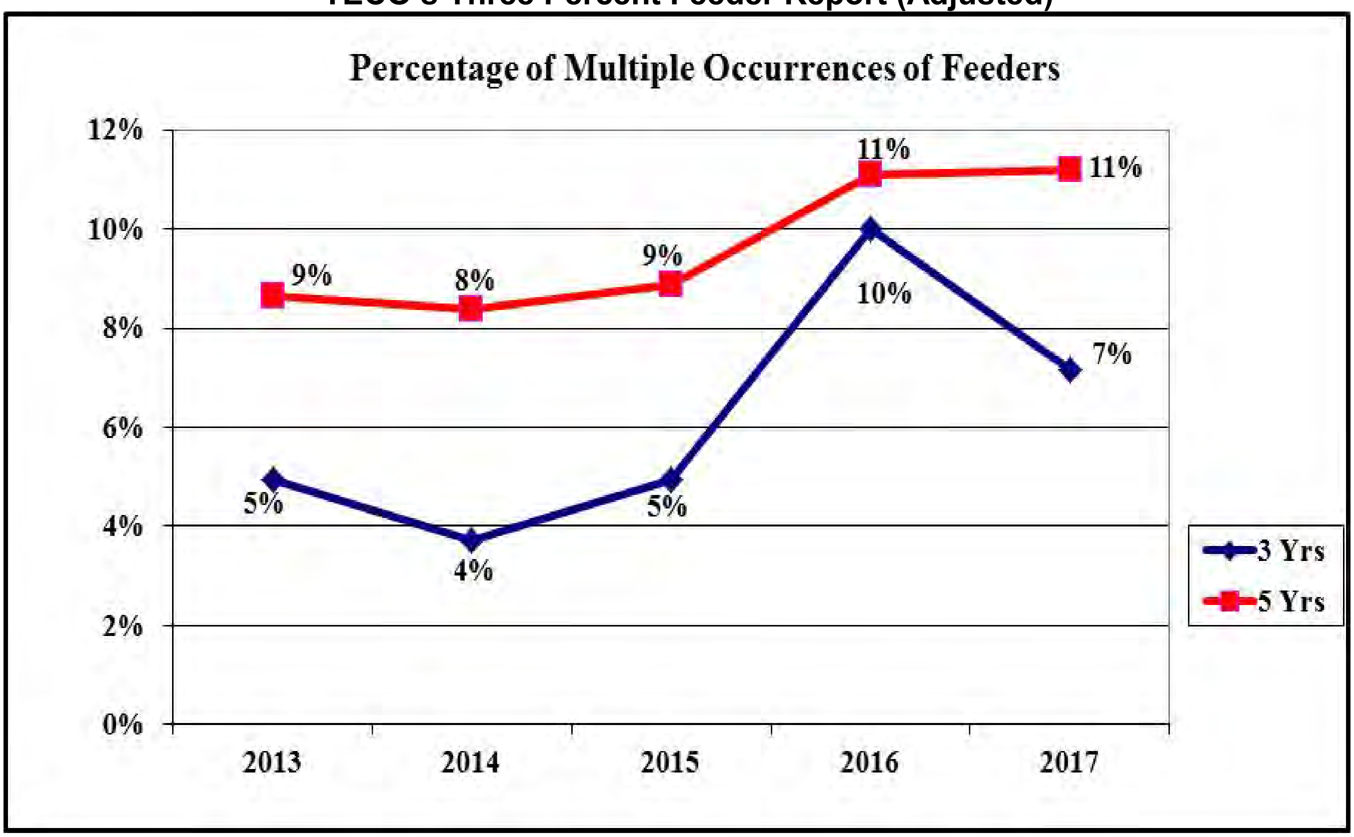
	2013	2014	2015	2016	2017
Highest CEMI5	Plant City	Dade City	Dade City	Dade City	Dade City
Lowest CEMI5	Winter Haven	Western	Winter Haven	South Hillsborough	Central

Source: TECO's 2013-2017 distribution service reliability reports.

Figure 3-36 represents an analysis of TECO's top 3 percent of problem feeders that have reoccurred (appeared on the Three Percent Feeder Report) on a five-year and three-year basis. The graph is developed using the number of recurrences divided by the number of feeders reported. The five-year average of outages per feeder did not change from 2016 to 2017 and the three-year average of outages decreased from 10 percent in 2016 to 7 percent in 2017. Both the five-year average of outages per feeder and the three-year average of outages appear to continue to trend upward for the five-year period of 2013 to 2017.

Staff notes that there was one feeder on the Three Percent Feeder Report for the last two years consecutively. Four circuit outages were reported for this feeder in 2017. The causes for the outages varied from "Animals" to "Defective Equipment." In 2017, the corrective action undertaken by TECO included replacing fault indicators, removing bird nest debris, and installing avian protection. TECO stated that it will continue to monitor circuit outage performance as part of its daily and ongoing review of system reliability and will respond accordingly at a regional level.

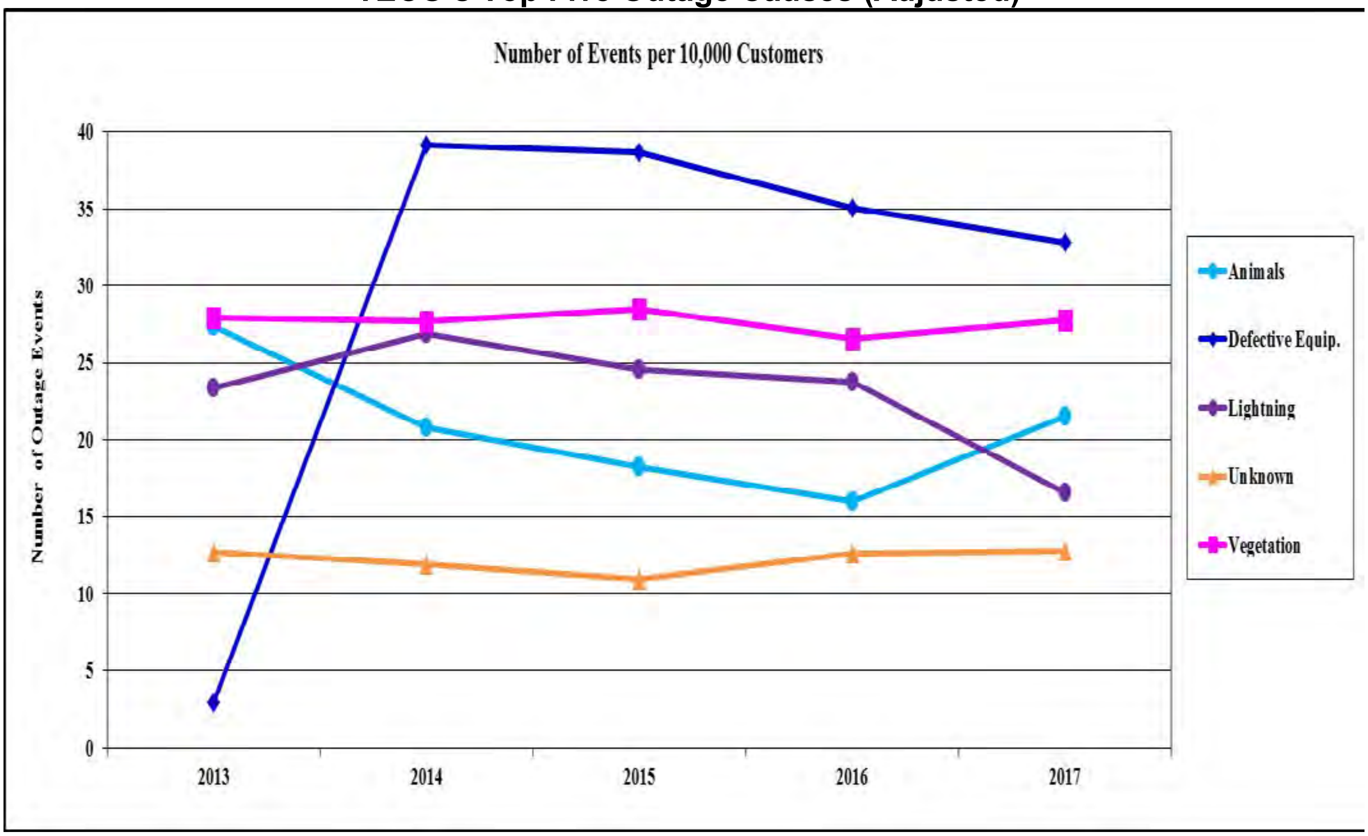
Figure 3-36
TECO's Three Percent Feeder Report (Adjusted)



Source: TECO's 2013-2017 distribution service reliability reports.

Figure 3-37 shows the top five causes of outage events on TECO's distribution system normalized to a 10,000-customer base. The figure is based on TECO's adjusted data of the top 10 causes of outage events and represents 89 percent of the total outage events that occurred during 2017. For the five-year period, the five top causes of outage events included "Defective Equipment" (26 percent), "Vegetation" (22 percent), "Animals" (17 percent), "Lightning" (13 percent), and "Unknown Causes" (10 percent) on a cumulative basis. "Defective Equipment" is the highest cause of outages for 2017. Beginning in 2014, the "Defective Equipment" category now includes outage categories that in the past were separately identified. "Vegetation" and "Animals" causes are the next two top problem areas for TECO. The outages due to "Vegetation" increased 8 percent from 2016 to 2017. The outages from "Lightning" decreased 28 percent for the same time period. The numbers of outages due to "Lightning" and "Animals" causes are trending downward while the number of outages due to "Vegetation" and "Unknown Causes" are remaining relatively flat. The number of outages due to "Defective Equipment" is trending upward.

Figure 3-37
TECO's Top Five Outage Causes (Adjusted)



Source: TECO's 2013-2017 distribution service reliability reports.

Observations: TECO's Adjusted Data

Three of TECO's 2017 reliability indices, SAIDI, CAIDI, and MAIFIe, showed an improvement in performance compared to 2016. For the five-year period of 2013 to 2017, the indices for SAIFI, CEMI5, L-Bar, the Three-Year Percent of Multiple Feeder outage events, and the Five-Year Percent of Multiple Feeder outage events are all trending upward. The indices for SAIDI, CAIDI and MAIFIe are trending downward. TECO reported the improvement in SAIDI, CAIDI, and L-Bar were attributed to less severe weather events combined with much quicker restoration times. TECO clarified that the less severe weather events were referring to non-excludable weather as compared to previous years. In addition, TECO explained that the main reason it was able to achieve quicker restoration times that help with the improvements to SAIDI, CAIDI, and L-Bar, was the installation of mid-point feeder/circuit reclosers which allows the Distribution System Operators to restore service to customers more quickly. MAIFIe's improvement was due to fewer breaker operations. The increases in SAIFI and CEMI-5 were contributed to an increased number of outages experienced in 2017 as compared to 2016.

In 2017, the Dade City region had the highest reliability indices in four of the five indices although Dade City did improve in two of the five indices. TECO has implemented the following measures to improve reliability in this region: installed 2 electronic reclosers and 34 TripSaver reclosers. The reclosers offer protection to upstream customers by giving TECO the ability to isolate faults and shorten the outage time experienced by customers. For 2018, TECO has already analyzed and will enhance the fuse coordination protection settings at an additional 87 locations. In addition, the Utility will install 7 more new electronic reclosers and 47 more TripSaver reclosers to help improve the reliability in the Dade City region.

Section IV: Inter-Utility Reliability Comparisons

Section IV contains comparisons of the utilities' adjusted data for the various reliability indices that were reported. It also contains a comparison of the service reliability related complaints received by the Commission.

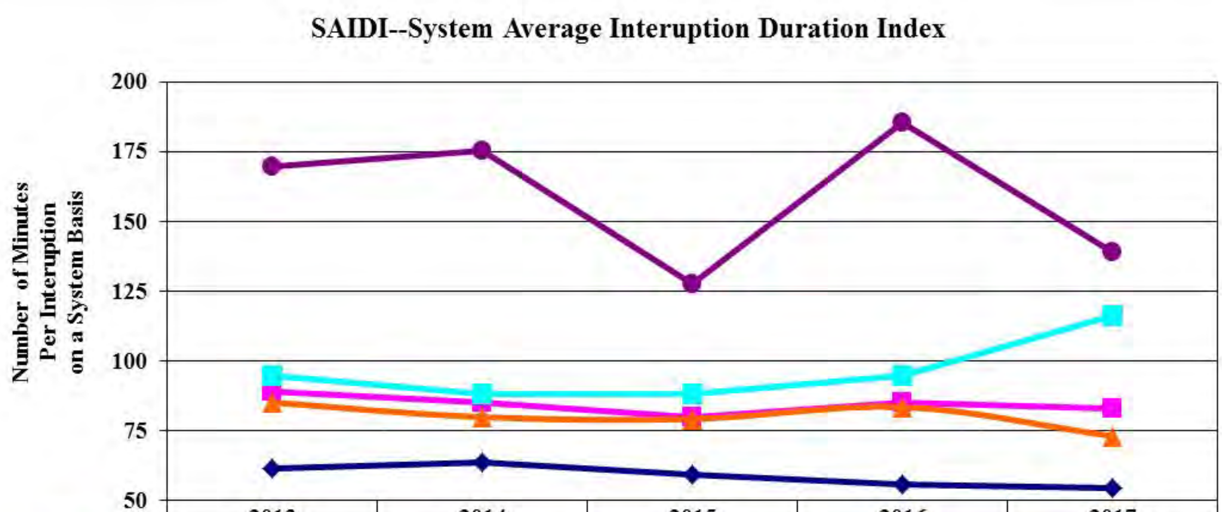
Inter-Utility Reliability Trend Comparisons: Adjusted Data

The inter-utility trend comparison focuses on a graphical presentation that combines all of the IOUs' distribution reliability indices for the years 2013 to 2017. **Figures 4-1** through **4-3** apply to all five utilities while **Figures 4-4** and **4-5** do not apply to FPUC because it is not required to report MAIFIe and CEMI5 due to the size of its customer base. The adjusted data is used in generating the indices in this report and is based on the exclusion of certain events allowed by Rule 25-6.0455(4), F.A.C. Generalizations can be drawn from the side-by-side comparisons; however, any generalizations should be used with caution due to the differing sizes of the distribution systems, the degree of automation, and the number of customers. The indices are unique to each IOU.

Figure 4-1 indicates that Gulf's SAIDI trend has risen since 2013, while DEF, FPL, FPUC and TECO are trending downward. Comparing 2016 SAIDI values to 2017 SAIDI indices, all utilities, except Gulf, have improved. Gulf's SAIDI value increased 7 percent from 2016 to 2017. DEF's SAIDI value has decreased 2 percent, FPL decreased 4 percent, FPUC decreased 25 percent, and TECO decreased 12 percent from 2016 to 2017.

SAIDI is the average amount of time a customer is out of service per retail customers served within a specified area of service over a given period. It is determined by dividing the total Customer Minutes of Interruption by total Number of Customers Served for the respective area of service.

Figure 4-1
System Average Interruption Duration (Adjusted SAIDI)



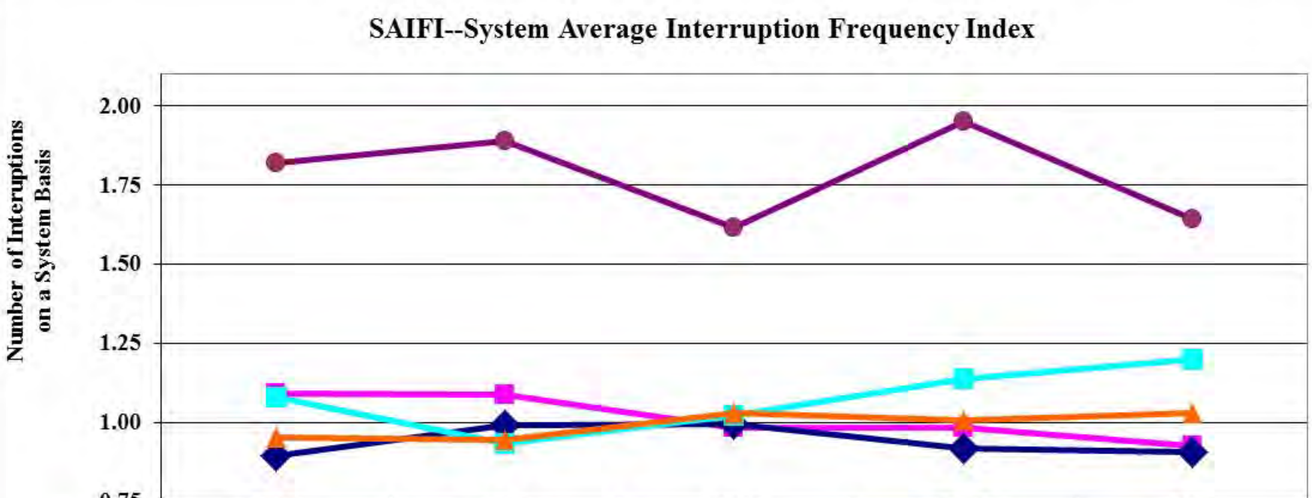
	2013	2014	2015	2016	2017
DEF	89	85	80	85	83
FPL	61	64	59	56	54
FPUC	170	175	127	185	139
Gulf	95	88	88	95	116
TECO	85	80	79	83	73

Source: The IOUs' 2013-2017 distribution service reliability reports.

Figure 4-2 is a five-year graph of the adjusted SAIFI for each IOU. The 2017 data shows DEF, FPL and FPUC's SAIFI values decreased (improved) from the 2016 results as Gulf and TECO's SAIFI values increased. Over the five-year period of 2013 to 2017, Gulf and TECO's SAIFI values are all trending upward. DEF, FPL and FPUC's SAIFI value is trending downward for the period of 2013 to 2017.

SAIFI is the average number of service interruptions per retail customer within a specified area of service over a given period. It is determined by dividing the Sum of Service (a/k/a Customer) Interruptions (CI) by the total Number of Customers Served for the respective area of service.

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



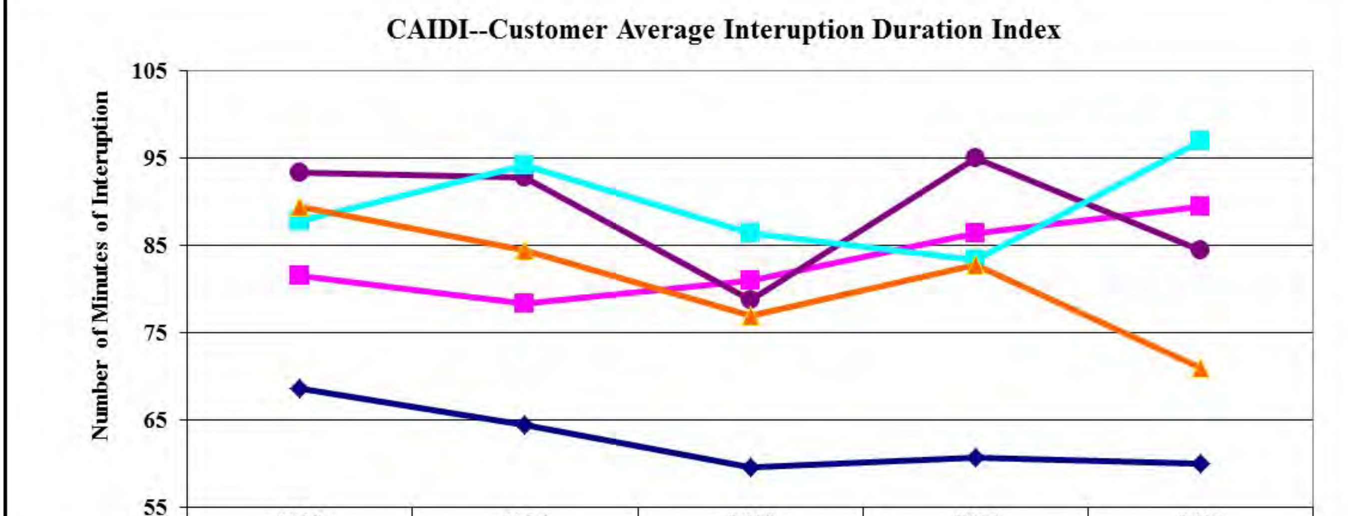
	2013	2014	2015	2016	2017
DEF	1.09	1.09	0.98	0.98	0.92
FPL	0.89	0.99	1.00	0.92	0.90
FPUC	1.82	1.89	1.62	1.95	1.64
Gulf	1.08	0.93	1.02	1.14	1.20
TECO	0.95	0.94	1.03	1.01	1.03

Source: The IOUs' 2013-2017 distribution service reliability reports.

Figure 4-3 is a five-year graph of the adjusted CAIDI for each IOU. DEF and Gulf had an increase in the CAIDI from 2016 to 2017 while FPL, FPUC, and TECO had decreases in the CAIDI. All utilities, except DEF and Gulf, CAIDI values are trending downward for the five-year period of 2013 to 2017. DEF's CAIDI value is trending upward for the same period, while Gulf's CAIDI value is trending slightly upward.

CAIDI is the average interruption duration or the time to restore service to interrupted customers. CAIDI is calculated by dividing the total system CMI by the number of customer interruptions, which is also SAIDI, divided by SAIFI.

Figure 4-3
Average Service Restoration Time (Adjusted CAIDI)



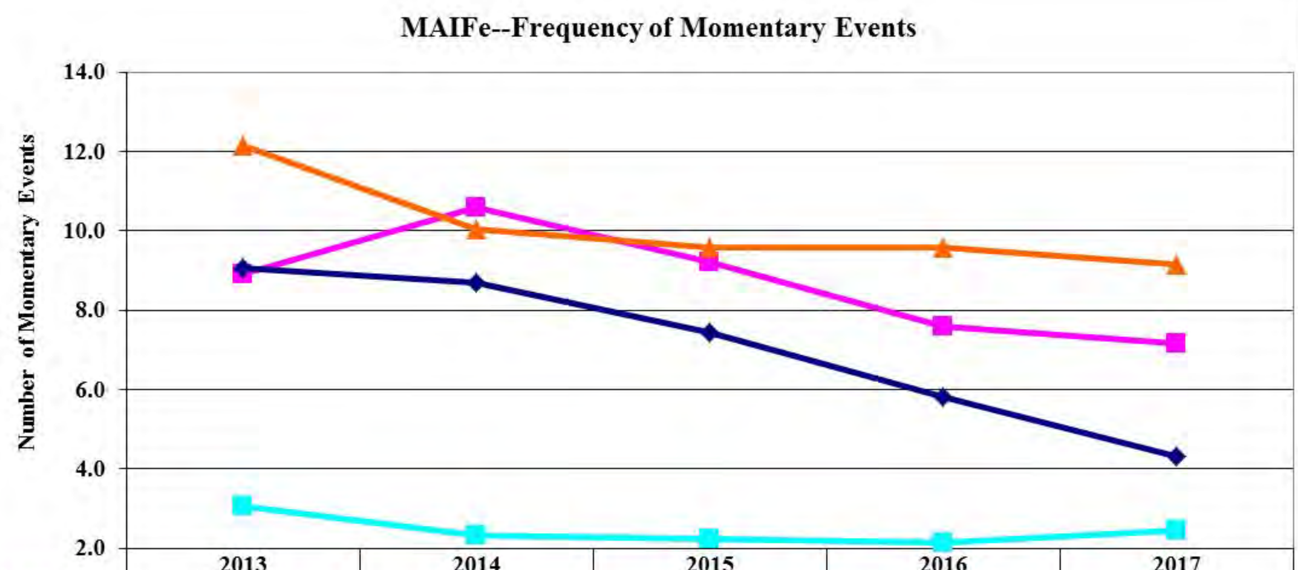
	2013	2014	2015	2016	2017
DEF	82	78	81	86	90
FPL	69	65	60	61	60
FPUC	93	93	79	95	85
Gulf	88	94	86	83	97
TECO	89	85	77	83	71

Source: The IOUs' 2013-2017 distribution service reliability reports.

Figure 4-4 shows a five-year graph of the adjusted MAIFIe for DEF, FPL, Gulf, and TECO. DEF, FPL, Gulf and TECO's MAIFIe indices are all trending downward for the five-year period of 2013 to 2017. Comparing the MAIFIe for 2016 to 2017, DEF decreased by 5 percent, FPL decreased by 26 percent, Gulf increased by 5 percent and TECO decreased by 4 percent. FPUC is exempt from reporting MAIFIe and CEMI5 because it has fewer than 50,000 customers.

MAIFIe is the average frequency of momentary interruption~~s~~ events or the number of times there is a loss of service of less than one minute. MAIFIe is calculated by dividing the number of momentary interruptions events recorded on primary circuits (CME) by the number of customers served.

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

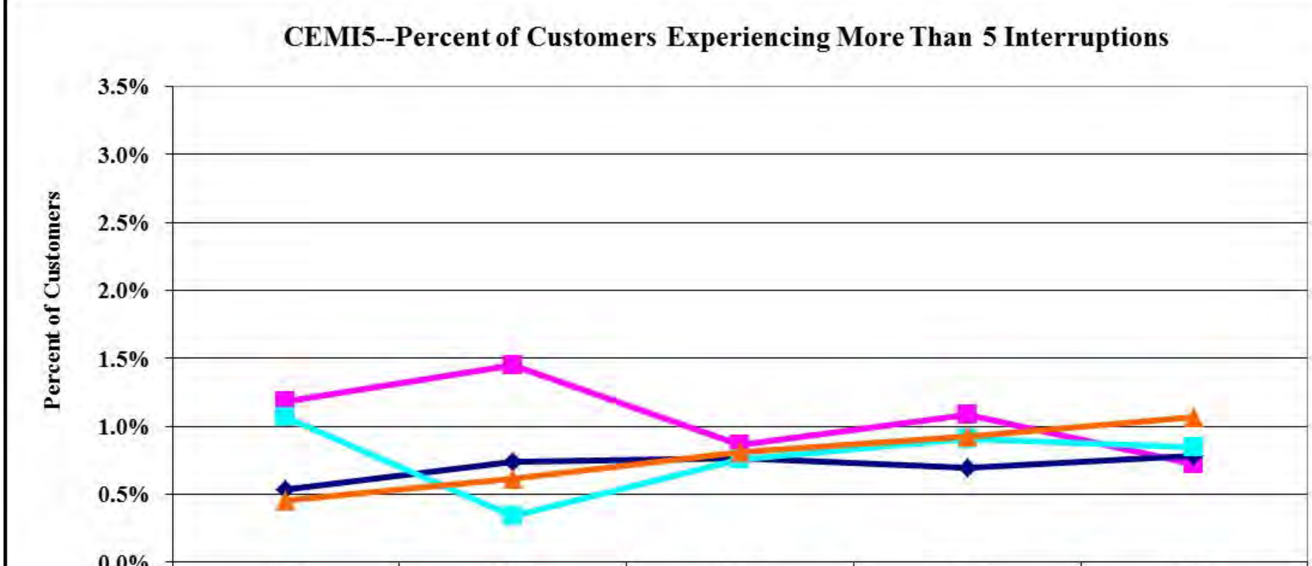


	2013	2014	2015	2016	2017
DEF	8.9	10.6	9.2	7.6	7.2
FPL	9.1	8.7	7.5	5.8	4.3
Gulf	3.1	2.3	2.2	2.1	2.4
TECO	12.2	10.0	9.6	9.6	9.2

Source: The IOUs' 2013-2017 distribution service reliability reports.

Figure 4-5 is a five-year graph of the adjusted CEMI5 for FPL, Gulf, DEF, and TECO. CEMI5 is a percentage. It represents the number of customers that experienced more than five service interruptions in the year divided by the total number of customers. In 2017, FPL and TECO's CEMI5 percent increased to 0.8 percent from 0.7 percent in 2016 for FPL and 1.1 percent from 0.9 percent in 2016 for TECO. DEF decreased from 1.1 percent in 2016 to 0.7 percent in 2017, while Gulf decreased from 0.9 percent in 2016 to 0.8 percent in 2017. FPL and TECO are trending upward as DEF is trending downward for the period of 2013 to 2017. Gulf is trending relatively flat for the same period.

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

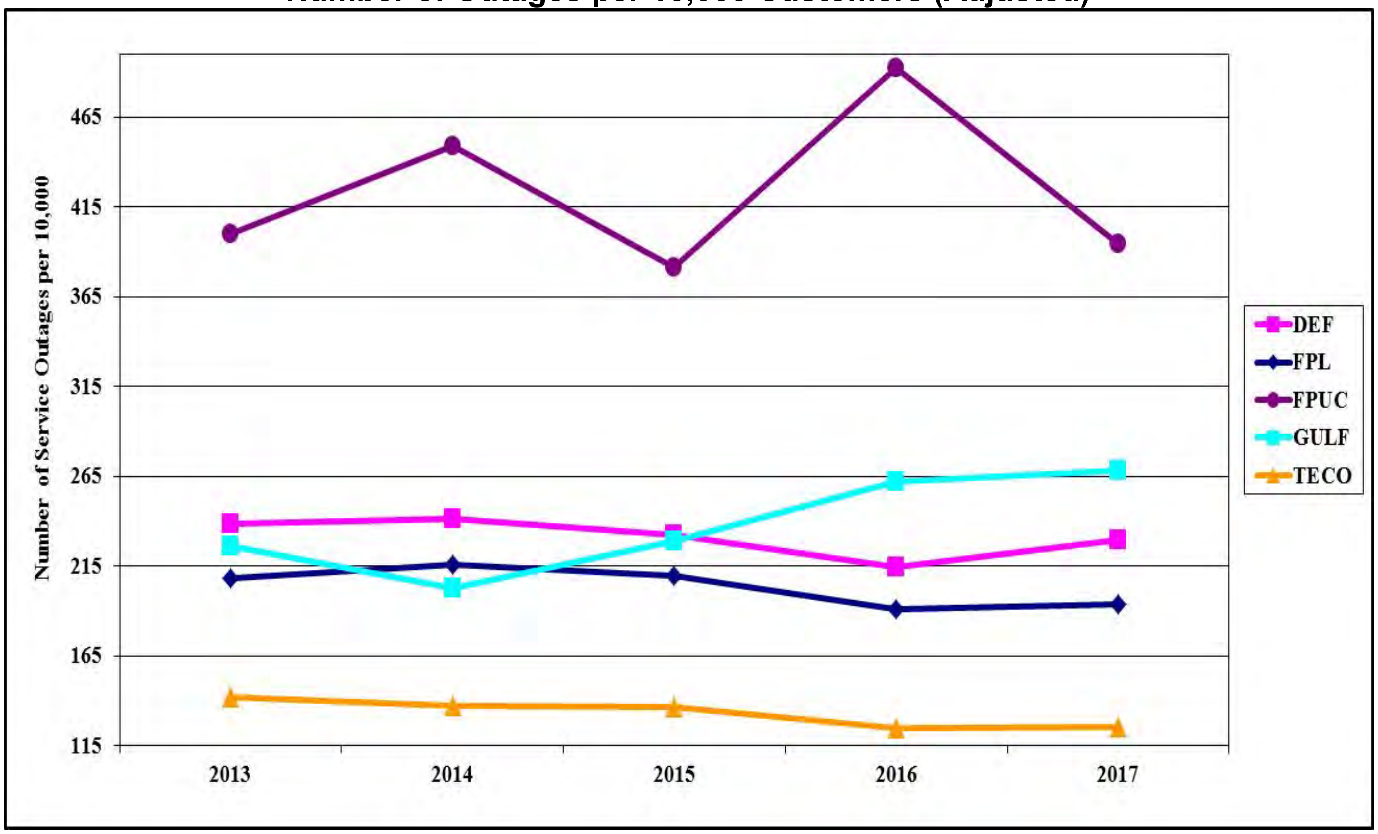


	2013	2014	2015	2016	2017
DEF	1.2%	1.5%	0.9%	1.1%	0.7%
FPL	0.5%	0.7%	0.8%	0.7%	0.8%
Gulf	1.1%	0.3%	0.8%	0.9%	0.8%
TECO	0.5%	0.6%	0.8%	0.9%	1.1%

Source: The IOUs' 2013-2017 distribution service reliability reports.

Figure 4-6 shows the number of outages per 10,000 customers on an adjusted basis for the five IOUs over the last five years. The graph displays each utility's adjusted data concerning the number of outage events and the total number of customers on an annual basis. The number of FPL outages increased from 92,686 in 2016 to 95,077 in 2017, and the number of outages per 10,000 customers is trending downward for the five-year period. TECO's results are trending downward for the five-year period. DEF's number of outages increased for 2017 and the results are trending downward for the five-year period. Gulf's number of outages increased for 2017, and is trending upward for the five-year period. FPUC's results increased for 2013 to 2014, decreased for 2014 to 2015, increased for 2015 to 2016 and decreased for 2016 to 2017. Due to the small customer base, the line graph for FPUC could be subject to greater volatility.

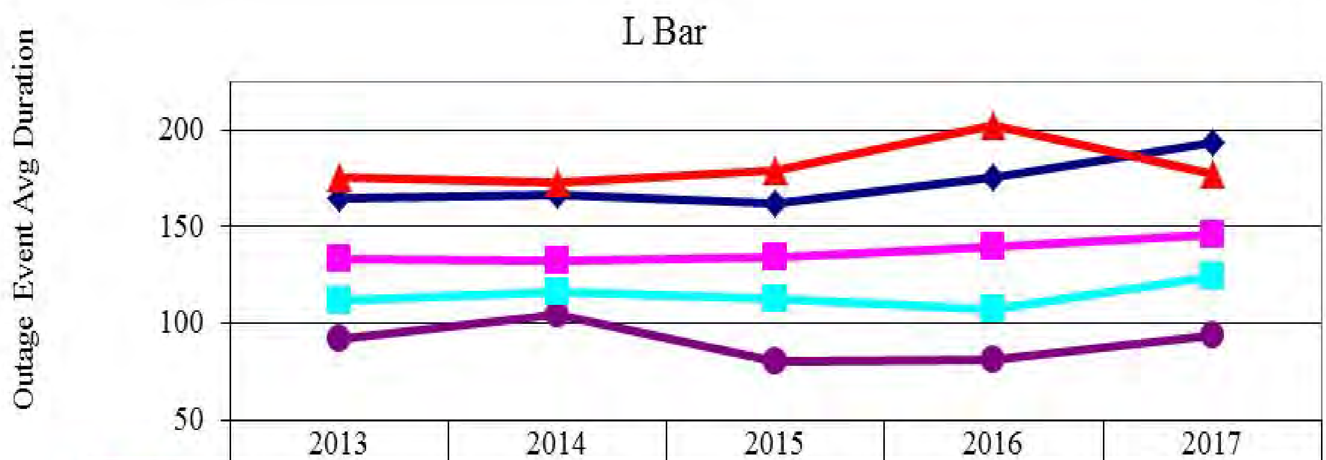
Figure 4-6
Number of Outages per 10,000 Customers (Adjusted)



Source: The IOUs' 2013-2017 distribution service reliability reports.

Figure 4-7 represents the average duration of outage events (Adjusted L-Bar) for each IOU. From the data shown, it appears that the utilities have been consistent with their restoral times for the five-year period of 2013 to 2017, even with increases from 2016 to 2017.

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



	2013	2014	2015	2016	2017
DEF	133	132	134	140	145
FPL	165	166	162	175	193
FPUC	92	105	80	81	93
Gulf	111	116	112	107	125
TECO	176	173	179	203	177

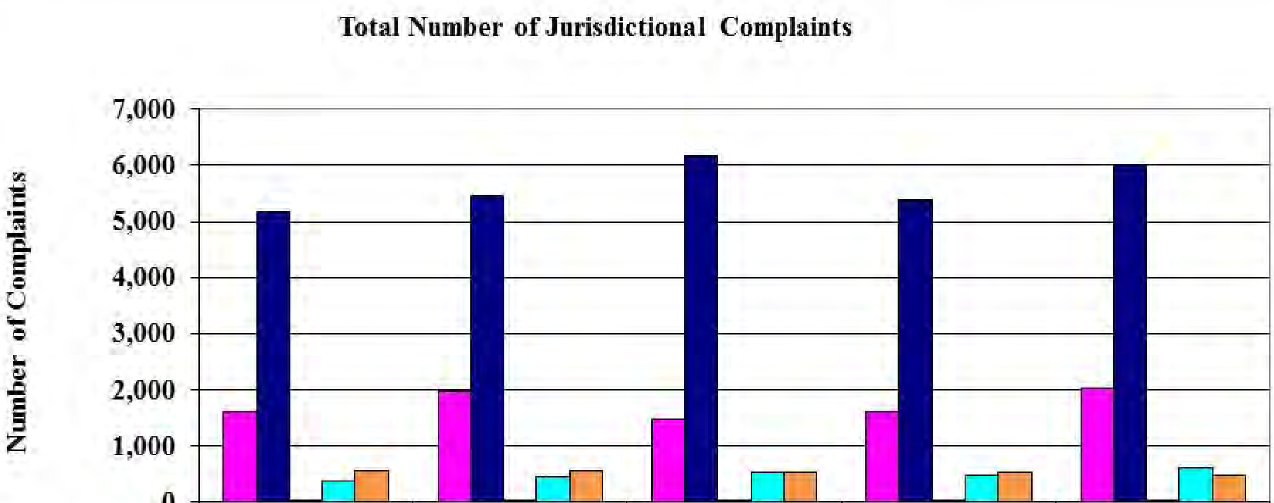
Source: The IOUs' 2013-2017 distribution service reliability reports.

Inter-Utility Comparisons of Reliability Related Complaints

Figures 4-8, **4-9**, **4-10**, and **4-11** represent consumer complaint data that was extracted from the Commission's Consumer Activity Tracking System (CATS). Each consumer complaint received by the Commission is assigned a code after the complaint is resolved. Reliability related complaints have 10 specific category types and typically pertain to "Trees," "Safety," "Repairs," "Frequent Outages," and "Momentary Service Interruptions."

Figure 4-8 shows the total number of jurisdictional complaints[17] for each IOU. In comparing the number of complaints by the different companies, the total number of customers should be considered. FPL has the higher number of complaints, but FPL also has more customers than the other companies.

Figure 4-8
Total Number of Jurisdictional Complaints



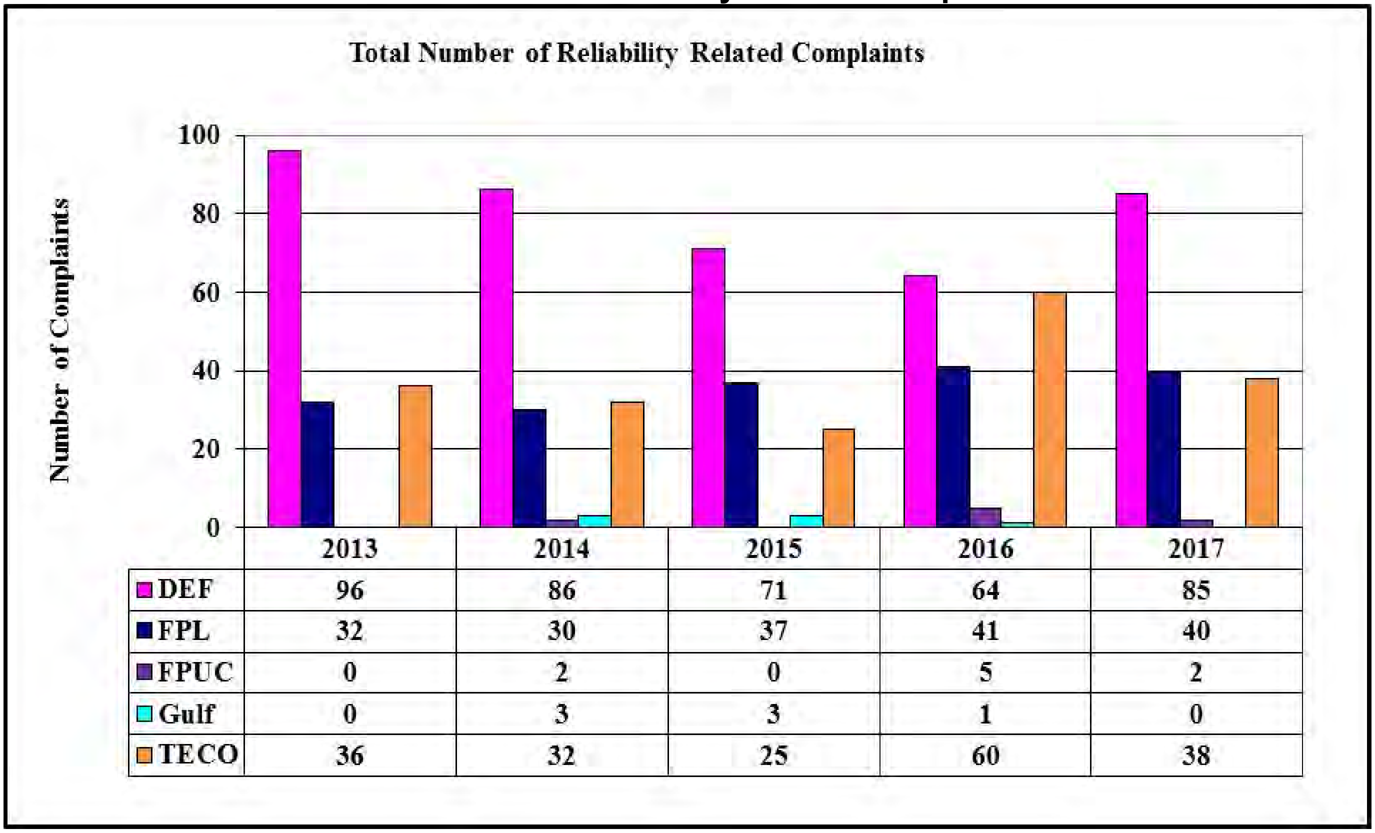
	2013	2014	2015	2016	2017
DEF	1,613	1,988	1,476	1,600	2,042
FPL	5,162	5,473	6,161	5,381	6,012
FPUC	8	15	12	18	13
Gulf	371	450	548	494	615
TECO	558	570	534	531	473

Source: FPSC CATS.

[17] Non-jurisdictional complaint codes include load management, hurricanes, and damage claims.

Figure 4-9 charts the total number of reliability related complaints for the IOUs. DEF is showing the largest amount of reliability complaints for the five-year period of 2013 to 2017 with FPUC and Gulf showing the least amount. DEF is trending downward in the number of reliability complaints, while FPL, FPUC, and TECO are trending upward. Gulf appears to be relatively flat.

Figure 4-9
Total Number of Reliability Related Complaints

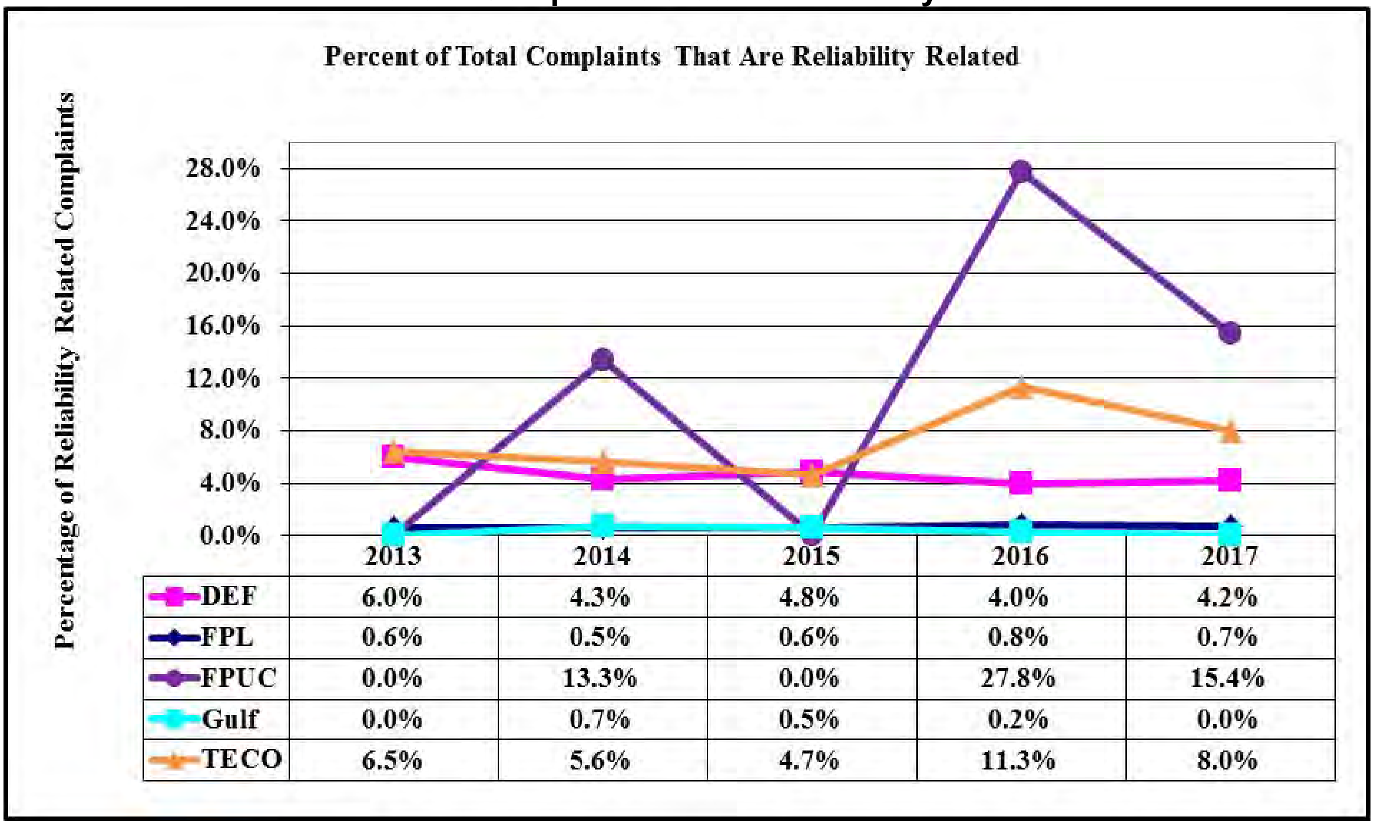


	2013	2014	2015	2016	2017
DEF	96	86	71	64	85
FPL	32	30	37	41	40
FPUC	0	2	0	5	2
Gulf	0	3	3	1	0
TECO	36	32	25	60	38

Source: FPSC CATS.

Figure 4-10 shows the percentage of reliability related customer complaints in relation to the total number of complaints for each IOU. FPL and Gulf's are relatively flat as FPUC and TECO are trending upward. DEF appears to be trending downward. The percentages of FPUC complaints compared to the other companies appears high, however FPUC has fewer customers and fewer complaints in total.

Figure 4-10
Percent of Complaints that are Reliability Related



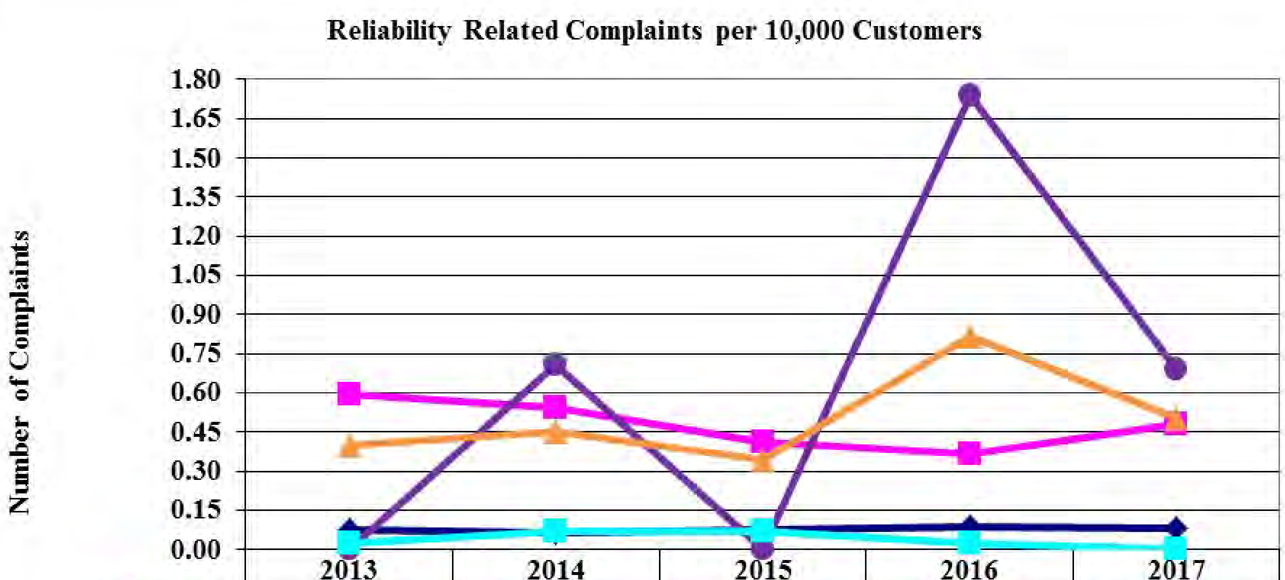
	2013	2014	2015	2016	2017
DEF	6.0%	4.3%	4.8%	4.0%	4.2%
FPL	0.6%	0.5%	0.6%	0.8%	0.7%
FPUC	0.0%	13.3%	0.0%	27.8%	15.4%
Gulf	0.0%	0.7%	0.5%	0.2%	0.0%
TECO	6.5%	5.6%	4.7%	11.3%	8.0%

Source: FPSC CATS.

Figure 4-11 charts the volume of reliability related complaints per 10,000 customers for the IOUs. The volume of service reliability complaints is normalized to a 10,000-customer base for comparative purposes. This is calculated for each IOU by dividing the total number of reliability complaints reported to the Commission by the total number of the utility's customers. This fraction is then multiplied by 10,000 for graphing purposes.

All the IOUs have less than one reliability complaint per 10,000 customers since 2013 except FPUC. For the five-year period, DEF is trending downward as FPL and Gulf are staying relatively flat. FPUC and TECO are trending upward for the five-year period. The volatility of FPUC's results can be attributed to its small customer base, which typically averages 28,500 customers.

Figure 4-11
Service Reliability Related Complaints per 10,000 Customers



	2013	2014	2015	2016	2017
DEF	0.592	0.542	0.412	0.366	0.478
FPL	0.073	0.063	0.077	0.084	0.081
FPUC	0.000	0.708	0.000	1.742	0.688
Gulf	0.023	0.068	0.067	0.022	0.000
TECO	0.400	0.449	0.345	0.814	0.500

Source: The IOUs' 2013-2017 distribution service reliability reports and FPSC CATS.

Section V: Appendices

Appendix A – Adjusted Service Reliability Data

Duke Energy Florida, LLC

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

	2013	2014	2015	2016	2017
North Central	383,011	388,187	396,395	400,510	406,483
North Coastal	194,394	196,321	198,525	200,565	203,300
South Central	438,088	449,363	458,457	470,534	484,848
South Coastal	656,073	663,973	670,743	677,255	682,618
DEF System	**1,671,566**	**1,697,844**	**1,724,120**	**1,748,864**	**1,777,249**

Source: DEF's 2013-2017 distribution service reliability reports.

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

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
North Central	91	84	72	78	75	1.11	1.11	0.85	0.90	0.84	82	76	84	87	90
North Coastal	147	159	145	155	154	1.51	1.57	1.47	1.39	1.45	97	101	99	111	107
South Central	88	83	72	79	70	0.97	1.04	0.91	1.01	0.84	91	80	77	78	83
South Coastal	71	66	71	73	75	1.04	0.96	0.97	0.90	0.88	69	68	74	81	85
DEF System	**89**	**85**	**80**	**85**	**83**	**1.09**	**1.09**	**0.98**	**0.98**	**0.92**	**82**	**78**	**81**	**86**	**90**

Source: DEF's 2013-2017 distribution service reliability reports.

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

	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than 5 Service Interruptions (CEMI5)				
	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
North Central	8.9	10.8	8.3	8.6	7.6	1.53%	1.07%	0.32%	0.36%	0.37%
North Coastal	8.1	10.0	7.1	7.8	8.2	4.13%	3.47%	3.96%	4.00%	2.83%
South Central	7.8	10.3	8.1	7.0	6.9	0.80%	1.04%	0.64%	1.06%	0.87%
South Coastal	9.9	10.8	11.2	7.3	6.8	0.38%	1.36%	0.43%	0.68%	0.21%
DEF System	**8.9**	**10.6**	**9.2**	**7.6**	**7.2**	**1.19%**	**1.45%**	**0.87%**	**1.09%**	**0.73%**

Source: DEF's 2013-2017 distribution service reliability reports.

Table A-4
DEF's Primary Causes of Outages Events

	Adjusted Number of Outages Events						Adjusted L-Bar Length of Outages				
	2013	2014	2015	2016	2017	Percentages	2013	2014	2015	2016	2017
Animals	5,488	5,020	5,321	5,369	5,597	13.7%	71	75	75	80	80
Storm	4,755	-	-	-	-	-	115	-	-	-	-
Tree-Preventable	3,938	-	-	-	-	-	123	-	-	-	-
Unknown	3,333	2,867	1,224	1,097	998	2.4%	84	82	77	90	94
All Other	7,015	8,073	7,900	7,390	8,287	20.3%	147	170	167	174	180
Defective Equipment	3,358	7,221	8,572	9,195	10,475	25.7%	171	150	142	147	150
Vehicle-Const. Equipment	392	-	-	-	-	-	222	-	-	-	-
Connector Failure	3,000	-	-	-	-	-	117	-	-	-	-
Tree Non-preventable	5,205	-	-	-	-	-	154	-	-	-	-
UG Primary	2,039	-	-	-	-	-	252	-	-	-	-
Lightning	1,344	1,647	1,201	1,216	1,261	3.1%	178	166	145	150	151
Vegetation	-	9,816	8,240	7,879	8,143	20.0%	-	137	136	145	150
Other Weather	-	5,875	7,141	4,965	5,478	13.4%	-	108	134	134	145
Vehicle	-	420	412	429	505	1.2%	-	241	227	235	223
DEF System	**39,867**	**40,939**	**40,011**	**37,540**	**40,744**	**100%**	**133**	**132**	**134**	**140**	**145**

Note: (1) "Other Causes" category is the sum of diverse causes of outage events which individually are not among the top 10 causes of outage events.
(2) Commission staff requested that, beginning with 2014 data, all IOU's use the same outage categories for comparison purposes. As such, the "Vegetation," "Defective Equipment," and "Other Weather" now include outage categories that in the past were separately identified.

Source: DEF's 2013-2017 distribution service reliability reports.

Florida Power & Light Company

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

	2013	2014	2015	2016	2017
Boca Raton	361,932	366,503	370,266	374,080	378,125
Brevard	293,491	297,877	301,843	305,151	307,825
Central Dade	277,807	282,155	287,147	292,421	297,237
Central Florida	275,033	279,726	283,868	286,492	289,426
Gulf Stream	327,898	331,643	335,006	337,828	339,518
Manasota	372,514	378,304	384,138	390,400	395,636
North Dade	232,018	235,112	237,328	240,194	241,259
North Florida	146,184	150,052	153,683	157,967	161,216
Naples	371,866	379,012	386,710	394,355	399,295
Pompano	306,692	310,483	314,209	317,731	319,630
South Dade	295,283	299,919	304,336	309,022	311,692
Toledo Blade	249,533	254,982	260,053	265,547	269,787
Treasure Coast	279,202	283,693	287,508	291,334	294,545
West Dade	249,935	254,130	257,539	261,484	264,888
West Palm	351,875	357,064	361,717	364,292	366,570
Wingate	265,120	268,737	271,478	273,692	276,218
FPL System	**4,656,383**	**4,729,392**	**4,796,829**	**4,861,990**	**4,912,867**

Source: FPL's 2013-2017 distribution service reliability reports.

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

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2013	**2014**	**2015**	**2016**	**2017**	**2013**	**2014**	**2015**	**2016**	**2017**	**2013**	**2014**	**2015**	**2016**	**2017**
Boca Raton	61	63	54	51	45	1.10	1.21	1.08	1.08	0.89	55	52	50	47	50
Brevard	56	69	53	53	56	0.89	1.14	0.96	0.87	1.04	63	61	55	60	54
Central Dade	51	54	47	41	42	0.67	0.80	0.78	0.66	0.79	75	68	60	63	53
Central Florida	67	61	50	49	46	0.93	0.95	0.90	0.80	0.85	71	64	55	61	54
Gulf Stream	59	58	52	43	42	0.93	0.96	0.88	0.83	0.79	63	60	59	51	54
Manasota	58	57	55	52	50	0.83	0.83	1.00	0.91	0.77	70	68	55	57	65
North Dade	60	77	71	59	69	0.68	0.83	0.87	0.72	0.96	88	92	82	82	72
North Florida	84	77	68	64	64	1.10	1.06	1.08	1.00	1.04	76	73	63	64	62
Naples	55	58	57	56	64	0.68	0.88	0.91	0.97	0.92	79	66	62	57	69
Pompano	49	52	57	48	38	0.69	0.86	1.03	0.80	0.65	71	61	55	60	58
South Dade	77	73	76	68	63	0.99	0.90	1.08	0.99	0.79	77	81	71	69	80
Toledo Blade	72	73	65	75	77	1.04	1.16	0.98	1.14	1.12	70	63	66	66	69
Treasure Coast	72	74	72	81	66	1.08	1.07	1.05	1.19	1.11	67	69	69	68	59
West Dade	59	72	68	56	54	0.85	1.20	1.24	0.99	0.85	69	60	55	57	63
West Palm	54	49	55	51	46	0.95	0.85	1.01	0.88	0.96	57	58	55	58	47
Wingate	70	74	64	58	61	0.99	1.25	1.14	0.86	1.11	71	59	57	67	55
FPL System	**61**	**64**	**59**	**56**	**54**	**0.89**	**0.99**	**1.00**	**0.92**	**0.90**	**69**	**65**	**60**	**61**	**60**

Source: FPL's 2013-2017 distribution service reliability reports.

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

	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than 5 Service Interruptions (CEMI5)				
	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
Boca Raton	8.4	8.6	7.4	5.6	4.6	1.31%	0.89%	0.76%	1.36%	0.37%
Brevard	10.1	9.6	7.8	5.2	4.0	0.58%	0.33%	0.27%	0.17%	0.86%
Central Dade	6.7	7.8	7.5	5.0	3.6	0.08%	0.66%	0.29%	0.55%	0.78%
Central Florida	10.0	8.9	6.5	5.2	3.4	0.52%	0.51%	0.30%	0.15%	0.24%
Gulf Stream	8.7	8.8	6.6	5.1	4.0	0.45%	0.68%	0.79%	0.13%	0.60%
Manasota	7.7	7.0	6.1	5.3	4.0	0.23%	0.33%	0.91%	0.21%	0.34%
North Dade	6.8	8.4	7.7	5.3	3.3	0.45%	0.89%	1.01%	0.28%	1.23%
North Florida	10.8	10.3	8.7	5.8	4.2	0.47%	0.60%	0.71%	0.44%	0.72%
Naples	7.0	7.0	7.1	6.8	6.0	0.36%	0.74%	0.56%	0.44%	0.34%
Pompano	7.5	6.9	6.1	4.5	3.1	0.07%	0.46%	1.01%	1.23%	0.07%
South Dade	8.0	7.9	7.1	5.8	4.3	0.70%	0.61%	0.89%	0.24%	0.67%
Toledo Blade	12.9	9.7	8.2	7.8	4.5	1.21%	1.33%	0.65%	1.57%	1.48%
Treasure Coast	14.3	11.0	8.1	6.4	4.0	0.87%	0.96%	1.03%	2.87%	1.73%
West Dade	7.3	8.2	7.8	6.4	4.4	0.29%	0.60%	1.46%	0.57%	0.72%
West Palm	9.8	8.5	7.5	5.5	4.4	0.73%	1.39%	1.01%	0.50%	2.04%
Wingate	11.6	12.9	10.4	7.9	6.5	0.22%	0.81%	0.59%	0.53%	0.66%
FPL System	**9.1**	**8.7**	**7.5**	**5.8**	**4.3**	**0.54%**	**0.74%**	**0.76%**	**0.70%**	**0.78%**

Source: FPL's 2013-2017 distribution service reliability reports.

Table A-8
FPL's Primary Causes of Outage Events

	Adjusted Number of Outage Events						Adjusted L-Bar Length of Outages				
	2013	**2014**	**2015**	**2016**	**2017**	**Percentages**	**2013**	**2014**	**2015**	**2016**	**2017**
Equipment Failure	31,110	-	-	-	-	-	199	-	-	-	-
Unknown	12,000	11,703	11,022	10,139	10,436	11.0%	122	124	124	133	163
Vegetation	18,774	21,633	23,155	20,331	17,264	18.2%	183	187	182	197	205
Animals	10,320	9,359	9,878	9,506	9,219	9.7%	94	94	93	100	109
Remaining Causes	5,075	3,410	3,147	2,821	3,308	3.5%	201	142	140	158	167
Other Weather	5,795	10,141	9,426	7,978	7,458	7.8%	125	160	167	173	215
Other	7,826	9,187	8,358	7,340	9,402	9.9%	143	148	149	161	217
Lightning	1,567	1,938	1,770	1,647	1,192	1.3%	246	245	241	255	245
Equipment Connect	3,306	-	-	-	-	-	148	-	-	-	-
Vehicle	1,042	877	969	911	1,026	1.1%	230	251	230	248	253
Request	27	-	-	-	-	-	80	-	-	-	-
Defective Equipment	-	33,733	32,838	32,013	35,772	37.6%	-	190	179	195	206
FPL System	**96,842**	**101,981**	**100,563**	**92,686**	**95,077**	**100%**	**165**	**166**	**162**	**175**	**193**

Notes: (1) "Other Causes" category is a sum of outages events that require a detailed explanation.
(2) "Remaining Causes" category is the sum of many diverse causes of outage events, which individually are not among the top 10 causes of outage events, and excludes those identified as "Other Causes."
(3) Starting in 2014, "Defective Equipment" includes "Equipment Failure," "Equipment Connect" and "Dig-in," which were all separate categories, in prior years.

Source: FPL's 2013-2017 distribution service reliability reports.

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

	2013	2014	2015	2016	2017
Fernandina(NE)	15,509	15,628	15,787	16,037	16,286
Marianna (NW)	12,602	12,621	12,649	12,663	12,764
FPUC System	**28,111**	**28,249**	**28,436**	**28,700**	**29,050**

Source: FPUC's 2013-2017 distribution service reliability reports.

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

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
NE	76	88	105	128	93	0.95	1.14	1.19	1.41	1.04	81	77	88	90	89
NW	284	284	155	258	197	2.89	2.81	2.15	2.63	2.41	98	101	72	98	82
FPUC System	**170**	**175**	**127**	**185**	**139**	**1.82**	**1.89**	**1.62**	**1.95**	**1.64**	**93**	**93**	**79**	**95**	**85**

Source: FPUC's 2013-2017 distribution service reliability reports.

Table A-11
FPUC's Primary Causes of Outage Events

	Adjusted Number of Outage Events						Adjusted L-Bar Length of Outages				
	2013	2014	2015	2016	2017	Percentages	2013	2014	2015	2016	2017
Vegetation	265	262	295	436	354	30.9%	83	87	76	78	83
Animals	275	245	201	354	267	23.3%	56	60	53	51	56
Lightning	48	96	148	128	77	6.7%	85	110	90	82	81
Unknown	95	66	75	89	62	5.4%	64	67	64	75	89
Corrosion	65	-	-	12	-	-	92	-	-	102	-
All Other	32	45	27	58	44	3.8%	96	62	94	65	86
Other Weather	299	381	178	148	152	13.3%	136	155	94	147	168
Trans. Failure	29	-	-	-	-	-	148	-	-	-	-
Vehicle	16	25	25	26	30	2.6%	117	108	130	121	94
Defective Equipment	-	138	136	163	160	14.0%	-	232	97	94	117
FPUC System	**1,124**	**1,258**	**1,085**	**1,414**	**1,146**	**100%**	**92**	**105**	**80**	**81**	**93**

Notes: (1) "Other Causes" category is the sum of many diverse causes of outage events which individually are not one of the top 10 causes of outage events.
(2) Blanks are shown for years where the quantity of outages was less than one of the top 10 causes of outage event.
(3) Beginning with 2014, the "Defective Equipment" category now includes outage categories that in the past were separately identified.
Source: FPUC's 2013-2017 distribution service reliability reports.

Gulf Power Company

Table A-12
Gulf's Number of Customers (Year End)

	2013	2014	2015	2016	2017
Central	113,179	114,363	115,524	116,745	118,010
Eastern	112,462	113,897	115,099	116,702	117,847
Western	213,748	215,787	218,848	221,968	225,949
Gulf System	**439,389**	**444,047**	**449,471**	**455,415**	**461,806**

Source: Gulf's 2013-2017 distribution service reliability reports.

Table A-13
Gulf's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017	2013	2014	2015	2016	2017
Central	62	115	75	91	110	0.79	1.07	0.82	1.04	1.05	79	107	92	88	105
Eastern	118	73	59	93	108	1.25	0.78	0.86	1.21	1.27	95	93	69	77	85
Western	100	81	110	97	123	1.14	0.94	1.21	1.15	1.24	87	87	91	85	100
Gulf System	**95**	**88**	**88**	**95**	**116**	**1.08**	**0.93**	**1.02**	**1.14**	**1.20**	**88**	**94**	**86**	**83**	**97**

Source: Gulf's 2013-2017 distribution service reliability reports.

Table A-14
Gulf's Adjusted Regional Indices MAIFIe and CEMI5

	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than 5 Service Interruptions (CEMI5)				
	2013	**2014**	**2015**	**2016**	**2017**	**2013**	**2014**	**2015**	**2016**	**2017**
Central	3.0	2.8	1.8	1.5	2.1	0.17%	0.36%	0.17%	0.22%	0.91%
Eastern	2.3	1.9	1.7	1.6	2.3	2.78%	0.43%	1.66%	1.84%	0.86%
Western	3.5	2.3	2.7	2.7	2.7	0.64%	0.28%	0.59%	0.77%	0.80%
Gulf System	**3.1**	**2.3**	**2.2**	**2.1**	**2.4**	**1.07%**	**0.34%**	**0.76%**	**0.91%**	**0.84%**

Source: Gulf's 2013-2017 distribution service reliability reports.

Table A-15
Gulf's Primary Causes of Outage Events

	Adjusted Number of Outage Events						Adjusted L-Bar Length of Outages				
	2013	2014	2015	2016	2017	Percentages	2013	2014	2015	2016	2017
Animals	2,857	2,132	2,743	3,557	3,514	28.3%	64	64	60	65	70
Lightning	1,452	1,827	1,788	1,913	1,633	13.2%	139	136	134	138	164
Deterioration	2,067	-	-	-	-	-	146	-	-	-	-
Unknown	715	557	598	748	818	6.6%	85	86	79	82	101
Trees	1,354	-	-	-	-	-	129	-	-	-	-
Vehicle	272	289	293	381	377	3.0%	178	185	170	164	171
All Other	314	445	379	457	428	3.5%	112	113	101	100	113
Wind/Rain	203	-	-	-	-	-	151	-	-	-	-
Vines	237	-	-	-	-	-	91	-	-	-	-
Other	249	-	-	-	-	-	102	-	-	-	-
Contamination Corrosion	211	-	-	-	-	-	118	-	-	-	-
Vegetation	-	1,294	1,888	1,954	2,460	19.8%	-	123	138	116	144
Other Weather	-	196	251	220	366	3.0%	-	181	137	126	243
Defective Equipment	-	2,257	2,340	2,714	2,804	22.6%	-	138	137	132	140
Gulf System	**9,931**	**8,997**	**10,280**	**11,944**	**12,400**	**100%**	**111**	**116**	**112**	**107**	**125**

Notes: (1) "Other Causes" category is the sum of many diverse causes of outage events which individually are not among the top 10 causes of outages events.
(2) Blanks are shown for years where the number of outages was too small to be among the top 10 causes of outage events.
(3) The "Defective Equipment," "Other Weather," and "Vegetation" categories now include outage categories that in the past were separately identified.

Source: Gulf's 2013-2017 distribution service reliability reports.

Tampa Electric Company

Table A-16
TECO's Number of Customers (Year End)

	2013	2014	2015	2016	2017
Central	188,161	190,459	193,436	196,431	202,572
Dade City	13,965	14,165	14,372	14,492	14,801
Eastern	113,053	115,122	117,268	119,286	122,667
Plant City	56,438	57,220	58,472	59,381	61,187
South Hillsborough	67,071	69,431	72,340	75,450	80,194
Western	193,320	196,085	198,224	199,891	203,805
Winter Haven	68,529	69,687	70,799	71,888	74,403
TECO System	**700,537**	**712,169**	**724,911**	**736,819**	**759,629**

Source: TECO's 2013-2017 distribution service reliability reports.

Table A-17
TECO's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2013	**2014**	**2015**	**2016**	**2017**	**2013**	**2014**	**2015**	**2016**	**2017**	**2013**	**2014**	**2015**	**2016**	**2017**
Central	70	63	70	63	64	0.79	0.80	1.06	0.85	0.82	88	79	66	74	78
Dade City	261	206	199	153	153	2.75	2.36	1.92	1.79	2.10	95	87	104	86	73
Eastern	93	76	67	85	63	0.87	0.96	0.90	0.99	0.89	106	80	75	86	72
Plant City	131	117	117	113	92	1.49	1.47	1.46	1.20	1.44	87	79	80	94	64
South Hillsborough	94	74	86	104	84	1.11	0.85	1.10	1.35	1.20	84	88	78	77	70
Western	75	81	78	81	71	0.86	0.86	0.89	0.94	0.99	88	94	87	86	72
Winter Haven	61	77	66	82	76	0.81	0.93	0.93	0.94	1.21	76	83	71	87	62
TECO System	**85**	**80**	**79**	**83**	**73**	**0.95**	**0.94**	**1.03**	**1.00**	**1.03**	**89**	**85**	**77**	**83**	**71**

Source: TECO's 2013-2017 distribution service reliability reports.

Table A-18
TECO's Adjusted Regional Indices MAIFIe and CEMI5

	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than 5 Service Interruptions (CEMI5)				
	2013	**2014**	**2015**	**2016**	**2017**	**2013**	**2014**	**2015**	**2016**	**2017**
Central	10.0	8.3	8.5	7.8	7.9	0.20%	0.83%	0.51%	0.96%	0.18%
Dade City	17.4	19.8	18.0	14.7	14.2	1.48%	5.94%	10.41%	2.72%	6.64%
Eastern	13.8	9.9	9.1	9.2	8.8	0.41%	0.33%	0.27%	0.47%	1.79%
Plant City	17.8	15.1	11.8	13.4	12.8	1.65%	1.37%	2.61%	2.15%	3.02%
South Hillsborough	12.9	8.7	11.0	12.8	10.8	0.84%	0.23%	0.82%	0.17%	2.43%
Western	10.9	9.6	8.7	8.8	8.4	0.33%	0.15%	0.42%	0.63%	0.30%
Winter Haven	12.6	11.4	11.1	9.7	9.7	0.01%	0.54%	0.15%	1.81%	0.20%
TECO System	**12.2**	**10.0**	**9.6**	**9.6**	**9.2**	**0.45%**	**0.62%**	**0.81%**	**0.92%**	**1.07%**

Source: TECO's 2013-2017 distribution service reliability reports.

Table A-19
TECO's Primary Causes of Outage Events

	Adjusted Number of Outage Events						Adjusted L-Bar Length of Outages				
	2013	2014	2015	2016	2017	Percentages	2013	2014	2015	2016	2017
Lightning	1,639	1,917	1,779	1,751	1,258	13.2%	214	199	218	255	206
Animals	1,918	1,483	1,321	1,178	1,632	17.2%	95	98	100	97	105
Vegetation	1,959	1,974	2,064	1,959	2,108	22.2%	202	192	190	214	195
Unknown	892	850	792	931	972	10.2%	143	134	125	144	141
Other Weather	261	209	166	-	-	-	190	82	192	-	-
Electrical	1,154	-	-	-	-	-	186	-	-	-	-
Bad Connection	837	-	-	-	-	-	229	-	-	-	-
Vehicle	306	343	397	363	401	4.2%	215	76	199	211	214
Defective Equipment	206	2,788	2,803	2,581	2,494	26.2%	164	419	198	243	203
All Other	187	182	559	428	649	6.8%	141	165	166	173	147
Down Wire	599	-	-	-	-	-	187	-	-	-	-
TECO System	**9,958**	**9,746**	**9,881**	**9,191**	**9,514**	**100%**	**176**	**173**	**179**	**203**	**177**

Notes: (1) "Other Causes" category is the sum of many diverse causes of outage events which individually are not among the top 10 causes of outages events.
(2) Blanks are shown for years where the number of outages was too small to be among the top 10 causes of outage events.
(3) Beginning in 2014, the "Defective Equipment" category now includes outage categories that in the past were separately identified.
Source: TECO's 2013-2017 distribution service reliability reports.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	**Major Planned Work Expansion, Rebuild or Relocation**	**Targeted Critical Infrastructures and major thoroughfares**	**Effects of flooding & storm surges on UG and OH distribution facilities**	**Placement of distribution facilities to facilitate safe and efficient access**	**Written safety, pole reliability, pole loading capacity and engineering standards for attachments**	**Description of policies, guidelines, practices, procedures, cycles, and pole selection**	**Number and percent of poles and structures planned and completed**	**Number and percent of poles and structures failing inspections with reasons**	**Number and percent of poles and structures by class replaced or remediated with description**	**Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation**	**Quantity, level, and scope of planned and completed for transmission and distribution**
Alachua, City of	Yes	Yes. The City design is based on 110 mph wind load with a 1.25 (minimum) safety factor for wind gusts.	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	The City's inspection cycle is on an eight-year cycle (12.5% per year) The City of Alachua owns only distribution poles, no transmission poles. In October 2015, the City completed its first eight-year cycle.	For 2017, the City inspected 374 (16.4%) of its 2,271 distribution poles.	From the 2017 inspection report: 32 (9%) poles were rejected. Six poles were deemed priority rejects requiring immediate change-out due to shell rot. 26 poles were deemed non-priority rejects due to shell rot, decay top, split top and woodpecker holes.	From the 2017 inspection report: the failed poles were 40, 45, or 50 foot, Class 3 or 4 and replaced accordingly. The 26 non-priority reject poles were treated and wrapped.	The City continues to use the information from the PURC conference held in 2007 and 2009, to improve vegetation management.	The City trims approximately 62 miles of overhead distribution on a three-year cycle. Approximately 20% of the facilities are trimmed each year. GIS mapping system is used to track trimming annually and to budget annual trimming projects.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Bartow, City of	Yes. The City is currently guided by the EWL standards as specified in the 2017 edition of the NESC. The City lies within the 100-110 mph region.	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	The facilities are inspected on an eight-year cycle. Inspections are visual, and tests are made to identify shell rot, insect infestation, and excavated to determine strength.	The City began round two of its eight-year pole inspection cycle in 2016 and elected to perform pole inspections every other year. In 2017, the City did not complete any pole inspections.	260 (19%) distribution poles failed inspection due to pole top rot or rotten ground decay in 2016.	16 poles were replaced ranging in size from 30 to 45 feet Classes 4 to 5 in 2017. Also in 2017, 78 poles were braced ranging in size from 30 to 45 feet Classes 4 to 5.	The City is on a four-year trim cycle with trim out at 6-10 feet clearance depending on the situation and type of vegetation, along with foliage and herbicidal treatments.	The City feels that its four-year cycle and other vegetation management practices are effective in offering great reliability to its customers. The City is currently contracting additional line clearance personnel to maintain the four-year cycle.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	**Major Planned Work Expansion, Rebuild or Relocation**	**Targeted Critical Infrastructures and major thoroughfares**	**Effects of flooding & storm surges on UG and OH distribution facilities**	**Placement of distribution facilities to facilitate safe and efficient access**	**Written safety, pole reliability, pole loading capacity and engineering standards for attachments**	**Description of policies, guidelines, practices, procedures, cycles, and pole selection**	**Number and percent of poles and structures planned and completed**	**Number and percent of poles and structures failing inspections with reasons**	**Number and percent of poles and structures by class replaced or remediated with description**	**Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation**	**Quantity, level, and scope of planned and completed for transmission and distribution**
City of Jacksonville Beach d/b/a Beaches Energy Services	Yes. BES has a program in place where all OH distribution lines, roughly three city blocks inland of the Atlantic Ocean, will be replaced with UG conductors, pad mounted transformers, switches, and junction cabinets.	Yes. BES uses stronger concrete poles rather than wood poles and eliminates of static lines with shorter distribution structures to reduce moment loads on the structures. BES has a distribution wooden pole replacement program where BES will replace the wooden poles with concrete. To date, 664 concrete poles have been placed in service.	BES eliminated all exposed "live-front" connected transformers. The high voltage cables are connected to the transformers with sealed "dead front" elbows. Fiberglass foundations for pad mounted equipment have been replaced with thick heavy concrete foundations.	Yes. "Back lot line" construction has been eliminated, all electric kWh meters are located outside & near the front corner of buildings, all replacement or new URD underground cables are being installed in conduits & have a plastic, jacketed sheath, & all pad mounted equipment located near buildings have minimum access clearance.	Yes	The transmission structure is inspected annual, which includes insulators, downguys, grounding, and pole integrity. The distribution poles are inspected on an eight-year cycle using sound and bore method for every wood pole. Poles 10 years old and older were treated at ground level for rot and decay.	424 (100%) transmission structure inspections were planned and completed. In 2017, 75 (1.4%) distribution poles were inspected.	No transmission structures failed the inspection. In 2017, no distribution structures failed inspection.	No transmission structures failed the inspection. In 2017, no poles were replaced.	The transmission line rights of way are mowed and maintained annually. Tree trimming crews work year round to maintain a two to three year VMP cycle for transmission and distribution lines.	All vegetation management activities for 2017 have been fully completed and the vegetation management activities for 2018 are on schedule.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Blountstown, City of	Yes	Yes. The City of Blountstown adopted a larger minimum pole standard of a Class 3 pole in 2007 in an effort to harden facilities.	The City does not have any underground facilities. The City is looking at measures to flood proof substation.	Yes	No. Guidelines do not include written safety, pole reliability, pole loading, capacity and engineering standards and procedures for attachments by others to the transmission and distribution poles.	The City owns 1,947 utility poles and does visual inspections of all poles once a year.	100% of all poles are visually inspected annually.	29 (1.5%) poles required replacement because of ground rot, extreme cracking and warping and upgrading the lines. The City also reconductored about 3,200 linear feet of distribution line.	29 Class 5 poles were replaced with Class 3 poles.	The City has a four-year tree trimming cycle with 10-foot clearance of lines and facilities. The City has policies to remove dead, dying, or problematic trees before damage occurs.	The City will trim 25% of the system with a 10 foot clearance in 2018.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	**Major Planned Work Expansion, Rebuild or Relocation**	**Targeted Critical Infrastructures and major thoroughfares**	**Effects of flooding & storm surges on UG and OH distribution facilities**	**Placement of distribution facilities to facilitate safe and efficient access**	**Written safety, pole reliability, pole loading capacity and engineering standards for attachments**	**Description of policies, guidelines, practices, procedures, cycles, and pole selection**	**Number and percent of poles and structures planned and completed**	**Number and percent of poles and structures failing inspections with reasons**	**Number and percent of poles and structures by class replaced or remediated with description**	**Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation**	**Quantity, level, and scope of planned and completed for transmission and distribution**
Bushnell, City of	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	No written policy. All existing attachments inspected as part of the City's pole program initiated in 2007. An attachment audit was completed in 2016 to verify the current number and location of existing attachments.	The City has no transmission facilities. All distribution poles are on a seven-year cycle. The inspection includes visual, sound/bore, pole condition, and wind loading.	In 2017, the City inspected 297 poles.	Of the poles inspected in 2017, 27 poles failed. The reasons for the failures were upper roof rot, split top, and ground rot.	Of the 27 poles that failed inspections, to date, none have been replaced.	Tree removal, power line trim, and rights of way clearing are on a three-year cycle. Annual trimming is performed before hurricane season. Distribution lines not located on rights of way are trimmed on an “as needed” basis.	PURC held a vegetation management conference March 2007. Through Florida Municipal Electric Association, the City has a copy of the report and will use the information to continually improve vegetation management practices.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Chattahoochee, City of	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	The distribution facilities are on a three-year cycle inspection using visual, excavation around base, sounding, and probing with steel rod. The City does not have any transmission facilities.	1,957 distribution poles were inspected in January 2018.	In 2018, 53 (2.7%) poles failed the inspection due to ground line and pole top decay.	In 2018, the City replaced 53 poles ranging from 30 feet to 45 feet, Class 4 to 6.	The City trims the distribution system on an annual basis. This cuts down on animal outages by limiting their pathways to poles and conductors.	The 2007 and 2009 PURC workshops reports are used to improve vegetation management.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Clewiston, City of	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	The City does not have standard guidelines for pole attachments as all attachments are reviewed by engineers, and place all new construction underground.	The facilities are on a five-year inspection cycle, which began in 2014, using sound, prod and visual inspections. The City performs infrared inspections on the facilities on a three- to four-year cycle.	In 2017, 640 (40%) poles were scheduled for inspection and 445 (67%) poles were inspected.	33 (8%) poles failed inspection due to pole rot.	All of the City's transmission poles are concrete. In 2017, the City replaced 23 - 40 foot distribution poles previously identified. The 33 poles failing the 2017 inspection were Class 4 and 5 poles and are scheduled for replacement in the near future.	The City has a City ordinance that prohibits planting in easements. 100% of the distribution system is inspected annually for excessive tree growth. The City trims the entire system continuously as needed. The City will also accept requests from customers for tree trimming.	All transmission and feeders checked and trimmed in 2017 as every year, and the City completed 54 customer requests for tree trimming.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Fort Meade, City of	Yes	Yes	The current procedures address flooding & storm surges. Participant in PURC study on conversion of OH to UG.	Yes	Yes	The City's facilities are on an eight-year cycle using visual and sound and probe technique.	The City has distribution lines only. The City replaced 67 poles in 2017. 30 poles were due to Hurricane Irma.	The City has approximately 2,750 dist. poles. Of those poles 25 (1%) poles failed inspection. The poles failed inspection due to age deterioration & animal infestation.	The City replaced 67 (2.4%) poles with poles ranging from 55 feet to 30 feet, Class 5 to Class 3.	The facilities are on a three-year inspection cycle, and have a low outage rate due to problem vegetation.	The City has completed approximately 30% of trimming. The city reported 122 outages in 2017, with 20% (24) due to vegetation.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Fort Pierce Utilities Authority	Yes	Yes	Yes. FPUA references FEMA 100 Year Flood Zone for pad mounted equipment installation and alternatively, may elect to install fully submersible equipment as deemed necessary.	Yes	Yes	FPUA utilizes a contractor to perform inspection of all wood distribution and transmission poles on an eight-year cycle. The inspection includes visual inspection from ground line to the top and some excavation is performed on older poles.	3,000 distribution and 100 transmission poles were planned for inspection in 2017. 3,404 distribution and 29 transmission poles were inspected in 2017 indicating 16.9% were inspected.	No transmission pole failed inspection in 2017. 140 (4.1%) distribution pole failed inspection in 2017. 139 failures are non-priority because the calculated strength fell below 67% due to decay at ground line but had sufficient integrity for reinforcement.	FPUA replaced 182 wood distribution poles in 2017. 140 poles were from the 2017 inspection and 42 poles were from earlier inspections.	FPUA maintains a three-year VM cycle for transmission and distribution system with a goal of maintaining foliage cut back at a minimum to a three-year level. FPUA also aggressively seeks to remove problem trees when trimming is not an effective option.	FPUA spent $330,000 for the trimming, removal and disposal of vegetation waste in fiscal year 2017, which was sufficient to meet the yearly target of addressing one-third of the system.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Gainesville Regional Utilities	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes; GRU has instituted a Continuous Improvement Program, which identifies the worst performing devices, circuits and most compromised primary voltage underground cable.	Yes	The facility are on an eight-year cycle for all lines and includes visual, sound, and bore, and below ground line inspection to 18 inches around the base of each pole.	One transmission pole was scheduled for inspection in 2017. GRU planned 4,295 distribution pole inspections and completed 4,296 (100%) inspections.	No transmission poles were planned or identified for replacement. 46 (1.1%) distribution poles failed due to shell rot, internal decay, and decayed tops.	46 (1.1%) distribution poles were replaced in 2017, ranging in size from 30 feet to 55 feet Class 3 to Class 7.	The VMP includes 560 miles of overhead distribution lines on a three-year cycle. The VMP includes an herbicide program and standards from NESC, ANSI A300, and Shigo-Tree Pruning.	The VMP is an on going and year round program. 100% of the transmission facilities were inspected in 2017, with 54 trees identified for trimming and /or removal. 200 distribution circuit miles were trimmed in 2017.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Green Cove Springs, City of	Yes	Yes	Yes, all facilities are installed a minimum 8 inches above the roadway.	Yes	Yes	The City does not have transmission lines as defined by 69kV and above. The City is continuing to evaluate the benefits of an inspection program versus accomplishing the same activity during capital improvement programs. The City completed converting 4.1 kV lines to 13.2 kV in 2017.	The City visually inspects any distribution pole it interfaces with under normal maintenance workflow patterns. In 2017, the City initiated a third-party inspection of over 1,000 poles. By the end of 2018, the City estimates 98 percent of its poles will be inspected.	In 2017, five (6%) wood distribution poles were replaced. The poles failed visual inspection due to rot.	The poles that were replaced ranged from 30 feet to 45 feet, all Class 3.	The City contracts annually to trim 100% of the system three-phase primary circuits including all sub-transmission and distribution feeder facilities. Problem trees are trimmed and removed as identified.	100% of system was trimmed in 2017. PURC held two vegetation management workshops in 2007 and 2009 and the City has a copy of the report and will use the information.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Havana, Town of	Yes	No. Participating in PURC granular wind research study through the Florida Municipal Electric Assoc.	Non-coastal utility; therefore storm surge is not an issue	Yes	Yes	Total system is 1,173 poles; inspected several times annually using sound and probe method.	100% planned and completed in 2017.	5 (0.43%) poles failed inspection.	Three 35 foot, Class 4 poles and two 40 foot, Class 4 poles for a total of five were replaced.	Written policy requires one-third of entire system trimmed annually.	33% of the system was trimmed in 2017.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Homestead Energy Services	Yes	Yes	Yes. Participating in PURC's study on the conversion of overhead to underground facilities through Florida Municipal Electric Association.	Yes	Yes	All transmission poles concrete. A drone thermographic inspection of all the transmission lines was completed in 2017. The distribution facilities are on an eight-year cycle using sound and bore and loading evaluations and the annual thermographic inspection was completed May 2017.	Entire transmission system was inspected in 2017. Approximately 15% of the distribution poles were inspected during 2016/2017 fiscal year.	2 (1.5%) transmission poles of the 135 poles inspected failed inspection due to cracks in the concrete top. 101 (2.1%) distribution poles of the 4,713 poles inspected failed inspections due to ground rot, upper roof rot and split tops. In addition, following Hurricane Irma, 162 wooden poles were replaced due to vegetation, high winds, or poles failing previous inspections but not yet addressed.	Two transmission poles are scheduled for remediation in 2018. Based on the results of the 2016 and 2017 inspections, HES removed five poles, reworked six poles, transferred facilities to one storm hardened pole, installed two 55 foot Class 3 poles, replaced four 35 foot Class 4, twelve 40 foot Class 3, five 40 foot Class 3, and sixteen 45 foot Class 3 poles.	Trimming services are contracted out and entire system is trimmed on a two-year cycle. HES added an additional tree trimming crew at the end of 2016. There are no issues for transmission facilities.	HES enacted code changes, which require property owners to keep vegetation trimmed to maintain 6-feet of clearance from city utilities.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
JEA	Yes	Yes	Yes. Currently has written Storm Policy and associated procedures addressed for Category 3 storms or greater.	Yes	Yes	Transmission circuits are on a five-year cycle, except for the critical N-1 240kV, which is on a two-year cycle. Distribution poles are on an eight-year inspection cycle, using sound and bore with excavation.	26 transmission circuits (which includes many poles on each circuit) and 25 distribution circuits were inspected in 2017.	Based on 2017 inspection: 34 (14%) transmission wooden poles failed inspection. Based on 2017 inspection: 6.5% distribution poles failed inspection due to ground decay, pole top decay, and middle decay.	In 2017, 21 transmission wood poles and 193 distribution poles were replaced. The poles listed as emergency poles (under 1%) are replaced immediately. Two poles failing the 2017 inspections were listed as emergency poles.	The transmission facilities are in accordance with NERC FAC-003-1. The distribution facilities are on a 2.5-year trim cycle as requested by their customers to improve reliability.	JEA fully completed all 2017 VM activities and is fully compliant with NERC standard for vegetation management. VMP activities are on schedule for 2018.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Keys Energy Services, City of Key West	Yes	Yes	Yes	Yes. The KEYS will ensure all future construction occurs adjacent to public roads, will relocate all primary high voltage facilities that are currently inaccessible over a three-year period, and will develop a multi-year program to relocate all secondary facilities that are currently inaccessible.	Yes	The Keys does not have any wooden transmission poles. The concrete and metal transmission poles are inspected every two years by helicopter and infrared survey. 100% of the distribution poles were inspected in 2015 by Osmose, Inc.	An inspection of all transmission facilities was done in 2014. From the 2015 inspection, 5,823 concrete poles, 6,616 wooden, and 6 other type of distribution poles were inspected.	No transmission poles failed inspection. 70 (1.2%) concrete poles and 484 (7.3%) wooden poles failed inspection in 2015. The reasons for the failures are decayed top, excessive cracking, excessive spur cuts, hollow, mechanical damage, rotten ground rot, ground shell rot, wind shake, wood borers, woodpecker holes.	No transmission facilities failed inspection. The KEYS bid out the project of replacing 485 poles with storm harden facilities. The KEYS approved a multi-year contract to manufacture 485 new ductile iron poles. 257 of the 485 poles have been replaced. Due to Hurricane Irma, 519 poles were replaced in 2017.	The Keys' 241 miles 3 Phase distribution lines are on a two-year trim cycle and 68 miles of transmission lines are a quarterly cycle. The Keys tree crews remove all invasive trees in the rights of way and easements. The trees are cut to ground level and sprayed with an herbicide to prevent re-growth.	In 2017, the Keys had 3 recloser outages, 5 feeder outages, and 9 lateral outages due to trees. The Keys will strive to continue to improve its VMP to further reduce outages.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Kissimmee Utility Authority	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue. Low areas susceptible to flooding have been identified and are monitored.	Yes	Yes	All transmission and distribution inspections are outsourced to experienced pole inspector who utilizes sound and bore and ground-line excavation method for all wood poles. Transmission poles are inspected on a three-year cycle and distribution poles are inspected on an eight-year cycle.	109 transmission poles were inspected in 2017. 2,488 distribution poles were inspected in 2017, which is 17.3% of the system.	4 (0.002%) distribution poles failed inspection due to split top and shell rot. No new failures were identified during the transmission inspection.	No transmission poles were replaced and three distribution poles were replaced in 2017. The distribution poles were 30 to 40 feet and range from Class 3 to Class 6.	KUA has a written Transmission Vegetation Management Plan (TVMT) where it conducts visual inspection of all transmission lines semi-annually. The guidelines for KUA's distribution facilities are on a three-year trim cycle.	100% required remediation during the transmission facilities inspection was completed in 2017. Approximately 104.1 miles (33%) of distribution facilities were inspected and remediated in 2017.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address: Guided by Extreme Wind Loading per Figure 250-2(d): Major Planned Work Expansion, Rebuild or Relocation	The extent to which Standards of construction address: Guided by Extreme Wind Loading per Figure 250-2(d): Targeted Critical Infrastructures and major thoroughfares	The extent to which Standards of construction address: Effects of flooding & storm surges on UG and OH distribution facilities	The extent to which Standards of construction address: Placement of distribution facilities to facilitate safe and efficient access	The extent to which Standards of construction address: Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Transmission & Distribution Facility Inspections: Description of policies, guidelines, practices, procedures, cycles, and pole selection	Transmission & Distribution Facility Inspections: Number and percent of poles and structures planned and completed	Transmission & Distribution Facility Inspections: Number and percent of poles and structures failing inspections with reasons	Transmission & Distribution Facility Inspections: Number and percent of poles and structures by class replaced or remediated with description	Vegetation Management Plan (VMP): Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Vegetation Management Plan (VMP): Quantity, level, and scope of planned and completed for transmission and distribution
Lake Worth Utilities, City of	Yes	The facilities are not designed to be guided by the extreme loading standards on a system wide basis. However, CLW is guided by the extreme wind-loading standard for new construction, major planned work, etc. after December 10, 2006.	Underground distribution construction practices require installation of dead front pad mounted equipment in areas susceptible to flooding.	Yes	Yes	Visual inspections are performed on all CLW transmission facilities on an annual basis. The transmission poles are concrete and steel. CLW performs an inspection of the distribution facilities on an eight-year cycle. Pole tests include hammer sounding and pole prod penetration 6 inches below ground.	In 2017, CLW inspected 640 poles.	102 poles were deemed unsatisfactory in 2017. Poles are replaced when pole prod penetration exceeds 2 inches or there is evidence of pole top shell rot.	CLW replaced 82 poles in 2017, with 20 poles pending replacement.	CLW has an on-going VMP on a system wide, two-year cycle. Minimum clearance of 10 feet in any direction from CLW conductors is obtained.	Contractor attempts to get property owners permission to remove trees which are dead or defective and are a hazard; fast growing soft-wooded or weed trees, small trees which do not have value but will require trimming in the future, tress that are unsightly as a result of trimming and have no chance for future development, and trees that are non native and invasive.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Lakeland Electric	Yes	Yes. For all pole heights 60 feet and above; and meet or exceed Grade B construction below this height.	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	The facilities are on an eight-year inspection cycle using visual, sound and bore, with ground line excavation and in addition; visual inspection during normal course of daily activities. Lakeland Electric initiated its second eight-year cycle in 2017.	There were 81 (12.5%) transmission poles planned for inspection and 71 (11%) were completed. There were 7,080 (12.5%) distribution poles planned for inspection and 7,197 (12.7%) completed.	4 (5.6%) transmission poles failed inspection due to decay. 486 (6.89%) distribution poles failed inspection due to decay.	All poles recommended in 2017 were assessed for appropriate action. 607 distribution poles were replaced, repaired, or removed in 2017. 1,849 distribution poles were deferred to 2018. 29 transmission poles were repaired or replaced in 2017 and 44 replacements were deferred to 2018.	The facilities are on a three-year inspection cycle for transmission and distribution circuits. VMP also provides in between cycle trim to enhance reliability.	17.6 miles of 230kV transmission lines were inspected in 2017. 14.36 miles of 69 kV transmission lines were inspected in 2017. LE completed 253 of the planned 400 miles of distribution lines for 2017.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Leesburg, City of	Yes	Yes. Participation in PURC granular wind research study through the Florida Municipal Electric Assoc.	Leesburg is approximately 60 miles inland from the Atlantic and Gulf coasts and is not subject to major flooding or storm surge.	Yes	Yes. Foreign utility attachments are inspected on an eight-year cycle.	No transmission facilities. The Distribution facilities are on an eight-year cycle using visual, sound/bore, excavation method, and ground level strength test.	2,082 poles were inspected in 2017. The current inspection cycle was started in 2017.	178 (6.3%) poles failed inspection due to. but not limited to ground line rot, woodpecker damage, and other causes. .	During 2017, 89 poles were replaced that failed inspection. The City also replaced 181 poles due to decayed tops and pole loading.	Four-year trim cycle for feeder and lateral circuits. Problem trees are trimmed or removed as identified.	In 2017, 48.5 miles of distribution lines were trimmed as planned.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Moore Haven, City of	Yes	At this time, the facilities are not designed to be guided by the extreme loading standards on a system wide basis. The City is participating in PURC granular wind research study through Florida Municipal Electric Assoc.	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	The City inspects all the distribution facilities annually by visual and sound inspections.	The City continuously inspected the distribution facilities in 2017. The City is one square mile and easily inspected during routine activities. The City does not own any transmission facilities. The City is upgrading its 3 Phase poles.	The City is working on the rear-of secondary, making them more accessible. The City has approximately 410 poles in the distribution system and streetlights.	The City replaced eight 30-foot poles, seven 35-foot poles, and, twenty-three 40-foot poles.	The City is continuous tree trimming in easements and rights of way. 100% of distribution system is trimmed each year.	The City expended approximately 20% of Electric Dept. Resources to vegetation management. All vegetation management is performed in house.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Mount Dora, City of	The City retained an engineering firm and developed construction standards for 12 kV distribution poles.	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	A new construction standard was developed to use guy wires for all levels on poles. The standards for poles that the City developed in 2012 reflect the impact of pole attachments on pole loading capacity.	The City does not own any transmission lines. Distribution lines and structures are visually inspected for cracks and a sounding technique used to determine rot annually. The City engaged a contractor to inspect and treat all wood poles on December 5, 2017. The project was completed in March 2018.	The City completed 100% of planned distribution inspections in 2017.	The City had 33 distribution poles in 2017 that failed inspection. The reasons for the failures were tree trimming needed, remove vegetation, loose or missing guy, damaged or missing guy guard, rotten or damaged pole, missing or damaged squirrel guard, insulators or grounds, blown lightning arrestor, and damaged pole attachment.	The city had 1,799 wooden poles as of January 1, 2017. The City's table shows 19 wooden poles were replaced. The wooden replaced range from 30 foot to 45 foot. The wooden poles were replaced with 30 to 55 feet concrete, fiberglass, or steel poles.	An outside contractor working two crews 40 hours per week completes tree trimming on a 12-month cycle.	The City trimmed trees on a 12-month cycle, and removed limbs from trees in rights of way and easements that could create clearance problems.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
New Smyrna Beach Utilities Commission, City of	Yes	Yes	Yes. The City only installs stainless steel dead front pad mounted transformers in its system and existing pad mounted transformers are being upgraded to dead front stainless steel transformers.	Yes	Yes	The transmission and distribution facilities are on an eight-year inspection cycle. Additionally, distribution facilities are inspected as part of the City's normal maintenance when patrolling distribution facilities.	76 (18%) transmission poles were inspected during 2017. 1,500 (12.5%) distribution poles were inspected in 2017.	12 (15%) transmission poles were rejected in 2017 due to decay, slit top, and woodpecker damage. 116 (7.7%) distribution poles failed inspection due to decay, split top, and woodpecker damage.	No transmission poles were replaced in 2017. The City replaced/ repaired 51 distribution poles. The poles are sizes 30-50 feet and Class 3-5.	The City maintains three crews on continuous basis to do main feeder and hot spot trimming. The City mows its transmission lines on a yearly basis.	The City trimmed approximately 30% of distribution system in 2017, and performed clear cutting on 20% of the transmission lines.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Newberry, City of	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	Distribution poles are inspected on an eight-year inspection cycle at ground line for deterioration, entire upper part of the pole for cracks, and soundness of upper part of pole.	The City inspected 196 (12.67%) of 1,560 the poles in 2017.	4 (2%) of the poles were rejected due to ground rot from the inspection in 2017.	Four distribution poles were replaced in 2017: all four wooden poles were Class 4 and varied from 35 to 40 foot with Class 3 40 foot poles.	The City trims all distribution lines on a three-year trim cycle, with attention given to problem trees during the same cycle. Problem trees not in the rights of way are addressed with the property owner.	One third of distribution facilities are trimmed each year to obtain a three-year cycle.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Ocala Electric Utility, City of	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	The City inspects its system on an eight-year inspection cycle, which include above ground inspection, sounding, boring, excavation, chipping, internal treatment, and evaluation of each pole to determine strength. 2015 is the first year in the second eight-year cycle.	No transmission poles were inspected in 2017, since 100% were inspected in 2015. The transmission poles will again be inspected in 2023, which is the beginning of the next cycle. 4,657 (14.4%) of the 32,369 wood distribution poles were inspected in 2017.	99 (2.1%) distribution poles failed inspection due to shell rot, decayed top, exposed pocket, and other reasons.	32 (0.7%) of the distribution poles were braced and 67 (1.4%) poles were replaced.	The City is on a four-year trim cycle for distribution and three-year trim cycle for transmission, with additional pruning over areas allowed minimal trimming. In 2013, an IVM style-pruning program was implemented which uses manual, mechanical, and chemical control methods for managing brush.	In 2017, the City trimmed one-fourth of the distribution system and one-third of the transmission system.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Orlando Utilities Commission, City Orlando	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	OUC facilities are on an eight-year inspection cycle, which includes visual inspection, sounding & boring, excavation, removal of exterior decay, ground line and internal treatments.	OUC planned 6,200 (12%) inspection for distribution and transmission facilities and completed 6,389 (13%) inspections in 2017.	27 poles (0.4%) failed inspection. Failure causes include: decay and others.	2 poles were deemed priority replacement, 2 were completed. There are no poles pending restoration using reinforcing truss. The remaining 25 will be replaced in 2018 and 2019.	213 miles of transmission facilities are on a three-year trim cycle. 1,261 miles of distribution facilities are on a three-year trim cycle. OUC follows safety methods in ANSI A300 & Z133.1.	For 2017, 450 distribution miles were planned and 100% were completed. For 2017, 99 transmission miles were planned and 100% were completed.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Quincy, City of	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue	Yes	Yes	The City's pole inspection procedures include visual and sound and bore methods for an inspection cycle of eight years.	Visual inspections were carried out on all 2,869 distribution poles in 2017. Detailed inspections were carried out on all 31 transmission poles and 216 distribution poles for 2017. All transmission poles are made of concrete and found to be in good condition.	17 distribution poles (0.6%) failed inspection. The poles showed signs of rotting around the base of the pole or the top of the pole. The poles were replaced with wood poles. No transmission poles failed inspection.	17 distribution poles were replaced as follows: One 25 foot Class 7, five 30 foot Class 6, two 35 foot Class 3, four 40 foot Class 3, four 45 foot Class 3, and one 50 foot Class 3.	The City trims its electric system rights of way on a regular basis using in-house crews. The City strives to trim 25% of the system per year.	Approximately 24.8 miles (33.1%) of vegetation trimming was planned and completed on the distribution system in 2017. 100% of the City's transmission lines were inspected in 2017.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Reedy Creek Improvement District	Yes. The District has less than 2 miles of overhead distribution lines and roughly 296 miles of underground distribution.	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	The District does not have any foreign attachments on the facilities.	The District performs a visual inspection monthly, and inspects the distribution facilities every eight years.	All distribution poles were inspected and treated by an outside contractor in 2013. The District has 19 wooden distribution poles. No inspections were completed in 2017.	All distribution poles passed inspection.	The District's transmission system has no wooden poles in service. The transmission system includes approximately 14 miles of overhead transmission ROW. The distribution system is essentially an underground system with 19 wooden poles.	14 miles of transmission rights of way is ridden monthly for visual inspection. The District contracts tree trimming each spring to clear any issues on rights of way.	Periodic inspections in 2017 yielded minimal instances of vegetation encroachment. In each scenario, tree-trimming services were engaged to remove any concerns. The District continues its long-term vegetation management plan to ensure all clearances remain within acceptable tolerances.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Starke, City of	Yes	Yes. The City participates in the PURC granular wind research study through the Florida Municipal Electric Association.	Non-coastal utility; therefore storm surge is not an issue.	Yes	The City is in the process of studying this issue.	The City is in process of having all their poles GIS mapped. To date, they have approximately one-third of their poles mapped and inspected. The poles are replaced as needed on a visual basis.	One third of the City's poles (1,255) poles were inspected.	In 2017, eleven poles (0.87%) were found to be rotten or damage caused by a vehicle accident.	The City has no transmission poles. The following distribution poles were replaced in 2017: One (0.026%), Class 2, 30 foot, One (0.79%) Class 2, 35 foot, six (0.159%) Class 2, 40 foot, one (0.026%) Class 2, 45 foot and two (0.53%) Class2, 50 foot.	The City trims their trees upon visual inspection. The City trims 33% of their electrical distribution system annually.	The City trims distribution lines throughout the year as needed and when applicable removes dead or decayed trees. The City trimmed 33% of distribution system in 2017. The City will use the information from PURC's VM workshops to improve their VM.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Tallahassee, City of	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue. However, the City's Electric Purdom Generation Station in St. Marks is subject to storm surge and flooding. There is a plan in place to address flooding and storm surge that is reviewed annually.	Yes	Yes	Every 8 years a new pole inspection cycle is initiated to inspect all poles over a three-year period. The inspection includes visual inspection, sound & bore, internal & fumigant treatment, assessment & evaluation for strength standards. The City performs a climbing and physical inspection of its transmission structures on a five-year cycle.	598 (19%) transmission poles were inspected in 2017. All distribution poles were inspected from FY 2013-FY 2014. No distribution pole inspections were performed in 2017. The next cycle will begin in 2021.	The annual climbing inspection identified 8 (0.2%) transmission poles/structures to be rejected due to wood decay or other deteriorating conditions.	8 (0.2%) transmission poles were replaced with poles ranging from 60 feet to 85 feet, Classes 2-3. The City replaced 146 (0.263%) distribution poles and structures in 2017. The poles ranged from 30 feet to 60 feet, Classes 1 to 5.	The transmission facilities are on a 3-year trim cycle with target of 25 to 32 feet clearance on lines. The distribution facilities are on an 18-month trim cycle on overhead lines to 6 feet clearances.	The transmission rights of way & easements were mowed in 2017. Approximately 1,037 miles of overhead distribution lines were managed in 2016 and 2017.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Wauchula, City of	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	The City of Wauchula has a third-party contractor inspect its substation yearly and 40% of distribution poles in 2017-18.	The City of Wauchula has a third-party contractor inspect its substation yearly and 40% of distribution poles in 2017-18.	Approximately 8% (out of 3,200 poles) have failed due to poles rotting.	98 distribution poles were replaced in 2017 ranging from 35 feet to 55 feet, all Class 4.	The policy on vegetation management is on a three-year cycle that includes trimming trees and herbicides for vines.	The City completes one-third of the system every year. The City also uses PURC's 2007 and 2009 vegetation management reports to help improve its practices.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Williston, City of	Yes	Yes	Not applicable, the City of Williston is a non-costal utility; therefore storm surge/flooding is not an issue.	Yes	As a result of employee turnover within the management ranks the City has not established any data on pole reliability, pole loading capacity, or engineering standards and procedures for attachments by others to our distribution poles. The City anticipates outsourcing this function in the 2017–2018 budget years.	All distribution poles are visual and sound inspection on a three-year cycle. The city uses both the bore method and the visual and sound method to inspect poles.	33% of 1,100 poles were inspected in 2017. This is the third year of the three-year cycle.	Two (0.55%) poles found defective due to wood decay at or below ground level.	Two poles failing inspection were 45 feet, Class 2, which all have been replaced with the same type of pole.	The distribution lines are on a three-year trim cycle with attention to problem trees during the same cycle. Any problem tree not in rights of way is addressed to the property owner to correct.	One-third of distribution facilities are trimmed every year to obtain a three-year cycle.

Appendix B. Summary of Municipal Electric Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Winter Park, City of	The City has an initiative to put its entire distribution system underground The City requires new residential service to be installed underground and to date, 65.5% of the system is underground.	The facilities are not designed to meet extreme loading standards on a system wide basis. The City participates in PURC's granular wind research study through Florida Municipal Electric Association.	Non-coastal utility; therefore storm surge is not an issue	Yes	Yes	The City does not own transmission poles or lines. The distribution facilities are on an eight-year cycle, which the City is evaluating the cycle for length. The inspection includes visual, assessment prior to climbing and sounding with a hammer.	The City does not own transmission poles. The City did not conduct pole inspections in 2017; however, WPE routinely inspect poles that are involved with daily jobs and work orders.	The City replaced one pole in 2017. The cause was damaged during a seasonal storm.	Based on the 2007 full system inspections, all repairs and replacements have been made. The City routinely inspects the poles involved with daily jobs and work orders. The pole replaced was a 30 foot Class 1 wood pole. This pole was replaced with a 30 foot concrete light pole.	Vegetation management is performed by an outside contractor on a three-year trim cycle, which is augmented as needed between cycles.	The trimming crews trimmed approximately 45.0 miles of distribution lines in 2017. The City is using the PURC 2007 and 2009 reports to improve VMP practices.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Central Florida Electric Cooperative, Inc.	Yes	Central Florida's facilities are not designed to be guided by the extreme loading standards on a system wide basis. However, the wind standard for central Florida's facilities is between 100 mph inland and 130 mph at the coast.	Central Florida continues to participation in evaluation of PURC study to determine effectiveness of relocating to underground.	Yes	Yes	100% of the transmission facilities are inspected annually using above and ground level inspections. The distribution facilities are on a nine-year cycle for inspections using above and ground level inspections.	Central Florida planned and inspected 43 miles of the transmission facilities in 2017. 14,150 (16%) distribution poles were inspected in 2017.	Of the 14,150 distribution poles inspected in 2017, 530 (3.75%) were rejected. These poles are scheduled to be replaced.	453 distribution poles were replaced in 2017. The poles varied from 30 feet to 50 feet, Class 2 to Class 6.	Trees are trimmed or removed within 15 feet of main lines, taps, and guys on a five-year plan.	In 2017, 611 miles of 3,141 miles of primary overhead line on the system were cleared.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Choctawhatchee Electric Cooperative, Inc.	Yes	Yes	Yes	Yes	Yes. Inspect and physically count every attachment on a three-year cycle.	The Coop inspects new construction of power lines on a monthly basis and has an eight-year cycle to cover all poles.	During 2017, 7,783 poles or 13% of 59,824 total poles were inspected.	682 poles or 8.8% of the poles failed inspection ranging from spit top to wood rot.	47.6% of 682 failed poles were replaced.	Current rights of way program is to cut, mow, or otherwise manage 20% of its rights of way on an annual basis. Standard cutting is 10 feet on either side of primary from ground to sky. In 2015, the Coop increased the standard overhead primary line easement area from 20 feet to 30 feet.	In 2017, 500 miles were cut on primary lines and the Coop worked to remove problem tress under the primary lines, which reduces hot-spotting requirements between cycles. The Company also established herbicidal spraying program.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Clay Electric Cooperative, Inc.	Yes	Clay's distribution facilities are not designed to be guided by the extreme wind loading standards specified by Figure 250-2(d) except as required by rule 250-C, but Clay's transmission facilities are guided by the extreme wind loading. Clay is participating in the PURC's granular wind research study through the Florida Municipal Electric Association.	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	Clay's transmission facilities are on a ten-year cycle, which includes sound/bore techniques, excavation, climbing inspection (four-year cycle), and ground (two-year) patrol. Clay's distribution system is now on a ten-year cycle using excavation, sound and bore at the ground line and visual inspection (five-year cycle) and system feeder inspection excluding ground line (five-year cycle).	Clay completed the transmission ground patrol inspection in 2016 & the next inspection will be done in 2026. Clay performed a climbing inspection in 2016. In 2017, 42,313 distribution poles were inspected.	The inspection found 6 (0.2%) transmission poles inspected required some form of maintenance and 9 (0.3%) poles resulted in rejects. 18,154 (43%) distribution poles were rejected due to ground rot, top decay, holes high, split, rot, and storm damage.	6 (0.2%) transmission poles required maintenance. 9 (0.3%) transmission poles were replaced with 55 to 75 feet, Class 1 poles. 1699 distribution poles were replaced with poles ranging from 20 feet to 60 feet, Class 2 to 7.	Clay's VMP for the transmission facilities is on a three-year cycle and includes mowing, herbicide spraying and systematic re-cutting. Clay's VMP for the distribution facilities is on a three-year cycle for city, a four-year cycle for urban and five-year cycle for rural and includes mowing spraying and re-cutting.	In 2017, Clay mowed 54.14 miles, sprayed 54.85 miles, and recut 47.64 miles of its transmission rights of way. In 2017, Clay mowed 2,399.38 miles, sprayed 2,361.03 miles, and recut 2,011.8 miles of its distribution circuits.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Escambia River Electric Cooperative	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue.	Yes	Yes	Escambia River inspects its distribution facilities on an eight-year cycle using visual, sound, and bore techniques in accordance with RUS standards.	4,800 (14%) distribution poles were planned and 4,854 (14%) inspections were completed in 2017. Escambia River does not own any transmission poles.	Approximately 530 poles failed inspection in 2017. The common cause was pole rot.	In 2017, Escambia River replaced 176 poles and retired 17 poles.	Escambia River's distribution facilities are on a five-year trim cycle. Distribution lines and rights of way is cleared 20 feet; 10 feet on each side.	In 2017, approximately 300 miles (19.3%) of the power lines were trimmed with 310 miles (20%) planned.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Florida Keys Electric Cooperative Association, Inc.	Yes	The facilities were not designed to the extreme loading standards on a system wide basis. However, the Company has adopted the extreme wind loading standard in April 2007.	Yes	Yes	Yes	The company inspects 100% of the transmission structures annually by helicopter. The distribution poles are on a four-year cycle. The four-year cycle was completed in 2010. All 10,698 distribution poles have been inspected and all 1,003 rejects have been replaced. Inspections and treatment resumed in 2015.	100% of the transmission poles were inspected in 2017 by helicopter. 32 structures in the water alongside Long Key bridge were inspected above and below the water line in 2016. The remaining 88 water structures were inspected in 2017. 3,520 (25%) distribution poles were inspected in 2017.	The 32 structures alongside Long Key bridge will have repairs to the foundations to extend the life of the structure. This work will take place in 2017/2018. The remaining 88 transmission structures will also have foundation repairs beginning late 2018 or 2019. 84 (2.3%) distribution poles failed inspection in 2017.	No transmission poles were replaced in 2017. 84 distribution poles were replaced in 2017.	100% of the transmission system is inspected and trimmed annually. The distribution system is on a three-year trimming cycle. The trade-a-tree program was implemented in 2007 for problem trees within the rights of way.	Annual transmission line rights of way clearing from mile marker 106 to County Road 905 to the Dade/Monroe County line was completed in 2017. The remainder of the transmission system was spot trimmed. All substations were trimmed prior to April 1, 2017. Approximately 120 circuit miles of distribution lines were trimmed in 2017. Additional distribution spot trimming was conducted as necessary.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Glades Electric Cooperative, Inc.	Yes	Yes	Non-coastal utility; therefore storm surge is not an issue; GEC participated in a workshop hosted by Florida Catastrophic Planning that addressed flooding and storm surges.	Yes	Yes	The facilities are on a 10-year sound and bore inspection cycle with excavation inspection cycle for all wood poles in addition to System Improvement Plan inspections.	100% of total 83 miles of transmission lines were planned and completed by visual inspections. 2,502 miles of distribution lines and 125 miles of underground distribution lines were planned and inspected in 2017. 5,050 poles were also inspected in 2017.	421 (8%) distribution poles failed due to decay, rot and top splits. The Cooperative also replaced an additional 830 poles after Hurricane Irma.	All 421 distribution poles rejected in the 2017 inspection was replaced. The distribution poles ranged from 35 to 40 foot, Class 5 to 6 and were replaced with 35 to 40 foot, Class 3 or Class 5 poles.	All trimming is on a three-year cycle. The rights of way are trimmed for 10-foot clearance on both sides, and herbicide treatment is used where needed.	GEC trimmed 526 miles of distribution circuits in 2016. The transmission rights of way are inspected annually and trimmed if necessary. Vegetation growth is not an issue for the transmission lines.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address: Guided by Extreme Wind Loading per Figure 250-2(d): Major Planned Work Expansion, Rebuild or Relocation	The extent to which Standards of construction address: Guided by Extreme Wind Loading per Figure 250-2(d): Targeted Critical Infrastructures and major thoroughfares	The extent to which Standards of construction address: Effects of flooding & storm surges on UG and OH distribution facilities	The extent to which Standards of construction address: Placement of distribution facilities to facilitate safe and efficient access	The extent to which Standards of construction address: Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Transmission & Distribution Facility Inspections: Description of policies, guidelines, practices, procedures, cycles, and pole selection	Transmission & Distribution Facility Inspections: Number and percent of poles and structures planned and completed	Transmission & Distribution Facility Inspections: Number and percent of poles and structures failing inspections with reasons	Transmission & Distribution Facility Inspections: Number and percent of poles and structures by class replaced or remediated with description	Vegetation Management Plan (VMP): Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Vegetation Management Plan (VMP): Quantity, level, and scope of planned and completed for transmission and distribution
Gulf Coast Electric Cooperative, Inc.	Not bound by the extreme loading standards due to system is 99.9% under the 60 foot extreme wind load requirements.	The method of construction used by GCEC does, however, meet the "design to withstand, without conductors, extreme wind loading in Rule 250C applied in any direction on the structure."	Yes. GCEC continues to evaluate the PURC study to determine effectiveness of relocating to underground	Yes	Yes	No transmission lines. Performs general distribution pole inspections on an eight-year cycle. Also, GECE inspects underground transformers and other padmount equipment on a four-year cycle.	GCEC inspected 7,852 (16.1%) distribution poles, in 2017. Also, in 2017, GCEC inspected 270 padmount transformers, 193 pull box cabinets, 91 secondary pedestals, and 5 switchgears, which accounts for approximately 29.7% of padmounted equipment.	Of the 7,852 poles inspected in 2017, 104 (1.3%) poles were rejected. The poles were rejected due to decay pockets (3, 2.9%), decay/split tops (12, 11.5%), ground rot (85, 81.7%), mechanical damage (2, 1.9%), and woodpecker holes (2, 1.9%)	In 2017, GCEC replaced 81 wooden poles.	GCEC owns approximately 2,158 miles of overhead and 435 miles of underground distribution lines. GCEC strives to clear the entire ROW on a five-year cycle. GCEC clears between 20 and 30 foot width, from ground to sky.	GCEC trimmed approximately 400 miles of ROW in 2016 and 2017. GCEC also works closely with property owners for danger tree removal.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Lee County Electric Cooperative, Inc.	Yes	Yes	Yes. The majority of LCEC's underground facilities, excluding conduits and cables, are at or above existing/ surrounding grade.	Yes	Yes	Transmission facilities are inspected ever two years for 138 kV systems. The inspections are done by climbing or the use of a bucket truck. The distribution facilities are on a two-year visual inspection cycle and on a ten-year climbing inspection cycle for splitting, cracking, decay, twisting, and bird damage.	In 2017, 1,160 (50%) transmission poles were inspected, which was 100% of the poles that were scheduled. 62,520 (38.9%) distribution poles were inspected, which was 100.0% of the inspections scheduled.	39 (3.4%) transmission poles failed inspection due to rot and life expectancy. 1,134 (1.6%) distribution poles failed inspection due to rot/split top, out of plumb, and woodpecker damage.	38 transmission poles were replaced with concrete and steel poles. 29 (2.5%) distribution poles were repaired through trussing and patching. 1,651 poles were replaced in 2017. The sizes varied by Class 1 to Class 6.	VMP strategies include cultural, mechanical, manual, & chemical treatments and the plan is on a six-year cycle for 1 Phase distribution facilities and three years for 2 & 3 Phase distribution facilities. The 138 kV transmission systems are on an annual cycle.	LCEC completed 36.77 miles (100%) of Transmission trimming, 395 miles (100%) three-phase trimming, and 351 (100%) miles of single-phase trimming,

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Okefenoke Rural Electric Membership Cooperative	Yes	The facilities are not designed to be guided by the extreme loading standards on a system wide basis. OREMC is participating in PURC's granular wind research study.	OREMC is continuing the evaluation of the PURC study to determine effectiveness of relocating to underground.	Yes	Yes	OREMC owns no transmission facilities. The inspections for the distribution systems include visual, sound/bore with excavations, and chemical treatment.	In 2017, OREMC performed inspections on 7,644 (13.1%) poles. OREMC has 58,146 wood poles as of December 31, 2017.	In 2017, 64 (0.84%) poles were rejected. The cause of the rejection was ground rot and above ground damage.	The 32 poles failing inspection in 2017 are scheduled to be replaced in 2018. During the course of other projects, 976 new poles were added and 700 poles were retired in 2017.	Vegetation control practices consist of complete clearing to the ground line, trimming, and herbicides. The VMP is on a five-year trim cycle. OREMC utilizes contractors for its VM programs.	OREMC planned 500 miles of rights of way for trimming and completed 588 miles in 2017. Also in 2017, contractors sprayed 728 miles of rights of way.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Peace River Electric Cooperative, Inc.	Yes	The facilities are not designed to be guided by the extreme loading standards on a system wide basis. Peace River is currently participating in PURC granular wind research study.	Peace River is continuing the evaluation of PURC study to determine effectiveness of relocating to underground to prevent storm damage and outages.	Yes	Yes	Peace River currently uses RDUP bulletin 1730B-121 for planned inspection and maintenance. The facilities are located in Decay Zone 5 and are inspected on an eight-year cycle. The transmission poles are visually inspected every two years.	391 transmission (170 concrete, 3 steel, 218 wooden) poles are inspected every two years. 3,248 (5.7%) of 56,835 distribution poles were inspected.	Peace River did not replace any transmission poles in 2017. 337 (10%) distribution poles were rejected in 2017.	Peace River replaced 331 poles in 2017. The distribution poles receiving remediation in 2017 varied from 25 foot to 55 foot, Class 3 to 7.	Peace River utilized guidelines in either RUS bulletins or other materials available through RUS. In addition, Peace River uses a Georgia Rights of Way program, which uses a ground to sky method by removing trees. The VMP is on a four- to five-year cycle.	In 2017, the Company completed rights of way maintenance on 432 (15.47%) of its 2,804 miles of overhead distribution.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Sumter Electric Cooperative, Inc.	Yes	Transmission and distribution facilities are designed to withstand winds of 110 MPH in accordance with 2012 NESC extreme wind load	Non-coastal utility; therefore storm surge is not an issue	Yes	Yes	The transmission facilities are on a five-year cycle using ground line visual inspections, which includes sounding and boring and excavation. The distribution facilities are on an eight-year cycle using sound, bore, & excavation tests.	19 (1.7%) transmission poles were planned and 19 (100%) were inspected in 2017. 18,720 (13.6%) distribution poles were planned and 18,720 (100%) were inspected in 2017. 7,362 (12.2%) distribution underground structures were planned and 7,362 (100%) were inspected in 2017.	Zero transmission poles failed inspection. 3,007 (16%) distribution poles failed inspection. The causes are due to ground rot and top deterioration.	19 (100%) wooden transmission poles were replaced with spun-concrete poles. 3,006 distribution poles were replaced (99.97%). The transmission and distribution poles ranged from 25 to 85 foot and Class 1 to Class 7.	Distribution and transmission systems are on a three-year trim cycle for feeder and laterals. In 2017, due to budgetary constraints, the scheduled miles for trimming were reduced from 1,500 to 1,211, then again to 925 miles due to the impact of Hurricane Irma. In 2017, Sumter trimmed 974.5 circuit miles, applied herbicide to 351 miles and removed 20,784 trees.	Sumter plans to meet current tree trim cycles, tree removals, and herbicide treatment. An estimated 1,500 miles of underbrush treatment is being scheduled for 2018.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Suwannee Valley Electric Cooperative, Inc.	Yes	SVEC facilities are not designed to be guided by the extreme loading standards on a system wide basis. SVEC participates in PURC wind study.	Non-coastal utility; therefore storm surge is not an issue	Yes	Yes	SVEC inspects all structures on an eight-year cycle using sound/bore and visual inspection procedures.	SVEC inspected five (100%) transmission structures in 2017. 10,343 (12%) distribution structures were inspected in 2017.	1,114 (11%) inspections of distribution poles failed due to ground line decay, excessive splitting, & woodpecker damage. Zero inspections of transmission poles failed.	851 (8%) distribution poles of total inspected were remediated by ground line treatment and 721 (7%) distribution poles were replaced. Zero transmission structures were remediated.	SVEC's facilities are on a four- to three-year inspection cycle includes cutting, spraying and visual on as-needed basis.	In 2017, 1,074 (29%) miles were cut and 967 miles rights of way sprayed. 950 (28%) miles are planned for cutting and 1,044 miles are planned for spraying in 2018.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
Utility	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
Talquin Electric Cooperative, Inc.	Yes	Yes	Talquin has a very small percentage subject to storm surge. Stronger anchoring systems are in place to better secure pad-mount transformers and installation of grounding sleeves to secure underground cabinets.	Yes	Yes, inspecting on a five-year cycle.	Annual inspections in house of transmission lines are performed by checking the pole, hardware, and conductors. An outside pole-treating contractor inspects distribution and transmission poles each year. The poles are inspected on eight year rotation since 2007.	8,982 distribution poles were inspected in 2017. There were no transmission poles scheduled for inspection in 2018.	168 (1.9%) of the distribution poles inspected were rejected.	The priority poles were replaced and the rejected poles are being inspected and repaired or replaced if necessary. Talquin replaces 30-foot Class 7 poles with stronger 35-foot Class 6 poles with guys and 35-foot Class 6 poles with 40 foot Class 4 poles as a minimum standard.	Talquin maintains its rights of way by mechanical cutting, mowing, and herbicidal applications.	439 (16%) miles of distribution and 2.76 (5.2%) miles of transmission rights of way were treated in 2017. In addition, Talquin received 1,100 non-routine requests for tree maintenance.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Tri-County Electric Cooperative, Inc.	Yes	Yes	The current standard practice is to restrict electrification of flood prone areas. Due to natural landscape within area, storm surge issues are low.	Yes	Yes	The transmission facilities are inspected on a five-year cycle by both ground line and visual inspections. The distribution facilities are on an eight-year cycle using both ground line and visual inspections.	During 2017, the transmission poles were visually inspected. Tri-County inspected 6,169 (11%) distribution poles in 2017.	146 (2.4%) distribution poles were rejected. The Coop repaired 78 broken ground wires.	The 146-rejected distribution poles found during the 2017 inspection, which required replacement, are in the process of being changed out.	The Coop attempts to acquire 30-foot rights of way easement for new construction. The entire width of the obtained ROW easement is cleared from ground level to a maximum height of 60 feet in order to minimize vegetation and ROW interference with the facilities.	In 2017, approximately 600 distribution miles were trimmed and sprayed.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)										
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares	Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
West Florida Electric Cooperative Association, Inc.	Yes	Yes. In addition, WFEC completed its long-range system study in 2017. The goal of this study was to develop a guide to relate long-range plant requirements to present actions and to develop a systematic schedule for developing major facilities in order to meet anticipated future system requirements.	Non-coastal utility; therefore, storm surge is not an issue. Some areas in territory are subject to flooding. In these areas, line design is modified to compensate for known flooding conditions.	Yes	Yes. General inspections are completed on an eight-year cycle.	West Florida continues to use RUS Bulletin 1730B-121 as its guideline for pole maintenance and inspection.	During 2017, West Florida inspected 10.5% of entire system.	Out of the 10.5% inspected, 8.3% required maintenance or replacement.	During 2017, 1,091 poles were replaced. 5.3 miles of single phase line was converted to 3 Phase to correct loading issues. The Company re-insulated and upgraded approximately 35 miles of distribution lines from 12.5 KV to 25 KV. The Company relocated 5 miles of line to accommodate the upgrade and widening of local roads.	West Florida's VM includes ground to sky side trimming along with mechanical mowing and tree removal.	During 2017, the Company mowed and side trimmed 685 miles of its distribution system. Also, the Company chemically sprayed approximately 698 miles of rights of way. Approximately 685 miles will be sprayed and approximately 784 miles will be trimmed and mowed during 2018.

Appendix C. Summary of Rural Electric Cooperative Utility Reports Pursuant to Rule 25-6.0343, F.A.C. – Calendar Year 2017

Utility	The extent to which Standards of construction address:					Transmission & Distribution Facility Inspections				Vegetation Management Plan (VMP)	
	Guided by Extreme Wind Loading per Figure 250-2(d)		Effects of flooding & storm surges on UG and OH distribution facilities	Placement of distribution facilities to facilitate safe and efficient access	Written safety, pole reliability, pole loading capacity and engineering standards for attachments	Description of policies, guidelines, practices, procedures, cycles, and pole selection	Number and percent of poles and structures planned and completed	Number and percent of poles and structures failing inspections with reasons	Number and percent of poles and structures by class replaced or remediated with description	Description of policies, guidelines, practices, procedures, tree removals, with sufficient explanation	Quantity, level, and scope of planned and completed for transmission and distribution
	Major Planned Work Expansion, Rebuild or Relocation	Targeted Critical Infrastructures and major thoroughfares									
Withlacoochee River Electric Cooperative, Inc.	Yes	The facilities are not designed to be guided by the extreme wind loading standards on a system wide basis. However, most new construction, major planned work and targeted critical infrastructure meets the design criterions that comply with the standards.	Yes	Yes. In 2016, WREC relocated 61.5 miles of overhead primary lines from rear lots to street, changing out hundreds of older poles and facilities; this will continue until older areas are all upgraded.	Yes	WREC inspects the transmission and distribution facilities annually (approximately (3,008 miles for 2017) by line patrol, physical and visual inspections.	68 miles or 100% of transmission facilities were inspected by walking, riding or aerial patrol. 3,008 miles of distribution facilities were inspected annually by line patrol, voltage conversion, rights of way, and Strategic Targeted Action and Repair (S.T.A.R.).	OSMOSE (a contractor for pole inspection and treatment) found 6.2% poles with pole rot and 1.0% poles were rejected in 2003 to 2004. WREC discontinued this type of inspection/ treatment plan and now data is unavailable on the exact failure rates.	3,344 wooden, composite, cement, concrete, steel, ductile iron, aluminum, and fiberglass poles ranging in size from 12 to 90 feet were added; 2,399 poles were retired.	In 2017, WREC contracted with an arborist company to assist with the aggressive VMP that includes problem tree removal, horizontal/vertical clearances and under-brush to ground. WREC maintains over 150 overhead feeder circuits (over 7,100 miles of line) on a trim cycle between four to five years.	All transmission lines are inspected annually. 12.06 miles of rights of way issues were addressed in 2017. In addition, during 2017, WREC addressed 3,811 rights of way service orders ranging from trimming a single account to trimming an entire subdivision or area.

TAB 11

U.S. Energy Information Administration

ELECTRICITY

OVERVIEW | DATA | ANALYSIS & PROJECTIONS | GLOSSARY › | FAQS ›

Home > Electricity > Status of the California Electricity Situation

Status of the California Electricity Situation

Complete report

Background

- Federal Energy Regulatory Commission (FERC) Orders 888 and 889 were put in place in 1996. These regulations allowed for the wholesale trading of electricity (between generators and customers regardless of where they are in the country) and helped California to implement competition at the retail level.

- In 1996 (when California passed deregulation legislation), the average revenue per kilowatthour (a proxy for price) of electricity sold in California was 9.48 cents, the 10th highest among the 50 States and the District of Columbia. The U.S. average price was 6.86 cents per kilowatthour.

- During the period from 1990 through 1999, overall demand increased by 11.3 percent. Electric generating capacity decreased by 1.7 percent during the same period.

- California's reliance on power imports increased with the State currently relying on about 11,000 megawatts of out-of-state capacity. Less than 5,000 megawatts of new capacity is projected to come on line in California by 2004.

    - California Assembly Bill 1890
    - Subsequent Events

Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply

Trends in California's Electricity Retail Prices Fact Sheet

California's Electricity Situation Briefing for the staff of the U.S. House of Representatives A Powerpoint Presentation
(March, 2001, Energy Information Administration)

Selected California Electric Energy Statistics for 1999

Useful Information on California's Electricity & Natural Gas. The information shown below provides a quick-reference guide to the Energy Information Administration's (EIA) data sources related to the California electicity crisis. The publications cited are developed from data collected from respondents to various electricity surveys managed by the EIA, as well as information on the California Power Exchange and ISO. Products from EIA's Natural Gas Division are also provided.

A Snapshot of California Natural Gas Supply and Demand	pdf
California Independent Service Operator (ISO)	html
California Regulatory Commissions and Major Utilities	html
California Energy Commission	html
American Public Power Association	html
Edison Electric Institute	pdf
Standard & Poors Site (Information related to California)	html

More Electric Information

A. 646

TAB 12

DEREGULATED ELECTRICITY IN TEXAS

A MARKET ANNUAL
2018 EDITION

A special research project by
Texas Coalition for Affordable Power

tcaptx.com

Table of Charts

Table of Contents

This Report at a Glance

Deregulated Electricity in Texas tells the story of Senate Bill 7, the retail electric deregulation law. It's also "A Market Annual" because this report describes key electric market-related events in Texas, but organized chronologically in a year-by-year fashion. This report includes a preliminary section describing the period before to passage of SB 7 as well as 18 separate annual sections. The first version of this report was released to the Texas Legislature in 2008 under the title "The History of Electric Deregulation in Texas."

About TCAP

The Texas Coalition for Affordable Power ("TCAP"), a political subdivision corporation, enjoys a unique vantage point within the state's deregulated electricity market. Originally two separate non-profit corporations — the Cities Aggregation Power Project and the South Texas Aggregation Project — TCAP pools the resources of its more than 160 member political subdivisions to purchase electricity in bulk for the needs of local government authorities.

TCAP members purchase in excess of 1.3 billion kilowatt-hours of power each year for street lighting, office buildings, water plants and other municipal needs. An increase by even a single penny in electric rates can cost cities millions of dollars — money that can impact municipal budgets and the ability to fund essential services. High electric prices also can impact the welfare of city residents. TCAP wants what all Texans want: a fair system for delivering electricity.

- Deregulated Electricity in Texas includes subsections that highlight key issues. These subsections are interspersed chronologically throughout the report. They have blue backgrounds and are located along the right-hand margins of most pages.

- A description of the key components of Senate Bill 7 can be found in Appendix A. There are several other appendices, including those describing ERCOT, electricity complaints and utility unbundling.

- Deregulated Electricity in Texas includes charts and graphs that describe electric prices and complaint data. The charts also examine the effect of natural gas generation on the market, compare prices in regulated states versus deregulated states, and compare price increases among all states over time.

Executive Summary and Overview

On Jan. 1, 2002, precisely at the stroke of midnight, Texas broke with its long tradition of regulating most electric service. It was a colossal policy change. No longer would giant, vertically-integrated utilities maintain their monopoly grip on residential and business customers. No longer would Austin political appointees determine directly the price of air conditioning and lighting homes. Instead, new Retail Electric Providers (REPs) would vie for business in most parts of Texas. In theory, the free market and competition would keep a lid on rates. There would be more choices, and better service.

These were the promises of electric deregulation.

But have electric prices improved? Is service better? And what about the bumps along the way? With the luxury of hindsight, what can we say about the policies that worked and those that have not?

Deregulated Electricity in Texas: A Market Annual examines these questions and more.

THIS REPORT EXAMINES THE FACTS THAT:

- Average electricity prices in areas of Texas both inside and outside deregulation have declined in recent years. However, Texans in deregulated areas consistently have paid more for power than Texans outside deregulation.
- The number of electricity shopping choices has expanded greatly since the early years of the electric deregulation law, but comparison shopping remains a challenge.
- Transmission and distribution rates have increased in recent years at a pace greater than inflation. Although these rates are regulated, they contribute to electricity costs in deregulated areas.
- The Texas Legislature has failed to act on important reforms, including proposals to guard against market abuse.

KEY QUESTIONS RAISED IN DEREGULATED ELECTRICITY IN TEXAS:

- *What can be done to reduce confusion in the retail electricity market?*
- *What reforms would help guard the deregulated market against anti-competitive abuse?*
- *Regulated transmission and distribute rates impact electricity costs in deregulated areas. What can be done to ensure those regulated rates don't rise needlessly?*
- *What is the right balance between system reliability and cost?*
- *Deregulated Electricity in Texas, first published in 2009 but now updated and expanded, tells the story of electric deregulation from the beginning. It includes sections summarizing key milestones, new pricing charts and updated spotlight articles highlighting key policy challenges.*

Major Findings

Texans Lost Ground during the first 10 years of Retail Electric Deregulation in Texas

For the 10 years prior to the law, Texans paid average residential prices 6.4 percent below the national average. In the 10 years after deregulation, Texans paid prices 8.5 percent above the national average.

Texans in Deregulated Areas have Consistently Paid More for Electricity

All told, Texans living in deregulated areas would have saved nearly $25 billion dollars in lower residential electricity bills from 2002 through 2014 had they paid the same average prices during that period as Texans living outside deregulation. This "lost savings" amounts to more than $5,100 for a typical household. However, the difference between average residential electricity prices inside and outside deregulation has been trending downward since 2011.

Price-To-Beat Mechanism Failed to Protect Consumers

High natural gas prices, a flawed "price-to-beat mechanism" under Senate Bill 7, and a reluctance of Texas consumers to switch providers contributed to high average electricity prices in Texas during the early years of the deregulated era. Natural gas prices have come down in recent years and the Price-To-Beat has expired. This has contributed to lower average electricity prices since 2008.

Generators Shift Costs to Consumers

Deregulation-related charges known as stranded costs have added nearly $7 billion to consumer bills. In recent years generators have been lobbying for additional payments from consumers, in the form of capacity subsidies.

Renewable Energy Gains May be Tempered by Higher Costs for Consumers

Over the past 10 years Texas has become a leader in the development of wind power. However, the construction of transmission lines to serve West Texas wind generators will add to transmission costs for all Texans. The aggressive pursuit of wind power has created new reliability challenges.

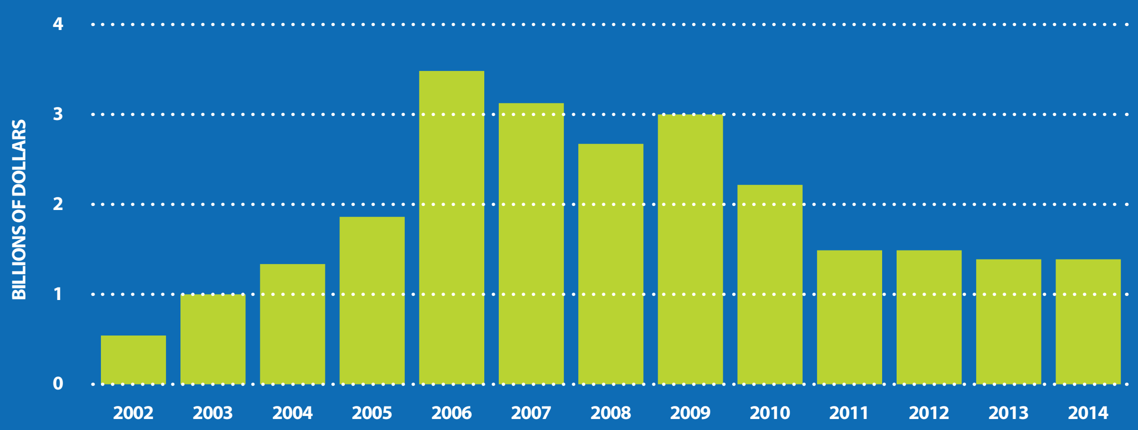
Transmission and Distribution Rates Impacting Deregulated Electricity Prices

Although monopoly transmission and distribution utilities operate under regulation, their rates impact electricity prices charged by competitive retail electric providers. Transmission and distribution charges paid around the Houston, Dallas and Fort Worth areas have increased at a pace outstripping inflation and comprise an increasing share of monthly electric bills.

Nearly $25 Billion in Lost Savings

This exhibit analyzes the most recent relevant pricing data from the U.S. Energy Information Administration, as of the time of publication. Only residential prices rates are examined.

Source: United States Energy Information Administration http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls



Average electric prices in Texas charged by deregulated providers have been consistently higher than average prices charged by providers exempt from deregulation. The exhibit above measures the potential impact of these higher prices. The green bars illustrate the aggregate savings that would have accrued to Texans in deregulated areas had they instead paid the lower average rates charged in areas outside deregulation. The lost savings ranges from about a half billion per year to more than $3.5 billion. Providers exempt from deregulation include municipally-owned utilities and electric cooperatives. Also, investor-owned utilities operating within Texas but outside the ERCOT region are exempt. Only residential prices are considered.

Recommendations

TCAP members are committed to making electric deregulation work. Affordable power in a fully competitive market means economic development for our communities and a better life for our citizens. The Texas Coalition for Affordable Power proposes the following reforms to protect competition in the deregulated market and to encourage the delivery of affordable electricity to Texas homes and businesses.

Avoid Changes in the Market Structure that Increase Wholesale Costs

Policymakers should look for ways to stimulate growth in generation resources other than through price supports and subsidies that are inconsistent with the principles of competition and a free market. Policymakers should reject all proposals for "capacity markets" in which generators get paid even when they do not operate. This will only add to consumer bills.

Enhance Protections against Anti-Competitive Activities in the Wholesale Market

Anti-competitive behavior should be prohibited in the wholesale energy market, and legal loopholes that exempt some generators from prosecution should be closed. The submission of "hockey stick bids" and anti-competitive practices prohibited in other states by the Federal Energy Regulatory Commission should be outlawed in Texas. Penalties for anti-competitive activities should be increased. When market power abuses occur, market participants harmed by such anti-competitive activities should be given the right to participate in investigations and enforcement actions undertaken by regulators.

Promote Standard Offer Deals

All retail electric providers operating in Texas should offer a standard fixed-rate product, with terms and conditions set by the Texas Public Utility Commission. The REPs would be free to set their own price for the standard-offer product. Standard Offer Products will help reduce confusion in the retail electricity market and allow for apples-to-apples comparison shopping.

Improve the PowertoChoose.com Website

The PowertoChoose.com website, which is designed to facilitate comparison shopping, should be as complete as possible. The Public Utility Commission should maintain its vigilance against gaming of the site by unscrupulous retail electric providers. All retail electric providers that operate in Texas should be required to list at least one deal on the website, and to promote powertochoose.com through a printed notice on home electricity bills.

Oppose One-Way Ratemaking

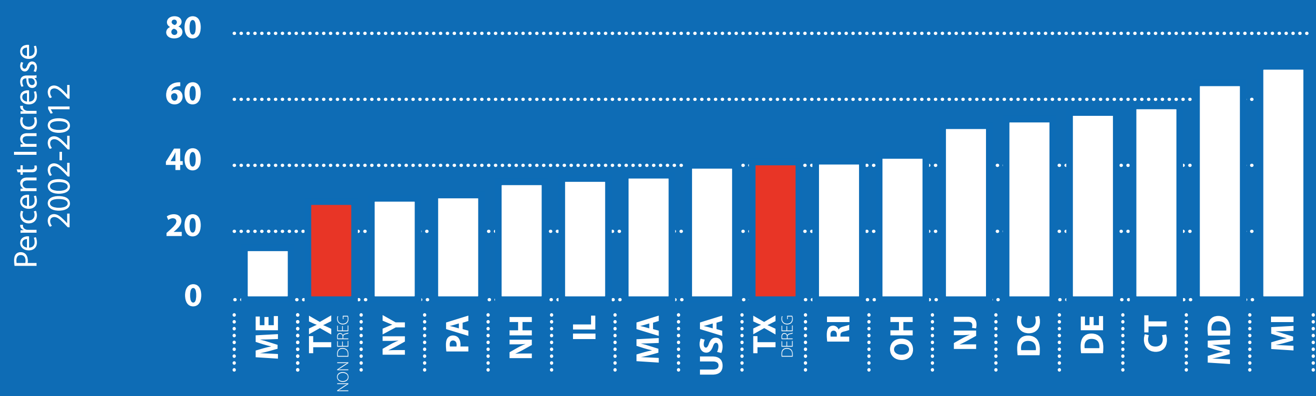
Utility proposals for "streamlined," "alternative" or "one-way" rate-setting for regulated distribution and transmission services should be rejected. These rate-making proposals are known as "one-way" because they work only in one way: against ratepayers. They would lead to higher overall bills — even in deregulated areas.

Re-regulation is Not the Answer

Policymakers should strive to make the state's deregulated electricity system as efficient and fair to Texas consumers as possible. Re-regulation is not the answer. Instead, the Public Utility Commission should pursue a balanced approach with regard to the state's electricity market. Consumer protection and affordability should have equal footing with the promotion of competition.

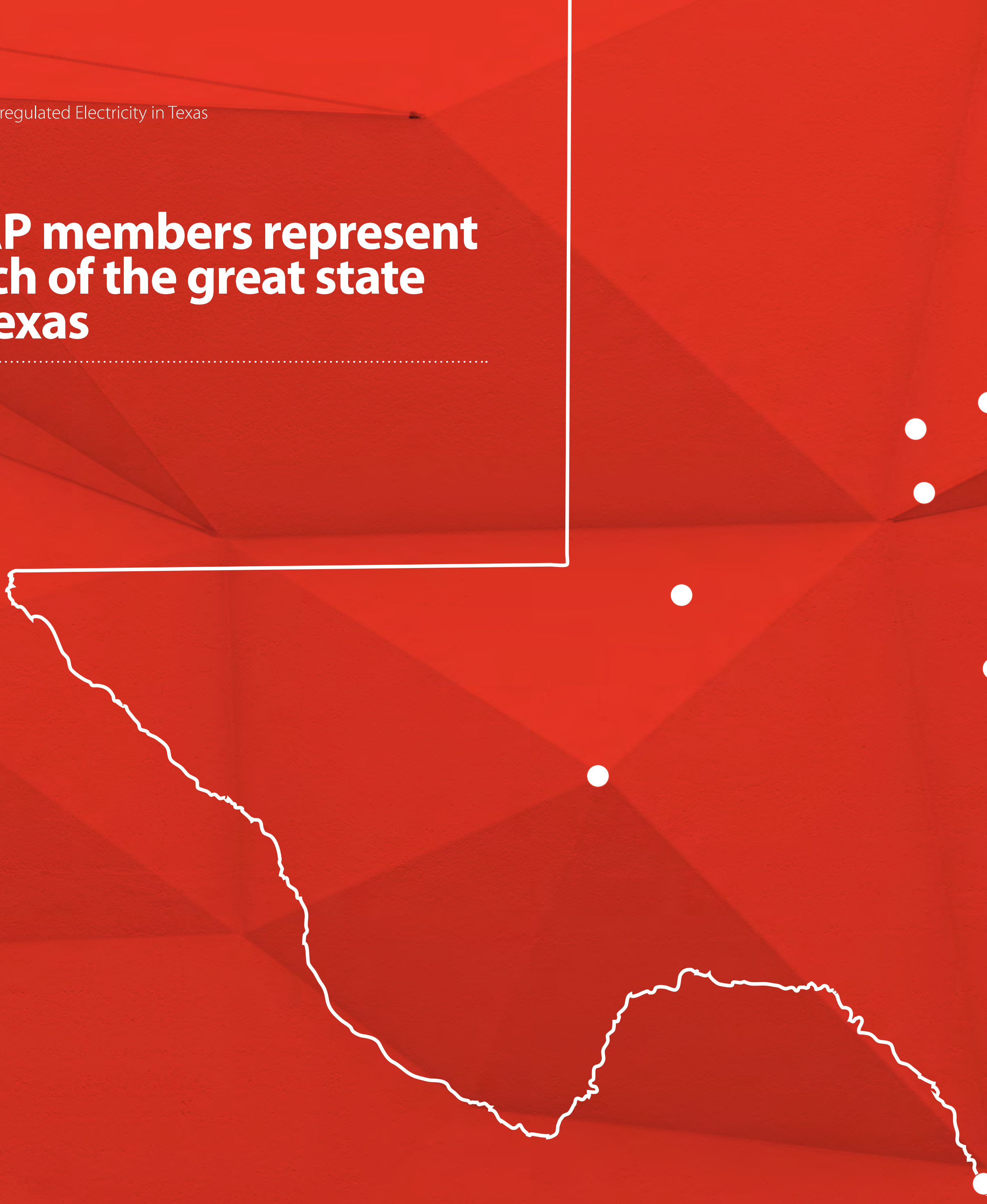
Residential Electricity Price Increases: 2002-2012

15 DEREGULATED STATES, INCLUDING DEREGULATED TEXAS
Source: United States Energy Information Administration http://www.eia.gov/cneaf/electricity/page/sales_revenue.xls



When it comes to price increases under deregulation, Texas fares better than 8 states and worse than 6. This exhibit compares changes in average residential price in deregulated areas of Texas with price changes in other dereregulated states. The time period is 2002 through 2012. This exhibit uses 2002 as a starting point because 2002 was the year deregulation took effect in Texas. It ends with 2012 because that year was the most recent (at the time of publication) for which there was relevant data to conduct the analysis.

TCAP members represent much of the great state of Texas



MAKE A **POWERFUL CHOICE**

The Early Years

Electric deregulation — that is, the use of free-market principles to dictate prices — did not begin in Texas, nor did it arise in a vacuum. Rather, electric deregulation was a part of a larger nationwide trend that took hold during the 1970s and included the deregulation of railroads, airlines and telephone service.[1]

"With declining costs and the strong load growth in the State, it is likely that the commission could find itself facing a never-ending stream of rate cases in an attempt to harness utility over-earnings."

— PUC report to the 76th Texas Legislature

Most of the nation's electricity markets are governed by the Public Utility Holding Company Act, a Depression-era law that Congress adopted as a bulwark against anti-competitive behavior by power companies. Under that system, the states' public service commissions[2] — agencies like the Public Utility Commission ("PUC") in Texas — design rates sufficient to cover the monopoly utility's operating and investment costs, plus a reasonable level of profit.

The first meaningful change to the model came in 1978 with congressional passage of the Public Utility Regulatory Policies Act. Congress acted again in 1992 when it adopted the Energy Policy Act that led to the deregulation of wholesale markets.[3] In 1995 lawmakers passed legislation deregulating the wholesale power market in Texas.[4] The Federal Energy Regulatory Commission in 1996 also issued Order 888 requiring that utilities provide open access to their transmission lines to other power companies.[5]

Together these changes opened the door to a new market system, one clamored for by big industrial users. Utilities had invested in costly nuclear and coal generation during the 1970s. Industrial users wanted to be free to buy cheaper

Postage Stamp Pricing

Different electric companies in Texas have for years maintained interconnected transmission systems, and these companies would sometimes use their interconnections to transfer power between one another for reliability reasons. In 1995 state lawmakers adopted legislation that also opened these interconnections to any power company wishing to trade wholesale power. This was an important step on the road to more complete deregulation that would follow.

But moving power across a transmission system is not free. Lawmakers understood that in order for competition in the wholesale market to work, power must be able to move freely across the state. Electricity transportation costs that varied by transmission company could hamper the ability of a generator to sell power to buyers throughout ERCOT. The 1995 legislation attempted to address this issue through a policy of "postage stamp pricing."[20] Postage stamp pricing means that, like the price of a stamp on a piece of mail, the price to transmit one megawatt of power is the same whether the power is sent across the state or to the next city.

Moving power from parts of the state where power is plentiful to areas where it is needed most has become a major problem in the deregulated market. The transmission system in Texas was built to support the old monopoly system, not the dynamic deregulated market. Without enough transmission capacity, power cannot flow smoothly in some areas. Transmission bottlenecks and system constraints lead to congestion costs that are ultimately passed on to retail customers.

power from other generating units, but that could only happen if they could extricate themselves from rate regulation. Industrial users also predicted that their economic and organizational clout would allow them to negotiate better deals under a deregulated system.[6]

By 1996 Enron, the Houston-based energy company also had begun aggressively advocating for deregulation.[7]

Some economists perceived a potential benefit in electric deregulation, arguing that regulated utilities as monopoly providers lacked strong incentives to keep down costs and to pursue efficiencies in their operations. They argued that under the traditional regulated system, utilities had an economic incentive to build out their systems to the largest extent possible. They could then shift costs on to their captive ratepayers and, in the process, increase overall profits.

Others cautioned that technological and economic barriers unique to electric power make deregulating electric markets infeasible. Electricity — unlike most tradable commodities — cannot be stored. This means that in a deregulated system, consumers are captive to volatile price swings. And because electricity is essential to the public's welfare, dips in reliability or increases in prices can cause serious hardships, medical problems, or — in the most extreme cases — death.

CALIFORNIA DEREGULATES

California became the first state to move to deregulate its electric market when legislators there unanimously adopted Assembly Bill 1890 in August of 1996. AB 1890 had been pushed through the California legislature in just a few weeks at the urging of Enron, other power lobbyists and big business interests.[8] Perhaps indicative of the increased attention on the California electric market, Gov. Pete Wilson and other major political players in the California deregulation effort took in nearly three times the amount of political donations from utilities that year than they had just two years earlier.[9]

Problems appeared almost immediately. Enron and other new suppliers quickly realized that there was no profit in serving residential customers and so stopped signing them up. Three months after the power market deregulated the price for reserve power jumped from $1 to $2,500 per megawatt-hour. It then jumped to $5,000, stayed there for three hours and then mysteriously dropped back to $1. Four days later, it spiked again — this time to $9,999. The price stayed there for four hours and then dropped to one penny.[10]

"All of us saw those numbers and realized … there was nothing to stop someone from bidding infinity," said Jeffrey Tranen, then the chief executive for the California grid operator.[11]

Meanwhile in Texas, Gov. George W. Bush wanted to proceed beyond wholesale deregulation. He unveiled an Enron-

The Senator and the Napkin Doodle

Even state Sen. David Sibley, the Waco Republican now remembered as one of the architects of the Texas law, saw that the proposed system could be manipulated.

During the plane ride back from an early fact-finding mission to California, Sen. Sibley began doodling out some ideas on a napkin.

"We got a napkin, and it looked like you could game the power exchange," Sen. Sibley later told a reporter. "We had our (PUC) guy and our staff and people just started talking about how you could figure out how to withhold just enough electricity. We were just kind of toying with it, kind of war games things on the airplane".

"Now, I'm a dentist," Sen. Sibley said, "and if I could figure it out, it seemed like someone else could, too."[19]

supported bill[12] in 1997 that would deregulate the Texas retail electric market.[13] But big utilities like Texas Utilities Co. (later TXU) questioned whether the "Texas Consumer Power Act" would allow them to receive payments for investments they said would become uneconomical under the new system. Gov. Bush and Lt. Gov. Bob Bullock brokered a compromise that appeased the utilities, but the effort fell short, and the bill died in committee.[14]

Texas lawmakers continued studying the issue during the 1998 interim with a seven-member Senate committee going so far as to fly to England to examine that country's deregulation efforts. During this period, Enron, industrial users and Gov. Bush shored up political support for electric deregulation.[15]

New Hampshire, Rhode Island and Pennsylvania also had begun implementing retail deregulation in 1997.[16]

UTILITY OVEREARNINGS

By 1999, the PUC, under then-Chairman Pat Wood, openly acknowledged that the rates charged by utilities were too high. In its Scope of Competition report, the PUC made clear that selling electricity in Texas was a declining-cost industry: "With declining costs and the strong load growth in the State, it is likely that the commission could find itself facing a never-ending stream of rate cases in an attempt to harness utility over-earnings."[17]

This meant that by 1999 utilities in Houston, Dallas and elsewhere were charging regulated rates that the PUC realized were producing profits in excess of what the commission had previously found reasonable. But instead of initiating proceedings to lower regulated rates, the PUC allowed the companies to continue charging the same amounts. The commission reasoned that in the event that the Legislature moved to deregulation, the utilities would demand certain payments for so-called "stranded investments" in such things like nuclear power plants that could become uneconomical in the new market. Under the commission's reasoning, extra revenue from the inflated regulated rates could be applied to accelerate debt payments on the stranded investments.[18]

These PUC-sanctioned over-earnings by utilities were intended to help facilitate the transition to deregulation. Instead, they became a contentious point during the upcoming legislative session when deregulation supporters began promising savings.

Texas Electricity Prices Before and After Deregulation

**Year to Date, Through June 2012*
Source: United States Energy Information Administration, http://www.eia.gov/cneaf/electricity/page/eia861.html

8.5%
The 10 years post deregulation

National Average

6.4%
The 10 years pre deregulation

For the 10 years prior to the adoption of Senate Bill 7, Texans paid average residential electric prices that were 6.4 percent below the national average. In the most recent 10 years under the Texas electric deregulation law (through June 2012), Texans paid average rates that were 8.5 percent above the national average.

Year: 1999 The 76th Texas Legislature - Senate Bill 7 Becomes Law

On Jan. 20, 1999, during a packed press conference in a room just outside the Senate chambers, state Sen. David Sibley laid out his plan to deregulate the Texas electric market. The 76th legislative session was just getting under way. Sibley, co-sponsor of Senate Bill 7, would become a leading force behind the legislation that would fundamentally change how electricity is bought and sold in Texas. Sen. Sibley was clear in his intention.

"We want this bill to bring down the cost of electricity for all Texans," he said.[1] Building on that goal, Sen. Sibley later added that "if we don't get [for] consumers lower rates, then we have been a failure — I'll be the first to say it." [2] The Waco Republican also pledged his law "would benefit virtually everyone living within our state's borders."[3]

In announcing the landmark legislation, the governor underscored its purpose: 'Competition in the electric industry will benefit Texans by reducing monthly rates.'

Rep. Steve Wolens, champion of deregulation in the Texas House, acknowledged that while Texans already enjoyed relatively low electric rates, they spent more money on electricity than the national average. Never mind that the main reason for these bigger bills was not a flawed market design but rather Texans' reliance on air-conditioning to battle the state's famous summer heat — a fact no amount of electric deregulation could change.

"Lower electric rates will help Texas companies compete in the international marketplace, make more household money available for spending on non-energy goods and services and bring new investments into Texas," Wolens said.[4]

Deregulation proponents also predicted (incorrectly as it turned out) that the federal government could soon require retail deregulation nationwide. By adopting its own deregulation law first, Texas could avoid coming under federal jurisdiction, according to the proponents.[5]

Eventually Rep. Wolens and Sen. Sibley merged their ideas into a single piece of legislation, approximately 200 pages long. Enron was a big supporter of the legislation, as were traditional electric companies.[6] Consumer groups, however, expressed skepticism.

"I think it's the industry people who are pushing it, trying to create this kind of frenzy so that legislators feel like they have to act," said Consumers Union analyst Janee Briesemeister. "They're trying to create urgency by putting ads on television, trying to tell people what they want, even though people don't know they want it," she said.[7]

A few lawmakers also urged caution.

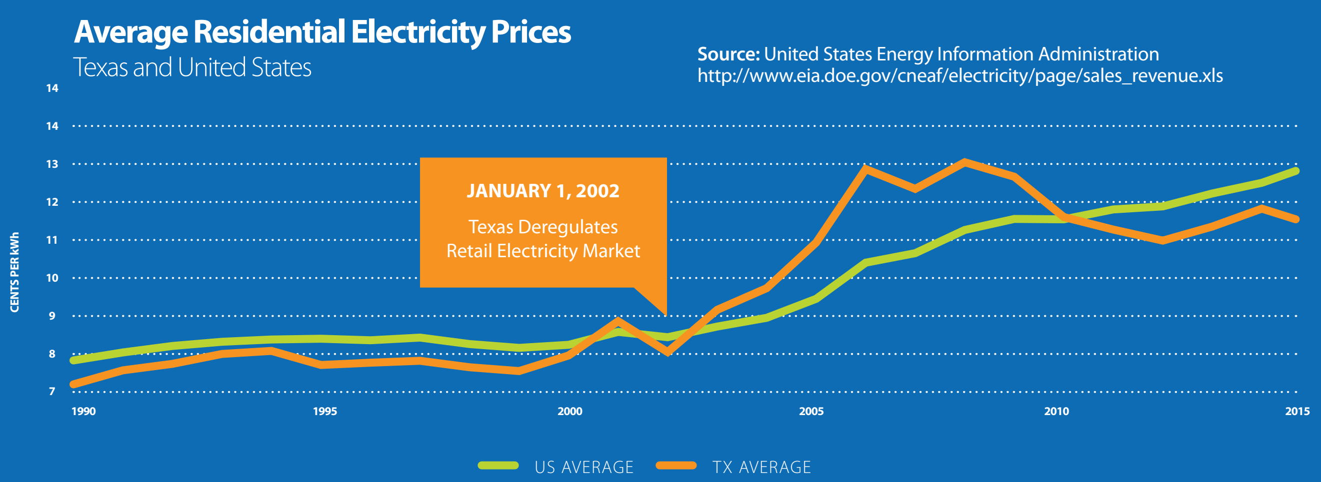
"I don't see the great public necessity for what we're doing," said one East Texas lawmaker. "Texas has some of the lowest rates in the nation. We have some of the best reliability in the nation … And obviously, we don't know what this will do."[8]

On March 8 a Senate committee adopted the legislation unanimously. On March 17 the full Senate gave its approval. Wolens' House committee signed off on the bill on May 12th and then it was adopted by the full House on May 21.[9] Gov. Bush signed Senate Bill 7 on June 18 proclaiming that "competition in the electric industry will benefit Texans by reducing monthly rates."[10]

SB 7 resulted in some of the most significant changes to the state's electricity market in history. It included more than a half dozen major provisions, including a wide expansion of wholesale electric deregulation, the first-ever authorization for competition among retail electric providers, new renewable energy mandates and a green light for utilities to seek billions of dollars in "stranded costs" payments. All of this had the potential to dramatically impact the consumer pocketbook. (Read a more complete description of Senate Bill 7 in Appendix A.)

Major environmental groups supported the law. Most major consumer advocacy organizations opposed it or

Average Residential Electricity Prices Texas and United States 1990-2015



Texans enjoyed average statewide electricity prices below the national average for many years prior to the implementation of the deregulation law. After the Texas electric market deregulated, average residential electricity prices increased above the national average and remained significantly above that mark for many years. Note that this exhibit does not differentiate between average prices inside and outside areas of Texas with deregulation. Rather, it compares average residential prices statewide with average prices nationwide.

As has been demonstrated separately, average residential prices in Texas outside deregulation remained consistently below the national average after 2002, while average prices in deregulated areas shifted above the national average [See Exhibit 1]. Therefore, the high residential electricity prices statewide relative to the nationwide average must be attributed to the deregulated sector of Texas.

Note that Exhibit 5 demonstrates that average residential prices in Texas spiked above the national average in 2001. Although that spike occurred before the deregulation of the state's retail electricity market, it was nonetheless a function of deregulation. This is because the Texas Public Utility Commission allowed utilities in 2001 to collect excess earnings and high fuel surcharges as a down payment on anticipated collections from the restructuring law. Average residential prices in Texas dropped after the deregulated market opened in 2002 because the fuel surcharges expired and because the deregulation law mandated a 6 percent cut in base rates. Average statewide residential prices then remained above the national average through 2011.

Source: United States Energy Information Administration — http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls

eyed it with deep skepticism.[11] A large majority of Texans said they were satisfied with the current regulated system, which for more than a decade had resulted in rates below the national average.[12]

In fact, most Texans in 1999 were probably unaware that electric deregulation was underway, or even contemplated. And yet with the passage of SB 7, electric deregulation is what they would get. (For summary of SB 7 see Appendix A).

Year: 2000 The California Crisis and the Texas Experience

With the turn of the century came the beginning of California's energy crisis, brought on by that state's electric deregulation law. Wholesale prices surged to unprecedented levels and some consumer bills increased three-fold.[1] California's largest utilities were brought to the brink of financial ruin. The state suffered rolling blackouts because power was unavailable or overscheduled.[2]

California had removed price controls in the wholesale market, but left them on retail rates. That pinched the utility companies. Adding to the woes was a spike in natural gas prices, a drought in the Northwest that reduced hydropower and — as was revealed later — price manipulation by Enron traders. "Every possible thing that could go wrong has happened," said Michael Worms, an energy-industry analyst with Gerard Klauer Mattison in New York.[3]

But unlike other states that began cautiously pumping the brakes on deregulation in the face of the unfolding disaster in California, Texas continued forward with its plans. "We don't foresee going back and working and doing any changes," said state Rep. Steve Wolens, during a legislative hearing on Aug. 22, 2000.[4]

Wholesale prices surged to unprecedented levels, and some consumer bills increased three-fold.

Rep. Wolens and state Sen. David Sibley rightly pointed out that their law differed in many respects from the Golden State legislation. They noted, for instance, that electric retailers in Texas had greater incentives to enter into long-term contracts. By entering into long-term contracts, retailers could more easily avoid the price spikes that can accompany seasonal increases in electricity demand. They also noted that Texas enjoyed healthy power reserves and that this extra generating capacity should help keep wholesale prices down.

STRANDED COSTS: CUSTOMERS OWE NOTHING?

In September 2000, an administrative law judge ruled that instead of owing $2.8 billion to TXU Electric for its stranded costs, that ratepayers instead may be due $1.45 billion in credits. The judge ruled that TXU ignored PUC instructions when it made its calculations.

TXU immediately blasted this preliminary ruling, claiming that it "robbed" the company of due process. "Our stranded costs are $2.8 billion, and we have the right to prove it," utility spokesman Christopher K. Schein said.[5]

Stranded costs, remember, represent the value of expenditures made by utilities in a regulated environment that would be recoverable from ratepayers over time under regulation but which might be unrecoverable in a competitive environment. The theory is that if generation assets become uneconomical burdens under deregulation, then ratepayers owe utilities the lost value of those assets.

Stranded costs are calculated by considering the difference under deregulation between the book value of a utility's generation assets like coal, lignite and nuclear generation plants and the market value of those assets. While the book value remains relatively constant (changing annually with depreciation accounting entries) during the transition to deregulation, market value changes daily. The calculation of market value is tied to natural gas commodity prices, which can directly impact the value of a utility's entire generation fleet.

Rep. Wolens and state Sen. David Sibley rightly pointed out that their law differed in many respects from the Golden State legislation. They noted, for instance, that electric retailers in Texas had greater incentives to enter into long-term contracts. By entering into long-term contracts, retailers could more easily avoid the price spikes that can accompany seasonal increases in electricity demand. They also noted that Texas enjoyed healthy power reserves and that this extra generating capacity should help keep wholesale prices down.[6]

"The Worst They'd Seen in 30 Years"

The California power crisis of 2000 was so profound that it put a quick end to the nationwide trend toward utility deregulation and even prompted many states that had passed deregulation laws to change course.

Wholesale electricity prices in California surged to unprecedented levels. Consumer electricity prices went up as well — in some cases bills tripled.[9] The state suffered rolling blackouts because power was unavailable or overscheduled. The deregulation disaster threatened the state's then-booming economy and nearly sank its biggest utilities. Said Paul Patterson, an analyst at Credit Suisse First Boston in New York: "No one wants to hold stock in a company that is subsidizing its customers — if PG&E has to swallow this loss, investors will run in droves."[10]

The crisis also led the state's Independent System Operator — California's version of ERCOT — to declare "energy emergencies" on an almost daily basis. But supplies continued to dwindle. Near the end of the year the system operator declared an unprecedented Stage 3 alert, a signal that power reserves had dropped so low as to become almost non-existent. "Operators here in the control room were saying this was the worst they'd seen in 30 years in the utilities business," said Stephanie McCorkle, a spokeswoman for the organization.[11]

Only by frantically pushing through power from other states at the last minute could the grid operator dodge system-wide blackouts.

To understand the judge's ruling, consider that when natural gas commodity prices are low — as they were in the years preceding deregulation — the cost to generate power using natural gas plants is also low compared to plants that use coal, lignite or nuclear fuel. That means that low natural gas commodity prices would tend to make a utility's standard fleet of coal, lignite and nuclear plants relatively less valuable in the market — and therefore increase the value of the utility's stranded costs.

By contrast, when natural gas commodity prices go up, plants that use coal, lignite and nuclear fuel become more attractive, and their market value increases. That would tend to decrease stranded costs or — theoretically — create negative stranded costs. Rather than owing billions of dollars to utilities for uneconomical plants, ratepayers instead may be owed billions of dollars in refunds for having helped finance lucrative generating plants that now put the incumbent utilities at an economic advantage in the deregulated market.

Generally speaking, this was the assessment of the administrative law judge when she ruled against TXU in the September case. The PUC staff likewise suggested the total value of some utilities' stranded costs may have become negative. "The increases in the cost of natural gas over the past year have resulted in revised stranded cost projections that for most utilities are much lower or negative amounts, based on the commission model," the agency noted in its 2001 Scope of Competition report. "Since the commission first estimated stranded costs, the magnitude of total stranded investment has been reduced—and, in fact, may have become negative."[7]

Of course, the mere suggestion of negative stranded cost refunds caused a ripple through the entire industry. Senate Bill 7 "only recognizes positive stranded costs," said TXU spokesman Schein, echoing the prevailing industry sentiment among incumbent utilities.[8] This policy divide – how to calculate stranded costs and whether ratepayers could receive credits if calculations produced a negative result—would foreshadow one of the bitterest regulatory fights of the decade.

Year: 2001 The 77th Texas Legislature — Saying No To Ratepayer Refunds

APPREHENSION ABOUT DEREGULATION

Lawmakers should apply the brakes: with the crisis in the news daily, that's what Texans were telling pollsters in 2001. More than 40 percent of respondents to a Scripps Howard survey said deregulation should be put on hold, and another 13 percent said plans to deregulate should be scrapped altogether; three-fourths of those surveyed said they were satisfied with the regulated electric system already in place.[1] There had never been a public groundswell in the first place — it was a market change pushed by and for big business — and now the public was calling for lawmakers to reconsider it. But the move toward deregulation in Texas continued undeterred.

During the 77th Texas Legislature, lawmakers rejected two measures that could have added significant consumer protections to SB 7.

The first of those consumer-friendly bills, House Bill 918 by state Rep. Sylvester Turner, would have allowed regulators to extend price limits on residential electricity, put limits on wholesale electric prices and suspend a number of deregulation-related collections from ratepayers. Also, importantly, HB 918 would have given regulators more authority to delay the Jan. 1, 2002 market opening.[2] Industry representatives warned against tampering with Senate Bill 7,[3] and the legislation died in House committee.

In February, Rep. Turner filed House Bill 2107. This bill addressed the issue of so-called "negative" stranded costs — that is, the ratepayer refunds that can theoretically result when market value exceeds book value of generation assets. Under some estimates, HB 2107 could have resulted in nearly $7 billion in customer refunds, or more than $300 for every man, woman and child living in Texas — an astronomical amount.[4]

The utilities argued that SB 7 never contemplated negative stranded costs, and that such refunds were out of order. Tom Baker, then president of TXU Electric, said all those billions of dollars in potential refunds belonged to the company's investors, not the ratepayers who funded the construction of the plants through the rates they paid — and that taking the money away from the company would constitute an illegal confiscation. "No legal or business model would support such a confiscation," he said.[5]

But the Public Utility Commission, in a report issued shortly before the legislative session, said the question of negative stranded costs was an open one. Chairman Pat Wood III, an architect of the deregulation law, said making utilities pay for their over-earnings "would be the fix that will make this whole thing work because, otherwise, you've got money that would make the market work going to the owners of the generators." Chairman Wood said SB 7 left open the question of whether consumers can be awarded negative stranded costs and that Rep. Turner's bill would clarify that issue.[6]

. . . in April, ERCOT officials received a confidential internal report warning that their systems were in disarray. . . it added, presciently, that ERCOT's upgrade project would go over-budget. It noted that ERCOT had failed to meet numerous project goals. . .

It was a wild ride for HB 2107. It made it through the House committee, just barely, and then improbably onto the floor of the House, where it won passage. But it was killed in early May before it could be considered by the full Senate. The coup de grace was a parliamentary move by state Sen. Tom Haywood. A spokesman for Sen. Haywood said that by killing the bill the senator was doing consumers a favor.[7]

Responded one consumer advocate: "How is it bad for consumers to get their own money back? When consumers overpay, decent responsible businesses usually give the money back."[8] (For more about stranded costs and related issues, see page 66 and Appendix C).

PROBLEMS AT ERCOT

In preparation for the new deregulated market, ERCOT, the operator of the Texas power grid, had consolidated its six regional centers into a single control facility near Austin. In addition to ensuring the power grid had exactly enough power moving across its lines to meet demand and prevent blackouts, ERCOT also assumed responsibility for overseeing a six-month deregulation pilot project to give its engineers an opportunity to test new computer systems. During the trial period, new retail electric providers could compete for up to 5 percent of the market. As it would be under full deregulation, ERCOT was responsible for transferring customers between companies participating in the pilot project.[9]

On Feb. 15, 2001—exactly on schedule—the PUC allowed new electric providers to begin signing up customers for the pilot project. Businesses began receiving information about the project in electricity bills that went out in February.[10] Residential customers received information a month later. Service in the trial market was to begin in June. "The time is right," said Jeannie Verkinnes, marketing manager for Shell Energy.[11]

ERCOT had spent months upgrading its systems in preparation for the pilot project. But in April officials there received a confidential internal report warning that their systems were in disarray. The report called for a host of last-minute changes. "Many of the changes identified ARE critical, and there is already a significant amount of risk in the marketplace," the April report stated. It added, presciently, that ERCOT's upgrade project would go over-budget. It noted that ERCOT had failed to meet numerous project goals and that ERCOT employees and contract workers required better management. But instead of discussing the report with the auditors, ERCOT officials got sidetracked and filed the report away.[12]

Two months after the first report, ERCOT received another internal draft report. It stated that the new system setup for deregulation "remains at high risk for (technical) and marketplace failures" and that "major delays were a result of systems that were not tested and/or ready." Like the previous report, it was authored by technical experts hired by ERCOT and was intended to guide the organization in its decisions as it prepared to handle customer switches once the market opened in January 2002. At the time of their release, very few people outside of ERCOT knew of either report's existence.[13]

As a result of its incorrect projections, the price of wholesale power appeared to spike to $15,000 per megawatt-hour when the cost was actually closer to $1.

Problems began to emerge even before the pilot project was underway. Power companies sent switch requests to ERCOT, but ERCOT's new computer systems couldn't handle them. So instead ERCOT officials turned to less technically sophisticated "work-arounds"— that is, they used emails and phone calls to process the switch requests. Customer switching was supposed to have begun by June, but problems at ERCOT led to repeated delays.[14] "There is a risk to the marketplace … this performance is unacceptable," PUC commissioner Brett Perlman told ERCOT leaders. He also said he had been regaled with complaints about giant billing errors generated by the organization. Industry insiders expressed alarm.[15]

The pilot project got underway on July 31st — two months behind schedule.[16] But even after delaying the pilot project three times, ERCOT still could not get its systems to work correctly. The organization had managed to get a computer center up and running on schedule but then could manage only to switch service for a handful of the 80,000 residential customers who signed up under the pilot project. ERCOT said the new system would be able to handle 20,000 switches daily once they got it to work properly.[17] But during the pilot project it was almost wholly incapable of managing any customer switches at all.

ERCOT's computer problems were harming not only residential customers and companies seeking to serve those customers — but companies not even participating in deregulation. Austin Energy, a municipally-owned utility outside the state's deregulated area, reported multi-million dollar errors on ERCOT-generated bills. "At the time of this filing, Austin Energy has not yet received a single accurate settlement," wrote Bob Kahn, Austin Energy vice president. "In fact, the statements we received contain gross allocation and calculation errors. In one case, Austin Energy received a statement for $90 million… when in fact it owed nothing."[18]

On July 31, the pilot project officially got under way. It had been delayed three times, was two months behind schedule and was immediately beset by problems.

An official at another municipally owned utility complained of "bigger than big" errors — errors so colossal that they could drive the utility to bankruptcy.[19]

ERCOT also drafted a budget that year that it kept almost entirely secret. It outlined its spending plans for 2002, the first full year of deregulation, and noted that spending would nearly double from the levels experienced in the previous few years. But other than that, details were scarce. "There is no accountability on the spending at ERCOT," Janee Briesemeister of Consumers Union said. "They adopt their budget in secret … and the budget results in a fee on every consumer electric bill."[20]

PRICE SPIKES IN THE WHOLESALE MARKET

Also in 2001, prices in the wholesale market began spiking. The magnitude of the price spikes —100 times typical price levels — were similar to spikes seen during the California crisis. The first occurred on July 31, the very first day of the pilot project, when power that had been selling for between $10 and $45 per megawatt-hour suddenly shot up to $1,000 per megawatt-hour. That price doubtlessly would have increased even more if not for caps established by the PUC to guard against the price-gouging witnessed in California.[21]

ERCOT officials blamed the first spike on an anomaly. "I don't think people are going to do it again," said Tom Noel, chief executive officer of ERCOT, referring to a supposed one-time mistake by power generators.[22] But then on Aug. 5 the market experienced more price spikes. In this new case, the power surged to 100 times its regular price. The prices could go no higher because of the regulatory cap.[23] On Aug. 8 wholesale prices spiked again — from a relatively typical level of less than $60 per megawatt-hour for balancing energy to $999. An hour later, the balancing energy price skyrocketed to $10,000 — but was adjusted downwards to $1,000 because of the price caps.[24]

Although the spikes impacted a relatively small segment of the wholesale market called the "Balancing Energy Market," they signaled big trouble. This is because the overall cost of power in the wholesale market — even the price of power in so-called longer-term bilateral contracts — parallels these spiking prices set in the smaller spot market. Also, under the ERCOT-managed spot market, the cost of the highest acceptable bid for power dictates the price to all successful bidders. For example, ERCOT might receive scores of bids ranging from $50 per megawatt-hour to $1,000 per megawatt-hour. If the grid operator needs 100 percent of that power to meet demand, then all bidders get the top price, or $1,000 per megawatt-hour — even those who submit bids offering to accept payment of $50 per megawatt-hour.

The price spikes experienced during the first week of the pilot project would prove pernicious, a problem that would plague the deregulated market for years. The spikes spurred regulatory investigations, lawsuits and bankruptcies. Underscoring the gravity of the situation and the uncertainty regarding appropriate controls, Danielle Jaussaud, the PUC's director of economic analysis, warned: "We don't know if the market is going to work — we don't know how well these rules are going to perform. … People ought to be concerned."[25]

Other warnings appeared in various reports to the PUC, ERCOT or in the comments of policy makers. One expert told the PUC in 2001 that under the Texas system, shortfalls could give electric companies "perverse incentives"

The Balancing Energy Market

The state's wholesale spot market, when it was known as the "Balancing Energy Market," established real-time prices at regular intervals, 24 hours a day. Through this market, ERCOT technicians ensured the continuous "balancing" of production and consumption of energy on the grid — hence the market's name.

Under ERCOT rules, generators bid power into the balancing market and then the highest-cost bid for required energy set the price for all other accepted bids. This meant that generators that produced relatively cheap coal-fired or wind energy still received payments as if they were producing more expensive power from natural gas-fired plants. These prices eventually got passed onto consumers. Said another way, under Senate Bill 7, the economic benefit of producing cheap electricity mostly has ended up in the pockets of generators as extra profits, not in the pockets of consumers as savings. This differs from a regulated cost-based system, whereby wholesale prices are linked more directly to the cost of production.

Balancing energy historically has comprised less than 10 percent of the energy bought and sold in the state's deregulated wholesale market, and yet it has been crucial in setting wholesale electricity prices overall. To the extent that balancing energy prices were higher than market conditions warranted, then it was a good bet that wholesale power prices overall also were too high.

Before Senate Bill 7, if a utility obtained power from both low-cost and high-cost generators, then the utility's rates reflected that mix of low-cost and high-cost power. But in the Balancing Energy Market — and indeed, in the restructured wholesale energy market overall — the direct link between energy prices and the cost of producing energy was severed.

In 2010 ERCOT replaced the Balancing Energy Market with a "Nodal" market (see page 53 for more details about the nodal market). However, many of the pricing principles of the Balancing Energy Market remain.

to inflate prices.[26] Another expert warned that some of the underlying premises behind Texas deregulation could be incorrect. Industry backers of Texas deregulation were blaming California's problems on a lack of generation capacity, but Harvard expert William W. Hogan and University of California-Berkeley expert Shmuel S. Oren told the PUC that more complicated factors in California that also impacted Texas were at play. In 2001, both Hogan and Oren forecasted possible price spikes, bureaucratic headaches and anti-competitive price inflation.[27]

SYSTEM RELIABILITY IS TESTED

Errors by ERCOT— an organization that literally has "reliability" as one of its middle names — also nearly caused blackouts during the pilot project. On the third, fourth and fifth day of the project, the organization grossly miscalculated the state's energy needs. As a result of its incorrect projections, the price of wholesale power appeared to spike to $15,000 per megawatt-hour when the cost was actually closer to $1. Grid operators went scrambling for the phones, frantically imploring power generators to ignore the erroneous computer data and ramp down production.

ERCOT officials attributed the miscalculations to human error and not to any defect in the market itself. No market participant actually paid the misstated prices.[28]

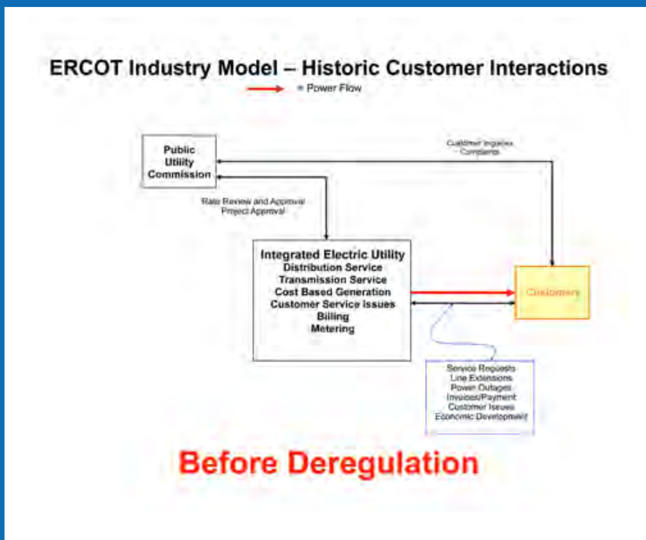
ERCOT blamed the next meltdown — on Aug. 9 — on a computer failure. It said an unknown problem shut down part of the wholesale market for four hours, a malfunction that was serious enough that officials had to make another round of urgent phone calls to generators to prevent blackouts.

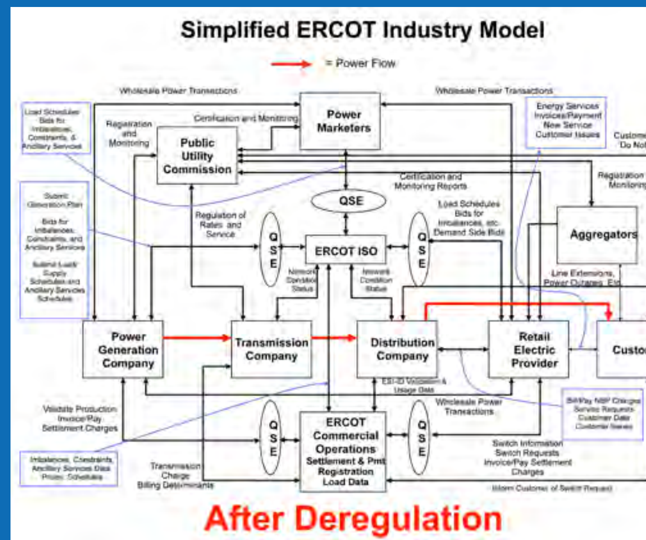
The pilot project was supposed to have given ERCOT an opportunity to test its systems, and give Texas a moment to take a deep breath before beginning the big show on Jan. 1. But as one consumer advocate wryly quipped: "They (ERCOT officials) don't appear to be ready to play with live ammo." Industry insiders began raising concerns about the readiness of ERCOT to handle the market going live in January.[30] Many would-be residential customers, commercial customers and other market participants echoed those concerns.

Sam Jones, the chief operating officer at ERCOT, said the problem was with the transmission system itself. He attributed the price spikes experienced during the pilot

New Market, New Complications

Source: ReSolved Energy Consulting





Sam Jones, then the chief operating officer for ERCOT, said in 2002 that "in exchange for an ability to shop around and get savings, (customers must allow) for a process that is more complicated than it used to be." The charts above illustrate graphically the complexity of the deregulated market in Texas. Under the previous system, electricity provided by the bundled utility flowed directly to the end-use customer. Under the Texas deregulated system, a much larger number of interconnected entities play a role in getting power to customers.

project to the lack of power lines: "We have a south-north constraint on the system, and people are trying to move a lot of power to the north — and it's driving prices up."[32]

Regulators had known for years that the lack of transmission could stymie deregulation. The wires system was never built to move power across vast regions of the state — a vital necessity if deregulation was going to efficiently lower wholesale power prices. Jones explained that without enough transmission, there would always be bottlenecks — especially during times of high demand, like during hot summer days.[33] Because of the bottlenecks, also called "congestion constraints," the cheapest power sometimes cannot get moved to parts of the state where it's needed most. And because electricity cannot be stored, power companies cannot keep cheap electricity in reserve.

STRANDED COSTS ARE SETTLED FOR TXU CUSTOMERS

One other highlight in 2001 bears note: an agreement reached late in the year between TXU and a coalition of cities, consumer groups and other market participants that is still seen today as one of the most far-reaching regulatory settlements in Texas history. Under the deal, TXU agreed to surrender billions of dollars in claims for "stranded" costs.

"I cannot think of a single case in Texas regulatory history that has been as comprehensive," TXU spokesman Christopher Schein said. "It settles, resolves or eliminates a dozen different lawsuits. We're looking at (an effect) going back as far as the Comanche Peak deal (of the '80s) and going forward for a decade."[34]

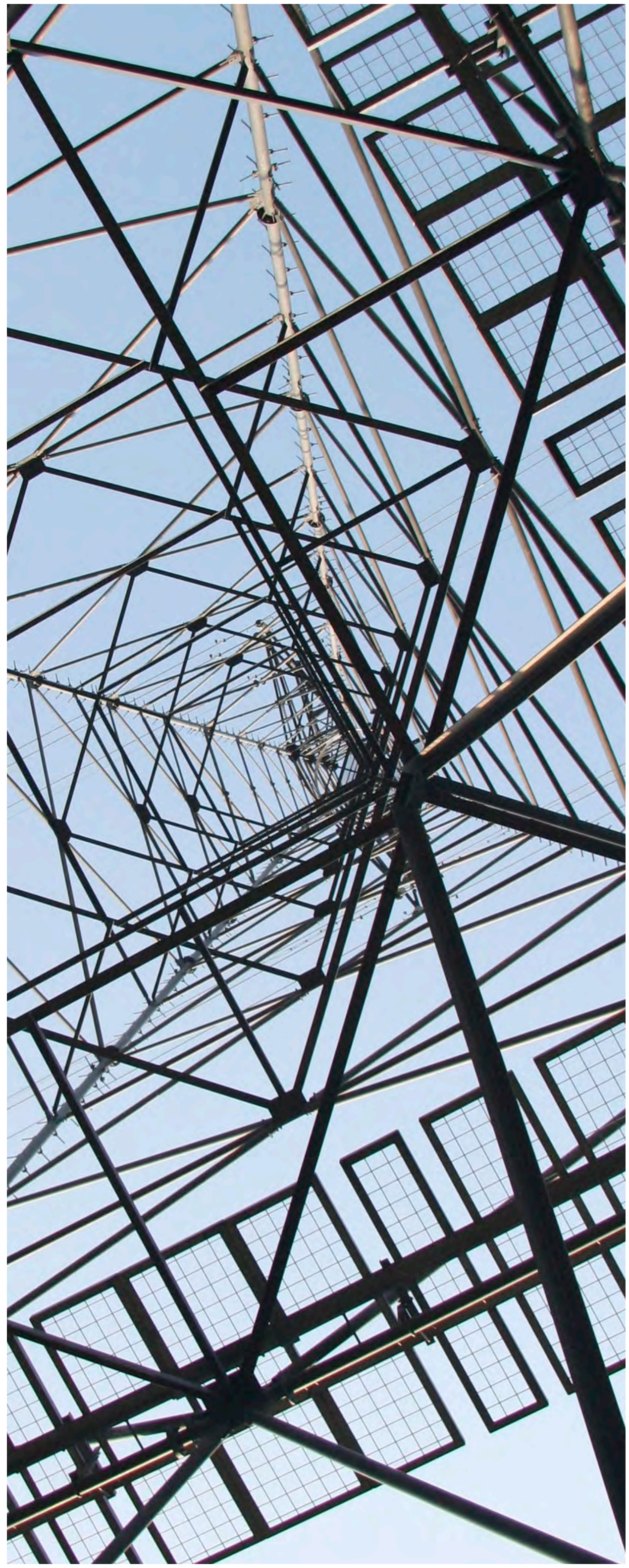
Under the terms of the deal, TXU would relinquish its claim on reimbursements for stranded investments — that is, those investments like nuclear power plants that utilities claim would become uneconomic under deregulation. SB 7 allowed companies like TXU to seek ratepayer reimbursements for such stranded investments. TXU at one time said it was owed more than $6 billion.[35]

The deal in 2001 recalculated the value of TXU's stranded costs to zero. TXU also agreed to surrender claim on about $350 million in fuel related charges. In exchange, consumer groups agreed to lift their objections to a bond-financing technique known as securitization that allowed the company to get up-front payment for over $1 billion in ratepayer obligations.[36] The PUC, with the support of consumer groups, had objected to the company's securitization claim, and prior to the settlement, the issue had been tied up in court.

…shortfalls could give electric companies 'perverse incentives' to inflate prices.

The settlement is now seen as an extremely significant consumer victory because companies other than TXU have subsequently argued successfully for billions of dollars in stranded costs. Houston's CenterPoint Energy, for instance, was awarded $4 billion[37] — money that every customer of CenterPoint would pay through surcharges on their transmission and distribution rates.

(For more information about stranded costs awards in Texas, see the chart on page 66).



The Enron Collapse

On Aug. 15, 2001, just months before the Texas market was set to open, Enron's chief executive Jeffrey Skilling unexpectedly announced his resignation. He had been in the CEO position only six months and by voluntarily resigning, he was surrendering what would have been a sizeable severance package. Predictably, the departure set off alarm bells on Wall Street. But Enron chairman Ken Lay, who announced he would resume his role as chief executive officer, told analysts to expect "no change in the performance or outlook of the company going forward." He said there was "absolutely no accounting issue" behind Skilling's departure — "no trading issue, no reserve issue, no previously unknown problem issues."[38]

Skilling sold 450,000 shares of Enron stock worth at least $33 million in the months before his departure. Enron stock surged in 2000 and for the early part of 2001 before dropping precipitously. By the time Skilling announced his resignation it was down nearly 50 percent for the year. In after-hours trading shortly before news of Skilling's departure was public, it fell again another 8 percent.[39] The value of Enron's shares dropped another 10 percent during the first week of September, bringing it down 62 percent for 2001.[40]

On Oct. 16 Enron posted a third-quarter loss of $618 million, the result of what it said was $1 billion in one-time charges for various businesses. Much of the losses were related to the poor performance of New Power, the complaint-maligned company set up to vie for retail business in deregulated markets.[41] On Oct. 23, in a conference call to nervous investors, Lay insisted the company had sufficient cash on hand to keep from writing off additional investments.[42]

By this point, analysts had begun asking questions about the company's labyrinthine business practices and financial reporting. The Securities and Exchange Commission initiated inquiries into transactions involving the company's chief financial officer, Andrew Fastow. Lay declined to provide details of those transactions during the conference call but nonetheless insisted that Enron board members "continue to have the highest faith and confidence in Andy." A day later, the board relieved Fastow of his duties.[43]

Time was running out for the once giant energy trader. The company consistently avoided giving straight answers to investors' questions, Moody's Investor Services lowered Enron's credit rating and shares continued to nosedive. It was becoming unclear whether the company could even raise enough cash to maintain day-to-day operations.[44]

On Nov. 9, rival Dynegy agreed to acquire Enron for about $8 billion.[45] It was a short-lived offer: after Enron's financial situation continued to deteriorate and more of Enron's questionable practices came to light, Dynergy pulled its offer. Once the world's largest energy trader and the seventh largest company in the country, Enron imploded. The company filed for bankruptcy on Dec. 2.[46]

In a story marking the company's end, *The New York Times* noted that the company's "decade-long effort to persuade lawmakers to deregulate electricity markets had succeeded from California to New York." *The Times* pointed out that Enron pioneered large-scale energy trading, a practice that had existed for less than a decade before the company's demise.[47]

The Times noted Enron's "ties to the Bush administration assured that its views would be heard in Washington." Enron, *The Times* noted, "dripped contempt for the regulators and consumer groups that stood between it and fully deregulated markets."[48] Enron's end came just days before Texas went forward with the deregulation system the company had pioneered.[49]

In August, not long before the collapse and just as Enron was attempting to open up electric transmission systems in the southeast, President Bush appointed former Public Utility Commission chairman Pat Wood III to chair the Federal Energy Regulatory Commission.[50] Enron CEO Lay had recommended Wood for that post, just as Lay earlier had recommended Wood's appointment to the PUC.[51] In June 2001, shortly before Enron went belly-up, Gov. Rick Perry appointed Max Yzaguirre, a former Enron executive, to chair the PUC.[52]


MAKE POWER L CHOICE

Year: 2002 The Market Opens

On Jan. 1, 2002, at precisely midnight, Texas opened its electricity markets to retail competition. Under the rules of Senate Bill 7, retail electric providers affiliated with the state's traditional utilities were required to charge 6 percent less than the regulated rates they charged prior to the start of competition.[1] This became the "Price To Beat" — that is, the price that new competitors tried to beat with lower rates. By undercutting the Price To Beat, the new competitors could steal away customers from the legacy electric providers. In theory, competition between the new providers all fighting to undercut the Price To Beat would keep prices down.[2]

That almost no residential customer paid a price other than the Price To Beat on the first day of deregulation was no surprise. Of course it would take time for customers to become comfortable with the deregulated market, investigate price offerings and make the switch. No one expected, however, that most customers would remain on the Price To Beat for years and years. The market remained "sticky," and customers remained cautious.

"In exchange for an ability to shop around and get savings, (customers must allow) for a process that is more complicated than it used to be…"

— ERCOT Chief Operating Officer Sam Jones

Deregulation's proponents claimed that Price To Beat customers were saving money. The enthusiasts pointed to the 6-percent cut, comparing the Price To Beat to the rates on Dec. 31, 2001 — the final day of the old regulated era. "The Price To Beat rates that we've established strike a good balance between immediate customer savings and attracting retail electric providers to enter our market and offer even greater savings and service innovations," said Max Yzaguirre, the Public Utility Commission chairman.[3]

But there's another side to the story. Consider this: while state regulators put potential savings to residential customers at more than $900 million, their analysis included savings attributed to the expiration of an unnecessary and overstated surcharge relating to fuel costs.[4] That surcharge would have expired even under the old regulated system (and the overcharges refunded to customers) and can't be attributed as customer savings from deregulation. In fact, when controlling for natural gas prices — as the state's Office of Public Utility Counsel (OPUC) did in one report — it becomes clear that customers ended up paying more for power on the first day of deregulation compared to regulated rates in place just prior the adoption of Senate Bill 7.

An example: a typical Dallas/Fort Worth Metroplex homeowner had paid about $74.08 a month for electricity in January, 1999. By January 2002, even with the rate cuts required by SB 7, that customer would pay $76.74, according to the OPUC analysis.[5]

The new Price To Beat rules also included a provision for calculating changes in fuel costs that would continue to drive up prices. Under it, companies could increase the Price To Beat rate twice a year to cover increases in the cost of natural gas, which fuels many of their plants.[6] But SB 7 — at least, as it was interpreted by the Texas Public Utility Commission — included no provision that would push the Price To Beat down in the event that natural gas prices decreased. As a consequence, the price paid by most Texans in the deregulated market went up, never down, for several years. If the price of natural gas increased, then the utilities increased Price To Beat rates. But if the natural gas price dropped, Price To Beat rates still remained high.[7] Rather than aggressively undercutting Price To Beat rates that were already out of step with the market, competitive retail electric providers inexplicably clustered their prices around Price To Beat rates.[8]

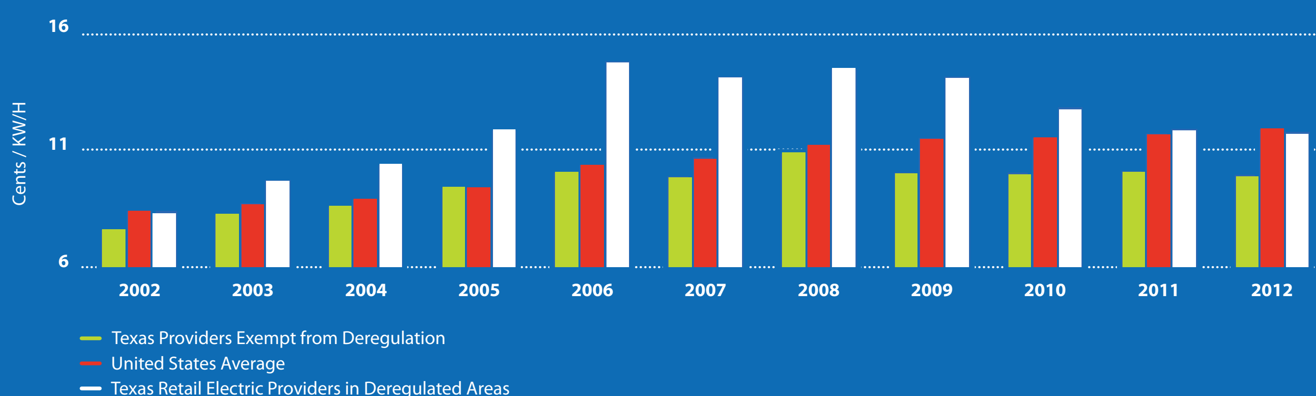
Another closely-related problem was that all adjustments made to the Price To Beat fuel factor were based entirely on changes in the price of natural gas. Generators use plenty of other fuel sources — including cheaper coal, lignite and nuclear generation — and the price of these fuels is much less volatile than natural gas. But lawmakers created SB 7 when natural gas prices were low and based the legislation upon the incorrect assumption that natural gas prices would stay that way. However, natural gas prices climbed steadily upward for many years after the passage of SB 7, and the Price To Beat prices marched up right behind them.

On April 23, 2002, TXU filed for its first increase under this controversial natural gas-based Price To Beat fuel factor mechanism.[9] The PUC approved that rate hike and others — nearly to 10 percent in some regions — within eight months of the market opening.[10] A spokesman for the electric company said increasing the Price To Beat would foster deregulation because new retailers would have more room to undercut it and still make a profit. Consumer advocates were skeptical.

"You have to raise rates to lower rates?" asked a puzzled Carol Biedrzycki, director of the Texas Ratepayers' Organization to Save Energy. "Competition was supposed to provide electricity at lower prices and with a higher level

Electricity Prices Higher Under Deregulation

AVERAGE RESIDENTIAL ELECTRICITY PRICES INSIDE AND OUTSIDE DEREGULATED AREAS OF TEXAS
(Providers exempt from competition include investor-owned utilities outside the ERCOT region, municipally-owned utilities and electric cooperatives.)
Source: United State Energy Information Administration http://www.eia.doe.gov/cneaf/electricity/page/eia861.html



Texans paid below-the-national-average electricity prices before the state deregulated its retail electricity market. But in 2002, the year that the deregulation law took effect, Texans in areas of the state participating in deregulation began paying above the national average, while Texans in areas exempted from deregulation continued paying below the national average.

Average residential rates in deregulated areas of Texas have been anywhere from 9 to 46 percent higher than average rates for areas of Texas outside deregulation. Moreover, average rates in deregulated areas of Texas have been generally higher than the nationwide average, while average rates in areas of Texas outside deregulation have been generally below the nationwide average. In 2012, for the first time in 10 years, average electricity prices in deregulated areas of Texas dipped below the nationwide average. The most recent relevant federal data available at the time of publication was used for this analysis.

of service. . . . If we have to raise [rates] so a competitor can afford to operate in the market place . . . [that] defeats the whole purpose of opening the market in the first place."[11]

DELAYED SWITCH REQUESTS, LATE BILLS AND EXCESSIVE SPENDING

ERCOT officials began the year by making bold promises. Despite the clunker of a pilot project and wholesale prices that went haywire, ERCOT officials said the organization was now up to the task of managing the new market. Sam Jones, the system's chief operations officer, predicted that ERCOT would be able to switch about 41,000 residential and business customers each day in January.[12] (Not that so many customers were choosing new providers. Rather, all customers in deregulated areas of ERCOT — even those who did not choose a competitive provider — had to get switched to the retail electric provider affiliated with the incumbent.)

The ratepayer-financed organization's 266 employees earned an average of $99,000 annually in salary and benefits, including fully paid health, vision and dental insurance. This compensation was well in excess of the state government employee average.

But problems persisted. In early January, in a report to regulators, Jones acknowledged that incorrect data entries, service switching mistakes and communication problems continued to hamper ERCOT operations. Jones went so far as to indicate that some inefficiencies would become permanent fixtures of deregulation. "In exchange for an ability to shop around and get savings, (customers must allow) for a process that is more complicated than it used to be," Jones said.[13]

ERCOT problems also prevented retail electric providers from delivering accurate and timely bills. — As many as 150,000 customers in the TXU service territory and 90,000 customers in the Reliant service territory were not getting their bills on time, according to company officials.[14] Sometimes the bills were delayed for several months.[15] Even some of deregulation's leading advocates began second guessing the grid operator. "In hindsight, we should have given deregulation a longer trial period before we plunged in," said TXU chairman Erle Nye.[16]

In April 2002, Public Utility Commissioner Brett Perlman said a multi-million dollar ad campaign designed to alert consumers to the new market should be put on hold. He warned that if the media blitz went forward as scheduled, a backlog of 100,000 switch requests could result. The campaign was to include a mass mailing of 5 million customer guides, as well as television advertising. Commissioner Perlman also complained that no one seemed willing to take responsibility for ERCOT's poor performance.[17]

Also in 2002, the public got its first real glimpse of ERCOT's financial dealings — and what they saw was alarming: $500,000 for marketing and advertising (even though the quasi-governmental organization had absolutely zero reason to advertise because it had no competitors); ratepayer money spent to send employees to baseball games and up to $10,000 per ERCOT employee-authorized travel expenses.[18] The ratepayer-financed organization also spent $29,000 for a holiday party at a four-star hotel in Austin and $18,500 on a sponsorship deal for a minor league hockey team. The ratepayer-financed organization's 266 employees earned an average of $99,000 annually in salary and benefits, including fully paid health, vision and dental insurance. This compensation was well in excess of the state government employee average.[19]

On June 11, ERCOT agreed to curb some of its most egregious spending.[20] A month later, however, ERCOT called for a near doubling of the ratepayer fee that supports its operations. The hike would come in addition to the Price To Beat increases requested by the state's major utilities. "Clearly, there needs to be greater oversight," said state Rep. Sylvester Turner, then vice chairman of the House panel overseeing deregulation.[21]

Wholesale Market

More details emerged in 2002 about the wholesale price spikes that occurred during the deregulation pilot project. A PUC investigation found that six companies had improperly profited by incorrectly projecting their own energy needs in late 2001. In one case, a company consistently missed its projections by incredible margins — between 75,000 percent and 400,000 percent.[22] By failing to accurately project their power needs, the companies would create the appearance that power demand did not match power availability and then get paid extra for relieving congestion that did not exist.

All told, the companies netted $29 million in improper revenues for engaging in activities similar to the illegal activities that Enron used in California.

The PUC declined to publicly identify these companies, claiming they were protected by privacy rules.[23] But gradually the companies identified themselves. Among them were: TXU, Constellation Power Source, Mirant Americas Energy Marketing, Reliant Energy Service and American Electric Power Service. In April, after being confronted by a reporter, the last company finally owned up. It was Enron.[24]

All told, the companies netted $29 million in improper revenues for engaging in activities similar to the illegal activities that Enron used in California. In Texas, TXU made the most money off the activities. The company and others claimed the overpayments were the result of start-up problems in the wholesale market. In terms of missed projections, Enron was — by far — the worst offender. According to PUC documents, Enron improperly received $1 million to $6 million

Enron's Illegal Market Manipulation

In October 2002, Timothy Belden, the chief energy trader for Enron's West Coast power trading desk, pleaded guilty to conspiracy to commit wire fraud. Belden was among several Enron traders who created schemes with nefarious sounding names like "Ricochet" and "Death Star." Their purpose was to manipulate California's energy markets in order to gain unfair profits.

"Beginning in approximately 1998, and ending in approximately 2001, I and other individuals at Enron agreed to devise and implement a series of fraudulent schemes through these markets," Belden admitted in his plea agreement. Toward that end, the company knowingly submitted false information to the system operator in California, he said.

"We intentionally filed schedules designed to increase congestion on California transmission lines," Belden stated in his plea agreement. "We were paid to 'relieve' congestion when, in fact, we did not relieve it. … We scheduled energy that we did not have, or did not intend to supply. As a result of these false schedules, we were able to manipulate prices in certain markets."

Belden would later testify that the activities resulted in as much as $1 billion in profits for Enron during the California energy crisis. In audio tapes that became public in 2004, Enron traders could be heard making jokes about stealing from "those poor grandmothers" in California and gleefully proclaimed "burn, baby, burn" when a fire on a transmission line allowed the company to increase profits.

Enron also allegedly engaged in market manipulation in Texas during this state's deregulation pilot project in 2001, according to the Public Utility Commission and the Office of Public Utility Counsel.

by over-scheduling transmission by an average of 66,000 percent for a period of 29 days. Municipally-owned utilities reported that they would have to pay about $10 million in excess charges as a result of Enron's activities and those of other power wholesalers.[25]

CUSTOMER PROTECTIONS TESTED: Enron Affiliate Abandons Texas Market and its Customers

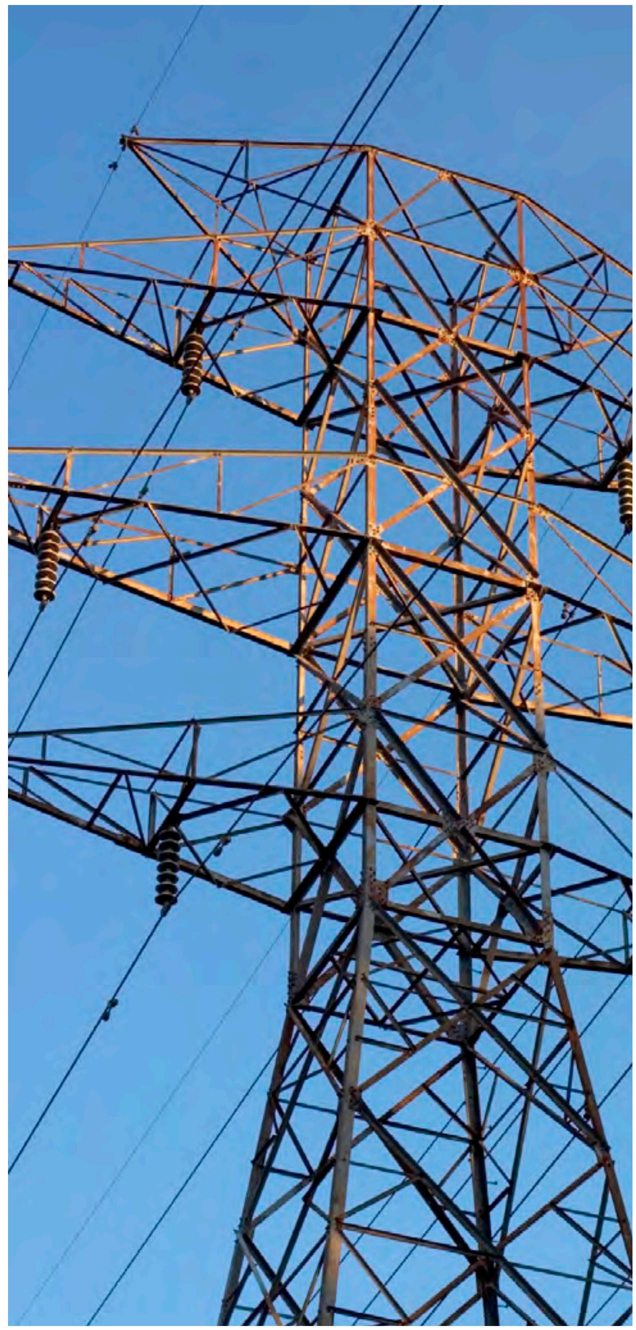
On June 10, 2002, New Power, the cash-strapped Enron affiliate, announced it was abandoning the state's electric market and switching its nearly 80,000 customers to other providers.[26] A day later, the company, which had lost $173 million during the first nine months of 2001, filed for bankruptcy.[27]

Until its implosion, New Power had been the most aggressive marketer of energy in Texas — so aggressive, in fact, that it also led all other electric retailers for the number of complaints lodged against it for signing up customers without proper authorization. In September, the PUC went after New Power for errors on about 46,000 bills.[28] PUC executive director Lane Lanford said in a letter to New Power that the agency sought to fine the company based on "the egregiousness and repetition of the violations, the seriousness of the violations, the resulting economic harm, previous history of violations and efforts to correct the violations."[29]

The company also figured in conflict-of-interest lawsuits filed during 2002. Max Yzaguirre, a former Enron executive, was serving as PUC chairman during December when the PUC was setting the initial Price To Beat rates. A coalition of cities argued that the PUC set those rates too high and that as such they unfairly benefited New Power. Two other city lawsuits alleged a similar conflict by Commissioner Brett Perlman, who had worked as an Enron consultant. The suits said both Commissioner Perlman and Commissioner Yzaguirre should have recused themselves because their actions, in effect, benefited the company that formerly wrote their paychecks.[20]

Although the suits were ultimately dismissed, Chairman Yzaguirre came under even more harsh criticism because he had failed to disclose the extent of his Enron connections and ultimately resigned from the PUC in early 2002.[31]

"This also calls into question the whole process as to how we establish rates," said Tom "Smitty" Smith, director of the Texas office of Public Citizen. "Is our goal to make electricity affordable for consumers, or is it to ensure profits for companies? Is our government designed to protect the people or the power companies?"[32]



Year: 2003 The 78th Texas Legislature — Staying the Course

Not long after the 78th Texas Legislative Session convened in January, state Sen. Gonzalo Barrientos, D-Austin, proposed Senate Bill 1792. It was designed to correct some of the flaws in the Price To Beat rule. State Rep. Sylvester Turner, D-Houston, likewise proposed House Bill 2335. It was designed to prevent electric companies from controlling too much of the market and manipulating prices.[1] The electric industry responded predictably. "Any further change to the system could upset the competitive electric market in Texas," said John Fainter, president of the Association of Electric Companies of Texas.[2] Despite price spikes during the opening days of the market, more suspicious spikes during a recent cold snap and increasing retail prices — industry representatives insisted the Texas market was a model for the rest of the nation. Both Senate Bill 1792 and House Bill 2335 failed.[3]

. . . In TXU's case, its first new rate hike of the year amounted to a 12-percent price increase – the largest in recent memory, far larger than any rate increases initiated under regulation.

But the Texas Legislature did manage to roll back one important consumer protection in 2003. As part of their negotiations with consumer representatives in 1999, lawmakers had created a special fund through Senate Bill 7 to provide bill-paying assistance for low-income Texans. This was known as the "System Benefit Fund." But in 2003 the Texas Legislature used $185 million of the $405 million so far accrued in the fund to certify the state's budget. As a consequence 700,000 low-income Texans ended up paying more for electricity than they otherwise would have. Ratepayers continued to financing the System Benefit Fund through regular surcharges on their home bills — even though much of the money was not being used for its intended purpose.[4]

PRICE TO BEAT INCREASES CONTINUE

Retail electric providers continued using the controversial Price To Beat mechanism in 2003 to ratchet up rates in lockstep with increases in natural gas prices. In TXU's case, its first new rate hike of the year amounted to a 12-percent price increase[5] — the largest in recent memory.[6] In August, the company increased its prices for a second time.[7] By any measure, Price To Beat customers would now be paying more for electricity than they did on the last day of the old regulated system. And this, even though the price of natural gas had gone down from the level it was before the market deregulated.[8] The flawed Price To Beat mechanism effectively became a one-way street for prices. Under the Price To Beat, prices went in only one direction: up.

WHOLESALE MARKET: Hockey Stick Bidding Causes Price Spikes

Prices in the wholesale market spiked during a cold snap in late February. The freezing temperatures hampered plant operations, curtailed natural gas supplies and sent wholesale spot prices soaring to $990 per megawatt hour for brief periods.[9] But the PUC also turned up evidence that energy traders took advantage of the unusual weather on Feb. 24, 25 and 26 to ratchet up prices and increase profits.[10]

How can this occur? ERCOT in 2003 was managing an automated bidding process for the spot market, called the "balancing energy market." Power companies would submit bids to ERCOT that reflected both the amount of power they could supply during given intervals and the price they were willing to receive for that power. ERCOT would accept the bids, starting with the lowest price bid first and continuing with higher priced bids until enough power was committed to cover demand during the interval.

But pursuant to its rules, the last accepted bid price— that is, the most expensive selected bid — gets paid to all successful bidders. That means a bidder who offered electricity for $1 per megawatt-hour could end up getting paid $1,000 for that same energy if the highest accepted bid was for $1,000 per megawatt-hour. This aspect of ERCOT rules leaves the market vulnerable to an improper bidding strategy known as "hockey stick" bidding. In its

The PUC and ERCOT

The Texas Legislature created the state's Public Utility Commission in 1975 to regulate telephone and electric service. The PUC is led by three commissioners, each appointed by the governor to serve six-year terms. The PUC's responsibilities include:

- Regulating rates for the monopoly transmission and distribution providers that operate within deregulated areas of the state.
- Overseeing the Electric Reliability Council of Texas, the organization that oversees most of the state's power grid.
- Overseeing the competitive electricity market within the area of the ERCOT grid.
- Adopting and enforcing rules relating to retail electric competition.
- Regulating retail rates in areas outside the boundaries of ERCOT.
- Licensing new transmission facilities for investor-owned utilities and cooperatives.
- Licensing retail electric providers.

The Electric Reliability Council of Texas was formed in 1970 to help enforce standards to ensure the reliability of the state's power grid. ERCOT was not considered to be a government entity that exercised state power, but rather a volunteer membership organization of electric utilities. ERCOT was given dramatic new responsibilities with the adoption of the state's electric deregulation law in 1999 and now functions as both the technical operator of the transmission grid and the decision-making organization that creates rules for the wholesale electricity market. ERCOT's responsibilities include:

- Managing the flow of electricity across a grid that covers 75 percent of the state's geographic territory, and 85 percent of the electricity market.
- Supervising transmission planning to meet existing and future electricity demands.
- Maintaining a database to record the relationship between retail electricity providers and their customers.
- Administering the state's Renewable Energy Credit Program.

For more about ERCOT, see Appendix E

Source: The Energy Report 2008, Office of Texas Comptroller, Chapter 27; Jared M. Fleisher, "ERCOT's Jurisdictional Status: a Legal History and Contemporary Appraisal," Texas Journal of Oil, Gas and Energy Law, March 19, 2008.

investigation of the February price spikes, the PUC determined that some companies were engaging in these sorts of practices. "Hockey stick bidding occurs when a market participant offers a small portion of its capacity or energy at an extremely high price," the PUC noted in a report on the February cold snap. "Under normal circumstances, these small amounts of energy and capacity are not needed, and therefore do not affect prices. However, during the extreme weather event, ERCOT needed the entire energy bid into the (wholesale spot market), and the resulting price was set by a hockey bid." The commission estimated that the hockey stick bidding cost the market an extra $17 million. [11]

Such manipulative strategies potentially can have other potential downsides. For instance, the price spikes experienced during the February ice storm led to the bankruptcy of a competitive electric provider, Texas Commercial Power. The company sued, alleging that TXU and other companies were unfairly manipulating the market in order to drive up revenues.[12]

ERCOT BEGINS MOVE TOWARD THE NODAL MARKET

In the wake of early price spikes in the wholesale market — spikes typically associated with congestion on the overburdened transmission system — the PUC gave the green light to a new market design. This proposed new system, a "nodal" system, would change how ERCOT oversees wholesale electricity transactions. It would replace the then-existing "zonal market" system whereby ERCOT supervises transactions as they occur in broad geographic regions (zones) of Texas with one where ERCOT would oversee transactions in thousands of smaller areas, or nodes. At the PUC's direction, ERCOT began ironing out the details in 2003.[13]

In the investigation of the February price spikes, the PUC determined that some companies were engaging in hockey stick bidding.

In theory, this new nodal system would allow the laws of supply and demand to bring more efficiency to grid operations. "This is the natural progression of things — the question is how far we need to go," said Tom Noel, the organization's chief executive officer.[14] But to implement this new system, ERCOT — an organization that as yet had failed to inspire much confidence with lawmakers and regulators — would have to traverse an ocean of complex technical hurdles. In discussions with policymakers in 2003, ERCOT officials said they expected the nodal market to "go live" within three years. A consultant hired at the direction of the PUC projected the costs to ERCOT for implementing the nodal market at between $59.8 million and $76.3 million.[15]

But the transition would have to take place without ERCOT CEO Tom Noel. Already under fire for the disastrous pilot project in 2001, the billing errors and the switching problems, Noel announced his resignation from ERCOT in October. Some lawmakers had openly called for it.[16]

BAD NEWS/GOOD NEWS: Consumers Complain to PUC in Record Numbers; State Exceeds Energy Efficiency Goals

The number of complaints regarding electric service filed at the Texas Public Utility Commission increased steadily since the market opening and peaked in July and August of 2003. Over the course of the fiscal year, the PUC's Customer Service Division received about 17,000 electricity complaints — about half relating to billing, although many consumers also complained about service disconnections and faulty service. This would mark an all-time high for the number of annual complaints under the Texas deregulation law.[17]

Also in 2003, the state exceeded an energy efficiency goal set forth in Senate Bill 7 by 11 percent. Under the legislation, regulated transmission utilities were to administer incentive programs designed to reduce by 10 percent annual increases in energy demand. In 2003, utilities spent $70 million on the program, according to the PUC.[18]

The agency reported that the demand reduction goal for 2003 was 135 megawatts, and utilities exceeded that target with an actual reduction of 151 megawatts. The PUC noted that the program equitably served residential, commercial and industrial customers.[19]

Year: 2004 The ERCOT Scandal — A "Crisis of Confidence"

DOMINANT TXU CAN DRIVE UP PRICES

In January 2004, the Texas Public Utility Commission issued a 33-page report concluding that at least one generator, TXU, owned or controlled so much generation capacity that it was capable of undermining a segment of the wholesale energy market. By virtue of the amount of power it could deploy or withhold, TXU was able to drive up prices, even if it did not intend to do so. The agency's report concluded the company's uniquely dominant position raised questions for the future of competition.

. . . while the megawatt-hour price of such energy typically sold for less than $50, it spiked to $990 during the study period...

The PUC report analyzed prevailing market conditions at the time of the price spikes in a segment of the wholesale market known as the balancing energy market. (For more about the Balancing Energy Market, see the sidebar on page 20.) It found that while the megawatt-hour price of such energy typically sold for less than $50, it spiked to $990 during the study period, which was between May 2002 and August 2003.

The analysis demonstrates that TXU routinely was guaranteed to have its bids selected — no matter the price — simply because it controlled so much power. "The results of this study show that TXU's market position is so pivotal that just about anything the company does with respect to (that segment of the wholesale market) will affect balancing energy prices, regardless of the reasons behind its decisions," the study said.[1]

Legislation considered during the 2003 session would have addressed pivotal provider problems by adding more market controls on wholesale providers. But generators successfully opposed the legislation, just as they opposed any suggestion of improper conduct raised by the price spikes. "Our position is that we do not have control over prices," TXU spokesman Chris Schein said. "They [the authors of the PUC report] are saying we have an impact on momentary prices, but there's no way that we can sustain control over prices."[2] In December, however, the PUC announced it was again looking at TXU for its involvement in a new round of price spikes. In the newest case, TXU had submitted bids to sell its power for $400 per megawatt-hour, although such power typically sold for about $50 at the time.

These price spikes occurred with shocking regularity. All told, power prices spiked nearly 100 times in late November and early December of 2004. The problem was so pronounced that PUC Chairman Paul Hudson threatened to call upon the Attorney General's Office or the Securities and Exchange Commission to investigate.[3]

ERCOT: COST-BENEFIT ANALYSIS OF THE NODAL PROJECT RAISES QUESTIONS

ERCOT and regulators continued working in 2004 on creating a "nodal" market. ERCOT hired a Massachusetts-based consulting firm to conduct a cost-benefit analysis of implementing a nodal market in Texas — a study that regulators said they wanted to see before giving their final OK.

However, the review did not include any consideration of the nodal system's potential impact on home bills.[4] "How can you do a cost-benefit study without knowing the impact on consumers? That doesn't make any sense at all," said Diane Weklar, executive director of the DFW Electric Consumer Coalition. ERCOT also declined to say publicly how much it spent on the report, even though (as with all ERCOT expenditures) it was Texas ratepayers who ultimately would foot the bill. "We're not in the habit of releasing information on ongoing business practices," Susan Vincent, corporate counsel for ERCOT, said in early July.[5]

The Procurement Scandal

Less than one month later, then ERCOT-board chairman Mike Green, a TXU executive, would be telling the PUC: "I want openness." But he wasn't responding to PUC inquiries about the nodal project or consultant's reports. Rather, Green was responding to inquiries about what then became a much more pressing matter: possible criminal activity.[6]

At issue were what ERCOT officials vaguely termed "vendor procurement irregularities."[7] ERCOT's CEO had learned about the irregularities on March 29, 2004, but waited two months before alerting the commission. The Department of Public Safety was also alerted, and ERCOT acknowledged its own investigation.[8]

Details remained elusive, although eventually it became clear that the allegations involved billing improprieties and possible self-dealing by ERCOT's cyber-security personnel. ERCOT failed to detect the criminal background of a former employee allegedly involved in improprieties. As a result of the allegations, several ERCOT staff members quit or were fired.

The criminal investigation began to focus on three managers in two firms that handled computer security for ERCOT. The two firms, Cyberensics Corp. and ECT Global Solutions Inc., had ERCOT contracts worth at least $2.5 million. Investigators attempted to ascertain whether the managers had stolen or laundered ERCOT funds.[9]

By June, PUC chairman Paul Hudson had declared a "crisis of confidence" with ERCOT's internal controls.[10] By July, more than four dozen witnesses had been interviewed by DPS investigators, and a grand jury in Williamson County had subpoenaed notes from an ERCOT lawyer.[11] In September, ERCOT was taking heat from a joint interim House-Senate committee for its lack of financial controls, for perceived arrogance among top officials in the face of these problems and for cutting checks to a contractor that had a dead man on its payroll.

"There appears to have been some serious breakdowns of internal controls and management practices at ERCOT," said Sen. Troy Fraser, R-Horseshoe Bay, chairman of one of the committees reviewing the organization.[12]

Continued Customer "Stickiness"

As of September 2004, fewer than 20 percent of residential customers were getting service from a power company not affiliated with one of the state's traditional utilities.[13] Although more customers were testing the deregulated market than in 2003, the fact that such a small percentage of customers had switched from traditional electric providers illustrated the continued "stickiness" in the residential market.

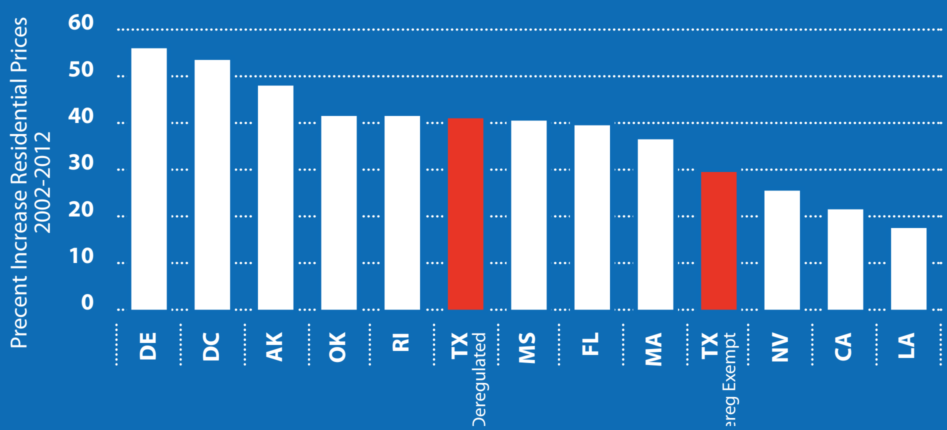
The PUC reported that between seven and 12 retail electric providers were serving residential customers in the state's major service territories.[14] The PUC blamed "substantial customer acquisition costs" — that is, the expense of advertising faced by electric competitors. The PUC also said competitors faced increasing investments for billing systems and call centers as well as added costs associated with resolving customer complaints.[15]

In September, ERCOT was taking heat from a joint interim House-Senate committee for its lack of financial controls, for perceived arrogance among top officials in the face of these problems and for cutting checks to a contractor that had a dead man on its payroll.

The PUC acknowledged that the Price To Beat rate paid by many Texans was above-market.[16] Repeated Price To Beat increases had driven up Price To Beat rates 20 to 35 percent between January 2003 and September 2004, according to the agency.[17] Competitive prices generally remained below the Price To Beat, but nonetheless rose in tandem with it.[18] The PUC also noted that since the market had opened to competition, the price of electricity in Texas had risen at a greater pace than it had in the United States as a whole.[19]

Price Increases: Residential Electric Rates vs. Natural Gas

Source: NYMEX Exchange, United States Energy Information Administration, http://www.eia.doe.gov/ cneaf/electricity/page/eia861.html



This exhibit gives us a sense of pricing trends among states heavily reliant upon natural gas to fuel electric generating units. Electricity prices roughly parallel natural gas prices in such states. Here, deregulated Texas sits in the middle of the pack. This exhibit demonstrates that residents in six other gas-reliant states endured less onerous price increases than those endured by residents in deregulated Texas. Meanwhile, residents in five other gas reliant states endured greater price increases than those observed in deregulated Texas.

BILLIONS OF DOLLARS IN STRANDED COSTS ADDED TO ELECTRIC BILLS

In November, 2004, the Texas Public Utility Commission determined that ratepayers owed Houston's CenterPoint Electric Delivery Company $2.3 billion in stranded costs.[20] The PUC would also make similar determinations for other Texas generating companies — albeit for lesser amounts.[21]

Stranded costs, remember, are meant to represent the difference between the book value of a company's assets and the price that would be paid by someone buying the assets on the open market. Think of a company that pays $1 billion to build a nuclear power plant under regulation but then can only sell it for $500 million in a deregulated market. In this over-simplified example, the $500 million difference would be the "stranded cost" of the nuclear plant. Under Senate Bill 7, electric companies have the right to recover from ratepayers the stranded costs attributable to generation assets that the utilities were ordered to build but are no longer valuable. (For more about stranded costs payments, see page 66).

The idea behind stranded costs is that utilities should not be harmed by the transition to the deregulated market because they owe more for generating plants than what they could sell those plants for in the open market. Ultimately, it was decided that ratepayers would pay the utilities their "stranded investment" through surcharges that would be assessed against every customer. In exchange for paying stranded costs, it was rationalized that ratepayers would have access to better prices in the competitive market. In theory, the benefit of lower prices would far outweigh the burden of stranded cost surcharges.

But decisions relating to stranded costs for CenterPoint, Texas Central Company and Texas-New Mexico Power caused real harm to consumers. That's because clear evidence suggests that supposedly uneconomic plants were woefully undervalued.

For instance, in determining the stranded cost pay-out to Houston's CenterPoint, the PUC considered a partial stock sale by the company that established the value of its generating assets at $3.65 billion. But days after the PUC calculated CenterPoint's stranded costs, the company's equity owners resold those same generating assets for $8.3 billion.[22]

So what was the true value of those assets — $3.65 billion or $8.3 billion? If the PUC had used something closer to the $8.3 billion figure, the stranded costs associated with the assets would be very close to zero. Instead the $3.65 billion asset valuation was used. As a result, all customers of the former HL&P must pay billions of dollars in stranded costs for years to come.

. . . ratepayers who never received any benefit from the excess mitigation credits nonetheless were on the hook for paying them back. And these payments were to be added to already questionable multi-billion dollar charges to ratepayers for stranded costs.

In fact, all assets in Texas used to calculate the billions of dollars of stranded cost charges to ratepayers were resold at a substantial profit.

Also, remember that the PUC earlier projected that Texas electric companies would end up with negative stranded costs. In 2001, the PUC's economic modeling showed that assets like nuclear power plants would become more valuable, not less, and as a consequence the owners of those assets should surrender some money to reflect the windfall they would receive under deregulation.[23]

When legislation failed in 2001 that would have required electric companies to refund that projected windfall to ratepayers, the PUC stepped in and ordered generators to make corresponding payments in the form of "excess mitigation credits," or EMCs. But the credits for the most part ended up in the pockets of electric retailers, not ratepayers. The total value of the EMCs exceeded $2 billion.[24] The PUC then added the excess mitigation credits — again credits that never went to ratepayers — to their stranded cost calculations.[25] Said another way: Ratepayers who never received any benefit from the excess mitigation credits nonetheless were on the hook for paying them back. And these payments were to be added to already questionable multi-billion dollar charges to ratepayers for stranded costs. (For more about excess mitigation credits, see Appendix C).

Year: 2005 The 79th Texas Legislature — The Wind Power Initiative

In April 2005, Public Citizen, an environmental and consumer advocacy group, released a study showing that the price of electricity in deregulated areas of the state had increased at more than twice the rate as electricity prices outside deregulation.[1] In May, a consult hired by the Public Utility Commission concluded yet again that TXU had the ability to unilaterally drive up wholesale prices.[2] These factors together, plus clear problems with the defective Price To Beat mechanism and a scheduled top-to-bottom agency review of the Public Utility Commission,[3] increased expectations that the Texas Legislature would adopt major reforms in 2005.

In April 2005, Public Citizen released a study showing that the price of electricity in deregulated areas of the state had increased at more than twice the rate as electricity prices outside deregulation.

That none were forthcoming is all the more surprising given that industry representatives had convinced lawmakers during previous legislative sessions to put off the consideration of any important reforms until 2005, arguing that it made more sense to wait until the completion of an expected efficiency review of the PUC that year. But then after the completion of that review process — and with electric bills up nearly 50 percent since the beginning of deregulation[4] — utility lobbyists still argued against reform. As one utility representative said: "If it ain't broke, don't fix it."[5] Two important bills that lawmakers considered and ultimately rejected during the 79th session were Senate Bill 759 and Senate Bill 764. The first would have made it easier for cities to aggregate together their citizens into bulk-purchasing groups in order to negotiate for them better electricity deals.[6] The PUC reported that such aggregation projects in other states had resulted in ratepayer savings.[7] The second bill would have limited how much supply could be owned or controlled by generation companies. The legislation would have addressed market power issues by discouraging electric companies from unfairly controlling wholesale prices.[8]

But while both those bills failed, that's not to say that ratepayers would be unaffected by the actions of their lawmakers in 2005. Here are a few of the measures adopted during the 79th regular and special sessions. Some had the potential to increase bills.

- Money meant for the System Benefit Fund (which had been created as part of Senate Bill 7 to provide bill discounts for low-income Texans) was diverted to support the state's general revenue fund. The Texas Legislature had taken money from the ratepayer-supported fund once before, in 2003, to also help fill a budget gap that year. With the latest budget action, lawmakers used the last of the available money — and as a result, 350,000 low-income Texans ended up paying more for electricity than they otherwise would have.[9] The budget action also had the effect of converting what otherwise would be considered a surcharge on ratepayers' bills into a sales tax on electricity.[10]

- Senate Bill 5 was technically not an electric bill, but one relating to the telecommunications industry. Adopted during the second called special session of 2005, it permitted electric utilities to enter into deals to create broadband service over ratepayer-financed transmission systems. Broadband companies that sell the service could keep the revenue, although some of it would potentially flow back to the utility. Ratepayers who paid for the transmission system and made the arrangement possible would not be able to receive the broadband service unless they were to pay for it.[11] Ratepayers would also have to pay for the digital meters that work with the broadband service. Oncor Electric later would cite this bill and separate legislation[12] for its costly decision to order and install more than 100,000 digital meters before state operating standards were in place.[13] The obsolete meters were replaced by the company — although Oncor was still allowed to charge its customers for them.[14]

- Senate Bill 20, adopted during the first called special session, established special zones (called "Competitive Renewable Energy Zones" or CREZ for short) to mark the site of future transmission construction.[15] However, the new lines would not directly address the state's ongoing transmission shortage but rather would connect to sparsely populated areas of the Panhandle and far West Texas to support future wind generation. The cost of the CREZ transmission projects would reach into the billions of dollars. Such new wind construction also would lead to more reliability challenges for ERCOT.[16] Senate Bill 20 likewise expanded renewable energy goals included in Senate Bill 7 — from 2,880 megawatts of capacity by Jan. 1, 2009, to 3,272 megawatts — and established a new target of 10,000 megawatts of renewable energy capacity by 2025.[17]

STATE EXCEEDS SENATE BILL 7 TARGET FOR RENEWABLE ENERGY

Senate Bill 20 set forth other targets as well: 4,265 megawatts of renewable energy capacity by 2011, 5,256 by 2013 and 5,880 by 2015.[18] And lawmakers had plenty of reason to believe the state would meet those ambitious targets. The construction of renewable energy generation already had exceeded the goals set forth in Senate Bill 7 and the Public Utility Commission was estimating that there would be more than 1,300 megawatts of new renewable energy capacity online in 2005.[19] That exceeded the original target in SB 7 by more than 500 megawatts, or nearly 63 percent. The PUC reported that wind generation comprised the lion's share of the new renewable generation and linked much of the growth to federal tax credits.[20]

The PUC also reported success in its implementation of energy efficiency programs established by Senate Bill 7. Under the legislation, utilities were required to administer energy efficiency incentive programs with the goal of reducing annual growth in energy demand by at least 10 percent.[21] The PUC noted that the programs saved nearly 500,000 megawatt-hours of energy in 2005. Utilities exceeded their demand reduction goals in 2005 by 27 percent, according to the PUC.[22]

"Overall, program performance appears to have been successful," the PUC reported.[23]

The PUC also acknowledged that for part of 2005, the average price of competitive offers was actually higher than the Price To Beat.

Utilities spent roughly $78 million in ratepayer money on the program in 2005. The PUC estimated the potential 10-year savings from the program at $290 million.[24]

The ERCOT Procurement Scandal Continues

In January, a grand jury indicted six former ERCOT managers in the procurement scandal that had come to light in 2004. The officials were accused of having improperly billed $2 million to the organization for work that was never done. In August, prosecutors obtained a guilty plea from the former director of information technology and information services for ERCOT. The former executive admitted to conspiring with five others to set up shell security companies and using those companies to bilk ERCOT.[26] The Attorney General said some invoices corresponded to unperformed work or undelivered goods. The group also billed for work supposedly performed by non-existent employees, according to the AG's office.[27]

Responding to the scandal, lawmakers in 2005 adopted legislation giving the Public Utility Commission greater authority over ERCOT's finances and activities.[28]

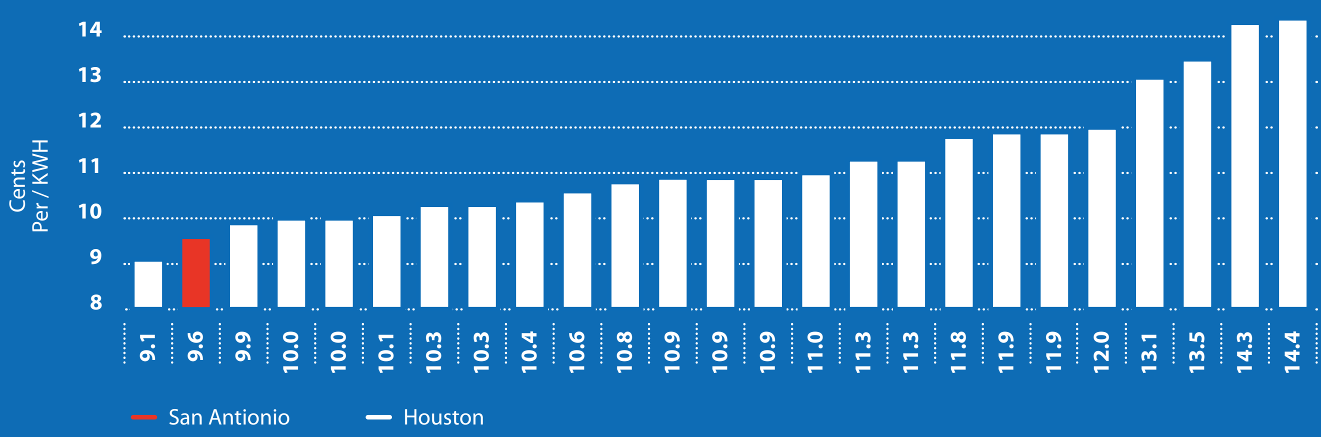
Customer Choice: Higher Prices than Regulated Rates, Plus More Complaints

By the end of 2005, after four years of deregulation, fewer than half of residential customers had switched off the above-market Price To Beat rate, according to PUC estimates.[29] In part, this reflected the inherent "stickiness" in the residential market. But many consumers also complained that the deals offered by competitors were less than enticing. "Guess what? There is only a cent or two difference in the cost between all providers," one frustrated resident wrote to PUC Chairman Paul Hudson.[30] The PUC also acknowledged that for part of 2005, the average price of competitive offers was actually higher than the Price To Beat.[31]

To make matters worse, Hurricanes Katrina and Rita disrupted natural gas production during the last months of 2005. That sent both natural gas and electricity prices to historically high levels.[32] In November, TXU began phasing in a 24-percent rate increaseto its Price to Beat rate.[33] Other companies followed suit with similar increases.[34] Because of the defective Price To Beat rule, electric rates would remain at those historically high levels even after natural gas production came back online and gas prices stabilized.

*A Tale of Two Cities — Houston and San Antonio**

**Based on rate surveys by the Public Utility Commission.*



In Houston's deregulated market, dozens of retail electric providers compete for customers. In San Antonio, a single municipally-owned utility serves everyone. Houston is the state's largest Texas city with a deregulated retail electric market. San Antonio is the state's largest city outside retail deregulation. Where do customers get a better deal?

According to data from an December 2013 pricing survey by the Public Utility Commission, electricity sold through almost every fixed-rated deal in Houston costs more than electricity sold by the single municipally-owned utility in San Antonio. This follows a common trend. For instance, a PUC pricing survey from April 2011 showed that electricity then sold under Houston's very lowest fixed-rate deal was still more expensive than electricity sold by every municipally-owned utility surveyed by the agency, and more expensive than all but one investor-owned utility.

Year: 2006 Mixed Reviews and Rolling Blackouts

The year began with what the PUC touted as good news for consumers. According to a report released by the agency in February, Houston residents could have saved over $1,000 under deregulation and Dallas residents could have saved about $800.[1]

Not that Texans had actually saved this money under Senate Bill 7. Only that they *could have.*

The "savings" were created by comparing the last regulated rate — meaning the rate charged on Dec. 31, 2001 — to the lowest competitive offers in Houston, Dallas and Fort Worth for the years 2002, 2003, 2004 and 2005. The agency then calculated the difference, assuming that a hypothetical resident had selected the lowest-priced offer during each of those four years. A Dallas resident, for instance, could have saved 17 percent over what he would have paid under the old regulated system, according to the report.[2]

However the analysis was flawed. First, it was unclear how many customers would have been eligible for the lowest priced offers. Moreover, Texans receiving service through fixed-rate electricity contracts cannot willy-nilly switch providers without paying early termination penalties.

There is also the question of what is the appropriate benchmark price with which to make a comparison. By using the regulated rate charged on Dec. 31, 2001, the study relied upon a benchmark that was inflated by exorbitant fuel surcharges and excess earnings valued at hundreds of millions of dollars.[3] Utilities were allowed to keep charging this regulated rate in anticipation of deregulation.

Even if the study is accepted at face value, it is clear that the millions of ratepayers still paying the Price To Beat in 2006 were getting an awful deal by paying unnecessarily high prices. And indeed, a separate review of rate filings showed that by 2006, the Price To Beat had increased by 84 percent in the Metroplex, by 81 percent in Houston, by 101 percent in Corpus Christi and by a whopping 116 percent in West Texas.[4] Outside deregulated areas, price increases occurred over the same period but were much more modest. In Austin, with its municipally owned utility, rates increased by 19.4 percent, for example. That means the most commonly paid rate in deregulated Houston increased five times faster than the rate paid in Austin, which remained outside deregulation.[5]

"…without a doubt, (these environmental goals) could have been accomplished without going to full-scale deregulation … without creating the series of unnecessary middlemen, in the form of Retail Electric Providers."

— Tom "Smitty" Smith, Director of Public Citizen-Texas

The PUC analysis did not focus on the Price To Beat rate but rather the lowest-competitive offer in each service territory. But several reports from 2006 suggested that even those Texans who shopped around for electricity were paying too much for it. In March, for instance, AARP released a report showing that TXU and all of its cheapest North Texas competitors were charging rates out of line with fuel costs.[6] Another survey released later that same year demonstrated that rates offered to customers in deregulated areas of North Texas were higher, on average, than rates in areas that remain under regulation. The survey showed that the best offer under deregulation was still more expensive than rates from almost every company outside deregulation.[7] Likewise, Kenneth Rose, a senior fellow at Michigan State University and a leading expert on electric pricing and policy, released a nationwide survey in 2006 showing that electricity prices had gone up in Texas since deregulation, while those in regulated states had gone down.[8] Another expert concluded that under deregulation Texans had paid some of the highest rates in the nation, a reversal of a decade of relatively cheap power under the old system.[9]

The nationwide comparisons between regulated and deregulated prices were possible because the mix of markets provided for a control group to help answer a basic question: Does deregulation save money for consumers? Rose said the growing consensus among experts was that it does not. "Evidence that we're gathering (shows that the effectiveness of deregulation) — at least as we had originally thought it would work — is not bearing out from the customer perspective," Rose said.[10]

In response to these concerns, the chairman of the Public Utility Commission pushed a proposal in 2006 to lower the Price To Beat. Chairman Paul Hudson noted that the price of natural gas had gone down substantially since Hurricanes Katrina and Rita, but that the Price To Beat rates didn't reflect the decrease. He wanted to push down the Price To Beat shortly before it expired for good in January, 2007. "It would be a disservice if … residential customers remained on a final regulated rate (the Price To Beat rate) … that no longer reflected the market," said Chairman Hudson, also noting that natural gas prices then embedded in Price To Beat rates were at least 15 percent higher than the actual price of natural gas in the open market.[11]

The chairman's plan, which would have saved Texans an average of $17 on their monthly power bills, was ultimately rejected. The commission voted 2-1 against it. Two commissioners even voted to block agency staff from taking testimony on the issue.[12]

COMPLAINTS

In addition to concern about the Price To Beat, the PUC continued receiving thousands of complaints each year related to electricity service. Complaints had been on the rise ever since the state deregulated its market, peaking in 2003 and 2004 and then, after a dip in 2005, increasing again in 2006 to more than 10,000.[13]

Problems with customer switching motivated a significant portion of those complaints. It had become clear that a process that typically had taken a day under the previous regulated system now could take two weeks or longer. (See Appendix B for more about consumer complaints filed with the PUC.)

ROLLING BLACKOUTS

On April 17, shortly after 4 p.m., hundreds of thousands of Texans started losing power. The operator of the Texas power grid, the Electric Reliability Council of Texas, suddenly found itself without enough available generating capacity and ordered rolling blackouts across the state.[14] Although ERCOT acted quickly to avert a more serious system-wide outage, its response nonetheless raised serious management questions. "You can't be out there cowboying, operating on your own," state Sen. Troy Fraser told organization officials shortly afterwards.[15] Sen. Fraser and others complained that ERCOT had failed to alert key policymakers and law enforcement officials. He said regulators were caught flat-footed, and police officers were sent scrambling to direct cars after traffic signals unexpectedly stopped working.[16]

PUC Chairman Paul Hudson also blasted ERCOT's response, complaining that grid managers did not call him directly about the emergency. "My immediate one-word reply is a bit too colorful to restate," Hudson said. But the PUC chairman also said that when it came to dealing with ERCOT, such communications breakdowns were nothing new.[17]

The organization charged with scheduling power across 38,000 miles of transmission lines had done little to earn the confidence of lawmakers and regulators. Since the passage of SB 7 in 1999, ERCOT had mismanaged the deregulation pilot project, appeared incapable of efficiently processing switch requests for many months and drew fire for multi-million dollar billing errors. There were also problems with the organization's financial controls, as evidenced by the guilty pleas of several former executives on bribery and corruption charges.[18]

In May, ERCOT chief executive officer Thomas F. Schrader resigned amid questions about his leadership.[19] Schrader had, on occasion, bucked the PUC — even awarding raises to some employees over the objections of the commissioners.[20] Schrader, when he came on board in 2004, had followed the tenure of Tom Noel, another ERCOT CEO who left under pressure.

MARKET POWER ABUSES PERSIST

Enron agreed shortly before the beginning of the new year to pay more than $1.5 billion to settle claims that it had manipulated the California market. Federal regulators also accepted a $512 million settlement from Houston's Reliant Energy to resolve claims it charged unfairly high prices during the California energy crisis. In Texas, meanwhile, TXU Wholesale came under investigation for allegedly engaging in similarly questionable practices that "raise substantial competitive concerns."[22]

The 2006 review continued a history of such inquiries involving TXU. In 2003, for example, the company drew regulatory scrutiny when energy that typically sold for less than $50 a megawatt-hour in the spot wholesale market shot up to $990.[23] That same year TXU also was targeted in an unsuccessful lawsuit alleging market manipulation.[24] The next year the PUC focused on TXU's bidding practices after a series of price surges. The commission eventually concluded there was no manipulation involved, but nonetheless warned that the state's power system was vulnerable to abuse by the state's largest generation companies.[25]

TEXAS MEETS RENEWABLE ENERGY MILESTONES

Senate Bill 7 called for the creation of 2,880 megawatts of new renewable energy capacity by 2009. Texas exceeded that goal in 2006 — three years early — and was ahead of schedule for meeting updated renewable energy targets created by Senate Bill 20, adopted in 2005.[26] Texas also surpassed California in 2006 as the number one state in the nation for installed wind power. Worldwide, only Germany, Spain and Denmark had more wind power than Texas in 2006.[27]

About 2.1 percent of electricity generated in Texas came from renewable sources in 2006, up from 1.5 percent from 2005. Within the ERCOT region, renewable energy provided 2.1 percent of peak generation, up from 1.5 percent in 2005.[28]

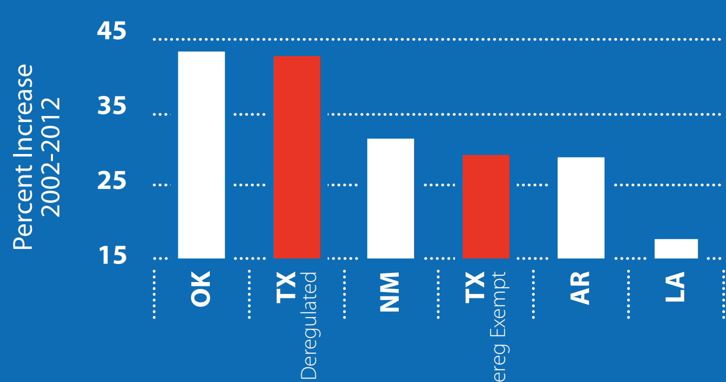
To foster the creation of new renewable generation, Senate Bill 7 established a system whereby electric retailers could earn and trade "Renewable Energy Credits" (RECs) for a portion of their energy sales. Under the program, electric retailers that do not acquire enough renewable energy to satisfy their obligations can purchase credits from other companies that have exceeded their obligations. Electric retailers that market so-called "green power" to customers also can obtain renewable energy credits for that purpose.

The RECs needed for the state to meet its renewable energy goals represented about 1.7 percent of energy sold to retail customers in 2006.[29]

"This has been more successful than any other provision of the bill," said Tom "Smitty" Smith, director of the Texas office of Public Citizen, referring to the environmental safeguards included in Senate Bill 7. He added, however, that "without a doubt, (these goals) could have been accomplished without going to full-scale deregulation … without creating the series of unnecessary middlemen, in the form of Retail Electric Providers." He also noted that much of the dramatic increase in wind power in Texas was attributable to federal tax credits.[30]

Price Increases in Texas and Adjoining States: 2002-2012

Source: United States Energy Information Administration, http://www.eia.gov/cneaf/electricity/page/sales_revenue.xls



Since 2002, average electricity prices increased more in deregulated areas of Texas than they increased in all adjoining states except Oklahoma. This exhibit examines residential prices only.

Year: 2007 The 80th Texas Legislature — The TXU Buyout

Lawmakers in 2007 reported phone calls from hundreds of constituents irate about electric rates. The AARP said Senate Bill 7 had created a "deregulation mess" and made reform its No. 1 legislative priority.[1] Even key supporters of Senate Bill 7 began raising doubts. "There has been insufficient participation of lower-cost providers — unfortunately, we have not seen the Southwest Airlines of the electric industry," lamented former state Rep. Steve Wolens, the co-author of SB 7. He went on to say that "there are many, many issues, there are a ton of issues" with SB 7 and acknowledged that it had failed to create meaningful savings.[2]

This was particularly troublesome given that Texas in 2007 had passed one of the last major milestones under SB 7.

The AARP said Senate Bill 7 had created a deregulation mess…

On Jan. 1, the Price To Beat expired. TXU in Dallas, Reliant Energy in Houston and the other legacy providers had been allowed to offer a variety of rate packages for some time. But one of them always had to be the Price To Beat. No longer. Now the legacy providers had free rein to charge whatever they wanted. The brakes were completely off.

In theory, market forces would keep prices down now that there were no capped rates. But evidence emerged in 2007 that the deregulated market continued to have problems transitioning into a fully competitive one.

For instance, a survey of residential electric prices through 2007 showed that Texans paid below average rates in the years prior to Senate Bill 7 and then well above the national average after deregulation came into effect. The survey indicated that consumers in Texas paid on average more for electricity than consumers in all other deregulated states with retail competition.[3]

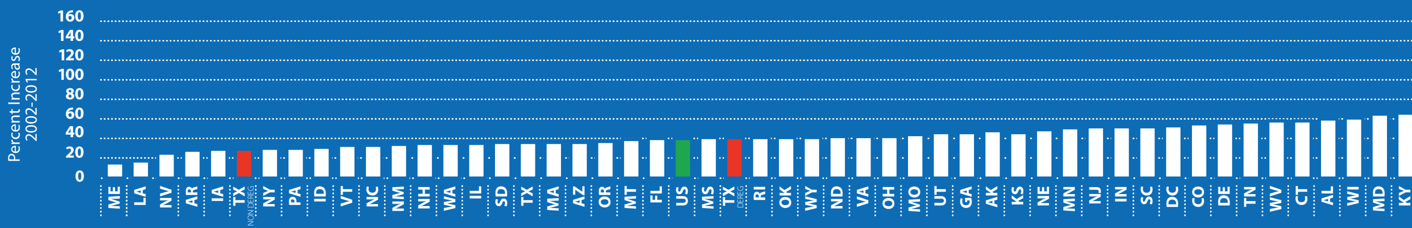
Industry representatives have consistently blamed high prices in Texas on the state's reliance on natural gas as a fuel source for generation. But the survey showed that regulated states with a similar dependence on natural gas, such as Louisiana, experienced residential rate increases smaller than those in Texas. The PUC likewise noted that CenterPoint's Price To Beat rate had been second highest among a sample of major providers that relied heavily on natural gas.[4]

These findings illustrate a central fact about pricing under deregulation: High prices in Texas are not simply a function of the market's reliance on natural gas but rather a function of *how* the market relies on natural gas. Under ERCOT's traditional rules all power accepted to meet demand in the spot market is paid for at the price of the most expensive power accepted to meet that demand. This becomes the "clearing price" on the wholesale spot market — and in most cases, it's a gas plant that sets it. So, natural gas prices help set the price for *all* spot energy in ERCOT. These spot prices then send ripples throughout the entire wholesale market, and in 2007 this meant higher residential bills.

By contrast, regulated investor-owned utilities are required to charge rates that reflect the *actual* cost to generate power, based on the average of *all* of the fuel used in the utility's generation fleet. This means that regulated retail rates include a fuel cost that is a blend of costs associated with several kinds of fuel, ranging from stable, low-priced lignite or coal, coal or nuclear generation to high-priced gas.

Residential Electric Price Increases — Texas vs. United States 2002-2012

Source: United States Energy Information Administration, http://www.eia.gov/cneaf/electricity/page/sales_revenue.xls



Residential electricity prices in deregulated areas of Texas increased by slightly more than 40 percent between 2002 and 2012.That's slightly more than the increase registered nationwide, and about 10 percentage points higher than the increase registered in areas of Texas exempt from deregulation. This exhibit uses 2002 as a starting point because that was the year deregulation took effect in Texas. It ends with 2012 because that year was the most recent (at the time of publication) for which there was relevant data to conduct the analysis. This exhibit considers prices only within continental US.

WHOLESALE ENERGY PRICES DOUBLE

The price of energy on the spot market more than doubled in September 2007, as compared to the price during the same month in 2006, according to an ERCOT report. This created revenues of $76 million for generators in September of 2007, as compared to $37.4 million during the same month in the previous year.[5] This price increase — and others — were made possible in part because of rule changes at ERCOT and by the Public Utility Commission. Among other things, the PUC increased the price caps at which generators can offer their energy into the wholesale spot market. Previously, the cap was set at $1,000 per megawatt-hour, a very high price and far in excess of the cost to operate any power plant on the system. After the PUC's decision, the cap went to an even higher level.[6]

As for ERCOT, the organization had earlier implemented market rules that allow for higher prices during the deployment of a particular form of capacity used to protect against power shortages.

That these changes contributed to the doubling of those September energy prices was not met with alarm by most market participants or by the PUC. That's because many market participants believed that higher prices represented a "truer" economic result under the theory that they provide an incentive for additional generation construction.[7] Far from raising questions about whether the ERCOT market works for consumers, under this view high prices (and consistent price increases) were seen as evidence that the market is correct from an economic standpoint.

Of course, higher spot energy prices eventually lead to

higher retail prices — that is, the prices that end-use consumers like homeowners pay. That's because ERCOT's spot market for energy heavily influences the prices paid by all wholesale buyers — whether they deal directly through that market or not.

In lawsuits, two former TXU power traders alleged a pattern of market manipulation by the power company.

This approach — that is, equating low prices with a problem in the market and higher prices as "success" — raised troubling questions for Texas electricity consumers. It was also an approach that continued to inform policy debates about the state's deregulated electricity market for years to come.[8]

ALLEGED MARKET POWER ABUSES IMPACT THE MARKET

TXU's trading practices remained an issue in 2007. In lawsuits, two former TXU power traders alleged a pattern of market manipulation by the power company. The traders said they notified their superiors about the improper activities, and the superiors condoned the behavior. The company denied wrongdoing.[9]

The PUC also concluded on March 12 that TXU Wholesale had engaged in unfair trading practices. An outside expert hired by the agency said that TXU during one period in 2005 had driven up some wholesale prices by 15.5 percent and racked up $19 million in unfair profits. The consultants found that "since TXU raised prices in the market and profited from its activities . . . TXU's behavior constitutes market power abuse." [10] Two weeks later the PUC recommended $210 million in fines, a record for the agency.[11]

The very next month, on April 3, 2007, wholesale prices spiked to levels never before seen in Texas. ERCOT reported that balancing energy shot up to $1,500 per megawatt hour on three separate occasions. The prices could have gone even higher if not for an existing cap of $1,500. Typically, the power sells for less than $100.[12]

Later that same month a sister company of Houston's Reliant Energy improperly held back wholesale power. It later agreed to pay over $100,000 in penalties.[13]

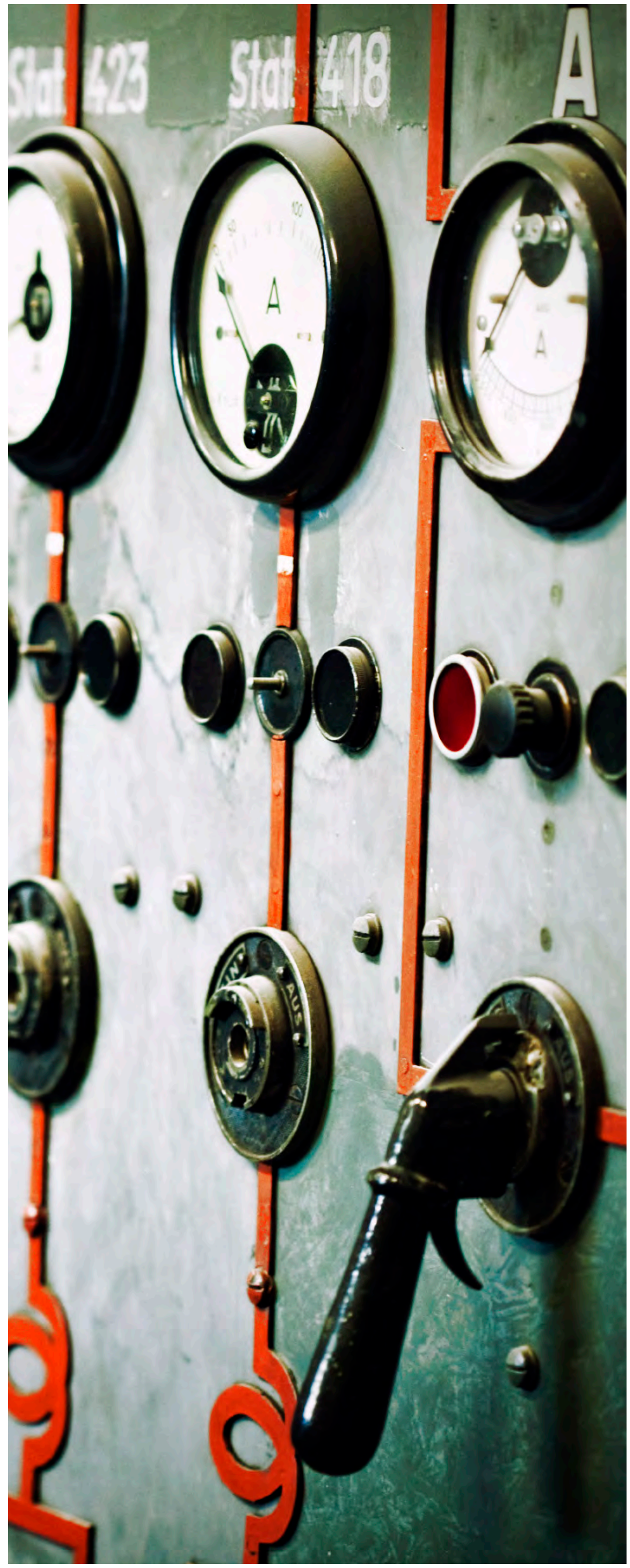
THE TXU BUYOUT: THE LARGEST LEVERAGED BUYOUT IN HISTORY

The 80th legislative session began with bold talk of reform. Many lawmakers reported complaints from constituents that the deregulated market was not living up to its potential. Lawmakers vowed to pursue changes to create real competition and to lower rates. They floated bills to establish new controls over potential market manipulation by wholesale generators, to create some price controls, and to allow municipalities to negotiate deals on behalf of large blocks of customers.[14] They received support from consumer groups across the state, some of whom mounted door-to-door campaigns.[15]

By contrast, industry representatives warned against changing SB 7. Despite the price spikes, the numerous findings of questionable conduct and evidence of ratepayer overpayments, the industry's position remained immutable: SB 7 was, for the most part, working as intended. Said John Fainter, president of the Association of Electric Companies of Texas: "You've got to be careful about what you do. We think that we have a well-designed market."[16]

Among the most important of the reform bills were Senate Bills 482 and 483, both by state Sen. Troy Fraser, R-Horseshoe Bay. The first would have made TXU split into separate entities to limit its dominance in Texas. It would also have given the Public Utility Commission power to cap residential rates if the agency found them out of line with market prices. As drafted, the second bill, SB 483, would have prohibited any company from controlling more than 20 percent of power generation in any of four distinct regions or zones within Texas. In the North Texas zone, TXU owned about 45 percent of the generation — and indirectly controlled much more than that.[17] Sen. Fraser unveiled both bills on Feb. 7, noting that SB 7 had not sufficiently helped residential ratepayers. "The legislation filed today will strengthen competitive forces and improve the residential market," he said.[18]

Other important bills included one that would reinstate the System Benefit Fund, one that would allow for the creation of a regulated rate if the PUC determined the market was insufficiently competitive, one that would create a regulated rate based on cost of service and one that called upon the PUC to recommend alternatives to deregulation.[19] But



the political landscape changed dramatically after word leaked out of a proposed business deal between TXU and Kohlberg Kravis Roberts & Co., a private equity firm. The outside investors were offering to buy TXU for $45 billion, including debt. If the deal went through, it would be the largest such transaction in history.[20]

The price of energy on the spot market more than doubled in September 2007, as compared to the price during the same month in 2006, according to an ERCOT report.

To garner support the buyout partners promised a host of inducements, including lower rates through 2008 and an agreement to build only three of 11 coal generating plants supposedly planned for construction by TXU. However the *Dallas Morning News* released an independent study on June 24 that concluded that TXU probably would have cut prices and shelved plans for the coal plants anyway — even without the buyout. The study concluded that ratepayers would eventually see higher bills and that the "the buyout of TXU provides no inherent benefits to the customer."[21]

Sen. Fraser feared as much and so drafted Senate Bill 896 that expressly granted the PUC authority to ensure the transaction was in the public interest. By mid-May, however, it was increasingly clear that that change in law — as well as any other legislation that was seriously opposed by TXU and KKR — would not survive the session.[22]

Energy companies typically employ plenty of lobbyists, but in 2007, with the buyout at stake, they deployed a vast army of them. According to one report TXU and its buyout partners spent $6 million for lobbyists, $11 million for advertising and $200,000 for legislative gifts. That figure was about twice what TXU had said it planned to spend before the announcement.[23]

Under intense lobby pressure, Senate Bill 482 was killed May 27 on the House floor.[24] Senate Bill 483 died during the waning days of the session after House and Senate negotiators failed to come up with a compromise.[25]

The deal closed on Oct.11, with the new company to be called Energy Future Holdings. It would be comprised of three major units: retail electric provider TXU Energy, wholesale power company Luminant, and regulated transmission and distribution utility Oncor.[26] The final deal included several important financial covenants intended to protect Oncor (and its captive ratepayers) should the whole enterprise go bust. [See Ring Fence article, page 48.]

And many observers felt this was a real possibility, given the massive debt used to finance the deal. Others simply warned about the potential fall-out for ratepayers, no matter how the new company fared. "To be honest — and this is a very un-Republican thing to say, but I'm going to say it anyway because I'm out of office now — very few of these mergers ever turned out very good for folks," said former PUC chairman Pat Wood III, speaking to the *Dallas Morning News.*

"You know, a lot of these things don't look great a year later," he said.[27]

System Benefit Fund provides some assistance to low-income Texans

Low-income ratepayers did, however, get one smallbit of good news. The System Benefit Fund had been financed through what is typically a $1 average fee on electric bills. It was created as part of SB 7 to finance discounts for low-income residents. Previous legislatures had raided the fund mercilessly, using the money for budget balancing purposes. But in 2007, at the urging of state Rep. Sylvester Turner, lawmakers appropriated about $170 million for the System Benefit Fund — meaning that it would again begin funding rate discounts for poor Texans.[28]

However, about $400 million in money already collected for the System Benefit Fund — plus another $100 million that would accrue over the next two-year budget cycle — was used for budget balancing purposes.[29]

Oncor's Ring Fence

Anyone living within its service territory and who wants electric service must, by necessity, become a customer of Oncor. As a state-sanctioned monopoly, the north Texas transmission and distribution utility is obligated to serve all homes and businesses in a wide swath of territory extending from just north of Austin to Wichita Falls, up through Dallas and Fort Worth and even westward into Midland and Odessa. Lacking a free-market choice, Oncor's customers — like customers of all monopoly utilities — are *captive*.

It is for this reason that the Texas PUC possesses regulatory authority over Oncor (and other electric transmission and distribution utilities in Texas), and it is for this reason that the agency has a say if the utility changes ownership. The utility was subject to such an ownership change in 2007 when it was swept up into leveraged acquisition of TXU.[30] As part of that deal — and at the urging of municipal groups and others — the PUC ordered the creation of a legal "ring fence" around Oncor that is meant to insulate the utility from any potential financial distress of its new parent company. Ratepayer organizations, municipal coalitions and other interested parties insisted on this extra level of protection out of concern regarding the massive debt employed in the buyout.[31]

In utility world parlance, a "ring fence" typically refers to financial and legal covenants that are intended to insulate consumers of essential services (such as gas, electric or water utility service) from the financial losses of a utility parent company that operates in the open market.

Some of Oncor's ring-fencing provisions include:

- Oncor's sale of a 19.75% equity interest to a separate entity.
- Maintenance by Oncor of separate books and records.
- A requirement that Oncor's board of directors be comprised of a majority of independent directors.
- Prohibitions against Oncor providing credit support to, or receiving credit support from, its open-market affiliates.
- Prohibitions against Oncor employing its assets to satisfy the debt or contractual obligations of free-market affiliates.

Year: 2008 ERCOT's Over-Budget and Behind-Schedule Market Overhaul

Research released in 2008 found that deregulated market structures in Texas and elsewhere had failed to produce lower prices. A study[1] released that September by the Technology Policy Institute, an independent Washington-based economics think tank, reviewed wholesale energy prices in ERCOT and other states that operate similar regional transmission organizations, or RTOs. These RTOs are an intrinsic feature of deregulated electricity markets.

The study demonstrated that almost without exception, wholesale electricity prices in states with RTOs had increased more steeply than in markets without them. The researchers confirmed that differences in fuel costs and start-up challenges in newly deregulated markets could not explain the differences. Many deregulation proponents had pointed to both factors as possible explanations for higher prices in deregulated markets relative to regulated ones. "Our results show that RTO membership is consistently related to higher average wholesale electricity prices," the authors determined. "With the exception of (New England), RTOs have failed to deliver lower wholesale electricity prices."

…the research shows that even by this measure, deregulation is missing the mark in Texas. The study reported that there were 58 electricity wholesalers in 1999, but only 46 in 2006.

Moreover, the authors found that the move to RTO-based retail competition had led to less wholesale competition, not more. Many proponents of deregulation have pointed to an increase in market competitors as evidence of success. But the research showed that even by this measure, deregulation was missing the mark. In Texas, for instance, the study reported there were 58 electricity wholesalers in 1999, but only 46 in 2006.

"There appears to be much more work still to do before the promise of competition is realized in areas that currently have organized wholesale markets," the authors concluded. "Regulators in regions still served by traditional markets would do well to wait for the results of these efforts to be evaluated before moving to develop and implement new RTOs."

PRICES SPIKES CONTINUE DURING TIMES OF SYSTEM STRESS

And as if to confirm those findings, wholesale prices in ERCOT spiked to unprecedented levels in 2008. Generation companies were prohibited by PUC rules from offering to sell their power into the spot market at prices above $2,250 per megawatt-hour. But on several occasions prices in the spot market hit that cap and even exceeded it. According to reports, the balancing energy price topped $3,800 per megawatt-hour in the Houston area on April 25th, and $3,460 and $4,233 in Houston and South Texas respectively on May 23rd.[2]

That spot market electricity was selling for such astronomical high prices (this is electricity that generally sells for less than $100 per megawatt-hour) was due to a quirk in ERCOT's pricing rules. Although generation companies could not *offer* their electricity for more than the 2008 cap of $2,250 per megawatt hour, they were not prohibited from *accepting* more per megawatt hour. And under certain circumstances ERCOT's market rules produced such above-the-offer-cap prices.[3]

ERCOT blamed several days of high temperatures and the loss of a number of plants and power lines, which were down for maintenance. "All of these factors contributed to higher wholesale prices during the spring," the PUC reported in its 2009 Scope of Competition Report.[4] And while isolated to a relatively small portion of the market, such dramatic price spikes do not occur without repercussions. In 2008 they contributed to failures of five retail electric providers, and, as a result, thousands of Texans served by those retailers ended up getting dumped to high-cost Provider Of Last Resort service.[5] Customers harmed in this way had taken action recommended by members of the Texas Public Utility Commission and deregulation proponents: they

The GE Study

Under the Competitive Renewable Energy Zone (CREZ) process, the Texas Public Utility Commission delineated various geographical regions for multi-billion dollar transmission construction to support wind generation. As part of the CREZ process, ERCOT hired General Electric to conduct a cost-benefit and reliability analysis to determine the amount of transmission to build. The GE study was largely glowing, with the company claiming that system reliability would not suffer with the addition of another 15,000 megawatts of wind power. GE said the new wind generation would reduce market prices.[51] Those supporting the transmission build-out cited the report often. But the study had various problems. For instance, the company did not account for the extra payments that would have to be made to gas generators that must stand ready to provide back-up power when the wind stops blowing.[52] GE also declined to release key background data and assumptions used in its computer models.[53]

Another point lost on many was that GE, as the nation's largest manufacturer of wind turbines, had a very large financial stake in Texas going forward with the Competitive Renewable Energy Zone process. This is because GE had entered into contracts with wind developers doing business in Texas, including T. Boone Pickens, whose Mesa Power had ordered 667 turbines from the company at a cost of $2 billion.[54] GE also had a $300 million equity investment in Horizon Wind Energy, a leading proponent of one of the CREZ transmission scenarios considered by the PUC.[55] For more about wind power, see Appendix F.

had shopped around in the open market and selected a competitive electric provider. But as a consequence of getting forced onto provider-of-last-resort service, many reported a doubling of the prices on their bills.[6]

Former state Rep. Steve Wolens, one of the co-authors of Senate Bill 7, was among those getting service from a competitive electric provider that failed in 2008. Mr. Wolens said he checked with the PUC after his company closed and was told not to pay his last bill. He ended up getting turned over to a collection agency.

Given his role in creating the restructured market, Wolens said: "It serves me right. I'm getting my just desserts."[7]

The Texas Public Utility Commission held emergency meetings in which they called for changes in market rules and more customer protections relating to Provider Of Last Resort service.[8] The proposed changes included requirements for higher capitalization standards for Retail Electric Providers and additional security for customer deposits to prevent their loss in the case of a company default.[9]

Reliant Energy, one of the state's largest electric retailers, also announced in October 2008 that it was looking for a buyer.[10] The company was soon acquired by NRG, an independent power producer with major holdings in the Houston area.[11]

MARKET "WATCHDOG" REPORTS PRICES ARE TOO LOW

Despite the clamor about high bills, a key regulatory advisor explicitly called for new rules that would not result in lower prices, but higher ones.[12]

In a report from August, the consultant hired to serve as the Independent Market Monitor recommended the use of mechanisms that would artificially increase wholesale prices. "More reliable and efficient shortage pricing could be achieved by establishing pricing rules that automatically produce scarcity level prices when defined shortage conditions exist on the system," he stated in the report.[13] In other words, the consultant called for new rules that would create wholesale price spikes.

The consultant, Potomac Economics of Delaware, was hired at the behest of the Texas Legislature in 2005 as an independent market watchdog.[14] The consultant's findings carry considerable weight with ERCOT and especially with the Texas Public Utility Commission, where commissioners have echoed many of the same concerns.

This proposal for higher prices was in no way an anomaly for Potomac. In annual reports for both 2007 and 2008,[15] Potomac concluded that without higher prices — and especially without higher prices during periods when power supplies run short — generators won't make enough money to invest in new construction.

The market monitor likewise concluded that the reason there aren't more spikes is because there's already too much generation. That is, the market monitor asserted that generation reserves were too high, which puts downward pressure on prices, which prevents companies from making enough money to build more generation. He said that the market needs to support the creation of more generation, but it can't because it already has too much generation.

In a report from August, the consultant hired to serve as the Independent Market Monitor recommended changes that would artificially increase wholesale prices.

The ERCOT "watchdog" did not express concern that price spikes of 2,000 percent that occurred in March of 2008 caused harm to consumers, but rather concern that there were not similar price spikes during an earlier period of scarcity.

The cap on wholesale prices in ERCOT's balancing energy market stood then at $2,250 per megawatt-hour, which was already more than twice the level of similar caps in other states and represented a price more than 20 times greater than typical energy prices. Generators had received that much for their power on numerous occasions, and stood to receive even more when the cap eventually went to $3,000 in 2011.[16]

MARKET ABUSE?

In November, Luminant — formerly TXU — agreed to pay a $15 million penalty for alleged abuses in the wholesale market.[17] While the $15 million penalty is one of the largest paid by a generator, the PUC had originally recommended penalties of more than $200 million. The PUC's own investigation found evidence that the company had profited by nearly $20 million through its improper activities and that the company's actions had cost the market at least $57 million.[18]

"Settling for pennies on the dollar just reinforces the belief that the PUC is unwilling or unable to stand up to electric companies," said Tim Morstad, a policy analyst for the AARP.[19]

THE NODAL MARKET: OVER PROMISED, OVER BUDGET AND BEHIND SCHEDULE

PUC commissioners and some industry representatives said an ambitious overhaul of the wholesale market would cure many of the problems. Supporters said the new market design —known as a "nodal" or "marginal locational pricing" market (see pages 53-54) — would reduce or eliminate gaming opportunities and produce incentives to build generation where it is needed most.

The PUC initially authorized nodal in 2003,[20] and expected to have it operational by the fall of 2006.[21] But that deadline came and went. The next deadline for the end of 2008 was also abandoned. Then, on the day before Thanksgiving, ERCOT announced that the project wouldn't be ready until at least the end of 2010, and estimated its cost at a whopping $660 million.[22] That was more than double the size of ERCOT's last estimate and far in excess of initial cost estimates for ERCOT of less than $100 million.[23]

"It's exceptionally disturbing," said Rep. Phil King, R-Weatherford, chairman of the House Regulated Industries Committee. "I don't want to see us strap $660 million on Texas consumers unless the savings exceed that."[24]

The new system is supposed to make the market more efficient by changing the assignment of wholesale costs associated with line congestion. That is, when complete, customers in the zones with the most congestion (where the demand for power outstrips the supply of available transmission lines) likely will end up paying more than they would under the old system.

...wind power is so unstable that ERCOT would only factor in only 9 percent of total available wind capacity when determining available power during summer peak hours.

A cost-benefit analysis commissioned by the PUC found that consumers would save $5.6 billion in wholesale power costs during the first 10 years of the nodal system. The Boston-based consulting firm, CRA International, said those savings did not reflect a system-wide benefit, but rather a "transfer of wealth" from generators to consumers. Generators have been among the greatest advocates of the market overhaul.[25]

A separate report commissioned by a coalition of West Texas and North Texas cities found that incorrect and speculative assumptions in the CRA report led to a massive over-estimation of benefits for consumers. The cities found that flaws in the CRA report were so pervasive as to call into question its conclusion that the nodal market would benefit consumers.[26]

Also a report by the American Public Power Association (APPA) found that proponents had oversold the benefits of nodal, and that similar markets elsewhere had not worked particularly well in practice. The APPA noted, for instance, that customers living in the Northeast had not realized any cost savings from a nodal system there. It also noted that implementing such a system does not guarantee competitive markets or prevent market abuse. Nor does a nodal market provide incentives for investment in some areas with the most overburdened power lines.[27] (For more about the nodal project, see pages 53-54.)

SYSTEM RELIABILITY AND WIND POWER

On February 26, 2008, ERCOT officials took emergency action to avoid blackouts. A sudden loss in wind power, coupled with other factors, sent grid operators scrambling.

"This situation means that there is a heightened risk of … regular customers being dropped through rotating outages, but that would occur only if further contingencies occur, and only as a last resort to avoid the risk of a complete blackout," the state's command center for disasters stated in an e-mail notice to municipalities.[28]

It was a serious emergency for ERCOT, and one that illustrated the inherent challenges associated with wind power. Kent Saathoff, ERCOT's vice president for system operations, said because wind doesn't give advance notice before it stops blowing, grid engineers must remain nimble enough to respond quickly with replacement power.[29] Otherwise, blacouts occur.

That fickle nature of wind also means the state cannot forego building other sorts of generators — more polluting ones — to provide replacement power. Those generators have to remain on standby and ready to ramp up quickly. That's an extra expense to the system. In fact, wind power is so unstable that ERCOT factor in less than 9 percent of total available wind capacity when determining available power during summer peak hours.[30]

In its 2009 Scope of Competition report, the PUC suggested that wind generation has suppressed electric wholesale and retail prices. As evidence, it cited findings by the Independent Market Monitor that correlated wholesale prices on the one hand, and wind production, system load and fuel prices on the other.[31]

The monitor said that for each additional 1,000 megawatts of wind power produced, the clearing price in the balancing energy market fell by $2.38.[32]

However, that analysis didn't appear to tell the whole story. For instance, the calculation of balancing energy savings did not account for the multi-billion dollar expense of building new transmission.[33] Neither did it account for the increased cost of purchasing additional backup capacity, known in ERCOT as "ancillary services." ERCOT also has found separately that wind is one of the most expensive forms of power commonly used in Texas, with each megawatt of power costing $53 to generate.[34] And if one figures in the increased cost of purchasing additional backup capacity (known in ERCOT as "ancillary services) and other factors, then the cost of wind power goes to $70-$90 per megawatt hour — even after factoring in federal subsidies.[35]

In fact, for every $100 million of investment, wind-power developers receive more than $74 million in federal tax credits and other benefits, according to a study from the University of North Texas. Wind developers also receive corporate income tax breaks from the state and property tax abatements from local governments.[36]

The Houston Chronicle's Loren Steffy, in an analysis from July 2008, called wind power "an open trough of government subsidies, tax credits and state mandates." He described government and captive ratepayer sponsorship of wind in Texas "a massive corporate welfare effort that means big money for the wind-power developers and big costs for the rest of us."[37]

CREZ ZONES

The wind industry has grown exponentially in Texas. By 2008, Texas had 6,000 megawatts of installed generation capacity — an amount far exceeding that then existing in most other states, and even many nations.[38]

Texas was also planning through its Competitive Renewable Energy Zone process to construct enough new transmission lines to West Texas and the Panhandle for nearly 18,500 megawatts of additional wind generation. The PUC estimated the cost of building those lines at $4.9 billion[39] — a rather startling figure considering that all investment in ERCOT transmission since 1999 was only $3.9 billion.[40]

And while West Texans and residents of the Panhandle could clearly reap the benefits of economic development from that construction, ratepayers statewide would foot the bill. By some estimates, the new construction would cost typical Texas residents around $50 per year.[41] The Commission expected the new lines in service within four to five years. (For more about the CREZ transmission lines and wind power in Texas, see Appendix F.)

PROVIDERS AND PRICES

By July 2008 about 44 percent of Texans had switched to electric service other than that offered by the old legacy providers like TXU.[42] By comparison, only 14.3 percent of New Yorkers had switched in that state by the end of 2007.[43] "Though retail competition exists in a number of other states, including New York, Michigan, Illinois and several New England states, few REPs have attempted to compete for residential customers in those states and few residential customers have switched or changed providers," the PUC reported in its 2009 Scope of Competition Report.[44]

The same report noted that as of September 29, a customer visiting the state's PowerToChoose would find as many as 27 competitive retail electric providers in areas of Texas with deregulated retail electricity markets. It noted that these REPs offered 96 different plans in those various territories — including 23 different renewable energy options.[45]

The PUC said that this large number of competitors is an important indicator of success for the state's deregulated system. "The number of REPs has increased steadily since 2002," the report stated. "Residential customers have at least 50 percent more options than they did at the end of 2006."[46]

That switching activity, however, had not translated into lower prices. A survey by the Texas Coalition of Cities For Utility Issues in 2008 found that north Texans could shop around all they like — that is, they could switch to the very best deal in their area — and still not find more affordable electricity than that offered by municipally-owned utilities, cooperatives and Texas investor-owned utilities outside competition.[47]

The report considered all the best competitive offers in North Texas, and compared those prices to electric providers outside deregulation. The seven lowest rates in the survey were offered by providers outside competition. The average of typical monthly bills under competition was higher than the bill averages for customers in municipally-owned utilities, cooperatives and investor-owned utilities outside competition.

Noted the report: "Clearly, nothing about a deregulated system inherently drives prices lower than a non-competitive system. Otherwise, one might expect most — if not all — of the ten lowest rates in the survey to be offered by competitive REPs."[48]

POWER AGGREGATION

In 2008 a group of six West Texas cities located in deregulated areas of the state tried and failed to use a bulk purchasing strategy in order to lower rates for their constituents.

The strategy, known as opt-in aggregation, is explicitly authorized by Senate Bill 7. However, as the cities of Cisco, Comanche, Dublin, Eastland, Hamilton and Snyder discovered in 2008, the aggregation provision in the law doesn't work particularly well in practice.

The cities managed to sign up 1,600 households during an extensive outreach program and then attempted to negotiate a bulk rate power deal on their behalf. But citing the relatively small number of customers, electric providers either decided not to participate or would not offer prices lower than those already advertised on a website operated by the Texas Public Utility Commission.

Organizers of the bulk rate effort concluded that they would have been more successful using another bulk rate purchasing strategy, known as opt-out aggregation. However, opt-out aggregation is not permitted under Senate Bill 7 (see Appendix A).[50]

Opt-Out Aggregation

Many experts – including those at the Texas Public Utility Commission – report that consumers have saved money in states that permit a purchasing strategy known as "opt-out aggregation."[56] But while an unambiguous success in other deregulated markets, opt-out aggregation is not available to consumers in Texas.

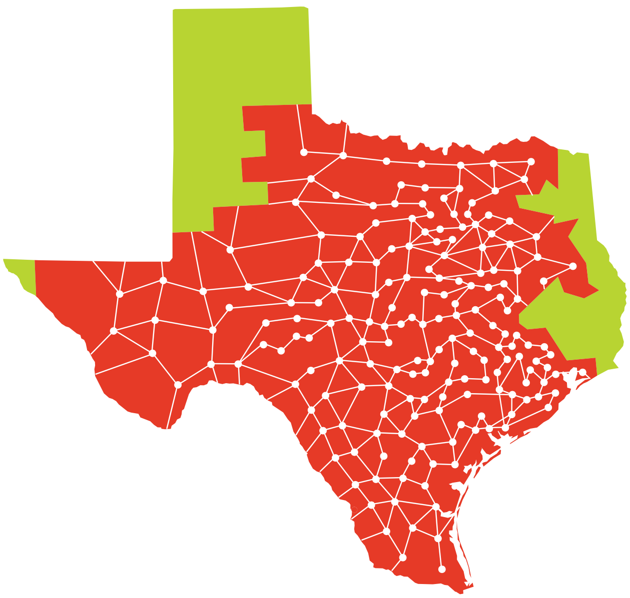
What is opt-out aggregation? In the simplest terms, it is a method that cities, counties or other political subdivisions deploy to purchase affordable power, in bulk, on behalf of their constituents. Under typical opt-out programs, the city council authorizes the aggregation of the residents' power needs through a public hearing and vote. Once approved, the political subdivision then mails notices to ratepayers advising them of the new energy aggregation program. Citizens who do not wish to participate in the program can check a box on the advisory and send it back, or can contact program organizers via the Internet or telephone. Those ratepayers who choose to participate need not take any further action at all. If the ratepayer doesn't respond within a given timeframe, it is assumed they want to participate and the political subdivision will negotiate a bulk-rate electricity deal on their behalf.

This is in contrast to opt-in aggregation, which is explicitly authorized by Senate Bill 7. Under opt-in aggregation, citizens must affirmatively sign up for service before their political subdivision will begin negotiations on their behalf. But opt-in aggregation creates an untenable conflict because large numbers of customers typically won't sign up for service unless they know how much money they will save, and retail electric providers won't offer substantial savings unless they have a reliable estimate of customers and the power to serve them.

A group of six West Texas cities tried and failed to use opt-in aggregation in 2007 and 2008. About 1,600 households in the cities of Cisco, Comanche, Dublin, Eastland, Hamilton and Snyder (in largely rural West Texas) agreed to participate after being contacted by their cities' representatives through a long, extensive and costly outreach program.[57] Most of the residents had never before negotiated electric contracts and many expressed enthusiasm about the sense of empowerment they received from the program. Their city representatives then attempted to negotiate a bulk rate deal. But competitive electric providers — some noting the relatively small number of residential participants — either declined to submit bids to serve them or would not beat the lowest prices already advertised on a website operated by the Texas Public Utility Commission.[58]

A study by the National Center for Appropriate Technology describes opt-out aggregation programs in states other than Texas as one of the few bright spots for consumers under electric deregulation.[59] In Ohio and Massachusetts, opt-out aggregation programs clearly led to lower prices, the study concluded.[60] The Texas Public Utility Commission likewise has acknowledged the success of opt-out aggregation programs and has suggested the creation of an opt-out aggregation in Texas as a way of enhancing the competitive market.[61] However, proposals to allow opt-out aggregation programs in Texas have been rejected by the state legislature.

What is Nodal?



Power lines can handle only so much electricity without overheating. This can become a problem when lines get congested, that is — when there is too much power and too few power lines. Under the system in place in 2008, ERCOT managed congestion by paying generators to ramp up or ramp down production during peak energy-use periods. ERCOT then determined the extra cost for this congestion management, and assigned the expense to those entities that purchase electricity in the wholesale market. However, the prices paid for congestion management were not assessed in a uniform fashion across the state, but rather varied by large areas within the state, known as zones.

This differed from a nodal market, which assigns costs in a more granular fashion. ERCOT and the Texas Public Utility Commission decided to replace the old zonal market with a nodal structure in the theory that it would reduce the overall cost of grid operations. Under nodal, ERCOT has the ability to charge entities responsible for "creating" congestion — that is, those that demanded more power than can be supplied over transmission lines in their area — and then re-allocate the money it collects to generators that relieve the congestion. This means that the new nodal market is designed to increase revenues to some market participants, like certain generators, while increasing costs to some entities that buy power.

Using a bank of computers and complicated software, the new system spits out rapid-fire calculations for electricity prices. The computers calculate these prices at thousands of points on the transmission grid, or "nodes", where power is either added or removed by wholesalers or users. The computerized nodal system also gives ERCOT the ability to model electricity demand and the ability to manage a trading system similar to those operated by eBay, which, in theory, will improve ERCOT's energy-management system to help guard against outages. It is claimed that the new technical systems also will improve ERCOT's ability to collect and aggregate technical data, which can help the organization guard against market abuses.

QUESTIONS REMAIN

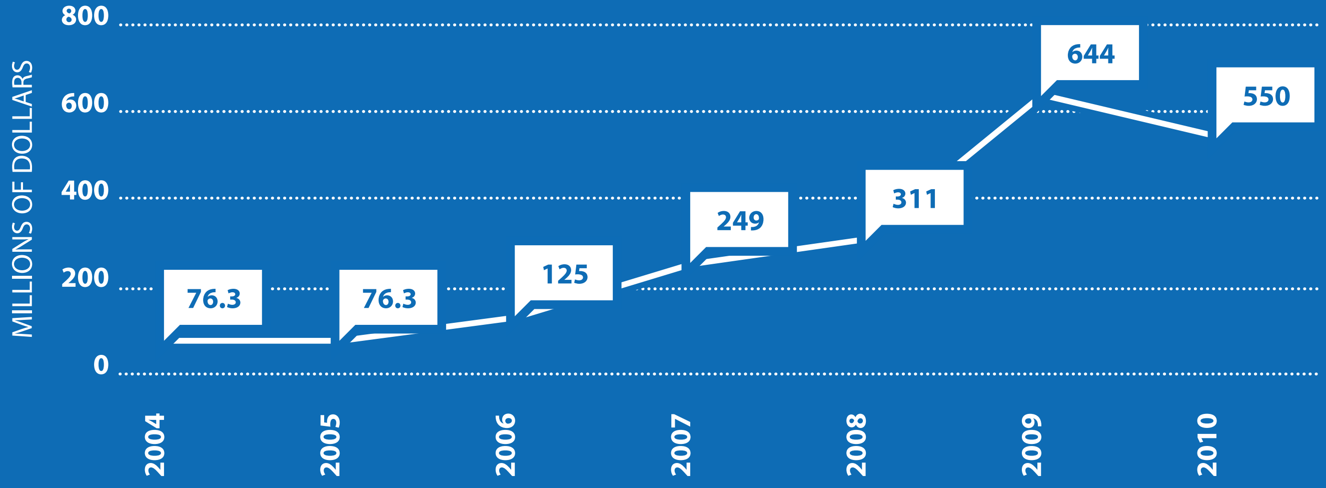
However, the PUC and ERCOT could have ordered many of the improvements now associated with the new nodal system without ever having gone forward with it. For instance, there is nothing "inherently nodal" with collecting and aggregating technical data. Also, the entire nodal system was proposed as a way of reducing congestion costs, but ERCOT's independent market monitor reported that congestion costs had already come down — from a high of about $275 million in 2004 to $186 million in 2008. This was probably the consequence of new strategies ERCOT employed for dealing with overburdened lines, and with the construction of new lines by utilities — not from a new-fangled nodal system.

And no one ever suggested that the nodal system will completely eliminate congestion costs.

Given the stunning expense and budget overruns, some questioned whether nodal was worth the trouble. The project once projected to cost less than $76.3 million ended up costing more than $500 million.

Nodal Project Final Costs Exceed Original Estimates By More Than 600 Percent

Source: ERCOT, "Nodal Timeline and Budget History," January 2011; Tabors, Caramanis, & Associates and KEMA Consulting, "Market Restructuring Cost-Benefit Analysis: Final Report," November 30th, 2004



An initial analysis commissioned by the Texas Public Utility Commission put the cost to ERCOT of transitioning from a zonal market to a nodal market at between $59.7 million and $76.3 million. The cost estimate eventually increased to $311 million, and by 2010 grew to $550 million.

Year: 2009 The 81st Texas Legislature

Residential electricity prices in Texas were down in 2009 compared to the previous year. Although this was good news for consumers, a look behind the numbers showed that the market was underperforming.[1] Consider, for example, the difference in average prices for Texans living inside and outside deregulated areas. Residential electricity prices dropped by 3.1 percent between 2008 and 2009 for Texans inside deregulated areas of the state, but dropped more than twice that much for customers in areas outside deregulation.[2] The declines in both areas were largely related to drops in the price of natural gas, which fuel many power plants in Texas. The regulated areas of Texas responded much more nimbly than the deregulated areas because of regulatory mandates that require fuel costs to be passed through to ratepayers, while retail electric providers in deregulated areas mark up their energy purchases from wholesale suppliers.

. . . the research shows that even by this measure, deregulation is missing the mark in Texas. The study reported that there were 58 electricity wholesalers in 1999, but only 46 in 2006.

Also, despite the short-term pricing drops, Texans in 2009 under deregulation continued paying more than the national average for electricity.[3] This disparity was in contrast to a long history of below-national-average prices before the adoption of the retail deregulation law, and in contrast to the below-average rates paid by Texans who resided in areas exempted from deregulation. These disparities were evidence that the market switch-over had yet to meaningfully benefit consumers. A survey of 21 major U.S. cities released in early 2009 also revealed that residents of Houston and Dallas were getting stuck with some of the highest electric bills in the nation. The survey found that summertime electricity bills in Houston and Dallas even exceeded those in scorching hot Las Vegas and Phoenix and surpassed those in northern cities like New York and Chicago during the winter months.[4]

THE TEXAS LEGISLATURE CONVENES

Lawmakers in 2009 convened for the 81st regular session of the Texas Legislature, the fifth since the state adopted Senate Bill 7 and the third since the opening of the restructured market. Electric prices in Texas had for the most

Electricity $488 more expensive in 2009 for Texans under deregulated system*

**Analysis compares average prices in areas of Texas inside and outside deregulation, and assumes 1,300 kw/h monthly usage.*

Source: US EIA, http://www.eia.gov/cneaf/electricity/p

Cents / KW/H

14.1

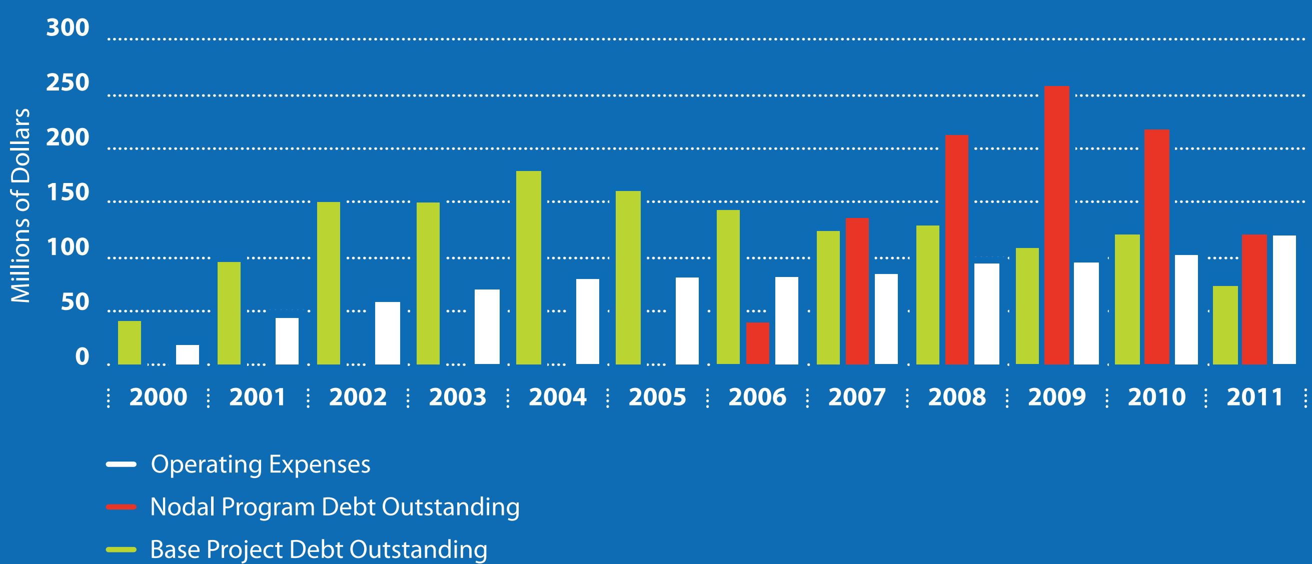
Average Price from Deregulted Retail Electric Providers

Average Price from Provider Exempt from Deregulation

10.1

Growth of ERCOT Debt and Operating Expenses

Source: ERCOT



Much of the debt incurred by ERCOT since 2006 is the result of the nodal project, which consistently ran over budget. The organization's overall outstanding debt has declined in recent years. ERCOT's operating expenses have gone up. For more about ERCOT, see Appendix E.

part increased during the intervening years, and problems continued relating to electric restructuring in general. But the legislature had declined to make significant changes in the market's structure. There was some indication that the 81st session would prove to be different — especially after lawmakers began promoting reform bills such as those to encourage competition by generators and those that would give the PUC greater authority to assess fines in market manipulation cases.[5] Some of the pro-consumer bills were pegged to an AARP study showing that with more market transparency, Texas electric consumers could potentially save nearly $1 billion annually — or more than $50 per year for the average household.[6] There were also bills that would have required a top-to-bottom review of ERCOT's operations and management, and to overhaul its board structure. Other promising pieces of legislation included House Bill 2781, by state Rep. Jim Keffer, and SB 1481, also by Sen. Wendy Davis. HB 2781 would have ended ERCOT's efforts to implement a dubious wholesale electricity pricing system, known as the nodal project.[7] The project was over-budget and behind schedule. Senate Bill 1481 would have facilitated the use of bulk electricity purchasing by cities on behalf of their citizens in order to help reduce their energy bills.[8]

But unfortunately, it would not be these bills that would win the day,[9] but rather Senate Bill 769, which would tend to increase energy bills. Under SB 769, utilities were granted authority to more quickly add extra charges onto home bills to help defray costs associated with disastrous weather. Regulated transmission utilities could obtain these rate hikes without the full scrutiny of a traditional rate case.[10] That is, SB 769 partially deregulated the monopoly part of the energy business in Texas. Houston's CenterPoint Energy was a leading proponent of SB 769, and a day after the bill became law, the company filed a request at the PUC for a nearly $678 million rate hike.[11]

One of the few bright spots for consumers was Senate Bill 2. This was not an energy bill per se, but rather a bill related to the legislative Sunset Advisory Commission that oversees the effectiveness of government agencies. An amendment added to SB 2 required ERCOT to come under special review by the Sunset Commission in 2010, and the conclusions of that review would then form the basis of ERCOT-related legislation in 2011.[12] Lawmakers in 2009 also adopted House Bill 1783, by state Rep. Burt Solomons, requiring ERCOT to broadcast its board meetings on the Internet[13]; and House Bill 1799, by state Rep. Dwayne Bohac, requiring retail electric providers to include on each residential customer's bill a statement directing the consumer to the powertochoose website , where they can find information regarding electric service options.[14]

THE NODAL PROJECT

The PUC in 2009 authorized another request from ERCOT to spend even more money on the nodal project. The new price tag: $644 million,[15] or about eight times the original cost estimate.[16] The new spending plan also included $58.6 million for "discretionary" spending and $77.7 million for financing costs.[17] Just the discretionary spending and financing costs alone were close to equaling the original cost estimate in 2004 for the entire nodal project.[18] The cost overruns may have contributed to a decision by ERCOT CEO Bob Kahn to quit the job. Kahn announced his resignation in September 2009 after two years in charge of the organization. The CEO had been heavily criticized by key lawmakers, including members of the Senate Business and Commerce Committee.[19] He was ERCOT's fourth CEO since 2000.

TEXAS SURPASSES ENERGY RECORDS

Texas energy consumption continued to increase during 2009, with the state hitting new records of 62,786 megawatts on July 8 and 63,400 megawatts on July 13.[20] As a result of the high summertime use of air conditioning and the unexpected outages of power plants, ERCOT declared an emergency alert on July 8 in which they called upon Texans to conserve energy.[21] Wholesale electricity spot market prices shot up July 8 to $500 per megawatt-hour.[22] This was far above the then-prevailing spot market prices and more than 50 times higher than the lowest retail electric rates at the time.

Texas surpassed another record on the evening of October 28, 2009. At precisely 8:19 p.m. Texas wind generators hit the 6,223-megawatt mark, which was the most wind power ever produced and successfully absorbed by the ERCOT grid. Wind power accounted for about 17.5 percent of all energy flowing across the grid at that time.[23] Earlier in the evening, wind power had accounted for an even greater proportion of total load — about 25 percent.[24]

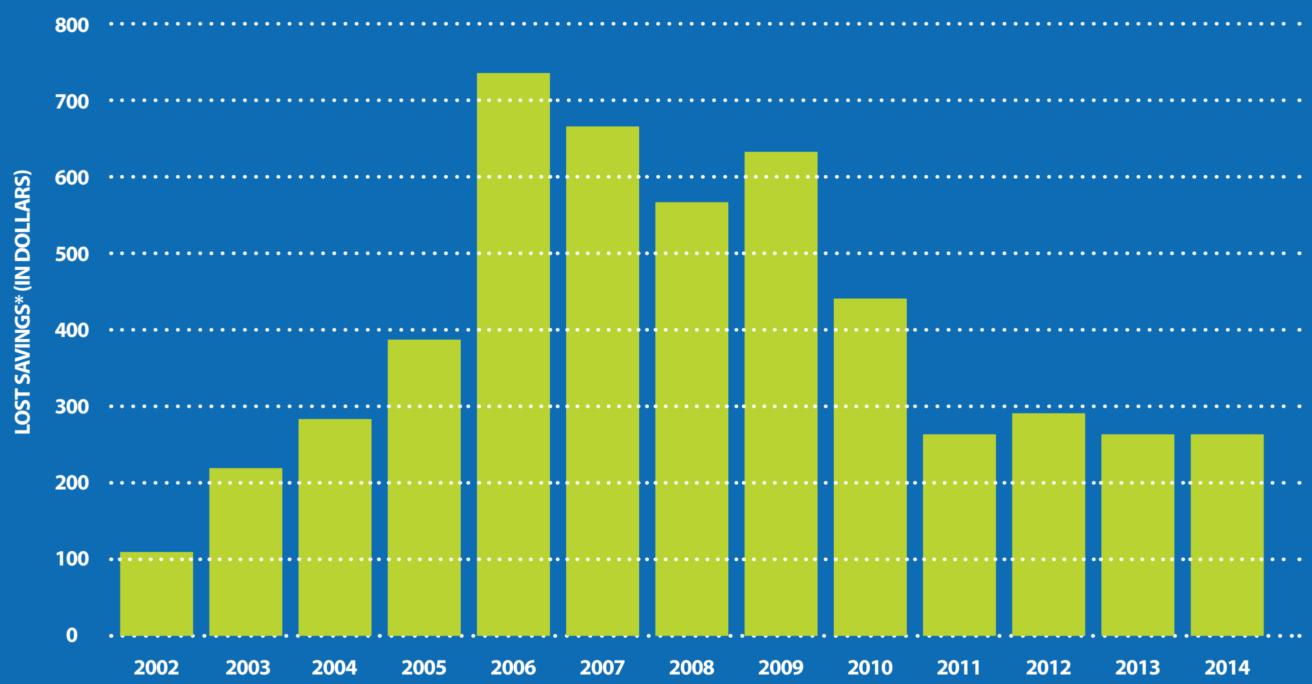
WIND GENERATION CHALLENGES

The increased development of wind power in the Lone Star State attracted the attention of Federal Energy Regulatory Commission (FERC) Chairman Jon Wellinghoff, who said policymakers should consider linking the ERCOT grid to other states. "If Texas could be more strongly interconnected to the Midwest, for example, they could integrate even more wind into the system," said Wellinghoff. The ERCOT power grid is wholly located within the boundaries of Texas and has very limited connections with outside grids, which makes it free from most federal oversight. Wellinghoff said that he understood the concern of many Texas policymakers that more connections could lead to federal control of ERCOT, but he insisted that such a takeover was not FERC's intention.[25]

Also in 2009, Texas billionaire oilman T. Boone Pickens announced his intention to scale back his much publicized plans to build the world's largest wind farm in Texas. Part of the problem was the drop in natural gas prices, he said. In an interview with the *Dallas Morning News*, Pickens said that he had already ordered an initial round of wind turbines (from his plan to purchase nearly 700 from GE), and that officials with his Mesa Energy were considering locating them in various sites in addition to Texas — including Wisconsin, Oklahoma and Kansas.[26]

*More than $5,100 in Lost Savings**

Source: United States Energy Information Administration — http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls



This exhibit compares electricity costs for a typical customer paying average rates charged by deregulated retail electric providers in Texas, to costs for a customer with the same usage but paying average rates charged by Texas providers exempt from deregulation.

**For purposes of comparison, this exhibit assumes monthly electricity usage of 1,300 kWh.*

Year: 2010 Nodal Project Goes Live

WHOLESALE ENERGY PRICES

According to data collected by the federal government, residential customers in Texas paid, on average, 11 percent less for electricity than they paid in 2008.[1] The decline corresponded to a similar drop in the price of natural gas, which fuels many of the state's power plants. Overall, residential prices remained at about the same level as the national average in 2010.[2] This was a welcome change from nearly a decade of prices above the national average since the implementation of deregulation.

But it also became clear in 2010 that the state's largest electric provider depended upon these higher rates for its financial well-being. Energy Future Holdings had taken on a massive amount of debt in 2007 to acquire TXU Corp., the state's largest electric company, and the lower wholesale electricity prices were making it difficult to pay off that debt. In August, after EFH finalized plans to pay some lenders between 72 cents and 79 cents on the dollar, the company suffered a downgrade from all three debt-rating agencies.[3] In October, the company's debt was downgraded again. "EFH is likely to remain in financial distress," wrote analyst Jim Hempstead, on behalf of Moody's Investors Services.[4]

And while electricity prices may have declined over the short term, they were nonetheless up more than 50 percent since the adoption of the retail deregulation law.[5] Between 1999 (the year that Texas lawmakers adopted the deregulation law) and about the midway point of 2010, the percentage increase in electricity prices in Texas had outpaced increases in all but eight states. Electricity price increases also outpaced those in most other deregulated states. Electricity prices in Texas remained higher than prices in neighboring states, including those relying heavily upon natural gas to fuel generating plants.[6]

These higher prices meant that Texans had less to spend on other priorities. An analysis of federal data showed that Texas residential consumers could have saved more than $11 billion through 2010 had their electric prices remained more consistent with pre-deregulation levels. When higher electricity prices paid by commercial and industrial customers were factored in, the lost savings amounted to $16.4 billion.[7]

PUC's "Guard Rails"

New "guard rails" ordered by the PUC capped wholesale spot energy prices during the first 45 days of the new nodal market. These "guard rails" limited offers in this energy market to $185 per megawatt/hour, or a multiplier related to the price of natural gas. The temporary guard rails were largely favored by market participants, many of whom recalled the punishing price spikes of 2001 and 2002 during the initial transition to deregulation. Even greater price spikes in 2008 drove five retail electric providers into bankruptcy.

Upon the expiration of the guard rails in early 2011, a new $3,000 per megawatt/hour offer cap would come into place. Although intended to protect against price gouging, this new cap nonetheless allowed electric companies to seek prices about 60 times higher than those typically paid in the market. The cap also was three times higher than those in other states.

ERCOT

A consultant's report in June 2010 found evidence of "poor corporate governance, leadership and culture" at ERCOT, the organization that operates the Texas power grid.[8] Citing the "overall below-average quality of people" employed there, the consultants recommended 166 staff cuts, or about 24 percent of the organization's personnel.[9] Shortly afterwards ERCOT eliminated 37 positions, reductions that ERCOT President Trip Doggett said were part of the expected transition to the nodal market. The layoffs were fewer than those recommended by the consultants, but still amounted to about 5.5 percent of the organization's workforce.[10]

In a separate report released in April, staffers for a key legislative committee concluded that ERCOT lacked sufficient financial oversight.[11] Issued on behalf of the Sunset

Advisory Commission, the report noted that ERCOT's debt had ballooned from $40 million in 2000 to more than $360 million in 2009. It also questioned the wisdom of ERCOT's borrowing, citing specifically some of ERCOT's older debt that required a 14-year payout even though the underlying assets were in use for only three to five years. The Sunset staff recommended that ERCOT's annual budgets and borrowing become subject to PUC approval, and that ERCOT remove self-interested industry representatives from its board of directors. Some of these recommendations would become the subject of proposed legislation in 2011.

NODAL PROJECT STATUS

ERCOT certified late in 2010 that the nodal system was finally ready to go live.[12] (For an explanation of nodal, see pages 53-54.) ERCOT's engineers had conducted months of technical trials, including one lasting 168 hours. Although they continued to identify problems, the engineers determined none were significant enough to prevent easing forward with a partial "soft launch" on November 15, and then going completely live with the nodal systems on December 1.[13] The final price tag remained a source of displeasure for many. Including interest, the nodal project would end up costing Texas electricity customers nearly $548.6 million[14] — or more than five times more than original[15] estimates. The project was years behind schedule. "There were times, two and three years ago, when I did not think this was going to happen — and I'm still concerned about the cost," then-PUC Chairman Barry Smitherman said shortly after the launch.[16]

Anticipating glitches, ERCOT set aside an additional $25 million to make early fixes.[17] Several electricity retailers also added language to customer contracts allowing for extra nodal-related surcharges should the system go awry.[18] The PUC agreed to temporary "guard rails" in the wholesale market to guard against unintended price spikes (See sidebar on opposite page).[19] For the most part, however, the new systems became operational without incident.[20]

Average Residential Electricity Prices, 2010

AREAS OF TEXAS INSIDE AND OUTSIDE DEREGULATION*

**Providers exempt from deregulation include municipally-owned utilities, electric cooperatives and investor owned utilities outside of ERCOT.*

Source: United States Energy Information Administration

Cents / KW/H

Areas Inside Deregulation

12.8

10.0

Areas Outside Deregulation

As was the case during every year since 2002, average electricity prices in deregulated areas of the state in 2010 were higher than average electricity prices in areas of the state exempt from deregulation.

Year: 2011 The PUC Under Sunset Review

THE 82ND LEGISLATIVE SESSION

The Texas Legislature's 82nd regular session, the fifth since the deregulation of the state's retail electricity markets, convened on January 11, 2011. Although electricity prices and complaints had fallen in recent years, they nonetheless remained above pre-deregulation levels.[1] (For more about complaints, see Appendix B). Flaws in the state's wholesale energy market also remained uncorrected. Consumer groups hoped that lawmakers in 2011 would finally order reforms. The electric power industry either worked to maintain the status quo, or pushed for changes that would reduce regulatory oversight of their monopolistic transmission and distribution rates.

The single most anticipated piece of energy legislation was Senate Bill 661, which grew out of 2010 recommendations from the staff of the Sunset Advisory Commission. SB 661 included the Commission's reform proposals for the Texas Public Utility Commission, the Electric Reliability Council of Texas, and, to a lesser degree, the Office of Public Utility Counsel, which is a state agency charged with consumer oversight.[2]

If it had been adopted, SB 661 would have directed the PUC to exercise more fiscal oversight of ERCOT and would have required ERCOT to obtain approval from the PUC before borrowing money. Additionally, the legislation would have authorized the PUC to assess greater fines against electric companies that endanger grid reliability and also to issue emergency cease-and-desist orders against companies suspected of engaging in improper conduct.[3] Each of these proposed reforms were included in the Sunset staff report and were supported by consumer groups. On balance SB 661 was useful legislation — a bill that could have made some beneficial tweaks to the system. However it fell victim to an 11th-hour technical objection raised on the House floor.

Other helpful bills met similar fates. For instance, House Bill 1006 and Senate Bill 948 — legislation that would have required retail electric providers to offer a single standardized offer along with their other offers — did not even receive committee votes.[4] The companion bills were intended to simplify shopping in the deregulated electricity market, but died under a heavy industry lobbying effort. Lawmakers also rejected Senate Bill 319, which would have ensured that a special fund created under Senate Bill 7 was used for its intended purpose. The fund, financed through a charge on electricity and meant to finance bill discounts for low-income ratepayers, had been used in previous years for budget-balancing purposes.

However lawmakers did manage to adopt Senate Bill 1693, which was a top legislative priority for many within the energy lobby. SB 1693 was signed by the governor on May 28.[5] Under SB 1693, the state's transmission and distribution utilities — that is, the state's monopoly wires companies — received new authority to periodically hike rates pertaining to their distribution system without a comprehensive regulatory hearing, reversing decades of regulatory precedent. Like SB 769 from the previous legislative session, SB 1693 further benefited those electric companies that under the Texas deregulation law still retained their monopoly status. Lawmakers adopted the legislation despite warnings from consumer representatives and community leaders that it would lead to higher electric prices. "The intent of this legislation is to make it easy for electric utilities to raise rates every year with little documentation or justification," said Clifford Brown, the mayor of Corsicana.[6]

The Sunset Advisory Process in Texas

Under the Sunset process, the professional staffers assigned to the legislative Sunset Advisory Commission review state agencies, and then offer recommendations to state lawmakers. The lawmakers then vet the staff recommendations — accepting some, rejecting others — on their way to drafting legislation used to reauthorize state agencies.

There was one legislative accomplishment for consumers in 2011, and that was the passage of House Bill 2133, by state Rep. Burt Solomons. The legislation pertained to what consumer groups had come to describe as the "rip-off loophole" in the Public Utility Regulatory Act. That is, the PUC had claimed for many years that it lacked the legal authority to order restitution payments from companies found to have engaged in anti-competitive activities.[7] As a consequence, the state's largest electric company made nearly $4 million in profits in 2008 even after paying a settlement for allegedly engaging in anti-competitive behavior.[8] The PUC and Sunset staff said this loophole should be closed. Consumer groups agreed.

The bill was not perfect. For instance, the final version of HB 2133 barred city coalitions and other consumer representatives from participating in enforcement cases. It also gave electric companies a path to avoid future prosecution under certain circumstances.[9] But it was, on balance, helpful legislation and its adoption by the Texas Legislature marked a rare win for consumers. The governor signed the bill into law in June 2011.

RESERVE MARGINS

Grid operators and regulators often speak of "reserve margins," which refer to the ratio between the total potential output of electricity generation within a given system and the peak electricity usage in that system. That is, reserve margins measure the relationship between how much electricity generators theoretically can produce in a single instant, to predicted highest-case demand for electricity by consumers. Because power shortfalls can put a system at risk for blackouts — especially during extreme weather events — the reserve margin measurement is a good indicator of system reliability.

During the transition into deregulation, back in 2001, the state enjoyed the highest reserve margin in the nation. This helped to calm the anxieties of some Texas lawmakers and the public after California's market began collapsing during that state's transition to deregulation. Recall that electric price spikes and rolling outages in California had been blamed both on a flawed deregulation law and low reserve margins. But in Texas, lawmakers were assured in 2001, we had neither of these problems. "We have the highest electricity reserve margin of any region on the entire continent," said Pat Wood III, then the chairman of the PUC, in an attempt to reassure deregulation skeptics.[10]

His agency noted that Texas enjoyed excess capacity of up to 25 percent even during the hottest days of summer.[11]

But such a claim could not be made in 2011. The National Electric Reliability Corporation reported ERCOT's reserve margin ratio in 2011 at about 14 percent, which marked a nearly 40 percent decline from pre-deregulation levels and far below the national average in 2011 of around 25 percent.[12] In fact, after 10 years of deregulation the Lone Star State possessed the lowest reserve margin in the nation, according to NERC.[13]

The Texas reserve margin dwindled during 10 years of deregulation even as electricity prices increased. Was some aspect of the deregulated system contributing to this problem? Some observers seemed to think so, especially after the state suffered reliability crises during both the summer and winter of 2011. "Consumers were told (deregulation) would lower prices, but it didn't — now, it's becoming clear that even at those prices, the deregulated market can't deliver reliable power," wrote Loren Steffy, a business columnist for the *Houston Chronicle*.[14] The state's reliability challenges, wrote Steffy, exposed the "fundamental lie" of deregulation.

Dan Jones, a vice president of the consulting firm that serves as the independent monitor of the deregulated wholesale energy market, said the market was failing to produce high enough prices for certain sorts of energy. Writing in a 2011 report, Jones noted that these low prices "were insufficient to support new generation investment for any generation technology in any region of the ERCOT market."[15] His proposed solution was to create a system to encourage higher prices in the wholesale power market. That is, his prescribed cure was to create a system whereby consumers would pay more. Generation companies also recommended the creation of artificial price supports as well as the creation of a "capacity market," in which they could get paid even when their generators do not operate.[16]

Consumer groups expressed alarm, especially given that generation owners were offering no guarantees that these artificial price supports would lead to new plant construction. "This dynamic highlights a key risk to consumers: what if a mechanism is put into place to increase wholesale prices to ensure resource adequacy, but does not work?" warned one advocate for cities.[17] The proposals also raised issues of basic fairness. That is, generators pushed competition and supported it when prices were high, but eagerly sought artificial price supports when they felt the system was failing to deliver to them sufficient profits.[18] For consumers, generators were offering "a heads I win, tails you lose" vision of deregulation.

Those representing city coalitions, industrial users, and other consumer groups urged policymakers to exercise restraint when addressing these issues. While reserve margins had declined in recent years, consumers noted that they remained above safe levels. Representatives for large industrial customers likewise warned that the so-called "remedies" pushed by generation companies could lead to as much as a 93-percent increase in some wholesale energy prices. That would be bad news not just for big business customers, but for anyone who pays an electric bill. "These cost impacts are extreme and unjustified, and … will result in great harm to the market," stated the Texas Industrial Energy Consumers in a PUC proceeding.[19]

For consumers, generators were offering "a heads I win, tails you lose" vision of deregulation.

In October the PUC approved price floors for certain sorts of reserve energy that ERCOT deploys during emergency situations. But representatives for generation companies continued pressing for higher price floors and other artificial supports to further enhance their profits.[20]

DEREGULATION AND RELIABILITY

The resource adequacy issue received even more scrutiny in 2011 after a series of reliability emergencies. The first occurred in early February, when dozens of generating plants seized-up during a cold snap. At the same time usage peaked. ERCOT responded by ordering rolling blackouts and as a result, millions of Texans lost power. (For more on ERCOT, see Appendix E). All told, approximately one-third of the state's generation fleet was unavailable during the most difficult point of the crisis, according to federal officials.[21]

ERCOT also faced repeated grid emergencies in July and August, when the state broke demand records during a historic heat wave. Although ERCOT did not resort to rolling blackouts, it took other emergency action — such as disconnecting some big industrial consumers, and calling for the public to shut off appliances during peak hours. New statewide electricity usage records were set on Aug. 1st, 2nd and 3rd.

Although Luminant in North Texas claimed that it lost money during the February blackouts, the crises represented a potential profit bonanza for other generators.[22] That's because in both the summer and winter grid emergencies, prices in the wholesale electricity market shot up to a $3,000 per megawatt/hour cap[23] — or about 50-60 times higher than typical prices. Prices remained at those inflated levels for hours. That some companies were rewarded during the emergencies raised additional questions about the state's electricity market, especially given that ERCOT had been obligated to order statewide rolling blackouts twice in just five years under the system, but only once ordered similar rolling outages in its 30-plus years before deregulation.[24]

Robert McCullough, an Oregon-based economist, was among those raising questions. He noted, for instance, that the cold snap that led to the rolling outages in 2011 was not an unprecedented event. There were similar cold weather events in 1983, 1989, 2003, 2006, 2008 and 2010, but in only one of those instances — during the cold weather event of 1989 — had ERCOT resorted to rolling blackouts.[25] McCullough also questioned whether a lack of efficiency under the new nodal system played a role, noting that prices spiked to the nearly unprecedented levels shortly after the new nodal system went into effect, and only within a day of the lifting of price caps.[26]

However, a separate investigation by the state's Independent Market Monitor failed to find problems with the nodal system or any evidence of market manipulation.[27] A government organization known as the Texas Reliability Entity blamed the outages for the most part on inclement weather, although it said plant operators could have done a better job.[28] The North American Electric Reliability Corporation noted that "given the high demand and the huge loss of generation" it was not so surprising that prices hit the $3,000 per megawatt/hour cap.[29]

PRICES

Electricity prices declined in 2011, bringing some relief to Texas consumers. This continued a trend that had begun in 2009 and related to changes in the commodity cost of natural gas, which fuels many generating plants in Texas. All told, the average residential price of electricity was down a little less than 3 percent, compared to prices during the same period in 2010. Also, it appeared that annual average residential electricity prices in 2011 would dip below the national average. This is in contrast to the years of higher-than-average prices following deregulation.[30]

ERCOT Usage Records

Source: Electric Reliability Council of Texas

Aug 3, 2011
68,379 megawatts

Aug. 2, 2011
67,929 megawatts

Aug. 1, 2011
66,867 megawatts

Aug. 23, 2010
65,776 megawatts

One megawatt of power is enough electricity to power about 200 homes during hot weather.

This relief in prices only served to mask the market's relatively poor performance over the long term. For instance, data collected by the federal government revealed that the average price of electricity for residential consumers in Texas had gone up 45 percent between 2002 and 2011, but only 37 percent nationwide. Average electricity prices also remained significantly higher in Texas in 2011 than in adjoining states, even among those states with a similar reliance on natural gas.[31]

Wholesale spot electricity prices spiked to a regulatory cap of $3,000 per megawatt/hour during several intervals in September and October. These high spot market prices trickled down into the retail electricity market, which, when combined with high usage, contributed to punishingly high electric bills for many Texans. "My first reaction was there must be an error," said one Dallas resident after receiving a $1,200 bill after his rates tripled.[32] A 2011 survey by Whitefence.com, a commercial website, also found that electric bills in Houston were the second highest among 21 major cities nationwide. Dallas was ranked 6th in the survey.[33]

As of June 2012, average overall electricity prices in Texas were higher than average prices in adjoining states.

The number of complaints lodged against electric companies at the PUC fell somewhat in 2011, but remained more than three times higher than those filed on an annual basis before deregulation.[34] (See Appendix B). An industry survey also found that many Texans in 2011 remained confused about basic aspects of the deregulated market. "This demonstrates that after ten years of retail competition and deregulation, many people are unclear about the details of how the electric market in Texas works," the survey's authors concluded.[35]

STRANDED COSTS

Consumers were also hit in 2011 with additional deregulation-related costs as a consequence of important rulings by the Texas Supreme Court. Two major utilities — CenterPoint Energy serving the Greater Houston area, and American Electric Power Texas Central Company in south Texas — had asked the court to overturn earlier PUC rulings relating to the companies' requests for "stranded costs" reimbursements. The PUC had consented to more than $3.5 billion of these deregulation-related charges, but the companies wanted more. In 2011, the Texas Supreme Court awarded the utilities much of their request — and as a result, millions of Texans around Houston and elsewhere will get hit with additional charges on their home bills for at least another decade.[36]

In 1999, the PUC forecast that Texans would not be liable for more than about $5 billion in these deregulation costs.[37] It is now evident that Texans will be on the hook for more than $6.5 billion. It's also clear that if not for the hard work of city coalitions and other consumer representatives, the final tally could have been nearly $10 billion. That's because the state's largest utility in 2001 agreed to forfeit all stranded costs.[38] The value of this agreement alone might now be estimated as exceeding $4 billion. (For more on stranded costs, see Page 66).

Stranded Costs Awards in Texas

**North Texas customers of the utility formerly known as TXU owe no stranded costs thanks to a settlement negotiated with the company by a coalition of cities and other consumer representatives.*

Stranded costs and related charges by utility (in Billions of Dollars)

TXU*	**$0**
CenterPoint	**$4**
AEP	**$2.5**
TNMP	**$0.129**

CenterPoint Energy had claimed under the terms of Senate Bill 7 that it was owed more than $4.25 billion in stranded costs and other related charges. (Stranded costs are the theoretical losses the company would accrue because its investments made under the previous regulated system would be less valuable under the new deregulated system.) Over the objections of a city coalition and other consumer representatives, the PUC in 2004 awarded CenterPoint $2.3 billion of its request. The company appealed to the courts. On March 18, 2011, after a series of lower court decisions, the Texas Supreme Court awarded the company approximately $1.7 billion more.

Combined, the PUC and Texas Supreme Court rulings were a tough blow for consumers. The generating assets that CenterPoint claimed had become less economic under deregulation were subsequently shown to be quite valuable. Through negotiations, city coalition attorneys and others representing consumers had managed to shave off hundreds of millions of dollars from the final stranded costs payment to the company — thereby ameliorating some of the price shock. But Houston-area residents will still be on the hook for around $4 billion, and as a consequence can expect to pay about $7.30 more per month for years to come.

The second major stranded cost case to conclude in 2011 involved Texas Central Company, a division of American Electric Power. Its customers are largely located around Corpus Christi and throughout South Texas. In 2006, the PUC authorized AEP to recover $1.5 billion in these deregulation-related costs from its customers. In July, 2011 the Texas Supreme Court awarded the company an additional $420 million, plus interest. Since the interest has been accruing for 10 years, the full amount to be collected from ratepayers could range from between $800 million and $1.2 billion. That puts AEP's customers on the hook for about $2.5 billion, for an average bill impact of approximately $7.45 per month.

The Texas Supreme Court in 2011 denied a petition to overrule the PUC in a third stranded cost case, this one involving Texas-New Mexico Power. The PUC earlier had awarded the company $129 million, but also denied it another $106 million at the urging of city coalitions. By denying the company's petition, that PUC decision remains final.

Year: 2012 Pricing and Reliability Challenges Continue

Residential electricity prices in areas of Texas with deregulated electricity service dipped below the national average for the first time in a decade. For Texas under deregulation, 2012 marked the fourth consecutive year of declining electricity prices.[1]

Although welcome news, a closer look behind the numbers revealed that serious challenges remained. For example, an analysis of federal data revealed that Texans in deregulated areas continued paying significantly more, on average, than Texans outside deregulation. In 2012 Texans in deregulated areas would have saved more than $1.5 billion collectively (and $280 individually) had they paid average residential prices that matched those paid by Texans in areas exempt from deregulation.[2] Relative to the national average, residential electricity customers in Texas received a better deal prior to the adoption of Senate Bill 7.[3]

"Nobody wants rolling blackouts (but) neither do we want higher electric bills"

— State Senator Wendy Davis

On a separate front, new power plant construction was just barely keeping up with demand, and some policy experts were diagnosing serious "structural" problems with the Texas market.[4] In 2012, the North American Reliability Council declared that the Lone Star State had the nation's least reliable grid.[5] This was in contrast to big generation reserves prior to the adoption of the Texas electric deregulation law.[6] Major generation companies like NRG and Luminant continued to clamor for regulatory intervention, complaining that the market was not producing sufficiently high prices to support new investment.[7] This was in contrast to the industry's earlier warnings against market intervention, when prices were sky high.[8] ERCOT officials released projections showing the state's reserve margins for generation capacity falling below safe levels within only a few years.[9]

The PUC took action in June by increasing the offer price cap on wholesale electricity by 50 percent.[10] This decision allowed generators to offer their power into the spot market at prices of up to $4,500 per megawatt hour, up from the previous cap of $3,000. The Commission reasoned that this change would deliver more revenues to generators and therefore spur new investment. But the Commission engaged in very little public deliberation of the potential bill impact on Texas consumers, despite very public concerns raised by the editorial boards of major newspapers and several state representatives.[11] "Nobody wants rolling blackouts (but) neither do we want higher electric bills," wrote Wendy Davis, a state Senator from Fort Worth, in a May 4th letter to the agency.[12] Moreover, some retail electric providers claimed the right to break fixed-rate deals with customers as a result of the change,[13] and at least one company apparently did so.[14]

Even before the increase, Texas had the highest wholesale offer cap in the nation by far. Spot market generation prices shot up to the previous $3,000 cap several times after it went into effect in 2011, and generators in 2012 also quickly hit the $4,500 cap, albeit for a brief period.[15] To put those prices in perspective, $4,500 per megawatt hour represents a price more than 100 times higher than those typically paid in the wholesale spot market. In November, the PUC

ERCOT's Energy Consultant: "Price is not Relevant"

On Oct. 24, during a meeting of the State Affairs Committee of the Texas House of Representatives, Brattle Group principal Sam Newell told lawmakers that price "is not relevant to the choice that you have to make" relating to generation reserves, reasoning that costs would rise with whatever option was selected. A representative for large scale electricity consumers disagreed, saying that price was extremely relevant to the debate — and that not all options proposed by Brattle would cost the same.[32]

agreed to phase in even more increases — to $5,000 in 2013, $7,000 in 2014 and finally to $9,000 in 2015.[16]

A coalition of industrial customers found that a $9,000 cap could cost the state an additional $14 billion annually. For its analysis, the industrial coalition assumed the extreme weather conditions of 2011. A separate analysis, using the same assumptions, calculated bill increases of $48 to $50 per month.[17] "These are staggering numbers and the impact of the Commission's decision … should not be trivialized or viewed as a purely academic exercise," wrote an attorney for the Texas Industrial Energy Consumers in a June 15th regulatory filing.[18]

In July a consulting firm known as The Brattle Group released a 135-page report analyzing the state's generation challenges. This Brattle report laid the framework for much of the ensuing policy debate in 2012, although — as with deliberations generally on the issue — it failed to include any comprehensive analysis of consumer costs.[19] The Brattle report enumerated various policy options and ranked them in terms of cost and complexity (see page 70). It also cautioned against implementing changes too quickly and without adequate analysis.

Among the more controversial proposed options in the Brattle report was a "capacity market," which is a market structure common in deregulated states in the northeast. Under a capacity market, generators are paid both when they produce energy, and for providing capacity — that is, they are paid for plants that simply exist and stand ready to produce energy. It would be akin to paying a supermarket for the groceries you buy, plus an extra fee for the supermarket shelf space.

Texas, by contrast, operates a variation of an "energy-only" market in which generators typically get paid only for the power they sell, and not for owning capacity. Energy-Only markets require much less regulatory intervention than capacity markets.

Capacity markets have been controversial and unpopular in the northeast because they layer additional costs on top of existing energy costs. Another complaint is that capacity markets are extremely complex, opaque, and prone to litigation about their outcomes. They also can lead to windfall revenues for power companies with large generation fleets — whether those power companies invest in new capacity or not.

Capacity markets have been controversial and unpopular in the northeast because they layer additional costs on top of existing energy costs.

The Brattle report in some ways seemed to lean toward the capacity market option, and during an Oct. 24th hearing Brattle principal Samuel Newell appeared to issue a full-throated endorsement of that option. "If you're very intolerant of (black-outs) … then a capacity market is unambiguously the best way," said Newell.[20] But consumer groups expressed alarm, calling a capacity market one of the costliest options. The Texas Industrial Energy Consumers, in a regulatory filing, also questioned the validity of some of the Brattle analysis, calling it "a result-oriented exercise that begins with … false assumptions."[21]

Another flash point in the debate was the reserve margin itself. Recall that the reserve margin is a measurement, expressed as a percentage, of the potential output of the state's generators beyond that which is needed to meet peak demand by consumers. As such, it measures surplus generation and is a useful gauge of system reliability. The higher the generation reserves, the lower the chance of blackouts. ERCOT had targeted a 13.75 percent reserve margin, under which it was thought the state would not endure more than one system-wide outage every 10 years.

But during a PUC hearing in July, Newell suggested that some of the publicly expressed concerns over blackouts had been exaggerated, and that even with a smaller reserve margin the blackout risk would not necessarily increase dramatically. For instance, with a 10 percent reserve margin, outages would increase by another 40 minutes per year per customer — even during a year with extreme heat and cold. "We are not talking about the doomsday scenario that we've seen described in the press that Texas is on the verge of having, you know, constant rolling blackouts — that's just an extreme exaggeration," said the Brattle Group principal.[22] The consultant also noted that Texans were already accustomed to several blackouts per year, but on the more limited distribution level.[23]

"We are not talking about the doomsday scenario that we've seen described in the press that Texas is on the verge of having, you know, constant rolling blackouts — that's just an extreme exaggeration,"

— Brattle Group principal.

ERCOT had released a report in May predicting that the state's reserve margins would dip below 10 percent by 2014.[24] However, in October the organization revised its projections upward, after accounting for planned new plant construction.[25] Separately, the Texas Industrial Energy Consumers concluded that when available mothballed generation plants were added to those calculations, the state's reserve margins would remain above safe levels through 2017.[26] PUC Commissioner Ken Anderson said forecasts showed healthy reserves through at least 2018.[27]

VOLUNTARY MITIGATION PLANS

Think Enron's bad behavior, market manipulation, gaming — what precisely constitutes market abuse can be hard to describe, but most would agree that it's bad when it happens. Under a number of proposals adopted by the PUC in 2012, generation companies obtained additional legal protections against such allegations.

Known as "Voluntary Mitigation Plans," these proposals are designed by the generation companies themselves and are meant to describe fair business practices. They typically include descriptions of bidding behaviors and other rules that, if followed, should signal to regulators that the generation company is playing by the rules. As long as the companies do not deviate from the actions they describe in the plans, the companies remain protected against prosecution for anti-competitive behavior. By October the PUC had approved voluntary mitigation plans for two companies, while another plan remained pending.

Voluntary mitigation plans present serious problems for consumers. First, they are extremely complex and no single entity will have the same understanding of these plans as the companies that devise them. This has raised concerns because each company that submits a voluntary mitigation plan has a direct interest in maximizing its own position in the market. So while these plans supposedly describe fair practices, theoretically they also could open the door to gaming opportunities.

Also, only the companies, the independent monitor of the state's electric market and PUC staff have been allowed to negotiate the details of these plans. No substantive input so far has been permitted from experts with entities that attempt to safeguard the market and protect ratepayers.

Another worry is that these plans may allow companies to further leverage the extremely high prices permitted in the state's wholesale energy market. Texas maintains the nation's highest wholesale price cap for energy, and that offer cap will continue to increase through at least 2015. Through these plans, the companies may gain an ability to more easily price power at these extreme levels. This, in turn, could lead to higher bills for businesses and homes.

The plans were authorized under House Bill 2133, adopted in 2011 by the Texas Legislature. Ratepayer groups generally supported HB 2133 because it closed a loophole in Texas law that allowed generation companies to profit from anti-competitive behavior.[28] But ratepayer groups had serious concerns regarding the voluntary mitigation plan provisions.

As *Houston Chronicle* columnist Loren Steffy pointed out, the "plans, combined with the PUC's earlier vote to raise the price limits on the wholesale market by 50 percent, will give big generators greater potential to control the market."[29] By October, the PUC had adopted voluntary mitigation plans by Houston's NRG and GDF-Suez.[30]

Brattle Report: Comparisons of Policy Options

Source: ERCOT Investment Incentives and Resource Adequacy, Brattle Group, June 2012, Table 1 pg. 5

Option	How Reliability Level is Determined	Who Makes Investment Decisions	Risk of Low Reliability	Investor Risks	Economic Efficiency	Market Design Changes
1. Energy-Only with Market-Based Reserve Margin	Market	Market	High in short-run; Lower in long-run	High	May be highest in long-run	Easy
2. Energy-Only with Adders to Support a Target Reserve Margin	Regulated	Market	Medium	High	Lower	Easy
3. Energy-Only with Backstop Procurement	Regulated (when backstop imposed)	Regulated (when backstop imposed)	Low	High	Lower	Easy
4. Resource Adequacy Requirement	Regulated	Market	Potentially Low	Med-High	Medium	Medium
5. Resource Adequacy Requirement with Capacity Market	Regulated	Market	Low	Med-High	Medium	Major

A report by a consulting firm known as The Brattle Group enumerated several policy options to address the state's generation challenges. The chart, above, summarizes some of those options. Brattle also cautioned in the 2012 report against implementing changes without adequate analysis.

On June 1, 2012 ERCOT made public a report prepared by The Brattle Group — a national energy consultancy — on the state's wholesale energy market. The consulting group had been charged with analyzing the market's ability to attract generation investment. ERCOT and the Public Utility Commission had begun considering such questions after the particularly difficult summer of 2011, when the state experienced power shortfalls and came close to rolling outages. The Brattle Report included a number of important findings. Among them:

- ERCOT and the PUC should revisit the 1-in-10 year blackout standard, under which the state's reserve margin targets are set in such a way as to avoid more than one major blackout every 10 years. ERCOT and the PUC have used this standard to justify a 13.75 percent target for reserve capacity. But ERCOT enforces a more stringent interpretation of the 1-in-10 standard than is employed elsewhere. That is, ERCOT interprets the standard to mean "1 outage event in 10 years," while other system operators interpret it to mean "24 outage hours in 10 years." These two interpretations may sound semantically similar, but in reality differ greatly: Brattle cited a case study in which the less stringent standard reduced reserve margin requirements by nearly 50 percent.[31] "The 1-in-10 standard is also poorly-defined with respect to the events it describes," Brattle noted, explaining that the standard makes no distinctions between small-scale blackout events and widespread events.
- In ERCOT, the resource adequacy target implies average outages of less than 1 minute per year, per customer. But customers are accustomed to much greater outage times caused by disturbances in the more local electricity distribution systems. "During storm events, annual outages durations can reach several hundred to several thousand minutes per customer," according to Brattle.
- As of the first half of 2012, the ERCOT market was not producing wholesale energy prices that were sufficiently high to maintain a 13.75 percent reserve margin. Increasing the offer cap on wholesale energy prices would stimulate investment, but at a level still insufficient to obtain that targeted reserve margin.
- Demand response — that is, programs under which customers can curtail their energy usage in exchange for a payment — could help meet the state's generation supply challenges. However, it will take too long to create sufficiently robust demand response programs to meet the state's near-term energy needs.
- A modified energy-only market could risk low reliability in the short term, but improved reliability in the long-term. Such a strategy also may have the highest economic efficiency over time — that is, Texans would get the best bang for their buck with regards to financing improved reliability.

Year: 2013 Texans Make Payments for Non-Existent Utility Taxes

An early 2013 report from TCAP found that Oncor, the North Texas electric utility, had charged its customers hundreds of millions of dollars for a non-existent federal tax liability.[1] Citing federal and state government filings, the report documented more than $500 million in payments by Oncor customers since 2008 — supposedly for the utility's federal income taxes. But the utility does not have a federal income tax obligation and its beleaguered majority owner, Energy Future Holdings, had not owed income taxes since at least 2008, the report showed.

Under state law then in effect, Texas regulators had the ability to recongnize the tax savings enjoyed by utilities when they file a tax return jointly with their parent and affliates. Although the Public Utility Commission had declined to exercise that authority with regards to Oncor, the PUC commissioners utilized it when considering the treatment of taxes in rates charged by other utilities.

TCAP issued a recommendation during the 2013 Legislative Session that money collected from electric ratepayers for federal taxes should be used to pay federal taxes — or the utilities should not collect the money at all.

Unfortunately the Texas Legislature in 2013 took the opposite tack. Bowing to industry pressure, lawmakers

Legislative Session

The 83rd Regular Session of the Texas Legislature concluded on May 27, 2013. Over 100 bills pertaining to the gas and electricity market were filed by lawmakers. Here are a few highlights:

- Electric and gas utilities pressed unsuccessfully for the passage of House Bills 1148 and 1149, which would have made it more difficult for cities to protect their citizens in utility rate cases. City and consumer groups testified in opposition to these bills, and with the help of the Texas Municipal League derailed them in committee.
- The Legislature adopted House Bill 1600, which reauthorizes operations at the Public Utility Commission. HB 1600 includes a handful of new reforms, including rules giving the PUC additional oversight authority to protect the electric power grid. During the debate over HB 1600, lawmakers also specifically directed the PUC to conduct a cost-benefit analysis before authorizing an expensive "capacity market" that could increase annually electric costs by billions of dollars. However, that provision was removed before final passage.
- Lawmakers adopted House Bill 7, which includes language to discontinue the System Benefit Fund that provides rate discounts for low-income customers. The System Benefit Fund is financed through a charge on electric bills, although lawmakers over the years had held back a sizable amount for state budget-balancing purposes. Under HB 7 the accrued funds will be paid out to low income customers through 2016, and then the System Benefit Fund will be discontinued.
- As noted above, the Texas Legislature adopted Senate Bill 1364, over the objection of municipal coalitions and consumer groups. SB 1364 limits the PUC's discretion over how much electric utilities charge to their customers for federal corporate income taxes.

adopted Senate Bill 1364 that deprived the PUC of an important ability to adjust rates for utilities with parent companies that file consolidated returns. Such consolidation results in tax savings that would be impossible otherwise. Previously the PUC could adjust rates to reflect the local utility's fair share of that savings. Under SB 1364, the PUC lost that ability and the utility or its parent company can now simply pocket the extra money. Adoption of the bill was a top priority of the Houston-based transmission and distribution utility, CenterPoint.

Approximately 100 additional bills relating to electricity and gas service were filed during the 83rd Legislative Session, including many bills harmful to consumer interests. The electric and gas utilities deployed their usual army of lobbyists, with between $5 million and $10 million spent on lobby contracts by five electric companies alone.[2] But despite the well-funded opposition, energy consumers won significant victories — including some reforms to the Public Utility Commission. Several bills harmful to the interests of municipal, business and residential energy consumers also failed during the waning days of the session.

"The good news is that this money collected to help low-income people for utility bills is going to be used — there's a tremendous need,"

— AARP's Tim Morstad.

LEGISLATURE DISCONTINUES SYSTEM BENEFIT FUND

In 1999, with the adoption of the electric deregulation law, the state legislature created the System Benefit Fund. Part of a negotiated deal with consumer groups, the main purpose of the fund was to provide rate discounts for low-income Texans. It was financed entirely through a fee on electricity bills.

But despite the agreement with consumers groups, lawmakers in subsequent years began holding back the money and reducing the bill discounts. Instead, the unappropriated funds were employed in an accounting trick to balance state budgets.[3] This occurred year after year. By 2013, approximately $800 million had accumulated in the System Benefit Fund, having served as offsets to spending elsewhere in the state budget.

But with the passage of House Bill 7, in 2013, that practice came to an end. The bill called for the disbursement of all System Benefit Fund money, and then the eventual discontinuance of the SBF after 2016. As a result, large bill discounts — $170 for a typical low-income user — began appearing in customer bills during the summer of 2013, with smaller discounts to be applied during the summers of 2014, 2015 and 2016.[4]

About 600,000 low-income Texans were eligible for the discounts. The discounts were so large in 2013 that for several months some bills were reduced to zero.[5] "The good news is that this money collected to help low-income people for utility bills is going to be used — there's a tremendous need," said AARP's Tim Morstad. "The not-so-good news is that in several years, the program will be terminated."[6]

Another potential bit of collateral damage with the loss of the System Benefit Fund could be the powertochoose.com website. The state-run website lists various retail electric providers, and was created by the PUC to help Texans shop for electricity. It is funded with proceeds from the System Benefit Fund. Whether the state would identify a separate source of revenue to fund the website remained an open question in 2013.[7]

NEW COMMISSIONER APPOINTED AND SUBSIDY MANDATES DEBATED

In August Gov. Rick Perry named his former chief of staff, Brandy Marty, to a position on the three-member Texas Public Utility Commission. Marty assumed a seat vacated

Capacity Subsidies

Under the subsidy proposals, generators would collect extra payments — potentially billions of dollars of extra payments — beyond what they otherwise would receive from selling electricity. There would be a government requirement that retail electric providers and other entities that serve customers pay these subsidies. Although promoted as a way to ensure generation investment and guard against future blackouts, critics questioned the effectiveness and expense of the proposed subsidies. Those critics include business, consumer, environmental and free-market groups.

by Rolando Pablos, who resigned in March.

Marty had worked in various capacities with Gov. Perry, including as a policy director during his 2010 campaign.[8] She came to a divided commission, with PUC Chair Donna Nelson and Commissioner Kenneth Anderson remaining split on the controversy regarding proposed capacity subsidies to Texas power generators.[9] For many months Ms. Marty said little to reveal her thoughts regarding the issue, but in October Marty joined Chair Nelson in supporting a mandated reserve margin.[10] This was seen by many observers as a step toward the implementation of a capacity market.

In a heated exchange during the Oct. 25 meeting Commissioner Anderson blasted the decision.[11] "I am... opposed to mandatory reserve margins as uneconomic with the potential to destroy the economic engine that is Texas," he said.[12] The distinction between a mandated reserve margin and a targeted reserve margin is an important one. Under the deregulated electricity system, Texas has operated with a reserve margin target, not a reserve margin mandate. The reserve margin target represents ERCOT's goal for generation reserves. In Texas, no government requirement exists that the reserve margin target be met.

Free market groups and others complained that by favoring a mandated reserve margin, the PUC had retreated from the free market principles under which the state established its electric deregulation law in the first place.[13] The unofficial decision to mandate a reserve margin also drew the ire of Democrat Wendy Davis, a state senator running for governor, and Republican Troy Fraser, who chairs a key energy-related committee in the Texas Senate. Davis said it was wrong for the PUC to move forward without first conducting an analysis on consumer costs.[14] Fraser, during a meeting of his Senate Natural Resources Committee, claimed the PUC had overstepped its authority. "You are way ahead of yourself," he told the PUC chair.[15]

Whether targeted or mandated, reserve margins are expressed as percentages. These percentages express the ratio between the total amount of generating capacity available within a given service territory and the hypothetical greatest electricity demand within that area. In 2013, generators and some others pressed to increase the reserve margin target from 13.75 percent to 16.1 percent — a change that would potentially cost Texans more than $3 billion over 10 years.[16] ERCOT put the proposal on hold after it drew the ire of Sen. Fraser, who wrote in a letter that "an increase … of this scale could not help but serve the interests of those advocating for a capacity market, a system which would subsidize existing generation."[17]

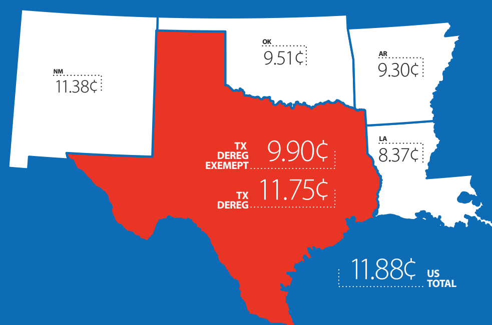
PUC Commissioner Anderson continued speaking out against the capacity market proposals throughout 2013.[18] That summer, for instance, he took aim at a study released by NRG that predicted multiple blackouts each year unless the PUC created a capacity payment system. The NRG study put the resulting cost to the Texas economy at more than $14 billion. Commissioner Anderson said NRG had baked bad math into its analysis, citing the work of his policy advisor who calculated the energy giant had overstated the costs "by at least a factor of 10 (likely by a factor of at least 40)."[19]

The generators themselves were not particularly consistent on the issue. In a June 2013 guest editorial, John Ragan, an executive for energy giant NRG, warned that Texas was falling behind with regards to generation construction and could face serious shortfalls unless they could collect subsidy payments. "We support the capacity market option," wrote NRG regional vice president.[20] But then in August, in an earnings report to investors, NRG CEO David Crane acknowledged that new generation construction was not supported in competitive electric markets anywhere in the U.S. — including in those jurisdictions that already allow capacity payments.[21] Ragan also appeared to have been contradicted in Arizona by an electric industry trade group, which claimed in written comments that the "outlook for dire consequences" with respect to generation reserves

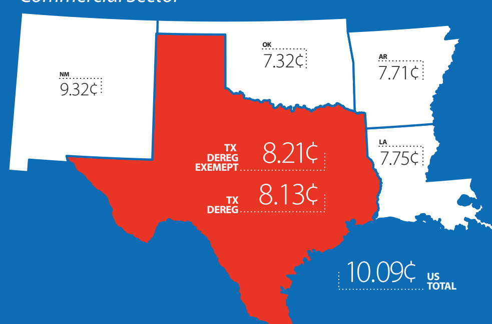
Electricity Prices in 2012: Texas and Adjoining States

Source: United States Energy Information Administration/ http://www.eia.doe.gov/cneaf/electricity/page/eia861.html

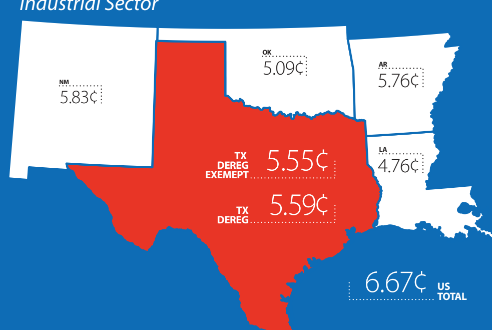
Residential Sector



Commercial Sector



Industrial Sector



in Texas "appears to be wholly overstated."[22] This trade group, the Retail Energy Supply Association, counts NRG among its members.[23]

PROBLEMS CONTINUE FOR ENERGY FUTURE HOLDINGS

Luminant, the state's largest electric generation company, agreed in November to pay $750,000 to settle charges relating to the statewide power outages. Staff at the Public Utility Commission said Luminant failed to comply with ERCOT's instructions during the outages, which occurred during a 2011 cold snap. Luminant's failure meant that the grid operator "did not receive capacity resources it needed," the PUC said.[24] As is usual with such cases, Luminant agreed to pay a penalty but declined to admit culpability.

The Luminant penalty came as more bad news for the failing Energy Future Holdings, the generation company's holding company. Although the Dallas-based company showed a modest profit during the third quarter of 2013,[25] it recorded $3.36 billion in losses in 2012 and nearly $2 billion in 2011. Many analysts predicted restructuring in 2014, when it faces a balloon payment on its massive debt acquired during the 2007 buyout of TXU.[26]

PRICES

TCAP released a report in 2014 showing that Texans in deregulated areas have continued paying significantly more, on average, than Texans outside deregulation. Texans in deregulated areas would have saved more than $22 billion collectively since 2002 had average residential electric prices under deregulation matched average prices outside deregulation. Over the course of deregulation, the computed savings for a typical customer under deregulation would have exceeded $4,500, according to the report.[27]

Year: 2014 Pause in the Debate Over Capacity Subsidies

After gaining steam for several years, a proposal to dramatically overhaul the state's deregulated electricity market stalled in 2014.

Generation companies had been calling for the overhaul, through which they would have received multi-million dollar "capacity payments" that theoretically would subsidize new power plant construction. But critics said the subsidies were unnecessary, would needlessly inflate electricity costs and would mark a departure from the free-market principles upon which the state's deregulated electricity system was premised.

That the PUC would adopt the complex proposals appeared increasingly certain — especially after two of the three commissioners expressed some level of support for them during previous years. But momentum stalled in January 2014 after the release of a Brattle Group report showing the current unsubsidized system was supporting relatively healthy supplies of generation.[1] Shortly afterwards ERCOT released a report concluding that the state would enjoy future reserves significantly greater than previously forecast.[2]

State Sen. Troy Fraser, chair of the Senate Natural Resources Committee, said "we don't have a crisis; the system's not broken."[3] PUC commissioner Brandy Marty, who during 2013 was seen by some observers as a proponent for the market overhaul, said early in 2014 that "our energy market seems to be healthy."[4]

Taken together, the new reports — as well as push back from key policymakers — ended the public push for the expensive market overhaul.

The PUC also had already taken other steps to encourage new generation construction, including raising a price limit for wholesale power offered into a segment of the ERCOT market. The cap at one time was set at $1,000 per megawatt hour — about typical for other parts of the nation — but was increased to $7,000 in June.[5]

[For more information about the Capacity Market debate, see the TCAP Snapshot Report, "A Retreat from Electric Competition," Nov. 2013. It can be found online at http://tcaptx.com/wp-content/uploads/2013/11/Capacity-Report.pdf.]

Did you know?

EFH's wholesale power unit, Luminant, controls approximately 18 percent of the market within ERCOT[12] — a share that was down slightly from previous years.[13] Under the 1999 electric deregulation law, no single generator can control more than 20 percent.[14] This prohibition against amassing too much market power should limit the ability of some of the state's larger generation companies from acquiring all of Luminant's assets in the EFH bankrputcy.

STATE'S LARGEST ELECTRIC COMPANY GOES BUST

On April 29, just six years after it was formed through the buyout of the former TXU Corp., Energy Future Holdings filed for bankruptcy. This came as a surprise to approximately no one. EFH had been losing money for years.

But the financial collapse nonetheless was dramatic. Formed in what had been the largest leveraged buyout in U.S. history, EFH now was at the center of one of the largest-ever bankruptcies for a non-financial company.[6] Investors who led the $45 billion acquisition of TXU in 2007 saw their stake reduced in 2014 to less than 1 percent.[7] Many creditors were expected to be wiped out completely.[8]

What happened? In three words: a bad bet. The investors who borrowed so much money had wagered that natural gas prices would continue rising and in the process elevate wholesale electricity prices. Instead, new natural gas exploration technology led to a commodity glut. Natural gas prices fell, and along with them, electricity prices . . . and the fortunes of Energy Future Holdings.

According to reports, EFH owned more than $36 billion in assets when it filed for Chapter 11 protections. But it also owed more than $49 billion to creditors and had no way to keep up with its debt payments.[9]

Most of the losses were accrued by the generation side of the company — Luminant — which operated in the wholesale power market. But EFH still controlled a profitable retail electric arm, with more than 1.7 million customers,[10] and it also controlled an 80-percent stake in Oncor, the monopoly transmission and distribution utility in North Texas. Oncor continued making big profits through 2014 —more, in fact, than had been authorized by regulators. [See sidebar: Oncor's Overearnings on page 77.]

It remained unclear how the bankruptcy eventually would impact rates. For instance, it could contribute to lower rates if the company's fleet of coal, gas and nuclear plants were to be divvied up among several new owners. More diverse wholesale ownership means more wholesale competition, potentially putting downward pressure on prices.

However, the opposite could occur if the fleet were to be transferred, en masse, to a single buyer — especially one that already controlled generation assets in Texas.[11] The good news is that Senate Bill 7, the electric deregulation law, sets limits on how much generation can be owned by a single entity.

Also, thanks to the deregulation law, investors — as opposed to ratepayers — should shoulder much of the financial risk from the EFH collapse. Financial protections set in place at the time of the 2007 buyout — protections put in place at the insistence of cities and the Texas Public Utility Commission — likewise are designed to protect Oncor ratepayers.

But it is unlikely that such a debt-heavy buyout would have occurred in the first place in the absence of deregulation. Warren Buffet, who invested $2 billion in EFH, described his involvement in the debacle as a "major unforced error."[15]

ONCOR BATTERIES

Oncor made headlines of a different sort during 2014. In November the EFH-owned transmission and distribution utility announced an ambitious proposal to install large-scale batteries throughout Texas.[18] If given the green light, units with about 5,000 megawatts of storage capacity would be placed along transmission and distribution lines, at locations where they come to dead ends or near feeders that have consistent outage problems.

Although Oncor says the batteries would improve reliability, important questions remained unanswered about their costs and how they would impact the state's deregulated power system.

And because the batteries could be considered — at least, technically — as a generation source, the plan likely would require legislative authorization. Under the state's electric deregulation law, transmission and distribution utilities are barred from owning generation.

Oncor said the batteries would reduce costs associated with transmission line congestion — and thereby wholesale power costs overall. And to the extent that it helps drive down the

Good Work If You Can Get It

In October, over the objections of the federal bankruptcy monitor, U.S. District Judge Christopher Sontchi ruled that EFH could reward 26 of its top executives with up to $20 million in bonuses. Despite its historic collapse, the company described itself in bankruptcy court as "one of the best operated companies in the industry" and said it wanted to implement an executive bonus program to drive its "operational and financial excellence."[16] The bankruptcy judge — operating in court in Wilmington, Delaware, far from the company's employees, customers and assets in Texas[17] — agreed with the request.

ONCOR's Overearnings

Has Oncor systematically shortchanged its electric distribution system? That was the question from Public Utility Commissioner Kenneth Anderson, who wrote in an Oct. 17 memo that repeated outages on the Oncor system had him wondering whether the company was doing enough to maintain reliability.

The commissioner documented a nearly 5 percent drop in Oncor's distribution investment between 2005 and 2013.[20] Anderson also specifically referenced a controversial tax sharing agreement with Energy Future Holdings, and questioned whether too much money from Oncor's ratepayers was flowing upstream to the parent company.

Oncor responded with a Nov. 6 "Letter to Our Customers," which it had published as a full-page newspaper advertisement in Austin.[21] In it, the state's largest monopoly utility insisted that it takes very seriously the needs of its ratepayers.

"Some people ask whether we are willing to spend the money to enhance reliability. Of course we will, because we always have," the company's top executive wrote in the letter.

But the company also made at least one claim that appeared to have been contradicted by records at the Public Utility Commission. In defending itself in the open letter, the company wrote its "return to our investors (are) well below" authorized levels.

But in an Oct. 9 memo to Commissioners, agency experts said Oncor's revenue levels during 2013 were not "well below" authorized levels, but rather about $47 million higher than those deemed reasonable.[22] Oncor also has publicly reported healthy profits, including $355 million during 2013 — or about a 31 percent increase from 2008.[23]

cost of utility-scale batteries, the project could help kick start similar investments by other players.

But the technology also would cost billions of dollars.[19] Without an impartial cost-benefit analysis and more detailed plans from the company, it remained impossible to predict whether the proposal would save Texans money or add to their monthly bills.

The plan also marks a departure from deregulation, since Oncor is a regulated monopoly that would be using money from its captive ratepayers to invest in battery technology.

SMALL FISH SWIM FREE RULE

The PUC in 2014 reaffirmed a controversial rule that — according to critics — makes it easier for some companies to manipulate the Texas wholesale power market. The PUC's decision came in response to a complaint filed by a power trader that had accused a competitor of improperly driving up prices.

The rule in question is known as the "Small Fish Swim Free Rule." It was first established by the PUC in 2006. Under it, relatively small generation companies — i.e., the "small fish" — can engage in trading practices that might otherwise be construed as illegal market manipulation if they instead had been conducted by a larger company. The rule defines "small fish" companies as those that control 5 percent or less of the ERCOT market.

Under the logic of the rule, small-fish generators should not have the ability to manipulate the wholesale power market because their share of it is so small. But critics — such as Raiden Commodities that filed the PUC petition — say the rule lets small-fish generators off the hook for predatory practices.

In its April 21st petition, Raiden claimed that some small-fish competitors possess the ability to drive up prices when energy surpluses run short. To support their position Raiden cited findings by the independent monitor of the state's wholesale power market.

But PUC chair Donna Nelson said that if a "small fish" company were to attempt to bid its power into the market at excessively high prices, other generators would enter the market. "It's a short-term issue — and one that the market handles well," she said.[24]

Commissioner Kenneth Anderson said the panel vetted the issues raised by Raiden when it originally adopted the small-fish rule in 2006. "The question is: where do you draw the line?" he said, referring to the 5 percent threshold.

Commissioner Brandy Marty said Raiden had raised interesting points, but that she was not yet prepared to revisit the small-fish rule. "To the extent that a small fish is big enough to have an impact, we should keep an eye on it," she said.

The final PUC vote was 3-0 against Raiden. The company in 2014 also filed a separate lawsuit in federal court accusing a rival generator of manipulating the Texas market. As of late 2014, that lawsuit remained pending.

HOUSTON IMPORT PROJECT

The ERCOT board in April approved a massive transmission construction project that could lower electric prices in Houston.[25] That approval came over the objections of two major generation companies.

Dubbed the Houston Import Project, the new transmission lines will cost an estimated $590 million.[26] When complete, they will run 130 miles from the northern portion of the Houston metro area to east-central Texas.[27]

Power companies NRG and Calpine successfully opposed an earlier version of the project and continued opposing this most recent effort.[28] Their objections did not surprise observers given that both companies have a concentration of generation plants around Houston. The new lines could open the region to more competition and lead to a decline in wholesale power costs — and potentially cut into both companies' bottom lines.

NRG has argued that higher market prices around Houston encourage investors to build more power plants, which, in turn, could help the state serve future energy needs. But Houston's dense population and environmental restrictions there have severely limited the ability of investors to build new plants locally. And while NRG announced in November[29] that it would break ground on a relatively small 360-megawatt plant just southeast of Houston, the development was more the exception than the rule.

Consumer representatives active at the ERCOT board support the Houston Import Project. Although construction won't be cheap, the additional costs will be borne by ratepayers statewide. That means the per-customer cost of construction should be nominal, while the lines themselves should contribute to energy affordability and reliability in the Houston area.

ERCOT's technical experts recommended the project not for economic reasons, but rather to help ensure grid stability. The expansion project, which is scheduled for completion by 2018,[30] is similar to others given the green light for reliability purposes. These include projects around the Lower Rio Grande Valley.[31]

WIND POWER AND ENVIRONMENTAL PROTECTION AGENCY MANDATES

A June report from the United States Information Administration found that thousands of miles of new transmission lines in Texas had reduced instances in which wind generators were prevented from getting their power onto the statewide grid.

As a result of these new lines, wind turbines in Texas continued to generate record amounts of power during 2014. Nearly 30 percent of all electricity on the ERCOT grid during a brief period in March came from wind generators.[32] Over the last decade, wind power generation in Texas expanded more than 1,000 percent.[33]

Public Utility Commission chairwoman Donna Nelson, in a May 29 memo to her colleagues,[34] wrote that the continued expansion of wind power in Texas would require more transmission system upgrades and that the agency should consider shifting some expenses onto the wind industry.

"Should we ask electric customers to fund further investment in the transmission system to improve stability or should some of the risk be borne by generators?" she wrote.

In June, the U.S. Environmental Protection Agency announced a new "Clean Power Plan" that calls for a 39 percent reduction in carbon dioxide emissions from Texas power plants by 2030 as compared to 2012 levels.[35] The ERCOT grid operator released a report in November saying that the retirement of coal plants under the plan would undermine electric reliability. It also said the plan could increase electricity costs by 20 percent by 2020.[36]

Year: 2015 Hunt Bid to Buy Oncor

A federal judge in September authorized a plan for Energy Future Holdings ("EFH") to exit bankruptcy. Under the plan, EFH's competitive assets would go to its creditors and EFH's regulated transmission and distribution utility, Oncor, would go to a consortium that includes creditors as well Ray L. Hunt, the Dallas billionaire.[1]

But the proposed transfer of the regulated wires company drew heated criticism — and it remained unclear during 2015 whether it would receive needed regulatory approval. Without that approval, the EFH bankruptcy plan would almost certainly fail.[2]

Because Oncor is a public utility, state law requires that the Texas PUC approve its change of ownership. The agency has 180 days from a Sept. 29 regulatory filing by Hunt to certify that the sale does not violate the public interest. A major sticking point was Hunt's proposal to divide Oncor into two different companies — one to own the lines and poles; the other to lease the equipment and operate the company.

Consumer groups warned this bifurcated structure — a key necessity of a "Real Estate Investment Trust," or REIT — would create new ratepayer risk without providing offsetting benefits. In addition, the REIT structure would lead to dramatic, immediate and permanent corporate tax savings, but Hunt made no commitment to share those savings with ratepayers. One PUC expert said that if Hunt's proposal received regulatory approval, then millions of dollars in customer wealth would end up with the utility's owners.[3]

Oncor, which serves 10 million customers at 3 million meters,[4] is the state's largest transmission and distribution utility.

HOUSTON IMPORT PROJECT

A massive transmission project that could lower electric prices in Houston received approval from the Texas PUC in December— despite objections from two major generation companies.[5]

Dubbed the Houston Import Project, it will include transmission lines that will run 130 miles from the northern portion of the Houston metro area to east-central Texas. The estimated cost is $590 million.[6]

Wholesale power companies NRG and Calpine — two wholesale power companies with a concentration of generation plants around Houston — were among the principle opponents. Consumer representatives supported the project and noted that the companies' opposition wasn't surprising, given that the new lines could open the region to more suppliers and lead to a decline in wholesale power costs there.

Although construction won't be cheap, the additional costs will be borne by ratepayers statewide. That means the per-customer cost of construction should be nominal, while the lines themselves should contribute to energy affordability in and around Houston.

CenterPoint, the Houston-based transmission and distribution utility, estimated the project could increase utility rates by about five cents per month.[7] ERCOT earlier gave its approval to the Houston Import Project.[8]

"SMALL FISH" KEEP SWIMMING IN ERCOT

A federal judge in February 2015 dismissed a lawsuit involving the controversial "small fish swim free" rule.[9] This follows a similar ruling in 2014 by the Texas PUC.

Under the rule, relatively small energy companies — i.e., the "small fish" — can engage in wholesale energy trading practices that otherwise might be construed as illegal market manipulation if conducted by larger companies. The rule defines "small fish" as generation companies that control less than 5 percent of the wholesale power market within ERCOT.

Under the logic of the Small Fish rule, comparatively small generation companies cannot game the market because their share of it is so small. But critics disagree and cite findings by ERCOT's independent market monitor to support that position.[10]

Raiden Commodities and Aspire Commodities, two commodity trading companies, had alleged in their dismissed lawsuit that French trading company GDF Suez had improperly manipulated the Texas market. GDF is a "small fish" under the Texas rules.

Transmission and Distribution Charges

Although monopoly transmission and distribution utilities operate under regulation, their rates impact electricity prices charged by competitive retail electric providers. This is because transmission and distribution utility rates are non-bypassable, which means they are included in a uniform fashion in the rates charged by all retail electric providers that operate in the utility's service territory.

Rate increases since 2003 by the Oncor utility (operating in the Dallas-Fort Worth area) and the CenterPoint Electric utility (operating around Houston) have outpaced inflation. Transmission and distribution charges paid by Oncor and CenterPoint customers also comprise an increasing share of monthly electric bills.

Non-Bypassable Charges: CenterPoint
(September 2003 – September 2015)

2003

$24.61

2016

$42.41

TRANSMISSION & DISTRIBUTION CHARGES
(IN DOLLARS, ON 1,000KWH MONTHLY BILL)

Transmission and distribution utilities operate as regulated monopolies, even in areas of Texas with deregulation. The rates assessed by these utilities continue going up, sometimes at a rate well beyond that of inflation. For instance, rates charged by CenterPoint Electric in the Houston area have increased 73.4 percent between 2003 and 2016. In 2003, CenterPoint charges comprised 20.2 percent to 29.2 percent of a typical 1,000 kWh electric bill. In 2016, CenterPoint charges comprised 30.2 percent to 54.9 percent of a typical bill. All electric customers in deregulated areas around Houston must pay CenterPoint's rates, regardless of the retail electric provider the customer chooses for service.

Source: Archived TDU Rate Summaries, PUC
http://www.puc.texas.gov/industry/electric/rates/TDArchive.aspx

Non-Bypassable Charges: Oncor
(September 2003 – September 2015)

2003

$23.01

2016

$36.87

TRANSMISSION & DISTRIBUTION CHARGES
(IN DOLLARS, ON 1,000KWH MONTHLY BILL)

Rates charged by Oncor utility in the Dallas-Fort Worth area increased by more than 60 percent between 2003 and 2016. That rate outpaces the rate of inflation. In 2003, Oncor charges comprised 20.1 percent to 27.4 percent of a typical 1,000 kWh electric bill. In 2016, the charges comprised 28 percent to 53.6 percent of a typical bill. All customers in deregulated areas of the Dallas-Fort Worth region must pay Oncor's rates, regardless of the retail electric provider the customers choose for service.

Source: Archived TDU Rate Summaries, PUC
http://www.puc.texas.gov/industry/electric/rates/TDArchive.aspx

TEXAS LEGISLATURE

The 84th Session of the Texas Legislature convened on Jan. 13. State lawmakers considered scores of bills relating to the state's deregulated electricity market. Most failed, but one important piece of legislation, House Bill 1101, won approval.

HERE ARE A FEW HIGHLIGHTS FROM THE 84TH LEGISLATIVE SESSION:

- House Bill 1101, by state Rep. Sylvester Turner, will ensure that approximately $200 million left unspent in the System Benefit Fund will be used for its intended purpose: to assist low-income ratepayers. Funding for this program comes not from tax dollars, but from fees already paid on electric bills. Gov. Greg Abbott signed House Bill 1101 on June 17th.

- House Bill 2254, also by Rep. Turner, would have prohibited electric companies from applying minimum use fees to home bills. Although Rep. Turner couldn't get HB 2254 out of committee, the PUC took action shortly after the session to require disclosure of such fees on the powertochoose.org website. [11]

- Senate Bill 777, by Sen. Troy Fraser, would have given the PUC more tools to crack down on bad actors in the state's retail electric market. The Texas Coalition for Affordable Power joined the PUC staff in supporting this legislation. SB 777 emerged from the Senate, but died in the House.[12]

ENERGY CONSUMPTION IN ERCOT REGION GROWS

Texas businesses and homes consumed 2.2 percent more power in 2015 than they did the previous year — an increase driven by an unusually hot summer. The ERCOT grid operator also recorded a new record in peak usage during 2015.[13]

In all, five demand records were set inside ERCOT during 2015. "By summer's end, the system had new records for monthly energy use, July peak demand, weekend peak demand and all-time peak demand," the grid operator stated in a press release.[14]

TEXAS WIND BREAKS RECORDS DURING 2015

Texas wind power also broke records in 2015 — aided in large part by the completion of the expensive CREZ transmission network.[15] Here's a quick rundown of some of the year's broken records.

— At 11:07 a.m. on Dec. 22 Texas wind generators pumped out 13,883 MW of electricity, a new record.[16]

— A slightly smaller burst of wind power at 3:05 that same day accounted for 44.7 percent of the overall power on the ERCOT grid at that time. That set a new record for wind power's percentage of load.[17]

— Wind farms supplied about 18.4 percent of the electricity in November, a new monthly record. That beat the previous single-month record of 15.2 percent set in ERCOT during March of 2013.[18]

— On Nov. 25, wind generators pumped out 12,971 MW of power, a record at that time. This represented 36.9 percent of the load on the ERCOT grid.[19]

— On Oct. 22, wind generators produced 12,238 MW in ERCOT, a record at that time.[20]

— On Sept. 13, wind generators produced 11,467 MW in ERCOT, a record at that time.[21]

COMPLAINTS

Electricity complaints filed with state regulators dropped to a new post-electric deregulation low in 2015. Texans filed 6,973 electricity-related complaints or inquires with the PUC during the fiscal year, beating the previous low in FY 2013 when Texans filed 7,129.[22] However, complaints against a single company — Dallas-based Sharyland Utilities — shot up more than 800 percent during FY 2015. Sharyland is owned by many of the same parties seeking control of Oncor. The complaints against Sharyland were so numerous that the PUC opened a special proceeding that resulted in a slight rate decrease for some customers.[23]

New ERCOT Records

According to the grid operator, peak demand records set in 2015 were 69,877 MW on Aug. 10, 69,775 MW on Aug. 11, 68,979 MW on Aug. 6, 68,731 MW on Aug. 7 and 68,683 MW on Aug. 5. Also, homes and businesses in ERCOT consumed 347,522,948 megawatt-hours of electricity in 2015, as compared to 340,033,353 MW during 2014.

Year: 2016 NextEra Replaces Hunt in Oncor Bid

By year's end it appeared that Florida-based NextEra — and not a consortium that included Dallas billionaire Ray L. Hunt — had the inside track to take possession of Oncor.

Recall that the Hunt consortium had proposed a complicated and controversial tax structure for the utility. As it turned out, it was that tax structure that proved to be the deal's undoing. Consumer groups and others[1] had criticized the proposed structure (described in the Year 2015 chapter) because it would have delivered a multimillion-dollar windfall to the new utility owners, but at ratepayer expense. In March, the PUC approved the consortium's proposal[2], but also attached a slew of conditions[3] that prompted the prospective buyers to walk away.[4]

Florida-based NextEra then proffered an alternative deal, albeit one with more traditional financing. Some experts (including TCAP general counsel Geoffrey Gay) warned the NextEra proposal also could lead to a rate hike, and NextEra itself acknowledged it would seek new Oncor rates in 2017, if the deal closed.[5]

The PUC was expected to consider whether to approve the NextEra proposal or reject it during proceedings in early 2017. If finalized, the transaction would be valued at more than $18 billion and require $9.5 billion in financing.[6]

ALTERNATIVE RATEMAKING

Not necessary and maybe even a bad idea. Those were two of the bottom-line conclusions of PUC staff regarding proposals that would allow electric utilities to more easily increase rates. "No significant evidence suggests that the current ratemaking system is in major need of repair," Public Utility Commission staff wrote in an Oct. 21 agency filing.[7]

At issue were "alternative rate-making" proposals that would replace the current system for adjusting electricity rates. Although the proposals differed in their specifics, in general all of them would make it easier for monopoly utilities to obtain rate hikes. Transmission and distribution utilities have lobbied hard for such changes for years, and the Texas Legislature in 2015 directed the PUC to examine alternative rate-making proposals and report back.

In response, the PUC in 2016 hired a team of energy consultants to examine alternative rate-making proposals elsewhere in the country. The consultants released a white paper in May[8] describing "formula rate plans" (in which rates are adjusted automatically to keep utility revenues within a specified band), "straight fixed-variable rate" plans (in which utilities recoup their fixed costs through per-customer charges that are independent of the volume of electricity consumed) "lost-revenue adjustment mechanisms" (in which rates are adjusted periodically to compensate the utility for lost revenues resulting from consumer conservation) and other schemes.

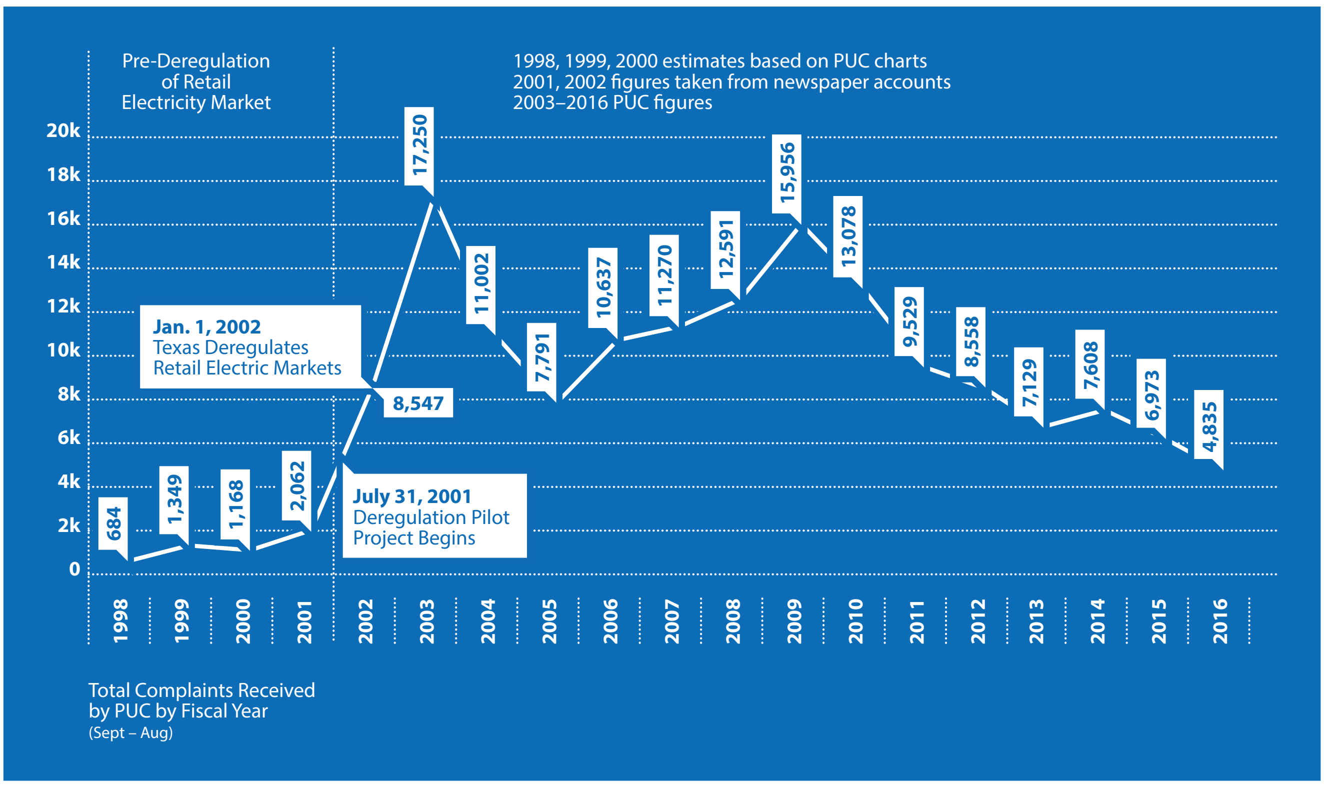
But upon reviewing the report, PUC Staff concluded that such changes weren't necessary. "The Commission believes that no compelling need currently exists for specific legislative authorization of a particular type or types of alternative ratemaking mechanisms," staff wrote.[9]

Staff noted further that "the use of inappropriate alternative ratemaking mechanisms could result in uncertain and unintended consequences for the Texas competitive retail market" and could interfere with the pricing strategies of retail electric providers.[10]

Those findings were in line with the opinions of various consumer groups and others who found that the proposed schemes would lead to higher prices for ratepayers, more paperwork for regulators and big headaches for retail electric providers.

ELECTRIC COMPLAINTS

The number of annual electricity-related complaints filed with Texas regulators dropped to a new low during the 2016 fiscal year. All told, Texans filed 4,835 electricity-related complaints or inquiries with the Texas Public Utility Commission during the 2016 fiscal year — down from the 6,973 electricity-related complaints or inquires filed in 2015. This nearly 31 percent year-over-year decline was among the steepest since the state deregulated most of its retail electricity market in 2002. The PUC also reported a drop in almost all discrete categories of electricity complaints.[11]



WIND CONTINUES TO SURGE

On Nov. 27, wind generation briefly surpassed the 15,000 megawatt mark — a first for Texas. The 15,033 MW output at 12:35 p.m. represented about 45 percent of all electricity transmitted on the state's main power grid at the moment.[12] The 15,033 MW also beat the state's previous record — 14,122 MW — which had been set only 10 days earlier. Wind producers in 2016 also set a new record for percentage of overall load when, on March 23, Texas turbines briefly produced 48.28 percent of all power on the grid.[13]

POWERTOCHOOSE REFORM

After receiving reports of potentially misleading offers on the powertochoose website, PUC chair Donna Nelson began pushing during 2016 to reform it. Among problems identified in press reports were deals featuring extremely low and unsustainable prices. Because the state's official electric shopping website sorts from lowest-priced to highest, these unrealistic deals were featured very prominently on powertochoose.org.

In response to recommendations from TCAP and others, Chair Nelson directed the agency to adjust the website query function in such a way as to reduce the prominence of misleadingly low-priced deals.[14] She also presided over several stakeholder meetings to identify additional improvements for powertochoose.org.

ELECTRICITY PRICES

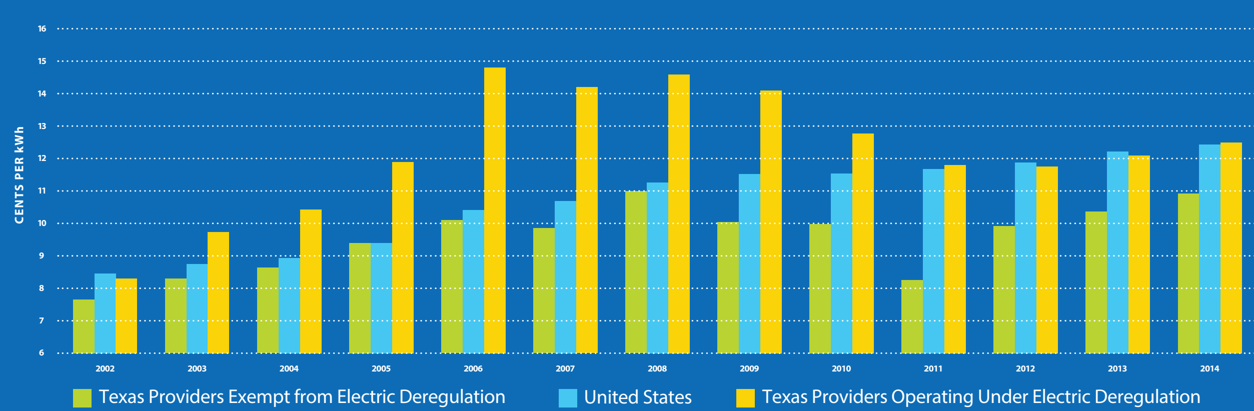
Residents in areas of Texas with electric deregulation could choose from a growing number of comparatively low-priced power deals during 2016. However, a pricing analysis released by TCAP in June reaffirmed previous findings that Texans living in deregulated areas had historically paid more for electricity, on average, than Texans living in areas exempt from deregulation. From 2002 through 2014 the imputed "lost savings" from higher average electric costs in areas with retail electric competition exceeds $24 billion, according to the TCAP report. This confirmed findings from previous reports.[15]

TCAP also found that rates charged by the state's two largest transmission and distribution providers had increased in recent years beyond the level of inflation, and that these rates comprised a larger proportion of home residential bills than they had in previous years. Transmission and distribution charges are "non-bypassable," which means that all electric customers in a given region must pay them, regardless of the retail electric provider the consumer has selected for service.[16]

Average Residential Electricity Prices
Inside & Outside Areas of Texas with Retail Electric Deregulation

EXHIBIT 1: Residential prices inside and outside deregulated Texas

Source: United State Energy Information Administration; http://www.eia.doe.gov/cneaf/electricity/page/eia861.html



Year: 2017 The Buyout Continues

The year began with Florida-based NextEra poised to take control of Oncor Electric, the state's largest transmission and distribution utility. But that bid — the second since Oncor went on sale in 2015 — fell short during 2017, as did two others. That left a fifth potential suitor in position to take control of the utility.

ONCOR on Sale

Oncor went up on the auction block after the bankruptcy of its erstwhile parent company, Energy Future Holdings. Because Oncor is a state-sanctioned monopoly — and because it was part of EFH — it cannot be sold without the consent of Texas regulators and a federal bankruptcy court. See "Oncor's Ring Fence" from the 2007 Chapter.

Here's a quick summary developments during 2017 relating to the potentially multi-billion-dollar sale of Oncor.

- In February the PUC quashed a bid by Florida-based NextEra to take control of Oncor after commissioners and consumer groups expressed concern that it would have undermined existing "Ring Fence" legal protections for the utility and its ratepayers. [To read more about the Oncor Ring Fence, see the 2007 chapter].

- On July 7 Berkshire Hathaway Energy, a unit of the investment conglomerate owned by Warren Buffett, announced it had tentatively agreed to a $9 billion all-cash deal to acquire Oncor. The Berkshire Hathaway offer was more straightforward than the NextEra offer and a previous offer made in 2016 from a consortium that included Dallas billionaire Roy Hunt. [See the 2016 chapter]. But the Berkshire Hathaway deal also failed under the weight of separate objections by Elliott Management, a New York City hedge fund that was the largest creditor of Energy Future Holdings.

- In early July Elliott floated a deal said to be worth $300 million more to creditors than that offered by Berkshire Hathaway. This briefly put Elliott in the lead position for Oncor.

- In August California-based Sempra Energy announced yet another offer, this one based both on cash and debt. Both Elliott Management and Energy Future Holdings threw their support behind this new deal. The federal bankruptcy court approved the Sempra offer in September. The PUC will review it in 2018 to determine whether it comports with the public interest.

MORE UTILITY NEWS

In September the PUC approved an important regulatory swap under which Oncor would begin serving customers of the beleaguered Sharyland utility, and Sharyland would take control of $380 million in transmission lines from Oncor. The deal also required Oncor to pay Sharyland $20 million, and for Sharyland to surrender to Oncor an electric distribution network that served retail customers.

Sharyland serves about 54,000 customers in West Texas and in portions of the Rio Grande Valley. Oncor serves nearly 10 million customers throughout Texas.[1] The agreement between the two utilities was expected to shave $50 or $60 per month from Sharyland customer rates, which, in 2017, were among the state's highest. [see 2015 chapter].

The swap — part of a broader rate case for Oncor — also was expected to slightly rate increase for Oncor's legacy customers.[2]

In October the PUC convened a special hearing to consider a number of technical proposals that could impact ERCOT operations. Included in a report sponsored by Houston energy giants NRG and Calpine, the proposed changes to wholesale power market rules also could lead to increased wholesale energy prices around Houston and other areas under certain circumstances. Although the PUC did not formally approve or reject the recommendations in 2017, the report and discussions around it signaled continued dissatisfaction among some big generators with wholesale power market prices.

The generators sponsoring the report argued that one unfortunate side effect of ordering extra power plants to come on line for system reliability purposes was that such action inappropriately dampened certain wholesale power prices. The generators argued for revised ERCOT pricing rules that they said would better incentivize new plant construction.

These arguments were reminiscent of earlier ones made by large generation companies seeking to create a capacity market in Texas. [See Year: 2012 chapter] NRG and Calpine also were the principal opponents of the Houston Import Project, a major transmission line project that could open that region to more suppliers and potentially lower wholesale power costs there [See the Houston Import Project articles in the Year: 2014 and Year: 2015 chapters].

Those opposing NRG and Calpine on the issue — including representatives of major industrial electricity users and consumer groups — said the companies' proposed changes (as outlined in the technical report) were unnecessary because the ERCOT market was functioning reasonably well. They said the NRG and Calpine proposals would prop up the companies' own power plants at the expense of electric customers within the Houston area and at the expense of competing generation companies outside of the Houston area.

Report Proposes ERCOT Technical Changes

Intimidatingly entitled *Priorities for the Evolution of an Energy-Only Market Design in ERCOT,* the NRG/Calpine report was prepared by William Hogan of Harvard and Susan Pope of FTI Consulting.[3] It included a menu of arcane changes relating to the ERCOT-managed market. Among them:

- Adjust the parameters of a complicated wholesale market mechanism known as the Operating Reserve Demand Curve, also known as the ORDC. Under the ORDC, generators receive an enhanced payment for electricity they sell during periods when other available power becomes scarce. Under the NRG/Calpine proposal, the sliding scale used to calculate this adder would be adjusted in such a way as to favor generators that relieve power scarcity.
- Adjust the allocation of costs associated with transmission line losses. This proposal relates to the engineering of power grids: that is, a certain amount of electricity is always lost during transmission, and that amount is in direct proportion to the length of transmission lines. This proposal would change existing rules under which costs associated with line losses are shared broadly among wholesale users across the ERCOT region. Under the proposed change, charges would be allocated on a more granular, local level — and calculated based upon line distances and associated line losses associated with serving that local area.
- Change policies with regards to the planning and financing of transmission projects, and amend the current rules under which transmission costs are spread out across the ERCOT system.

MORE POTENTIAL CHANGES IN THE ERCOT MARKET

In October Lubbock Power & Light submitted a formal application to the PUC seeking permission to link to the ERCOT power grid[4] and to disconnect from a separate grid that serves portions of West Texas, portions of New Mexico and several other states.[5] Lubbock Power & Light is the third largest municipal electric utility in Texas. It serves more than 104,000 electric meters, and owns and maintains 4,936 miles of power lines and three power plants.[6]

Also in October, Vistra Energy (the newly rebranded parent company for TXU Energy and Luminant)[7] announced it would be shuttering three of its coal-fired plants — Monticello, Sandow and Big Brown.[8] San Antonio's city-owned CPS Energy also announced plans to close its coal-fired plant, J.T. Deely. All the retirements were expected in 2018.

The retirements, the first for the Texas market since at least 2000, would mean the loss of nearly 5,000 megawatts of generating capacity. The retirements also followed a nationwide pattern: traditionally a dominant energy source, American coal nonetheless was losing ground to natural gas as the commodity cost of that resource remained comparitively low and power plants burning natural gas gained in efficiency. Technology improvements also were making renewable resources relatively more competitive.

However — even given the coal retirements, Texas was expected to have sufficient generating capacity through at least May 2018, according to a pair of reports released by ERCOT in November.[9]

RENEWABLE POWER MAKES GAINS

Wind power blew past coal during 2017 to become the second largest electricity source in the ERCOT market. The milestone was reached in October when a 155-megawatt wind farm in West Texas began commercial operations. This brought the state's wind power capacity to more than 20,000 megawatts. Texas coal-fired plants, by contrast, comprised only 19,300 megawatts of capacity, according to ERCOT.[10]

The solar industry also marked its strongest quarter ever in Texas, with 375 megawatts of new capacity added in the three months from April through June. A report by the Solar Energy Industries Association ranked Texas second among states for solar growth during the second quarter of 2017.[11]

ELECTRIC PRICES AND COMPLAINTS

Complaints from electricity consumers dropped to a new post-deregulation low during 2017. The PUC registered 4,175 electric-related complaints or inquiries during FY 2017, as compared to 4,835 during FY 2016. That marked a 14 percent year-to-year drop. A report issued by TCAP in October found that the number of complaints and inquiries filed by electric consumers had been falling more or less steadily since 2008, roughly paralleling a trend of lower electricity prices in Texas.[12]

A separate TCAP report issued in July[13] found that residential electric prices in areas of Texas with retail competition had declined during a recent 10-year period, while average prices in deregulation-exempt areas had increased during

Vistra/Dyndergy Merger

Vistra in 2017 announced it would merge with Houston-based Dynergy. The newly combined company would serve about 2.9 million customers, according to the *Dallas Morning News*.[14]

the same period. However — even accounting for those pricing shifts — average residential electricity prices in deregulated areas remained consistently higher during every year of the study period.

The TCAP analysis found that charges assessed by monopoly transmission and distribution providers comprised a growing portion of home bills, and that increases since 2003 had far outstripped the pace of inflation.

TEXAS LEGISLATURE: GOVERNOR SIGNS RATE CASE BILL

The Texas Legislature convened for its 85th Regular session in 2017. Although lawmakers considered scores of bills that potentially could impact electric ratepayers, few made it to the governor's desk. One exception was Senate Bill 735, which would require the PUC to establish a schedule under which it periodically reviews the fairness of electric utility rates. SB 735 included other changes to rate-setting procedures that, taken collectively, should be something of a mixed bag for ratepayers. The governor signed Senate Bill 735 on May 27.[15]

Appendix A: Senate Bill 7 — Key Components

When Gov. George Bush signed Senate Bill 7 into law in 1999, he instituted what some have called America's most audacious experiment in the deregulation of electric power. Gov. Bush was clear about his intentions. "Competition in the electric industry will benefit Texans by reducing rates and offering consumers more choices," he said.

No longer would the production and sale of electricity be considered monopoly enterprises. Instead, SB 7 called for "the establishment of a fully competitive electric power industry" where market forces dictate prices and service. The companies that own, operate and manage the transmission and distribution system remained regulated — but most regulation of companies that produce and sell electricity would end.

SB 7 states "the Legislature finds that the production and sale of electricity is not a monopoly warranting regulation of rates, operations and services and that the public interest in competitive markets requires that… electric services and their prices should be determined by customer choices and the normal forces of competition." The Legislature ordered far-reaching changes to the market.

STRUCTURAL CHANGES

The electric power industry has three main functions – generating power, transporting power over power lines to the customer, and interacting with the customer (billing, opening new accounts, resolving problems, etc.). Prior to deregulation, a single electric company performed these services for all customers within its designated service area. SB 7 made power generation and the provision of retail electric service subject to the normal forces of competition and customer choice. Transmission and distribution services remain regulated. Accordingly, the statute required the former monopoly provider to "unbundle" – that is, to separate – its operations into three distinct entities:

- The power generating company owns and operates the electric power plants and sells its power into the deregulated wholesale power market.
- The regulated transmission and distribution company owns and operates the wires to transport power from the plant to all customers within a certain geographical area.
- The deregulated retail electric provider purchases wholesale power from power-generating companies and re-sells the power to customers. The retail provider is responsible for most interaction with the customer, including billing the customer for transmission and distribution services and for the power purchases. However, a retail provider may not own generation.

At the very minimum, the former monopoly providers were required to create separate companies for each service although the new companies could remain under the same ownership.

SB 7 exempted municipally-owned utilities and cooperative utilities although those entities could opt into deregulation. Areas of Texas not covered by the state's main transmission grid remained outside deregulation unless they met certain requirements. The Panhandle, El Paso, the Golden Triangle and the far northeast corner of the state remain outside those areas where deregulation is mandated.

RECOVERY OF STRANDED COSTS

Before deregulation, utilities were required to build plants to serve the energy needs of their customers. In order to build a plant, a company would invest millions of dollars in construction costs. Once the Public Utility Commission (PUC) determined that the construction costs were prudently incurred, the company was allowed to recover all of its costs and a reasonable level of profit from ratepayers. However, because the costs were substantial, the utilities were not paid back immediately. The payback, with interest, was spread over the projected life of the plant — usually 30 years.

Once the electric market became deregulated, former monopoly providers could not continue to charge regulated rates to recover power plant construction costs they had already incurred to serve customers. Former monopoly providers feared that they would not be able to sell the power plants at a price that would offset the outstanding debt, and the companies would be forced to choose between two untenable options: charge high prices that could not compete or absorb all of the costs related to the uneconomic plants. The difference between the net book value of the plant and the price that the plant could fetch if sold in the market became the former monopoly providers' "stranded costs."

Lawmakers determined that former monopoly providers should have the right to recover so-called stranded costs from ratepayers. SB 7 includes several provisions regarding the calculation and collection of stranded costs. The statute also imposes some restrictions on the utilities' ability to recover stranded costs and stipulates that no utility would be allowed to over-recover stranded costs.

To minimize the impact to customers, SB 7 established a three-phase process for stranded cost recovery:

- First Phase (Sept. 1999 – Dec. 31, 2001) – Regulated rates that otherwise should have been reduced are frozen. All profits in excess of Commission-set levels are applied to buy down the uneconomic plants' book value.

- Second Phase (Jan. 1, 2002 – Dec. 31, 2004) – Preliminary estimates of potential stranded costs are developed for each utility to determine whether efforts taken in the first phase were successful. If the preliminary estimates indicate stranded costs are still possible, an initial fee is surcharged to the transmission and distribution utility. The fee to the transmission and distribution utility is passed on to customers by the retail electric provider and would be used to continue buying down the uneconomic plants' book value.

- Third Phase (Beginning January 2004) – Former monopoly providers are required to true-up the actual, final value of stranded costs, taking into account the efforts in the previous two phases. Unlike the stranded cost projections in the earlier phases that relied upon a mathematical model to calculate potential-stranded costs, SB 7 provided utilities four different options to derive a final market value for potentially stranded generation assets. If the net book value exceeds the final market value, then the utility is entitled to recover stranded costs. Stranded costs are to be recovered through a fee that will be surcharged to the regulated rates of all customers within the former monopoly provider's service area.

THE PRICE TO BEAT

SB 7 required utilities to freeze their rates beginning on Sept. 1, 1999. When the deregulated market opened on Jan. 1, 2002, retail electric providers affiliated with the utilities were required to charge a price that was six percent less than the regulated rate that existed on Dec. 31, 2001. Until 2005, this new rate (known as the "Price To Beat") was the only rate that the provider affiliated with the former monopoly company was allowed to charge residential and small commercial customers in the old service area. The Price To Beat created a target for competitors to undercut with lower prices. A provider affiliated with a former monopoly electric company was required to offer the Price To Beat rate until Jan. 1, 2007. However, it also could offer plans with alternative prices after Jan. 1, 2005, if it could demonstrate that it had lost more than 40 percent of its customers.

SB 7 offered one exception to the fixed Price To Beat rate providers must charge. Individual Price To Beat providers were able to increase or decrease the rate no more than twice each year to reflect changes in natural gas fuel prices, which fuel some generation plants. The decision to increase or decrease the Price To Beat rate and the timing of the change was left to the Price To Beat provider.

PROHIBITION AGAINST MARKET POWER ABUSES

SB 7 requires the PUC to monitor market power associated with the generation, transmission, distribution and sale of electricity and to protect against any company acquiring generation capacity sufficient to exercise market power in the newly deregulated market. A company with market power is capable of restricting, impairing, or otherwise reducing the level of competition in the market.

Market power abuses specifically prohibited by SB 7 include predatory pricing, withholding of power, precluding entry to the market, and collusion.

Because a company usually has market power by virtue of controlling a large portion of the market, no company is generally allowed to own and control more than 20 percent of generation capacity within a power region. If the PUC finds market power abuses, the statute requires that the offending company submit a plan to mitigate its market power. These market mitigation plans could require the company to sell assets, auction off capacity, or take other measures to decrease the amount of generation capacity they own and control.

ENVIRONMENT

SB 7 included two major provisions relating to the environment, and established new energy efficiency guidelines.

The first provision relates to older generating plants that had been exempted from obtaining clean air permits under the 1971 Texas Clean Air Act. SB 7 set a deadline of May 2003 for utilities to cut overall nitrogen oxide emissions on this fleet of generating plants by 50 percent, and sulfur dioxide emissions by 25 percent (with deeper cuts of nitrogen oxide and sulfur dioxide emissions in urban areas around Houston, Galveston, Dallas and Fort Worth). To accomplish the reductions, SB 7 created a "cap and trade" system. The statute allowed utilities to recover the cost to meet the new standards by including the expenditures in their calculations of stranded costs.

SB 7 also established new statewide mandates and corresponding deadlines for the use of renewable energy. The responsibility for meeting the mandates was assigned to electric retailers based upon their individual share of the overall market. To help carry out this provision, SB 7 created a Renewable Energy Credit trading program, which is managed by the Electric Reliability Council of Texas (ERCOT). Under the program, an electric retailer that acquires more than enough renewable energy to meet its own requirements can sell credits for its excess renewable energy to other companies that have fallen short.

Although the overall renewable energy mandates in this section have increased since SB 7 was first enacted, it was originally intended to foster the construction of 2,000 megawatts of additional renewable energy by 2009 — or enough to power about 1.6 million homes.

New energy efficiency requirements were also introduced in SB 7, including a requirement that regulated transmission utilities administer energy savings incentive programs, provide customers access to energy efficiency alternatives and provide incentives for electric retailers to engage in energy efficiency efforts. Under this provision, electric utilities were expected to reduce their annual growth in energy demand by at least 10 percent by Jan. 1, 2004.

CUSTOMER PROTECTIONS

The Provider Of Last Resort

It was critical to lawmakers that customers always receive power in the deregulated market, even if some providers went out of business or if there was a billing dispute. To ensure reliable service, SB 7 established the "Provider Of Last Resort" service for customers who cannot get power from other providers, or for customers of failed companies that abruptly leave the market. The Provider Of Last Resort is selected by the commission and charges a commission-approved fixed rate for standard service.

The System Benefit Fund

SB 7 established a user fee on electric service. Funds generated by this fee were to be deposited in a special account, known as the System Benefit Fund. The System Benefit Fund was intended to support electric rate discounts for low-income customers, finance energy efficiency programs for low-income households, fund a customer education media campaign relating to retail competition and compensate school districts for the loss of any property tax revenue attributable to the deregulation law.

The Price To Beat

SB 7 created the Price To Beat to serve as both a target for competitors to undercut in order to win new customers and to provide a modest rate cut for customers that were unwilling or unable to switch providers.

Registration and Certification of Market Participants

Although the production and sale of electricity to customers was no longer subject to regulation, SB 7 authorized the PUC to establish minimum requirements for registration and certification of entities operating in the deregulated market.

Aggregation

SB 7 specifically contemplates that multiple customers could join together for the purpose of negotiating better deals in the new market. For example, municipalities and other political subdivisions that procure electricity for their own purposes — consider the expense of lighting city buildings or powering a wastewater station — can join together to purchase electricity. SB 7 refers to entities that band customers together in this fashion as "aggregators." The law requires aggregators to register with the PUC.

Municipalities and other political subdivisions are authorized to act as aggregators to join together their citizens in order to purchase electricity on their behalf. Under this provision, the citizens must affirmatively request to be included in the aggregation group.

INDEPENDENT SYSTEM OPERATOR

SB 7 requires that an independent entity oversee important operational aspects of the new market. ERCOT was designated as an "Independent System Operator" to fulfill this function.

SB 7 stipulates further that the Independent System Operator remain independent from the individual buyers and sellers of electricity in the market. At the same time, the independent organization must ensure that such buyers and sellers have equitable access to the transmission network. Under SB 7, this organization also is charged with ensuring the reliability and adequacy of power.

As manager of the Texas power grid, ERCOT already was charged with maintaining reliability and adequacy of its operations. ERCOT also was already designated as an Independent System Operator under the provisions of the 1995 law that partially deregulated wholesale electricity.

But under SB 7, ERCOT's duties — especially those relating to its mission as an Independent System Operator — would expand greatly. Its responsibilities would include the management of new billing and settlement systems, the establishment of broad new rules for wholesale power transactions, and the creation of policies relating to the scheduling of power.

As an Independent System Operator under SB 7, ERCOT must:

- Provide an accurate accounting of electricity production and delivery among generators and wholesale buyers and sellers.
- Ensure that entities that require information relating to a customer's choice of retail electric provider receive that information in a timely fashion.
- Establish and enforce rules governing wholesale electricity transactions.

As the Independent System Operator, ERCOT also must set up a governing body comprised of four representatives of power generators, four representatives of transmission and distribution operators, four representatives of businesses that sell power, and three members representing consumers.

Appendix B: 2015 PUC Complaint Data

**Originally published as a TCAP Snapshot Report, October 2015*

Electricity complaints filed with the Texas Public Utility Commission have fallen to a new post-electric deregulation low, according to a review of agency data.

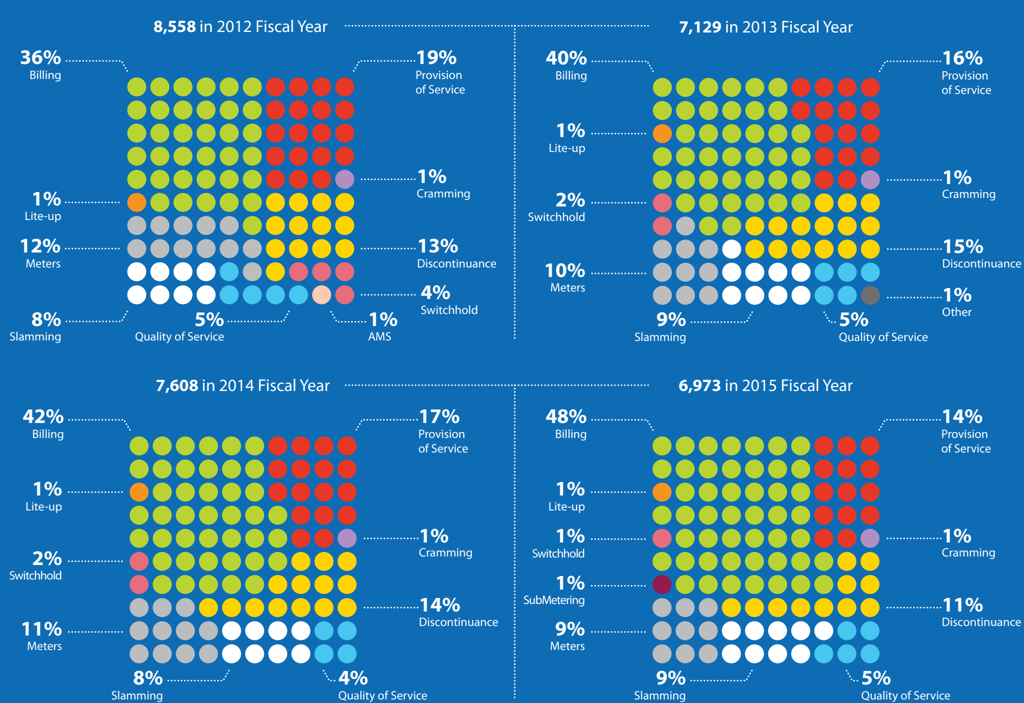
All told, Texans filed 6,973 electricity-related complaints or inquiries during the most recent fiscal year. The previous low during the electric deregulation era came in FY 2013, when the PUC tallied 7,129 complaints and inquiries. The state deregulated most of its retail electricity market in 2002.

But despite the encouraging numbers, complaints remain more numerous now than they were prior to the switch to deregulation. Also less encouraging is the dramatic uptick in complaints filed in FY 2015 against a single electric company — Dallas-based Sharyland Utilities.

This Snapshot Report is based upon a review of electricity complaints and inquiries filed with the PUC's Office of Customer Protection, which was established in July 1997. The Texas Coalition for Affordable Power reviews this data on an annual basis.

All data are given for fiscal years and have been obtained under the Texas Open Records law or extrapolated from publicly available PUC reports and from newspaper accounts. Data for 1998, 1999 and 2000 are estimated figures. TCAP considers both complaints and inquiries in order to gauge general consumer sentiment and also to maintain a uniform methodology across the study period.

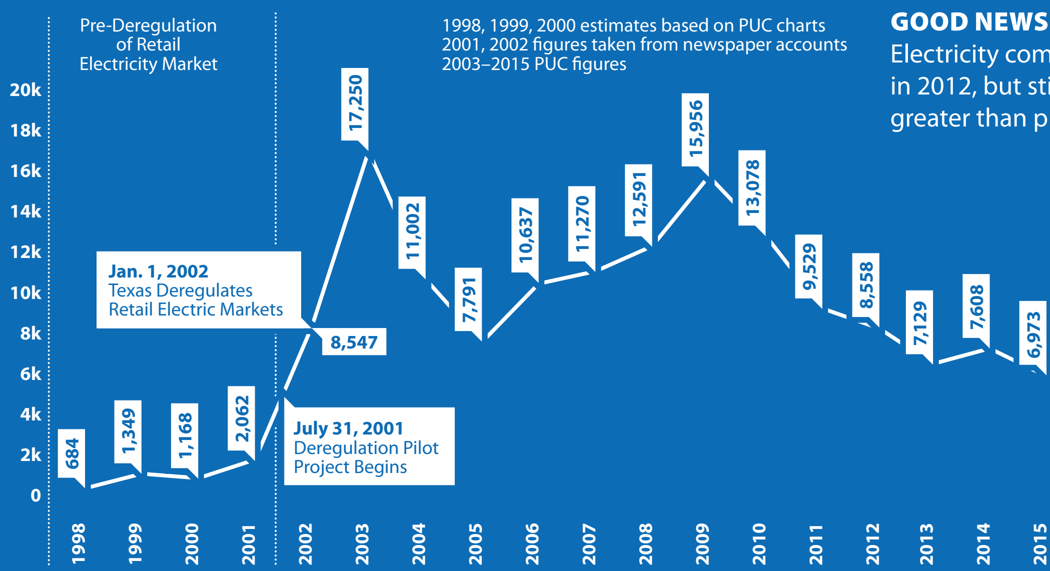
Electricity Complaints Filed with Texas PUC



KEY FINDINGS:

- The PUC recorded 6,973 electricity-related complaints or inquiries during the 2015 fiscal year. That's the fewest tallied by the agency since retail electric deregulation began in 2002.
- The average number of electricity-related complaints or inquiries filed on an annual basis since the retail electric deregulation law took effect is 10,566. The highest number of complaints filed during a single fiscal year was 17,250, during the second year of the retail electric deregulation law.
- The average number of electricity-related complaints and inquiries filed with the PUC during each fiscal year prior to electric deregulation was 1,315.8. However, there are only four years of data for that analysis.
- The average number of electricity-related complaints and inquiries filed with the PUC during each fiscal year prior to electric deregulation was 1,315.8. However, there are only four years of data for that analysis.
- Complaints quadrupled with the transition to deregulation in 2002 and have never returned to pre-deregulation levels. Although population growth and the increased use of the Internet to facilitate the complaint process can explain some of the increase, it's unlikely that those factors alone account for the dramatic differences — especially those registered during the early years of the deregulation law.
- Although Texans filed fewer complaints in FY 2015 than they did in FY 2014, they nonetheless received more complaint-generated refunds in FY 2015 than during the previous year. According to PUC records, Texans who filed complaints with the PUC received $450,183 in refunds during the 2015 fiscal year, or about 6.7 percent more than the $421,862 awarded during the 2014 fiscal year.
- The plurality of complaints and inquiries submitted to the PUC in FY 2015 relate to electric bills. Approximately 48 percent related to billing and another 14 percent related to provision of service. In FY 2014, 42 percent related to billing and 17 percent related to provision of service.
- The PUC received more than nine times the number of complaints and inquiries against Dallas-based Sharyland Utilities in FY 2015 than it received against the Dallas-based company in FY 2014. Sharyland serves retail customers in West Texas. Most of the complaints and inquiries relate to rates and bill charges.
- Complaints and inquiries were up from last year in a few discrete categories — including a nearly 5 percent increase related to billing. In FY 2015, billing complaints and inquiries numbered 3,332. That's up from the 3,178 in FY 2014 and 2,862 in FY 2013.
- The PUC in FY 2015 registered 953 complaints or inquiries for provision of service, 772 for discontinuance of service, 651 for meters and 628 for slamming, which is the practice of switching a consumer's service provider without authorization.
- The practice by some companies of ordering holds on customer accounts generated 82 complaints in FY 2015. Under controversial "switch hold" rules approved by the PUC, some households can be barred from the retail electric market if they get behind in their payments or if they are accused of tampering with their utility meters.
- According to recent weighted complaint rankings from the PUC (as of March 1, 2015 through August 31, 2015), retail electric providers with the worst complaint rankings included TruSmart Energy (formerly DPI Energy), Hino Electric, Potentia Energy (also known as Verde Energy) and Brooklet Energy Distribution (also known as Acacia Energy).
- Potentia and Hino also were among companies with the highest complaint ratings in a survey last year. Acacia Energy was among those with the highest complaint rates in a survey reported last year and in 2013. DPI Energy was among those with the highest complaint rates in surveys in 2014, 2013 and 2012.
- According to recent weighted complaint rankings from the PUC (as of March 1, 2015 through August 31, 2015) retail electric providers with the best complaint rankings were MP2 Energy Texas, Alliance Power (APC Electric), MidAmerica Energy, Iluminar Energy (Conservice Energy), Nueces Electric Coop (NEC Retail), Andeler, Hudson Energy Services, Our Energy, TXU Energy, WTU Energy and Reliant Energy.
- Alliance Power and MP2 Energy Texas also were among those with the best complaint rankings in a survey last year.

Customer Complaints



GOOD NEWS / BAD NEWS STORY

Electricity complaints continue decline in 2012, but still more than five times greater than pre-deregulation average.

UPBEAT NUMBERS FOR FY 2015

The FY 2015 data suggest that, overall, electric customer sentiment in Texas is improving. This year's findings build upon similar upbeat analyses conducted by TCAP during FY 2014 and FY 2013.

For instance, other than the 2015 fiscal year, the two post-deregulation years in which the PUC registered the fewest electricity complaints and inquiries were FY 2014 and FY 2013. The PUC tallied about 2 percent fewer electricity-related complaints and inquiries during FY 2015 than it tallied in FY 2013, the previous low-water mark during the deregulation era.

The PUC also reported a drop in various discrete categories of electric complaints over the last fiscal year. These include a drop in meter complaints, provision of service complaints and those relating to "switch-holds," which is the practice of blocking residential electric service.

While Texans filed fewer complaints in FY 2015, they nonetheless received more complaint-driven refunds in FY 2015 than during the previous fiscal year, according to PUC data.

However, one clear area of customer dissatisfaction relates to Sharyland Utilities, which is owned by the same party seeking to control the Oncor Electric utility as its parent Energy Future Holdings emerges from bankruptcy. Complaints against Sharyland skyrocketed to 437 in FY 2015 from 47 in FY 2014.

The complaints against the tiny utility were so numerous in 2015 that the Texas Public Utility Commission opened a special proceeding that resulted in a slight rate decrease for some customers.

For this analysis, TCAP reviewed all electricity-related complaints and electricity service inquiries reported to the PUC for each fiscal year since 1998. This analysis does not tabulate complaints filed directly with electric companies.

Texans can find complaint data for individual retail electric providers at the state's electricity shopping website, powertochoose.org. On the site, companies are assigned weighted complaint rankings that take into account both the number of customers the company serves and the number of complaints the PUC has received about that company.

Sharyland Complaints Skyrocket

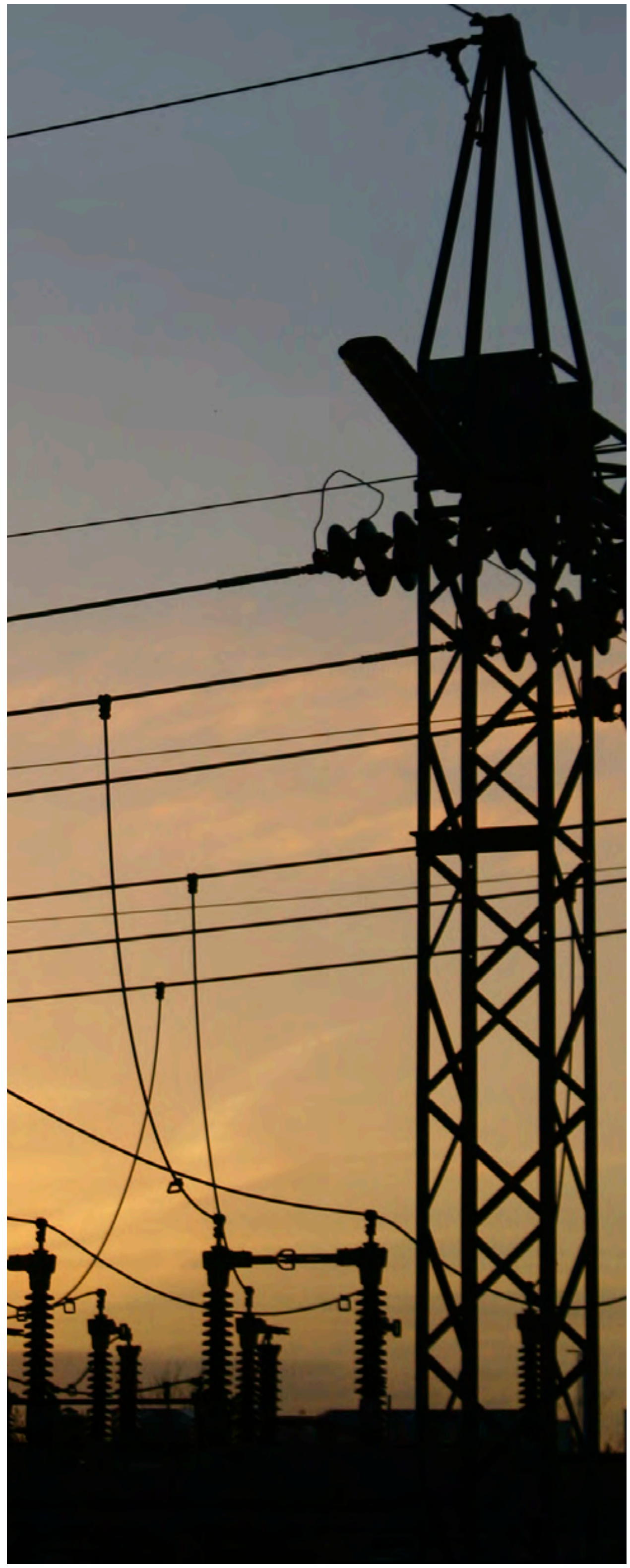
Media reports describe Sharyland electric bills as two or three times higher than those typically found elsewhere. In October, the PUC authorized a slight decrease in Sharyland rates.1 The owners of Sharyland are in negotiations to purchase Oncor, the state's largest transmission and distribution utility.[1]

How to Lodge a Complaint with the PUC

Under the PUC's complaint process, customers can file a complaint against a company with the agency's Office of Customer Protection. Agency employees then make an inquiry with the company, which has 21 days to respond. A PUC investigator evaluates the company's response to determine whether it failed to follow the law.

The Office of Customer Protection can be reached by calling 1-888-782-8477, by email at *customer@puc.state.tx.us*, or online at *puc.state.tx.us/consumer/complaint/Complaint.aspx*.

Texans can also review specific complaint data for competitive electric providers at powertochoose.org. TCAP recommends that consumers always check this complaint data when shopping for electricity.



Appendix C: Excess Mitigation Credits

The Public Utility Commission responded to the collapse of House Bill 2107 in 2001 with a decision that ultimately increased prices for ratepayers. In November, not long after the end of the 77th legislative session, the PUC ordered the payment of what became known as "excess mitigation credits." Termed "EMCs" in the alphabet soup of ratemaking, these credits represented the value of refunds that would have gone back to ratepayers had the Legislature adopted HB 2107 (the start of this section). But instead of flowing back to ratepayers, the PUC sent the money (through an indirect process) to electric retailers. These retailers had never suffered from the stranded cost overcharges, and yet they would now benefit from them. In many cases, the retailers were financially affiliated with the companies that were ordered to pay the EMCs.

HOW THEY WORK

Under the PUC-initiated excess mitigation credit ruling, generation companies affiliated with the incumbent monopoly provider that presumably over-collected for stranded costs were directed to return the money (in the form of EMCs) to transmission and distribution companies. Those transmission and distribution companies, in turn, were directed to make a corresponding reduction in rates they charged to electric retailers. But the retailers were not required to pass those savings onto customers. In fact, in some cases they were actually prohibited from doing so.

Remember: under SB 7, retailers affiliated with the state's traditional utilities charged the Price To Beat rate. Setting aside adjustments for fuel costs, the Price To Beat was a fixed rate. Customers on the Price To Beat paid that rate and only that rate — no more, no less — which meant they could not receive EMCs. But the Price To Beat retailers who served them were receiving almost all of the excess mitigation credits because these retailers then controlled 85 to 95 percent of the residential market. Said another way: the Price To Beat retailers took the EMCs but were prohibited by rule from passing along the benefit to their residential customers.

Because the retailers charging the Price To Beat typically remained affiliated with the incumbent generators who owed the excess mitigation credits, the effect of the PUC order was to require companies to take money due to ratepayers and instead pay it to a separate arm of the same company, a transfer sometimes characterized as moving ratepayer money from one company pocket to another.

The PUC ordered the collection of $55 million in excess mitigation credits from Central Power & Light in South Texas, $1.24 billion in excess mitigation credits from the predecessor of Houston's CenterPoint Energy and $888 million in excess mitigation credits from TXU in North Texas. Although most of this money ended up with retail electric providers affiliated with the state's traditional utilities, some of it ended up with competitive electric providers. The PUC argued that the competitors could use the money to lower prices and potentially steal away more customers. But there's little evidence that this worked or that these competitive retailers did anything but pocket the windfall.

The Public Utility Commission's EMC rule also led to even greater consumer expenditures in 2005, during final stranded cost decisions that year. (For more about stranded costs, see page 66.)

Under Senate Bill 7, consumers would end up paying: the expense of excess mitigation credits from which they derived no benefit, the expense of reimbursing energy companies for supposedly uneconomic investments that actually ended up becoming quite profitable for those companies, and the expense of overpriced power in the restructured market.

Here's how consumers lost with Excess Mitigation Credits and Stranded Costs:

1. Senate Bill 7 contemplated that as a result of deregulation, ratepayers eventually would owe stranded cost payments to utilities. The 1999 legislation provides methods for mitigating presumed future stranded costs by allowing utilities to overcharge ratepayers in the run-up to deregulation. For ratepayers in the Houston area, stranded costs will add about $7.30 to monthly bills for many years to come. Ratepayers in other parts of the state also face hefty stranded cost awards. (For more about stranded costs, see the chart on page 66.)
2. But in 2001, the PUC made a determination that utilities instead could face "negative" stranded costs — and as a consequence, it appeared that ratepayers were needlessly making overpayments to utilities.
3. This prompted the PUC to order generators to surrender the stranded-cost related overcharges they had received to that point. The refund of these overcharges became known as "excess mitigation credits." But because the Price To Beat prohibits any discounts, most of the credits went into the pockets of the electric retailers. Most customers weren't able to benefit.
4. Beginning in 2004, the PUC reversed course again and found that electric companies did not face negative stranded costs but rather positive ones. That is, the PUC agreed with electric companies — despite great evidence to the contrary — that key generating assets lost value in the transition to deregulation.
5. This finding, in turn, led the PUC to determine that the excess mitigation credits awarded in 2001 were unwarranted and should be returned.
6. The value of those credits — more than $2 billion — was added to already questionable stranded cost bills faced by ratepayers. This meant that ratepayers, most of whom never received the benefit of the excess mitigation credits in the first place, were nonetheless on the hook for paying them back. All told, the value of stranded costs in Texas (including the value of the excess mitigation credits) has been estimated at more than $6.5 billion. For ratepayers in the Houston area, stranded costs will add more than $7 to monthly bills for many years to come. Ratepayers in other parts of the state also face hefty stranded cost charges. (For more information about stranded costs, see chart on opposite page).
7. Meanwhile, the nuclear and coal plants that created billions of dollars in presumed stranded costs for electric companies end up becoming quite profitable in the newly restructured market. Instead of becoming uneconomic burdens, the plants proved to be efficient producers of relatively inexpensive power. But under the structure of the deregulated market, such relatively inexpensive coal and nuclear power got re-priced for retail customers as if generated by more costly natural gas-fired plants. Ratepayers lost again.

Appendix D: Unbundling

Under Senate Bill 7 vertically-integrated utilities operating within the ERCOT region were required to split into three discrete entities: generation companies, the still regulated transmission and distribution utilities, and retail electric providers. Under this "unbundling" provision, these entities were required to function separately — even if they remained under the same corporate ownership.

GENERATION COMPANIES

Under deregulation, generation companies are expected to compete with one another on price. However, some generation companies have begun pressing for price supports, claiming the current deregulated system is not providing them with enough revenue to justify new investment.

TRANSMISSION AND DISTRIBUTION UTILITIES

The power produced by generation companies travels across the system of wires owned by transmission and distribution utilities. These "wires" companies retain their monopoly status, and remain regulated under Senate Bill 7. The wires companies in recent years have obtained legislative changes that allow them to hike rates more rapidly, and with less regulatory oversight. These extra charges are passed onto retail electric providers, which then pass them onto end-use customers.

RETAIL ELECTRIC PROVIDERS

Senate Bill 7 allows for competitive Retail Electric Providers to sell power directly to home consumers. REPs are free to set their own price for power.

Texans have remained confused about the deregulated system. An industry survey in 2011 found that a majority of Texans did not clearly understand the division between their deregulated retail electric provider and their regulated transmission and distribution provider. Complaints filed against electric companies with the PUC also have increased significantly over pre-deregulation levels.

How electricity flows to its users

Major regulatory players

PUC (Public Utility Commission of Texas)
- Where applicable, sets rules for the deregulated electricity market
- Regulates investor-owned utilities within Texas but outside of the ERCOT service territory
- Implements electric and telecommunications legislation
- Oversees development of regulated transmission and distribution system for electricity
- PUC commissioners are appointed by the governor

ERCOT (Electric Reliability Council of Texas)
- A quasi-governmental organization
- Funded by ratepayers but technically a non-profit corporation managed by market participants
- Is overseen by the PUC

How electricity is sold (in a deregulated market)

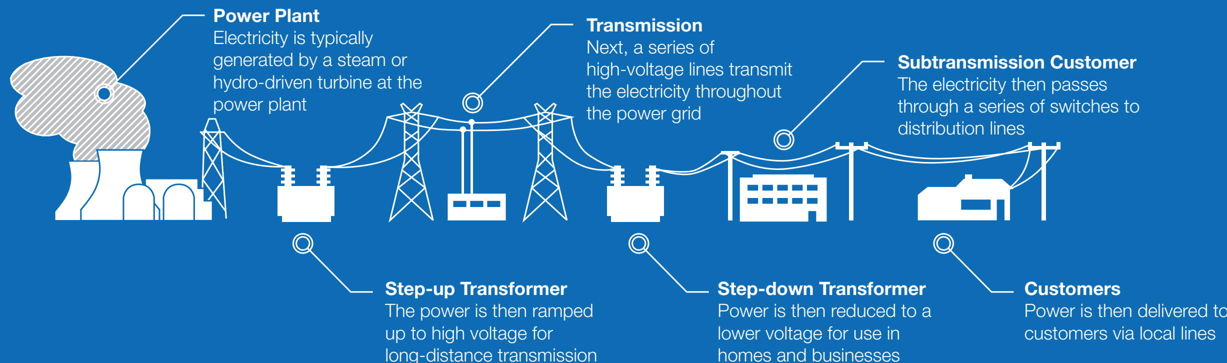
Power Plant
Power generation companies own and operate power plants, including nuclear plants or those fueled by natural gas, coal or from renewable resources such as the wind. Power generation companies sell their power in the wholesale market, where prices are deregulated.

Retail Electric Providers
REPs purchase electricity from power generation companies and sell that power to residential and business consumers. Electricity at the retail level is deregulated, meaning that REPs are free to set their own prices.

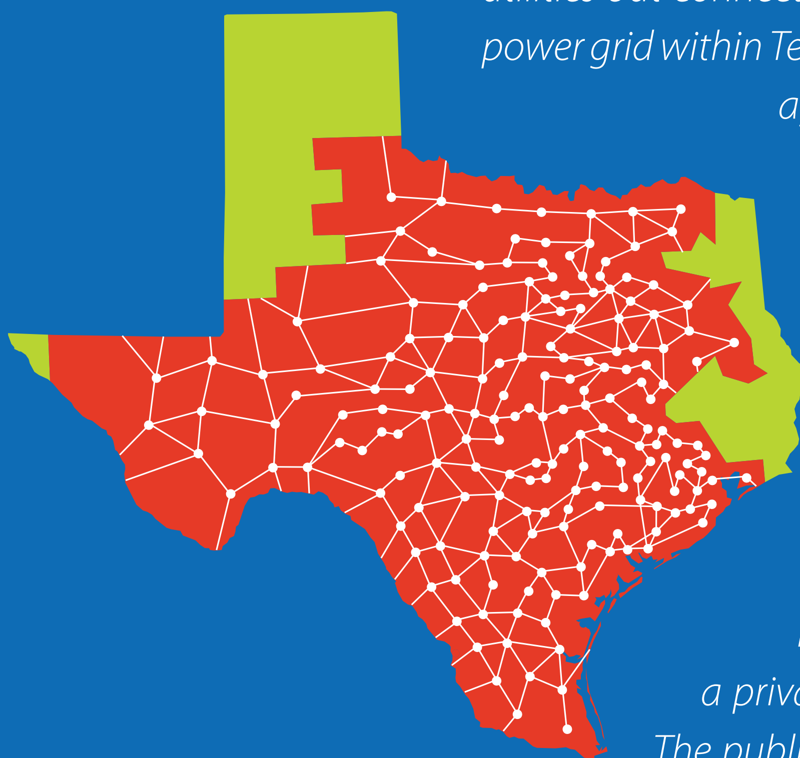
Transmission and Distribution Utilities
Transmission and distribution utilities own and operate the poles and wires that transport electricity in Texas. TDUs are monopolies, and remain regulated by the Public Utility Commission.

Your Home
Home consumers in deregulated areas of the state such as Houston or the Dallas/Fort Worth areas can choose between different electricity deals.

Flow of electricity



Appendix E: Electric Reliability Council of Texas



The network of transmission lines owned by different utilities but connected to each other forms a single power grid within Texas. The organization that manages most of this network is known as ERCOT, the Electric Reliability Council of Texas. There are two other power grids in the United States — an Eastern grid and a Western grid — but ERCOT is an island unto itself with only limited connections to the other grids. ERCOT is not a government agency, nor a private business, nor a court of law. The public does not elect its leaders, and yet those leaders make some of the state's most important public policy decisions. ERCOT does not spend tax dollars, and yet its policies impact what is inside every Texan's wallet. ERCOT decisions impact the health and welfare of all Texans, can benefit or greatly undermine the state's economy, and can mean the difference between massive blackouts or reliable service.

WHAT IS ERCOT?

Technically a non-profit corporation, ERCOT was created by the state in 1970. It has responsibility for managing the flow of power across 38,000 miles of transmission lines to more than 21 million Texans. It facilitates operations of the wholesale electricity market, supervises transmission planning, ensures that there is always adequate power on the grid and takes action to minimize congestion on transmission lines.

ERCOT has an approximately $171 million annual budget, which is financed through charges on electric bills. Stakeholders — that is, representatives of electric generators, transmission companies, consumers and other interested market participants set ERCOT policy and determine the rules by which the wholesale market operates.

WHAT ARE ERCOT'S RESPONSIBILITIES?

ERCOT functions both as the technical operator for the transmission grid and a decision-making organization that creates rules for the wholesale electricity market.

As an independent system operator, ERCOT employs technicians and engineers at two control centers in the Austin area. Using complex computer systems, ERCOT manages the flow of electricity on the grid by continually ordering generators to ramp up or ramp down production to match the amount of power demanded by consumers during any given 5-minute period. Because of the physics of electricity, if the amount of power scheduled to be consumed is not exactly in sync with the amount of power to be produced then load and generation become unbalanced, and blackouts can result.

ERCOT technicians also take actions to control congestion on transmission lines. During emergency situations, these actions can include the curtailment of electricity to certain big customers and the implementation of limited rolling blackouts.

As a decision-making forum, ERCOT depends upon interested market participants to study, debate and ultimately recommend or reject complicated wholesale market rules. These stakeholders — men and women representing power generators, commercial customers, industrial users, retailers and other interested parties — make recommendations to the full ERCOT board, which in turn makes binding decisions for the market.

ERCOT Board decisions can be overturned only by the Texas Public Utility Commission. The PUC also has limited authority over the ERCOT budget and general operations.

Because ERCOT's transmission grid serves only Texas and does not cross state lines, there is minimal federal jurisdiction that applies to ERCOT's day-to-day market operations.

HOW DOES ERCOT MAKE DECISIONS?

The most important and frequently made decisions by stakeholders involve ERCOT protocols, which are the complicated rules that govern the wholesale electricity market. Revisions to ERCOT protocols typically begin within a work group or task force. ERCOT work groups and task forces are comprised of interested stakeholders who make decisions by consensus. From there, recommended protocol changes go to the "Protocol Revision Subcommittee," then to the "Technical Advisory Committee" and finally to the ERCOT Board of Directors, which usually has the last word.

The ERCOT Board of Directors is made up of 16 men and women, most of whom represent various segments of the market. ERCOT stakeholders from each of those segments elect their own Board representatives. Non-voting board seats are reserved for the chief executive officer of ERCOT and the chairperson of the Texas Public Utility Commission.

Appendix F: Understanding Texas Wind Power

**Originally Published as a TCAP Snapshot Report, Aug. 2, 2012.*

The Lone Star State leads the nation in wind-generated power. *With an installed capacity totaling 10,648 megawatts in 2011, Texas boasts a fleet of wind generators dwarfing that in any other state. But while it appears likely that wind power may lower some wholesale energy costs, such potential savings may be outweighed by other necessary expenses. Wind power also presents tough challenges for the operators of the state's power grid. The Texas Coalition for Affordable Power offers this mini-report as a quick and easy primer on these and other issues. What you'll find here are key statistics, historical context – and a wide variety of views from the experts. As a matter of policy, TCAP supports the use of wind power, but urges regulators, lawmakers and other decision makers to remain mindful of the associated costs and reliability challenges.*

WIND POWER AND THE ENVIRONMENT

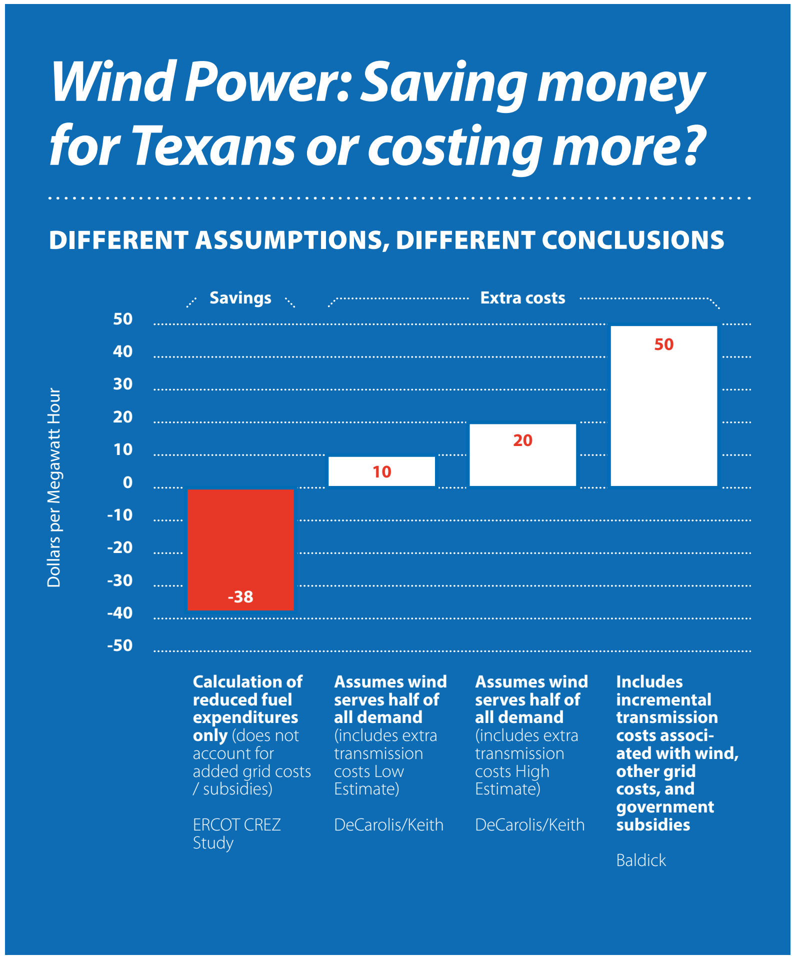
Various academic studies have concluded that the use of wind power reduces potentially harmful Carbon Dioxide (CO2) emissions. For instance, a study by R. Gross of the Imperial College of London states unambiguously "that wind energy can displace fossil fuel-based generation, reducing both fuel use and carbon dioxide emissions." Similarly, the National Renewable Energy Laboratory, in a 2008 report for the U.S. Department of Energy, noted that "choosing to build wind projects results in CO2 reductions from fewer new coal plants built and less natural gas consumption." A separate report by the U.S. Department of Energy examining the feasibility of expanded wind energy use through 2030 also predicts related drops in CO2 emissions.

However, many of the relevant studies assume that units of CO2-free electricity created by wind turbines have the effect of offsetting units of fossil-fuel electricity on a one-to-one basis. Separate research has found that this is not necessarily the case. In a 2006 study, the Institute of Electrical and Electronics Engineers (a non-profit professional association) found that fossil-fuel plants that provide backup power for wind generators must operate in ways that produce more emissions than they wound produce under ordinary circumstances. "Thus, it may be that some environmental benefits from wind power may be negated by an increase in emissions from combustion plants accommodating wind generation," the report stated. Similarly, physicist and mathematician Herbert Inhaber, in a report published in the Renewable and Sustainable Energy Reviews, concludes that "as wind penetration increases, the CO2 reduction will gradually decrease due to cycling of fossil fuel plants" that must be kept running and ready to produce energy when the wind stops blowing.

DOES WIND POWER SAVE MONEY FOR CONSUMERS?

Whether wind power results in savings or extra costs for consumers is a question of perspective. For instance, wind generators have zero fuel costs and receive public subsidies in the form of tax credits for up to two-thirds the value of wind turbines, according to some estimates. As a consequence, wind generators often bid their power into the state's spot wholesale energy market at levels below what would otherwise be the prevailing marginal cost of energy set by the state's natural gas plants. Because of the nature of the deregulated electricity market, these lower wind prices on the spot market can then put downward pressure on wholesale spot energy prices overall.

This effect is most often observed in West Texas, where there exists a high concentration of wind turbines and insufficient transmission lines to move that energy into more populated areas of the state. West Texas wind producers even occasionally bid their power into the wholesale spot energy market at negative prices. A 2008 study by ERCOT concluded that Texas should save $38 per megawatt-hour in average fuel costs from wind power, assuming the completion of new power lines to serve those wind turbines in West Texas. That would equate to monthly savings of about $38 for a typical household, assuming the savings trickle down to the retail level.



However, such calculations do not tell the whole story. According to a 2008 report from the Texas Comptroller of Public Accounts, wind generators receive larger federal subsidies, as measured as a proportion of their sales, than do natural gas and coal-fired generators. Consumers also must pay the incremental cost of wind-related transmission construction and grid-reliability services. Joseph F. DeCarolis and David W. Keith, writing in the 2006 edition of Energy Policy, conclude that such incremental costs will only increase as the use of wind energy also increases. "We find that, with somewhat optimistic assumptions about the cost of wind turbines, the use of wind to serve 50 percent of demand adds 1-2 cents per kilowatt-hour to the cost of electricity, a cost comparable to that of other large-scale low-carbon technologies." Ross Baldick, a professor in the Department of Electrical and Computer Engineering at the University of Texas-Austin, calculates that the total unsubsidized cost of new wind energy in Texas at about $105-$110 per megawatt-hour. This figure includes the incremental cost of transmission lines to serve wind generators and extra charges to account for the intermittent nature of wind. He also accounts for the cost of federal tax subsidies. Thus, "wind adds about $50 per megawatt-hour to costs," concludes Dr. Baldick.

7 KEY THINGS TO KNOW ABOUT WIND ENERGY

FACT #1
TEXAS LEADS THE NATION FOR WIND POWER

Texas in 2011 was home to more than 10,000 megawatts of installed wind capacity, which is nearly three times that of any other state. Texas has more installed wind power capacity than all but five countries worldwide.

FACT #2
WIND POWER HAS ZERO FUEL COSTS

The wind blows free, which means that wind generators can sometimes bid into the wholesale spot energy market at very low prices. Because of federal tax credits, wind generators sometimes bid their energy into the spot market at negative prices. This sometimes reduces overall spot market prices for electricity In Texas, in particular in the western part of the state where there exists a high concentration of wind generators.

FACT #3
FACTORS OTHER THAN FUEL CAN DRIVE UP THE FINAL PRICE FOR WIND POWER

Consumers pay a number of incremental costs associated with wind energy, including the costs of extra backup power because wind turbines can quit suddenly when the wind stops blowing. Wind energy also receives taxpayer-supported subsidies and Texans are on the hook for billions of dollars in wind-related transmission projects. Also, because of the structure of the deregulated wholesale market in Texas, wind generators that submit relatively low-cost bids into the spot market typically receive higher-than-bid prices.

FACT #4
DEVELOPMENT OF TRANSMISSION FOR TURBINES WILL COST BILLIONS MORE THAN ANTICIPATED

ERCOT initially estimated the cost of transmission lines to serve the state's growing wind fleet at $4.9 billion. Those projected costs were understated by nearly $2 billion. All told, every customer within the areas of the state's principal power grid is on the hook for more than $1,000 to pay for the transmission lines.

FACT #5
WIND POWER CAN PROVIDE ECONOMIC BENEFITS TO LOCAL COMMUNITIES

Texas landowners that have wind turbines on their property typically receive ongoing compensation in the form of royalties, operating fees or monthly production payments. Landowners receive one-time payments for electric transmission lines that pass across their land, plus damages for lost property value. As with the case for other sorts of generating plants, the construction, maintenance and operation of wind generators also creates jobs, which in turn produces income for local businesses and communities.

FACT #6
WIND GENERATION CANNOT BE DISPATCHED AS RELIABLY AS MANY OTHER SOURCES OF ENERGY

For planning purposes, the organization that operates the state power grid counts on the state's wind power fleet to produce at less than 9 percent of its capacity during peak summer periods. Official figures show that wind comprises nearly 12 percent the overall generation capacity in Texas, but wind generators provide just 1.1 percent of available capacity during summer peaks. This makes wind power, at peak, much less dependable than energy from natural gas-fired plants, coal plants, nuclear plants or even biomass sources.

FACT #7
WIND POWER CANNOT COMPLETELY REPLACE OTHER GENERATION SOURCES

Because of the variability of the wind, fossil-fueled power plants are needed to provide replacement power. These plants are typically fueled by natural gas. This means that wind power can periodically displace the use of fossil- fuel plants, but with current technology cannot completely displace the construction of them.

WIND POWER AND RELIABILITY CHALLENGES

By its very nature, wind is fickle. It blows one moment, cuts off the next.

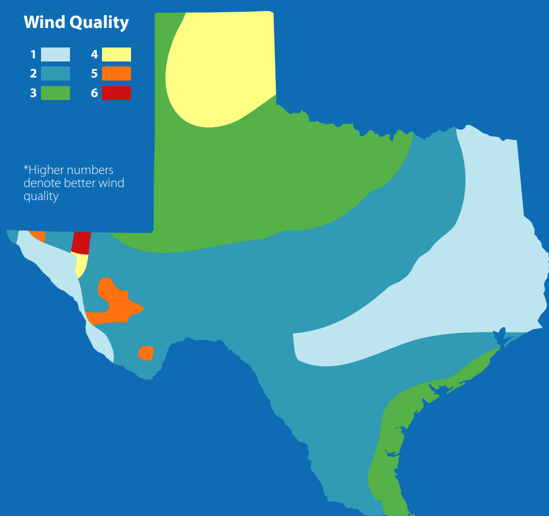
Because ERCOT must keep electricity supply and demand exactly balanced at all times on the grid, this intermittent nature can create challenges for the organization. In February 2008 a sudden drop off of wind coupled with other factors nearly led to blackouts. ERCOT also faced another near reliability crisis in January 2010 caused, in part, by the variability of wind.

The reliability challenges posed by the state's growing reliance on wind power have been acknowledged by the Texas Public Utility Commission, ERCOT and outside experts. In its 2011 Scope of Competition Report to the Texas Legislature, the PUC also noted that wind generators typically do not provide the same level of technical support to bolster grid reliability as is provided by traditional generators. Jay Zarnikau, an adjunct professor at the LBJ School of Public Affairs at the University of Texas-Austin, has noted that many wind generation operators have had little prior experience with electric operations. ERCOT has stated that such a "lack of understanding regarding the details of certain operational procedures … produced inconsistent results in unit responses to instructions and introduced operational challenges" for the organization's operators.

However ERCOT also has taken steps to mitigate many of these challenges. For instance, the grid operator adopted more advanced wind forecasting methods after the January 2010 incident. As a matter of policy, ERCOT also deliberately under-forecasts wind power output while simultaneously over-forecasting demand. The PUC has noted that various technical improvements on new turbines and the retrofitting on old ones may help mitigate some of the challenges.

Wind Classification

Source: seco.cpa.state.tx.us



FROM THE STATE ENERGY CONSERVATION OFFICE:

"The Panhandle contains the state's greatest expanse with high quality winds. Well-exposed locations atop the caprock and hilltops experience particularly attractive wind speeds. As in all locations throughout the state, determination of areas appropriate for development must include consideration of environmental and social factors as well as technical viability.

South of Galveston, the Texas coast experiences consistent strong sea breezes that may prove suitable for commercial development.

The mountain passes and ridgetops of the Trans-Pecos exhibit the highest average wind speeds in Texas. Since the wind in mountainous terrain can change abruptly over short distances, the best wind farm locations in West Texas are quite site specific."

THE DEVELOPMENT OF WIND POWER IN TEXAS

The use of wind power in Texas has grown substantially over the last decade — largely the result of important state mandates, the planned construction of expensive transmission lines, and favorable treatment for wind generators in the federal tax code.

THE MANDATE

Besides deregulating the state's retail electricity market, Senate Bill 7, adopted by the Texas Legislature in 1999, also included requirements for the use of renewable energy by retail electric providers. Companies that exceeded the mandate gained an ability to sell renewable energy credits to companies that fell short.

This credit program was designed to foster the creation of 2,000 megawatts of renewable energy by 2009, or enough to power about 1.6 million homes. But Texas easily surpassed the original target and so the Legislature adopted in 2005 Senate Bill 20 setting forth new goals: 3,272 megawatts of renewable energy by 2009, 4,264 megawatts by 2011, 5,256 by 2013, 5,880 by 2015 and 10,000 by 2025. Texas exceeded those goals as well.

FEDERAL TAX INCENTIVES

According to calculations by renewable energy expert Ed Feo, wind energy developers have received tax breaks valued at as much as two-thirds of the capital cost of wind turbines. Others have placed a smaller value on such subsidies. In sheer dollars, refined coal and nuclear power receive more federal energy subsidies, but wind power leads other energy sources for the size of federal subsidies as a ratio to energy output.

However, there remains some doubt whether Congress will extend the important federal production tax credits for wind which will expire at the end of 2012. This raises questions about the future profitability of wind power. Travis Miller, a Chicago-based utility analyst at Morningstar, Inc., estimates that natural gas commodity prices must rise above $6.50 per million British thermal units for unsubsidized wind generation to remain profitable. The United States Energy Information Administration projects that natural gas prices will remain below that level for many years to come.

TRANSMISSION LINES

Senate Bill 20, in 2005, also called for the creation of special zones, known as Competitive Renewable Energy Zones, to mark the site of future transmission construction to serve wind generators. The Public Utility Commission embarked on a vigorous process to delineate the borders of these zones, eventually settling on a plan that would support 18,500 megawatts of new wind generation. In establishing this plan the PUC used estimates, produced by ERCOT, that indicate the lines would cost $4.9 billion. Cities and other groups warned that the ERCOT numbers were flawed because they did not take into account financing costs, inappropriately assumed straight-line paths for the transmission construction, and other factors.

It later became clear that the cities' concerns were quite valid. In 2011, a PUC consultant determined that the CREZ lines will end up costing nearly $2 billion more than original estimates, for a total of $6,789,775.933. All told, these new lines will cost the state's residential, commercial and industrial users more than $1,000 each. Notes one expert: "Texas could have built 6,900 megawatts of new gas-fired capacity for what the state is now spending on wind-related transmission alone."

The Cost of Transmission Lines to Serve Wind Energy

Source: Elizabeth Souder, "Texas' multibillion dollar cost to build wind energy lines raises doubts," Dallas Morning News, Dec. 5, 2011

Texas is set to spend approximately $7 billion to build transmission lines to serve wind generators in West Texas and the Panhandle. What else could $7 billion pay for?

- The electricity bills for every household in Texas for about seven months.
- The construction of about 7,000 megawatts of natural gas-fired power plant generation — or enough extra capacity to keep the lights on during an extreme heat emergency.
- 175 million fluorescent light bulbs with LED lights, which could provide enough energy savings to shut down 10 coal plants.

End notes

EARLY YEARS

[1] "Electric Company Deregulation May Be Next," Associated Press, Sept. 21, 1987.

[2] "The Broken Promise of Electricity Deregulation," Steven T. Dennis, *Congressional Quarterly Weekly*, Sept. 23, 2006.

[3] "Electricity Restructuring: A Review of Efforts around the World and Consumer Response," John A. Anderson, *Electricity Journal*, April 2009.

[4] See bill analysis of Senate Bill 373, from the 74th Regular Session of the Texas Legislature found at www.capitol.state.tx.us.

[5] "Electricity Restructuring: A Review of Efforts around the World and Consumer Response," John A. Anderson, *Electricity Journal,* April 2009.

[6] "The Broken Promise of Electricity Deregulation," Steven T. Dennis, *Congressional Quarterly Weekly*, Sept. 23, 2006.

[7] "The Broken Promise of Electricity Deregulation," Steven T. Dennis, *Congressional Quarterly Weekly*, Sept. 23, 2006.

[8] "Roots of Power Problems Run Deep; Miscalculations and Ignored Warnings Add Up To Deregulation Nightmare," Sam Stanton, *Modesto Bee*, May 6, 2001.

[9] "Deregulation: Who Were the Power Brokers," Mark Gladstone and Brandon Bailey, *San Jose Mercury News*, Dec. 1, 2000.

[10] "Roots of Power Problems Run Deep; Miscalculations and Ignored Warnings Add Up To Deregulation Nightmare," Sam Stanton, *Modesto Bee*, May 6, 2001.

[11] "Roots of Power Problems Run Deep; Miscalculations and Ignored Warnings Add Up To Deregulation Nightmare," Sam Stanton, *Modesto Bee*, May 6, 2001.

[12] "Competition in power industry will aid consumers," Kenneth Lay, *Dallas Morning News*, March 16, 1997.

[13] "Bush submits electric utility deregulation bill," Carlos Sanchez, *Fort Worth Star-Telegram*, May 6, 1997.

[14] The legislative history of Senate Bill 684 during the 75th Regular Session of the Texas Legislature can be found online at www.capitol.state.tx.us.

[15] "Generating Debate: Utility deregulation in other states, England adds to Texas legislators' skepticism," Richard A. Oppel Jr. and Dianne Solis, *Dallas Morning News*, July 7, 1998.

[16] "Ohio Examining Pennsylvania's Deregulation," Alan Johnson, *Columbus Dispatch*, March 7, 1997.

[17] "Report to the 76th Texas Legislature: The Scope of Competition in the Electric Industry," Public Utility Commission of Texas, Page 16, January 1999.

[18] "Report to the 76th Texas Legislature: The Scope of Competition in the Electric Industry in Texas," Public Utility Commission of Texas, January 1999; see the section entitled "Competitive Issues in Rate Cases and Transition Plans" beginning on page 6.

[19] "Roots of Power Problems Run Deep; Miscalculations and Ignored Warnings Add Up To Deregulation Nightmare," Sam Stanton, *Modesto Bee*, May 6, 2001.

[20] A description of Senate Bill 684 adopted during the 75th Regular Session of the Texas Legislature can be found online at www.capitol.state.tx.us.

YEAR: 1999

[1] "Legislator's bill would deregulate electricity markets," R.A. Dyer, *Fort Worth Star-Telegram*, Jan. 21, 1999.

[2] "Electric overhaul clears 1st hurdle," R.A. Dyer, *Fort Worth Star-Telegram*, March 9, 1999.

[3] "Electric bill passes Senate; Vote supports switch to competition in Texas," R.A. Dyer, *Fort Worth Star-Telegram,* March 18, 1999.

[4] "Electric utilities criticize revised competition legislation," R.A. Dyer, *Fort Worth Star-Telegram*, April 7, 1999.

[5] "Electric Deregulation; Goal should be to provide consumers real choice," Editorial Staff, *Dallas Morning News*, Feb. 22, 1999.

[6] "Corporations big contributors for celebration; Watchdog group challenges motives expressed by firms," George Keumpel, *Dallas Morning News,* Jan. 17, 1999.

[7] "Utilities overhaul pushed; Electricity deregulation may not lower costs," R.A. Dyer, *Fort Worth Star-Telegram,* Jan. 18, 1999.

[8] "Electric bill passes Senate; Vote supports switch to competition in Texas," R.A. Dyer, *Fort Worth Star-Telegram*, March 18, 1999.

[9] A description of the legislative progress of Senate Bill 7 can be found online, at www.capitol.state.tx.us.

[10] "Utility overhaul bill signed by Bush; The law will force companies to compete for customers by 2002," R.A. Dyer, *Fort Worth Star-Telegram*, June 19, 1999.

[11] "Utility overhaul bill signed by Bush; The law will force companies to compete for customers by 2002," R.A. Dyer, *Fort Worth Star-Telegram,* June 19, 1999.

[12] "Texans wary of decontrol of electricity; Poll reveals ratepayers' concern," R.A. Dyer, *Fort Worth Star-Telegram*, March 11, 2001.

YEAR: 2000

[1] "Summer ushered in a power crisis that promises only to get worse," David Lazarus, *San Francisco Chronicle*, Dec. 29, 2000.

[2] "California Shares Tales of Energy Woe," Richard Burnett, *Orlando Sentinel,* June 1, 2001.

[3] "Energy: Summer ushered in a power crisis that promises only to get worse," David Lazarus, *San Francisco Chronicle*, Dec. 29, 2000.

[4] "Transmission Line Shortage Inhibits Texas Electric Deregulation," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 23, 2000.

[5] "Judge Rules Against Dallas-Based Utility TXU Electric on Stranded Costs," R.A. Dyer, *Fort Worth Star-Telegram*, Sept. 20, 2000.

[6] "New lines key to electric deregulation," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 23, 2000.

[7] "Report to the 77th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, Page 21, January 2001.

[8] "Judge Rules Against Dallas-Based Utility TXU Electric on Stranded Costs," R.A. Dyer, *Fort Worth Star-Telegram*, Sept. 20, 2000.

[9] "Summer ushered in a power crisis that promises only to get worse," David Lazarus, *San Francisco Chronicle*, Dec. 29, 2000.

[10] "Summer ushered in a power crisis that promises only to get worse," David Lazarus, *San Francisco Chronicle*, Dec. 29, 2000.

[11] "Summer ushered in a power crisis that promises only to get worse," David Lazarus, *San Francisco Chronicle*, Dec. 29, 2000.

YEAR: 2001

[1] "Texans wary of decontrol of electricity," R.A. Dyer, *Fort Worth Star-Telegram*, March 11, 2001.

[2] Text of the legislation can be found online, at www.capitol.state.tx.us.

[3] "Electric deregulation limits urged for Texas," R.A. Dyer, *Fort Worth Star-Telegram,* Jan. 25, 2001.

[4] "Measure asks utilities to pay back $7 billion," R.A. Dyer, *Fort Worth Star-Telegram*, March 26, 2001.

[5] "PUC chief favors electricity refunds," R.A. Dyer, *Fort Worth Star-Telegram*, March 28, 2001.

[6] "Measure asks utilities to pay back $7 billion," R.A. Dyer, *Fort Worth Star-Telegram*, March 26, 2001.

[7] "Action likely kills refunds on utility bills," R.A. Dyer, *Fort Worth Star-Telegram,* May 11, 2001.

[8] "Action likely kills refunds on utility bills," R.A. Dyer, *Fort Worth Star-Telegram*, May 11, 2001.

[9] "Consumers pan deregulation schedule," Charlene Oldham, *Dallas Morning News*, Oct. 12, 2001.

[10] "Test of utility market slated: Some Texas customers can sample electric deregulation beginning next week by signing up for a pilot program," R.A. Dyer, *Fort Worth Star-Telegram*, February 7, 2001.

[11] "Electric deregulation test run starts today," R.A. Dyer, *Fort Worth Star-Telegram*, Feb. 15, 2001.

[12] "Reports say grid facing big risk," R.A. Dyer, *Fort Worth Star-Telegram,* Oct. 11, 2001.

[13] "Reports say grid facing big risk," R.A. Dyer, *Fort Worth Star-Telegram*, Oct. 11, 2001.

[14] "State electric deregulation test project gets go-ahead," R.A. Dyer, *Fort Worth Star-Telegram*, July 26, 2001.

[15] "Billing errors are impeding test of deregulation, officials say," R.A. Dyer, *Fort Worth Star-Telegram*, July 20, 2001.

[16] "Start of electricity pilot called success," Laura Goldberg, *Houston Chronicle*, Aug. 1, 2001.

[17] "Electric changes delayed; technical difficulties postpone deregulation," R.A. Dyer, *Fort Worth Star-Telegram*, July 4, 2001.

[18] "Utilities say bills they got had 'bigger than big' errors," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 23, 2001.

[19] "Utilities say bills they got had 'bigger than big' errors," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 23, 2001.

[20] "Groups hit overseer of power grid; Consumer activists slam budget secrecy," *Associated Press*, Nov 26, 2001.

[21] "Electric price spikes called a 'mistake'," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 2, 2001.

[22] "Electric price spikes called a 'mistake'," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 2, 2001.

[23] "Power costs surge again, officials say," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 8, 2001.

[24] "Part of electric market shuts down for 4 hours; computers mysteriously stopped setting prices, official says," R.A. Dyer, *Fort Worth Star-Telegram,* Aug. 10, 2001.

[25] "Power costs surge again, officials say," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 8, 2001.

[26] "Electric deregulation untested; Texas system has flaws, advisers warn," R.A. Dyer, *Fort Worth Star-Telegram*, March 7, 2001.

[27] "Electric deregulation untested; Texas system has flaws, advisers warn," R.A. Dyer, *Fort Worth Star-Telegram*, March 7, 2001.

[28] "Power costs surge again, officials say; Latest 100-fold price spike lasts 15 minutes," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 8, 2001.

[29] "Power costs surge again, officials say; Latest 100-fold price spike lasts 15 minutes," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 8, 2001.

[30] "Power changeover still lacks rating to define success," Laura Goldberg, *Houston Chronicle*, Aug. 24, 2001.

[31] "Consumers pan deregulation schedule, Energy pilot program problems unresolved, groups believe," Charlene Oldham, *Dallas Morning News*, Oct. 12, 2001.

[32] "Price spikes linked to lack of power lines," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 13, 2001.

[33] "Price spikes linked to lack of power lines," R.A. Dyer, *Fort Worth Star-Telegram*, Aug. 13, 2001.

[34] "TXU drops billions in rate claims," R.A. Dyer, *Fort Worth Star-Telegram*, Dec. 29, 2001.

[35] "TXU drops billions in rate claims," R.A. Dyer, *Fort Worth Star-Telegram*, Dec. 29, 2001.

[36] "TXU drops billions in rate claims," R.A. Dyer, *Fort Worth Star-Telegram*, Dec. 29, 2001.

[37] "CenterPoint reaches tentative settlement on stranded costs in Texas," J.P. Finlay, *SNL Electric Utility Report*, Oct. 10, 2011.

[38] "Enron's Chief Executive Quits After Only 6 Months in Job," Richard A. Oppel, Jr. and Alex Berenson, *New York Times*, Aug. 15, 2001.

[39] "Enron's Chief Executive Quits After Only 6 Months in Job," Richard A. Oppel, Jr. and Alex Berenson, *New York Times*, Aug. 15, 2001.

[40] "A Self-Inflicted Wound Aggravates Angst Over Enron," Alex Berenson, *New York Times*, Sept. 9, 2001.

[41] "Enron posts loss after write-downs; Core businesses considered solid," Laura Goldberg, *Houston Chronicle*, Oct. 17, 2001.

[42] "Lay tries to assure Enron investors; Company credibility questioned," Laura Goldberg, *Houston Chronicle,* Oct. 24, 2001.

[43] "Enron replaces CFO as analysts cut ratings; Chairman says change necessary to restore investor confidence," Charlene Oldham, *Dallas Morning News*, Oct. 25, 2001.

[44] "Enron Credit Rating is Cut, And Its Share Price Suffers," *Bloomberg News*, Oct. 30, 2001.

[45] "Dynegy will buy Enron; $7.8 billion earmarked to purchase troubled rival," Juan A. Lozano, *San Antonio Express-News*, Nov. 10, 2001.

[46] "Enron Corp. Files Largest U.S. Claim for Bankruptcy," Richard A. Oppel, Jr. and Andrew Ross Sorkin, *New York Times*, Dec. 3, 2001.

[47] "Once-Mighty Enron Strains Under Scrutiny," Alex Berenson and Richard Oppel, Jr., *New York Times*, Oct. 28, 2001.

[48] "Once-Mighty Enron Strains Under Scrutiny," Alex Berenson and Richard Oppel, Jr., *New York Times,* Oct. 28, 2001.

[49] "Enron Corp. Files Largest U.S. Claim for Bankruptcy," Richard A. Oppel, Jr. and Andrew Ross Sorkin, *New York Times*, Dec. 3, 2001.

[50] "National Briefing Washington: Bush Selects Energy Agency Chief," *New York Times*, Aug. 16, 2001.

[51] "The Fall of Enron; Records: Bush Smoothed Path for Enron," R.G. Ratcliffe, *Houston Chronicle,* Feb. 16, 2002.

[52] "Former Executive Fills Spot on Texas Agency that Is Overseeing Deregulation," Janet Elliott, *The Houston Chronicle*, June 14, 2001.

YEAR: 2002

[1] "The Power of Choice: It is the dawning of deregulation in Texas, allowing consumers to choose their electric provider and get a rate reduction as well," Nelson Antosh, *Houston Chronicle*, Jan. 1, 2002.

[2] "Officials expect smooth transition to deregulation," Monica Wolfson, *Corpus Christi Caller-Times*, Dec. 31, 2001.

[3] "Texas launches electric choice Jan. 1," Phil Magers, *United Press International*, Dec. 20, 2001.

[4] "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission, Page 9, January 2003.

[5] "Power rate may not be as low as envisioned," R.A. Dyer, *Fort Worth Star-Telegram*, Dec. 7, 2001.

[6] The text of Senate Bill 7 can be found online, at capitol.state.tx.us.

[7] "Legislators slam record TXU profits," Elizabeth Souder, *Dallas Morning News*, Nov. 10, 2006.

[8] "TXU rates raised; State Oks jump, 4th since electricity deregulation began," Sudeep Reddy, *Dallas Morning News*, May 14, 2004.

[9] "TXU seeks to increase electricity bills by 5%," R.A. Dyer, *Fort Worth Star-Telegram,* April 24, 2002.

[10] "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, Page 43, January 2003.

[11] "TXU seeks to increase electricity bills by 5%," R.A. Dyer, *Fort Worth Star-Telegram,* April 24, 2002.

[12] "Electric deregulation begins," Dan Piller and R.A. Dyer, *Fort Worth Star-Telegram,* January 1, 2002.

[13] "Report lists snags in deregulation," R.A. Dyer, *Fort Worth Star-Telegram*, Jan. 11, 2002.

[14] "Texas electric grid operator rebuked," Charlene Oldham, *Dallas Morning News*, May 9, 2002.

[15] "Utility billing outrages panel," R.A. Dyer, *Fort Worth Star-Telegram*, May 9, 2002.

[16] "Confidence in deregulation declining as problems arise," Dan Piller, *Fort Worth Star-Telegram*, June 9, 2002.

[17] "Regulator urges PUC to delay state ad campaign," R.A. Dyer, *Fort Worth Star-Telegram*, April 12, 2002.

[18] "Power grid operator sparks controversy," R.A. Dyer, *Fort Worth Star-Telegram*, April 4, 2002.

[19] "Consumers groups settle objections with ERCOT," *Associated Press,* June 12, 2002.

[20] "Power grid operator's spending comes under fire," Claudia Grisales, *Austin American-Statesman*, June 12, 2002.

[21] "Power grid operator sparks controversy," R.A. Dyer, *Fort Worth Star-Telegram*, April 4, 2002.

[22] "TXU says unit part of inquiry," R.A. Dyer, *Fort Worth Star-Telegram*, March 23, 2002.

[23] "TXU says unit part of inquiry," R.A. Dyer, *Fort Worth Star-Telegram*, March 23, 2002.

[24] "Enron admits PUC inquiry," R.A. Dyer, *Fort Worth Star-Telegram*, April 17, 2002.

[25] "Enron admits PUC inquiry, R.A. Dyer, *Fort Worth Star-Telegram*, April 17, 2002.

[26] "New Power to leave Texas; Troubled provider to transfer customers to TXU, Reliant," Charlene Oldham, *Dallas Morning News*, June 11, 2002.

[27] "New Power files for bankruptcy," R.A. Dyer, *Fort Worth Star-Telegram*, June 11, 2002.

[28] "PUC, New Power have plan for exit," *Associated Press*, Oct. 13, 2002.

[29] "PUC seeks huge fine against New Power," R.A. Dyer, *Fort Worth Star-Telegram*, Sept. 14, 2002.

[30] "PUC seeks block of Enron-related allegations," R.A. Dyer, *Fort Worth Star-Telegram*, May 11, 2002.

[31] "The Fall of Enron; PUC leader quits post amid fallout," Polly Ross Hughes and R.G. Ratcliffe, *Houston Chronicle*, Jan. 19, 2002.

[32] "Dozens of Texas cities sue over electric rates," R.A. Dyer, *Fort Worth Star-Telegram*, May 7, 2002.

YEAR: 2003

[1] The text of the original bills can be found online at www.capitol.state.tx.us

[2] "Electric rate rollback proposed," R.A. Dyer," *Fort Worth Star-Telegram*, March 15, 2003

[3] More about the fate of those bills can be found online at www.capitol.state.tx.us

[4] "Consumer groups want funds for utility program restored," Sudeep Reddy, *Dallas Morning News*, Aug. 1, 2003

[5] "TXU secures 12 percent rate hike in North Texas," Sudeep Reddy, *Dallas Morning News,* March 6, 2003

[6] "TXU seeking 12 percent hike in electric bills," R.A. Dyer, *Fort Worth Star-Telegram*, March 5, 2003

[7] "TXU bills to rise by 3.7 percent," *Fort Worth Star-Telegram*, March 5, 2003

[8] "TXU bills to rise by 3.7 percent," *Fort Worth Star-Telegram,* March 5, 2003

[9] "Plano, Texas-Based Power Firm Accuses Marketers of Manipulation," Bill Hensel, Jr., *Houston Chronicle*, July 8, 2003

[10] "Market and Reliability Issues Related to the Extreme Weather Event on Feb. 24-26, 2003," Public Utility Commission Market Oversight Division, Project 25937, Item 475, May 20, 2003.

[11] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission, Page 32, January 2005

[12] "Plano, Texas-Based Power Firm Accuses Marketers of Price

Manipulation," Bill Hensel, Jr., *Houston Chronicle,* July 8, 2003

[13] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, Page 20, January 2005

[14] "Electricity plan may add to Metroplex bills," *Fort Worth Star-Telegram*, R.A. Dyer, Oct. 19, 2003

[15] "Market Restructuring Cost-Benefit Analysis — Final Report," Tabors Caramanis & Associates, Nov. 30, 2004

[16] "ERCOT leader to retire in June," R.A. Dyer," *Fort Worth Star-Telegram*, Oct. 21, 2003

[17] "Retail electricity complaints up," Bill Hensel, Jr., *Houston Chronicle*, Feb. 21, 2004

[18] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, Page 67, January 2005

[19] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, Page 68, January 2005

YEAR: 2004

[1] "Staff Inquiry into Allegations Made by Texas Commercial Energy regarding ERCOT Market Manipulation," Market Oversight Division, Public Utility Commission of Texas, Jan. 28, 2004

[2] "PUC: TXU may be too dominant," R.A. Dyer, *Fort Worth Star-Telegram*, Jan. 29, 2004

[3] "Utility panel is looking at electricity price spikes," R.A. Dyer, *Fort Worth Star-Telegram*, Dec. 9, 2004

[4] Market Restructuring Cost-Benefit Analysis — Final Report," Tabors Caramanis & Associates, Nov. 30, 2004

[5] "Critics call overhaul plan impractical, costly, risky," R.A. Dyer, *Fort Worth Star-Telegram*, July 6, 2004

[6] "Power-grid operator under fire," R.A. Dyer, *Fort Worth Star-Telegram*, July 20, 2004

[7] "Scandal inside Texas power grid," Pete Slover and Sudeep Reddy, Dallas Morning News, July 4, 2004

[8] "Key dates in the investigation," *Dallas Morning News*, July 4, 2004

[9] "Cracks emerge in ERCOT's image; State's electric grid operator grew quickly but lacked controls," Sudeep Reddy, *Dallas Morning News*, July 4, 2004

[10] "Cracks emerge in ERCOT's image; State's electric grid operator grew quickly but lacked controls," Sudeep Reddy, *Dallas Morning News*, July 4, 2004

[11] "Scandal inside Texas power grid," Pete Slover and Sudeep Reddy, *Dallas Morning News*, July 4, 2004

[12] "Lawmakers discuss ERCOT investigation," Natalie Gott, *Associated Press*, Sept. 29, 2004

[13] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Page 9, Public Utility Commission, January 2005

[14] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Page 51, Public Utility Commission, January 2005

[15] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Page 61, Public Utility Commission, January 2005

[16] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Page 69, Public Utility Commission, January 2005

[17] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Page 52, Public Utility Commission, January 2005

[18] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Page 54, Public Utility Commission, January 2005

[19] "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Page 56, Public Utility Commission, January 2005

[20] "CenterPoint Energy gets part of claim, utility commission rules," Janet Elliott, *Houston Chronicle*, Nov. 11, 2004

[21] See chart on page 66.

[22] "Deal diary," David Marcus, Vipal Monga, Dan Slater, Amy Wu, *Daily Deal,* March 5, 2007

[23] "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission, Page 115, January 2003

[24] "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission, Pages 38-39, January 2003

[25] "CenterPoint Energy Receives Ruling From Austin Court of Appeals in Company's True-Up Case," *Prime Newswire*, Dec. 20, 2007

YEAR: 2005

[1] "Electricity up more in deregulated areas," R.A. Dyer, *Fort Worth Star-Telegram*, April 19, 2005

[2] "Consultant finds TXU's bidding strategy added to spikes in ERCOT," Matt Cook, *Platts Power Markets Week*, May 2, 2005

[3] "School finance and beyond: Lawmakers to wrestle with tough issues during session," *Austin American-Statesman*, Jan. 9, 2005

[4] "TXU files request for 12 percent electric-rate increase," Dan Piller, *Fort Worth Star-Telegram*, Oct. 5, 2005

[5] "Bill aims to deter monopoly-like control," R.A. Dyer, *Fort Worth Star-Telegram*, April 18, 2005

[6] According to a review of the draft legislation, found online at www.capitol.state.tx.us

[7] "2005 Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas," Page 70, Public Utility Commission of Texas, January 2005

[8] "Bill aims to deter monopoly-like control," R.A. Dyer, *Fort Worth Star-Telegram,* April 18, 2005

[9] "Low-income Texans to see increase in electric bills," Associated Press, Aug. 9, 2005

[10] "Editorial: It's your electric bill, and now it's your stealth tax; Texas Legislature broke deal it made with the needy," Sylvester Turner, *Houston Chronicle*, Aug. 10, 2005

[11] According to a description of the legislation, found online at www.capitol.state.tx.us

[12] Direct Testimony of Walter M. Carpenter, Oncor Electric Delivery 2008 Rate Case, Public Utility Commission Docket # 35717, Item No. 2, June 7, 2008

[13] "Oncor's haste may cost residents; Firm wants to recoup $93 million for units that will never be used," Steve McGonigle, *Dallas Morning News*, June 5, 2009

[14] "Meters' cost falls on public; PUC lets Oncor boost rates," Elizabeth Souder, *Dallas Morning News*, Aug. 14, 2009

[15] According to a review of the bill text, found online at capitol.state.tx.us

[16] See Appendix F, Understanding Wind Power in Texas

[17] According to a review of the bill text, found online at capitol.state.tx.us

[18] According to a review of the bill text, found online at capitol.state.tx.us

[19] 2005 Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas, page 67, January 2005

[20] 2007 Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas, page 79, January 2007

[21] According to a review of the legislation, found online at capitol.state.tx.us

[22] 2007 Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas, page 79, January 2007

[23] 2005 Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas, page 67, January 2005

[24] 2007 Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas, page 79, January 2007

[25] "Grand Jury issues 23 indictments in ERCOT case," Sudeep Reddy and Pete Slover, *Dallas Morning News*, Jan. 28, 2005

[26] "Man pleads guilty electric-grid fraud case," Associated Press, Aug. 17, 2005

[27] "Attorney General Abbott Obtains First Guilty Plea Tied to Insider Profit Scheme Within Electric Reliability Council of Texas," Press Release, Office of Attorney General Greg Abbott, Aug. 17, 2005

[28] According to a review of Senate Bill 408, found online at capitol.state.tx.us

[29] 2007 Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas, page 58, January 2007

[30] "Rate boost to begin in days," R.A. Dyer, *Fort Worth Star-Telegram*, Oct. 29, 2005

[31] 2007 Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas, page 61, January 2007

[32] 2007 Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas, page 50, January 2007

[33] "Consumers grapple with burden of energy bills, debts," Pamela Yip, *Dallas Morning News*, Nov. 14, 2005

[34] 2007 Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas, January 2007

YEAR: 2006

[1] "Electricity Pricing in Competitive Retail Markets in Texas," Public Utility Commission of Texas, Docket 32198, Item 5, Feb. 3, 2006

[2] "Electricity Pricing in Competitive Retail Markets in Texas," Public Utility Commission of Texas, Docket 32198, Item 5, Feb. 3, 2006

[3] "PUC report citing savings of deregulation criticized," R.A. Dyer, Fort Worth Star-Telegram, Feb. 11, 2006

[4] "Bills up 84 percent since end of regulation," R.A. Dyer, *Fort Worth Star-Telegram*, Nov. 8, 2005

[5] "Bills up 84 percent since end of regulation," R.A. Dyer, *Fort Worth Star-Telegram,* Nov. 8, 2005

[6] "Study: Rates are out of line," R.A. Dyer, F*ort Worth Star-Telegram*, March 2, 2006

[7] "Overrated: Deregulation was supposed to lower Texans' electric bills. Instead, rates are through the roof," Forrest Wilder, *Texas Observer*, June 30, 2006

[8] "2006 Performance Review of Electric Power Markets," Kenneth Rose, Review conducted for the Virginia State Corporation Commission, Aug. 27, 2006

[9] "Study: Rates are up, not down," R.A. Dyer, *Fort Worth Star-Telegram*, March 20, 2006

[10] "Study: Rates are up, not down," R.A. Dyer, *Fort Worth Star-Telegram*, March 20, 2006

[11] "PUC chief calls for lower electric service," R.A. Dyer, *Fort Worth Star-Telegram*, Feb. 22, 2006

[12] "PUC rejects chief's plan to trim rates," R.A. Dyer, *Fort Worth Star-Telegram*, Feb. 24, 2006

[13] "Scope of Competition in Electricity Markets in Texas: 2007," Page 74, Public Utility Commission of Texas, January 2007

[14] "Heat forces power cuts across Texas," Tony Plohetski and Claudia Grisales, *Austin American-Statesman*, April 18, 2006

[15] "PUC report rebukes grid council members," Polly Ross Hughes, *Houston Chronicle,* April 26, 2006

[16] "Officials criticize ERCOT's conduct," R.A. Dyer, *Fort Worth Star-Telegram*, April 26, 2006

[17] "Officials criticize ERCOT's conduct," R.A. Dyer, *Fort Worth Star-Telegram*, April 26, 2006

[18] "Former power firm exec pleads guilty," Sudeep Reddy, *Dallas Morning News*, March 25, 2006

[19] "Power grid agency's chief leaving post," Elizabeth Souder, *Dallas Morning News*, May 17, 2006

[20] "ERCOT chief resigns," Liz Austin, *Associated Press*, May 17, 2006

[21] "Reliant FERC Settle Over Energy Crisis," *Associated Press*, Dec. 23, 2005

[22] "TXU identified as target of state's energy inquiry," Elizabeth Souder, *Dallas Morning News*, Oct. 21, 2006

[23] "Electricity price spikes in February prompt Texas agency to probe trading," Bill Hensel, Jr., Houston Chronicle, March 8, 2003

[24] "Houston energy firm acquires Allen's TCE," Sudeep Reddy, *Dallas Morning News*, Dec. 28, 2004

[25] "TXU identified as target of state's energy inquiry," Elizabeth Souder, *Dallas Morning News*, Oct. 21, 2006

[26] "Perry signs bill boosting renewable energy," Tim Eaton, *Corpus Christi-Caller Times*, Aug. 2, 2005

[27] "Scope of Competition in Electricity Markets in Texas: 2007," Page 75, Public Utility Commission of Texas, January 2007

[28] "Scope of Competition in Electricity Markets in Texas: 2007," Page 75, Public Utility Commission of Texas, January 2007

[29] "Scope of Competition in Electricity Markets in Texas: 2007," Page 76, Public Utility Commission of Texas, January 2007

[30] Author's interview with Tom "Smitty" Smith, director of the Texas office of Public Citizen, on Jan. 2-3, 2009

YEAR: 2007

[1] "Electric bill waters down ratepayer benefits," R.A. Dyer , *Fort Worth Star-Telegram*, May 24, 2007

[2] "A controversy brews as a milestone nears," R.A. Dyer, *Fort Worth Star-Telegram*, Dec. 24, 2006

[3] "Unplugged, High Prices under Texas Deregulation," Cities Aggregation Power Project, November 2008

[4] "Report to the 80th Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, January 2007

[5] "Market Operations Presentation," report to the ERCOT board of directors, November 13, 2007, Page 6

[6] "Manipulation not found," Jim Fuquay, *Fort Worth Star-Telegram*, April 13, 2007

[7] "Firm named in sale of $1,500 per megawatt," Elizabeth Souder, *Dallas Morning News*, April 7, 2007

[8] "Texas wholesale power price drop could affect future electricity plants," Elizabeth Souder, *Dallas Morning News*, Aug. 4, 2010

[9] "More muscle," Editorial Board, *Fort Worth Star-Telegram*, April 20, 2007

[10] "Report Says TXU Abused Market Power," Brian Wingfield, *Forbes*, March 12, 2007

[11] "PUC proposes $210M fine for TXU," James S. Jordan, *Dallas Business Journal*, March 29, 2007

[12] "Firm named in sale of $1,500 per megawatt," Elizabeth Souder, *Dallas Morning News*, April 7, 2007

[13] "TXU deal expected to close today," David Koenig, Associated Press, Oct. 10, 2007

[14] Consumer aid on minds of legislators this session: Many bills likely to address relief in gas, electricity, insurance costs," Janet Elliott, *Houston Chronicle*, Jan. 4, 2007

[15] "Activists try to drum up support for lower rates," Mitch Mitchell, *Fort Worth Star-Telegram*, May 20, 2007

[16] "A controversy brews as a milestone nears," R.A. Dyer, *Fort Worth Star-Telegram*, Dec. 24, 2006

[17] "Bills target electricity," R.A. Dyer, *Fort Worth Star-Telegram*, Feb. 8, 2007

[18] "Fraser Announces Utility Legislation, press release, Office of State Sen. Troy Fraser, Feb. 7, 2007

[19] "Power is an issue again," R.A. Dyer, *Fort Worth Star-Telegram*, Feb. 15, 2007

[20] "TXU foes' unlikely friend in Austin," Claire Poole, *Daily Deal*, March 7, 2007

[21] "Exclusive Report: What are the chances consumers will benefit from TXU's sale?" Elizabeth Souder and Randy Lee Loftis, *Dallas Morning News*, June 24, 2007

[22] "Power Failure," Claudia Grisales, *Austin American-Statesman*, May 30, 2007

[23] "TXU's takeover lobby cost about $17 million," Lobby Watch Report, Texans for Public Justice, Aug. 14, 2007

[24] "Bill to limit electric rate may perish," Claudia Grisales, Austin American-Statesman, May 28, 2007

[25] "Fumbling reform," Forrest Wilder, *Texas Observer*, June 15, 2007

[26]"TXU, private investors wrap up power switch; Energy giant to run as 3 separate firms; future for consumers unclear," Elizabeth Souder, *Dallas Morning News,* Oct. 11, 2007

[27]"TXU, private investors wrap up power switch; Energy giant to run as 3 separate firms; future for consumers unclear," Elizabeth Souder, *Dallas Morning News,* Oct. 11, 2007

[28]"Negotiators reach agreement on $152.5 billion state budget; Some provisions aim to assure fees used as intended," Peggy Fikac, *Houston Chronicle*, May 26, 2007

[29] Negotiators reach agreement on $152.5 billion state budget; Some provisions aim to assure fees used as intended," Peggy Fikac, *Houston Chronicle*, May 26, 2007

[30] Letter to PUC Commissioner Brandy Marty Marquez, State Rep. Dan Flynn, PUC Project No. 45188, (Nov. 20, 2015) Page 1

[31] "Electric retailers accept fines related to blackouts," Tom Fowler, *Houston Chronicle*, May 5, 2006

YEAR: 2008

[1] "Evaluating the Effects of Wholesale Electricity Restructuring," Thomas M. Lenard and Stephen McGonegal, Technology Policy Institute, September 2008.

[2] "Electricity price flies off the grid," Tom Fowler, *Houston Chronicle*, May 31, 2008.

[3] "Report to the 81st Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, January 2009, page 32.

[4] "Report to the 81st Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, January 2009, page 32.

[5] "Cirro being sold to Virginia utility," Eric Torbenson, *Dallas Morning News*, Aug. 14, 2008.

[6] "Cirro being sold to Virginia utility," Eric Torbenson, *Dallas Morning News,* Aug. 14, 2008.

[7] "Electricity customers across Texas are angry about confusing rates. The state is finally going to do something," Dave Lieber, *Fort Worth Star-Telegram*, Sept. 14, 2008.

[8] "PUC calls meeting over price spikes," *Dallas Morning News*, June 11, 2008.

[9] "New Texas regulations are aimed at protecting vulnerable electric customers," Jack Z. Smith, *Fort Worth Star-Telegram*, Aug. 8, 2009.

[10] "Reliant Energy may seek buyer amid credit market turmoil," Eric Torbenson, *Dallas Morning News*, Oct. 7, 2008.

[11] "NRG to acquire Reliant retail operations," Joshua Boak and James P. Miller, *Chicago Tribune*, March 3, 2009.

[12] "2007 State of the Market Report for the ERCOT Wholesale Electricity Markets," Potomac Economics, Ltd., August 2008; "2008 State of the Market Report for the ERCOT Wholesale Electricity Markets," Potomac Economics, Ltd., January 2009.

[13] "2007 State of the Market Report for the ERCOT Wholesale Electricity Markets," *Potomac Economics, Ltd.*, August 2008.

[14] "Czar will oversee wholesale electricity," Dan Piller, *Fort Worth Star-Telegram*, Oct. 26, 2006.

[15] "2007 State of the Market Report for the ERCOT Wholesale Electricity Markets," Potomac Economics, Ltd., August 2008; "2008 State of the Market Report for the ERCOT Wholesale Electricity Markets," Potomac Economics, Ltd., January 2009.

[16] "Deregulation jolts Texas electric bills," Rebecca Smith, *Wall Street Journal*, July 17, 2008.

[17] "TXU successor settles with PUC over market manipulation," Elizabeth Souder, *Dallas Morning News*, Nov. 27, 2008.

[18] "TXU successor settles with PUC over market manipulation," Elizabeth Souder, *Dallas Morning News,* Nov. 27, 2008.

[19] "TXU successor settles with PUC over market manipulation," Elizabeth Souder, *Dallas Morning News,* Nov. 27, 2008.

[20] "Electric grid project behind and over budget," *Associated Press*, Nov. 28, 2008.

[21] "New answers to projected electric power shortfalls in Texas," Patrick D. Nolan, *Fort Worth Star-Telegram*, Oct. 19, 2008.

[22] "ERCOT doubles budget, extends deadline for switching to new grid system," Elizabeth Souder, *Dallas Morning News*, Nov. 27, 2008.

[23] "Market Restructuring Cost-Benefit Analysis," Tabors Caramanis & Associates and KEMA Consulting, Nov. 30, 2004.

[24] "Electric grid project behind and over budget," *Associated Press,* Nov. 28, 2008.

[25] "Study sees savings in power line overhaul, Analysis says consumers will net $5.6 billion," Tom Fowler, *Houston Chronicle,* Dec. 19, 2008.

[26] "Comments to the Updated Nodal Cost-Benefit Analysis," Steering Committee of Cities Served by Oncor, found at the Public Utility Commission interchange, Project 31600, Item 12, Jan. 7, 2009.

[27] "LMP Electricity Markets: Market Operations, Market Power and Value for Customers," Ezra Hausman, Robert Fagen, David White, Kenji Takahashi, Alice Napoleon, Synapse Energy Consultants, Feb. 5, 2007.

[28] "Power grid narrowly avoided rolling blackouts," *Fort Worth Star-Telegram*, Feb. 28, 2008.

[29] "Power grid narrowly avoided rolling blackouts," *Fort Worth Star-Telegram*, Feb. 28, 2008.

[30] "ERCOT expects adequate power supplies for summer," ERCOT press release, updated June 1, 2011, online at http://www.ercot.com/news/press_releases/show/381.

[31] "2009 Report to the 81st Texas Legislature: Scope of Competition in Texas Electric Markets in Texas," Public Utility Commission of Texas, January 2009, pages 65-66.

[32] "2009 Report to the 81st Texas Legislature: Scope of Competition in Texas Electric Markets in Texas," Public Utility Commission of Texas, January 2009, pages 65-66.

[33] "Price tag for new wind-power lines in billions," *Fort Worth Star-Telegram,* April 3, 2008.

[34] "Wind might have a big impact on our wallets," Loren Steffy, *Houston Chronicle,* July 20, 2008.

[35] "Renewable Energy: Is Texas writing the book on wind power," Peter Behr, *Climate Wire,* April 8, 2010.

[36] "Wind might have a big impact on our wallets," Loren Steffy, *Houston Chronicle,* July 20, 2008.

[37] "Wind might have a big impact on our wallets," Loren Steffy, *Houston Chronicle,* July 20, 2008.

[38] "Texas now taking on global leaders in wind energy," Vicki Vaughan, *San Antonio Express-News,* Oct. 23, 2008.

[39] "Texas is poised to pay big for wind power," Jim Vertuno, *Associated Press*, July 18, 2008.

[40] "ERCOT Quick Facts," Electric Reliability Council of Texas, June 12, 2008, found online at http://www.ercot.com/content/news/presentations/2008/ERCOT_Quick_Facts_May_2008.pdf .

[41] "Wind might have a big impact on our wallets," Loren Steffy, *Houston Chronicle*, July 20, 2008.

[42] "Report to the 81st Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, January 2009, page 55.

[43] "Report to the 81st Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, January 2009, page 56.

[44] "Report to the 81st Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, January 2009, page 56.

[45] "Report to the 81st Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, January 2009, page 51.

[46] "Report to the 81st Texas Legislature: Scope of Competition in Electric Markets in Texas," Public Utility Commission of Texas, January 2009, page 51.

[47] "The TCCFUI Annual Texas Rate Report: Comparison of Competitive and Non-Competitive Rates," Texas Coalition of Cities For Utility Issues, December 2008.

[48] "The TCCFUI Annual Texas Rate Report: Comparison of Competitive and Non-Competitive Rates," Texas Coalition of Cities For Utility Issues, December 2008.

[49] "Plan to lower rural electric rate fizzles; project lacked residents' support," Celinda Emison, Abilene Reporter-News, May 10, 2008.

[50] "Pilot project offers insight into impact of electricity deregulation," Business Wire press release, May 8, 2008.

[51] "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements," GE Energy, March 28, 2008.

[52] "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements," GE Energy, March 28, 2008.

[53] "Texas Industrial Consumers' Second Motion for Rehearing," Public Utility Commission interchange, Docket No. 33672, Item 1426, Oct. 27, 2008.

[54] "Pickens shelves ambitious wind farm plans," Christine Idzelis, *Daily Deal*, July 8, 2009.

[55] "GE Invests $117 Million in EDP Renewable's Oklahoma Wind Farm and Additional $111 Million in established Wind Farm Portfolio," Business Wire press release, Dec. 2, 2009.

[56] "Power to the people: Let cities bargain for cheaper electrical rates with 'opt-out aggregating,'" Editorial Board, *Houston Chronicle*, March 29, 2009.

[57] "Plan to lower rural electric rate fizzles; project lacked residents' support," Celinda Emison, *Abilene Reporter-News,* May 10, 2008.

[58] "Pilot Project Offers Insight into Impact of Electricity Deregulation," Business Wire press release, May 26, 2008.

[59] "Power to the people: Let cities bargain for cheaper electrical rates with 'opt-out aggregating,'" Editorial Board, *Houston Chronicle*, March 29, 2009.

[60] "Power to the people: Let cities bargain for cheaper electrical rates with 'opt-out aggregating,'" Editorial Board, *Houston Chronicle,* March 29, 2009.

[61] "Power to the people: Let cities bargain for cheaper electrical rates with 'opt-out aggregating,'" Editorial Board, *Houston Chronicle,* March 29, 2009.

YEAR: 2009

[1] Texas Coalition of Cities For Utility Issues Annual Electric Rate Report, December 2008.

[2] According to a TCAP analysis of U.S. Energy Information Administration data, found at http://www.eia.gov/electricity/data/eia861/index.html.

[3] According to a TCAP analysis of U.S. Energy Information Administration data, found at http://www.eia.gov/electricity/data/eia861/index.html.

[4] According to a pricing analysis from whitefence.com, found at http://whitefenceindex.com/service/Electricity.

[5] "Scope of Competition in Electric Markets in Texas" for 2009, Texas Public Utility Commission, pages 70-83.

[6] "Electricity wholesalers keep prices secret too long, AARP study says," Elizabeth Souder, *Dallas Morning News*, May 6, 2009; "ERCOT told quicker disclosure of bids would lower wholesale power prices," Andrew Engblom, SNL Power Week West, May 11, 2009.

[7] According to a review of the text of the bill, found online at http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB02781I.pdf#navpanes=0.

[8] According to a review of the text of the bill, found online at http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/SB01481I.pdf#navpanes=0.

[9] "Most bills on renewable energy failed in Austin," Jack Z. Smith, *Fort Worth Star-Telegram*, June 3, 2009.

[10] Initial Comments by the Steering Committee of Cities Served by Oncor Relating to Consideration of Alternative Ratemaking Mechanism, PUC Docket No. 36358, Jan. 6, 2009.

[11] "Thompson Friend of the Underdog," Emily Ramshaw *Texas Tribune*, July 22, 2011.

[12] According to a review of the legislation, found online at http://www.capitol.state.tx.us/BillLookup/Text.aspx?LegSess=811&Bill=SB2.

[13] According to a review of the legislation, found online at http://www.capitol.state.tx.us/BillLookup/History.aspx?LegSess=81R&Bill=HB1783.

[14] According to a review of the legislation, found online at http://www.capitol.state.tx.us/BillLookup/History.aspx?LegSess=81R&Bill=HB1799.

[15] "ERCOT Application Approval of a Revised Nodal Implementation Surcharge," March 31, 2009, Public Utility Commission Docket No. 36851.

[16] "Market Restructuring Cost-Benefit Analysis" Tabors Caramanis & Associates. Nov. 30, 2004.

[17] "ERCOT Application Approval of a Revised Nodal Implementation Surcharge," March 31, 2009, Public Utility Commission Docket No. 36851.

[18] "Market Restructuring Cost-Benefit Analysis" Tabors Caramanis & Associates. Nov. 30, 2004.

[19] "ERCOT chief resigns, says it's the 'right time,'" Elizabeth Souder, *Dallas Morning News*, Sept. 16, 2009.

[20] ERCOT Press Release, July 8, 2009, online at http://www.ercot.com/news/press_releases/show/319.

[21] ERCOT Press Release, July 13, 2009, online at http://www.ercot.com/news/press_releases/show/290.

[22] "Texas heat sends electricity demand to record high," Jack Z. Smith, Fort Worth Star-Telegram, July 9, 2009.

[23] ERCOT Press Release, Nov. 19, 2009, found online at http://www.ercot.com/news/press_releases/show/301.

[24] "Texas Breaks Record for Electricity Demand," Elizabeth Souder, *Dallas Morning News*, July 9, 2009.

[25] "Texans should rethink power 'island' status — FERC," Eileen O'Grady, Reuters, May 6, 2009.

[26] "Pickens paring down wind farm project," Elizabeth Souder, *Dallas Morning News*, July 5, 2009.

YEAR: 2010

[1] Derived from data from the United States Energy Information Administration, including information found at: http://www.eia.gov/cneaf/electricity/page/ sales_revenue.xls and at: http://www.eia.doe.gov/cneaf/ electricity/page/eia826.html

[2] Derived from data from the United States Energy Information Administration, including information found at: http://www.eia.gov/cneaf/electricity/page/ sales_revenue.xls and at: http://www.eia.doe.gov/cneaf/ electricity/page/eia826.html

[3] "EFH debt downgraded after deal with lenders," Elizabeth Souder, *Dallas Morning News*, Aug. 18, 2010

[4] "Energy Future Holdings debt downgraded," Elizabeth Souder, *Dallas Morning News,* Oct. 13, 2010

[5] Analysis of data from the United States Energy Information Administration, including information found at: http://www.eia.gov/cneaf/electricity/page/ sales_revenue.xls and at: http://www.eia.doe.gov/cneaf/ electricity/page/eia826.html

[6] Analysis of data from the United States Energy Information Administration, including information found at: http://www.eia.gov/cneaf/electricity/page/ sales_revenue.xls and at: http://www.eia.doe.gov/cneaf/ electricity/page/eia826.html

[7] Analysis of data from the United States Energy Information Administration, including information found at: http://www.eia.gov/cneaf/electricity/page/ sales_revenue.xls and at: http://www.eia.doe.gov/cneaf/ electricity/page/eia826.html

[8] "ERCOT Strategic & Organizational Assessment Presentation to the Board," Market Reform, June 15, 2010, found on ERCOT website at http://www.ercot.com/content/meetings/board/keydocs/2010/0615/Item_15_-_Strategic_&_Organizational_Assessment_of_ERCOT_-_M.pdf

[9] "ERCOT Strategic & Organizational Assessment Presentation to the Board," Market Reform, June 15, 2010, found on ERCOT website at http://www.ercot.com/content/meetings/board/keydocs/2010/0615/Item_15_-_Strategic_&_Organizational_Assessment_of_ERCOT_-_M.pdf

[10] Statement by ERCOT CEO Trip Doggett, Oct. 5, 2010, found on ERCOT website at http://www.ercot.com/news/press_releases/show/345

[11] Sunset Advisory Commission Staff Report on the Public Utility Commission, ERCOT and the Office of Public Utility Counsel," published in April 2010

[12] "ERCOT Board Certifies Full Nodal Systems Ready for Go-Live," Oct. 19, 2010, ERCOT press release found at http://www.ercot.com/news/press_releases/show/346

[13] "ERCOT Board Certifies Full Nodal Systems Ready for Go-Live," Oct. 19, 2010, ERCOT press release found at http://www.ercot.com/news/press_releases/show/346

[14] Financial Summary for ERCOT Board of Directors, Controller Mike Petterson, Jan. 18, 2011, ERCOT website at http://www.ercot.com/content/meetings/board/keydocs/2011/0118/Item_10a_-_Financial_Summary.pdf

[15] "Market Restructuring Cost-Benefit Analysis — Final Report" from Nov. 30, 2004, by Tabors Caramanis & Associates

[16] "Texas regulator declares launch of nodal market 'nothing short of miracle,'" Lynn Doan, *SNL Power Daily*, Dec. 3, 2010

[17] "The Report to the 82nd Texas Legislature, Scope of Competition of Electric Markets in Texas," Texas Public Utility Commission, January 2011, Page 24

[18] "Switch to nodal grid system could trouble Texas electric providers," Elizabeth Souder, *Dallas Morning News*, September 30, 2010

[19] "Prioritization Process Overview," ERCOT Technical Advisory Committee Report by Troy Anderson, Nov. 4, 2010; PUC Rulemaking to Address Initial Implementation of the Nodal Market (Order Adopting Amendments to P.U.C. Subst. R. 25.502 and 25.505); July 9, 2010, PUC website, filed under Project No. 35392

[20] "The Report to the 82nd Texas Legislature, Scope of Competition of Electric Markets in Texas," Texas Public Utility Commission, January 2011, Page 25

YEAR: 2011

[1] Based on an analysis of data from the United States Energy Information Administration

[2] From a review of the legislation, found at http://www.capitol.state.tx.us/

[3] Based on a review of the legislation, found at http://www.capitol.state.tx.us/

[4] Based on a review of legislative activities, found at http://www.capitol.state.tx.us/

[5] Emily Ramshaw, "Thompson: Friend of the Underdog — and the Powerful," *The Texas Tribune*, July 22, 2010.

[6] Emily Ramshaw, "Thompson: Friend of the Underdog — and the Powerful," *The Texas Tribune*, July 22, 2010.

[7] 2007 Report to the 80th Texas Legislature, Scope of Competition in Electric Markets of Texas, Public Utility Commission of Texas, January 2007

[8] "TXU Sibling Settles on Fine; $15 million is a fraction of what was proposed," Tom Fowler, *Houston Chronicle*, Nov. 27, 2008

[9] From a review of the legislation, found at http://www.capitol.state.tx.us/

[10] Jim Forsyth, "Texas Launches Electric Power Deregulation," United Press International, June 1, 2001

[11] Jim Forsyth, "Texas Launches Electric Power Deregulation," United Press International, June 1, 2001

[12] Jim Forsyth, "Texas Launches Electric Power Deregulation," United Press International, June 1, 2001

[13] 2011 Summer Reliability Assessment, North American Reliability Corporation, May 2011, page 27

[14] Loren Steffy, "Electricity market failing at both ends," *Houston Chronicle*, February 11, 2011

[15] ERCOT 2010 State of the Market Report, Potomac Economics, August 2011

[16] See filings in the Public Utility Commission document interchange, Docket #37897, including Oct. 14, 2011 filing by Exelon Generation

[17] Chris Brewster, Steering Committee of Cities Served by Oncor, PUC Comments, Oct. 14, 2011

[18] "Supply Pinch in Texas tests Electricity Rules," Rebecca Smith, *Wall Street Journal*, Oct. 3, 2011

[19] "TIEC Says "Compromise" Non-Spin Price Floors Would Have Raised Average Prices by $50/MWh," *Energy Choice Matters*, October 17, 2011

[20] "PUC Sets Price for Power Reserves," Laylan Copelin, *Austin American-Statesman*, Oct. 28, 2011.

[21] FERC/NERC Staff, "Report on the Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011," August 2011

[22] "Blackout Plants Also Failed," Elizabeth Souder, S.C. Gwynne and Gary Jacobson, *Dallas Morning News*, Feb. 27, 2011

[23] "Blackout Plants Also Failed," Elizabeth Souder, S.C. Gwynne and Gary Jacobson, *Dallas Morning News*, Feb. 27, 2011

[24] FERC/NERC Staff, "Report on the Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011," August 2011

[25] 2011 ERCOT Blackout and Emergencies, Robert McCullough, July 15, 2011

[26] 2011 ERCOT Blackout and Emergencies, Robert McCullough, July 15, 2011

[27] Investigation of the ERCOT Energy Emergency Alert Level 3 of Feb. 2, 2011, Potomac Economics, LTD., April 21, 2011

[28] Protocol and Operating Guide Compliance Report For the Feb. 2, 2011, Energy Emergency Alert Level 3 Event, Texas Reliability Entity, Inc., May 13, 2011

[29] Report on Outages and Curtailments During the Southwest Cold Weather Event of Feb. 1-5, 2011, Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, August 2011.

[30] Based on an analysis of data from the United States Energy Information Administration

[31] Based on an analysis of data from the United States Energy Information Administration

[32] "Dallas Resident Shocked to Receive $1,200 Electric Bill," Tommy Noel, KDAF-TV, Sept. 20, 2011

[33] Whitefence.com, http://whitefenceindex.com/service/Electricity

[34] According to the PUC data, obtained under a Texas Freedom of Information request

[35] AEP Retail Electric Provider Texas Consumer Attitude Report, Nov. 2011, The Guide Group, Inc.

[36] "Houston electric bills will rise another $2.20 per month in 2012," *Houston Chronicle Fuel Fix Blog*, Sept. 29, 2011, online at http://fuelfix.com/blog/2011/09/29/houston-electric-bills-will-rise-another-2-20-per-month-in-2012/

[37] "Special Interests Line Up to Spark Debate on Deregulation," Michael Davis, *Houston Chronicle*, Jan. 3, 1999

[38] "Deal helped TXU customers," *Fort Worth Star-Telegram*, June 27, 2004

YEAR: 2012

[1] Snapshot Report: Electricity Prices in Texas, Texas Coalition for Affordable Power, December 2013

[2] Snapshot Report: Electricity Prices in Texas, Texas Coalition for Affordable Power, December 2013

[3] United States Energy Information Administration: http://www.eia.gov/cneaf/electricity/page/sales_revenue.xls

[4] Testimony of Samuel Newell, Brattle Group Principal, Oct. 24, 2012 meeting of State House Committee on State Affairs, http://www.house.state.tx.us/video-audio/committee-broadcasts/committee-archives/player/?session=82&committee=450&ram=12102410450

[5] Kate Galbraith, "Texas Struggles to Keep up with Power Demand," *Texas Tribune*, July 20, 2012, http://www.texastribune.org/texas-energy/energy/texas-struggles-keep-power-demand/

[6]"Texas Launches Electric Power Deregulation," *United Press International*, June 1, 2001

[7]Project No. 40000, "Commission Proceeding to Ensure Resource Adequacy in Texas," Public Utility Commission Interchange, www.puc.state.tx.us

[8]"A Controversy Brews as a Milestone Nears; Irate Constituents are promoting lawmakers, even supporters of deregulation, to take another look at the law," *Fort Worth Star-Telegram*, Dec. 24, 2006

[9]"Electricity: Peak demand likely to outpace supply," Simone Sebastian, *Houston Chronicle*, May 23, 2012

[10]2013 Scope of Competition in Electric Markets in Texas (DRAFT), page 4, Public Utility Commission.

[11]"Regulators Urged to Consider Prices," Recharge Ratepayer Report, May 16, 2012, http://rechargetexas.com/uncategorized/lawmakers-electric-prices-should-matter-in-reliability-debate/

[12]Public Utility Commission Interchange, Docket No. 40268, http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40268_9_725044.PDF

[13]Public Utility Commission Interchange, Docket No. 37897, http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/37897_149_727044.PDF

[14]"Electricity Company Passing Costs Onto Customers," Jim Fuquay, *Fort Worth Star-Telegram*, Oct. 25, 2012, http://www.star-telegram.com/2012/10/25/4364803/electricity-provider-passing-on.html

[15]Elizabeth Souder, "Is the governor of Texas going to bail out Energy Future Holdings," *Dallas Morning News*, Oct. 9, 2012, http://bizbeatblog.dallasnews.com/2012/10/is-the-governor-of-texas-going-to-bail-out-energy-future-holdings.html/

[16]"Regulators Double Cap for Electricity Prices," Kate Galbraith, *Texas Tribune*, Oct. 25, 2012, http://www.texastribune.org/texas-energy/energy/texas-regulators-act-texas-electricity-prices/

[17]"Texas Blackout Avoidance Measures Could Cost Billions," Kate Galbraith, *Texas Tribune*, June 21, 2012, http://www.texastribune.org/texas-energy/energy/texas-blackout-avoidance-measures-could-cost-billi/

[18]http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40268_43_728656.PDF

[19]Chris Brewster, "ERCOT Publishes Much Anticipated Report on Effectiveness of Wholesale Market In Attracting Generation Investment," ERCOT Monitoring Report, May 2012

[20]Testimony to the House Committee on State Affairs, Oct. 24, 2012, http://www.house.state.tx.us/video-audio/committee-broadcasts/committee-archives/player/?session=82&committee=450&ram=12102410450

[21]"Texas Industrials Eviscerate Brattle Resource Adequacy Analysis," *Energy Choice Matters*, Oct.24, 2012, http://www.energychoicematters.com/stories/20121024b.html

[22]Polly Ross Hughes, *Texas Energy Report*, July 27, 2011

[23]"ERCOT Investment Incentives and Resource Adequacy," The Brattle Group, June 2, 2012

[24]"Some Good News for the Texas Grid: We've Got a Few More Years before Things Get Dicey," Terrence Henry, *State Impact Texas*, Oct. 23, 2012, http://stateimpact.npr.org/texas/2012/10/23/some-good-news-for-the-texas-grid-weve-got-a-few-more-years-until-things-get-dicey/

[25]"ERCOT Updated Report on Reserve Margin Analysis," Oct. 22, 2012, Public Utility Commission Interchange, Project No. 40000, Item No 319.

[26]"ERCOT Reserve Margin Target Projected At or Above Target through 2017," *Energy Choice Matters*, Oct. 24, 2012, http://www.energychoicematters.com/stories/20121024a.html

[27]Resource Adequacy in ERCOT, Powerpoint presentation by Public Utility Commissioner Kenneth Anderson, Winter 2012

[28]Text of HB 2133, http://www.capitol.state.tx.us/tlodocs/82R/billtext/doc/HB02133F.doc

[29]"Worst of Both Worlds for Electricity Users," Loren Steffy, *Houston Chronicle*, July 26, 2012, http://www.chron.com/business/steffy/article/Steffy-Worst-of-both-worlds-for-electricity-3739015.php

[30]"Request for Approval of a Public Utility Commission Voluntary Mitigation Plan for NRG Companies," Public Utility Commission Final Order, July 13, 2012, Public Utility Commission Interchange, Control Number 40488, Item 11

[31]"The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On," Kevin Carden, Nick Wintermantel and Johannes Pfeifenberger, *NRRI Report*, April 2011.

[32]Testimony to the House Committee on State Affairs, Oct. 25, 2012, http://www.house.state.tx.us/video-audio/committee-broadcasts/committee-archives/player/?session=82&committee=450&ram=12102410450

YEAR: 2013

[1]"Snapshot: Oncor Collecting Hundreds of Millions in Phantom Taxes," Texas Coalition for Affordable Power, online at http://tcaptx.com/report/tcap-snapshot-report-oncor-collecting-hundreds-of-millions-of-dollars-in-phantom-taxes

[2]"Special Interests Paid Lobbyists Up To $328 Million in 2013 Session," Texans for Public Justice, Online at http://info.tpj.org/reports/Top%20Lobbyists%202013.pdf

[3]"Low-income Texans catch a break on electric bills," Dave Lieber, *Dallas Morning News*, July 28, 2013

[4]"Low-income Texans catch a break on electric bills," Dave Lieber, *Dallas Morning News*, July 28, 2013

[5]"Low-income Texans catch a break on electric bills," Dave Lieber, *Dallas Morning News*, July 28, 2013

[6]"Utilities: Poor Texans are in Line for Big Cut in Electricity Bill," Allan Turner, *Houston Chronicle*, July 26, 2013

[7]"Electric Choice Website Gets a Makeover," Jonathon Coker, Recharge Texas website, Aug. 1, 2013

[8]"Perry names utility Commissioner," Laylan Copelin, *Austin American-Statesman*, August 22, 2013

[9]"Perry names utility Commissioner," Laylan Copelin, *Austin American-Statesman*, August 22, 2013

[10]"PUC sides with power industry on reserve margins," James Osborne, *Dallas Morning News*, October 25, 2013

[11]"PUC sides with power industry on reserve margins," James Osborne, *Dallas Morning News*, October 25, 2013

[12]"REGULATION; State calls for reserve power; Critics say requirement will drive up monthly consumer electric bills," Emily Pickrell, *Houston Chronicle*, October 26, 2013

[13]"A Retreat from Electric Competition: How a Texas Capacity Market Will Lead to Expensive Subsidies, New Regulations and Higher Prices" Texas Coalition for Affordable Power, November 2013

[14]"Wendy Davis says no on power market overhaul," James Osborne, *Dallas Morning News*, Dec. 13, 2013

[15]"Texas regulators warned against power capacity market without legislator support," Christine Cordner, *SNL Electric Utility Report*, December 2, 2013

[16]"Presentation made at the Gulf Coast Power Association Fall Conference," Julia Frayer, London Economics International, 2013

[17]Letter to ERCOT Board from Troy Fraser, Chairman Senate Natural Resources Committee, July 15, 2013

[18]"Regulator: Capacity Payments are 'Corporate Welfare','' Margaret Somereve, TCAP website at http://tcaptx.com/policy-and-reform/regulator-capacity-payments-are-corporate-welfare, Sept. 6, 2013

[19]"PUC rejects power outage prediction," James Osborne, *Dallas Morning News*, Dec. 9, 2013

[20]"Time for Texas to add to state's electric grid," John Ragan, *Houston Chronicle*, June 11, 2013

[21]"NRG CEO Admits Merchant Build "Nearly Impossible" in Any Market, Including Capacity Markets," Paul Ring, *Energy Choice Matters*, Aug. 9, 2013

[22]Competitive Suppliers: Outlook for Dire Resource Adequacy Consequences in Texas "Wholly Overstated," Paul Ring, *Energy Choice Matters*, Aug. 20, 2013

[23]According to RESA website, http://www.resausa.org/members

[24]"Luminant will pay $750,000 to settle PUC charges," Jim Fuquay, *Fort Worth Star-Telegram*, Nov. 27, 2013

[25]"Energy Future Holdings Posts First Profit in 3 Years," James Osborne, *Dallas Morning News*, Nov. 1, 2013

[26]"Energy Future Holdings Reports $3.36 billion loss," Jim Fuquay, *Fort Worth Star-Telegram*, Feb. 20, 2013

[27]"Electricity Prices in Texas," Texas Coalition for Affordable Power, December 2013

YEAR: 2014

[1] "Lights dimmed on plan," James Osborne, *Dallas Morning News*, Feb. 27, 2014

[2] "Overhaul of Texas electricity market put off by new forecast on power demand," Jim Fuquay, *Fort Worth Star-Telegram*, March 6, 2014

[3] "Overhaul of Texas electricity market put off by new forecast on power demand," Jim Fuquay, *Fort Worth Star-Telegram*, March 6, 2014

[4] "Lights dimmed on plan," James Osborne, *Dallas Morning News*, Feb. 27, 2014

[5] "Overhaul of Texas electricity market put off by new forecast on power demand," Jim Fuquay, *Fort Worth Star-Telegram*, March 6, 2014

[6] "Energy Future Holdings Corp.: What a bankruptcy means for investors," Moody's Investor Services, Sept. 9, 2013

[7] "Energy Future Holdings lost $2.3 billion last year, but CEO got a raise," Jim Fuquay, *Fort Worth Star-Telegram*, May 1, 2014

[8] "EFH enters bankruptcy, proposes breakup," James Osborne, *Dallas Morning News*, April 30, 2014

[9] "Texas power company Energy Future files for bankruptcy," Nick Brown and Billy Cheung, *Reuters*, April 29, 2014

[10] "Bankrupt power company owns businesses worth billions," Jim Fuquay, *Fort Worth Star-Telegram*, May 3, 2014

[11] "Snapshot Report: An Energy Future Holdings Bankruptcy," Texas Coalition for Affordable Power, March 2014, online at tcaptx.com.

[12] "Bidders ready to split EFH family," Mitchell Schnurman, *Dallas Morning News*, March 23, 2014

[13] "Will the Texas Market Succeed, where so many others have failed," Jay Zarnikau and Parviz Adib, 2007, page 11

[14] "Will the Texas Market Succeed, where so many others have failed," Jay Zarnikau and Parviz Adib, 2007, see footnote 8 on page 10.

[15] "Energy Future Holdings Could Avoid Paying Taxes on $23 Billion," Nicholas Sakelaris, *Dallas Business Journal,* Apr. 3, 2013

[16] "Judge lets bankrupt energy firm issue bonuses," Jim Malewitz, *Texas Tribune*, Oct. 15, 2014

[17] "Delaware messes with Texas, sparks flight over mega-bankruptcy," Tom Hals and Nick Brown, *Reuters*, April 29,2014

[18] "Oncor proposes giant leap for grid, batteries," James Osborne, Nov. 8, 2014, *Dallas Morning News*

[19] "Oncor proposes giant leap for grid, batteries," James Osborne, Nov. 8, 2014, *Dallas Morning News*

[20] "Memorandum Regarding Open Meeting of October 17, 2014, Agenda Item Nos. 15 and 16," Commissioner Kenneth W. Anderson, Public Utility Commission of Texas, Oct. 16, 2014, Page 2

[21] "A Letter to Our Customers," Oncor Management Team, *Austin American-Statesman*, Nov. 6, 2014

[22] Memorandum Re: Open Meeting, Oct. 17, 2014 — Agenda Item #12, Darryl Tietjen and Ruth Stark, Rate Regulation, Public Utility Commission, Oct. 9, 2014, PUC Project No. 42290, page 5

[23] "Outages, waits to have power restored put focus on Oncor's maintenance spend-ing," James Osborne, *Dallas Morning News*, Nov. 1, 2014

[24] According to discussion by Commissioners during PUC meeting of June 20, 2014, Item No. 21, Project No. 42424.

[25] "New transmission project to deliver more power to Houston area," ERCOT press release, April 8, 2014, online at http://www.ercot.com/news/press_releases/show/26616

[26] "ERCOT Independent Review of the Houston Import Regional Planning Group Project," Memo from Jeff Billo, Manager of ERCOT Transmission Planning, April 1, 2014, online at http://www.ercot.com/content/meetings/board/keydocs/2014/0408/8_ERCOT_Independent_Review_of_the_Houston_Import_Regional_Pl.pdf

[27] "Sparks fly over proposal for power line to Houston," Ryan Holeywell, *Houston Chronicle*, Sept. 17, 2014

[28] "Sparks fly over proposal for power line to Houston," Ryan Holeywell, *Houston Chronicle*, Sept. 17, 2014

[29] "Construction begins on New NRG Natural Gas Peaking Plant Near Houston," NRG Energy Press Release, Nov. 5, 2014

[30] "Texas PUC denies complaint about power line," Kassie Micek, *Platts Megawatt Daily*, Nov. 17, 2014

[31] "Upgrading South Texas power lines," J.M. Lozano, *Alice Echo-News Journa*l, Nov. 5, 2014

[32] "Alternative Energy: Transmission lines have helped boost Texas wind power," Ryan Holeywell, *Houston Chronicle*, June 26, 2014

[33] "Texas PUC chair raises prospect of cost increase for wind farms," James Osborne, *Dallas Morning News*, June 2, 2014

[34] Memo from PUC Chair Donna L. Nelson, May 29, 2014, Regarding Open Meeting Agenda Item #29, Project Number 42079

[35] "Texas grid operator says EPA plan raises reliability questions," Edward Klump, *EnergyWire*, November 18, 2014

[36] "Texas grid operator says EPA plan raises reliability questions," Edward Klump, *EnergyWire*, November 18, 2014

YEAR: 2015

[1] "EFH's restructuring gets OK," James Osborne, *Dallas Morning News,* Sept. 18, 2015.

[2] "Hunts officially file $18b plan to buy Oncor power utility from EFH," Bill Hethcock, *Dallas Business Journal*, Sept. 29, 2015.

[3] Direct Testimony of Darryl Tietjen, Rate Regulation Division of the Public Utility Commission of Texas, Dec. 9, 2015.

4 Oncor Website, www.oncor.com/en/pages/who-is-oncor.aspx

[4] "Power line wins approval by PUC; State regulators say Houston area needs project despite NRG Energy's opposition," Jordan Blum, *Houston Chronicle*, Dec. 18, 2015.

[5] "NRG, Calpine challenge Houston's transmission project in new lawsuit," Ryan Holeywell, *Houston Chronicle*, March 3, 2015.

[6] "Power line wins approval by PUC; State regulators say Houston area needs project despite NRG Energy's opposition," Jordan Blum, Houston Chronicle, Dec. 18, 2015.

[7] "NRG, Calpine challenge Houston's transmission project in new lawsuit," Ryan Holeywell, *Houston Chronicle*, March 3, 2015.

[8] "Factbox: U.S. court dismisses GDF power market manipulation complaint," Scott Disavino, Reuters, Feb. 5, 2015.

[9] "2012 State of the Market Report for the ERCOT Wholesale Electricity Market," Potomac Economics, Independent Market Monitor of the ERCOT Wholesale Market, June 2013.

[10] "Power to Choose will help consumers filter out electricity plans charging minimum use fees," Jordan Blum, *Houston Chronicle*, July 30, 2015.

[11] Texas Legislature Online, at http://www.capitol.state.tx.us/BillLookup/History.aspx?LegSess=84R&Bill=SB777.

[12] ERCOT press release, "Energy Use in ERCOT region grows 2.2 percent in 2015," Jan. 15, 2016.

[13] 2015 Demand and Energy Report, ERCOT.

[14] "U.S. wind industry hits 70 GW capacity mark, celebrates

tax credit extension," Herman K. Trabish, *Utility Dive*, Dec. 22, 2015.

[15] "ERCOT sets two new wind power records," Kassia Micek, Platts, Dec. 22, 2015.

[16] "ERCOT sets two new wind power records," Kassia Micek, Platts, Dec. 22, 2015.

[17] "Wind power sets new record for energy share in ERCOT in November," Mark Watson, Platts, Dec. 14, 2015.

[18] "ERCOT Sets Two New Wind Power Records," Kassia Micek, Platts, Dec. 22, 2015.

[19] ERCOT sets new wind power generation record at 12,238 MW," Kassia Micek, Platts, Oct. 23, 2015.

[20] ERCOT sets new wind power generation record at 12,238 MW," Kassia Micek, Platts, Oct. 23, 2015.

[21] Snapshot Report: 2015 PUC Complaint Data, Texas Coalition for Affordable Power, Oct. 2015.

[22] "Sharyland customers to see slight rate decrease," staff reports, *Midland Reporter-Telegram*, Oct. 8, 2015.

YEAR: 2016

[1] "AARP Objects to Oncor sale to Hunt-led group," Karen Robinson, *Dallas Morning News*, Jan. 7, 2016

[2] "How Oncor deal fell apart," Jeffrey Weiss, *Dallas Morning News*, May 21, 2016

[3] "Hunt Group says it can't buy Oncor under the terms of last month's PUC order, asks for rehearing," Jeffrey Weiss, *Dallas Morning News*, April 18, 2016.

[4] "NextEra would own Oncor in $18.4 billion deal," Jim Malewitz, *Texas Tribune*, July 31, 2016

[5] "Oncor suitor makes pitch to PUC," Jeffrey Weiss, *Dallas Morning News*, Nov. 1, 2016

[6] "Will a $275 million question derail NextEra's plan to buy Texas power giant Oncor?" Jeffrey Weiss, *Dallas Morning News*, Sept. 26, 2016

[7] Public Utility Commission Document interchange, Docket Number 46046, Item 24

[8] "Alternative Electricity Ratemaking Mechanisms Adopted by Other States," Laurence D. Kirsch and Mathew J. Morey, Christensen Associates Energy Consulting, May 25, 2016 (found in PUC Docket 46046, Item 2.)

[9] Public Utility Commission Document interchange, Docket Number 46046, Item 24

[10] Public Utility Commission Document interchange, Docket Number 46046, Item 24

[11] "Snapshot Report: 2016 PUC Complaint Data," TCAP, Oct. 2016, online at http://tcaptx.com/reports

[12] "ERCOT breaks wind energy record, but don't expect it to lower energy costs," Ryan Handy, *Houston Chronicle*, Nov. 29, 2016

[13] "Wind Generation output tops 15,000 MW in ERCOT region," ERCOT press release, http://ercot.com/news/releases/show/113533, Nov. 28, 2016

[14] "PUC's Nelson Pushes for PowertoChoose Reform," *TCAP Current*, June 22, 2016, http://tcaptx.com/rates-and-service/puc-chairwoman-seeks-reform-of-powertochoose-org

[15] "Snapshot Report: Electricity Prices in Texas," Texas Coalition for Affordable Power, June 2016, http://tcaptx.com/wp-content/uploads/2016/06/TCAP-ElectricityPricesinTX-Snapshot-A-Final.pdf

[16] "Snapshot Report: Electricity Prices in Texas," Texas Coalition for Affordable Power, June 2016, http://tcaptx.com/wp-content/uploads/2016/06/TCAP-ElectricityPricesinTX-Snapshot-A-Final.pdf

YEAR: 2017

[1] "Who is Oncor," from the Oncor website, online at http://www.oncor.com/EN/Pages/Who-is-Oncor.aspx

[2] "Deal will lower bills," Jeff Mosier, *Dallas Morning News,* July 25, 2017

[3] "Calpine, NRG post report that seeks changes in ERCOT pricing, settlement rules," Jeffrey Ryser, *Platts,* May 10, 2017

[4] "Lubbock Power & Light Moves to the Approval Stage

of ERCOT Integration Process," Lubbock Power and Light Press Release, Oct. 5, 2017, found online at http://www.lpandl.com/newsroom/news-releases/lubbock-power-light-moves-to-the-approval-stage-of-ercot-integration-proces/

[5] Southwest Power Pool Overview, found at the SPP website, https://www.spp.org/about-us/fast-facts/

[6] "Lubbock Power & Light Moves to the Approval Stage of ERCOT Integration Process," Lubbock Power and Light Press Release, Oct. 5, 2017, found online at http://www.lpandl.com/newsroom/news-releases/lubbock-power-light-moves-to-the-approval-stage-of-ercot-integration-proces/

[7] "Parent Company of TXU Energy and Luminant Announces Corporate Rebranding as Vistra Energy," Press Release, Nov. 4, 2016, online at https://www.vistraenergy.com/company-news-release-number-one/

[8] "Loss of plants may help others; Market could improve for power units fueled by coal," Rye Druzin, *San Antonio Express-News,* Dec. 4.

[9] "Sufficient generation expected for winter and spring seasons," ERCOT news release, Nov. 1, 2017, online at http://www.ercot.com/news/releases/show/139978

[10] "Deal to create Texas Energy Giant," Jeff Mosier, *Dallas Morning News,* Oct. 31, 2017

[11] "Wind power blows past coal in Texas; Capacity count is another milestone in state's increasing reliance on renewable energy," Ryan Maye Handy, *Houston Chronicle,* Nov. 27, 2017.

[12] "U.S. Solar Market Insight", GTM Researrch; Sept. 11, 2017; online at https://www.greentechmedia.com/research/subscription/u-s-solar-market-insight#gs.kE_dnqw

[13] "Electric Prices in Texas: A Snapshot Report — 2017 Edition," Texas Coalition for Affordable Power, July 2017, online at http://bit.ly/2AmCgky

[14] "Electric Prices in Texas: A Snapshot Report — 2017 Edition," Texas Coalition for Affordable Power, July 2017, online at http://bit.ly/2AmCgky

[15] "PUC Complaint Data: A Snapshot Report – 2017 Edition," Texas Coalition for Affordable Power, October 2017, online at http://bit.ly/2BTuewK

APPENDIX A

Based on a reading of Senate Bill 7, found online, at http://www.capitol.state.tx.us/tlodocs/76R/billtext/html/SB00007F.htm

APPENDIX B

This analysis found in this section is based on a review of electricity-related complaints received by the PUC for the 1998 through 2015 fiscal years. The PUC did not collect this data before 1998 and also reports that it discarded pre-2003 data under its documentation retention policy. As a consequence, estimates for complaints from 1998 through 2003 were obtained through journalistic accounts: a Dec. 14, 2002 article in the *Fort Worth Star-Telegram* entitled "Complaints from power customers pile up", and a Nov. 13, 2002 article in the *Dallas Morning News* entitled "Billing errors are down, but consumer complaints are up." It also includes data culled from page 106 of the 2003 *Scope of Competition Report*, produced by the PUC. Other data was obtained directly from the PUC, through a Freedom of Information request.

[1] "Sharyland customers to see slight rate decrease," staff reports, Midland Reporter-Telegram, Oct. 8, 2015.

APPENDIX C

This appendix gathers information from three articles: "CenterPoint Takes surprise charge; write-down to prepare for PUC ruling creates loss," *Houston Chronicle*, Nov. 10, 2004; "AEP plan would raise electric bills by almost $5," *Victoria Advocate*, March 5, 2006; and "Deregulation Helps buyout firms, if not the ratepayers," *Houston Chronicle*, Oct. 5, 2005. This appendix also refernces an April 3rd, 2012 article on the *Recharge Ratepayer Report* found online at http://rechargetexas.com/your-electricity-contract-a-mulligan-stew-of-fees-and-special-charges/.

APPENDIX D

Appendix D draws information from a review of Senate

Bill 7, as well as information from a survey on consumer attitudes conducted by The Guild Group, for AEP Retail Electric. The Guild Group report was dated November 2011.

APPENDIX E

This appendix includes information gathered from the ERCOT and from a reading of Senate Bill 7. It also includes information from an ERCOT spreadsheet, included in a Dec. 8, 2011 email from ERCOT's public information officer to the author of this report. This section references a June 26, 2012 press release from ERCOT, entitled "ERCOT board approves pilot for new demand response option, budget for 2013."

APPENDIX F

Appendix F draws from several academic reports, including the "2010 Wind Technologies Market Report," by Ryan Wiser and Mark Bolinger, of the Lawrence Berkeley National Laboratory; "The Energy Report (2008)," by the Texas Comptroller of Public Accounts, published on May 6, 2008; "The Costs and Impacts of Intermittency," by R. Gross, et al., of the Imperial College in London, published in March 2006; "Why Wind Power Does Not Deliver the Expected Emissions Reductions," by Herbert Inhaber for the 2011 edition of *Renewable and Sustainable Energy Review*; "Wind Generation, Power System Operation and Emissions Reduction," by Eleanor Denny and Mark O'Malley, for the February, 2006 edition *IEEE Transactions on Power Systems* (Vol. 21, No. 1); "The Economics of Large-Scale Wind Power in a Carbon Constrained World," by Joseph F. DeCarolis and David W. Keith, for *Energy Policy 34* (2006); "Successful Renewable Energy Development in a Competitive Electricity Market: A Texas Case Study," by Jay Zarnikau, for *Energy Policy 39* (2011) and information drawn from page 22 of the "Wind Energy Update," by Larry Flowers of the National Renewable Energy Laboratory. That report is dated Jan. 23, 2008.

Appendix F also draws from presentations given by leading energy experts, including "Wind and Energy Markets: A Case Study of Texas," presented by Ross Baldick for the April 29, 2009 National Academy of Engineering Regional Meeting in College Station, Texas. Appendix F also draws from a Dec. 15, 2004 presentation by Ed Feo to the Renewable Energy Resources Committee of the American Bar Association; and information from Chicago-based utility analyst Travis Miller, which can be found online at: http://www.hellenicshippingnews.com/News.aspx?ElementId=f021ac64-4fd8-4fb6-9ce0-d063782f47d0.

Other reports, including those from official sources, include "CREZ Progress Report No. 4 (July Update)," prepared for the Public Utility Commission of Texas, July 2011; ERCOT'S "CREZ Transmission Optimization Study," April 2, 2008; "The Report to the 82nd Texas Legislature, Scope of Competition in Electric Markets in Texas," prepared by the Public Utility Commission of Texas, January 2011; the "Texas Renewables Implementation Plan: Quarterly Update for the 3-Month Period ending March 31, 2010," for the ERCOT Renewable Technologies Working Group of the ERCOT Technical Advisory Committee, April 2010; "Economic Benefits, Carbon Dioxide Emissions Reductions, and Water Conservation Benefits from 1,000 Megawatts of New Wind Power in Indiana," produced for the U.S. Department of Energy by the National Renewable Energy Laboratory and information from the United States Energy Information Administration.

Appendix F draws from the following press reports: "Texas Wind Energy Fails, Again," Robert Bryce, *National Review*, April 29, 2011; "The Economics of Wind II: Subsidies — the Why and How Much," Kathryn Skelton, *The Sun Journal* (Lewiston, Maine), April 12, 2010; "Energy Industry Fears U.S. Tax Credit Won't Be Renewed," Dan Voorhis , *McClatchy Newspapers,* April 5, 2012; "Americans Gaining Energy Independence," *Hellenic Shipping News Worldwide*, Feb. 11, 2012 and "Negative Power Prices in ERCOT West: 2009 and 2010 Through September," Michael Giberson, Nov. 11, 2010, *The Energy Collective*.

This Appendix included information from a May 31, 2011 press release by ERCOT, entitled "ERCOT Expects Adequate Power Supplies for Summer (Update)," and wind industry statistics from the American Wind Energy Association, a trade group.

Appendix F originally appeared as a stand-alone report, which was released by the Texas Coalition for Affordable Power in August 2012. The online version of the report — and more detailed sourcing information — can be found online at http://texaswindenergy.tcaptx.com/.

About the Author

Policy analyst R.A. "Jake" Dyer has spent more than a decade monitoring consumer issues in Texas, its energy markets and ERCOT. His long journalism career included nearly a decade with the *Fort Worth Star-Telegram*, where he was named reporter of the year in 2007, and nearly a decade with the *Houston Chronicle*, where he was nominated for a Pulitzer Prize.

In 2010 Dyer authored *Natural Gas Consumers and the Texas Railroad Commission*, a report on pocketbook and policy issues. In 2011 he authored *The Story of ERCOT*, a special report on the Texas grid operator, power market and prices. His work with the Texas Coalition for Affordable Power and its predecessor organizations began in 2008.

A special research project by

Texas Coalition
for Affordable Power

tcaptx.com

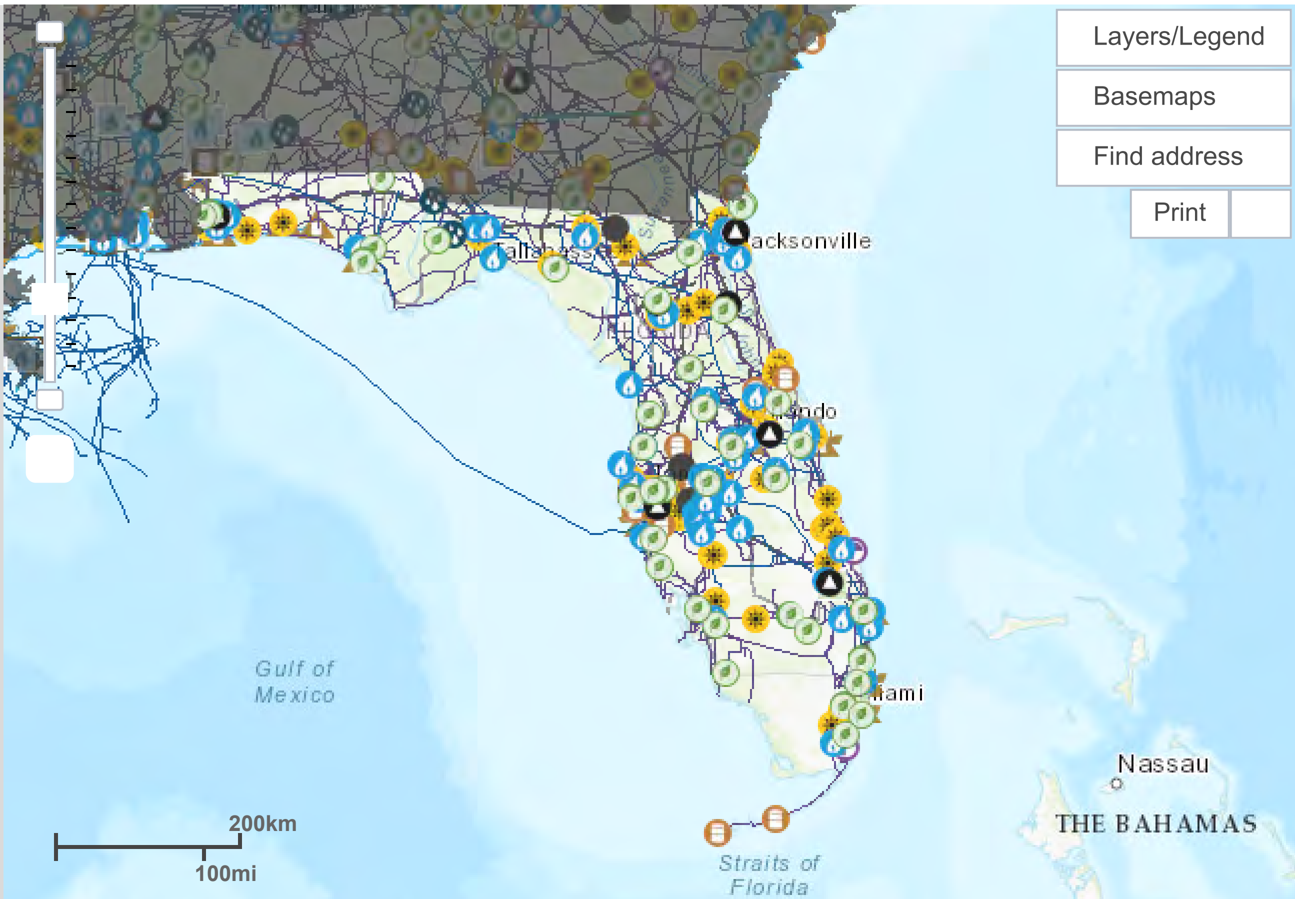
TAB 13

U.S. Energy Information Administration

Florida

State Profile and Energy Estimates

Profile Overview



❖ Layer information and map data

Map questions, comments and suggestions: mapping@eia.gov

U.S. Energy Mapping System
Energy Disruptions
Flood Vulnerability

State Energy Profiles
Gulf of Mexico Fact Sheet
Major Oil and Gas Plays

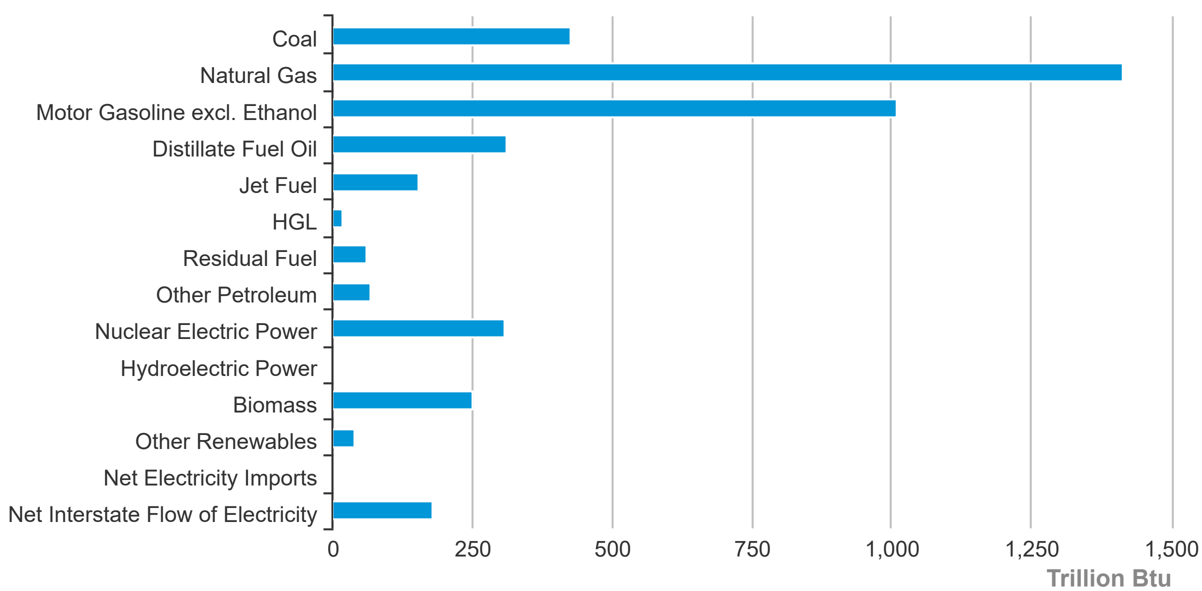
A. 788

Quick Facts

- Florida is one of only four states with utility-scale electricity generation from solar thermal technologies and is the only one east of the Rocky Mountains.
- Florida was second only to Texas in 2017 in net electricity generation, and it is typically third in the nation in electricity consumption, behind Texas and California.
- Florida accounts for almost 8% of the nation's biomass-fueled electricity generation, more than any other state except California.
- In 2017, almost 87% of the natural gas delivered to consumers in Florida was used to generate electricity, and natural gas fueled more than two-thirds of Florida's net electricity generation.
- Florida does not have any crude oil refineries or interstate pipelines and relies on petroleum products delivered by tanker and barge to Florida marine terminals, primarily at Jacksonville, Port Canaveral, Port Everglades, and Tampa.

Last Updated: September 20, 2018

Florida Energy Consumption Estimates, 2016



Source: Energy Information Administration, State Energy Data System

A. 789

More Data & Analysis in Florida

by Source

- Petroleum
- Natural Gas
- Electricity
- Coal

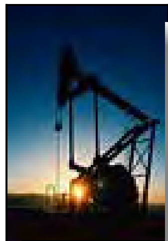
- Renewable & Alternative Fuels
- Nuclear
- Environment
- Total Energy

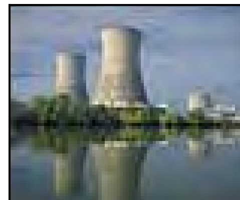
Summary Reports

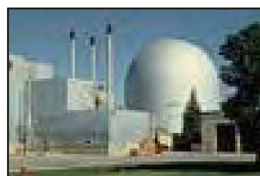
- Household Energy Use
- State Electricity Summary
- State Renewable Electricity Statistics
- Natural Gas Summary Statistics

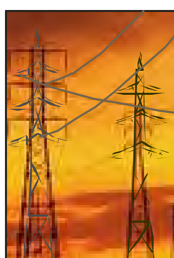
TAB 14

ELECTRIC UTILITY RESTRUCTURING LEGISLATIVE OVERSIGHT COMMITTEE









REPORT TO THE 77TH LEGISLATURE
NOVEMBER 2000

Electric Utility Restructuring Legislative Oversight Committee

REPORT TO THE 77TH LEGISLATURE

Representative Steven Wolens
Co-Chairman
Representative Kim Brimer
Representative David Counts
Representative Debra Danburg
Representative Sylvester Turner

Post Office Box 2910
Austin, Texas 78768
512 463-0814
FAX 512 463-6783

Senator David Sibley
Co-Chairman
Senator David Cain
Senator Frank Madla
Senator Jane Nelson
Senator John Whitmire

Post Office Box 12068
Austin, Texas 78711
512 463-0365
FAX 512 463-1617

ELECTRIC UTILITY RESTRUCTURING
LEGISLATIVE OVERSIGHT COMMITTEE

November 15, 2000

The Honorable George W. Bush, Governor
The Honorable Rick Perry, Lieutenant Governor
The Honorable James E. "Pete" Laney, Speaker of the House of Representatives

Gentlemen:

The Electric Utility Restructuring Legislative Oversight Committee hereby submits this interim report for consideration by the 77th Legislature pursuant to Section 39.907, Public Utility Regulatory Act.

This report tracks the progress of electric utility restructuring legislation implementation and summarizes major issues addressed during the Committee's interim hearings.

Respectfully submitted,

SIGNED	SIGNED
Rep. Steven Wolens, Co-Chairman	Sen. David Sibley, Co-Chairman
SIGNED	SIGNED
Rep. Kim Brimer	Sen. David Cain
SIGNED	SIGNED
Rep. David Counts	Sen. Frank Madla
SIGNED	SIGNED
Rep. Debra Danburg	Sen. Jane Nelson
SIGNED	SIGNED
Rep. Sylvester Turner	Sen. John Whitmire

PREFACE

The Electric Utility Restructuring Legislative Oversight Committee issues this report in accordance with Section 39.907 of the Public Utility Regulatory Act (Title II, Texas Utilities Code) as amended by Senate Bill 7, 76th Legislature.

The committee is charged with monitoring the effectiveness of electric utility restructuring and required to report on the committee's activities conducted during the interim, including meetings with the Public Utility Commission of Texas and information received about rules relating to electric utility restructuring. The committee is further required to analyze any problems caused by electric utility restructuring and recommend any legislative action necessary to address those problems or to further retail competition within the electric power industry.

Four public hearings were held featuring invited and public testimony from consumers and consumer advocates, state and federal agencies, the independent system operator, representatives of the electric power industry, community-based organizations and others. A summary of testimony presented to the committee at these hearings is included at the end of this report in Appendices D through G.

There have been many changes in global, national and local energy and power markets since the enactment of SB 7. The committee recognizes that the release of this report coincides with rising public concerns about increasing energy costs in Texas and volatile electricity prices elsewhere in the country. The committee has attempted to address many of these contemporary questions herein.

The committee extends its appreciation to all parties participating in the electric utility restructuring process, including the witnesses who offered testimony at committee hearings. The committee particularly wishes to thank the dedicated commissioners and staff of the Public Utility Commission of Texas for their tireless work on this complex issue to ensure that Texas' restructuring effort yields a fair market providing reliable, affordable electricity for all Texas customers. The committee also wishes to thank Mark Bruce and all committee staff for their contributions to this report.

Table of Contents

EXECUTIVE SUMMARY

The Electric Utility Restructuring Legislative Oversight Committee was established pursuant to Senate Bill 7, 76th Legislature, to study the effects of that bill on the state's electricity markets, transmission system and consumers of electricity. The committee conducted four public hearings during the 1999-2000 interim to accept invited and public testimony. The committee issues this report pursuant to Section 39.907, Public Utility Regulatory Act (PURA).

This oversight report includes an overview of implementation progress, analysis of Texas' system reliability and examination of developments in the Texas marketplace, including fuel price spikes, environmental issues, consumer protections and school funding impacts. Where illustrative, comparisons between the emerging market structure in Texas and other market models are presented.

Implementation Overview

Primary responsibility and authority for implementing customer choice, mandated by Senate Bill 7 and relevant provisions of Senate Bill 86, 76th Legislature, rests with the Public Utility Commission of Texas (PUC). Although several important rulemakings remain, the PUC has made great strides toward putting the foundation of the restructured market in place. Rules requiring utility business separation plans, codes of conduct, certification and registration of market participants and open access transmission service terms have been implemented. New programs promoting energy efficiency, renewable energy generation and customer education are being established. The PUC has engaged in restructuring activity at all levels, through workshops with industry participants and consumer representatives, market seminars and training sessions and regular updates at each of this committee's interim hearings. The PUC has also established a new Market Oversight Division to monitor and evaluate wholesale and retail market functions.

The majority of the technical issues of market restructuring have been decided by the Electric Reliability Council of Texas (ERCOT), a non-profit corporation serving as the Independent System Operator (ISO) of the Texas Interconnection, a power region covering approximately 85 percent of Texas. ERCOT's responsibilities include supervising the collective transmission facilities, systemwide transmission planning, nondiscriminatory coordination of market transactions, and network reliability. To facilitate the implementation process, the ISO contracted with Andersen Consulting, a firm with electric utility restructuring experience in other markets. ERCOT is in the process of expanding its infrastructure and staffing to comply with SB 7 and oversee retail access in the electric market. All restructuring efforts at the ISO are scheduled for implementation by the start of the retail competition pilot project on June 1, 2001. Andersen Consulting and ERCOT staff report implementation activity is proceeding close to schedule.[1]

Another state agency involved in electric power market restructuring is the General Land Office (GLO), which has begun converting state in-kind royalties to electricity and selling the power at discounted prices to itself and public schools in Texas. As of October 18, 2000, the GLO reported more than $350,000 in retail electric sales, providing almost $60,000 in savings to public schools.[2] The Land Commissioner has executed 46 contracts with public retail customers and 164 contracts are in progress as of the filing of this report. The vast majority of these contracts are with public school districts.

As required by SB 7, the Texas Natural Resource Conservation Commission (TNRCC) has established emissions caps affecting electric generating facilities (EGFs) previously exempted from air quality regulations, or "grandfathered facilities."[3] Some EGFs, both grandfathered and permitted, will be required to make further emissions reductions than those mandated by SB 7 under the TNRCC's State Implementation Plans (SIPs) for areas of Texas that are in violation of National Ambient Air Quality Standards (NAAQS) set by the U.S. Environmental Protection Agency (EPA). The Dallas SIP is currently under EPA review. The Houston/Galveston SIP is currently under development at the TNRCC.

[1]ERCOT Director Sam Jones, comments on the status of implementation activities, ERCOT Market Readiness Series No. 4, Sept. 25, 2000, Austin.

[2]Interview with Deputy Land Commissioner J. David Hall, Oct. 20, 2000.

[3]PURA §39.264.

Electric System Reliability

Because electricity cannot be stored, it must be made, delivered and used in real-time. This unique characteristic provides many challenges to keeping the system in balance so that the strength of electric current remains steady. Ensuring electric grid reliability requires three key components: adequate generation of electric power, sufficient transmission systems to move power from generators to end users and an operating and monitoring system to make the minute-to-minute adjustments necessary to keep the grid balanced.

Deservedly or not, San Diego became synonymous with deregulation in mainstream public discussion during Summer 2000. Residential electric bills skyrocketed from the previous year, and some businesses chose to close their doors in the face of unpredictable and seemingly uncontrollable power costs.[4] Rolling brownouts and regular service interruptions plagued San Francisco and Silicon Valley in an unusually hot May and June.[5] While state and federal agencies investigate charges of market abuses, system operators have already started planning for Summer 2001.[6]

Significant debate exists on the full range of causes behind California's restructuring problems, but the diagnosis is clear: the California system is not working.[7] As California's problems surfaced during the course of this committee's interim hearings, the committee sought answers to the question,"Could similar problems occur in Texas?"

---

[4]Craig D. Rose, "Average SDG&E Bill Is Going Up 16 Percent More; Rate-Wracked Consumers Caught In Surging Crisis," *San Diego Union-Tribune*, July 11, 2000, p. A1. San Diegans paid 13.8 cents per kilowatt hour, compared with 3.6 cents the previous year.

[5]Fred Bayles, "California Readies For Blackouts," *USA Today.com*, Web site visited Aug. 2, 2000.

[6]On August 2, 2000, California PUC President Loretta Lynch and Electricity Oversight Board Chairman Michael Kahn submitted a report requested by Governor Gray Davis addressing problems in California's electricity market. In the document, *California's Electricity Options and Challenges: Report to Governor Gray Davis*, the authors recommended that the attorney general participate in a broadened market abuse investigation. On August 23, 2000, the Federal Energy Regulatory Commission (FERC) also announced plans to investigate market problems. It issued its report on November 1, 2000.

[7]Michael Kahn and Loretta Lynch, *California's Electricity Options and Challenges: Report to Governor Gray Davis*, Aug. 2, 2000, p. 3. Authors state, "California is experiencing major problems with electricity supply and pricing caused by policies and procedures adopted over the past ten years ... These serious, but thus far isolated examples represent a precursor of what lies ahead for California's economy over the next 30 months."

The heart of California's problem lies in its lack of sufficient electric generation capacity to meet rising demand.[8] California's expensive and cumbersome siting process led to a near halt in new construction for most of the 1990s. Most of the new capacity currently planned and under construction in California will not be available by next summer.[9] In the meantime, demand for electricity continues to rise, creating scarcity in that market.

Electricity demand in Texas has also steadily increased in the 1990s, yet significant increases in generation capacity have been added to the system. Since the deregulation of wholesale power generation in Texas in 1995,[10] 22 new power plants totaling almost 5,700 megawatts (MW) of capacity have come on line,[11] compared to the 672 MW of new capacity added in California during the same period.[12] Since 1997, ERCOT has received more than 110 requests for generation interconnection.[13] Since the institution of market-based independent power production, siting new facilities in Texas can be accomplished in 24 to 36 months, compared to five to seven years in California.

Directly comparing the margin of reserve capacity against peak demand in each state illustrates the differences in generation system reliability. During Summer 2000, California's reserve margin dipped below 5 percent, whereas Texas enjoyed a greater than 12 percent reserve margin average.[14] As new generation currently under development is connected to the grid, ERCOT reserve margins are expected to increase to 30 percent by Summer 2001 and 2002.[15]

---

[8]Kahn and Lynch, p. 38.

[9]Ibid., p. 37.

[10]Senate Bill 373, 74th Legislature.

[11]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Legislative Oversight Committee, August 22, 2000 (See Appendix F for summary).

[12]Kahn and Lynch, p. 36.

[13]Electric Reliability Council of Texas, *Existing and Potential Electric System Constraints and Needs Within ERCOT*, Oct. 1, 2000, p. 17.

[14]Kahn and Lynch, pp. 21, 35; Chairman Wood, August 22, 2000.

[15]Public Utility Commission of Texas, *Draft Scope of Competition Report*, Project No. 22258, August 17, 2000, p. 42.

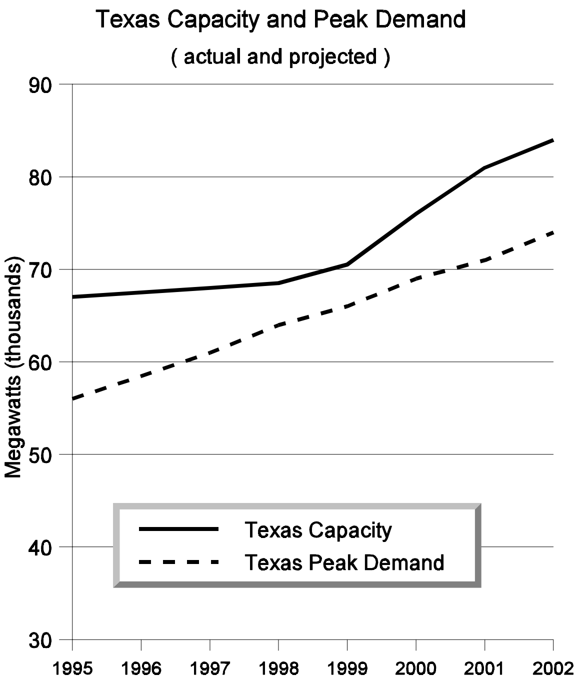


Fig. ES.1 source: Public Utility Commission of Texas

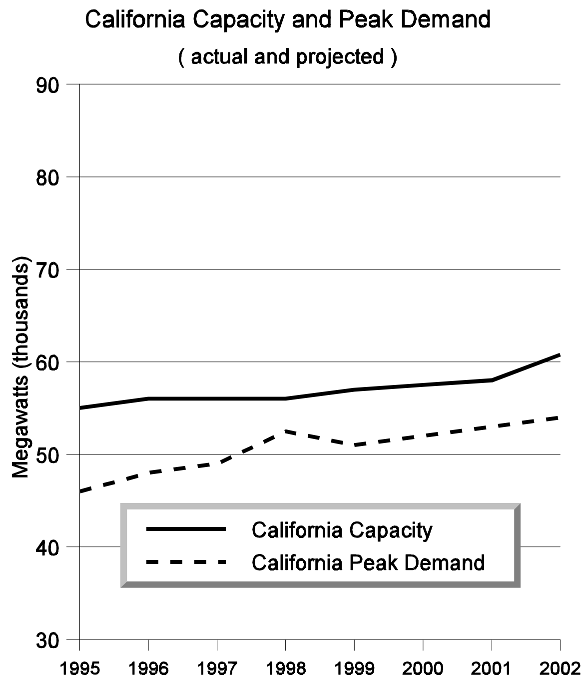


Fig. ES.2 source: California ISO

Most observers agree generation capacity in Texas will be adequate to meet demand for the next several years. However, the state's transmission system is in need of expansion to relieve existing bottlenecks and to distribute the power to be provided by new generation facilities. From 1994 to 2000, total load in ERCOT has grown 14,018 MW, or 32 percent, while very few bulk transmission additions have been made.[16]

Current constraints in the transmission system include moving electricity from power-rich areas of the state such as the Houston Ship Channel to power-hungry regions like the Dallas/Fort Worth Metroplex and moving power East to West in TXU's service territory. Seven major transmission projects are currently under development to resolve these problems, with completion anticipated in 2002 and 2003. Estimated spending on transmission-related improvements in the next three years

[16]Electric Reliability Council of Texas, p. 12.

is $543 million.[17] Seven additional projects have been reviewed and endorsed by ERCOT and await action by the PUC. ERCOT is currently evaluating 21 additional projects.[18]

Siting high-voltage transmission lines requires approximately the same amount of time as siting new power plants. Uncontested transmission projects might be constructed as quickly as one year, but most projects typically take 24 to 36 months. The siting process for high-voltage lines will likely lengthen in the future as transmission corridors are located in suburban and urban areas. Advances in micro-turbine design, fuel cell technology and other self-serve power options, collectively known as distributed generation, hold the promise of limited relief for the state's transmission network in the future. To facilitate increased introduction of distributed generation in Texas, standardized emissions permits and interconnection terms are under development at the TNRCC and PUC.

As previously noted, ERCOT is in the process of expanding its staff and technical infrastructure to meet the needs of the emerging market. ERCOT began monitoring the Texas Interconnection in the early 1970s and assumed security functions in 1983. Preparations to perform the additional functions required of an independent system operator began in 1995. The ERCOT ISO operates a control facility located in Taylor. A 45,000 square-foot back-up center in Austin is nearing the construction phase. If, for any reason, the Taylor facility were to experience a loss of power or other disabling event, operations control would switch to the Austin facility.

The Texas electric grid weathered several challenges during Summer 2000: wildfires, thunderstorms, drought, blistering heat and historic high electric demand. Despite these conditions, load interruptions were ordered less frequently than in 1998 and 1999, due in part to additions in generation capacity and cool temperatures in June. ERCOT directed some interruptible load shed five days in May, one day in July and two days in September. Unplanned energy transactions were also curtailed during Summer 2000, primarily due to North/South transmission constraints, although the number and volume of curtailments occurred at lower levels than the previous summer.[19] In other words, firm, uninterruptible load was reliably served through the year 2000 peak demand season.

[17]Chairman Wood, August 22, 2000.

[18]Electric Reliability Council of Texas, pp. 4-5.

[19]Interviews with ERCOT Director of Coordination and Reports Larry Grimm, Oct. 12, 2000 and ERCOT Director of Technical Operations Kent Saathoff, Oct. 23, 2000.

However, for successful market restructuring to occur, greater liquidity in unplanned energy transfers must be developed to allow retail electric providers (REPs) access to the most economical generation sources.

Market Structure

Rapid electrification of major urban areas in the United States occurred soon after Thomas Edison demonstrated that a series of electric lights could be powered from a generator in an adjacent building in 1882. The industry was very competitive from the outset, with dozens of firms competing for business in the same parts of American cities. As the use of electricity grew in the early 1900s, a dominant view emerged that electricity could best be provided by one large firm serving a single area, rather than multiple independent power producers. Proponents of this view claimed electric utilities were "natural monopolies," with each utility in a given area achieving significant cost savings through owning and planning its own generation, transmission and distribution systems. Since the 1970s, several changes in the industry have contributed to the decline of this theory in contemporary economics, including technological advances in power conversion and generation, advances in automated computer systems and new management models and practices.[20]

In Texas, electric utilities have assumed both public and private forms. Although one answers to an elected body such as a city council or cooperative board and the other to investors, both models share many consistencies, namely their vertically integrated structure coupled with the exclusive right to provide retail electric service in a given territory. Under this system, planning for additional generation capacity and transmission and distribution network upgrades is a very centralized process, with regulated rate structures designed to pay for those systems over their life of service.

The enactment of the Energy Policy Act of 1992 (P.L. 102-486) created opportunities nationwide for non-utility power generators to enter the wholesale electricity market. Texas began wholesale restructuring in 1995, by requiring transmission owners to provide non-discriminatory access to the electric grid and requiring utilities to consider power purchases from independent power producers

[20]A good source for introductory reading on the foundations of the electric utility restructuring debate is Peter Fox-Penner's *Electric Utility Restructuring: A Guide to the Competitive Era*, Public Utility Reports, Inc., Vienna, Va, 1997.

as a low-cost alternative to ratepayer-financed new plant construction. Non-utility generation has significantly increased in Texas as a result of these rules. Competitive energy services have also flourished in the state with demand-side management programs, energy efficiency audits and specialized time-of-use metering and billing functions. These unregulated market activities continue to grow in number and scope as the market evolves. This restructured competitive market places the risks and rewards of marketplace activity with investors rather than the captive ratepayer base.

Enacted in 1999, SB 7 directed utilities to separate business activities into three components: a competitive power generation company, a competitive retail electric provider and a regulated transmission and distribution service provider.[21] SB 7 did not require utilities to divest generation assets, leaving intact the ability to call on native generation to meet demand, a key distinction from the California model. However, the legislation did cap the total amount of generation any one firm can own in a power region at no more than 20 percent to mitigate potential market power abuse.[22] Additionally, codes of conduct adopted by the PUC restrict utilities from subsidizing competitive activities with revenues from regulated activities, and utilities are required to treat their affiliated companies and competitors equally in the marketplace.

The codes of conduct are especially important in the Texas market because bilateral contracts will be the predominant form of marketplace activity, another key distinction from the California model. In the Texas market structure, pricing information will remain privileged data between parties, as opposed to the California model, where prices are openly set in a centralized power exchange (PX). The California PX model has shown significant disadvantages since its implementation. The PX takes hourly bids from generators and then pays all generators the highest price set that hour. Buyers in the exchange, therefore, will pay the highest price for every kilowatt-hour of power at any given hour of the day, even if one or more generators is willing to sell electricity at a lower price.

The Texas bilateral market structure, on the other hand, will allow electric service providers to use long-term bilateral power contracts to hedge risk in the marketplace by seeking primary and secondary generation sources at the lowest prices available in the market. Again, a primary reason why this approach is feasible in Texas is the adequacy of generation capacity. A possible constraint

[21]PURA §39.051(b).

[22]PURA §39.156(b).

on the effectiveness of this approach, however, is the lack of liquidity in unplanned energy transfer capability during the peak demand season due to transmission system congestion.

As noted above, primary rulemaking and enforcement authority regarding electric utility industry restructuring is granted to the PUC. A new Market Oversight Division was created by the PUC to monitor several aspects of competition at all market levels: generation, wholesale and retail. Additionally, the PUC is granted authority to delay competition before January 1, 2002, if it determines a power region is unable to offer fair competition and reliable service to all retail customer classes.[23]

Stranded Costs

As utilities unbundle business activities into regulated and unregulated components, the issue of stranded costs arises from the fact that some facilities and contracts produced in the regulated environment prove to be uneconomical in a competitive market. The 76th Legislature decided these excess costs over market (ECOM), or stranded costs, should be reimbursed to the utilities through a non-bypassable charge on all customer bills until the costs are recovered. Another key difference between the California and Texas models is the treatment of stranded costs. San Diego Gas and Electric customers were exposed to wholesale market volatility when the utility paid off its stranded costs, which lifted the rate freeze under California's restructuring law. Under the Texas model, there is no correlation between stranded cost recovery and the lifting of the mandated 6 percent rate reduction and retail price cap, known as the price to beat. Furthermore, whereas California's other two major investor-owned utilities expect to complete stranded cost recovery and lift the rate freeze in their territories by 2002, stranded costs in Texas may be recovered over a much longer period of time, minimizing impact on the developing market.

In 1998, the PUC reported possible ECOM for Texas utilities at $4.39 billion.[24] The most recent ECOM estimates come from the utilities themselves, in their "unbundling filings" submitted in

---

[23]PURA §39.103.

[24]Public Utility Commission of Texas, *Report to the Texas Senate Interim Committee on Electric Utility Restructuring: Potentially Strandable Investment (ECOM)*, 1998.

March 2000. Orders have been issued by the PUC allowing securitization of $764 million in regulatory assets and transaction costs for Central Power and Light and $740 million for Reliant Energy HL&P. The PUC's securitization order of $363 million for TXU is under court challenge.

As the restructuring process continues, stranded costs in Texas are significantly impacted by a variety of market factors, particularly the price of natural gas, which has more than doubled in the past year. Natural gas is the fuel of choice for independent power producers because natural gas facilities are generally smaller and less expensive to build than other forms of generation. Natural gas is also a relatively inexpensive and abundant fuel source. However, recent increases in natural gas prices have translated into higher fuel charges on consumer electric bills in 2000.

Stranded costs should be lower because coal and nuclear plants — which comprise the bulk of stranded assets — have become more competitive with natural gas power generation, thereby increasing their market value. ECOM discussions will continue for the next four years. The PUC has not yet determined what costs related to emission reductions may be included in recovery proceedings. Additionally, TXU's pending request for recovery of nuclear plant costs could add as much as $941 million to total stranded costs.[25] A commission order on stranded costs is expected in Summer 2001, and the ECOM "true-up" will occur in 2004, at which time real data from a mandated 5 percent generation capacity auction and the first two years of market competition will be used to settle the issue.[26]

Rising Energy Costs

Quantifying the effects of higher natural gas prices on the Texas electric power industry is difficult at best. The recent increase in natural gas prices, if the trend continues, may provide the benefit of reducing stranded costs. Such a reduction could lower the non-bypassable charge on customer bills used as a repayment mechanism. However, this reduction in the "price floor" of the retail electricity

[25]TXU petitioned the PUC to securitize $1.65 billion in regulatory assets. The PUC concluded that only $363 million of TXU's regulatory assets met the criteria for securitization. TXU has appealed the decision to the courts. *Docket No. 21527 - Application of TXU Electric Company for a Financing Order to Securitize Regulatory Assets and Other Qualified Costs.*

[26]PURA §39.307.

price structure could be offset by increases in fuel costs for competitors.

Texans will see an increase in the retail price of electricity over the next few years, completely independent of market restructuring efforts if natural gas prices continue to increase. This issue is further compounded by the industry trend to rely on natural gas for generating fuel. All new generation capacity slated to come online in the next two to three years in Texas will be fueled by natural gas, with the notable exception of several new “wind farms” proposed in West Texas and other small renewable sources.

There is some question as to how much impact new gas-fired generation facilities will have on the total demand for natural gas. Although several new facilities have been announced or are under construction, new efficiencies in gas turbine technology allow more electricity to be produced from less fuel. However, rising electric demand means these plants will be running more often, and it is simply too early to tell what the net effect on total gas consumption will be. One noticeable impact of electric generating facilities on the gas market has been decreased levels of gas put into storage for the traditional peak winter season. Low gas production, coupled with all-time high summer electric demand largely fulfilled by gas-fired generators, has resulted in significantly decreased storage rates in 2000.[27]

Industry estimates vary considerably on the question of where natural gas prices will settle in coming months. Overall, exploration and drilling activity has declined since 1998, when prices remained low for most of the year. Approximately one third of all natural gas produced in the United States comes from Texas, yet Texas production has experienced an average annual decline of 2 percent per year since natural gas production peaked in 1972.[28] Many industry analysts predict shortfalls in natural gas availability during Winter 2000 as a result of production and storage declines.[29]

[27]Texas Railroad Commissioner Charles Matthews, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Sept. 26, 2000 (See Appendix G for summary).

[28]Ibid.

[29]“Panel: Consumers Face ‘Perfect Storm’ Of Energy Problems,” *Oil & Gas Journal Online*, Oct. 24, 2000.

Environmental Issues

The amount of pollution caused by EGFs in Texas will decline substantially under provisions of SB 7. Key reductions will be made in sulfur dioxide (SO2) and in nitrogen oxides (NOx), a pollutant that contributes to the formation of ground-level ozone, a widely-recognized health hazard. EGFs in Texas previously exempted from permitting requirements — so-called "grandfathered facilities" — were required under SB 7 to apply for an emissions permit from the TNRCC no later than September 1, 2000, or cease plant operation by May 1, 2003.[30] Total annual emissions from grandfathered facilities will decrease by 112,000 tons, or 12 percent, as a result of SB 7.[31] As of the filing of this report, 76 grandfathered EGFs had requested emissions permits.

The emissions cap and trade program established by the TNRCC also allows non-grandfathered facilities to implement pollution reduction measures and participate in the buying and selling of credits. This mechanism facilitates allocation of monetary resources where the greatest pollution reductions can be achieved for the least cost.

A common concern of the PUC, ISO administrators and industry participants is that EPA requirements to reduce ozone-forming emissions further in certain metropolitan areas may present challenges to maintaining overall reliability of the electric grid in Texas, particularly in the Dallas/Fort Worth area. The reliability challenges stem from two sources. First, some plants must be shut down in order to retrofit equipment with updated emissions control technology. This can generally be scheduled and accomplished during the off-peak season. However a high degree of coordination will be required to ensure sufficient capacity remains online to serve load. Second, some plants may be uneconomical to retrofit with improved emissions control devices and therefore are candidates for closure. Those same plants may also be integral parts of maintaining grid reliability by stabilizing voltage in a critical geographic area.

Industry response to the renewable energy mandate of SB 7 has thus far exceeded the goals of the bill. The PUC has established a renewable energy credits trading program, which allows all Texas

[30]PURA §39.904.

[31]TNRCC Executive Director Jeff Saitas, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Nov. 30, 1999 (see Appendix D for summary).

customers to participate in renewable energy development by requiring all REPs to own a proportional share of credits in the Texas market. Since 1999, almost 700 MW of new capacity from wind projects alone have been announced by traditional utilities and "green power" firms alike. This amount is roughly one third of the total new capacity required by 2009 under SB 7.

Customer Protection

Coming changes in provision of electric service coupled with recent developments in telecommunications services and mass marketing techniques spurred the 76th Legislature to adopt an extensive list of customer safeguards. Among other things, SB 86 entitles all buyers of telecommunications and retail electric service to:

protection from fraudulent, unfair, misleading, deceptive or anticompetitive practices, including protection from being billed for services that were not authorized or provided;

protection from discrimination on the basis of race, color, sex, nationality, religion, marital status, income level, source of income or geographic location;

impartial and prompt resolution of disputes with a certified telecommunications utility, a retail electric provider or an electric utility;

privacy of customer consumption and credit information; and

bills presented in a clear, readable format and easy-to-understand language.[32]

The first step to protecting consumers from anticompetitive behavior is to promote understanding of coming changes in the marketplace. To this end, the PUC adopted a two-stage approach to inform consumers of market changes and rights and protections afforded them by law. In the first phase, High Point/Franklin, a communications firm with experience in other market restructuring efforts, was selected by the PUC to develop a customer education plan. High Point/Franklin surveyed more

[32]PURA §17.004(a).

than 40 opinion leaders and policy makers statewide, conducted eight focus groups in six Texas cities and performed telephone surveys of 1,100 residential and 400 business customers of investor-owned utilities (IOUs). The education plan adopted by the PUC on July 18, 2000, was developed from the results of the survey, High Point/Franklin's experience in other markets and input from PUC staff, consumer advocates and industry representatives.

Key points of the customer education plan include integrated communications strategies, such as paid advertising, public relations efforts, printed materials, a toll-free call center, an electric competition Web site and specific tools designed to measure the overall effectiveness of each strategy. The plan also emphasizes communication through community-based organizations, which will form the primary channel to reach traditionally under-served populations such as low-income and non-English-speaking customers. On October 19, 2000, the PUC selected marketing firm Burson-Marsteller to implement the customer education plan.

Analysis of restructuring efforts in the telecommunications industry can provide some insight into possible pitfalls along the path of electric utility restructuring. Among the research findings of High Point/Franklin's interactions with both residential and commercial customers is the conclusion that Texas customers clearly framed their view of electric choice within their experience with long distance telephone service competition.[33] Anticompetitive practices such as slamming (changing service providers without customer authorization) and cramming (hiding unauthorized charges on customer bills) were commonly cited. Additional concerns were raised about the expected level of telemarketing activity associated with retail electric competition.

To prevent the slamming practices associated with long distance competition, ERCOT will function as the customer switching information center in Texas, and it will notify each customer by postcard whenever a switch request is received. The customer can verify the request by doing nothing, or nullify the request by returning the card. The PUC anticipates adopting a rule against cramming, along with related specific provisions addressing the content of customer bills, in coming months. Other rules addressing the customer safeguards established by SB 7 and SB 86 are expected to be adopted by the PUC in December 2000. Municipally-owned utilities and electric cooperatives are also required to adopt similar rules for customers within their certificated areas.

---

[33] High Point/Franklin, *Electric Competition in Texas: Customer Education Plan*, July 24, 2000, p. 13.

In much the same way monopoly utilities currently provide electric service to any requestor within their service territories, a provider of last resort (POLR) will be established to fulfill this function in the restructured marketplace.[34] Protections similar to those existing today have been established for both consumers and the REP serving as POLR. Customers who fail to pay for electric service can be disconnected except during extreme weather emergencies.

The POLR in each area of the state will be selected by the PUC through a bidding process. Large service territories, such as Reliant Energy HL&P, will likely be divided into several smaller POLR territories. If the bidding process is not successful, (e.g., the PUC does not receive enough bids for all POLR territories), the PUC can designate a REP to serve as POLR. The generally held perception is that POLR rates will be nominally higher than the market rate to allow the POLR to hedge risk against an unknown quantity and type of customer. Because customers who "choose not to choose" in areas of the state open to competition on January 1, 2002, will default to the affiliate REP of the incumbent utility, it is not expected that the POLR will be extensively utilized for the first few years of market development.

To further aid consumers in the restructured electric utility market, the System Benefit Fund (SBF) was created to fund four different programs: electric rate reductions for low-income customers, a targeted low-income weatherization program administered by the Texas Department of Housing and Community Affairs (TDHCA), appropriations for customer education programs of the PUC and administrative costs of the Office of Public Utility Counsel (OPC), and a mechanism to compensate the state and school districts for losses in property values of utilities' assets directly caused by restructuring. The source of revenues for the fund is a fee charged to customers based on the kilowatt-hours of electric energy used. Through fiscal year 2001, the SBF is expected to collect more than $90 million to fund early customer education efforts and payments to school districts. The PUC has worked with the Texas Department of Human Services to develop an automatic enrollment system for low-income customers to receive rate reductions. The PUC is expected to finalize rules relating to SBF administration in December 2000.

Thus far, the Texas Comptroller of Public Accounts has certified the property value losses directly attributable to restructuring of the electric utility industry at $6.29 billion. The Texas Education

[34] PURA §39.106

Agency (TEA) has certified that $65.12 million in Chapter 41 recapture dollars will be lost due to restructuring implementation. These losses to public school funding will be repaid through the SBF. The PUC will issue an order in December 2000 directing the IOUs to pay into the SBF their share of the amount determined by TEA.

Findings

The committee believes maintaining a reliable, affordable supply of electricity for all Texans is an essential component in our state's continued economic prosperity. The committee has observed the implementation process in action for more than a year and finds the provisions of SB 7 supply an adequate framework for electric utility restructuring in Texas.

Chapter One:
IMPLEMENTATION OVERVIEW

As expected, electric utility restructuring in Texas has proven to be a major undertaking requiring the combined efforts of several state agencies, industry participants and consumer organizations. Most regulatory implementation and market oversight functions were charged to the Public Utility Commission of Texas (PUC) and the Electric Reliability Council of Texas (ERCOT), a non-profit corporation serving as the Independent System Operator (ISO).

The task of creating a retail market structure in the electric power industry is nearing completion. The basic "rules of the road" are in place, business separation plans have been filed, registration of players in the new market has begun and the technical systems needed to meet restructuring requirements have entered the testing phase. The retail competition pilot project is expected to commence June 1, 2001, as established by PURA §39.104(b). Retail competition will begin for most of the state on January 1, 2002, as scheduled.

Implementation Strategies

Several implementation strategies have been exercised to meet the time frames set by SB 7.[1] An often-used approach in the development of both the regulatory structure and market mechanics employed collaborative, consensus-based processes involving branches of state and local government, market participants and consumer interest groups. For example, affected participants discussed implementation time lines, strategies, rules and procedures during a series of workshops hosted by the PUC. These deliberations served to delegate the work load to the appropriate levels. In many cases this process led to compromises generally accepted among affected stakeholders.[2]

---

[1]SB 7 established specific deadlines for certain restructuring activities, including adoption of rules (e.g., PURA §39.101(a)), filings and actions by market participants (e.g., PURA §30.051) and updates to state leaders (e.g., PURA §§ 39.907(g), 31.003(a), and 39.902(b)).

[2]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Nov. 30, 1999 (see Appendix D for summary).

On other implementation projects, the PUC staff issued a "straw man" rule and invited comment from interested parties. This approach also solicited a high level of communication among affected stakeholders. In other cases, traditional administrative rulemaking procedures were used. During most phases of the implementation process, public participation opportunities have existed either directly through public hearings or through interest group participation and monitoring activities.

During the restructuring period, particular attention has been focused on learning from the successes and problems of other states' deregulation efforts. Consulting firms with experience in other market restructuring efforts were utilized by the PUC, ERCOT and electric utilities, among others. Additionally, several industry participants in the Texas market have gained experience in other restructured markets, such as California and Pennsylvania, and have brought those lessons to bear on this state's restructuring efforts. Testimony regarding restructuring efforts in other markets was also presented to the committee.

Direct communication through seminars and training courses has also been extensively utilized. ERCOT has conducted several seminars known as the Market Readiness Series (MRS). The fourth in this series, held in Austin on September 25 and 26, 2000, drew more than 500 participants. ERCOT will conduct five more MRS seminars before the retail competition pilot project begins on June 1, 2001. ERCOT will also conduct seminar-style training classes on technical issues for market participants prior to the pilot project start date. Market players in the non-ERCOT areas of Texas have held similar functions immediately following the ERCOT seminar, in addition to participating in the ERCOT MRS seminars. These meetings have resulted in high levels of communication between industry participants, allowing shared questions and answers on every aspect of the new market from technical issues to understanding the new rules for the electric power industry.

Though not an implementation strategy, some issues related to the electric power industry and market restructuring have been or will be decided in the judicial system. Some specific cases are discussed in this report.

Public Utility Commission of Texas

In addition to continued regulation of the electric utility industry during the restructuring process, the PUC is also charged with developing most of the rules necessary to implement SB 7. Many of these rules are examined in detail in subsequent chapters of this report. A summary of completed rulemaking projects to date includes:

Code of Conduct for Electric Utilities and Affiliates: Adopted November 11, 1999, to implement PURA §39.157. This rule establishes safeguards to govern the interaction between utilities and their affiliates to prevent market power abuses and cross-subsidization between regulated and unregulated activities.

Cost Unbundling and Separation of Business Activities: Adopted December 16, 1999, to implement PURA §§ 39.051 and 39.201. This rule provides for the separation of each investor-owned utility (IOU) into a competitive power generation company (PGC), a competitive retail electric provider (REP) and a regulated transmission and distribution utility. The rule requires separation of competitive energy services from regulated utility activities and sets standards for determining transmission and distribution utility non-bypassable delivery charges, stranded cost estimation, System Benefit Fund assessment and nuclear decommissioning charges.

Certification of REPs: Adopted July 12, 2000, this is one of two rules that implement PURA Chapter 39, Subchapter H. The rule sets qualifying standards for certification as a REP.

Registration of PGCs and Aggregators: Adopted May 31, 2000, this is the other of two rules that implement PURA Chapter 39, Subchapter H. The rule sets qualifying standards for registration and operation of PGCs and aggregators.

Market Power Mitigation Plans: Adopted August 10, 2000, to implement PURA §§ 39.155 - 39.157. The rule establishes a methodology for calculating generation market share and requires reports from the owners of generation facilities.

Retail Competition Pilot Project: Adopted August 10, 2000, to implement PURA §39.104. This rule establishes the terms for the pilot project, which is scheduled to begin June 1, 2001.

Renewable Energy Mandate: Adopted December 16, 1999, to implement PURA §39.904. This rule defines the requirements for the purchase of renewable energy by competitive retailers and establishes a renewable energy credits trading program.

Public Retail Customers: Adopted September 23, 1999, to implement PURA Chapter 35, Subchapter D. This rule facilitates the sale of power by the General Land Office to public retail customers.

Energy Efficiency Programs: Adopted February 24, 2000, to implement PURA §39.905. This rule implements the statutory goal for energy efficiency. Utilities are required to fund market-based standard-offer programs and limited market transformation programs to reduce statewide energy consumption by at least ten percent of each utility’s annual growth in demand by 2004.

Electric Reliability Standards: Adopted December 1, 1999, to implement PURA §38.005. This rule establishes reliability standards for electric utilities.

Distributed Generation: Adopted November 18, 1999, to implement PURA §39.101. These rules ensure electric customers have access to on-site distributed generation. The rules prescribe terms and conditions for the connection of small power generation equipment and establish technical requirements to promote safe and reliable operation of distributed generation.

ISO Funding: Adopted September 9, 1999, to implement PURA §39.151. The rule permits ERCOT to charge a fee for the use of the transmission system to cover the additional funding required to develop the staff and computer systems needed for it to carry out ISO functions.

Natural Gas Generating Capacity: Adopted December 1, 1999, to implement PURA §39.9044. This rules establishes a natural gas credit trading program to meet the legislative goal that 50 percent of generation capacity installed in Texas after January 1, 2000, use natural gas as a primary fuel source. The natural gas credit trading program will not be implemented until the proportion of new generation capacity in Texas fired by natural gas falls below 55 percent.

Terms and Conditions for Transmission Service: Adopted December 1, 1999, to implement PURA §35.004. This rule sets a “postage stamp” method of ERCOT transmission pricing.

Provider of Last Resort (POLR): Adopted October 4, 2000 to implement PURA § 39.106. This rule establishes the POLR terms of service and sets procedures for selecting POLRs for different geographic areas.

Environmental Cleanup Costs: The methodology used to calculate environmental cleanup costs to be included in stranded cost recovery under PURA §39.263 has been adopted by the PUC. The rule requires a cost-benefit analysis of pollution control versus plant retirement. Consideration of likely future environmental regulations and their potential financial impacts is required. A final order on recoverable environmental cleanup costs will be issued during the 2004 true-up proceedings.

Several rules to implement retail electric choice remain to be set by the PUC. A summary of major projects remaining includes:

Customer Protections: Anticipated adoption in December 2000 to implement PURA §§ 17.001 and 39.101. The currently proposed rule includes requirements for metering and billing, protections against slamming and cramming, telephone solicitation rules, terms for access to consumer information and other safeguards mandated by SB 86 and SB 7. A more detailed examination of customer safeguards is included in Chapter 5.

Capacity Auction: This rule will set the terms and conditions for the generation capacity auctions required by PURA §39.153. Adoption is scheduled for December 2000.

System Benefit Fund (SBF): This rule will describe how the SBF will be administered and establish guidelines for the low-income programs to be supported by the SBF as mandated by PURA §39.903. Adoption is scheduled for December 2000.

Code of Conduct for Municipal Utilities and Cooperatives: This rule will establish standards to prevent market power abuses and cross-subsidization between regulated and competitive activities of municipal utilities and cooperatives, which are not subject to the code of conduct that has been adopted for IOUs. Adoption is scheduled for February 2001.

Terms and Conditions for Transmission and Distribution: This rule will establish the terms and conditions under which wires companies will provide service to retail electric providers. Adoption is scheduled for November 2000.

Additionally, the PUC is scheduled to review and approve the market protocols developed by ERCOT by March 2001. The protocols will set the rules and procedures for market participant interaction with the ISO.

Electric Reliability Council of Texas

ERCOT's primary function in the restructured marketplace is to serve as the ISO of the electric transmission grid. Additionally, ERCOT will maintain customer registration and switching information to protect consumers from slamming. To cover ISO operations and facilitate transition activities, a fee of 15 cents per megawatt-hour is levied against all energy transactions. Estimated revenue from transactions fees in 2000 is $40 million.[3]

Most restructuring activity deadlines in ERCOT are set for June 1, 2001, the retail competition pilot project start date. At the end of September 2000, ERCOT reported restructuring operations were about one week behind schedule.[4] Although it may be necessary to delay the pilot project if technical systems are not ready, the ISO anticipates meeting the June 1 target date.[5]

To accomplish restructuring objectives, ERCOT is engaged in hiring additional staff, constructing additional facilities and computer systems and drafting new market rules, called protocols. The ERCOT protocols will be reviewed by the PUC in early 2001. Additionally, some organizational restructuring was required for ERCOT to meet the ISO criteria established in SB 7. This activity is complete. A new board of directors will assume office in December 2000. Updates to hardware and software needed by ERCOT and market participants in the restructured market have entered the development and testing phases.[6] All ERCOT systems will undergo a "live test" phase in April 2001. This test, known as the mock market, will last approximately 60 days and will examine system performance under a variety of theoretical scenarios. Participants in the retail competition pilot

[3]Interview with ERCOT Director of Coordination and Reports Larry Grimm, Oct. 12, 2000.

[4]ERCOT Director Sam Jones, remarks at ERCOT Market Readiness Series No. 4, Sept. 25, 2000, Austin.

[5]Interview with ERCOT Director of Technical Operations Kent Saathoff, Oct. 23, 2000.

[6]Larry Grimm, Oct 12, 2000.

project will also test new systems during the April mock market.

A more thorough description of ISO duties and ERCOT's preparations to assume that role is provided in Chapter 4, which also includes a review of transmission coordination in the non-ERCOT areas of Texas.

Other State Agencies

Texas Natural Resource Conservation Commission (TNRCC): SB 7 directed the TNRCC to develop a cap and trade program for emissions from electric generating facilities (EGFs).[7] The program requires EGFs previously exempted from the requirements of the Texas Clean Air Act (TCAA), or "grandfathered facilities," to apply for an emissions permit by September 1, 2000. These facilities must obtain a permit or cease operating by May 1, 2003. For facilities receiving permits under this rule, emissions of nitrogen oxides are capped at 50 percent below 1997 levels. Coal-fired EGFs must reduce emissions of sulfur dioxide by 25 percent below 1997 levels. The rule allows EGFs already permitted under the TCAA to voluntarily reduce emissions for the purpose of obtaining credits for sale under the program. Of the 130 grandfathered EGFs in Texas, 76 applied for permits under the new rule. The TNRCC is considering an additional rule that would allow other industries to participate in the cap and trade program. The stated purpose of the rule is to allow companies flexibility to determine the best mix of using control technologies to reduce their own emissions and/or the purchase or trading of surplus allowances from other facilities. This rule is scheduled for adoption in December 2000.

General Land Office (GLO): SB 7 included a provision authorizing the GLO to negotiate and execute contracts for the conversion of state in-kind royalties to other forms of energy and sell the converted energy to public retail customers.[8] SB 7 defines the state in-kind royalties which may be used as oil or gas produced on state mineral lands, university mineral lands or the first three miles of federal waters adjacent to the state boundaries. The GLO has developed and implemented the Texas State Power Program to execute this authority.

[7] PURA §39.264.

[8] PURA Chapter 35, Subchapter D.

The provisions of SB 7 limit power sales to public retail customers, which are defined as public school districts, state colleges and universities, state agencies and political subdivisions of the state. GLO sales are capped at no more than 2.5 percent of the total retail load in a service territory. The GLO is prohibited from selling electricity to public retail customers served by electric cooperatives or municipal power agencies (MPAs) unless the cooperative or MPA member utility has decided to opt in to competition.

The GLO will not build or own any electric facilities or generate electricity. A contracted agent or energy service provider (ESP) and the incumbent utility will conduct all electric and utility-related business. The GLO will supply gas to the ESP and contract for service with customers. It will execute contracts with electric power providers that assist the GLO with all aspects of converting royalties, retail marketing, sales, billing, metering and ancillary services.

The State Power Program is structured to include a Gas Sales Agreement specifying oil and liquids to be converted at value, an Electric Service Agreement (ESSA) and a Retail Sales Contract with customers. Under the Gas Sales Agreement, the GLO will provide gas to the ESP for an industry standard indexed price at volumes determined in the ESSA. Under the ESSA, the GLO will provide gas or oil volumes necessary to generate the number of kilowatts contracted with customers. The ESP will provide electricity for a fixed price and set volumes and delivery points for gas and oil. The Retail Sales Contract with each customer will follow standard market utility provider contracts.

As mentioned above, the PUC enacted the rule granting GLO access to retail electric sales September 23, 1999. As of October 2000, the GLO reported more than $350,000 in retail electric sales, providing almost $60,000 in savings to public schools. The GLO has executed 46 contracts with public retail customers, and 164 contracts are in progress at the filing of this report. The vast majority of these contracts are with public school districts.

Earnings from royalty conversions are placed in the Permanent School Fund. Earnings from retail electric sales are placed in the Available School Fund.

Legislative Oversight

The Electric Utility Restructuring Legislative Oversight Committee conducted four public hearings in three Texas cities during the 1999-2000 interim. The hearings featured invited and public testimony from consumers and consumer advocates, state and federal agencies, the independent system operator, representatives of the electric power industry, community-based organizations and others. A summary of testimony presented to the committee at these hearings is included at the end of this report in Appendices D through G.

In addition to briefings regarding implementation activities, the committee received testimony related to various changes in energy markets both in Texas and elsewhere. The price spikes and reliability problems experienced in California received particular attention in the committee's investigation into market restructuring issues. Other issues figuring prominently in the committee's public discussions include air quality data and environmental regulatory impacts on the electric power industry, planning and reliability of the bulk power grid and energy price pressures. Each of these topics are addressed in succeeding chapters.

Chapter Two:
ELECTRIC SYSTEM RELIABILITY

Maintaining an adequate, affordable supply of electricity for all customer classes is a fundamental security issue. One of the most critical aspects of the restructuring process is to avoid compromising reliability of the bulk electric system in Texas. The process of planning, building and maintaining electric systems in Texas and the United States has undergone significant changes during the 1990s. In many ways, these changes have enhanced system reliability by channeling new development into the bulk power system infrastructure. In other ways, system planning has been complicated by the redistribution of some reliability functions and responsibilities. This chapter provides an overview of how electric systems work, current and anticipated generation capacity in Texas, challenges to electricity transmission across the state and other factors which complicate system reliability during the restructuring transition period.

Overview of Electric Systems

Basic knowledge of how electric systems work is essential to understanding the changes taking place in the Texas electricity market. Electricity is somewhat unique as a commodity in that it cannot be readily stored in significant quantities. Therefore, it must be made, distributed and consumed in real time. Ensuring electric system reliability requires three key components: adequate generation of electric power, sufficient transmission systems to move the power from generators to end users and an operating and monitoring system to make the minute-to-minute adjustments necessary to keep the grid balanced between available supply and demand at all times.

Generation refers to the physical production of electric power. Electricity is produced by generating units powered by burning fossil fuels such as coal or natural gas, running water such as a river controlled by a dam, renewable resources such as solar and wind energy, or by nuclear fission. These fuel sources serve as a catalyst which heats water to create steam. This steam is used to turn a turbine containing a metal coil which spins within a magnetic field, creating a current of electricity. The electricity is transported to consumers by use of transmission and distribution systems. Transmitting electricity involves sending it through high-voltage power lines, usually over long distances. Lower-

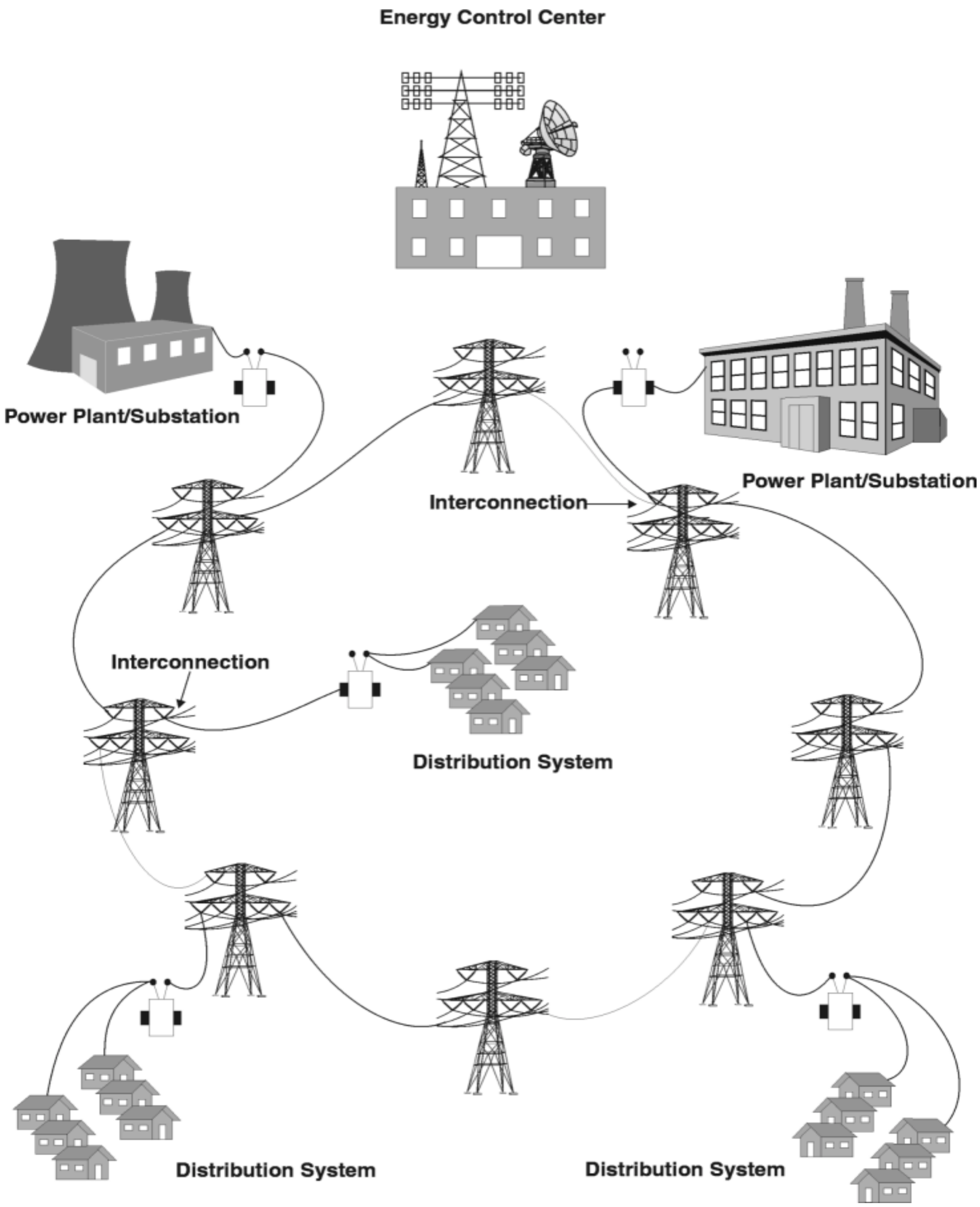


Fig. 2.1 **A Simple Electric System**

voltage distribution networks move the power from the transmission system to end users *(see Figure 2.1).* A defining feature of the bulk power system is the degree of interdependence between its various parts. The need for coordinated system operation stems from more than a simple energy balance. Because the system uses alternating current, every generating plant must be in precise synchronization in order to keep the network at the same frequency and maintain voltage. This is complicated by a phenomenon known as reactive losses, which are tiny amounts of energy stored in transmission lines as power is moved over great distances. Reactive losses generally have the effect of lowering voltage at one end of the transmission line, which can harm electronic equipment plugged into the system.

An energy control center is needed to apply the proper amount of reactive power from various points in the grid by remote control. The challenge of keeping a power system in supply-demand balance, synchronized and voltage-supported is made difficult by the fact that the electric transmission system generally does not allow power to be directed down a specific path from one generator to one consumer. The transmission system is more like a large water pool into which electricity flows from all generators. All users take from this pool, and the system is adjusted so that the total water flowing into the pool equals the total water being withdrawn by all users at every moment.[1]

Of the 48 contiguous states, Texas is in the unique position of controlling most of the power grid within the state's borders. Most other states lie within either the Eastern or Western Interconnections and fall under the guidelines of the Federal Energy Regulatory Commission (FERC). The Texas Interconnection, monitored by the Electric Reliability Council of Texas (ERCOT) covers all but four portions of the state: El Paso, the Northwest Panhandle and parts of Northeast and Southeast Texas. The principal regulatory body for the 84 percent of Texas located within ERCOT boundaries is the Public Utility Commission of Texas (PUC).

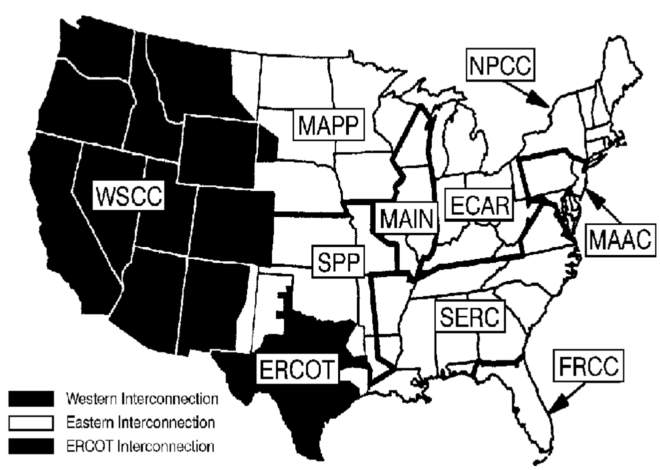


Fig. 2.2 **Major U.S. Interconnected Electric Systems**

Energy control center functions within the ERCOT boundaries will be performed by the ERCOT Independent System Operator (ISO). ERCOT will also perform some statewide functions, including maintaining

[1] Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era*, Public Utility Reports, Inc., Vienna, Va., 1997, pp. 25-26.

market participant and customer registration databases. In the non-ERCOT areas of Texas, energy control center functions will likely be performed by regional transmission organizations (RTOs) pursuant to FERC Order 2000. A more complete discussion of ISO implementation and control center functions can be found in Chapter 4.

Generation

Construction of additional generation capacity in Texas slowed during the early 1990s as utilities and independent power producers watched the development of wholesale market restructuring in the state. In 1995, the 74th Legislature passed SB 373, which required open access to utility transmission systems, paving the way for non-utility power producers to operate in Texas. Industry response to wholesale market restructuring has been positive. Twenty-two new power plants have added more than 5,700 megawatts (MW) of capacity. Approximately 15 more generation facilities are under construction.[2] The total available capacity above peak electric demand, or reserve margin, is widening in Texas after dipping below the recommended 15 percent from 1998 to Summer 2000. PUC staff predict reserve margins in ERCOT will approach 30 percent by Summer 2001 and 2002.[3]

Figure 2.3 provides details of many of the new generation capacity announced or under development in ERCOT as of October 2000. Because generation interconnection requests are considered proprietary information, this is a partial list reflecting only those projects approved for disclosure.[4] In some cases, market conditions may cause a power producer to alter plans or abandon a project. It is unlikely every project on the list will be developed in the anticipated time frame. Figure 2.4 summarizes power generation market activity since SB 373 implementation.[5]

---

[2]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Oversight Committee, August 22, 2000 (see Appendix F for summary).

[3]Public Utility Commission of Texas, *Draft Scope of Competition Report*, Project No. 22258, August 17, 2000, p. 42.

[4]Electric Reliability Council of Texas, “New Generation Projects Under Development in ERCOT,” Web site information retrieved Oct. 9, 2000.

[5]Public Utility Commission of Texas, *Update on Activities in the ERCOT Wholesale Electricity Market*, April-June, 2000, Project No. 19616, p. 13.

Fig. 2.3 **Announced New Generation Capacity in ERCOT**

In Service	Capacity (MW)	Location (County)	Owner
	Natural Gas		
June 2001	500	Bastrop	Calpine
May 2001	479 summer, 539 winter	Bexar	CPS-San Antonio
June 2002	306 summer, 357 winter	Bosque	Southern Company Energy
January 2002	800	Chambers	Calpine
June 2001	75	Collin	City of Garland
1st Quarter 2004	385	Duval	CCNG
July 2001	1,000	Ector	Texas Independent Energy
June 2000	1,000	Ellis	American National Power
September 2001	350	Ellis	Tractebel Power
June 2002	600	Fort Bend	Avista
May 2002	1,050	Freestone	Entergy Power Group
June 2000	830 summer, 910 winter	Grimes	Tenaska Power
December 2000	1,000	Guadalupe	Texas Independent Energy
June 2002	820	Guadalupe	Constellation Power
June 2000	545	Harris	Calpine
May 2001-Feb. 2002	830	Harris	Calpine
April 2002	770	Harris	Reliant Energy
June 2002	1,650	Harris	American National Power
May 2003	578	Harris	Sempra Energy
May 2003-May 2004	535 Phase 1, 535 Phase II	Harris	Energy Generation Corp.
June 2001	1,650 summer, 1,500 winter	Hays	American National Power
June 1999	514	Hidalgo	Frontera Generating
May 2000	510	Hidalgo	Duke Energy
February 2001	514	Hidalgo	Calpine
March 2002	750	Hood	AES
3rd Quarter 2002	1,500	Kaufman	Cosiba-Forney Power
July 2000	1,000	Lamar	FPL Energy
May 2003	578	Montgomery	Sempra Energy
April 2002	530	Nueces	Skygen Energy
May 2001	186	Travis	Austin Energy
July 2002	510	Wise	KN Power
June 2003	800	Wise	Tractebel Power
	Wind		
April 2001	175	Culberson	Orion Energy
July 2001	250	Ector & Winkler	York Research
Dec. 2000-Oct. 2001	150	Pecos	Enron Wind Corp.
January 2001	125	Pecos	Orion Energy
September 2001	100	Pecos	Cielo Power Market
Dec. 2001-Dec. 2002	400	Sweetwater	Enron Wind Corp.
Nov. 2000-Nov. 2001	300	Upton	Cielo Power Market

Source: Electric Reliability Council of Texas

Fig. 2.4 **New Generation Since SB 373**

Year in Service	All of Texas (MW)	ERCOT (MW)	Year in Service	All of Texas (MW)	ERCOT (MW)
Completed			**Announced**		
1996	341	341	2000	4	4
1998	570	570	2001	376	284
1999	1,277	897	2002	5,236	4,006
2000	3,202	3,004	2003	6,411	6,411
Total Completed	5,390	4,812	2004	885	885
			Indefinite	4,217	4,217
Under Construction			Total Announced	17,129	15,807
2000	2,963	2,920			
2001	7,646	6,776	Total New Generation	36,336	33,523
2002	3,208	3,208			
Total Under Construction	13,817	12,904	*Source: Electric Reliability Council of Texas*		

Adequate capacity is only one part of the equation. Access to a diverse source of generation fuels is an important factor to consider when estimating risk associated with a number of potential market scenarios. Figure 2.5 shows the installed capacity by fuel source for the 13 largest Texas utilities in 1998. Since 1998, almost all new capacity in Texas has been gas-fired non-utility generation facilities. Sustained higher natural gas prices have caused some in government and industry to speculate whether the Texas generation market is becoming too heavily dependent on natural gas as a fuel source.[6] A detailed look at recent activity in the natural gas market is included in Chapter 3.

Resource diversity can be an important risk management strategy, but several other considerations also factor into resource development decisions. Natural gas is favored in areas with air quality concerns because of its low emissions. As previously noted, however, if high natural gas prices are sustained, other fuel sources become more attractive in the marketplace. SB 7 required at least 50 percent of all new capacity installed in Texas to be fueled by natural gas.[7] The PUC has adopted a rule to implement this mandate. SB 7 also required additional investment in renewable resources, more than tripling the state's total renewable capacity by 2009.[8] A complete discussion of renewable

---

[6]Frank McCamant, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Nov. 30, 1999 (see Appendix D for summary).

[7]PURA §39.9044.

[8]PURA §39.904.

Fig. 2.5 **Installed Capacity in Texas by Fuel Type and Owner**

Owner	Gas	Coal	Lignite	Nuclear	Hydro	Wind	PV	Total
TXU	12,995	-	5,825	2,300	-	-	-	21,120
RHLP	9,335	2,415	1,520	770	-	-	-	14,040
CPS	2,425	1,385	-	700	-	-	-	4,510
CPL	3,116	684	-	630	6	-	-	4,436
SPS	1,624	1,588	-	-	-	-	-	3,212
EGS	2,268	269	-	281	-	-	-	2,818
AE	1,450	570	-	400	-	-	0.3	2,420
SWEPCO	938	971	443	-	-	-	-	2,352
LCRA	1,040	1,024	-	-	273	-	-	2,337
WTU	1,025	370	-	-	-	1	-	1,396
EPE	607	82	-	466	-	-	-	1,155
BEPC	687	-	-	-	-	-	-	687
TNMP	-	-	301	-	-	-	-	301
Total ERCOT	33,222	7,293	8,037	4,800	435	1	0.3	53,788
Total Texas	38,918	10,258	8,597	5,547	662	1	0.3	64,011

Source: Public Utility Commission of Texas
(The total capacity shown for ERCOT and Texas includes other utilities and merchant power plants not listed individually.)

energy resources is included in Chapter 7.

Transmission

Ensuring system reliability depends not only on how much power is produced, but also how it is transported around the state. Electricity must be available both *when* and *where* consumers need it. Texas suffers from transmission constraints that restrict the flow of electricity at critical times during the day, especially during the peak summer season.[9] These transmission constraints have two primary effects. First, load centers dependent on imported power, such as the Dallas/Fort Worth (D/FW) Metroplex, could experience a supply shortage during peak use hours, even though sufficient generation capacity exists elsewhere in the system. Second, constrained transmission systems decrease liquidity in the marketplace, limiting the volume, type and timing of energy transactions between buyers and sellers.

[9]Electric Reliability Council of Texas, *Existing and Potential Electric System Constraints and Needs Within ERCOT*, Oct. 1, 2000, p. 10.

Prior to restructuring, new generation facilities and transmission lines were often planned together. In a restructured market, the PUC will no longer have significant advance knowledge where new generation facilities requiring connection to the grid will be located. This fact complicates system planning. Because transmission utilities will continue to be regulated monopolies after the transition to a competitive market, several important decisions will still fall to the PUC through formal proceedings in much the same way it has been done in the past.

To mitigate potential market power abuse, transmission utilities are required to provide non-discriminatory access to their lines. The utility cannot deny an interconnection request in its service territory. Utilities recover the cost of lines through a "wires charge" set by the PUC. Construction of transmission facilities to connect a new generator may not always be in the public interest. For example, the cost or impact of a new line may outweigh the benefits of the electric power it would connect to the grid. In this instance, the PUC may deny the utility a certificate of convenience and necessity for the line, thus absolving the utility of its interconnection responsibility and effectively canceling the proposed generation project. Part of the ERCOT ISO's responsibilities include reviewing proposed transmission projects and making recommendations to the PUC.

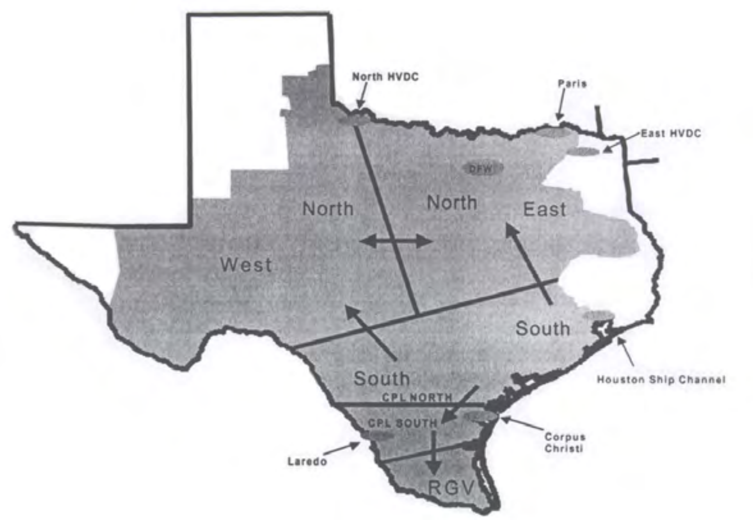


Fig. 2.6 **Major Transmission Constraints in ERCOT**

Currently in Texas, transmission systems are primarily constrained in the flow of power from South to North and to and from West Texas *(see Figure 2.6)*. The West Texas constraints have a particular impact on much of the state's new renewable energy projects, which are primarily wind facilities located in that area. Keeping the "green" megawatts flowing on the grid is important to obtaining the overall energy mix mandated by SB 7.

The most significant transmission challenge in Texas is importing power to the four-county D/FW Metroplex. Approximately 65 percent of the Metroplex's electric demand is served by power imported into the region over the ERCOT transmission grid. Peak demand in the Dallas area is approximately 15,000 MW. Current installed capacity is 5,900 MW. Population growth and increased demand will require utilities to import even more power in the near future. Population in the D/FW area grew 2.3 percent between 1996 and 1999. Electric load in the D/FW area has grown at about 2.9 percent annually and is expected to continue growing at approximately 3.4 percent per year. Projected growth in population and electric demand, existing air quality regulations and the lack of suitable sites for power plant construction near the load center point to the need for substantial additions in transmission capacity in and around the Metroplex.[10]

However, considering economics and good utility practice, ERCOT does not believe that sufficient transmission facilities can be installed to completely remove the need for new generation in the D/FW area. ERCOT believes a combination of new voltage support projects, strategic additions to the transmission system and an appropriate level of generation in the area is the only way future reliability needs for the D/FW area can be met. In addition, the existing transmission system is inadequate to handle significant increases in new generation at existing generation sites.[11]

Some relief for the Dallas area is scheduled to come online before the Summer 2001 peak demand season: a 75 MW power plant planned by the City of Garland and a new 345-kilovolt transmission line known as the Limestone Watermill Double Circuit. Other solutions under consideration by the PUC, ERCOT and D/FW transmission service providers include demand-side management, energy efficiency programs, distributed generation and price-responsive demand mechanisms. Lessons learned in the D/FW area from implementation of these non-traditional approaches to transmission constraints could be applied to other transmission-constrained areas of the state as well.

Seven transmission projects are currently under construction in the state, and seven more are in the review stage at the PUC. Projected spending on new transmission facilities in Texas is $543 million

---

[10]Public Utility Commission of Texas, "Meeting the DFW Reliability Challenge: Background Paper," October 2000, p. 3.

[11]Electric Reliability Council of Texas, *Existing and Potential Electric System Constraints and Needs Within ERCOT*, Oct. 1, 2000, p. 40.

through 2003.[12]

Independent System Operator

The final physical link in ensuring system reliability rests with the ISO. As noted, this role will be performed by ERCOT. The ISO performs several key functions in the real-time market: monitoring voltage levels on the grid, making the minute-to-minute adjustments required to keep the system in balance, ordering power interruptions in an emergency and shopping for additional power to import to the grid when a shortage occurs. A full report of ERCOT ISO preparations and transmission system operations in the non-ERCOT areas of Texas is provided in Chapter 4, along with a review of transmission system operations in the non-ERCOT areas of Texas.

Complicating Factors

Under normal conditions, reliable delivery of electric service to Texas consumers faces many challenges. During 2000, drought conditions threatened some West Texas power plants because large cooling ponds required for operation began to dry up.[13] Wildfires across the state destroyed miles of transmission and distribution lines, sporadically severing service to customers.[14] Thousands of Gulf Coast customers lost power for a few days after thunderstorms knocked down transmission and distribution lines in July.[15] These challenges exist with or without market restructuring efforts.

A final important factor complicating overall system reliability is the impact of mandated emissions reductions on electric generating facilities. As noted above, Texas is heavily dependent on a variety

[12]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Oversight Committee, August 22, 2000 (see Appendix F for summary).

[13]Scott Parks, "Drought Hindering Electricity Production," *Dallas Morning News*, August 26, 2000, p. 2B.

[14]Associated Press news service, August 31, 2000.

[15]Jeannie Wiggins, "2,000 Customers Still Without Power Monday," Port Arthur News, July 25, 2000, p. 1A.

of fossil fuels for power production. Many of these fuels emit pollutants with wide-ranging environmental impacts during the combustion process. Meeting the needs of a growing population with escalating electricity demands while maintaining clean air standards will likely be the toughest challenge for the industry in the next several years. A more detailed discussion of air quality concerns and impacts is provided in Chapter 6.

Although Texas is experiencing a boom of power plant construction now, some observers wonder how the market will react when installed electric power capacity significantly exceeds demand. PUC Chairman Wood said he expects new plant construction to level off in a few years, but he anticipates power generators will resume new plant construction when needed, "as long as the correct market signals are getting sent."[16] An analysis of industry response to Texas market signals is presented in the following chapter.

[16]Chairman Wood, August 22, 2000.

Chapter Three:
MARKET TRANSITION

This chapter reviews the major market restructuring requirements of Senate Bill 7 and the activities of the PUC, electric utilities and others to implement them. Lessons learned from other states' restructuring efforts are noted where appropriate, and particular attention is paid to the developing retail electricity price structure.

This chapter also examines emerging issues in Texas and national energy markets, with particular focus on recent developments in the natural gas industry and their impact on electric utility restructuring in Texas.

SB 7 Requirements and Implementation

SB 7 established a number of deadlines for state agencies and market participants to perform certain restructuring activities from 1999 through 2009. All statutory deadlines have been met to date, and implementation of retail electric competition is on schedule. The retail competition pilot project is scheduled to begin on June 1, 2001, and full competition in eligible areas of the state should commence on January 1, 2002.

SB 7 required the state's vertically-integrated investor-owned electric utilities (IOUs) to separate their businesses activities into three components:

a competitive power generation company (PGC);

a competitive retail electric provider (REP); and

a regulated transmission and distribution utility (T&D).[1]

[1]PURA §39.051.

This business separation, known as unbundling, may be accomplished through the creation of separate affiliated companies owned by a common holding company or through the sale of assets to a third party. As required by SB 7, utilities have filed business separation plans for review and approval by the PUC. Final orders on the separation plans are expected in March 2001.

Through this process, some utilities may be left with costs incurred under the regulatory structure which may not be economical in the competitive environment. These excess costs over market (ECOM), or stranded costs, primarily represent investments in nuclear power. When the 76th Legislature passed SB 7 in 1999, total ECOM was estimated at $4.39 billion.[2] Recent changes in market conditions have led to several revisions of this estimate. It is now generally expected that stranded costs will be much lower than previously estimated. The impact of stranded costs on the retail electricity price structure is examined below.

A code of conduct for IOUs was adopted by the PUC in November 1999 to prevent affiliated wires companies from subsidizing unregulated market enterprises with revenues from regulated activities and from giving the unregulated company and advantage in the marketplace. This code of conduct requires T&Ds to grant access and privileges to all market participants similar to those granted to their affiliated companies. A similar code of conduct for municipal-owned utilities (MOUs) and electric cooperatives (Coops) is scheduled for PUC adoption in February 2001.

SB 7 froze IOU retail base rates at September 1, 1999, levels and maintains this rate freeze until January 1, 2002, when retail competition begins.[3] At that time, residential and small commercial customers will receive a 6 percent rate reduction. This discounted rate will be known as the price to beat. In each IOU service territory in the state, the affiliated REP of the incumbent utility cannot offer rates different from the price to beat for three years (January 1, 2005, for most of the state) or until it loses 40 percent of its retail customer base, whichever occurs first.[4]

The price to beat mechanism will establish a rate under which new competitors may enter the market

[2]Public Utility Commission of Texas, *Report to the Texas Senate Interim Committee on Electric Utility Restructuring: Potentially Strandable Investment (ECOM)*, 1998.

[3]PURA §39.052.

[4]PURA §39.202.

and prevent the affiliated REP of the incumbent utility from exercising undue market influence and undercutting competition. The affiliated REP must offer the price to beat to all small customers requesting it until January 1, 2007, providing customers a five-year window of protection against any unforseen market forces which may create price volatility.

SB 7 also mandated that each power region of the state create and maintain an independent organization to monitor the transmission network and settle wholesale energy transactions. This organization is commonly known as the Independent System Operator (ISO). Transactions between wholesale power buyers and sellers will be settled through the ISO. The ISO will not function as a power pool, however, and will not set prices or match buyers with sellers. Wholesale contract terms and conditions will be established through bilateral contracts between buyers and sellers.

The ISO role will be fulfilled by a restructured ERCOT organization within the ERCOT power region. The PUC conditionally certified the ERCOT ISO in April 2000, and ERCOT requested final certification in November 2000. ISO functions in the non-ERCOT areas of Texas will likely be performed by a regional transmission organization (RTO) within the Southwest Power Pool reliability council and a privately-owned transmission company in the Entergy service territory. A more complete look at ISO functions is included in Chapter 4.

Retail Price Structure

Composition of the retail price structure is an important feature of the restructured electricity market. The price structure must cover all costs of market transition, power generation, customer assistance programs and transmission system administration while leaving enough room for each entity in the electricity delivery process to generate return on investment.

Figure 3.1 illustrates the retail electricity price structure in the competitive market. The horizontal time line at the top of the diagram shows the price ceiling imposed by the 1999 rate freeze and price to beat beginning in 2002. In addition to the price ceiling imposed by the price to beat, the retail price structure also has a floor composed of non-bypassable charges which will be included on all customer bills. These charges include the Competition Transition Charge (CTC), System Benefit Fund (SBF), and transmission and distribution (T&D) fees. The PUC will set the non-bypassable

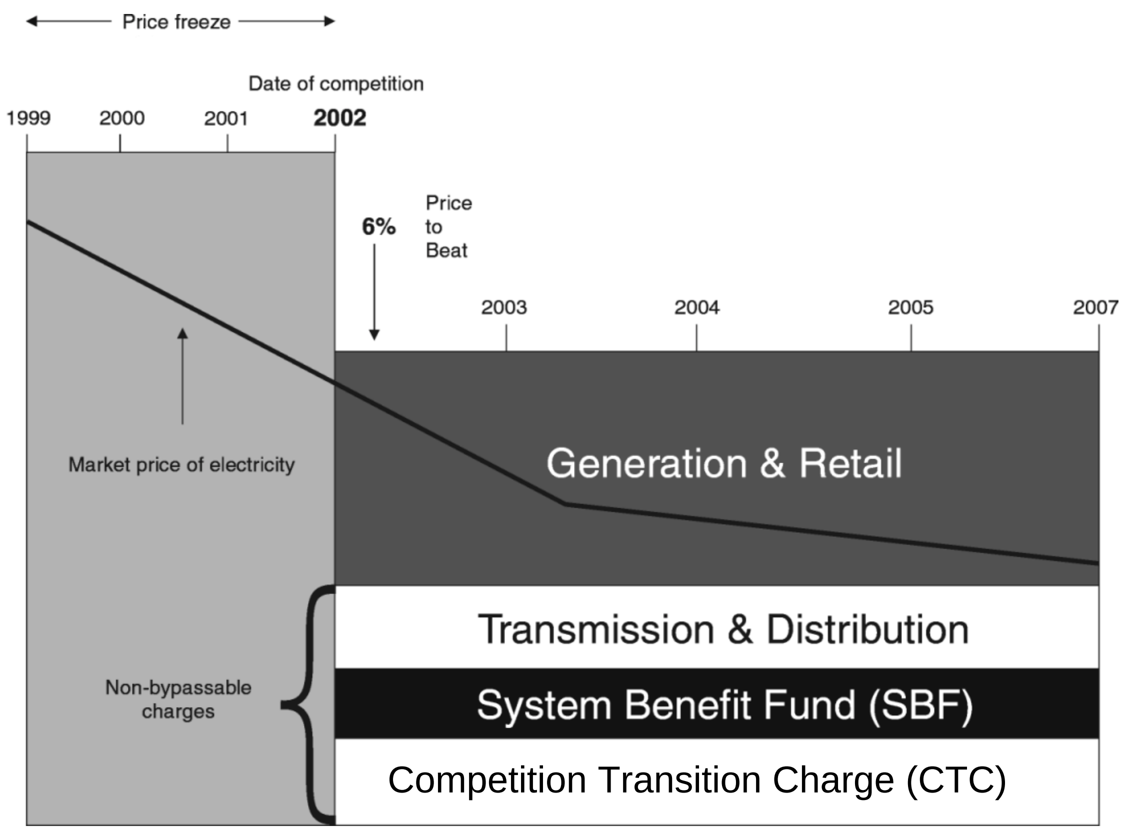


Fig. 3.1 **Texas Retail Price Structure and Time line**

charges in 2001.

T&D fees will be set during each utility's transmission cost of service proceedings as part of the business separation filings. The T&D portion of customer bills will pay for necessary expansion of the transmission system, ISO administration of the transmission system and a return on investment for T&D utilities. Even after competition begins, the PUC will continue to regulate T&D utilities and set their rates.

The SBF will be collected to fund rate reductions and energy efficiency programs for low-income customers, fund customer education programs and reimburse school districts for property value losses suffered as a direct result of electric utility restructuring. The customer education and low-income assistance programs funded by the SBF are examined in greater detail in Chapter 5. As required by SB 7, the Texas Comptroller of Public Accounts certified the property value losses directly attributable to restructuring of the electric utility industry at $6.29 billion. On October 31, 2000 the Texas Education Agency (TEA) certified that $65.12 million in Chapter 41 recapture dollars would be lost due to restructuring implementation.[5] These losses to public school funding will be repaid through the SBF. The PUC will issue an order in December 2000 directing investor-owned utilities to pay into the SBF their share of the amount, as determined by TEA.

The CTC is the mechanism through which utilities may recover stranded costs over time. The PUC will issue orders in the unbundling cases in 2001 and set the CTC at that time. Under SB 7, utilities also have the option to securitize certain regulatory assets. Securitization is a transaction that permits a utility to receive a lump sum payment for stranded costs from investors in lieu of collecting such costs through its regulated cost of service. The lump sum payment is financed through the issuance of debt securities to third party investors. From the investors' point of view, these debts exhibit less risk than the utility's common stock and therefore carry a lower interest rate than the utility's overall rate of return, which includes a return on common equity. The utility's customers pay the principle and interest on the securitized debt by a charge in their electric rates, but the stranded costs are paid at a lower rate of return and without federal income tax expense.

Orders have been issued by the PUC allowing securitization of $764 million in regulatory assets and transaction costs for Central Power and Light and $740 million for Reliant Energy HL&P. The commission's securitization order of $363 million for TXU is under court challenge.[6]

As the restructuring process continues, stranded costs in Texas are significantly impacted by a variety of market factors, particularly the price of natural gas, which has more than doubled in the past year. Natural gas is the fuel of choice for independent power producers because natural gas facilities are generally smaller and less expensive to build than other forms of generation and natural gas has historically been a relatively inexpensive and abundant fuel source. However, recent increases in natural gas prices have translated into increased fuel charges on consumer electric bills in 2000.

---

[5]Refers to Title II, Texas Education Code. Chapter 41 provides for determining an equalized wealth level of the state's public school districts.

[6]TXU petitioned the PUC to securitize $1.65 billion in regulatory assets. The PUC concluded that only $363 million of TXU's regulatory assets met the criteria for securitization. TXU has appealed the decision to the courts. *Docket No. 21527 - Application of TXU Electric Company for a Financing Order to Securitize Regulatory Assets and Other Qualified Costs.*

These price increases are occurring under the regulated structure and would be a factor even without electric utility restructuring. Although the generation portion of customer bills will likely increase due to higher prices for natural gas, these price increases may also benefit consumers by significantly lowering some utilities' anticipated level of stranded investment.

In the face of sustained higher natural gas prices, electricity generated from existing coal and nuclear plants has become more cost-competitive, leading some market observers to predict that some utilities may experience the opposite condition of stranded costs. In this scenario, the market value of certain generation assets wuld actually exceed the net book value of the assets. Because SB 7 provided for the application of excess revenues toward ECOM mitigation during the transition period, it is possible overmitigation of stranded costs may occur. Since overrecovery of stranded costs is expressly prohibited by SB 7, the PUC is currently evaluating how and when any overpayments would be returned to ratepayers. These ECOM discussions will continue for the next four years. The PUC has not yet determined what costs related to emission reductions may be included in recovery proceedings. A commission order on stranded costs is expected in Spring 2001, and an ECOM "true-up" will occur in 2004, at which time real data from a mandated capacity auction and the first two years of market competition will be used to settle the issue.

In addition to the non-bypassable charges, costs associated with power generation and REP overhead form the remaining components of the retail price floor. The difference between the floor and the ceiling in the retail price structure is known as "headroom." One lesson drawn from other market restructuring efforts is that for retail competition to flourish, new market entrants must have the headroom available to offer consumers sufficient savings to encourage REP switching while still maintaining ability to generate profits.

As previously mentioned, the prospect for sustained higher natural gas prices will almost certainly add costs to the generation portion of customer bills. Some Texas market observers claim higher gas prices must be offset by CTC reductions to maintain a workable competitive structure. "The high prices for generation erode the headroom for competition. If consumers and competitors do not receive the benefit of these high generation prices through reduced stranded cost charges, there will be little room for competitors to enter the market."[7]

---

[7]Testimony of Janee Briesemeister before the Electric Utility Restructuring Legislative Oversight Committee, Sept. 26, 2000 (see Appendix G for summary).

Prospects for sufficient headroom in the Texas retail electricity price structure are good. As discussed in Chapter 4, system administration costs are lower in Texas than other markets. Texas has a comfortable reserve margin of power capacity over peak demand creating downward pressures on generation prices. Finally, stranded costs are expected to be lower than previous estimates, possibly resulting in a low CTC, creating still more headroom for competition.

Natural Gas Price Impacts

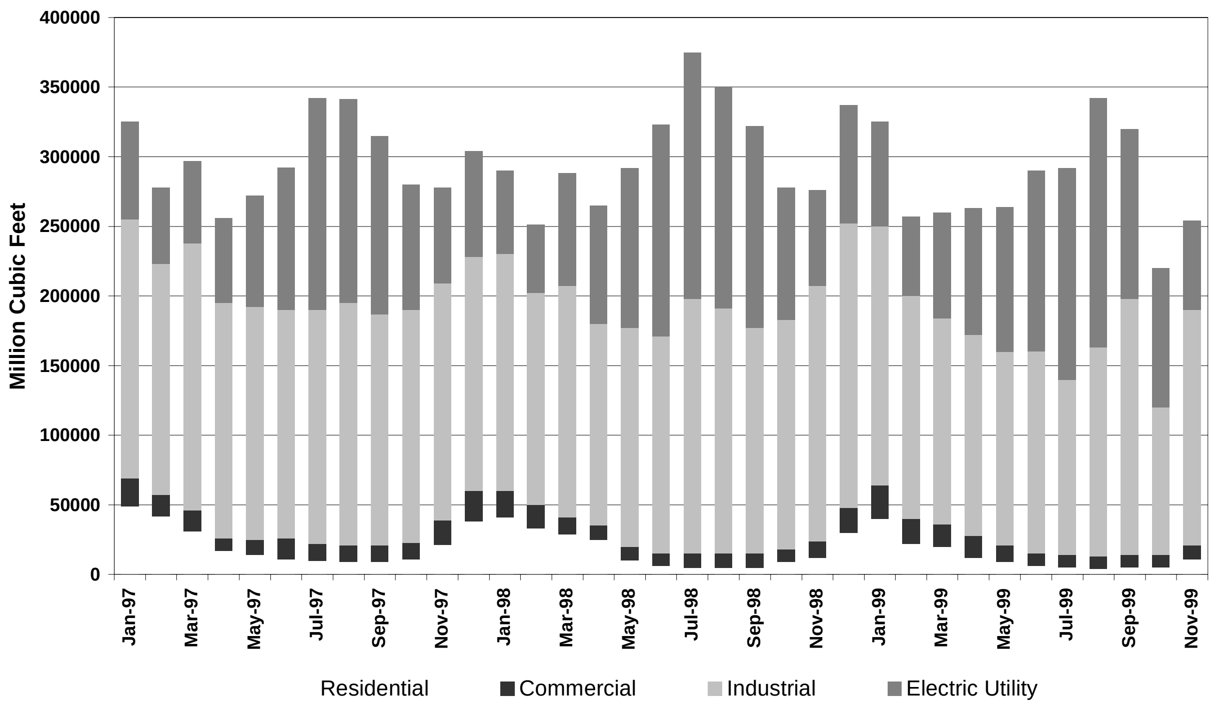
The variable with the greatest potential impact on electric power market restructuring efforts may be the recent increase in natural gas prices. The effects of higher gas prices touch every sector of the Texas economy either directly or indirectly. Quantifying the net effect of higher gas prices on economic activity is a complex task. However, some knowledge of the challenges to reliable delivery of affordable natural gas is essential to understand the fundamental forces reshaping the Texas electric power market.

Oil and gas production have long been staples of Texas economic activity. But increasing diversification of the state's economy has altered the significance of petroleum product price changes. As University of North Texas Center for Economic Development and Research professors Bernard Weinstein and Terry Clower noted in a July 2000 study:

> "For Texas, higher gas prices bring both good news and bad news. Because Texas ranks number one among the lower 48 states for on-shore production, higher prices generate added jobs, income and severance tax revenues ... Because more than 60 percent of the electric utility capacity in Texas uses natural gas, the cost of power generation has risen rapidly over the past six months. Each $1 increase per MCF (thousand cubic feet) boosts fuel costs to utilities and non-utility generators by about $1.46 billion. However, as has been the case for many years, these costs are passed on to households through 'fuel adjustment' and affect consumers differently depending on each utility system's configuration ... In sum, although rising natural gas prices are a boon to gas drilling, production and distribution companies and their employees, the resulting higher costs to Texas industries and households more than offset any gains."[8]

[8]Bernard L. Weinstein and Terry L. Clower, "The Impact of Higher Natural Gas Prices on the Texas Economy," University of North Texas Center for Economic Development and Research, July 2000, pp. iii-iv.

Fig 3.2 **Gas Consumption in Texas by Class**



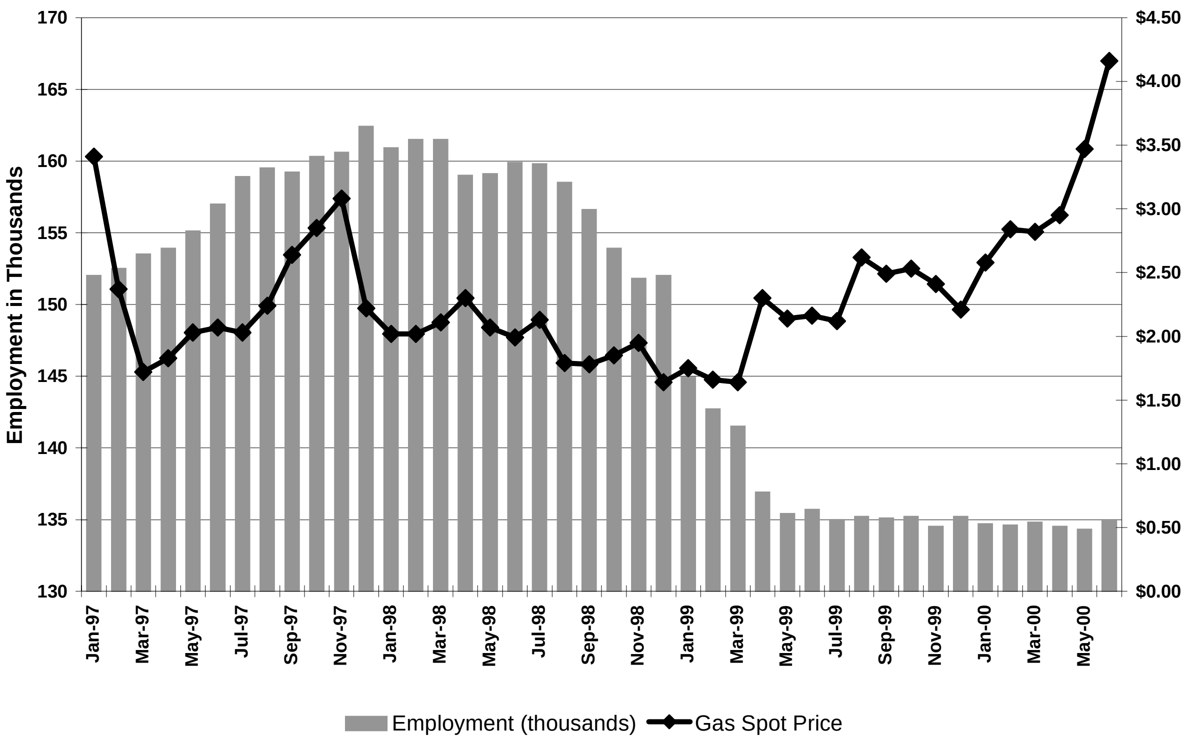
Source: Texas Railroad Commission

Many observers predict near-term natural gas prices to remain well above 1998 and 1999 levels, citing the combination of production declines and soaring demand largely driven by electric power generation.

Figure 3.2 illustrates the recent impact of gas-fired generator additions in Texas. Commercial and residential gas consumption continues to follow the traditional pattern — minimal demand in summer months and increased demand in winter months — and industrial consumption does not exhibit a significant seasonal differential. Electric generating facilities now account for almost half of all summertime natural gas demand.[9] Thus, the season during which gas has traditionally been injected into storage for the winter heating period is now the peak demand period in Texas.

[9]Weinstein and Clower, p. 11.

Fig. 3.3 **Texas Oil & Gas Employment and Natural Gas Price**



Source: Texas Railroad Commission

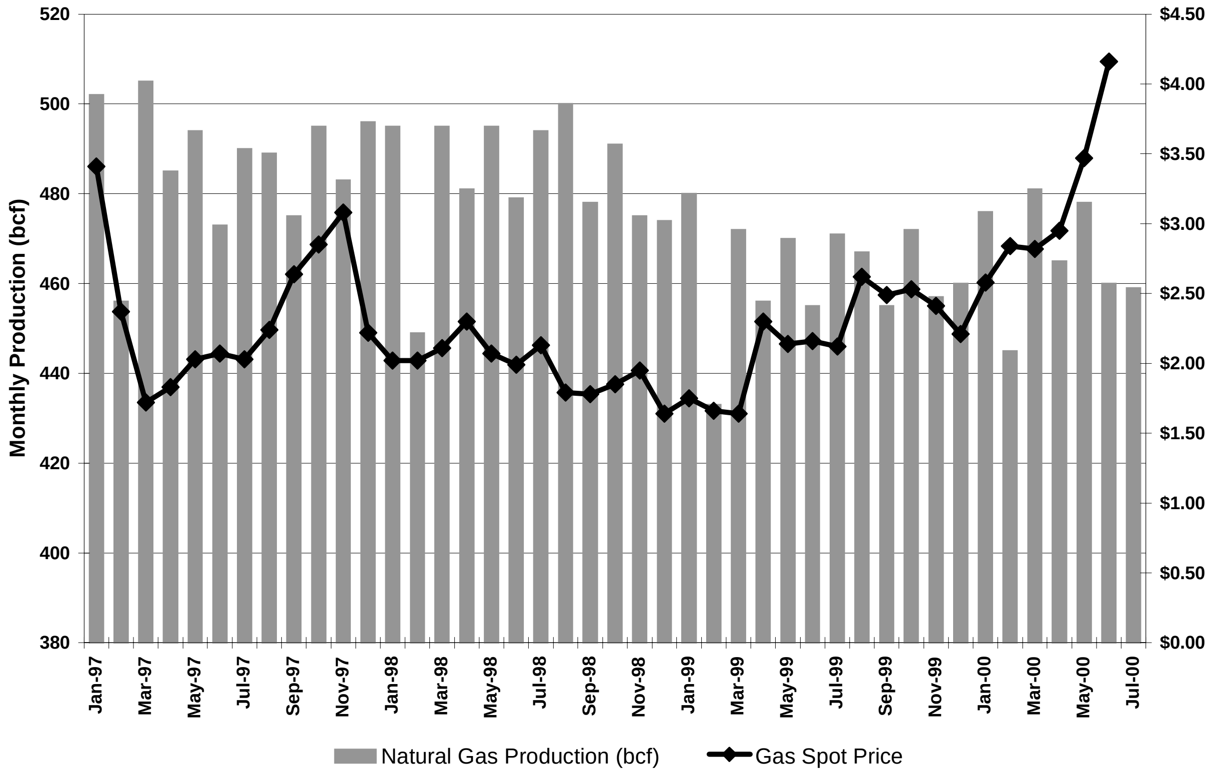
Some market watchers predict a long recovery period for gas storage inventories before the onset of lower prices. Following the market downturn in early 1998, Texas lost 18,000 oil and gas industry jobs, and exploration activities were reduced.[10] Higher prices in 2000 have yet to spur a significant increase in oil and gas employment, a critical factor in capturing necessary supply *(see Figure 3.3)*.

Lower production, a lack of skilled labor, higher demand and the absence of a traditional storage injection period will likely lead to sustained tight supplies and higher prices.[11] Tight supplies and higher prices for natural gas over the next year or more will have significant impacts on electric utility restructuring. Irrespective of restructuring efforts, electricity prices for most Texans will likely

[10]Texas Railroad Commissioner Charles Matthews, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Sept. 26, 2000 (see Appendix G for summary).

[11]Chip Cummins and Alexei Barrionuevo, "Stuck In The Mud: Spike In Demand Has Natural Gas Producers Struggling to Catch Up," *The Wall Street Journal*, Oct. 11, 2000, p. A1.

Fig 3.4 **Texas Natural Gas Production and Price**



Source: Texas Railroad Commission

increase if natural gas prices are sustained at higher levels. As previously noted, in addition to the 60 percent of current Texas generation capacity dependent on natural gas, most new generators in Texas will use natural gas as well. Demand from electric generating facilities not only stretches available gas supplies, but also the gas industry infrastructure as well. Adequate pipeline capacity and firm delivery prospects are potential hurdles to new EGF siting.[12] Some power producers have turned to other fuel sources as gas prices climbed throughout the year. City Public Service, the municipal utility of the City of San Antonio, in discussions about future alternatives, mentioned it had not ruled out a new coal-powered facility using advanced clean coal technology.[13]

---

[12]Jimmy Glotfelty, testimony before the Electric Utility Restructuring Oversight Committee, July 10, 2000 (see Appendix E for summary).

[13]Ann de Rouffignac, "City Public Service Mulls Building New Coal Plant," *Oil and Gas Journal Online*, Oct. 11, 2000.

Market Snapshot

The Texas electric power market has undergone significant changes since the passage of SB 7 in May 1999. Some utilities have been purchased or merged with other companies while others are busy separating business activities into regulated and unregulated components. Traditional utilities are engaging in new business ventures such as telecommunications services and energy trading. New participants, from generation to retail, have entered the Texas electricity market.

A major new Texas market participant is American Electric Power (AEP), an Ohio-based company now serving customers in Texas, Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Virginia and West Virginia. In the Texas market, AEP now operates in the former service territories of Cental Power and Light, Southwest Electric Power Company and West Texas Utilities. In other merger activity, Southwest Public Service Company merged with Public Service Company of Colorado to form New Century Energies, which in turn merged with Northern States Power Company to form Xcel Energy. Based in Minnesota, Xcel Energy serves customers in 12 Western states, including the Texas Panhandle.

The pending merger between Entergy, which serves customers in the non-ERCOT area of Southeast Texas, and Florida Power and Light would create the nation's largest electric power company. Pending regulatory approval, the deal could be complete just before the start of retail competition in Texas on January 1, 2002.

At the filing of this report, TXU is the one IOU to file for REP certification at the PUC. Enron Energy Services, Enron Power Marketing and the New Power Company have also filed for REP certification at the PUC. One REP has already been certified by the PUC: TXI Power, a unit of TXI, Inc., the state's largest concrete manufacturer. TXI intends to sell electricity to its own manufacturing facilities. However, in a September 2000 market participant survey conducted by ERCOT, 18 firms indicated intent to provide retail electric services in Texas.

The California Model

Many of the structural changes in the Texas electricity market can be more fully understood when specific features are compared to a different market structure. Widespread attention on California's recent problems has highlighted some key distinctions between the two approaches to market restructuring.

Like Texas, California required utilities to separate business activities into competitive and regulated enterprises. California's restructuring legislation also required utilities to divest generation assets and meet all power requirements through a centralized power pool managed by the California Power Exchange (PX). California's model has shown significant disadvantages since its implementation. The PX takes hourly bids from generators and then pays all generators the highest price set that hour. Buyers in the exchange, therefore, will pay the highest price for every kilowatt-hour of power at any given hour of the day, even if one or more generators is willing to sell electricity at a lower price. Texas did not structure its market in this manner. Instead, the Texas model will allow electric service providers to use long-term bilateral power contracts to hedge risk in the marketplace by seeking primary and secondary generation sources at the lowest prices available in the market. This approach is feasible in Texas because of adequate generation capacity.

The California model also mandated a rate freeze followed by a rate reduction of 10 percent, compared to the 6 percent reduction required in Texas. In California, this had the effect of lowering the available retail headroom, resulting in limited participation by new market entrants and thus less opportunity for customers to switch providers. During the rate freeze period, utilities were directed to allocate all overearnings to stranded cost mitigation. The rate freeze in each IOU service territory in California is lifted when the utility fully retires its stranded costs. San Diego Gas and Electric (SDG&E) was the first to do so, and during Summer 2000 its customers experienced the effects of a retail price structure without a cap coupled with a requirement that power be bought at the highest price through the PX pool. Price spikes are inevitable when demand exceeds supply and a utility is unable to engage in long-term contracts or call on native generation to serve its electric load. As the crisis in Southern California worsened, several wholesale power marketers offered long-term power contracts to SDG&E at rates well below peak prices, but the utility was unable to pursue any power purchases outside the PX and thus unable to shield customers from wholesale market price volatility.

Several investigations have been conducted at the state and federal level into California's electricity problems, resulting in numerous recommendations for structural changes. Although some consumer advocates and state regulators accused market participants of "gaming" the system, reports issued by the California PX, California ISO and Federal Energy Regulatory Commission (FERC) found the roots of the Golden State's problems in a flawed market design.[14] Many of the changes proposed in a FERC order issued November 1, 2000 mirror provisions of the Texas market design. FERC recommended California streamline its power plant siting procedures and enable utilities to engage in bilateral power contracts outside the confines of the PX.[15]

[14]See California Independent System Operator, *Report on California Energy Market Issues and Performance: May-June, 2000*, Aug. 10, 2000. See also Federal Energy Regulatory Commission, *Market Order Proposing Remedies for California Wholesale Electric System*, Nov. 1, 2000, Docket No. EL00-95-000, et al.

[15]Federal Energy Regulatory Commission, p. 24.

Chapter Four:
INDEPENDENT SYSTEM OPERATOR

The Independent System Operator (ISO) fulfills several key roles in the restructured electricity market. This chapter provides a more in-depth review of the various ISO functions which will be primarily fulfilled by the Electric Reliability Council of Texas (ERCOT) and a report on ISO implementation efforts. Proposed transmission operations in the non-ERCOT areas of Texas are also examined.

ERCOT Background and History

A non-profit corporation, ERCOT is one of 10 regional reliability councils in the North American Electric Reliability Council (NERC) organization, which was formed following the disastrous blackouts of 1965 along the eastern seaboard of the United States. ERCOT represents a bulk electric system located totally within the State of Texas and serves approximately 85 percent of the state's electrical load. Due to its intrastate status, the primary regulatory authority for ERCOT utilities is the Public Utility Commission of Texas (PUC). The Federal Energy Regulatory Commission (FERC) exercises limited authority over ERCOT. FERC has primary wholesale regulatory authority over the utilities and ISOs in the other nine reliability councils.

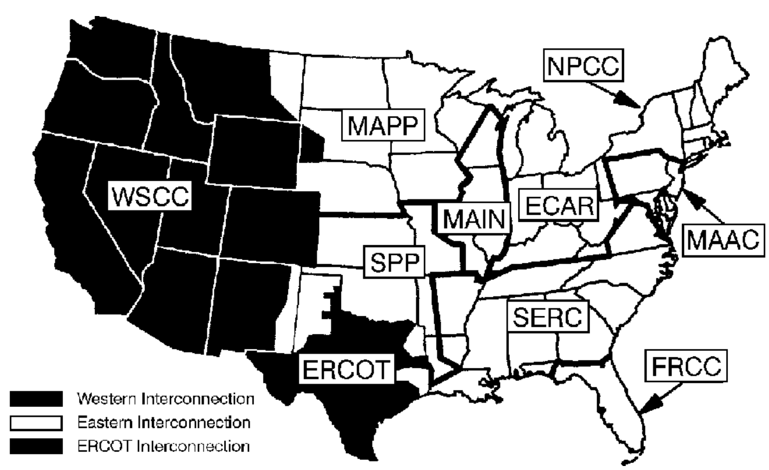


Fig. 4.1 **Major U.S. Interconnected Electric Systems**

The origins of the modern Texas electric grid can be traced back to the beginning of World War II when a number of electric utilities banded together to send excess generation to Gulf Coast area industries to aid the war effort. The group became known as the Texas Interconnected System (TIS). After the war, TIS members recognized the reliability advantages of remaining interconnected and continued to utilize and develop the system as electrical loads grew and larger generating units were installed. In the 1960s and 1970s, operating guidelines were adopted and ERCOT assumed security monitoring functions from stations located in the control centers of two utilities in North and South Texas.

During a severe cold weather event in 1981, small amounts of load were shed in ERCOT for what was thought to be a capacity shortage situation. A review of the event determined that the load had been shed unnecessarily and that better coordination was needed in the region. In 1983, two security centers replaced ERCOT's existing monitoring functions, and the operating guides were strengthened to provide for security center coordination of interconnected operations between the control areas in the region. A computerized Security and Information System (SIS) was created and operated by the two ERCOT security centers. The SIS began as a control area operator manual entry system and has since grown to include real-time telemetry with many automated security applications.

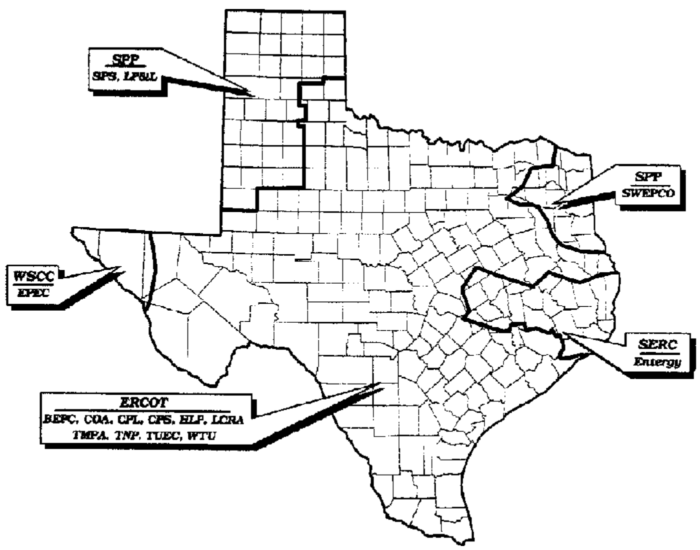


Fig. 4.2 **Texas Interconnected Electric Systems**

Following the passage of the Energy Policy Act of 1992 (P.L. 102-486), ERCOT began the process of studying the changes needed to create a central security center independent of the utilities. The federal legislation rolled back New Deal-era regulations and required utilities to open their transmission lines to all sellers of electricity, paving the way for independent power producers to sell electricity to utilities.

Three years later, the 74th Legislature passed SB 373, which opened the ERCOT wholesale market to competition. As a result of SB 373 implementation, the PUC issued revised rules in early 1996 requiring a joint industry filing for the creation of an ISO responsible for security of the bulk power system, facilitation of the use of the electric transmission system by all market participants and coordination of transmission planning in the ERCOT region.

Although the responsibilities of the ISO went beyond the broadened security coordination functions originally envisioned by ERCOT a broad-based industry task force preparing the joint industry filing decided the Texas ISO function should be fulfilled by a restructured ERCOT organization. The recommended ERCOT - ISO formation was endorsed by the PUC on August 21, 1996. The ERCOT membership approved the restructuring required in the joint filing and implementation began on September 11, 1996. The ISO operations center is now located in an independent facility in Taylor. A back-up facility is planned and will be located in Austin. Operations control would transfer to the Austin facility if the Taylor facility were unable to perform for any reason.

SB 7 Requirements and Implementation

SB 7 defined the ISO as an entity charged with supervising the collective transmission facilities of a power region, coordinating market transactions, planning systemwide transmission and ensuring network reliability.[1] To meet these goals, ERCOT's efforts have focused on two primary tracks: developing new protocols for market participants and solving the functional and technical issues of restructured market activity. The ERCOT protocols are under final development and are scheduled for review and adoption by the PUC in early 2001.

The ERCOT ISO is expanding its infrastructure and staffing to comply with SB 7 and oversee retail access in the electric market. Approximately 50 employees have been hired in the last six months. ERCOT expects to hire an additional 100 employees in the coming year. New facilities and new computer systems, including both hardware and software necessary to carry out market coordination functions, have been acquired.

To facilitate the implementation process, the ISO contracted with Andersen Consulting, a firm with

[1] PURA §39.151.

experience in other electricity market restructuring efforts. Several working groups were formed within ERCOT. System administrators, PUC staff, electric utilities, power marketers, consumer groups and other stakeholders have all been involved in ERCOT's restructuring efforts.

The ERCOT ISO is managed by a chief executive officer who is hired by and reports to the ERCOT Board of Directors. The 21-member board is composed of three members from each of the seven market groups: investor-owned utilities, municipal utilities owning generation or transmission facilities, electric cooperatives owning generation or transmission facilities, transmission-dependent utilities, independent power producers, power marketers and consumers. A new ERCOT Board of Directors will assume office in December 2000. The PUC Chairman and Public Utility Counsel are *ex-officio*, non-voting members of the ERCOT Board of Directors.

ERCOT responsibilities expanded by market restructuring include real-time system monitoring, long-term system monitoring, response to contingency situations, administration of a system-wide information system and system transmission tariffs and energy transaction scheduling. ERCOT also supervises regional transmission planning and acquisition. ERCOT will not function as a power pool and will not be responsible for energy pricing or matching buyers and sellers.

The transmission pricing methodology established by SB 7 is unique and forms the basis for many of the business practices now in place at ERCOT. Under the rule adopted by the PUC, all transmission service is considered to be either planned or unplanned. Planned service is defined as service to a specified load from designated resources. Unplanned service is between a specified load and specified resource, is 30 days or less in duration and is available subject to the availability of transmission capacity required for planned service. As noted in Chapter 1, constraints in the state's transmission system led to several curtailments of unplanned energy transfers in 2000.

In the ERCOT market protocols, which are still under development and awaiting PUC approval, transmission pricing will reflect the cost impacts of congested wires. If costs to clear commercially significant transmission exceed $20 million in any 12-month sliding window, ERCOT will institute a congestion management fee. The congestion management plan will be reviewed in 2003 if the $20 million threshold has not been reached. Final details of the congestion management plan have not been finalized, but it is likely the financial impact of congestion management fees will be borne by customers within transmission constrained zones such as the Dallas/Fort Worth area. The PUC opened a new project in October 2000 to study possible revisions to the transmission pricing rule adopted in 1999. The purpose of the possible revision is to eliminate inconsistencies between the adopted rule and the ERCOT protocols.

Planned transmission service is paid for by load entities on a load ratio basis. Effective December 1, 1999, the PUC required scheduling entities to begin paying a fee of 15 cents per megawatt-hour (MWh) for all planned and unplanned energy transactions in ERCOT. Transaction fees are the primary revenue source for ERCOT and are expected to generate approximately $40 million in 2000.[2] The ERCOT ISO fee compares favorably to other system administration fees in the country. In California, for example, the ISO fee is 80 cents per MWh in addition to a 30 cent per MWh fee charged by the California Power Exchange. It is anticipated that the ERCOT ISO fee will not have a negative impact on headroom in the retail price structure.[3]

Fig. 4.3 **Intended Roles in the Market**

Qualified Scheduling Entities
American Electric Power # Automated Power Exchange # Bryan Texas Utilities # Calpine # City of San Antonio # Coral Power # Dynegy # Enron # Entergy # Garland Power and Light # Lower Colorado River Authority # Southern Company Energy Marketing # Tenaska # Texas-New Mexico Power # TXU # Xcel Energy

Non Opt-in Entities
Big Country Cooperative # Bryan Texas Utilities # Greenville Electric Utility System

Power Generation Companies
American Electric Power # Calpine # City of San Antonio # Dynegy # FPL Energy # Guadalupe-Blanco River Authority # Lower Colorado River Authority # Southern Company Energy Marketing # Texas-New Mexico Power # TXU

Retail Electric Providers
AEP Retail Operations # Calpine # Dynegy # Entergy # Exelon # New Energy Texas # Reliant # Southern Company Energy Marketing # Texas-New Mexico Power # TXU

Load Acting as Resource
Dow

Source: Electric Reliability Council of Texas. Includes only those entities that have authorized ERCOT to disclose their intended roles in the restructured market.

One concern raised before the committee concerning ERCOT activities involves the creation of a new market participant not included in SB 7: qualified scheduling entities (QSEs). QSEs will be responsible for coordinating balanced energy loads with resources and providing ancillary service bids. The QSE requirement was devised to streamline energy scheduling communications between the various market participants and the ISO. QSEs are the only market

[2]Interview with ERCOT Director of Coordination and Reports Larry Grimm, Oct. 12, 2000.

[3]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Legislative Oversight Committee, August 22, 2000 (see Appendix F for summary).

participants requiring direct ERCOT certification. Consumer advocates expressed concern that an additional layer of costs in the wholesale market may act to squeeze available headroom in the retail price structure.[4]

As of October 2000, 26 firms have indicated intent to become certified QSEs in Texas. Additional market participants indicating intent to participate in the restructured market include 18 REPs, 17 power generation companies and 11 transmission and distribution utilities. Figure 4.3 provides the intended market roles of firms that have authorized ERCOT to disclose their intentions as of October 2000. One municipal utility or electric cooperative has indicated intent to opt-in to retail competition but has not permitted disclosure of identifying information by ERCOT. Also denying disclosure, 10 municipal utilities or electric cooperatives have indicated they do not intend to opt-in to retail competition.[5]

Non-ERCOT Areas of Texas

Although ERCOT will perform some statewide services, such as maintaining customer registration and switching information, operation of the bulk power system in Texas outside ERCOT boundaries will fall to other regional organizations in the Southwest Power Pool (SPP), the Western Systems Coordinating Council (WSCC) and the Southeastern Electric Reliability Council (SERC) *(see Figure 4.2)*.

Restructuring activity in the non-ERCOT areas of Texas must meet conditions set forth in both state and federal legislation and regulations. In 1996, FERC issued Orders 888 and 889 to provide non-discriminatory open access on the transmission system. While open access was achieved, the existing transmission system has become strained because of the resulting increases in wholesale electricity trading as well as the strong economy and state-mandated retail open access. FERC Order 2000 was issued on December 20, 1999, to encourage all transmission owners to voluntarily join regional transmission organizations (RTOs) to help address the engineering and economic inefficiencies

[4] Janee Briesemeister, testimony before the Electric Utility Restructuring Legislative Oversight Committee, Sept. 26, 2000 (see Appendix F for summary).

[5] Results compiled from ERCOT Quarterly Survey of Market participants, September 2000.

inherent in the current transmission system and to correct real or perceived discrimination by transmission owners. RTOs will perform functions similar to the ERCOT ISO, including transaction scheduling, congestion management, ancillary services, wholesale settlement and market monitoring. FERC Order 2000 establishes minimum characteristics for RTOs without establishing a particular geographic or organizational design. The order allows both ISOs and independent, privately-owned transmission companies (transcos) to apply for RTO status.

SB 7 requires Southwest Public Service Company to file a transition to competition plan with the PUC, and all utilities in non-ERCOT areas of Texas to separate competitive and regulated business activities and participate in the retail competition pilot project. Full customer choice will not be implemented in non-ERCOT areas of Texas until the PUC certifies the service area of a non-ERCOT utility as a competitive power region. Three requirements must be met to create a competitive power region: a sufficient number of interconnected utilities in the region must fall under the operational control of an ISO, transmission facilities must provide non-discriminatory open access and no market participant may own or control more than 20 percent of the electric generation capacity serving the region.[6]

Three of the four non-ERCOT areas of Texas plan to participate in the pilot project and offer full customer choice in 2002. El Paso Electric will not offer customer choice in Texas until the expiration of its rate freeze agreement with the PUC in August 2005. Although El Paso Electric is not required to unbundle its business activities until the end of the rate freeze period, the utility expects to do so in 2001, consistent with the State of New Mexico's restructuring requirements.

Southwest Public Service (SPS) in the Texas Panhandle and Southwestern Electric Power Company (SWEPCO), both members of the Southwest Power Pool regional reliability council, will participate in the retail pilot project and intend to move to full customer choice as soon as the three requirements for a competitive power region are met. For SPS, now a part of Xcel Energy in 2000, this means a significant number of power generation facilities must be sold. SWEPCO, now a unit of American Electric Power (AEP), has submitted a filing with the FERC indicating its intent to participate in the SPP RTO. SPP is seeking RTO recognition under FERC Order 2000, with a requested effective date of January 1, 2001. SPS is currently a member of the SPP but plans to join

[6]PURA §39.152.

the Midwest ISO when it begins commercial operations.

Entergy, on the other hand, has filed for FERC approval to establish a transco, or privately-owned transmission company, to manage bulk energy transfers. The Entergy transco would operate under the supervision of the SPP RTO. A FERC ruling on Entergy's proposal is anticipated in April or May 2001.

Retail Competition Pilot Project

The retail competition pilot project will allow the PUC to evaluate the ability of each power region and electric utility to offer customer choice.[7] Beginning June 1, 2001, each IOU in the state will offer customer choice to 5 percent of the customer base within its service area. In non-ERCOT areas of Texas, the pilot project may be extended by the PUC if a power region is not deemed competitive by January 1, 2002, when full customer choice begins in the ERCOT power region.

All ERCOT restructuring activities are scheduled for completion by March 31, 2001. A "mock market" will commence April 1, allowing full testing of new systems between the ISO and market participants. During March 2001, ERCOT will host a series of training seminars for employees of market participants in both the ERCOT and non-ERCOT areas of Texas so they can become familiar with the new ISO communications and settlement systems. ERCOT will begin accepting customer switch requests May 31, 2001, and anticipates "going live" with all new systems on June 1, 2001.

[7] PURA §39.104.

Chapter Five:
CUSTOMER PROTECTIONS

Protecting customers from unfair business practices and inadequate service in markets for essential commodities like electricity and telecommunications services is important not only for the individual consumers who may be adversely affected by anticompetitive behavior but also for the long-term health of the market itself.

The 76th Legislature adopted Senate Bill 86 to add new customer protection standards to the Public Utility Regulatory Act (PURA).[1] The statute provides the Public Utility Commission (PUC) authority to establish and enforce rules to protect retail customers from fraudulent, unfair, misleading, deceptive or anticompetitive practices. Specific consumer entitlements were established, including protection from fraud and discrimination, protection of choice, privacy of consumption and credit information, accuracy in billing and information presented in English, Spanish and any other language necessary.[2] Senate Bill 7 also established additional retail electric customer safeguards, including:

the right to safe, reliable and reasonably priced electricity, including protection against service disconnections in extreme weather emergency or in cases of medical emergency or for nonpayment of unrelated services;

bills presented in a clear format and in language readily understandable by customers;

information about rights and opportunities in the transition to a competitive electric industry;

access to providers of energy efficiency services, on-site distributed generation and providers of energy generated by renewable energy resources;

---

[1]PURA §17.001(a).

[2]PURA §17.004(a).

- sufficient information to make an informed choice of service provider;

- protection from unfair, misleading or deceptive practices, including protection from being billed for services that were not authorized or provided; and

- an impartial and prompt resolution of disputes with retail electric providers and transmission and distribution utilities.[3]

SB 7 also conferred authority on the PUC to oversee all providers of electric service and assess administrative and civil penalties for violations.[4]

The PUC rule implementing customer safeguards against anticompetitive practices is under development with adoption anticipated in December 2000. In addition to the protections outlined above, SB 7 also contained a number of market design features to further protect electric customers, including a campaign to raise awareness of coming changes in retail electric service, the establishment of a fund to assist low-income people and a universal service requirement.

Customer Education

SB 7 required the PUC to conduct a customer education campaign to raise awareness of coming changes in the retail electric market.[5] To implement the statute, the PUC adopted a two-stage approach to inform consumers of impending market changes and rights and protections afforded them by law. In the first phase, High Point/Franklin, a communications firm with experience in other market restructuring efforts, was selected by the PUC to develop a customer education plan. High Point/Franklin surveyed more than 40 opinion leaders and policy makers statewide, conducted eight focus groups in six Texas cities and performed telephone surveys of 1,100 residential and 400 business customers of investor-owned utilities (IOUs). The education plan adopted by the PUC on July 18, 2000, was developed from the results of the survey, High Point/Franklin's experience in

[3]PURA §§ 29.101(a) and (b).

[4]PURA §39.101(d).

[5]PURA §39.902.

other markets and input from PUC staff, consumer advocates, IOU representatives and potential retail electric providers (REPs) in the competitive Texas market.

Key points of the customer education plan include integrated communications strategies, such as paid advertising, public relations efforts, printed materials, a toll-free call center, an electric competition Web site and specific tools designed to measure the overall effectiveness of each strategy. The plan also emphasizes communication through community-based organizations, which will form the primary channel to reach traditionally under-served populations such as low-income and non-English-speaking customers. On October 19, 2000, the PUC selected marketing firm Burson-Marsteller to implement the customer education plan.

System Benefit Fund

To further aid consumers in the restructured electric utility market, the System Benefit Fund (SBF) was created to fund four different programs:

- electric rate reductions for low-income customers;
- a targeted low-income weatherization program administered by the Texas Department of Housing and Community Affairs (TDHCA);
- appropriations for customer education programs and administrative costs of the Office of Public Utility Counsel; and
- a mechanism to compensate the state and school districts for losses in property values of utilities' assets directly caused by restructuring.

The source of revenues for the fund is a fee charged to customers based on the kilowatt-hours of electricity used. Through fiscal year 2001, the SBF is expected to collect more than $90 million to fund early customer education programs and payments to school districts affected by electric utility restructuring. The PUC has worked with Texas Department of Human Services to develop an automatic enrollment system for low-income customers to receive rate reductions and weatherization benefits. As mentioned above, the customer education plan has completed the design phase and is now moving into the implementation phase. The PUC is expected to finalize rules relating to SBF administration in December 2000.

Provider of Last Resort

In much the same way monopoly utilities currently provide electric service to any requestor within their service territories, the provider of last resort (POLR) will be established to fulfill this function in the restructured marketplace. Protections similar to those existing today have been established for both consumers and the REP serving as POLR. Customers who fail to pay for electric service can be disconnected except during extreme weather emergencies.

The POLR in each area of the state will be selected by the PUC through a bidding process. Large service territories, such as Reliant Energy HL&P, will likely be divided into several smaller POLR territories. If the bidding process is not successful, (e.g., the PUC does not receive enough bids for all POLR territories) the PUC can designate a REP to serve as POLR. The generally held perception is that POLR rates will be nominally higher than the market rate to allow the POLR to hedge risk against an unknown quantity and type of customer. Because customers who "choose not to choose" in areas of the state open to competition on January 1, 2002, will default to the affiliate REP of the incumbent utility, it is not expected that the POLR will be extensively utilized for the first few years of market development.

Curbing Anticompetitive Behavior

Analysis of restructuring efforts in the telecommunications industry can provide some insight into possible pitfalls along the path of electric utility restructuring. Among the research findings of High Point/Franklin's interactions with both residential and commercial customers is the conclusion that Texas customers clearly framed their view of electric choice within their experience with long distance telephone service competition. Anticompetitive practices such as slamming (changing service providers without customer authorization) and cramming (hiding unauthorized charges on customer bills) were commonly cited. Additional concerns were raised about the expected level of telemarketing activity associated with retail electric competition.

To prevent the slamming practices associated with long distance competition, ERCOT will function as the customer switching information center in Texas and will notify each customer by postcard whenever a switch request is received. The customer can verify the request by doing nothing, or nullify the request by returning the card. The PUC anticipates adopting a rule against cramming, along with related specific provisions addressing the content of customer bills, in coming months. Other rules addressing the customer safeguards established by SB 7 and SB 86 are expected to be adopted by the PUC in December 2000. The governing bodies of municipally-owned utilities and electric cooperatives are also required to adopt similar rules for customers within their certificated areas.

PUC Oversight

As noted above, primary rulemaking and enforcement authority regarding electric utility industry restructuring is granted to the PUC. A new Market Oversight Division was created by the PUC to address market design flaws, identify and prevent market power abuses and encourage and facilitate competition in the bulk power, ancillary services and transmission services markets.

Additionally, the PUC is granted authority to delay competition before January 1, 2002, if it determines a power region is unable to offer fair competition and reliable service to all retail customer classes.

Chapter Six:
AIR QUALITY

Air quality concerns run parallel to virtually every aspect of electric utility restructuring efforts, affecting the emerging competitive market structure on numerous levels and presenting challenges to reliability of the bulk power grid.

Air quality concerns are a driving issue in most metropolitan areas of Texas. The underlying focus is to meet regulations established by the U.S. Environmental Protection Agency (EPA) to implement the Clean Air Act of 1990 (P.L. 101-549). The Act established National Ambient Air Quality Standards (NAAQS), which designate maximum allowable concentrations of certain pollutants. The EPA has designated four Texas metropolitan areas as "non-attainment" zones for compliance with the NAAQS: Beaumont/Port Arthur, Dallas/Forth Worth, Houston/Galveston/Brazoria and El Paso. All four of these areas do not meet the EPA standard for ground-level ozone concentration. This is of particular concern to the electric power industry because many electric generating facilities (EGFs) produce high levels of nitrogen oxides (NOx), a primary component of ground-level ozone formation. El Paso is also non-compliant with carbon monoxide and particulate matter standards. Other metropolitan areas of Texas classified as "near non-attainment" are Austin, San Antonio and Tyler/Longview/Marshall.[1]

The state is required to submit a State Implementation Plan (SIP) to the EPA that enumerates a strategy to meet the NAAQS. If the state plan is not approved, the EPA is required to draft its own plan for the state. In addition to mandatory remediation measures, penalties for NAAQS non-attainment can be assessed, including the withholding of federal funds for highway construction and other potential contributors to continued non-compliance.

SB 7 Requirements and Implementation

SB 7 directly addressed the contribution of EGFs to air pollution in the state. Prior to the enactment

[1]U.S. Environmental Protection Agency, "USA Air Quality Non-Attainment Areas," July 31, 2000.

of SB 7, 192 EGFs located at 75 sites in Texas had been exempt from the emissions permitting requirements of the Texas Clean Air Act. The Texas act requires state review and permitting for new point sources of air pollution. These exempted plants, known as “grandfathered facilities,” are responsible for up to 36 percent of total emissions from industrial sources in the state, according to a 1998 survey of U.S. Energy Information Administration (EIA) data.

SB 7 required the Texas Natural Resource Conservation Commission (TNRCC) to develop a mass emissions cap and trade program to distribute emissions allowances for use by EGFs.[2] One allowance represents authorization to emit one ton of NOx or sulfur dioxide (SO2) per year. The bill required grandfathered facilities to apply for a permit under the program by September 1, 2000. To secure a permit, grandfathered EGFs must reduce emissions of NOx by 50 percent and SO2 by 25 percent below 1997 levels. The bill further requires grandfathered EGFs to secure a TNRCC permit by May 1, 2003, or cease operation. Implementation of SB 7 will achieve a minimum annual reduction of 75,000 tons of NOx and 37,000 tons of SO2, representing a 12 percent reduction in total grandfathered emissions statewide.[3]

As required, the TNRCC adopted an emissions cap and trade program in December 1999. The TNRCC is currently reviewing all 76 applications submitted for the cap and trade program. No grandfathered EGF permits have yet been issued. Issuance of a permit will cap the maximum allowable emissions from each permitted facility at 1997 levels, minus the reductions in specific pollutants required by the statute. The program allows facilities to trade allowances, providing flexibility for facility owners to determine the most cost-effective means of achieving the statutory goals. As authorized by SB 7, grandfathered EGFs can also purchase allowances from permitted facilities which make voluntary emissions reductions in exchange for an equivalent number of allowances. The rule does not allow EGFs to earn allowances through reduced operations or shutdowns.

The TNRCC is considering an additional rule to expand the scope of emissions trading to include a wider array of facilities in larger geographics regions. The goal of the proposed rule is to allow

[2]PURA §39.264.

[3]TNRCC Executive Director Jeff Saitas, testimony before the Electric Utility Restructuring Legislative Oversight Committee, November 30, 1999 (see Appendix D summary).

additional point source polluters to contribute to overall emissions reductions goals through program participation. The rule is scheduled for adoption in December 2000.

Non-attainment Areas In Texas

Under the TNRCC trading program, permit holders are required to consider the impact of allowance transfers on those counties which are in non-attainment or near non-attainment. The stated goal of the program is to encourage actual reductions in non-attainment and near-non-attainment areas, rather than reductions in more distant areas with allowance transfers to facilities in trouble zones. This consideration is primarily due to the tougher standards which must be applied in non-attainment areas to meet NAAQS. Stricter emissions limits than those mandated by SB 7 will be required of EGFs in non-attainment areas of Texas. For example, generators in the Dallas area must reduce NOx emissions by 88 percent to meet the goals of the Dallas SIP as submitted to the EPA. Several corporate entities have pending legal challenges against the Dallas SIP, including airlines, cement makers, diesel engine manufacturers and waste haulers. On November 6, 2000, TXU and the TNRCC agreed to settle the utility's SIP challenge. Under terms of the agreement, total emissions reductions required of TXU by the SIP did not change. The utility gained the ability to trade emissions credits among its own facilities, providing greater flexibility in determining the most cost-effective method of achieving pollution reductions.[4]

Significant expenditures on emissions reductions in non-attainment areas of Texas is likely. The committee received testimony from TXU and Reliant that suggested environmental cleanup spending in the greater Dallas and Houston areas alone could top $812 million.

To further scientific understanding of the factors contributing to ground-level ozone formation, the TNRCC is participating in a cooperative $20 million study with public, private and academic institutions utilizing the expertise of more than 150 scientists and engineers from throughout the nation to develop better assessment tools and design more cost-effective strategies to improve air quality. The study primarily focuses on the eight-county Houston metropolitan area, but data from more than 60 monitoring stations in Texas, Louisiana, Arkansas and Oklahoma will also be analyzed to track pollution migration.

---

[4] Randy Lee Loftis, "State, TXU Settle On Clean Air Plan," *Dallas Morning News*, Nov. 7, 2000, p. 23A.

Complicating Factors

Balancing the costs of various environmental damage mitigation strategies with economic effects on businesses and households proves to be a delicate task. A common concern of the PUC, Independent System Operator (ISO) administrators and industry participants is that EPA requirements to reduce ozone-forming emissions present challenges to maintaining overall reliability of the electric grid in Texas, particularly in the Dallas/Fort Worth area. The reliability challenges stem from two sources. First, some plants must be shut down in order to retrofit old equipment with updated emissions control technology. This can generally be scheduled and accomplished during the off-peak season. However, a high degree of coordination will be required to ensure sufficient capacity remains online to serve load. Second, some plants may be uneconomical to retrofit with improved emissions control devices and therefore are candidates for closure. However, those same plants may also be integral to maintaining grid reliability by stabilizing voltage in a critical geographic area.[5]

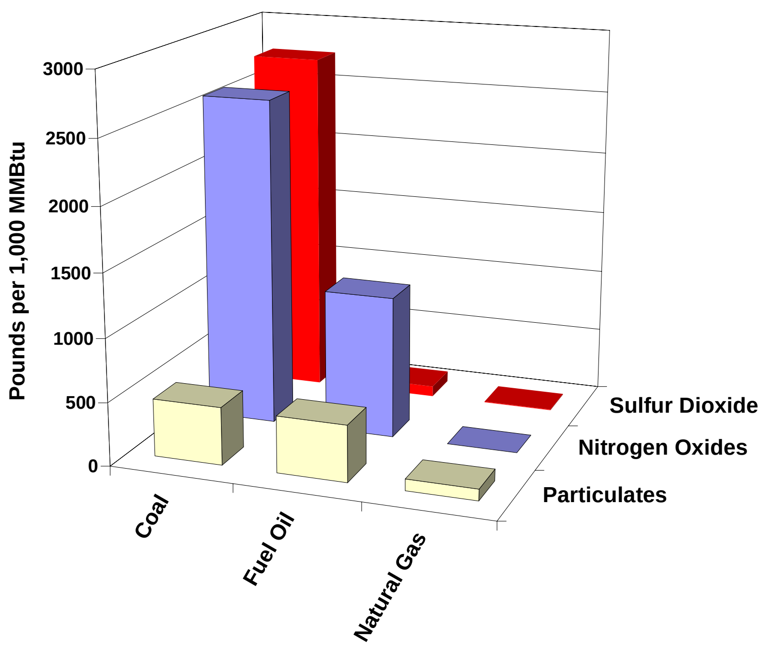
SB 7 allows utilities to include costs associated with implementation of improved emissions controls in stranded cost recovery proceedings.[6] The rule to implement this provision of the law was adopted by the PUC in August 2000. Under the rule, the PUC must determine for each candidate facility whether the public interest is better served by paying for cleanup costs or retiring the plant. Complicating the decision are further restrictions on EGFs planned by the EPA pertaining to emissions of mercury, carbon monoxide and particulate matter. In Texas, coal-fired facilities are at greatest risk from additional regulations. Although a number of mercury control technologies are under evaluation for utility boilers, most are still in the research stages, making it difficult to predict final cost-effectiveness as well as the time required to scale-up and commercialize the technologies. Because the chemical species of mercury emitted from boilers varies from plant to plant, there is no single control technology that removes all forms of mercury. There remains a wide variation in the projected end costs of control measures for utilities and the possible impact of such costs.[7] Similar

[5]TXU President Tom Baker and ERCOT ISO Director Sam Jones, testimony before the Electric Utility Restructuring Legislative Oversight Committee, July 11, 2000 (see Appendix E for summary).

[6]PURA §39.263.

[7]U.S. Environmental Protection Agency, "Mercury Study Report to Congress: Overview," Sept. 26, 2000, p. 3.

Fig. 6.1 **Fossil Fuel Emissions**



Source: Energy Information Administration

vagaries exist in determining the appropriate level of mitigation controls related to carbon monoxide and particulate matter. The primary concern of the PUC is that Texas electric customers do not foot the bill to retrofit a facility that might be retired in a few years because of additional federal regulations. The methodology adopted by the PUC for determining the allowable level of recoverable environmental cleanup costs considers potential future federal regulations as one criterion.

Air quality is decidedly impacted by the choice of fuels used to generate electricity. One benefit of rapid deployment of new gas turbine technology by independent power producers has been a significant increase in generation capacity without resultant increases in air pollution. Figure 6.1 illustrates the environmental benefit of natural gas combustion when compared to other commonly used fossil fuels in the electricity generation process. However, recent spikes in natural gas prices may lead to the increased utilization of alternate fuel sources, including less expensive fossil fuels. City Public Service, the municipal utility of the City of San Antonio, in discussions about future alternatives, recently mentioned it had not ruled out a new coal-fired facility using advanced clean coal technology as a hedge against sustained high natural gas prices.[8] Due to initial construction expense, however, it is unlikely any more nuclear facilities will be built in Texas for some time.[9]

Advances in renewable energy technologies offer at least a partial solution to maintaining fuel diversity in the face of high natural gas prices while still maintaining overall air quality goals. Development of renewable energy resources in Texas is covered in the next chapter.

[8]Ann de Rouffignac, "City Public Service Mulls Building New Coal Plant," *Oil and Gas Journal Online*, Oct. 11, 2000.

[9]PUC Chairman Pat Wood, testimony before the Electric Utility Restructuring Legislative Oversight Committee, August 22, 2000 (see Appendix F for summary).

Chapter Seven:
RENEWABLE ENERGY

Renewable energy is derived from sources that are not depleted by human use, such as wind, solar energy and water movement. These energy forms may be converted to heat, mechanical energy and electricity in several ways. Other technologies, including geothermal and biomass conversion are only now coming into their own. A primary impediment to widespread use of renewable resources has been its high cost relative to other generating fuels. For several renewable power sources, however, the gap in cost per kilowatt-hour compared to fossil fuels is decreasing as the technology becomes more advanced and their use becomes more common. Recent increases in natural gas prices have also enhanced the attractiveness of several renewable generation technologies. Customers of Austin Energy, the City of Austin's municipal electric utility, may participate in a "green choice" program in which the standard electric fuel charge is replaced by a "green power" charge. Originally, the green power charge for average Austin residential use came to $4 more than the standard fuel charge each month. Recent increases in natural gas prices have reduced the difference to $1.37 per month.[1]

SB 7 Requirements and Implementation

Senate Bill 7 directly addressed the twin pressures of rising power demand and air quality concerns through a mandate to add 2,000 megawatts (MW) of new generation capacity from renewable resources in Texas by 2009, more than tripling renewable capacity in the state.

In 1999, approximately 880 MW of generation capacity from renewable resources existed in Texas. Some Northeast Texas electric cooperatives also had standing contracts for hydroelectric power from out of state resources which were not calculated as part of the state's total renewable energy portfolio. The Public Utility Commission of Texas (PUC) was directed to create a system by which customers statewide could participate in development of the state's renewable resources.[2]

[1] Mary Alice Piasecki, "Generating a Powerful Role," *Austin Business Journal*, Sept. 1, 2000, p. 3.

[2] PURA §39.904.

To fulfill this requirement, the PUC established a renewable energy credit (REC) trading program for retail electric providers (REPs) in Texas. As required by the statute, the PUC also established a series of stair-stepped goals for the installation of renewable generation facilities. Power generators must add 400 MW of new capacity by 2003, an additional 450 MW by 2005, another 550 MW by 2007 and another 600 MW by 2009.

Renewable Energy Credits Program

Each REP and municipal utility or electric cooperative opting for customer choice in Texas is required to purchase a number of RECs proportional to its share of the Texas retail market. One REC represents one megawatt-hour (MWh) of renewable energy that is generated from a new resource and physically metered and verified in Texas. Each REP is not required to purchase an equivalent amount of electricity generated from renewable resources. The electricity is bought and sold in the marketplace independent of the sale of RECs. This should allow renewable generators to sell renewable power at market rates and make up the cost difference through the REC sales.

By requiring all competitive retailers (REPs and opt-in municipal utilities and electric cooperatives) to participate in the REC program, instead of mandating high-cost direct renewable energy purchases, investment dollars will likely be steered to the best location for the development of particular renewable resources. For example, an electric generator could build a wind plant in Galveston, but it would likely not produce the same amount of electricity as one atop a West Texas mesa. Rather than require REPs in the Houston area to buy renewable power, the program allows retailers to participate in renewable energy resource development where it makes sense for them to do so. The rule does not prevent a REP from purchasing both the renewable energy and the REC created from its production.

Some REPs will receive REC offsets under the PUC program. A REC offset represents one MWh of renewable energy from an existing facility that may be used in place of a REC to meet the renewable energy requirement imposed by the PUC. REC offsets may not be traded. REC offsets will be equal to the average annual MWh output of an existing resource. The REC offset provision precludes existing resources from deflating the value of RECs in the marketplace, which could negatively impact further renewable capacity development, while recognizing the contribution existing resources provide to the state's total energy portfolio. The offset provision received broad support from participants in the workgroup discussions. It was generally recognized that the REC offset provision will also make it easier for municipal utilities or electric cooperatives with rights to existing resources to opt in to competition.

The statewide REC program will be administered by ERCOT, which will determine the number of RECs required of each REP annually, subject to PUC approval, and will track the creation, retirement and banking of credits. ERCOT will issue a compliance report to the PUC each April. This annual report will also detail the number and type of operating renewable energy generators in the state.

Although the REC requirements will not be instituted until January 1, 2002, renewable generating facilities will be eligible to earn RECs beginning June 1, 2001. This "early banking" provision should ensure enough liquidity in the marketplace that scarcity does not artificially inflate REC prices. Liquidity of RECs will also place cost containment responsibilities on renewable energy generators. If generators hold more RECs than REPs are required to purchase, the price of RECs should fall. If both the price of RECs and wholesale energy prices are low, it will be difficult for high-cost renewable facilities to operate profitably.

Outlook for New Generation

Industry response to the renewable energy provisions of SB 7 has been encouraging. Six months after the PUC adopted the REC program, ERCOT received more than 20 renewable generation interconnection requests, representing a capacity greater than 2,800 MW.[3] Some of the projects are in competition with one another, however, so not all of them will materialize. The 2,000 MW by 2009 requirement of SB 7 will likely be met, even exceeded, in the time frame established by the bill. ERCOT estimates West Texas could ultimately host more than 8,600 MW of wind power, with around 5,400 MW available for export to other regions.

The majority of megawatts from proposed renewable generation facilities in Texas will come from

[3]Electric Reliability Council of Texas, "Presentation on Transmission in West Texas Related to Wind Projects," March 31, 2000.

"wind farms," large-scale projects located across several hundred acres of West Texas. Giant wind turbines, some hundreds of feet tall, will generate electricity by harnessing the strong West Texas winds. Although wind projects consume no fossil fuels, require no cooling ponds and release no toxic emissions, the surge in wind power development is not without problems. Transmission constraints in West Texas must be overcome to move wind-generated power to load centers in other parts of the state. Additionally, system administrators worry that wind turbines spinning in the night, when electric use is low, may create high-voltage problems on the grid.[4] Because wind turbines only produce electricity in windy conditions, incorporating wind resources into long-term energy and system reliability planning processes is likely to be challenging to the ERCOT ISO.

Other renewable projects under development, such as Reliant Energy Renewables' 12 proposed landfill gas conversion facilities, will likely become base-load generators that will be depended upon for a steady flow of power.

In addition to the REC trading program, federal tax incentives also play a role in encouraging new renewable generation capacity. The Energy Tax Act of 1978 (P.L. 95-618) created solar credits and residential and business credits for wind energy installations; it expired on December 31, 1985. However, business investment credits were extended repeatedly through the 1980s. Section 1916 of the Energy Policy Act of 1992 (P.L. 102-486) extended the 10 percent business tax credits for solar and geothermal equipment indefinitely. Also, Section 1914 of that Act created an income tax "production" credit of 1.5 cents/kwh for electricity produced by wind and closed-loop biomass systems. P.L. 106-170 expanded this credit to include poultry waste and extended it through December 31, 2001.[5]

[4] Ibid.

[5] Congressional Research Service, "Renewable Energy: Tax Credit, Budget, and Electricity Restructuring Issues," May 12, 2000, p. 3.

Chapter Eight:
COMMITTEE FINDINGS

The committee believes maintaining a reliable, affordable supply of electricity for all Texans is an essential component in our state's continued economic prosperity. The legislative actions establishing a new structure for the generation and delivery of electric power have been the result of years of intense study and difficult compromise. The committee has observed the implementation process in action for more than a year and finds the provisions of Senate Bill 7 supply an adequate framework for electric utility restructuring in Texas.

The committee recognizes that many issues remain to be resolved before full retail competition begins on January 1, 2002. The committee has endeavored to understand the nature of problems experienced in other restructuring markets in an effort to avert similar circumstances in Texas and ensure the development of a properly functioning marketplace that provides customers with a real choice of competitive providers. Where potential problems do exist, the committee recognizes multiple approaches or solutions may be available and legislation may be one of these solutions. The issues explored in this report will be important matters for the 77th Legislature to monitor during the upcoming session.

Since the enactment of SB 7 in 1999, several key events have transpired in local, national and global energy markets which add a degree of apprehension to a process already requiring tough decisions to be made in many critical areas. Although the committee's primary focus throughout the interim has been to monitor the implementation of SB 7, well-publicized problems in California and other energy markets caused the committee to re-focus its oversight activities to be certain Texas is not headed for similar problems.

Implementation of Statutory Goals

The committee finds substantial progress has been made towards implementing the goals of SB 7. Several state agencies were assigned specific functions in the bill, with specific deadlines for completion. Target dates for action by the Comptroller of Public Accounts, Texas Education Agency, General Land Office and Texas Natural Resource Conservation Commission (TNRCC) have been met. The Public Utility Commission of Texas (PUC) has diligently completed a wide array of projects in the time frame specified by restructuring legislation. The committee expects the PUC will continue implementation activities on schedule and will maintain regular communication to ensure this occurs. The committee notes most Texas market participants have met various statutory deadlines for restructuring activities, including PUC and TNRCC filings, business separation activities and technical operations implementation. As the restructuring process continues, the committee will continue observation to ensure all market participants and implementing agencies continue to perform within the parameters intended by acts of the Legislature to provide fair competition in the Texas retail electric market.

Reliability

The committee is encouraged by the surge in announced generation facilities in Texas, although some concern exists about heavy dependence on natural gas. The more than 5,700 MW of new generation capacity added in Texas since the wholesale restructuring process began should provide a dependable power reserve margin. The committee is further encouraged by the level of cooperation between the PUC, TNRCC and Electric Reliability Council of Texas (ERCOT) to facilitate the spread of distributed generation as a partial solution to air quality concerns and transmission constraints in the state. Although new difficulties in transmission planning have surfaced since wholesale market restructuring began in 1995, the committee finds sufficient coordination between power generators, utilities, ERCOT and the PUC exists to solve potential problems.

Price Volatility

The committee does not expect the Texas retail electric market to experience the wholesale or retail price volatility experienced elsewhere in the United States during Summer 2000. Abundant generation resources, a workable market structure and the price to beat mechanism will serve to stabilize power costs and protect customers from volatility. The committee will continue to monitor activities to ensure the restructured competitive market functions properly.

Stranded Costs

The committee finds changes in energy markets have led to ongoing revisions of estimated stranded investment. SB 7 provided mechanisms for the state's investor-owned utilities to recover costs incurred under the regulatory structure which prove to be uneconomical in the competitive market. It is believed these costs will be lower than previously anticipated. In any event, this is an issue requiring continued monitoring by the committee.

Consumer Protections

The committee received substantial testimony from consumer advocates concerning a wide array of customer protection issues. The committee finds basic consumer protections from anticompetitive activities are fundamental to maintaining a vibrant, healthy market. Final review and adoption of the ERCOT market protocols and PUC rules implementing the customer safeguards established in PURA by SB 7 and SB 86 are not yet complete. The committee will continue to monitor both the remaining implementation process and market participant adherence to Legislative intent.

Air Quality

The committee finds air quality in Texas will improve under the provisions of SB 7. Annual emissions from electric generating facilities will decline by at least 112,000 tons. However, continuing to improve air quality while maintaining electric system reliability is a complex task. Any future air quality regulations at the state or federal level may have broad, significant impacts on several sectors of the Texas economy. This is an issue requiring continued monitoring by the Legislature.

Renewable Energy

The committee is encouraged by the level of activity in the renewable energy market in Texas and finds that the renewable energy mandate of SB 7 will likely be met before the statutory deadline.

Continued Oversight

The committee finds further oversight of implementation activities is necessary to ensure a workable competitive environment develops. Remaining issues requiring the committee's continued attention include diligent monitoring of ERCOT operations, regular communication with the PUC about implementation progress and ongoing analysis of market events as retail electric competition begins in Texas.

Pursuant to PURA §39.907, the committee shall continue to meet at least annually with the PUC, receive information about rules related to electric utility restructuring, review recommendations for legislation and monitor the effectiveness of electric utility restructuring. In accordance with the statute, the committee shall issue a report in November 2002.

DISSENTING OPINION OF REPRESENTATIVES SYLVESTER TURNER AND DEBRA DANBURG

Estimates of stranded costs for utilities have fallen lower and lower throughout the course of the committee's four interim hearings, primarily due to higher natural gas prices. Since the conclusion of those hearings, it has become apparent that not only may stranded costs be fully mitigated before the start of retail competition, but also some generation assets may actually possess market value above their net book value, creating a negative stranded cost for some utilities. SB 7 prohibits utilities from overrecovering stranded costs, and any excess revenues collected by the utilities must be returned to ratepayers. Though the committee report recognizes this as a possibility, it does not present the kind of discussion on this issue that I believe is appropriate.

The Office of Public Utility Counsel (OPC) has filed testimony with the Public Utility Commission (PUC) that estimates the total overrecovery of stranded costs to be over $7 billion by 2004. PUC staff have also presented estimates of overrecovery to the commissioners in public meetings that are significantly lower than OPC's estimates but still amount to at least $2 billion by 2004. This begs the question of whether utilities should be allowed to hold onto any excess collections they may already have, not to mention whether ratepayers should be asked to continue paying down stranded costs that may not even exist.

We do not know what the final stranded cost figures will be. However, I believe the Legislature must make a policy decision as to whether this issue should be addressed before the true-up proceeding in 2004. If the potential for overrecovery is as great as some suggest, then this issue should be looked at now, not just allowed to proceed until 2004. This committee's report seems to exclude the possibility that the Legislature may wish to provide the PUC further guidance on how to handle any overrecovery of stranded costs. I understand that there is very little desire to reopen SB 7, but the issue remains that Texas electricity customers may have already paid for stranded costs.

Just as recent market changes unforseen in 1999 have altered our current discussions of potentially strandable investment, it is likely that estimates of excess costs over market will continue to shift as Texas moves closer to introducing retail competition in electricity markets. It is understandable that the committee is hesitant to predict market conditions for several years into the future and determine the possible effects of multiple market factors on potentially strandable investment.

Because the definition of stranded costs in SB 7 includes only the "positive excess" of net book value over market value, the Legislature must provide further guidance to the PUC as to how it should proceed. The PUC is investigating stranded costs, and it may have sufficient tools available under current law to deal with this issue appropriately during the transition period. For example, the PUC could redirect depreciation transfers from the transmission facilities to the generation assets or end the application of excess revenues to stranded costs.

The Legislature could also provide the PUC with additional tools to ensure that ratepayers are not asked to pay too much toward stranded costs, including the establishment of a negative Competition Transition Charge (CTC) or another mechanism that would reduce the non-bypassable charges on customers' bills to prevent overrecovery of stranded costs. Reducing non-bypassable charges means more headroom in the retail price structure, and thus more room for competition. If it would be appropriate to refund customers who have paid too much toward stranded costs, then it makes sense that we should consider applying those refunds no later than the start of competition.

In most respects, I agree with this committee's conclusion that SB 7 provides an adequate framework for successfully introducing retail electric competition in Texas. Continued monitoring of restructuring legislation implementation is needed to be certain a workable market develops. More than just monitoring, we should examine this stranded cost issue thoroughly during the upcoming session. The Legislature should commit to making a policy decision whether it is appropriate for utilities to continue collecting money from ratepayers to apply to their stranded costs or should the PUC set a CTC that is zero or possibly negative. This is an important issue for all electricity customers in Texas.

SIGNED	SIGNED
Rep. Sylvester Turner	Rep. Debra Danburg

Appendix A:
LIST OF FIGURES

EXECUTIVE SUMMARY

Chapter Two: ELECTRIC SYSTEM RELIABILITY

Chapter Three: MARKET TRANSITION

Chapter Four: INDEPENDENT SYSTEM OPERATOR

Chapter Six: AIR QUALITY

Appendix B:
COMMONLY USED ACRONYMS

AARP	American Association of Retired Persons
AE	Austin Energy
AEP	American Electric Power
AECT	Association of Electric Companies of Texas
bcf	Billion Cubic Feet
BEPC	Brazos Electric Power Cooperative
btu	British Thermal Unit
CCN	Certificate of Convenience and Necessity
Coop	Electric Cooperative
CPS	City Public Service Board of San Antonio
CPL	Central Power and Light
CTC	Competition Transition Charge
D/FW	Dallas/Fort Worth
ECOM	Excess Costs Over Market, also known as “stranded costs”
EGF	Electric Generating Facility
EGS	Entergy Gulf States
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPE	El Paso Electric
ERCOT	Electric Reliability Council of Texas
ESSA	Electric Service Agreement, a term used by the General Land Office
ESP	Electric Service Provider, a term used by the General Land Office
FERC	Federal Energy Regulatory Commission
GLO	General Land Office
ISO	Independent System Operator
IOU	Investor-Owned Utility
kwh	Kilowatt-hour
kw	Kilowatt

kv	Kilovolt
LCRA	Lower Colorado River Authority
mcf	Thousand Cubic Feet
MM	One Million
MOU	Municipal-Owned Utility
MPA	Municipal Power Agency
MRS	ERCOT's Market Readiness Series
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Council
NOx	Nitrogen Oxides
OPC	Office of Public Utility Counsel
PGC	Power Generation Company
PL	Public Law
POLR	Provider of Last Resort
PUC	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 1935
PURA	Public Utility Regulatory Act, Title II, Texas Utilities Code
PURPA	Public Utilities Regulatory Policy Act of 1978
PV	Photovoltaic
PX	Power Exchange
QSE	Qualified Scheduling Entity
REC	Renewable Energy Credit
REP	Retail Electric Provider
RHLP	Reliant Energy, Houston Light and Power
RTO	Regional Transmission Organization
SB	Senate Bill
SBF	System Benefit Fund
SERC	Southeastern Electric Reliability Council
SDG&E	San Diego Gas and Electric
SIP	State Implementation Plan
SIS	Security and Information System
SO2	Sulfur Dioxide

SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
SUV	Sport Utility Vehicle
SWEPCO	Southwest Electric Power Company
T&D	Transmission and Distribution Utility
TCAA	Texas Clean Air Act
TDHCA	Texas Department of Housing and Community Affairs
TEA	Texas Education Agency
TIS	Texas Interconnected System
TNMP	Texas New Mexico Power Company
TNRCC	Texas Natural Resource Conservation Commission
TREC	Texas Rural Electric Coalition
TXU	Texas Utilities
VOC	Volatile Organic Compound
WSCC	Western Systems Coordinating Council
WTU	West Texas Utilities

Appendix C:
GLOSSARY

A

aggregator: a person joining two or more customers, other than municipalities and political subdivision corporations, into a single purchasing unit to negotiate the purchase of electricity from retail electric providers. Aggregators may not sell or take title to electricity. Retail electric providers cannot be aggregators.

ancillary services: services called on to control electric system frequency by matching production and consumption. The key ancillary services are regulation and reserves. Regulation is provided by measuring the deviation of the system from the standard frequency and sending signals to generators to increase or decrease their output. Reserves are an "insurance policy" against larger events, such as the failure of a generating unit. Reserves can be provided by generating units that are able to quickly and significantly increase their output or by customers who are able to quickly and significantly decrease their consumption.

C

competition transition charge (CTC): a non-bypassable charge included on all electricity customer bills to recover stranded costs.

cogeneration: production of electricity from steam, heat or other forms of energy produced as a by-product of another process.

combined cycle: an electric generating technology in which electricity and process steam is produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

commercial information: information that can be used in the marketplace.

commonly-owned unit: a generating unit whose capacity is owned or leased and divided among two or more entities. Synonym: jointly-owned unit.

control area: an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection.

cramming: hiding unauthorized charges on customer bills.

curtailability: the right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission service. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exist.

curtailment: a reduction in the scheduled capacity or delivery of energy.

D

demand: the rate at which electric energy is delivered to or by a system or parts of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. Demand should not be confused with load.

demand-side management: the term for all activities or programs undertaken by an electric system or its customers to influence the amount or timing of electricity use.

distributed generation: a distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local substation level peak loads and displacing the need to build additional local distribution lines.

E

Electricity Reliability Council of Texas (ERCOT): one of 10 reliability councils in the North

American Electric Reliability Council, ERCOT is a non-profit corporation which administers the bulk transmission network within its boundaries. Approximately 84 percent of Texas lies within ERCOT.

estimated costs over market (ECOM): the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market. Other phrases are also used to describe the concept, include *potentially stranded investment*, or *stranded costs*. These terms emphasize that these historic costs are not yet stranded, but may become stranded in the future. The degree to which investments are ultimately stranded will depend upon changes in the market price of electricity, the speed with which markets become competitive, tax implications of restructuring options, mitigation efforts by utilities and the actions of utilities, the Legislature and the PUC regarding electric industry restructuring.

F

fuel factor: that portion of the regulated electric utility bill which pays for fuel as an input to the electricity generation process.

functional unbundling: the process by which a utility separates business activities according to the functional role of each activity in the electricity delivery process. In Texas, and most other restructured markets, monopoly utilities are separated into a power generation company, a transmission and distribution utility and a retail electric provider.

G

generation: the process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in megawatts.

grandfathered facilities: industrial plants in existence before implementation of the Texas New Source Review permitting program and exempt from the requirements of the Texas Clean Air Act.

H

headroom: the difference between the sum of non-bypassable charges and the price to beat, usually expressed in cents per kilowatt-hour.

I

independent power producer: any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other non-utility producers, such as exempt wholesale generators that sell electricity.

independent system operator (ISO): an entity charged with supervising the collective transmission facilities of a power region, coordinating market transactions, planning systemwide transmission and ensuring network reliability..

interconnected system: a system consisting of two or more individual electric systems that normally operate in synchronism and have connecting tie lines.

Interconnection: when capitalized, any one of the five major electrical system networks in North America: Eastern, Western, ERCOT, Quebec and Alaska. When not capitalized, the facilities that connect two systems or control areas. Additionally, an interconnection refers to the facilities that connect a non-utility generator to a control area or electric system.

K

kilovolt (kv): one thousand volts; see *volt*.

kilowatt (kw): one thousand watts; see *watt*.

kilowatt-hour (kwh): one thousand watt-hours; see *watt*.

L

load: an end-use device or customer that receives power from the electrical system. Load should not be confused with demand, which is the measure of power that a load receives or requires.

load cycle: the normal pattern of demand over a specified time period associated with a device or circuit.

load shedding: the process of deliberately removing, either manually or automatically, preselected customer demand from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

load shifting: demand-side management programs designed to encourage consumers to move their use of electricity from on-peak times to off-peak times.

M

margin: the difference between net capacity resources and net internal demand. Margin is usually expressed in megawatts.

marketer: an entity that has the authority to take title to electric power generated by itself or another entity and remarket that power at market-based rates.

Megawatt (MW): one million watts; see *watt*.

Megawatt-hour (MWh): one million watt-hours; see *watt*.

P

price to beat: in the restructured Texas electricity market, the price to beat is the rate charged by the affiliated REP of an incumbent utility. The price to beat is fixed at 6 percent below the rate in effect on September 1, 1999, adjusted for changes in the fuel factor. The price to beat must be offered to all small customers through January 1, 2007.

power exchange (PX): a centralized market mechanism matching wholesale power buyers and sellers.

Q

qualified scheduling entity (QSE): a market participant that is qualified in accordance with Section 16, Registration and Certification of Market Participants, by ERCOT to submit balanced schedules and ancillary service bids and settle payments with ERCOT.

R

renewable energy: energy derived from sources that are not depleted by human use, such as wind, solar energy and water movement.

S

securitization: a transaction that permits a utility to receive a lump sum payment for stranded costs from investors in lieu of collecting such costs through its regulated cost of service. The lump sum payment is financed through the issuance of debt securities to third party investors.

slamming: the unauthorized switching of a customer's service provider.

stranded costs: see *estimated costs over market.*

T

transco: short for *transmission company*. In the restructured Texas electricity market, independent system operator functions may be carried out by privately-owned, for-profit transmission companies.

true-up: as set forth in PURA §39.262, the true-up is a process scheduled to take place in 2004 in which the PUC will make a final determination of the stranded investment incurred by each utility.

V

volt: the unit of electromotive force that will drive a current of one ampere through a resistence of one ohm. Voltage may be thought of as a "push" that moves or tends to move a current through a conductor.

W

watt: a unit for measuring power, or the rate at which work is done. In electricity, a watt is equal to the flow of one ampere at a pressure of one volt (watts = volts X amperes). A watt-hour is the amount of electrical energy used to keep a one-watt unit working for one hour.

wind farm: a facility employing the use of several devices to harness the power of wind to turn turbines and produce electricity.

wires charge: that portion of a customer’s electric bill which covers costs associated with the construction, maintenance and administration of the bulk transmission system.

Appendix D:

SUMMARY OF TESTIMONY

November 30, 1999, Austin

PAT WOOD, Chairman, Public Utility Commission of Texas

Chairman Wood outlined the process and time line for Senate Bill 7 implementation, expressing confidence that implementation projects could be completed on schedule. Due to the large volume of work associated with implementing market restructuring legislation, Chairman Wood said the Public Utility Commission (PUC) has relied heavily on the use of collaborative, consensus-oriented processes. "We get members of the public and the industry, new players and old players, to come together and try to work through as many issues as they can. If we can't get consensus on the issues — and that has happened — then the PUC really decides the issue," he stated.

The chairman outlined five "big picture items" that must be completed on track for restructuring to take place in the time frame specified by the bill. First, he reminded committee members that utilities are still regulated, and the PUC must continue to regulate them effectively prior to opening the market on January 1, 2002.

Second, the "back end" systems must be prepared for opening day. "Based on the Commission's experience with Southwestern Bell and the long distance issues in the local competition market, we realized that if we have computers that don't speak to each other or if you don't have computers at all, it is going to be very difficult to deal with millions of customers and sending them accurate bills month after month," he said. By statute, the Electric Reliability Council of Texas (ERCOT) is charged with developing the new system infrastructure. ERCOT will also assume new duties: managing the settlement system, ensuring accurate bills between electricity providers and maintaining the customer registration system. Chairman Wood said, "I am comfortable with the progress ERCOT is making on these issues." Although the PUC allows ERCOT to handle its own business, Chairman Wood said a significant level of staff-to-staff communication is taking place. Ultimately, the PUC maintains an oversight function and must approve the ERCOT marketplace rules.

Third, industry standards must be developed. Chairman Wood said that PUC staff is working with industry and consumer groups to achieve consensus based on national models tailored to fit the Texas statutes.

Fourth, customer protection rules must be established. Chairman Wood said SB 7 "was very well filled out in that regard — not a lot of dotted lines to fill in. But it's still important to pull it all together." Some questions exist on how to pay for certain activities such as services needed for development and implementation of the consumer education plan, which must occur before 2002. Some anticipated difficulties concern establishing a protective framework that still allows a degree of freedom and innovation in the marketplace. For example, Chairman Wood said different consumers want different things from their utility bill. Some people may want a very detailed listing of all charges whereas others simply want a box highlighting the amount due. "We are trying to strike a fair balance that does not encourage fraudulent or misleading statements," he said.

Fifth, the PUC is still trying to work out how much interaction the transmission and distribution utilities will have with customers. In other words, "Who do you call when the wires go down?" As long distance telephone service has been restructured in the state, Chairman Wood said the PUC found it works better if there is one entity customers can go to when something goes wrong. "Otherwise you have a lot of blame-shifting behavior," he said.

Chairman Wood next addressed reliability issues, noting that a significant level of new power generation is planned or under construction in Texas. This new capacity will meet the growth in demand. In the time since SB 373, 74th Legislature, restructured wholesale electric markets, all new power plants in Texas have been built by non-utility companies, meaning the risks and rewards have been placed on the marketplace instead of retail customers. Chairman Wood envisions an industry requirement mandating a 15 percent reserve capacity margin to keep abreast of demand growth. Chairman Wood said he anticipates the market maturing in Texas by 2010, reducing the need for regulators to be involved in generation capacity monitoring.

Capacity is only the first part of the reliability equation. The question is not only can we generate enough power to meet demand, but also, is the infrastructure capable of moving the power from where it is generated to where consumers use it? As the process for siting and building power generation facilities has become more streamlined and faster, the process for siting and building additional transmission facilities has become longer and more complex. Environmental regulations and historical requirements are part of that, but the biggest single issue is landowner concerns associated with acquiring the right-of-way necessary for construction. More and more of the transmission network needs to be routed through urbanizing areas.

Seven major transmission projects are under way now, and seven more are planned. The PUC has been working to get these projects underway so certain bottlenecks in the transmission grid will be unclogged by the start of competition. The ability to move electricity from power-rich Houston to power-hungry Dallas is very important, requiring resolution of the state's South to North transmission constraint.

Chairman Wood said the power market has reacted favorably to both the new structure and the perceived need in Texas. He reported particular success in South Texas. "As a result of signals sent by the Rio Grande Valley market, we have one new completed plant, one near completion and one that will be ready by mid-01," he said. South Texas used to be a power-starved area of the country, but new generation sited in the Valley since the 1995 restructuring legislation will likely make it a power-rich region.

Some generators now want to increase ties to Mexico's power grid to sell excess power, an idea supported by Central Power and Light and the PUC. Some concerns have been expressed that tying into the Mexican grid may encourage further development of heavy-polluting plants. Chairman Wood said the efficiency of natural gas plants on the Texas side of the border decreases long-term viability of the older plants South of the border.

JEFF SAITAS, Executive Director, Texas Natural Resource Conservation Commission

Mr. Saitas provided the committee with an overview of the environmental provisions of SB 7, updated the committee on the progress of implementation and discussed emerging problems and policy issues.

The TNRCC anticipates a 75,000 ton per year reduction in nitrogen oxides (NOx) emissions and a 37,000 ton per year reduction in sulfur dioxide (SO2) emissions statewide as a result of SB 7. This represents a 12 percent reduction from the approximately 900,000 tons per year of total grandfathered contaminants released into the air. The grandfathered emissions portion of SB 7 affects 192 individual emissions sources located at 75 different sites in the state.

In some areas of the state, much more significant reductions are required to meet the eight-hour ozone standard promulgated by the U.S. Environmental Protection Agency (EPA) to fulfill the requirements of the federal Clean Air Act of 1990. To meet these standards, NOx emissions must be reduced by about 88 percent in the Dallas/Fort Worth area and 90 percent in the Houston area.

Mr. Saitas said some grandfathered facilities may have polluting equipment on site not covered by SB 7, since the legislation has been interpreted by TNRCC as dealing only with units that generate electricity. Under this interpretation, a train that transports coal would not be covered by the SB 7 permitting and reduction requirements because the train does not generate electricity. TNRCC is considering a rule that would allow companies who voluntarily seek permits for those additional facilities to use reductions beyond what is required for trading purposes.

In response to a question from Representative Danburg, Chairman Wood said any electric utility investment to clean air quality pursuant to TNRCC compliance with National Ambient Air Quality Standards is includable in stranded cost recovery at the true-up in 2004, not just those costs related to the grandfathered facilities, according to PURA §39.263.

Mr. Saitas also addressed reliability concerns from the TNRCC's perspective. "We want to make sure that as we proceed as a state in addressing the air quality part of our business, that we do not create a situation where permitting interrupts the ability to deliver power to the people so that we have to choose … between a brownout or clean air. Clearly the path we have to follow is that we've got to do both."

SAM JONES, Director, Electric Reliability Council of Texas, Independent System Operator

Mr. Jones summarized the activities of ERCOT in preparation to assume the role of Independent System Operator in the restructured Texas market. To facilitate the implementation process, ERCOT contracted Andersen Consulting to serve as project manager. The firm has experience in retail market transition in North America as well as overseas. Thus far the consulting team has produced cash flow models, staffing and facilities needs analyses and other planning items.

ERCOT formed several task forces that began meeting soon after the end of the 76th Legislature to discuss the market structure within ERCOT. The meetings have been open to any interested participants. Some outstanding issues requiring resolution include how to pay for congestion management and how to acquire some of the ancillary services needed. The ISO director expressed hope the ERCOT committees could reach consensus on these and other issues. If not, he expects the PUC will step in and make those decisions.

Mr. Jones reported that some interruptible load in North Texas was shed during the summer of 1999 solely due to transmission constraints. Some generators in the area had been forced out of service and the North-South transmission lines were already at maximum capacity.

As the transmission system operator, ERCOT informs a utility that a certain number of megawatts of load must be shed to maintain system integrity, Mr. Jones explained. The utility then interrupts load according to its procedures. After 2002, that procedure will change somewhat as the interruptible load becomes a tool or a commodity which a retail provider would exercise for money. To illustrate his point, Mr. Jones said an entity willing to interrupt load during a time of need would say, "Okay, I'll interrupt so many megawatts for so many dollars," and the ISO could accept the offer and pay that price for load reduction.

Co-chairmen Sibley and Wolens asked how the load interruption procedure will be handled in the future. The current system configuration only requires one call to the utility in each service area, but the future market structure involves several REPs, each of which may have some interruptible customers. Mr. Jones replied that at this time it is somewhat uncertain how that situation will be handled in the future.

The ISO director acknowledged the outlook for new power generation in Texas is positive but counseled that additional transmission lines will be needed to connect many of these facilities to the grid. Discussion ensued between Senator Sibley, Representative Turner, Mr. Jones and Chairman Wood concerning transmission planning. Under the regulated monopoly structure, generation and transmission were usually planned together. The new market environment requires non-discriminatory access to the grid, which complicates protecting the public interest against unnecessarily expensive transmission projects. Mr. Jones explained that ERCOT has no authority over plant siting or connection to the grid. The ISO is involved in transmission planning, however, and reviews proposed projects.

Chairman Wood explained the PUC maintains the authority to protect the public interest in this area. Generation plants only require two permits to build: an emissions permit from the TNRCC and a permit indicating compliance with local government rules. To operate, however, generation plants need a connection to the grid. Transmission utilities cannot reject a request for interconnection outright. This rule prevents discrimination in favor of the transmission utility's affiliated generation company. However, a Certificate of Convenience and Necessity (CCN) is still required from the PUC in order for the transmission utility to recoup the cost of the line through the non-bypassable charge on customer bills applied by the transmission and distribution utility.

If the PUC determines a proposed transmission line does not serve the public interest due to environmental, health, economic or other reasons, it may reject the CCN request. Such a decision would relieve the transmission utility of the responsibility to connect the proposed plant to the grid and would likely cause the power producer to abandon the proposed project.

Air quality issues have also presented problems for ERCOT. "We've made no decision at the ISO based on any of the air quality issues because we have not traditionally been involved in anything like that," Mr. Jones said. "We've depended on the TNRCC permitting process to deal with that." Air quality issues in North Texas present particular problems. Some of the grandfathered facilities are essential to maintaining system voltage on peak days, but they may not be retrofitted because of economic reasons. There has been talk of extensive transmission upgrades running from Houston to Dallas to address that problem. However, Mr. Jones said, "We need new, good, clean generation up there." New capacity is being built outside the non-attainment area, but the local transmission system in place there will not support the load in North Dallas without most of the older generating plants in full operation. Mr. Jones said ERCOT administrators are very concerned about air quality rules having a negative impact on system reliability on the Dallas metropolitan area.

Mr. Jones said in his opinion SB 7 was a good bill and did not anticipate needing any further legislation to allow ERCOT to fulfill its mission as the ISO.

STEVE SCHAEFFER, representing the Associated Electric Companies of Texas

Mr. Schaeffer first addressed issues related to the transition period. He echoed Chairman Wood's assessment that Texas had sufficient existing and planned generation capacity to meet demand. The market has responded well to the 1995 wholesale restructuring legislation. A number of new generating facilities have come online without ratepayer subsidization, but planning for new load requirements in the restructured market is somewhat complex and will begin in earnest before competition actually begins. The impact of market restructuring on the planning process is that strategies shift from a regional focus to more of a statewide outlook. For example, when the General Land Office (GLO) begins serving entities formerly served by the utilities, it will affect individual system planning, even though it does not affect ERCOT demand or capacity totals. In Reliant's territory, 200 to 300 MW of load should be dropped from the system due to GLO's activities. Another planning factor is the retail competition pilot program, which should shave Reliant's load again by another 5 percent.

Mr. Schaeffer said planning has been problematic for the past few years, largely due to weather impacts, and 1998 was one of the hottest years ever recorded in Texas. More accurate than simple high and low temperatures is measuring the number of degree-hours existing above 70 degrees, which draws a closer approximation of air conditioner use than other models. In fact, 1998 exceeded any other year on record for the number of degree-hours above 70 degrees.

Planning margins are figured assuming average weather and no forced outages. When the weather is exceptionally hot or a plant unexpectedly ceases operations, the reserve margin is supposed to be able to handle that power emergency. "We think the system has performed well for the past few years. We have had interruptions, but interruptible customers expect interruptions," Mr. Schaeffer said. As the market changes, he expects consumer habits to change with it. As customers witness price volatility in the marketplace, they will respond more directly than they did under the regulated rate system which tends to average costs over time, he said. This may be a beneficial effect for some consumers, but one which limits opportunities for others.

As a result of changing customer habits, electric companies expect load shapes to get flatter across the state. In the context of reliability and generation capacity, that means the state will have an even greater reserve margin as customers react rationally to price signals and reduce on-peak consumption. Mr. Schaeffer stated that nearly one-third of the kilowatt-hours Reliant currently sells are associated with customers whose metering technology allows them to observe and react to time-of-use pricing for electricity. This generally applies to the large industrial and commercial users. Smaller consumers are less likely to have to respond so specifically to price fluctuations. Mr. Schaeffer theorized that retail electric providers seeking residential market share are likely to use an average-price basis.

On the issue of transmission constraints, Mr. Schaeffer said both power plant and transmission network construction would be necessary to overcome capacity limits on the grid. “If there is a significant capacity constraint for transmission, what happens is prices will go up in a region and people will build generation that will take advantage of it and prices will go back down. It’s a normal market response. That’s one thing that we can expect to see happen in the future,” he said.

If a power plant fails in a region, however, the system still needs to be able to move replacement power into the area to keep the grid up. Although it may appear that areas can be served through the generation siting process without major commitments to the transmission infrastructure, that is not the case. Adequate transmission facilities are needed as a backup for generation failures.

Although new transmission projects are in progress, there has not been significant transmission construction in the state in more than a decade. Mr. Schaeffer expects new projects to move forward, but it is becoming increasingly difficult to site transmission projects in Texas today, primarily due to landowner concerns. It is also somewhat more difficult to plan for transmission projects since generation facilities are now privately planned.

The majority of announced generation projects in Texas will utilize natural gas as fuel, but it may be erroneous to assume this will lead to an increase in the total amount of natural gas consumed by the electric utility industry. Newer plants are more efficient, producing more kilowatt-hours of electricity from less gas combustion. Mr. Schaeffer said he expects older plants will primarily serve peak load and the newer, cleaner, more efficient plants will become base load servers. He predicted that a new class of plant will also develop in the market, called mid-merit, serving load somewhere between base and peak loads. Large coal plants are a good candidate for this class. Although they are not very fuel efficient, they are relatively inexpensive to operate. Some of the older gas plants will also fall into this mid-merit category. Mr. Schaeffer said nuclear plants will likely remain base load carriers.

On the subject of air quality, Mr. Schaeffer said it would make no sense to retrofit an older plant with new emissions technology just to get the money back through stranded costs. The decision to retrofit only makes sense if the owner thinks the plant still has life left in the wholesale market. Texas will probably need many of the grandfathered plants to handle peak demand, primarily because the state still has dramatic swings between peak and off-peak consumption.

Representative Danburg voiced concern that as the heavier polluting, less efficient facilities move toward peak demand fulfillment, negative impacts on air quality would emerge. “That’s precisely when the ozone problems are at their worst,” she stated. Mr Schaeffer replied that the bill will result in fewer total emissions statewide, “but you may well have emissions that are centered in areas you wish they weren’t.”

FRANK McCAMANT, representing the Lower Colorado River Authority

Mr. McCamant offered a more conservative analysis of electric power generation capacity than previous witnesses. “And I guess on one point we’ll take a little bit of a contrarian role in terms of adequate generation reserves,” he told the committee. “We think if you look at the numbers that have come out between ERCOT and the PUC, you can make a case that generation reserves are going to be fairly tight over the next few years. That means there will be adequate generation, but should there be some disruption in terms of weather or outages, we could see ourselves in potential shortage situations.”

Mr. McCamant said reserve margins in the regulated market have been adequate, and margins in the restructured market should be also. The transition period bears close scrutiny. An important question remaining in the restructuring rulemaking is whether the state will allow market forces to determine reserve capacity or develop a mechanism to ensure reserve margins are built into the system.

Mr. McCamant also voiced concerns about the adequacy of natural gas distribution systems. He agreed with Mr. Schaefer’s earlier assessment that the total volume of gas consumed by generating facilities could remain relatively stable in the face of additional gas-fired generation construction because of greater efficiencies in combustion processes. However, he contended there will still be a peak delivery issue as electric load grows and new plants are hooked up to the natural gas pipelines. An additional technological concern is that newer plants require gas at a higher compression. Mr. McCamant said government intervention in the natural gas distribution system is unnecessary because the market will likely address those system constraints.

A related question about the use of natural gas springs from a growing dependence on it as a primary fuel source for electric power generation. Mr. McCamant told the committee, "As capacity grows and we become more and more dependent on gas capacity in the future, you begin to have to ask yourself about strategic issues of risk management. Do we really want to put all our eggs in one basket in terms of depending so heavily on gas? … Gas plants are wonderful. They are efficient. The prices are great right now. But that could change quickly depending on what happens in the fuel market."

Mr. McCamant further stated, "On the flip side of that, you have the risk issue of environmental legislation related to coal emissions and greenhouse gases, which could also completely flip the economics of how you dispatch those plants."

BILL BURCHETTE, representing, East Texas Cooperatives

The East Texas Cooperatives are dissatisfied with the renewable energy credit program proposed by the PUC because they cannot receive credits for hydroelectric resources currently under contract. The East Texas Cooperatives have been purchasing hydroelectric power from the federal government since the 1950s. Investor-owned utilities had the option to purchase this power then but chose not to because it was more expensive than coal-generated power. The cooperatives currently purchase 128 MW of hydro power generated in Texas and five other states through the Southwestern Power Administration, a federal agency. Mr. Burchette suggested the rule be modified to allow federal hydropower allocated to Texas to be included in the renewable energy credit program.

Appendix E:
SUMMARY OF TESTIMONY
July 11, 2000, Dallas

PAT WOOD, Chairman, Public Utility Commission of Texas

Chairman Wood said one of the toughest issues facing the PUC is developing the rule to choose between spending resources to retrofit and clean up existing fossil fuel generation facilities or retire and replace them with newer, more efficient models.

He noted the Dallas/Fort Worth Metroplex comprises roughly one fourth of the state's total electricity demand, about 15,000 MW. But with only 6,000 MW of generation capacity in the area, the majority of that power is imported from outside the four-county area. The good news is several new generation projects have been announced in surrounding counties outside the non-attainment zone. However, significant upgrades to the transmission system will be needed to move that power to customers in Dallas, Fort Worth and the mid-cities.

Chairman Wood stated that of the three issues affecting reliability — air quality, transmission and new plant construction — he was least worried about luring new power producers into the market. Since the restructuring of the wholesale market in 1995, 22 new merchant power plants have been connected to the grid statewide.

Transmission issues are the real problem, he said. It is very difficult to add new plants near the load centers in the Metroplex due to air quality problems. But it is also becoming increasingly difficult to bring power from outside the Metroplex as well because major transmission lines must be built through urbanizing areas.

JEFF SAITAS, Executive Director, Texas Natural Resources Conservation Commission

Mr. Saitas explained that the TNRCC's emissions cap and trade program will function very differently in the Dallas/Fort Worth area than other parts of the state because the number of point-source polluters is limited. Thus, the credits market will be severely constrained by an initial lack of participants. Whereas in the Houston/Galveston non-attainment area there are several industrial point-source emitters, in Dallas there are basically three: TXU, the electric generation facilities owned by the City of Garland and the electric generation facilities of the City of Denton. Mr. Saitas said there may be some smaller industrial facilities that can achieve some credits for sale through voluntary emissions reductions. An entity wanting to construct a new electric generation facility could conceivably purchase several of these smaller batches of credits to qualify the new facility.

An effective emissions cap and trade program is important to make sure that the most-cost effective emissions reductions proposals are implemented. He said the TNRCC would rely on the trading program to allow market mechanisms to make the best choices on reducing emissions, whether from 15 small business or one large industrial source.

Mr. Saitas acknowledged a certain level of apprehension from potential market participants that even if they conform to current rules and emissions standards, they have no guarantee that the rules would not be tightened later in such a way as to prohibit making a return on investment. Unfortunately, there is really no way to limit what future commissions, the Legislature or the Environmental Protection Agency (EPA) may do. Some uncertainty in the political environment is always assumed to exist.

In the Dallas area, it is particularly important to achieve a high level of emissions reduction from the electricity generating facilities because there so few other sources of nitrogen oxides (NOx). Aside from the electric utilities, Mr. Saitas said the other two major sources of NOx are automobiles and the four area airports. Federal law preempts the state from imposing limitations on airplanes as they take off and land. Therefore, the state has instead asked for a high degree of reductions from the driving public, including the purchase of more expensive fuel-efficient cars, the use of more expensive reformulated gasolines, annual emissions testing and a requirement to fix problems identified by those tests.

Mr. Saitas also noted that while Texas government has a decisive role to play in cleaning the air, there are many contributing factors over which the TNRCC has no control such as airline operations, international shipping, ports and interstate railroads. Mr. Saitas said his agency was working with the EPA to accelerate implementation of federal rules which will help Texas' efforts to clean the air in non-attainment zones, such as the introduction of reduced-sulfur diesel fuel.

BECKY WEBER, Environmental Protection Agency, Region VI, Dallas

Ms. Weber focused her testimony on the importance of emissions reductions from utilities in the Dallas/Fort Worth area. Although the State Implementation Plan (SIP) submitted by the TNRCC has been approved by the EPA, there is still some concern that the plan could later be deemed incomplete if TNRCC loses any of the court challenges to the SIP. The Dallas/Fort Worth plan lacks a "safety margin," meaning if any of the controls proposed in the SIP are rejected by the courts, then a substitute control with equivalent reductions must be included in the plan or it could be rejected by the EPA. A rejection of the plan at any point by the EPA starts the clock ticking on implementation of federal sanctions.

Mr. Saitas responded that he was confident that TNRCC would prevail in each of the pending suits. He said some controls designed for the Houston area could be inserted into the Dallas SIP if a court strikes a particular remedy from the plan. Mr. Saitas said TNRCC could keep the Dallas SIP in compliance with EPA parameters regardless of future court decisions.

TOM BAKER, President, TXU Electric & Gas

Mr. Baker said TXU's preferred option to comply with TNRCC air emissions standards in the Dallas/Fort Worth area is to retrofit existing generation units with technological modifications that achieve those standards. Mr. Baker said the cost of such modifications over the entire TXU service territory would be about $635 million. The cost of such modifications within the Dallas/Fort Worth non-attainment area would be approximately $333 million. Although those estimates represent a significant capital expenditure, Mr. Baker said the cost divides out to approximately $65 per kilowatt of capacity. He said that cost compares favorably to the $475 per kilowatt of capacity to construct new facilities.

Other alternatives mentioned by Mr. Baker included shutting down the plants, which he maintained would sacrifice reliability, and building new plants to replace existing units, an option he said is not cost-effective. A final option would be construction of an extensive new transmission network throughout the urban area, an idea sure to encounter public opposition and fail to protect system reliability.

Mr. Baker said his company has six generation plant sites for sale on the market. TXU has temporarily suspended the sale process due to uncertainty in the regulatory arena regarding TNRCC emissions standards and PUC rules governing the inclusion of environmental cleanup costs in stranded cost calculations.

Mr. Baker next addressed transmission issues, saying the siting process in metropolitan areas is very difficult, expensive and time consuming. Furthermore, such projects will only become more complicated as population density and power demands increase in the future. He commented the processes outlined in SB 7 for the ISO to participate in transmission planning have worked well.

TOMMY FORD, general contractor

Mr. Ford informed the committee that he has actively attended workshops and symposiums regarding the SIP for the Dallas area. A 40-year veteran of the construction industry, Mr. Ford said proposed SIP restrictions on morning construction activity would be harmful to his business and to the families of his employees. The loss of three morning hours cannot be made up in the afternoon due to heat-related safety concerns. Prohibitions on morning construction activity translate into a 16 percent wage reduction for his employees and up to a 25 percent reduction in his firm's business volume. Mr. Ford suggested other remedies to NOx problems exist, especially in the area of better traffic control.

JIMMY GLOTFELTY, representing Calpine Corporation

Mr. Glotfelty said Calpine was excited about participating in the Texas electric generation market, noting that the company had three generation plants in Texas when SB 7 was passed, compared to 11 now. Some problems exist, however, in the procurement of some essential components of generation facilities: natural gas, transmission access and emissions credits.

Mr. Glotfelty said Calpine has experienced difficulty establishing generation facilities in North Texas because the company could not secure a firm natural gas commitment from TXU. Mr. Baker responded that TXU offers gas contracts under curtailment standards set by the Texas Railroad Commission. Mr. Baker said TXU uses a fuel oil backup system during the winter peak gas demand months when tight gas supplies can occasionally force curtailment to electric generating facilities.

Mr. Glotfelty said uninterruptible gas service for power generators should be a policy priority, especially during summer months.

Mr. Glotfelty next addressed the lack of liquidity in the NOx trading program within the four-county Dallas/Fort Worth non-attainment area. Because TXU has not made the emissions reductions necessary to create credits, there are not enough credits available to construct generation in the Dallas area, he said. Furthermore, he stated, when these credits are created, the majority will be owned by TXU, restricting credit trading capability and hampering new generation construction.

Mr. Glotfelty suggested that the regulatory structure allow firm gas contracts in North Texas and the emissions program be expanded to allow more industries to trade credits within a larger geographic area.

RICK LEVY, representing the Texas State Association of Electrical Workers, AFL-CIO

Mr. Levy contrasted the relationship between safety, reliability and profit under the old regulatory system with current trends emerging in the restructured competitive market. "In the past, electric utilities knew that if they were reasonable in their expenditures and they ran a sound operation, they would receive a certain measure of profit. And so there was no inherent conflict between safety, reliability, and profit because it all went together. The problem is in the transition to a new economic environment . . . there has to be a trade-off between how much money is going to be spent to address reliability and how much profit there is because it is not all recoverable."

Mr. Levy stated that some utilities, such as Reliant Energy, have made strong commitments to hiring and training new workers. Others, such as TXU, have approached the transition period in a more problematic fashion. He stated that workforce reductions at large TXU generating facilities are at least partly responsible for increased power interruptions to customers in recent years. Mr. Levy said the Trading House Plant near Waco suffered a failure in May, causing the interruption of several major employers in the Tyler area. Ten years ago, that plant employed 20 mechanics to perform maintenance. "Now it's down to five and there is just no way that five mechanics can do the same level of maintenance on a facility that 20 can do," he said.

JIM MARSTON, Director, Texas Office of Environmental Defense

Mr. Marston said implementation of the provisions of SB 7 related to renewable energy generation looks very positive, so far. Addressing discussion in earlier testimony on the negative effects of regulatory uncertainty on financial markets and investors, Mr. Marston suggested the way to create certainty is for the Legislature to push for caps on mercury and carbon dioxide emissions alongside current mandated reductions in sulfur dioxide (SO2) and NOx. "If anything makes it uncertain what utilities will have to face, it's what they are going to have to do on mercury, what they are going to have to do on carbon dioxide, because the cost of those two things will likely dwarf anything that had to be done about NOx in this state. That's the real uncertainty in the market in my opinion and we need to settle that."

Environmental Defense filed joint comments with public power companies calling for the emissions cap and trade program to expand across the entire spectrum of polluters. "We think it will reduce costs for everybody," he stated.

Mr. Marston next addressed concerns about the quality of data used in the SIP model. In his organization's estimation, the numbers undercount the amount of pollution in the Dallas area and overcount the estimated pollution reductions. For example, he said the TNRCC used the national average ownership rates for sport utility vehicles (SUVs) and light trucks rather than calculating input specific to the Dallas area. "I'm sorry," he said, "but Dallas is the SUV and pickup truck capital of the country."

H said legal challenges to the process for including environmental cleanup costs in stranded cost calculations would likely lead to delays in retrofitting activity. He urged legislators to stand firm on the deadline for inclusion of the costs as outlined in SB 7. "I think there ought to be an understanding that if you file a lawsuit and you delay the time in which the permits take place, that's at your own peril. We gave them a guaranteed payment. Why they don't take our money I still don't understand. But we said if you will come forward now and make reductions that we desperately need, we'll guarantee that you get paid back. That was the deal. We'll pay you if you make the reductions early. But don't let them file suit, delay the time of those implementations or investments and then come back later and say, 'Let's move the date back because our lawsuits delayed the time for us to make those investments.'"

Appendix F:
SUMMARY OF TESTIMONY
August 22, 2000, Houston

PAT WOOD, Chairman, Public Utility Commission of Texas

Chairman Wood first drew a distinction between the Texas and California restructuring plans by noting that, although the two states began deregulating the wholesale electricity market at approximately the same time, California moved to retail competition much faster than Texas. The retail market restructuring process in Texas will span about seven years, compared with two in California.

Since the Texas wholesale power market was opened in 1995, 22 new plants representing about 5,700 MW have come on line. By comparison, California saw only 672 MW in new generation capacity during the same period. The two states are comparably sized power markets, and both have growing economies.

Chairman Wood said 15 new plants, totaling approximately 9,600 MW, are scheduled to come online by the time the retail market opens January 1, 2002. Thirty-three additional plants are in the planning stages. Chairman Wood said Texas is an attractive state for investment in new power generation because the overall economic climate is good and the siting and permitting process is relatively simple and fast compared to other states. It now takes 24 to 36 months in Texas to take a power plant from the chalkboard to operational status compared with up to seven years in California.

California's dependence on hydroelectric power also provides a constraint on its electricity supply during dry seasons. Because Texas uses so little hydroelectric power, the same concerns do not apply here. The vast majority of generating facilities in Texas use coal and natural gas, two resources in abundant supply without seasonal limitations. Chairman Wood advised the committee that Texas' power supply portfolio is inherently more stable than California's, a point generally overlooked by mainstream media.

Chairman Wood said a successful component of a workable power market is to maintain reserve margins sufficiently high that power generators cannot game the system to their advantage by charging higher spot prices for electricity when demand outstrips supply during peak usage. He said the ERCOT area of Texas has traditionally planned to maintain a conservative 15 percent or higher reserve margin. The latest round of additions to Texas-based generation capacity should place the reserve margin near 20 percent in the next few years.

There is some concern that the Texas market is becoming overbuilt and that will send signals to investors that the prospect for high profit margins in Texas is dwindling, so they will likely choose to construct new facilities in other states. Chairman Wood's question is whether the market will respond again when Texas' reserve margin falls back into the 10 to 15 percent range or if there should be some kind of requirement on power generators to maintain a reserve margin of 15 percent based on their rated output capacity. Chairman Wood indicated solutions other than a mandatory reserve margin are also being contemplated at this time by both PUC staff and ERCOT engineers.

Although the PUC has a comfortable outlook on how much power generation will be available for the Texas grid for the next few years, Chairman Wood said he is somewhat unsure of the impact competition will have on demand. Although demand has been steadily increasing at roughly 4 percent a year in the ERCOT area of Texas, and the state's strong economic climate will likely contribute to that trend, the Chairman indicated that open market experience in other locales, notably England, has led to a demonstrable reduction in demand as larger consumers of electricity modify methods and behaviors to respond to more accurate price signals from the restructured marketplace.

Chairman Wood next addressed the issue of rising natural gas prices, saying multiple effects would be felt in the restructured marketplace. Higher natural gas prices could be considered useful because they lower stranded costs. Because coal-fired and nuclear generating plants will compete with natural gas-fired plants, rising gas prices make coal and nuclear fuel more cost competitive. Increased gas prices will also have the counter-effect of universally increasing electric costs because so much of the state's base-line generation is exclusively natural gas dependent. Chairman Wood pointed out that these higher prices would be paid by consumers whether the state restructured the electricity market or not. Fuel costs are always passed on to the consumer.

One area of uncertainty caused by increasing natural gas prices is on the headroom for new competitors to enter the marketplace. The price to beat mechanism employed in SB 7 acts in two distinct ways on the marketplace. First, by discounting and then freezing rates at the start of competition, it serves as a price ceiling for consumers through 2007. Incumbent utilities would not be able to charge more than the price to beat, allowing for adjustments related to the costs of fuel. Second, the price to beat mechanism acts as a floor, by not allowing the incumbent utilities to charge less than the price to beat until they lose more than 40 percent of their residential ratepayer base or January 1, 2005, whichever occurs first. This has the effect of leaving "headroom" for new market entrants to sell power at a price less than the incumbent utilities are allowed to offer.

Chairman Wood offered two additional notes on building headroom into the Texas retail price structure. First, he noted the charges related to administration of the electric system are much higher in California than Texas. ERCOT's transaction fee is 15 cents per megawatt-hour (MWh), whereas the California ISO and Power Exchange (PX) fees add up to $1.20 MWh. A second difference between the headroom in Texas and California is the treatment of stranded costs. These costs will be collected in Texas over a period of 12 to 14 years, whereas California set a much more aggressive time line, with disastrous consequences for the retail market. The main impact of California's more rapid stranded cost repayment was to reduce the available headroom for new market entrants. He also reminded the committee that unlike in California, the threshold for removing price to beat protections in Texas does not depend on stranded cost recovery, but on market share dilution. "Their price protection disappeared altogether when the stranded costs got paid off. There's no nexus in my mind between price protection and paying off stranded costs," he said.

Chairman Wood next addressed issues related to transmission constraints in Texas. "We might have enough power statewide, but we've got to make sure that power is near where it needs to be for the customers," he said. The PUC empowered ERCOT to oversee long-range transmission planning for the whole grid, ensuring that large transmission projects affect several power plants, rather than taking them one at a time. Regional planning will be used to build transmission in advance of the need. Representative Madden voiced concerns that non-attainment issues would cause more transmission problems, and Chairman Wood agreed with that possibility. Restrictions on plant siting in the four-county D/FW Metroplex will lead to new plant construction farther away from electric load centers, leading to new transmission requirements. Representative Brimer asked if utilities in the suburban Dallas area would likely have to take property through eminent domain procedures to site necessary transmission lines through the urban residential areas. Chairman Wood said that scenario is likely.

Chairman Wood updated the committee on the progress of the ERCOT ISO in implementing the customer choice provisions to eliminate problems with slamming, such as those that occurred with telephone service deregulation. He stated the ERCOT system would automatically send a customer a postcard when it is notified of a request to change service providers. If the information is incorrect, the customer simply returns the card to ERCOT and the customer is returned to his or her previous retail electric provider (REP).

Although the $12 million allocated to the customer education plan should be sufficient to complete the task, Chairman Wood emphasized that the scope and nature of the project is such that the money could be spent easily and quickly without accomplishing the goals of the program. “This is an appropriate budget, but it puts the onus on us to make sure that we spend every penny and then multiply it by 10 in free media.” Chairman Wood said he expected statewide interest in electric utility restructuring to become more noticeable after the pilot program is well under way and becomes a more common topic of discussion.

Discussing technological innovations likely to play a role in how the Texas electric market is reshaped in coming years, Chairman Wood said, “The silver bullet for our state and for our economy is little bitty power.” So-called micropower will likely serve commercial clients in the 100 to 1,000 kilowatt range. Such enterprises range in size from a fast-food restaurant to a large supermarket. The technology has come a long way, he said, and the economics of small-scale power generation are getting better. “I think this is probably what your successors and mine are going to be talking about ten years from now.”

Chairman Wood said the PUC and TNRCC have been working very closely to make sure such innovation can thrive in the Texas market. Generally speaking, micro-generators are so small and efficient that they produce few emissions. They give a lot of power in the aggregate and they can give a very high-quality power. Many of the high-tech firms in Texas, such as silicon chip manufacturers, demand very high power quality. They depend on voltage being absolutely precise for all their instrumentation. Much of the self-generated power never gets on the transmission grid. It is consumed mostly on-site or nearby so it stays in the distribution network but is not transported long distances on the major transmission grid.

JEFF SAITAS, Executive Director, Texas Natural Resources Conservation Commission

Mr. Saitas updated the committee on the status of the State Implementation Plan (SIP) to meet Environmental Protection Agency (EPA) rules for air quality in the Houston/Galveston non-attainment area. Texas will submit its plan to EPA for approval in December 2000. The deadline to clean the air is November 15, 2007. With respect to the plan for the Houston/Galveston area, Mr. Saitas said speed limit reductions to 55 miles per hour are likely in much of the eight-county area. Other components of the plan include incentives for carpooling, local government energy efficiency efforts and expansion of Harris County's automobile inspection and maintenance program to the other seven counties in the non-attainment zone.

TNRCC has also proposed rules to ban the use of certain construction equipment during key ozone-forming hours. Mr. Saitas said construction activity is a "significant contributor" to the formation of ground-level ozone. Although industry participants informed the TNRCC that new, cleaner technologies are on the horizon, Mr. Saitas said the commission did not feel comfortable including new technology mandates in a rule because cleaner machines are not yet widely available. The construction ban is proposed to begin in 2005, and TNRCC will identify specific emissions reducing strategies in the interim. The ban will likely have a trade-off component, where high-emitting equipment — bulldozers, backhoes and other older, heavy equipment — cannot be used before a certain hour of the morning unless they are retrofitted with scrubbing technology to reduce emissions. Mr. Saitas made clear his policy preference that the ban be combined with incentives to eliminate the use of older equipment and supplant those pieces with newer, cleaner machines. This is especially important in the Houston area, where meteorological conditions reduce the effectiveness of later construction start times as an ozone-reducing strategy. During the worst parts of ozone season, lingering high pressure systems combined with coastal wind patterns simply recirculate the pollutants over the city to be warmed up and turned into ozone on the next day. "The preferred option there is that we actually move forward and find a program to actually physically and technically reduce the emissions. We don't need to be shifting them. We need to be taking them out of the air."

Other strategies mentioned by Mr. Saitas included the introduction of cleaner diesel fuels and accelerated purchases of new heavy-duty equipment and airport ground support equipment. Response from the City of Houston and Continental Airlines has been encouraging, and Mr. Saitas said an arrangement with Southwest Airlines would be completed soon.

Addressing Chairman Wood's points on micro-power, Mr. Saitas said the TNRCC is in the process of developing a standard permit for small distributed generation plants. This permit would simplify the process by pre-certifying certain classes of equipment at the manufacturer so that each piece of installed equipment does not have to be physically inspected. He added that the TNRCC would likely adopt rules to allow for check-ups to ascertain that the equipment is being maintained in such a way as to keep emissions within determined guidelines.

Mr. Saitas said there are federal issues associated with other pollutants that may have a cost impact on electric generation. Some degree of uncertainty still exists in the regulatory environment with respect to emissions standards for electric power generators, such as federally mandated reductions in mercury emissions from coal-fired plants.

JIM LESTER, representing air quality researchers at the University of Houston

Mr. Lester testified that the scientific community is "short on knowledge in terms of understanding the predictive nature of air chemistry." He said the Texas Air Quality Study 2000 currently underway in Houston is the largest study to date on the physics and chemistry of Houston air. However, he lamented that the data will not be collected, analyzed and available for incorporation into an area-wide plan until 2003, by which time a number of policies will already have been put in place in order to meet approaching policy deadlines. He termed this phenomenon the "crisis mode of management."

"Working in this crisis mode, I'm very concerned about unintended consequences of the regulations, in particular some [issues] about health problems that might arise," he said. "I worry about the safety of construction workers at night if they expand that time period. I am also concerned that we will have short-lived policies, that we'll be tweaking the thing frequently as we go along as the science comes into play."

With respect to the reliability of the air quality models used in the Houston area, Mr. Lester said, "These are the best models that we've got and we've got extremely good people working on them." However, the models fall short for the Houston area because they lack some data-specific entry point relevant to Houston's meteorology and climate. For example, small-scale sea breezes often cycle air over the city, out to the Gulf, and then back over the city and Gulf again until a strong weather front appears and moves the air out of the region. "So if you move the timing of the generation of NOx to the afternoon, it doesn't necessarily help move it out of the region. It can be with you the next day," he said.

Another point lacking in the model is in the accidental release of volatile organic compounds (VOCs), a primary ingredient in the formation of ground-level ozone in Texas, particularly in the Houston area. The high concentration of chemical plants along the coast leads to an increased risk of accidental releases of VOCs, which can preempt all the other chemical calculations made to achieve compliance with the EPA's ambient air quality standards. Population growth also represents a constraint on the model. "We're getting more people, more cars, new houses, new demands for energy. It makes it very hard to model."

Mr. Lester said he did not think the Houston area would be able to achieve compliance with the air quality standards by the 2007 deadline. The technological limits on industrial reduction were being pushed to the maximum, and it is not clear how effective such a push would be in the long term, especially given the likelihood of occasional accidental releases from Houston's heavy industrial base. Much of the possibility of meeting the eight-hour standard also rests with the weather. If a high pressure system parks over Houston on days with really high temperatures, no matter how effective the SIP, no matter what the rate of compliance, he said the city is still likely to exceed ambient air quality standards on a day like that.

Mr. Lester said he sees a lack of public involvement and education on air quality issues. "Without the regulatory hammer, in the environmental area, we have seen that public education has driven things like recycling, litter control and a variety of personal choices." There is no major effort to try to encourage people to shift from gas-powered equipment at their houses, change their driving habits or undertake any of a number of things that could reduce the emissions of NOx on a voluntary basis. Mr. Lester also said that strides are being made in the policy arena to retreat from a "command and control model" in which regulatory bodies make decisions without much public input up front. He said experience has shown that it makes more sense to involve stakeholders throughout the policy-making process.

GREGG COOKE and NED MEYER, Environmental Protection Agency

In response to Mr. Lester's critique of the urban airshed model used in the Houston area, Mr. Cooke explained it can be adjusted with new input. The cost of generating additional data will be born by the state, chamber of commerce, or other entity willing to finance such data collection. Mr. Meyer added that the only area of the country to produce major funding to update the model was California, both in the South Coast Air Quality Management District and in the San Joaquin Valley. Mr. Meyer said it would be prohibitively expensive to model an area as large as the eight-county Houston/Galveston non-attainment zone in the detail required to observe the effect of the land-sea breeze phenomenon mentioned by Mr. Lester. However, such modeling could be done just over the city proper, and then a less-expensive large-scale model would prove sufficient in the surrounding parts of the non-attainment area.

Mr. Cooke also noted that Tier 2 federal fuel standards for sulfur in gasoline take effect in 2004 and represent the biggest single reduction of NOx from mobile sources. Emissions from gasoline combustion represent 45 percent of all mobile emissions and 17 percent of total emissions. Without the adoption of cleaner burning fuels, Dallas and Houston would never make Clean Air Act standards, Mr. Cooke said. He said discussions with the TNRCC suggest they would prefer to speed up the implementation of new gasoline standards and diesel fuel standards. However, Mr. Cooke noted that industry opposition to the diesel fuel standards would likely be subject to lengthy litigation, and he predicted that a refined product may be even longer in coming to market.

ED FEITH, representing, Reliant Energy

Reliant Energy began a program to reduce NOx emissions in the Houston area in 1998. Reliant believes the plan is consistent with the requirements of SB 7, and it will be fully implemented by May 2003. Reliant's plan achieves an 88 percent reduction in NOx in the Houston area at a cost to the company of $512 million, Mr. Feith said. The draft Houston SIP requires a 93 percent reduction and other short-term limitations which present a problem for Reliant. It plans to ask TNRCC for some modifications to the draft rules to make them more workable.

Mr. Feith testified that each coal plant viewed as a candidate for environmental cleanup through the addition of retrofitted scrubber devices has different costs associated with the implementation of that technology. In the Houston area, such costs will average approximately $70 million per plant. At Reliant's lignite plant in East Texas, where the air quality standards are not as strict as those in the Houston SIP, the cost is approximately $26 million per facility.

Mr. Feith described the $512 million plan as a “no regrets” plan in which “every dollar and every project will be helpful. It will reduce NOx. It will improve air quality.” Mr. Feith said achieving an additional 3 percent NOx reduction beyond Reliant’s plan would cost an additional $200 million.

In response to questions from the committee, Mr. Feith said he could not reasonably estimate the threshold at which natural gas prices would make a new coal plant look attractive to investors. Such calculations are very complex and specific to the individual plant. Coal plants have certain regulatory disadvantages, longer construction times and larger physical plants that make them unattractive unless high natural gas prices appear to be a long-term norm.

STEVE KEAN, representing Enron Corporation

Mr. Kean agreed with Chairman Wood’s previous testimony that California’s problems are a simple issue of supply and demand. The market has responded with proposals to increase generation capacity, but California’s siting process is lengthy and difficult. When San Diego experienced dramatic price spikes, 10 utilities stepped in to offer long-term contracts to stabilize their price structure, but the rules of the game in California prevented San Diego Gas & Electric from stepping outside the California Power Exchange to take advantage of those offers. “So their customers continue to face volatile prices from the wholesale market even though the market was more than willing and able to provide a solution to that problem,” he said.

In Mr. Kean’s opinion, the deregulated portion of California’s market is working fine. It is the remaining regulations causing many of the problems faced in the summer of 2000. “Our customers, the people who signed up with us, the people who signed up, presumably, with other energy suppliers out there, they got a fixed price. It’s at a lower rate than what people are paying in California today. We went out in the market and hedged that position. In other words, we bought the supply that we needed in order to serve our retail customers.”

Mr. Kean also indicated that having access to a customer’s metering technology would provide the information necessary to help the customer reduce peak demand or apply energy efficiencies in ways to lower the total electric bill, which should be a higher concern than simply locking in a low rate. Mr. Kean updated the committee on Enron’s projects to contribute to cleaning Houston’s air. Enron has subsidized Metro transportation. Enron’s downtown headquarters building received an EPA

Energy Star award for energy efficiency. Enron is implementing pilot telecommuting programs for employees. The company's Bammell gas storage facility has been recently converted to use electric engines, reducing annual NOx emissions by 1,250 tons. Enron is taking advantage of SB 7 provisions calling for renewable energy capacity and is investing heavily in wind power.

Enron is also gearing up to trade emissions credits. "In emissions markets in the U.S., we are making markets in both SO2 and NOx. And the lesson there is that those programs, if they are properly constructed, do work," Mr. Kean said. "When you put market mechanisms in place, even to serve environmental objectives, they work. The dollars start to chase the absolute lowest cost solution to whatever the NOx problem is. And in that regard, I've got a couple of reservations about what we're dealing with here in the Houston/Galveston region. So far we're looking at a cap and trade program for NOx that is really limited to the eight-county area. It's been our experience that that is not a big enough area."

Mr. Kean also predicted that, although the reliability issue looks good today, at some point the Houston area is going to need new generation capacity and whoever comes into the market to supply that generation will need access to those credits. Today those credits are held by a handful of dominant market participants. Some possible solutions offered by Mr. Kean include expanding the eight-county area to include other upwind participants in the air pollution problem or setting aside allowances for new market entrants.

GEORGE BEATTY, representing the Greater Houston Partnership

Mr. Beatty noted that some counties included in the Houston/Galveston non-attainment zone do not feel they should be a part of cleaning up Houston's air, something they largely consider a Houston problem.

Whatever is done to clean the air, the Partnership is very concerned that regulations should not hinder the economic growth of the Houston area, or any of the non-attainment or near non-attainment areas in the state. Whereas with Reliant Energy, the SIP NOx reductions target about 60 EGFs, greater industrial restrictions would have an effect on more than 2,000 manufacturing facilities in the Houston area.

Mr. Beatty stated Houston businesses are willing "to do our share," but he said the federal government must do its share also by implementing Tier 2 fuel standards in a reasonable time frame. He also noted that the local community has no control over areas preempted by federal regulation, such as the Port of Houston, interstate trucking and George Bush Intercontinental Airport.

Appendix G:
SUMMARY OF TESTIMONY
September 26, 2000, Austin

CHARLES MATTHEWS, Commissioner, Railroad Commission of Texas

Commissioner Matthews addressed some of his concerns affecting the provision of natural gas to electric generation utilities and gas distribution customers. "The Texas natural gas industry must be healthy if Senate Bill 7 is going to be implemented successfully and electricity costs for Texas businesses and residential customers are to remain reasonable," he said.

The Commissioner informed the committee that Texas produces roughly one third of all natural gas in the United States and has proven reserves of nearly 40 trillion cubic feet (tcf). Some experts predict yet another 325 tcf of reserves remain to be developed. However, he noted overall production in the state has declined by 2 percent per year since the market peaked in 1972.

Natural gas storage levels are down from previous years nationwide. The Commissioner said Texas will likely follow that trend. With high demand and prices, there is little incentive for producers to store gas. Non-utility electric generators are placing significant demands on the natural gas market. In Texas, the peak period of natural gas consumption has switched from the traditional winter months to July and August when electric generation is running at full capacity. Mr. Matthews advised the committee that new gas-fired generation in Texas will further impact the natural gas industry. Even if higher market prices lead to increased exploration and drilling activities, he expressed concern that Texas may suffer a shortage of skilled field workers.

JOHNETTE HICKS, A. R. KAMPSCHAFER, JOHNNY RAYMOND and DAVID OJEDA, JR., representing the Texas Association of Community Action Agencies

The four panelists testified as a group on issues related to the sufficiency of funding and administration of the System Benefit Fund (SBF). Member organizations of the Texas Association of Community Action Agencies currently provide energy efficiency and low-income ratepayer assistance programs with a combination of funds from the federal government (disbursed through the Texas Department of Housing and Community Affairs) and funds contributed by investor-owned utilities. When retail competition begins on January 1, 2002, the community action agencies will no longer receive funds from utilities. These funds are to be replaced by an allocation from the SBF. The panelists expressed concern that weatherization programs may not be funded at the level required to deliver services to everyone requiring assistance. Mr. Raymond said the SBF commitment for community-based weatherization programs should be $17 million. He said his organization had to turn down 426 families for weatherization assistance last year due to lack of funds.

Mr. Kampschafer said his organization spends an average of $1,500 per house in funds from utilities to supplement federal funds. Currently, only 50 percent of his organization's low-income clients are eligible for utility funds because the current rules require recipients to live in the service area of the participating utility. Mr. Kampschafer said the SBF provision for low-income rate reductions is important, but weatherization is more important in his opinion. Total energy bill reductions of 25 to 50 percent are possible by reducing energy loss.

PUC Chairman Pat Wood informed the committee that the SBF rule has been published for public comment and would likely be adopted in December. Chairman Wood said the present ambiguity in determining the funding level for each of the programs receiving SBF money stems from uncertainty in the number of payments required to school districts to offset property value reductions resulting from electric utility restructuring. If only one payment were required to offset initial reductions in property value, then the SBF fee would provide sufficient revenue for all four programs to be fully funded. If multiple annual payments to school districts are required, then other SBF programs may be limited because the fee is capped by statute. Chairman Wood said SBF funds should be available to provide the $5 million in funds the community action agencies currently receive from investor-owned utilities. It is unclear if the SBF will initially be able to support expansion of community-based energy efficiency programs at the level requested by the panelists.

ROY BAKER, representing the American Association of Retired Persons (AARP)

Mr. Baker addressed several ongoing rulemaking proceedings at the PUC. He expressed AARP's preference that uniform rules be required in term of service contracts and billing procedures to eliminate confusion in the retail marketplace. He supported granting allowing all customers the right to cancel any contract without penalty with 30 days notice. AARP survey data suggests older citizens are not likely to switch providers if they think such a decision will risk service reliability. Mr. Baker also stated opposition to the release of customer specific data to retail marketers without prior written consent of the customer.

LARRY OEFINGER, representing the Texas Rural Electric Coalition (TREC)

Mr. Oefinger informed members of the committee that, although his organization views high distribution costs as a barrier to successful competitive market restructuring, TREC will not pursue an amendment to SB 7 in the 77th Legislature on this issue. He then stated that the issue will be studied more fully by the cooperatives, with the stated goal of identifying a fair formula to implement an Equal Access Fund. At issue is the higher cost per meter to distribute electricity in rural areas because the number of customers per mile of line is low. Mr. Oefinger said he believes the issue of high distribution costs in rural areas is something the Legislature must deal with in a future session.

JOHN W. FAINTER, President, Association of Electric Companies of Texas (AECT)

Mr. Fainter opened his comments by saying that the industry is confident it will be ready for the retail choice pilot project on June 1, 2001, and full competition on January 1, 2002. “While other states, namely California, have encountered problems this summer, we believe, based on the progress we have made to date, that Texas’ model for competition in the electric industry will ensure that everyone benefits. We believe the current framework will provide consumers with competitive and affordable prices, preserve and enhance reliability and ensure fairness to all customers.”

An issue of concern for AECT regards the authority to disconnect service for non-payment. The association agrees current rules prohibiting disconnection, such as during extreme weather conditions, should continue to be enforced. However, if REPs are not able to disconnect a customer for non-payment, then losses sustained by REPs for bad debt will significantly increase.

Mr. Fainter next addressed rulemaking proceedings relating to the Provider of Last Resort (POLR). He said AECT recognizes the important function of the POLR in an evolving retail market. However, in order for the market to be truly competitive, this "universal provider" must be able to charge prices commensurate with the risk involved in serving an unknown volume and type of customer. At this time, he said, selection of the POLR for each area is expected to be achieved by auction. If the auction process does not go well and the PUC is forced to designate a POLR, it should do so at a price that reflects this non-traditional service. Mr. Fainter said it is not unrealistic to foresee a situation where a company serving as POLR might suddenly find itself with thousands of new customers at a time when the market price is high and the price to beat is insufficient to cover costs. For this reason, AECT hopes the final POLR rule will recognize this potential problem and determine that the affiliate REP cannot serve as POLR in its own territory at the price to beat.

The final issue addressed by Mr. Fainter was the rate of return on regulated wires investments. "At the heart of our concern is the erroneous notion held by some stakeholders that the regulated wires company will be a less risky business than the historic integrated utility and, therefore, can be given a lower rate of return in order to attract new capital. We submit that this will not be the case. In fact, the uncertainty of a new and largely untested market supports our contention that the new electric market structure may be more risky for the regulated wires company. Competition from self generation and the evolution of distributed generation will certainly work to undermine the stability of the wires utility."

To attract capital into the transmission market, Mr. Fainter suggested the rate of return should be established at near-historic levels. The electric industry will continue to have high fixed operating costs and correspondingly high debt costs which must be supported by the regulated market with adequate return on capital, he said. The rate of return issue is linked to the ability of the transmission utilities to assure enough infrastructure exists to facilitate a robust competitive environment in which REPs can successfully operate.

CAROL BIEDRZYCKI, Director, Texas Ratepayer's Organization to Save Energy

When SB 7 was debated, Texas ROSE was one of the few groups to formally oppose restructuring the retail electric market. Ms. Biedrzycki expressed concern about developments in California and other states where supply has been short and prices have risen. She offered a series of recommendations that can be implemented without reopening SB 7. "We believe it would be premature to amend SB 7 because the PUC has sufficient authority under the bill to control unpredictable problems. Most importantly, if we did change SB 7, we would not know how to change it. The bill and the market design developed by the Commission must be tested before we will know how it should be changed," she said.

Ms. Biedrzycki said it has been difficult at times to coordinate all the activities planned by the agencies involved in SBF rulemaking procedures. She suggested maintaining the SBF as a general revenue fund is insufficient for the fund to function successfully. A general revenue account is too restrictive, dependent on biennial appropriations, and not allowed to carry over or accumulate funds. She said an amendment to HB 3084, 76th Legislature, is needed to delete the reference to the SBF in §9(b)(8) of that bill.

Ms. Biedrzycki said that all four programs supported by the SBF — the school funding loss mechanism, low-income rate reductions, low-income weatherization and customer education — should be fully funded and one should not be given preferential funding over another.

In particular, she was concerned that the low-income weatherization program may be viewed as a lower priority item in disbursement of SBF dollars. In addition to providing a safety net for low-income customers, she pointed out that many utilities are depending on savings from the weatherization program to meet the energy efficiency goals set forth in PURA §39.905. She also noted that the labor-intensive nature of the weatherization program served to provide a number of jobs for low-income people. She recommended a funding level for weatherization programs from the SBF of $17 million.

Ms. Biedrzycki said workable competition must include a market structure which convinces residential consumers to choose electric providers. "We are concerned about proposals made by the industry before the PUC that we believe will leave competition dead in its tracks for residential customers from the opening of the market. The industry is seeking changes that will confuse customers, increase their risk and inhibit competition." Specific problems include industry proposals to force customers to sign long-term contracts and charge penalties for breaking the contract.

Ms. Biedrzycki said electric competition has been minimal in states that have restructured, especially in the residential portion of the markets. In California, only 1.8 percent of residential customers have switched. In Massachusetts, only 0.1 percent of residential customers have changed electric companies. Switching is usually concentrated in high-cost areas, she said.

"We support one set of customer protection standards. If terms of service are standard and the same as they are today, consumers can focus on price and make informed, confident decisions. When confronted with complicated contracts and a lot of fine print, most consumers will choose to do nothing. Competition could stop before it starts," she stated.

Ms. Biedrzycki said electric service providers should never be able to block a customer's switch and supported Mr. Baker's testimony that any customer should be able to cancel a contract without penalty with 30 days notice. "A customer's right to buy from another company is a powerful consumer protection. Tying customers into long-term contracts even if they are not satisfied with the service creates a captive market with no regulation," she said.

JANEE BRIESEMEISTER, representing Consumers Union

Although many of the problems experienced in California's transition to a restructured marketplace are the result of policies unique to that market, Ms. Briesemeister said there are systematic weaknesses in restructuring utility markets that have not been adequately addressed anywhere in the country. These include transmission systems to support a competitive market, increased corporate merger activity which reduces competition, the inability of small consumers to react to changes in price due to lack of information and inflexible demand, and the uniqueness of electricity as a commodity, such as its inability to be stored or substituted and the long lead time required for construction of facilities.

Ms. Briesemeister suggested market power remains a concern in the Texas generation market. The requirement that no generating company may own more than 20 percent of generation capacity is a feature unique in Texas law, designed to address market power concerns. However, market power can manifest itself in numerous other ways. For example, in California no generator is close to owning 20 percent of the market, yet several agencies are examining possible market power abuses there. Consumers Union welcomes the PUC's increased emphasis on monitoring these developments through the creation of a Market Oversight Division.

Consumers Union and others have been frustrated by the level of activity taking place outside the PUC at ERCOT and the difficulty in participating effectively at ERCOT. A lack of accountability of the ISO was one of the criticisms of the California market model included in a recent report prepared for Governor Gray Davis. Until a few months ago, Ms. Briesemeister said, ERCOT board meetings were closed to the press and the public.

Ms. Briesemeister also stated she was disturbed that the issue of reserve margins remains open in the ERCOT protocols. One side in the debate would have ERCOT set a reserve margin, others would let the market handle the reserve issue. ERCOT has traditionally required a reserve margin, a critical feature when unplanned outages occur. Reserves come into play when electricity is needed most and the opportunity to exercise abusive market power is greatest. "We do not endorse letting the market determine how reserves are handled," she said. "Obviously, there is a cost to acquiring a reserve margin, but there is also a cost to having no reserves."

Ms. Briesemeister raised concerns about the creation of Qualified Scheduling Entities (QSEs) through the ERCOT implementation process. These entities are not included or even contemplated in SB 7, she said. These entities have been created by ERCOT, not the PUC. Their role is to schedule power for competitive retailers. There has been some discussion that some entities intending to become QSEs do not intend to serve retailers serving residential customers, which creates another barrier to REPs wanting to serve residential customers. We recommend the PUC require QSEs to serve all types of loads. Because QSEs will charge for their service, additional cost will be added for market participants. The QSEs' fee schedules should be reviewed and approved by the PUC. Also, QSEs can be generators or affiliates of generators. The potential for anti-competitive conduct due to the affiliate relationship between a retailer and a wires company is precisely what the Code of Conduct in SB 7 addressed. The PUC should adopt a similar code of conduct for QSEs.

Ms. Briesemeister said stranded costs are the biggest issue affecting headroom for competition. The debate over stranded costs has shifted dramatically in just the past few weeks. Instead of debating how high the stranded costs are, customer groups and utilities are now arguing over how much of the already collected stranded costs the utilities should return to their customers, due in large part to the impact of high natural gas prices on the market. Consumers have already made a significant down payment on stranded costs through securitization, accelerated depreciation and the shifting of costs from generation assets to the transmission and distribution system. A top priority for Consumers Union will be to make sure consumers get the benefits of high gas prices reflected in low stranded costs. Where there is over-recovery, consumers must benefit. Otherwise, the high prices for generation will erode headroom for competition. If consumers and competitors do not receive the benefit of these high generation prices through reduced stranded cost charges, there will be little room for competitors to enter the market.

Ms. Briesemeister said the use of minimum term contracts with penalties for switching providers discourages consumers from shopping around. "We fear contracts could contain anti-consumer provisions in fine print or lock consumers into bad deals as the market opens, depriving them of benefits as competition develops," she said. The potential benefit of a contract is the guarantee of stable prices. However, Ms. Briesemeister said current proposals on the table are all one way in that they involve penalties for consumers who break the contract, but none for the REP. The REP could change the terms and conditions of the contract, or exit the market, with notice to the customer only. Yet the customer could not exit the contact without incurring a financial penalty. "Large corporations hire attorneys to read contracts and negotiate deals for telephone and electric service. But consumers should not have to hire a lawyer to read a contract prior to purchasing electric service from a new competitor. It is the PUC's job to make it easy for consumers to shop based on price and service by adopting a standard set of customer protections equivalent to those enjoyed today. If contracts are permitted they should be standardized, reviewed by the PUC and there should be equivalent penalties for both parties for breaking the deal."

TAB 15

ercot

History

ERCOT Celebrates 75 years as Interconnected System, 20 Years as ISO

2016

Record Demand, Wind Generation Continue

Systemwide demand topped 71 GW, reaching 71,110 MW at 5 p.m. on Aug. 11. Weekend demand also set a new record, at 66,921 MW on Sunday, Aug. 7, at 6 p.m. Monthly demand records in September and grew to 66,853 MW on Sept. 19 and 59,848 MW on Oct. 5.

Wind generation also continued to break records in 2016 as installed capacity grew to more than 17,000 MW by November. Instantaneous output set three new records, peaking at 15,033 MW on Nov. 27. The percentage of load served by wind also set three new records in 2016, topping out at 48.28 percent on March 23.

Grid-scale Solar Emerges

Installed capacity of grid-scale solar nearly doubled in 2016, from 288 MW to 554 MW, and ERCOT put a new solar forecast in place to support reliable integration of this emerging generation resource.

New CEO Takes the Helm

Former ERCOT General Counsel Bill Magness became ERCOT's new president and CEO on Jan. 1.

2015

Doggett Retires

ERCOT's longest-serving President and CEO Trip Doggett retired on Dec. 31, after more than six years in the role (including eight months as interim).

Record Demand Returns to Growing Region, Wind Continues to Grow

System-wide peak demand hit its first new record since 2011, at 69,877 MW on Aug. 10, and eight new output records for wind generation. Wind generation output peaked at 13,883 MW at 11:07 a.m. on Dec. 20. At 3:05 a.m. that same day, wind served up to 44.7 percent of load.

2014

Wind Output Tops 10,000 MW

Wind generation output topped 10,000 MW on March 26, with 1,433 MW coming from Gulf Coast area generation facilities and most of the remainder coming from the West Texas region.

2013

Competitive Renewable Energy Zones are Completed

Construction of about 3,600 miles of transmission lines is completed, fulfilling a goal set by the Texas Legislature in 2005 and enabling movement of more than 18,000 MW of primarily wind generation from the West Texas and Panhandle regions to more populated regions of the ERCOT grid.

2012

ERCOT Launches First-ever Mobile App

ERCOT introduced its Energy Saver mobile app, which provides system conditions, pricing information, conservation information and more to subscribers.

2011

New Records for Summer, Winter and Wind

ERCOT set a new all-time summer peak demand of 68,867 MW on August 3, in addition to breaking monthly demand records in February, May, June, July September and December. A new winter peak demand record of 57,315 MW was recorded on Feb. 10. ERCOT also hit an all-time high for wind output on Oct. 7, when wind generation reached 7,400 MW —more than 15 percent of the load at the time. Installed wind capacity surpassed 9,600 MW in 2011—maintaining ERCOT's lead as the top wind producer in North America.

2010

Solar Generation Connects to Grid

Blue Wing 1, the first utility-scale solar facility in the ERCOT region, began operations in Bexar County.

Nodal Market Launches Dec. 1

On December 1, ERCOT launched a comprehensive nodal market featuring locational marginal pricing for generation at more than 8,000 nodes, a day-ahead energy and ancillary services co-optimized market, day-ahead and hourly reliability-unit commitment, and congestion revenue rights.

Peak Demand Exceeds 65,000 MW

On August 23, ERCOT recorded a new record high peak demand of 65,776 MW of power.

Doggett Named CEO

On May 27, former chief operating officer and interim CEO Trip Doggett was officially named CEO.

2008

Nodal – New Go-Live Date

A new go-live date of December 2010 was announced for the nodal market implementation. Almost 6,600 miles of transmission improvements completed since 1999, and approximately 39,000 MW of new generation added since 1996.

2007

New Wind Record

A record 3,220 MW of wind generation was added to the ERCOT grid for a total of 8,005 MW, maintaining ERCOT's lead as the top wind-producing state.

Retail Market Grows

Five years after launching the retail market, 46 percent of residential customers had switched from the incumbent utility.

Kahn Named CEO

On May 31, Bob Kahn, former Austin Energy deputy general manager, was named CEO.

2006

Texas Moves Ahead of California

Texas moved ahead of California as the top wind-producing state.

Energy Usage Hits 62,339 MW

On August 17, a record high demand of 62,339 megawatts of power was used.

Nodal Market Protocols Approved

On April 5, the PUCT signed an order approving the stakeholder-developed protocols for the nodal market, with an implementation date of January 1, 2009.

2005

One Fourth of Residential Customers Switched to Competitor

More than 2 million total customer switches to a competitive retail provider had been completed. Almost one-fourth of residential customers had switched to a competitive retail provider, in addition to 29 percent of small non-residential customers and 72 percent of large non-residential customers.

PUCT Receives Draft Nodal Protocols

In September, the Texas Nodal Team submitted draft nodal protocols to the PUCT.

2004

First Cooperative Joins Competitive Market

Nueces Electric Cooperative (NEC) became the first cooperative or municipal utility to "opt in" to participate in the Texas competitive electricity market. NEC enrolled its first customer on September 1.

Major System Upgrade

In August, ERCOT launched a major transaction system upgrade, culminating a massive two-year project and representing the largest upgrade of the electronic transaction system since the retail market launch. Switching transactions averaged 38,000 per month and 9,000 per day during 2004.

2003

Nodal Market Design Project Begins

In September, as part of Project 26376, the PUCT ordered ERCOT to develop a nodal wholesale market design, with the goal of improving market and operating efficiencies through more granular pricing and scheduling of energy services.

2002

Retail Electric Market Opens, Enabling Customer Choice for 6.5 Million

On January 1, ERCOT launched the competitive retail electric market—on time and on budget—allowing individuals and corporations in most cities to choose power suppliers. SB 7 applied specifically to investor-owned utilities, enabling customer choice for 6.5 million, but allowed municipal utilities and electric cooperatives (approximately 24 percent of the ERCOT load) to decide if they wanted to opt to participate in competition.

2001

Ten Control Centers Merge into One Control Center

On July 31, the existing 10 control areas in the ERCOT region were consolidated into a single control area.Wholesale power sales between electric utilities began to operate under the new electric industry restructuring guidelines, including centralization of power scheduling and procurement of ancillary services to ensure reliability. Commercial functions were centralized to facilitate efficient market operations, including meter data acquisition and aggregation, load profiling and statewide registration of retail premises to facilitate switching by customers between competitive electricity providers.

2000

Market Protocols Developed through Stakeholder Collaboration

From 1999 to 2000, ERCOT sponsored a stakeholder process to address how ERCOT's organization would administer its responsibilities to support the competitive retail and wholesale electricity markets while maintaining the reliability of electric services. In thousands of hours of meetings and mark-up sessions, the stakeholders or market participants worked together to develop new ERCOT protocols, which are the rules and standards for implementing market functions regarding: energy scheduling and dispatch, ancillary services, congestion management, outage coordination, settlement and billing, metering, data acquisition and aggregation, market information systems, transmission and distribution losses, renewable energy credit trading, registration and qualification, market data collection, load profiling and alternative dispute resolution.

1999

Legislature Votes to Deregulate Retail Electric Market

On May 21, the Texas Legislature passed Senate Bill 7 (SB 7) which required the creation of a competitive retail electricity market to give customers the ability to choose their retail electric providers, starting January 1, 2002.

1996

ERCOT Becomes First ISO in the US

On August 21, the PUC endorsed an electric utility joint task force recommendation that ERCOT become an Independent System Operator (ISO) to ensure an impartial, third-party organization was overseeing equitable access to the power grid among the competitive market participants.
This change was officially implemented September 11, when the ERCOT Board of Directors restructured its organization and initiated operations as a not-for-profit ISO, making it the first electric utility industry ISO in the United States.

1995

Commercial Wind Generation Begins

The Texas Wind Power Project, the first commercial wind farm in Texas, began operations in Culberson County.

Texas Legislature Votes to Deregulate Wholesale Generation

The Texas Legislature amended the Public Utility Regulatory Act to deregulate the wholesale generation market. The Public Utility Commission of Texas (PUC) began the process of expanding ERCOT's responsibilities to enable wholesale competition and facilitate efficient use of the power grid by all market participants.

1986

ERCOT Opens First Office

ERCOT opened its first office in 1986 and hired four full-time employees.

1981

ERCOT Assumes Central Operating Coordinator Role

A. 926

TIS members transferred all operating functions to ERCOT, and ERCOT became the central operating coordinator for Texas.

1970

TIS Forms ERCOT to Comply with NERC Requirements

TIS formed the Electric Reliability Council of Texas (ERCOT) in 1970 to comply with North American Reliability (NERC) requirements. ERCOT was staffed by two retired employees from utilities.

1941

Utilities Band Together to Aid War Effort

At the beginning of World War II, several electric utilities in Texas banded together as the Texas Interconnected System (TIS) to support the war effort. They sent excess power supplies to industrial manufacturing companies on the Gulf Coast to provide reliable electricity supplies for energy-intensive aluminum smelting. Recognizing the reliability advantages of remaining interconnected, the TIS members continued to use and develop the interconnected grid. TIS members adopted official operating guides for their interconnected power system and established two monitoring centers within the control centers of two utilities, one in North Texas and one in South Texas.

TAB 16

ELECTRICITY PRICES IN TEXAS

tcaptx.com/reports/snapshot-report-electricity-prices-texas-april-2018

A Snapshot Report
2018 Edition

Executive Summary

Although average residential electric prices in areas of Texas with retail electric competition have remained consistently higher than prices in deregulation-exempt areas — the annual percentage price gap between these two areas has dwindled to the narrowest point ever.

Moreover, average residential electricity prices in areas of Texas with retail electric competition have declined during a recent 10-year period, while average prices in deregulation-exempt areas have increased.

Taken together, these developments suggest that the 16-year-old deregulated retail electric market in Texas is delivering some of its best results so far for residential consumers.

However, not all the pricing trends are positive for Texans living in areas with retail electric competition, also known as retail electric deregulation.

For instance, average residential electricity prices have remained consistently higher in those areas, as compared to prices in deregulation-exempt areas. This has been true for every year for which data exist to conduct this analysis.

Texas implemented its retail electric deregulation law in 2002. Under it, Texans in areas such as Houston and Dallas can choose among different electric providers. In other areas that remain exempt from the deregulation law residents receive service from a single provider.

This Snapshot Report on Electricity Prices, an update of similar analyses released by the Texas Coalition for Affordable Power, compares residential electricity prices in both deregulated areas of Texas and those in areas exempt from deregulation. It includes long-term pricing information, information about non-by-passable charges assessed by Texas wires utilities and a review of pricing trends nationwide.

About the Texas Coalition for Affordable Power

Unlike the sponsors of other reports about the state's deregulated power market, TCAP derives no profit from selling electricity. Instead, the more than 150 political subdivisions that comprise TCAP purchase electricity for their own governmental needs. TCAP understands how high-cost power can cause businesses to relocate out of state, and can place heavy burdens on home consumers. TCAP wants what all Texans want: an affordable and reliable supply of power and a vibrant economy.

Major findings include:

- Texans consistently have paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation. This annual trend began during the very first year of the retail electric deregulation law in Texas, in 2002, and has continued through 2016, the last year for which data are available to conduct this analysis.
- However, *the gap* in residential electricity prices between areas of Texas with deregulation and areas without it has dwindled precipitously over the last 10 years — and the percentage gap now stands at its narrowest point since Texas began retail electric deregulation.
- Average residential electric prices in deregulated areas have declined by nearly 19.6 percent during the 10-year period from 2007 through 2016. By contrast, average residential prices in areas exempt from deregulation during the same period have increased by nearly 6.1 percent.
- Average residential prices have increased in both deregulated areas and deregulation-exempt areas over the longer term since the implementation of deregulation in 2002. However, the rate of increase has been slightly lower in deregulated areas. The percentage increase in areas with deregulation was 36.48 during that period; the percentage increase in areas without deregulation was 36.95.
- Texas continues to fare well in comparison to other states with deregulated retail electric markets. Average prices for deregulated electricity in Texas have increased at the third lowest rate among 15 states with deregulation.

- Texans now can find many low-priced individual deals inside deregulated areas that beat prices commonly paid in deregulation-exempt areas. These comparatively low-cost competitive deals are more numerous than in previous years.
- Increases in the charges assessed by the state's major regulated transmission and distribution utilities have outpaced inflation over the last 15 years. Although transmission and distribution rates are regulated, these increases nonetheless contribute to prices in deregulated areas of the state.

Residential Price Increases

Exhibit 2: For 15 Deregulated States, Including Texas 2002-2016

Source: United State Energy Information Administration Electricity Data Broswer

The Analyses

Under the Texas electric deregulation law, consumers in Houston, Dallas, Fort Worth, Corpus Christi and surrounding areas can choose among different retail electric providers. These providers compete for customers by offering different terms of service and prices. Many other parts of the state remain exempt from this competitive system. Exempt areas include those served by municipally-owned utilities (such as in San Antonio and Austin) and those served by electric cooperatives. Also exempt from retail electric deregulation are investor-owned utilities operating outside the area covered by the state's primary power grid, known as the Electric Reliability Council of Texas.[1]

The existence of this bifurcated electricity system — one in which some Texans receive service from competitive electric retailers and others do not — provides a unique opportunity to compare pricing outcomes. The Texas electric deregulation law was adopted in 1999 with the promise that it would lower rates. But as this analysis shows, the results have been mixed.

About the Report

This report includes five discrete analytical sections:

The benchmarking analyses and the "Lost-Savings" analysis employ data obtained from the United States Energy Information Administration. The long-term benchmarking and Lost-Savings analyses compare pricing outcomes inside and outside deregulated areas of Texas and begin with 2002 — the first year of retail electric deregulation in Texas — and continue through 2016. These analyses do not extend to 2017 and 2018 because the necessary US EIA data for those years are not yet available.

The Recent Prices section samples more up-to-date individual offers in deregulated areas around Houston and Dallas. Readers can find these pricing samples from 2018 rate surveys conducted by the PUC.

The section entitled "Transmission and Distribution Charges" includes rate comparisons from two separate years (2003 and 2018) for the state's two largest monopoly wires companies, Oncor and CenterPoint. Readers can find the underlying data for this analysis on the PUC website.

For readability purposes, this report employs certain words and phrases interchangeably to refer to areas served by competitive retail electric providers. These words and phrases include "areas with retail electric competition," "areas with retail electric deregulation," "competitive areas" and "deregulated areas." Unless otherwise noted, references to electricity prices are for residential customers.

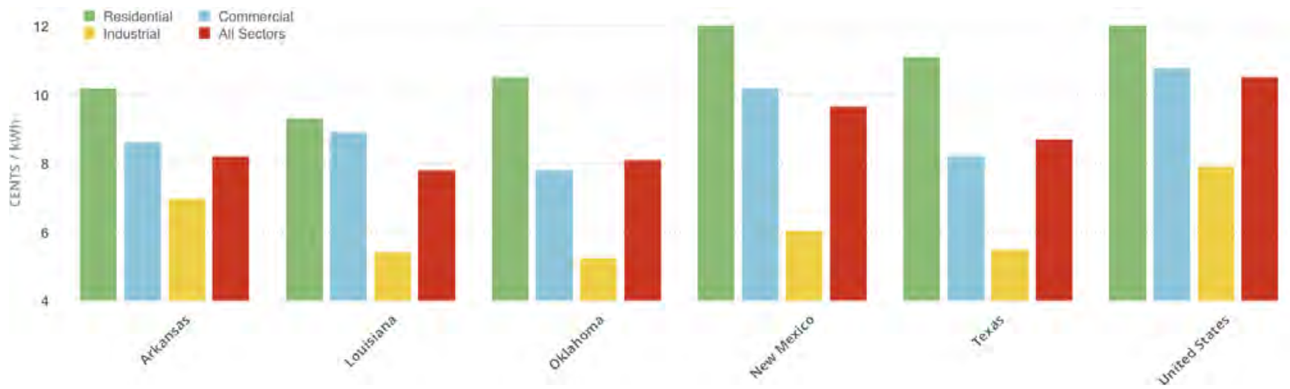
[1] See The Story of ERCOT, Februrary 2011

Background History

Texans enjoyed residential electricity rates below the national average for many years prior to the adoption of the retail electric deregulation law in 1999.[2] That trend flipped shortly after the law took effect, with average residential prices statewide rising above the national average in 2003 and remaining above the national average until 2011. [See Exhibit 8]

Average Electricity Prices 2017

Exhibit 3: Texas and Adjoining States



Source: United State Energy Information Administration & US EIA Electricity Data Browser

Some observers have said that the increase in statewide electricity prices after the deregulation law took effect is not related to the law, *per se*, but rather to an increase in natural gas prices. This is because natural gas prices are closely linked to wholesale electricity prices, and natural gas prices hit historically high levels after deregulation.[3]

However, fluctuations in natural gas prices alone cannot explain the historic disparity between average electricity prices inside and outside deregulated areas of Texas, particularly during the early years of the law. For every year for which data exist with which to conduct this analysis — that is, between 2002 and 2016 — average residential prices in deregulated areas of Texas have been higher than average prices in deregulation-exempt areas. [See Exhibit 1].

Moreover, average residential prices in Texas, statewide, remained below the national average for at least a decade prior to the implementation of retail electric deregulation in 2002. Shortly after the law took effect, in 2003, only residential prices in deregulated areas shot above the national average and for most years stayed there. Electric prices in areas exempt from deregulation continued below the national average after 2002 and, with the exception of one year, have stayed below it for the entire history of deregulation in Texas.

This report quantifies this gap in deregulated prices and those charged in areas exempt from deregulation through “lost savings” analyses found in Exhibit 4 and Exhibit 5. These analyses calculate the imputed savings that would have accrued to Texans living in areas of Texas with deregulation had they instead paid the same average prices as Texans living in areas exempt from deregulation.

Customer confusion about retail electric shopping, the details of rate offers and other aspects of the deregulated market may have contributed to historically higher prices there over time. Other contributing factors may include the cost of multi-million dollar marketing campaigns by some retail electric companies and increasing rates charged by monopoly transmission and distribution utilities. These “wires” rates comprise a growing portion of home electric bills in competitive areas.

However, the price gap between areas of Texas with electric deregulation and deregulation-exempt areas continues to narrow. In percentage terms, this differential was smaller during 2016 than during any other year since the beginning of retail electric deregulation in 2002.[4]

It remains unclear whether the gap has disappeared completely in 2017 and 2018 — or whether the trend of higher prices in deregulated areas has continued — given the unavailability of necessary data from those years for which to conduct the analysis.[5]

However, a survey of recent competitive pricing offers indicates that many such offers in Houston (the state's largest city operating under the retail electric deregulation) beat the price of electricity in San Antonio (the largest city in Texas exempt from deregulation). [See Exhibit 12 and See Exhibit 13]. The number of such offers that meet or beat prices in deregulation-exempt areas appears to be on the rise.

[3] Public Utility Commission Docket 40000, Item No.447, page 1, Memorandum to Commissioner Kenneth W. Anderson, Jr. from Chairman Donna Nelson.

[4] In absolute terms, as cents per kwh, the gap was smaller in 2002.

[5] In contrast to findings in this report, Rice University researchers, in a corrected May 2017 report, concluded that the average price paid for electricity by residential consumers in competitive areas during 2016 was "roughly equal, in the aggregate" to the average price paid by Texans in non-competitive areas. These findings appear to have been extrapolated from PUC website data, while TCAP's findings are extrapolated from US EIA data. For more about the use of US EIA and PUC Data, see the note below.

About US EIA Data and PUC Data

This analysis employs data collected by the United States Energy Information Agency, which is the statistical and analytical arm of the U.S. Department of Energy. U.S. EIA data is known to be impartial, and is widely cited by economists, scholars, industry experts, the news media and governmental agencies — including the Public Utility Commission of Texas.

The consistent manner in which the agency conducts its calculations across all 50 states allows analysts to make apples-to-apples market comparisons. How does the U.S. EIA calculate prices? First, it gathers both revenue and sales data from electricity providers in a given region. It then derives a kilowatt hour or megawatt hour price by dividing revenues in that region by the amount of energy sold there.

TCAP has employed granular U.S. EIA data to calculate average electricity prices inside and outside deregulated areas of Texas, inside and outside areas served by the state's principal power grid (the Electric Reliability Council of Texas) and for the state's residential, commercial and industrial customers.

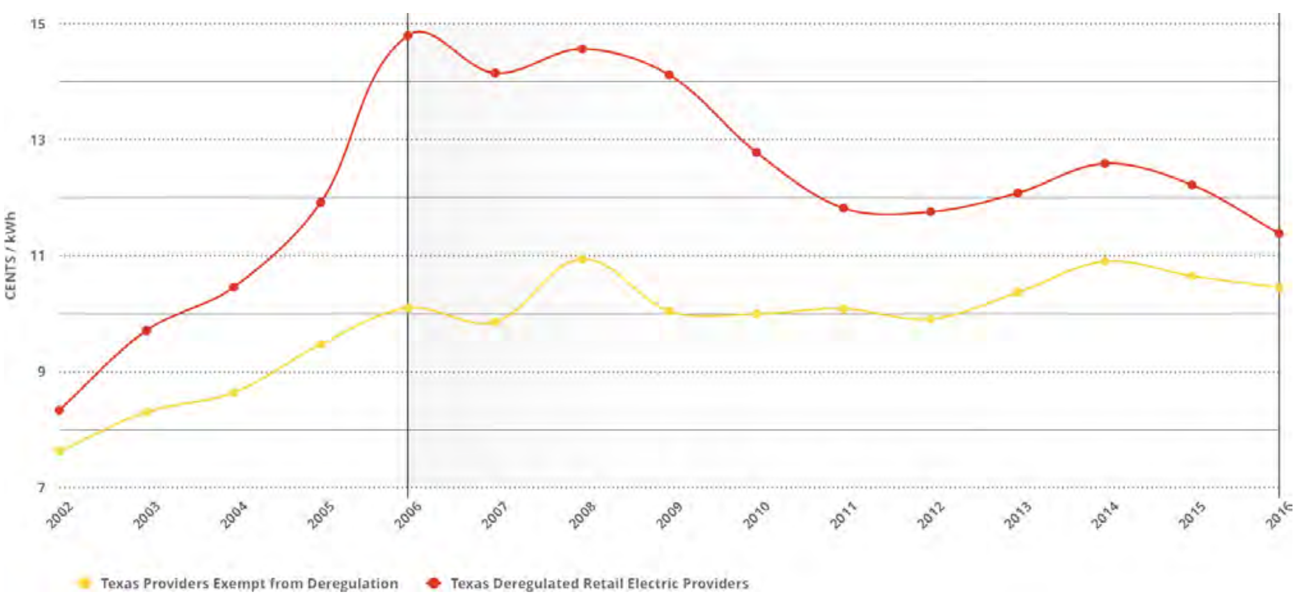
Employing U.S. EIA data in this fashion allows for calculations of average prices of consumed electricity, as opposed to average prices of individual offers made by electric companies. This distinction is important. The problem with averaging offers by electric companies — but without an understanding of how many customers take each offer — is that such an analysis can lead to conclusions that bear little resemblance to actual market outcomes. For instance, while it may be true that many low-cost offers are available in a given area, it may also be true that most Texans living in those areas do not or cannot avail themselves of those low-cost offers because of restrictions in their existing electricity contracts, or for a number of other reasons.

However, an examination of individual offers is nonetheless useful to gain a sense of commonly available electricity prices in deregulated areas, including prices found in fixed-rate and variable-rate deals. This report examines such individual pricing offers, as included in rate surveys conducted by the Texas Public Utility Commission.

This report also examines charges by the state's two largest transmission and distribution providers, as posted on the PUC website. Transmission and distribution charges by "wires" utilities are non-bypassable, meaning that these charges are imbedded in electricity prices paid by all consumers in the utility's service territory, regardless of the retail electric provider that the consumer selects for service.

Average Residential Electricity Prices

Exhibit 1: Inside and Outside Deregulated Areas of Texas



Average residential electric prices in deregulated areas of Texas consistently exceed average prices in deregulation-exempt areas. This was true in 2002 — the very first year of the deregulated retail electric market — and true in 2016, which was the last year for which data exist to conduct this analysis. It also has been true for every year in between.

The gap in residential electricity prices in deregulated and non-deregulated areas of Texas widened precipitously during the early years of the new market, but then narrowed by a similarly dramatic fashion in recent years.

During the first five years of deregulation in Texas — from 2002 through 2006 — prices in areas that remained deregulation-exempt increased by 32.3 percent. However, prices increased at more than twice that rate in deregulated areas, by 77.5 percent.

During the subsequent 10-year period, from 2007 through 2016, average residential prices in deregulation-exempt areas increased by 6.1 percent. However, they *decreased* by 19.6 percent in deregulated areas.

In 2016, the last year for which data exist to conduct these benchmark analyses, the difference in deregulated and non-deregulated residential prices narrowed to its smallest point on record: to 8.8 percent. However, the second smallest gap was observed in 2002, the first year of the deregulation law, when the difference stood at 9.2 percent. In absolute terms, as a difference in cents per kwh, the gap was smaller in 2002 (.7 cents) than it was in 2016 (.9 cents).

Source: United State Energy Information Administration & US EIA Electricity Data Browser

THE FINDINGS

Section 1: Long-Term Trends Benchmark Analysis

- Texans living in deregulated areas of the state have paid higher average rates for residential electricity than Texans living in areas exempt from deregulation. This is true for 2002 through 2016 — that is, for every year for which U.S. EIA data exist to conduct this analysis. [See Exhibit 8]. Over those years, average residential prices in deregulated areas have been between 9.2 percent (2002) and 46.5 percent (2006) higher than average prices in deregulation-exempt areas.
- From 2002 through 2016 average residential electricity prices increased at a greater rate at the national level than prices increased in both deregulated and deregulation-exempt areas of Texas. During that period, the percentage increase in average residential prices in deregulated Texas was very similar to the percentage increase in deregulation-exempt areas of Texas — 36.48 percent to 36.95 percent respectively. [See Exhibit 8].
- A shorter view — that is, confining the analysis to the 10 years from 2007 through 2016 — reveals that average residential prices have dropped in deregulated areas by 19.58 percent, while they have increased in areas exempt from deregulation by 6.05 percent. [See Exhibit 1].

- When it comes to residential pricing trends, deregulated Texas compares relatively well against other deregulated states. The 2002-2016 price increase observed in deregulated Texas stands as third lowest increase among 15 deregulated states during that period. This standing represents a slight improvement for Texas since TCAP's report last year. That report ranked Texas fourth among deregulated states for price increases. [See Exhibit 2].
- Annual average residential electricity prices in deregulated areas of Texas have been higher than the nationwide average during 10 of the 15 years included in the benchmark analysis (2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011 and 2014). Annual average residential electricity prices in areas of Texas exempt from deregulation have been higher than the nationwide average once during those 15 years (2005). [See Exhibit 8].
- It remains unclear whether the historic disparity between average electric prices in deregulated and non-deregulated areas continues after 2016 because the necessary data to conduct those analyses are not available. However, rate surveys of more recent competitive

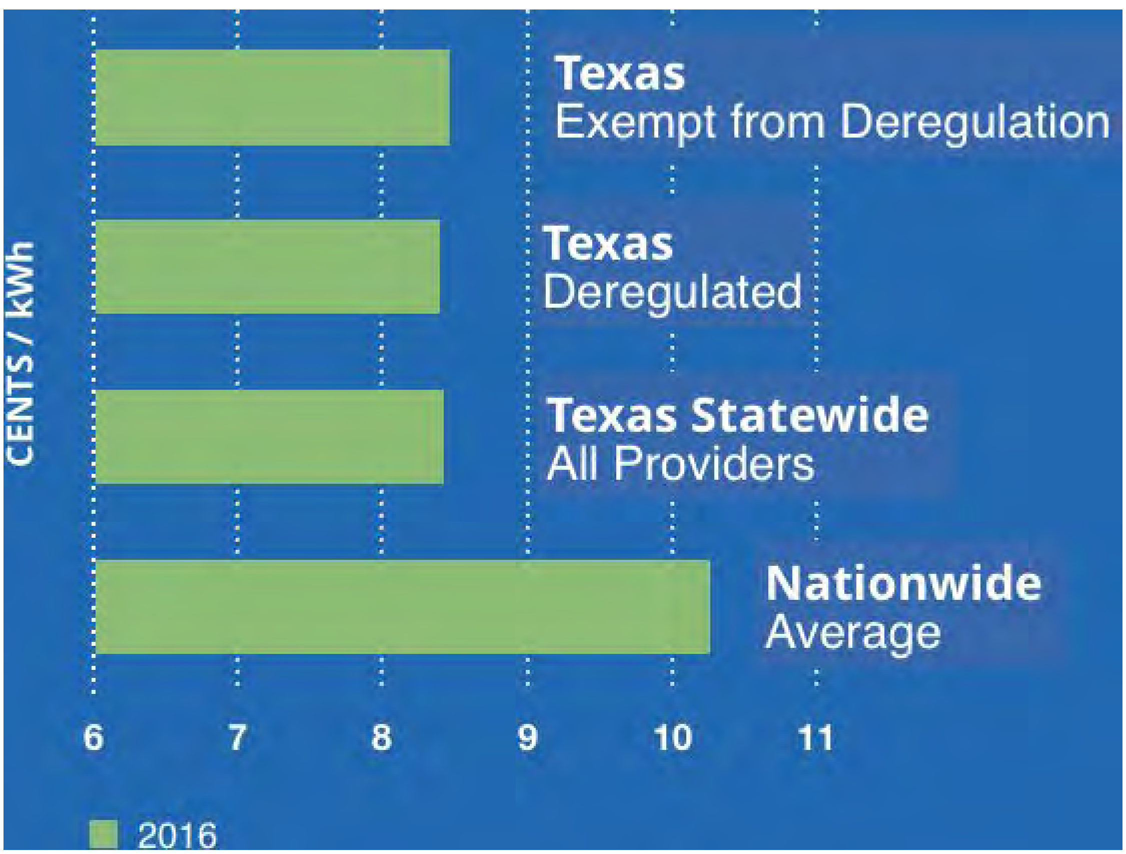
offers show a substantial number meeting or beating prices in deregulation-exempt areas. [See Exhibit 10 and Exhibit 11].

Section 2: 2016 Electric Prices Benchmark Analysis

- In 2016 Texans in deregulated areas paid, on average, 11.38 cents per kilowatt hour for residential electricity, while the average price of electricity in areas of Texas exempt from deregulation was 10.45 cents per kilowatt hour. The corresponding nationwide average was 12.55 cents. [See Exhibit 8].
- In 2016, the average statewide price of electricity (both inside and outside areas of Texas with deregulation) for all customer classes (residential, commercial and industrial) was 8.4 cents. This beats the 10.3-cent nationwide average price. [See Exhibit 6].
- In 2016, average residential electricity prices charged by deregulated providers within the region served by the Electric Reliability Council of Texas (the state's primary power grid operator) were higher than prices charged by deregulation-exempt providers within that region. This also was the case in other recent years. [See Exhibit 7].

2016: All Customer Classes

Exhibit 6: Combined Residential, Commercial and Industrial Prices



This exhibit depicts electricity prices among all customer classes (residential, commercial and industrial) during three years: 2013, 2014 and 2015. Average prices for these customer classes

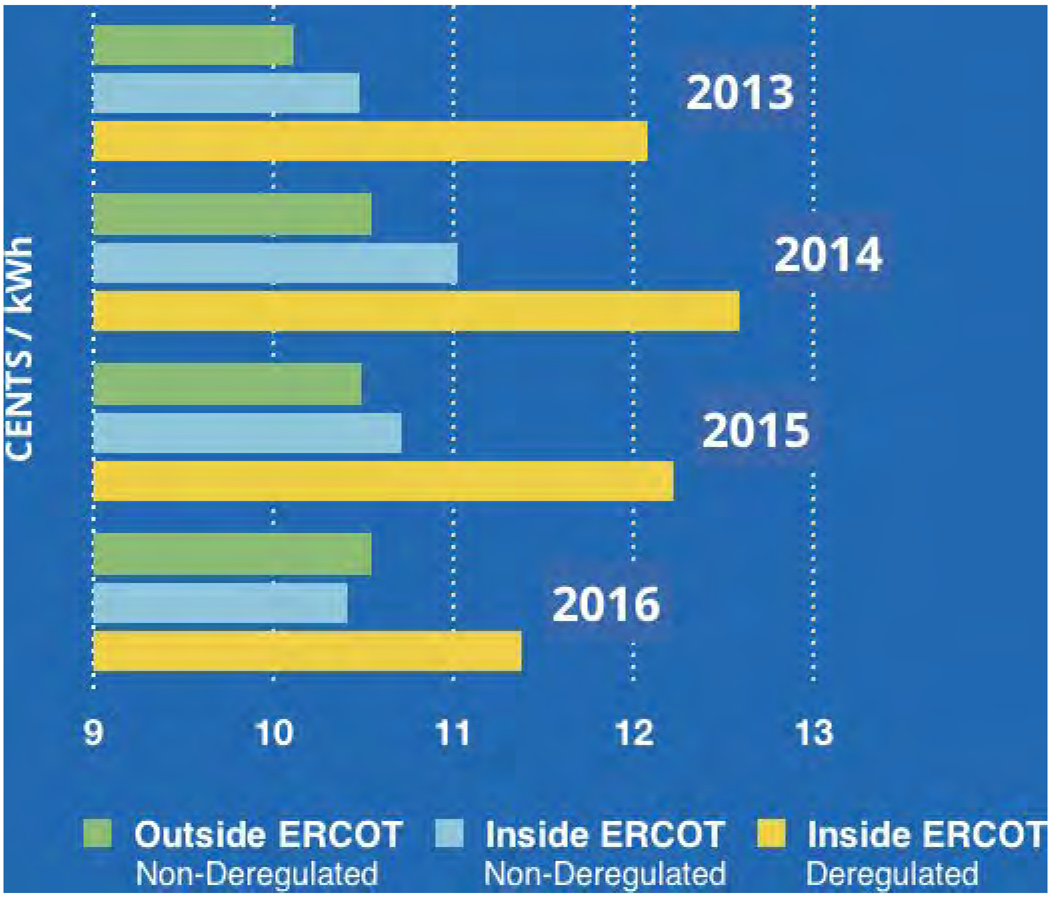
A. 937

combined were lower in Texas during these years than they were nationwide. This exhibit also shows average prices inside and outside areas of Texas with deregulation.

Source: United States Energy Information Administration

2013-2016: Inside and Outside ERCOT

Exhibit 7: Residential Electric Prices

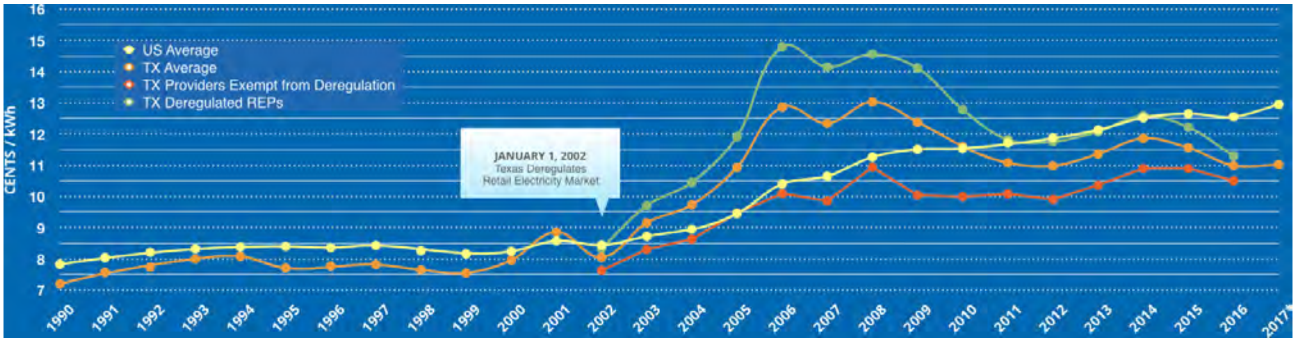


The state's primary grid operator, the Electric Reliability Council of Texas, oversees the transmission system in about 85 percent of the state. Deregulated service providers and those exempt from deregulation both operate within this service territory. In areas of the state outside of ERCOT, all service providers are exempt from deregulation. As this series of exhibits illustrates, average deregulated prices in Texas were significantly higher in 2013, 2014, 2015 and 2016 than those charged by providers exempt from deregulation — whether the deregulation-exempt providers operate inside or outside ERCOT.

Source: United States Energy Information Administration

Average Residential Electricity Prices

Exhibit 8: Texas and United States — 1990-2017*



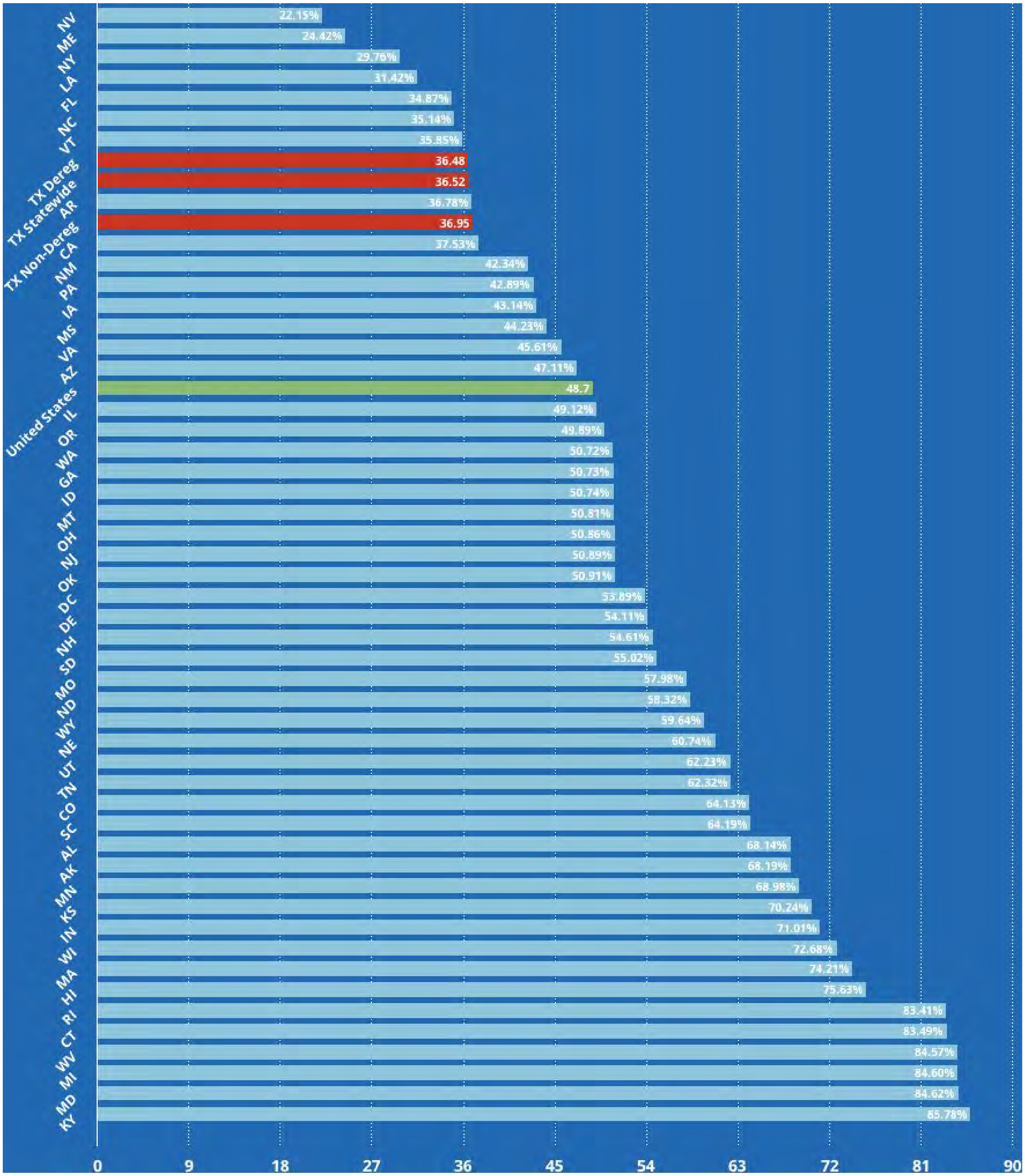
The statewide average price for residential electricity remained below the national average for many years prior to the implementation of the Texas deregulation law. But after Texas deregulated its retail electric market, the overall statewide average price for residential electricity surpassed the national average and remained significantly above that mark for many years. Note, however, that average residential prices in deregulation-exempt areas of Texas remained consistently below the national average after implementation of the deregulation law. By contrast, average prices in deregulated areas remained consistently above the national average for many years. This dynamic suggests that high residential electricity prices in deregulated Texas contributed to the comparatively high statewide average price after 2002.

This exhibit also shows average statewide residential prices in Texas spiking above the national average in 2001. Although that spike occurred before the deregulation of the state's retail electricity market, it likely was a function of deregulation. This is because the Texas Public Utility Commission allowed utilities in 2001 to collect excess earnings and high fuel surcharges as a down payment on anticipated collections from the restructuring law. Average statewide residential prices in Texas dropped after the deregulated market opened in 2002 because the fuel surcharges expired and because the deregulation law mandated a 6-percent cut in base rates. Average statewide residential prices then remained above the national average through 2010. [For more about this, see TCAP's separate report on the History of Texas Electric Deregulation.]

This exhibit does not distinguish between prices in areas of the state that are currently deregulated and non-deregulated prior to 2002. This is because the federal data to conduct that granular analysis are not readily available. The same is true for the years 2017 and 2018.

Source: United States Energy Information Administration & Electricity Data Browser

*2017 data through March 2017



Residential Electricity Prices

Exhibit 9: Percentage Increases 2002-2016

Residential electricity prices increased in deregulated areas of Texas from 2002 through 2016 by 36.58 percent, which is less than the 48.70 percent increase registered nationwide and also slightly less than the 36.95 percent increase registered in areas of the state exempt from deregulation.

Source: United States Energy Information Administration & Electricity Data Browser

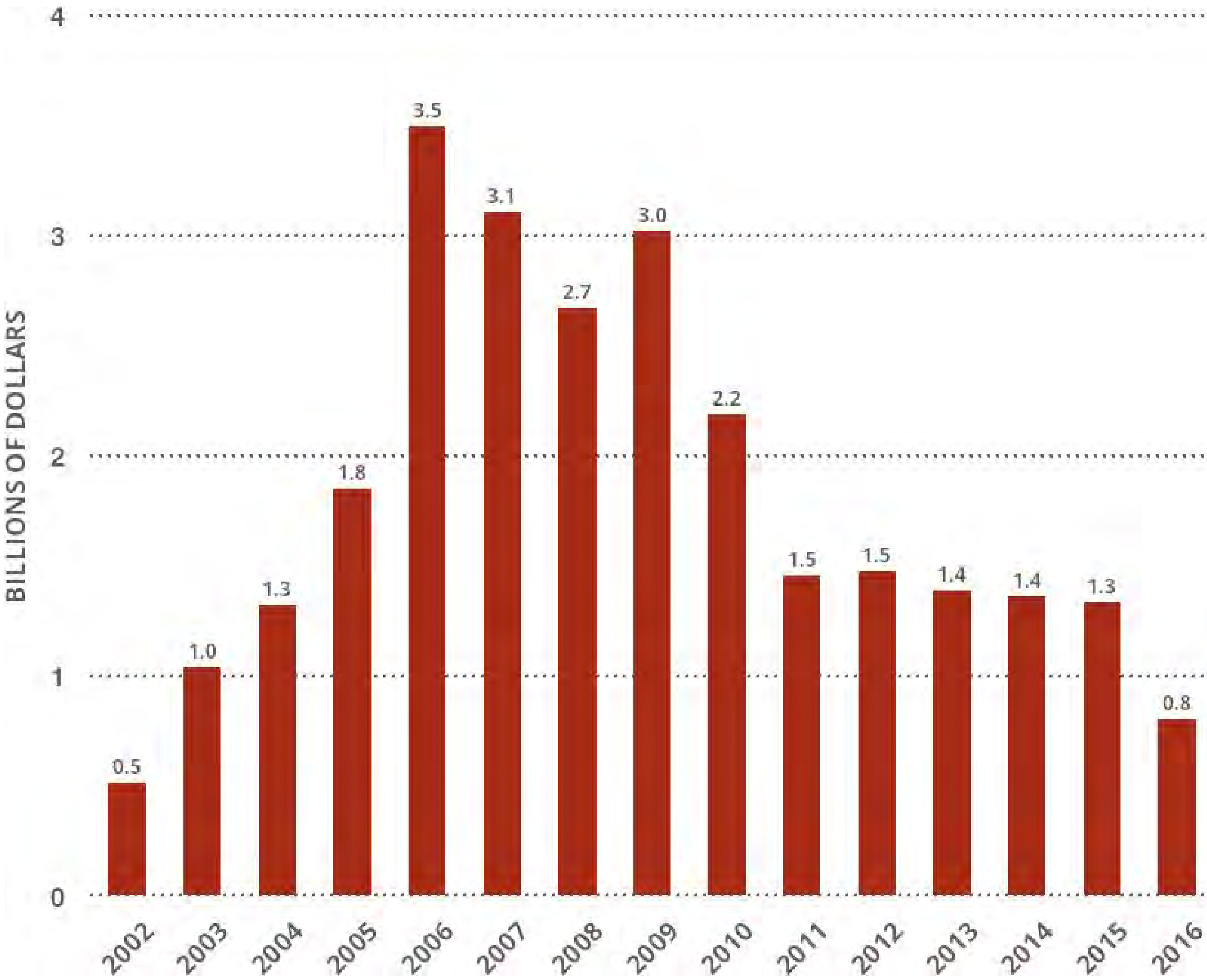
Section 3: Lost-Savings Analyses

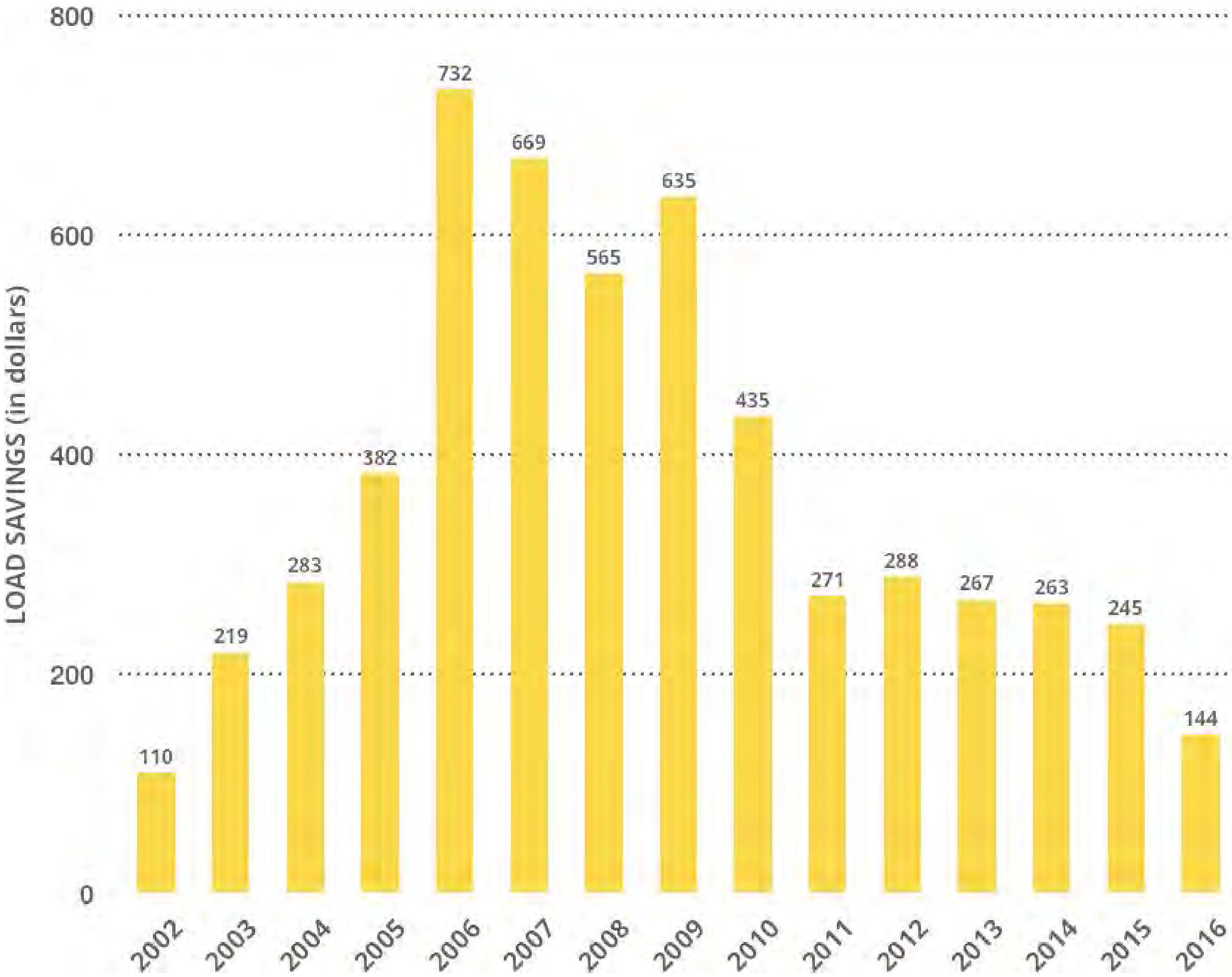
"Lost savings," as defined in this report, is the imputed savings that would have accrued to Texans living in areas of Texas with deregulation had they paid the same average prices as Texans living in areas exempt from deregulation. The report examines lost savings both market-wide and on an individual level — and for each year for which data is available to conduct the analyses.

- All told, Texans living in deregulated areas would have saved more than $27 billion in lower residential electricity bills from 2002 through 2016 had they paid the same average prices as Texans living outside deregulation. For 2016 alone, that lost savings amounts to about $800 million. [See Exhibit 4].
- On an individual basis, a typical residential customer under deregulation (defined as a customer paying average deregulated prices and consuming 1,300 kilowatt hours of electricity every month) would have saved more than $5,500 from 2002 through 2016 had he or she paid the same average prices as those charged outside deregulation. This imputed "lost savings" amounts to about $144 for a typical household in 2016 alone. [See Exhibit 5].

The Aggregate Impact: Imputed Higher Costs Exceed $27 Billion In the Aggregate.

Exhibit 4: *Average electric prices in Texas charged by deregulated providers have been consistently higher than average prices charged by providers exempt from deregulation. The exhibit at right measures the potential impact of these higher prices. The bars illustrate the aggregate savings that would have accrued to Texans in deregulated areas had they instead paid the lower average rates charged in areas outside deregulation. The imputed "lost savings" ranges from about a half billion per year to more than $3.5 billion.*


BILLIONS OF DOLLARS
4
3
2
1
0
0.5
1.0
1.3
1.8
3.5
3.1
2.7
3.0
2.2
1.5
1.5
1.4
1.4
1.3
0.8
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016



The Individual Impact: Imputed Higher Costs Exceeds $5,500 on Per-Customer Basis.

Exhibit 5: *This exhibit compares electricity costs for a typical customer paying average rates charged by deregulated retail electric providers in Texas, to costs for a customer with the same usage but paying average rates charged by Texas providers exempt from deregulation. Considered in this per-customer fashion, the imputed "lost savings" ranges from about a $110 per year, per customer, to $732 per year per customer. For purposes of comparison, this exhibit assumes monthly electricity usage of 1,300 kWh.*

Source: United States Energy Information Administration

Section 4: Transmission and Distribution Charges

Although monopoly transmission and distribution utilities operate under regulation, their rates impact electricity prices charged by competitive retail electric providers. This is because transmission and distribution utility rates are non-by-passable, which means they are included in a uniform fashion in the rates charged by all retail electric providers that operate in each utility's service territory.

Rate increases since 2003 by the Oncor utility (operating in the Dallas-Fort Worth area) and the CenterPoint Electric utility (operating around Houston) have outpaced inflation. Transmission and distribution charges paid by Oncor and CenterPoint customers also comprise an increasing share of monthly electric bills. [See Exhibit 10 and Exhibit 11 below].

Non-Bypassable Charges: CenterPoint

Exhibit 10: (September 2003 – March 2018)

Transmission and distribution charges

(in dollars, on 1,000kWh monthly bill)

Transmission and distribution utilities operate as regulated monopolies, even in areas of Texas with deregulation. The rates assessed by these utilities continue going up, sometimes at a rate well beyond that of inflation. For instance, rates charged by CenterPoint Electric in the Houston area have increased 89.3 percent since 2003. In 2003, CenterPoint charges comprised 20.2 percent to 29.2 percent of a typical 1,000 kWh electric bill. In March 2018, CenterPoint charges comprised 30.7 percent to 52 percent of a typical bill. All electric customers in deregulated areas around Houston must pay CenterPoint's rates, regardless of the retail electric provider the customer chooses for service.

Source: Archived TDU Rate Summaries, PUC

Non-Bypassable Charges: Oncor

Exhibit 11: (September 2003 – March 2018)

Transmission and distribution charges

(in dollars, on 1,000kWh monthly bill)

Rates charged by Oncor utility in the Dallas-Fort Worth area increased by nearly 69 percent since 2003. That rate outpaces the rate of inflation. In 2003, Oncor charges comprised 20.1 percent to 27.4 percent of a typical 1,000 kWh electric bill. In March 2018, the charges comprised 27.7 percent to 48.9 percent of a typical bill. All customers in deregulated areas of the Dallas-Fort Worth region must pay Oncor's rates, regardless of the retail electric provider the customers choose for service.

Source: Archived TDU Rate Summaries, PUC

Section 5: Recent Prices

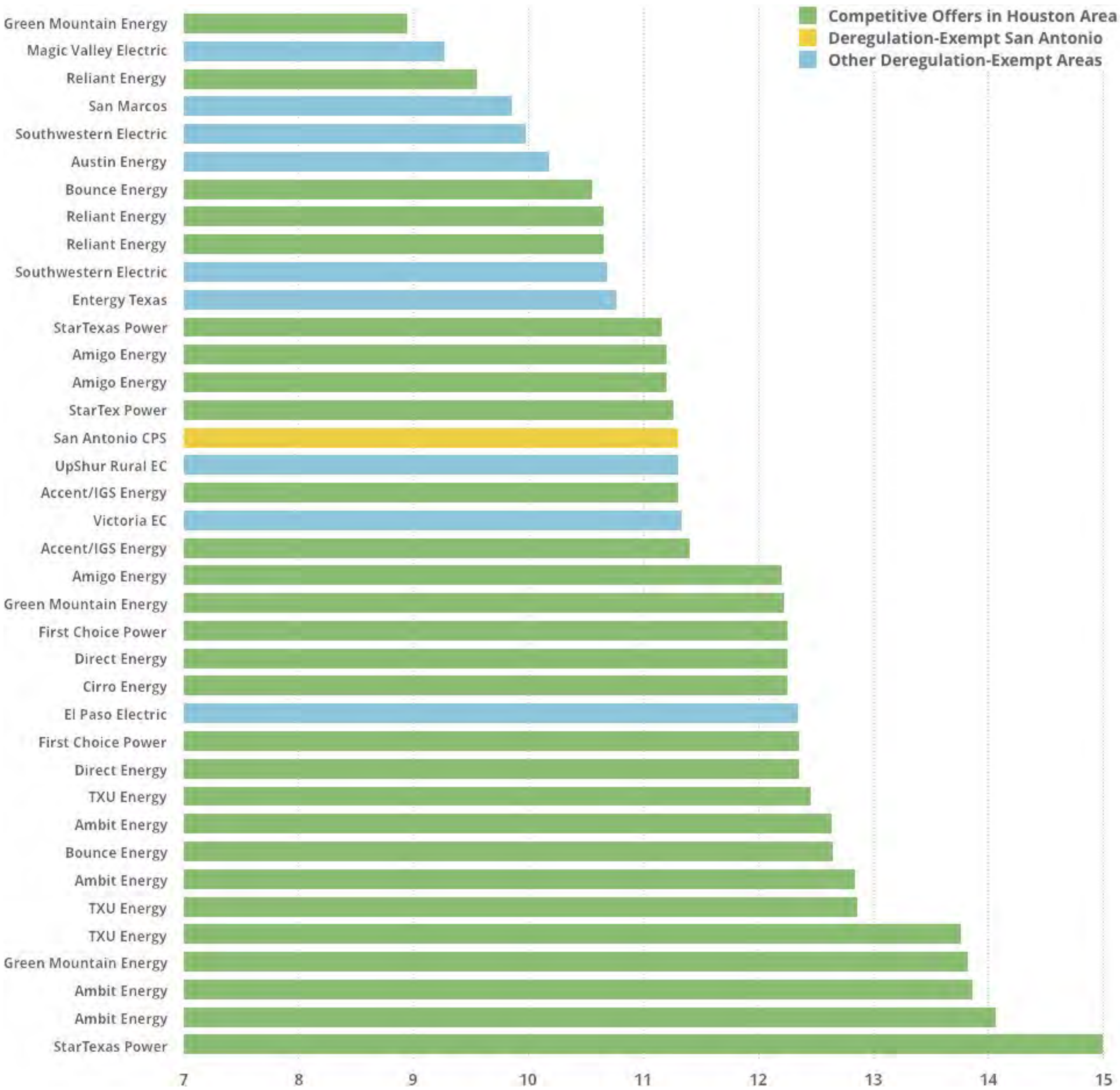
- Among adjoining states, residential prices in adjoining Oklahoma, Louisiana and Arkansas were lower during 2017 than in Texas. Residential electric prices in 2017 were higher in adjoining New Mexico and nationwide. [See Exhibit 3]
- Adjoining Louisiana and Oklahoma also enjoyed lower average industrial electric rates in 2017, while adjoining New Mexico and Arkansas had higher rates. [See Exhibit 3]
- Among all classes of customers (Residential, Commercial and Industrial Combined), lower average rates were to be found in adjoining Arkansas, Louisiana and Oklahoma during 2017, and higher in adjoining New Mexico and nationwide. [See Exhibit 3]

- A March 2018 Public Utility Commission survey of electricity deals in Houston reveals 9 competitive offers with prices lower than the electricity price paid in San Antonio. Houston is the largest city in Texas with deregulation. San Antonio is the largest city exempt from deregulation. [See Exhibit 12, below].
- A March 2018 Public Utility Commission survey of electricity deals in the Dallas-Fort Worth area reveals 18 competitive offers with prices lower than the electricity price paid in San Antonio. [See Exhibit 13, below].

Electricity Prices (Houston-Area)

Exhibit 12: Competitive Houston-Area Offers vs. Residential Prices in Deregulation-Exempt Area

(According to PUC Price Surveys, as of March 2018)



Average electricity prices paid by Texans living in areas outside deregulation have been consistently lower than average prices paid in deregulated areas. But that doesn't mean that Texans can't find plenty of good deals in deregulated areas. This exhibit shows a number of individual retail offers in the Houston area (as listed in a PUC rate survey for March 2018) that are lower than the residential price of electricity in San Antonio. Houston is the largest city in Texas with deregulation. San Antonio is the largest city exempt from deregulation. This finding is in contrast to the early years of the Texas deregulation law, in which PUC surveys revealed far fewer

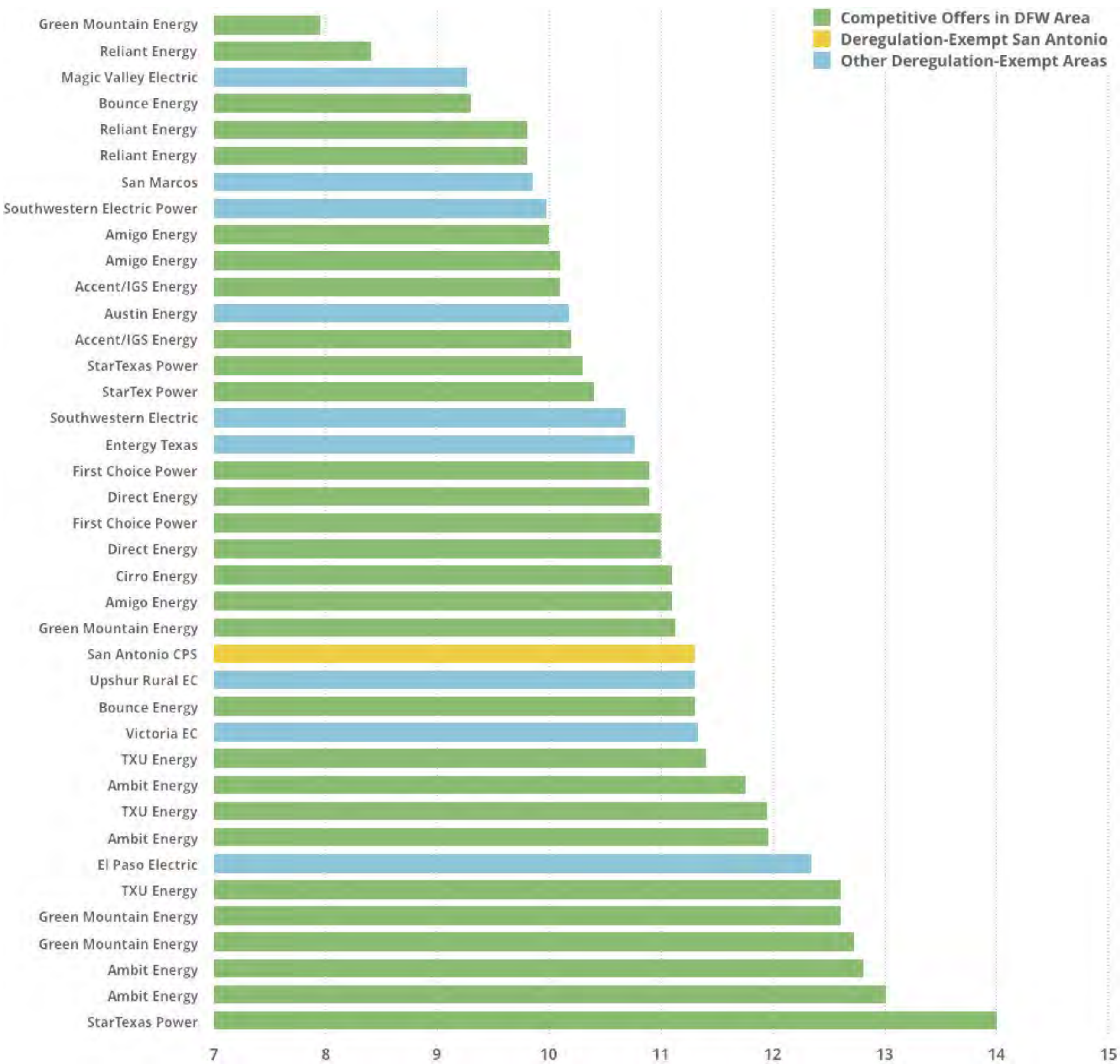
A. 946

deals in Houston that were lower than the San Antonio regulated rate. This exhibit also lists electricity prices in other areas of Texas exempt from deregulation. All data has been retrieved from PUC rate surveys.

Electricity Prices (DFW-Area)

Exhibit 13: Competitive DFW-Area Offers vs. Residential Prices in Deregulation-Exempt Area

(According to PUC Price Surveys, as of March 2018)



This exhibit shows individual retail electric offers in the Dallas-Fort Worth area, as listed in a PUC rate survey for March 2018. Those offers are shown in green. Exhibit 13 also shows electricity prices in many deregulation-exempt areas of Texas. These are marked in blue. The price of electricity in San Antonio, which is the largest city in Texas exempt from deregulation, is shown in yellow.

About the Author

R.A. "Jake" Dyer

Is a policy analyst for TCAP, a coalition of cities and other political subdivisions that purchase electricity in the deregulated market for their own governmental use. Because high energy costs can impact municipal budgets and the ability to fund essential services, TCAP, as part of its mission, actively promotes affordable energy policies. High energy prices also place a burden on local businesses and home consumers.

TAB 17

			RESIDENTIAL				COMMERCIAL				INDUSTRIAL		
			Revenue	Sales	Customers	Price	Revenue	Sales	Customers	Price	Revenue	Sales	Customers
Year	State	Data Status	Thousand Dollars	Megawatthours	Count	Cents/kWh	Thousand Dollars	Megawatthours	Count	Cents/kWh	Thousand Dollars	Megawatthours	Count
1990	FL	Final	5,527,171	71,114,670	.	7.77	3,421,034	51,342,235	.	6.66	844,104	16,604,581	.
1991	FL	Final	5,759,430	72,813,986	.	7.91	3,549,204	52,440,504	.	6.77	855,605	16,482,265	.
1992	FL	Final	5,671,187	73,188,923	.	7.75	3,461,113	52,620,260	.	6.58	828,372	16,497,053	.
1993	FL	Final	6,137,047	76,827,417	.	7.99	3,669,193	54,875,681	.	6.69	857,508	16,297,719	.
1994	FL	Final	6,270,547	80,595,125	.	7.78	3,649,159	57,447,392	.	6.35	847,620	16,512,739	.
1995	FL	Final	6,711,296	85,769,777	.	7.82	3,838,428	60,078,878	.	6.39	849,527	16,472,744	.
1996	FL	Final	7,059,881	88,314,753	.	7.99	4,042,818	60,988,112	.	6.63	878,978	17,212,026	.
1997	FL	Final	7,097,262	87,845,338	.	8.08	4,190,543	63,337,075	.	6.62	919,988	18,265,806	.
1998	FL	Final	7,557,067	95,768,183	.	7.89	4,297,770	67,346,459	.	6.38	887,094	18,448,022	.
1999	FL	Final	7,253,311	93,846,127	.	7.73	4,297,424	69,054,724	.	6.22	885,803	18,579,158	.
2000	FL	Final	7,696,331	99,005,604	.	7.77	4,510,746	72,129,915	.	6.25	913,460	18,883,858	.
2001	FL	Final	8,712,905	101,377,094	.	8.59	5,239,143	73,957,636	.	7.08	1,028,202	19,854,252	.
2002	FL	Final	8,822,970	108,163,825	.	8.16	5,150,090	77,561,349	.	6.64	990,641	18,959,313	.
2003	FL	Final	9,636,113	112,649,864	.	8.55	6,082,672	85,256,748	.	7.13	1,048,418	19,374,816	.
2004	FL	Final	10,085,887	112,203,013	.	8.99	6,601,385	86,765,232	.	7.61	1,139,932	19,518,052	.
2005	FL	Final	11,140,739	115,791,459	.	9.62	7,293,500	89,410,280	.	8.16	1,271,207	19,676,345	.
2006	FL	Final	13,263,647	117,053,005	.	11.33	9,047,713	91,300,018	.	9.91	1,523,471	19,767,807	.
2007	FL	Final	13,222,562	117,816,205	6,769,454	11.22	9,154,115	93,931,301	870,212	9.75	1,492,400	19,240,995	23,423
2008	FL	Final	13,278,713	113,936,978	8,478,407	11.65	9,446,376	93,205,138	1,129,095	10.14	1,562,089	18,944,917	22,382
2009	FL	Final	14,302,605	115,473,511	8,493,590	12.39	9,936,650	92,274,656	1,125,135	10.77	1,576,698	16,917,941	20,456
2010	FL	Final	13,982,243	122,244,650	8,529,202	11.44	8,941,652	91,614,094	1,127,137	9.76	1,528,592	17,265,268	18,046
2011	FL	Final	13,388,982	116,341,104	8,575,892	11.51	9,039,754	91,778,109	1,139,654	9.85	1,443,924	16,885,585	17,334
2012	FL	Final	12,806,821	112,127,057	8,645,205	11.42	8,894,821	92,037,799	1,160,572	9.66	1,319,868	16,425,583	17,415
2013	FL	Final	12,770,123	113,293,913	8,756,316	11.27	8,653,405	92,144,612	1,175,894	9.39	1,246,783	16,389,522	17,865
2014	FL	Final	13,854,538	116,535,263	8,891,018	11.89	9,169,986	92,925,670	1,180,767	9.87	1,306,052	16,522,425	18,777
2015	FL	Final	14,216,590	122,759,472	8,963,967	11.58	9,106,202	95,847,051	1,183,240	9.50	1,388,136	16,897,415	19,458
2016	FL	Final	13,545,273	123,320,547	9,149,213	10.98	8,506,823	95,547,214	1,199,895	8.90	1,288,401	16,758,825	21,162
2017	FL	Final	14,097,730	121,462,622	9,291,705	11.61	8,881,601	95,003,681	1,216,936	9.35	1,299,364	16,601,941	21,289
2018	FL	Preliminary	14,425,194	124,229,604	9,375,488	11.61	8,926,180	95,482,773	1,236,589	9.35	1,277,199	16,465,321	20,361
2019	FL	Preliminary	1,079,893	9,010,051	9,374,535	11.99	681,610	7,050,890	1,237,551	9.67	98,827	1,262,771	20,154

	TRANSPORTATION				OTHER				TOTAL			
Price	Revenue	Sales	Customers	Price	Revenue	Sales	Customers	Price	Revenue	Sales	Customers	Price
Cents/kWh	Thousand Dollars	Megawatthours	Count	Cents/kWh	Thousand Dollars	Megawatthours	Count	Cents/kWh	Thousand Dollars	Megawatthours	Count	Cents/kWh
5.08	.	.	.	.	305,558	4,473,395	.	6.83	10,097,869	143,534,878	.	7.04
5.19	.	.	.	.	315,166	4,599,488	.	6.85	10,479,404	146,336,239	.	7.16
5.02	.	.	.	.	320,479	4,703,701	.	6.81	10,281,151	147,009,941	.	6.99
5.26	.	.	.	.	330,288	4,747,000	.	6.96	10,994,034	152,747,819	.	7.20
5.13	.	.	.	.	335,447	4,989,047	.	6.72	11,102,776	159,544,297	.	6.96
5.16	.	.	.	.	346,169	5,170,741	.	6.69	11,745,420	167,492,140	.	7.01
5.11	.	.	.	.	361,783	5,317,131	.	6.80	12,343,460	171,832,022	.	7.18
5.04	.	.	.	.	380,317	5,592,800	.	6.80	12,588,110	175,041,019	.	7.19
4.81	.	.	.	.	384,715	5,791,930	.	6.64	13,126,646	187,354,594	.	7.01
4.77	.	.	.	.	382,865	5,790,250	.	6.61	12,819,402	187,270,259	.	6.85
4.84	.	.	.	.	405,365	5,823,599	.	6.96	13,525,899	195,842,975	.	6.91
5.18	.	.	.	.	422,864	5,563,152	.	7.60	15,403,113	200,752,133	.	7.67
5.23	.	.	.	.	430,077	5,789,042	.	7.43	15,393,778	210,473,531	.	7.31
5.41	7,009	97,194	.	7.21	.	.	.	.	16,774,212	217,378,622	.	7.72
5.84	7,320	98,202	.	7.45	.	.	.	.	17,834,520	218,584,495	.	8.16
6.46	7,943	98,926	.	8.03	.	.	.	.	19,713,387	224,977,010	.	8.76
7.71	10,184	98,720	.	10.32	.	.	.	.	23,845,014	228,219,544	.	10.45
7.76	9,354	96,100	25	9.73	.	.	.	.	23,878,429	231,084,599	7,663,114	10.33
8.25	8,732	85,763	25	10.18	.	.	.	.	24,295,913	226,172,794	9,629,909	10.74
9.32	8,825	84,214	25	10.48	.	.	.	.	25,824,776	224,750,323	9,639,206	11.49
8.85	7,345	85,601	25	8.58	.	.	.	.	24,459,828	231,209,615	9,674,411	10.58
8.55	7,545	85,623	3	8.81	.	.	.	.	23,880,210	225,090,423	9,732,883	10.61
8.04	7,094	83,894	2	8.46	.	.	.	.	23,028,603	220,674,333	9,823,194	10.44
7.61	7,948	91,467	2	8.69	.	.	.	.	22,678,259	221,919,514	9,950,077	10.22
7.90	8,760	94,753	2	9.25	.	.	.	.	24,339,336	226,078,111	10,090,564	10.77
8.22	8,515	95,460	2	8.92	.	.	.	.	24,719,443	235,599,398	10,166,667	10.49
7.69	7,921	95,236	2	8.32	.	.	.	.	23,348,418	235,721,822	10,370,272	9.91
7.83	7,443	86,305	2	8.62	.	.	.	.	24,286,139	233,154,549	10,529,932	10.42
7.76	6,589	82,865	2	7.95	.	.	.	.	24,635,162	236,260,563	10,632,440	10.43
7.83	591	7,165	2	8.25	.	.	.	.	1,860,921	17,330,878	10,632,242	10.74

TAB 18

ELECTRICITY PRICES IN TEXAS

tcaptx.com/reports/snapshot-report-electricity-prices-texas-july-2017

A Snapshot Report
2017 Edition

Executive Summary

Average residential electricity prices in areas of Texas with retail electric competition have declined during a recent 10-year period, while average prices have increased during that same period in areas exempt from electric competition.

Moreover, the average price of electricity for residential customers in areas with retail electric competition dipped below the national average in 2015. This marked the third such occasion in four years that average residential electricity prices in those areas fell below the national average.

But the news is not all good for Texans living in areas with retail electric competition, also known as retail electric deregulation. For instance, average residential electricity prices have remained consistently higher in those areas, as compared to deregulation-exempt areas. This has been true for every year for which data exist to conduct this analysis.

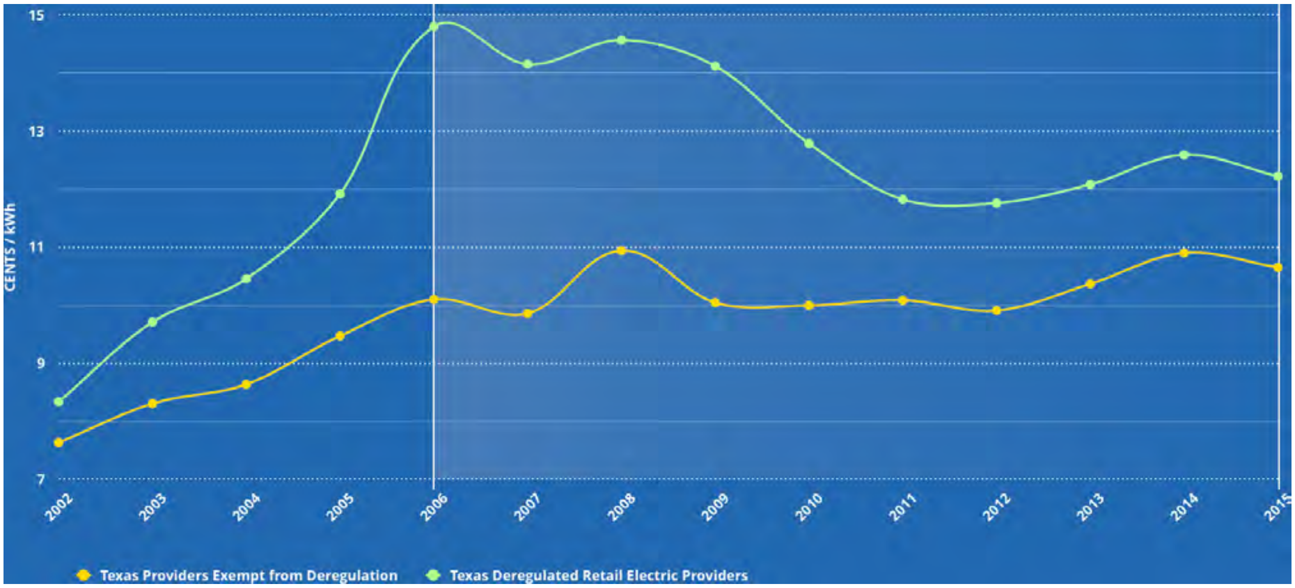
Texans in deregulated areas could have saved thousands of dollars individually — and billions of dollars in the aggregate — had they paid the same average prices as those observed in areas exempt from the deregulated system.

Texas implemented its retail electric deregulation law in 2002. Under it, Texans in areas such as Houston and Dallas can choose among different electric providers. In other areas that remain exempt from the deregulation law residents receive service from a single provider.

This Snapshot Report on Electricity Prices, an update of similar analyses released by the Texas Coalition for Affordable Power, compares residential electricity prices in both deregulated areas of Texas and those in areas exempt from deregulation. It includes long-term pricing information, information about non-by-passable charges assessed by Texas wires utilities and a review of pricing trends nationwide.

Average Residential Electricity Prices

Exhibit 1: Inside and Outside Deregulated Areas of Texas



Average residential electric prices in deregulated areas of Texas consistently exceed average prices in deregulation-exempt areas. This was true in 2002 — the very first year of the deregulated retail electric market — and also was true in 2015, which was the last year for which data exist to conduct this analysis. The price gap also has grown during this 2002-2015 time period. But a different story emerges if one removes the first years of deregulation from the analysis, and instead examines only 2006 through 2015. During those 10 years average residential electric prices in deregulated Texas decreased by 17.4 percent, while they *increased* in deregulation-exempt areas by 5.5 percent. One should note, however, that the average price of residential electricity in deregulated Texas was at a historic high in 2006, exceeding the average deregulation-exempt price by 46.5 percent. In 2002, the average deregulated price was 9.2 percent higher than the average deregulation-exempt price. In 2015, the average deregulated price was 14.7 percent higher.

Source: United State Energy Information Administration & US EIA Electricity Data Browser

Major findings include:

- Texans historically have paid higher residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation. This trend has been observed from the beginning of the retail electric deregulation law in Texas through 2015, the last year for which data are available to conduct this analysis.
- From the first year of the law through 2015 the average price of electricity for residential customers increased more in deregulated areas of Texas than areas of the state exempt from deregulation.
- All told, Texans living in deregulated areas would have saved more than $26 billion had they paid the same average residential electricity prices through 2015 as Texans living outside deregulation. These imputed higher costs amount to more than $5,300 for a typical household.
- The price gap between residential electricity prices inside and outside areas of Texas with deregulation has narrowed since 2009. Although average residential electricity prices

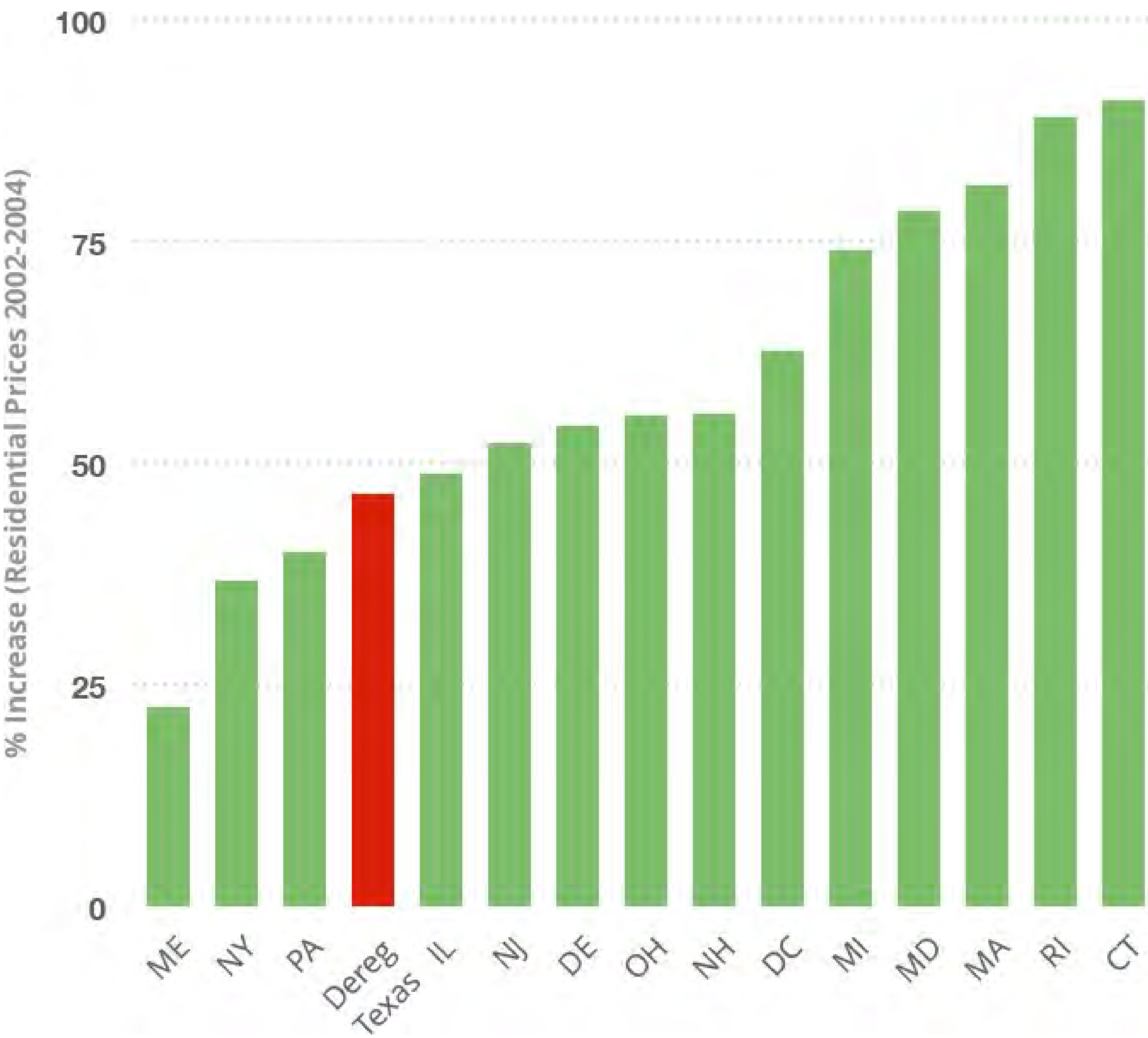
remained higher in deregulated areas than in deregulation-exempt areas in 2015, the gap that year was the smallest since the beginning of deregulation.

- Average residential electric prices in deregulated areas have declined since 2006. By contrast, average residential prices in areas exempt from deregulation during the same period have increased.
- Texans now can find many low-priced *individual* deals inside deregulated areas that beat prices commonly paid in deregulation-exempt areas. These comparatively low-cost competitive deals are more numerous than in previous years.

Texas has fared comparatively well in relation to other states with deregulated retail electric systems. Average residential prices in deregulated Texas increased at the fourth lowest rate among 15 such states from 2002 through 2015.

Residential Price Increases

Exhibit 2: For 15 Deregulated States, Including Texas 2002-2015



Source: United State Energy Information Administration Electricity Data Broswer

> Charges assessed by the major regulated transmission and distribution service providers have increased since 2003 — and at a pace greater than inflation. Although transmission and distribution rates are regulated, these increases nonetheless contribute to higher prices in deregulated areas of the state.

About the Texas Coalition for Affordable Power

Unlike the sponsors of some other reports about the state's deregulated power market, TCAP derives no profit from selling electricity. Instead, the more than 150 political subdivisions that comprise TCAP purchase electricity for their own governmental needs. TCAP understands how high-cost power can cause businesses to relocate out of state, and can place heavy burdens on home consumers. TCAP wants what all Texans want: an affordable and reliable supply of power and a vibrant economy.

The Analyses

Under the Texas electric deregulation law, consumers in Houston, Dallas, Fort Worth, Corpus Christi and surrounding areas can choose among different retail electric providers. These providers compete for customers by offering different terms of service and prices. Many other parts of the state remain exempt from this competitive system. Exempt areas include those served by municipally-owned utilities (such as in San Antonio and Austin) and those served by electric cooperatives. Also exempt from retail electric deregulation are investor-owned utilities operating outside the area covered by the state's primary power grid, known as the Electric Reliability Council of Texas[1].

The existence of this bifurcated electricity system — one in which some Texans receive service from competitive electric retailers and others do not — provides a unique opportunity to compare pricing outcomes. The Texas electric deregulation law was adopted in 1999 with the promise that it would lower rates[2]. But as this analysis shows, the results have been mixed.

This report includes a benchmarking analysis that employs data obtained from the United States Energy Information Administration. This benchmarking analysis compares pricing outcomes inside and outside deregulated areas of Texas and begins with 2002 — the first year of retail electric deregulation in Texas — and continues through 2015. The benchmarking analysis does not extend to 2016 and 2017 because the necessary US EIA data for those years are not yet available.

However, this Snapshot report also includes an analysis of more recent statewide and nationwide pricing trends — but of a more generalized nature. This separate analysis employs pricing data through 2017 gathered both from the US EIA and the Texas Public Utility Commission.

This report also includes a non-comprehensive sample of individual offers in 2017 from deregulated areas around Houston and Dallas. The pricing samples were retrieved from rate surveys conducted by the PUC.

Finally, this report compares rates charged during two separate years, 2003 and 2017, by the state's two largest monopoly transmission and distribution providers. The underlying data for this analysis were retrieved from the PUC website.

For readability purposes, certain words and phrases will be used interchangeably to refer to areas served by competitive retail electric providers. These words and phrases include "areas with retail electric competition," "areas with retail electric deregulation," "competitive areas" and "deregulated areas." Unless otherwise noted, references to electricity prices are for residential customers.

[1] See The Story of ERCOT, Februrary 2011

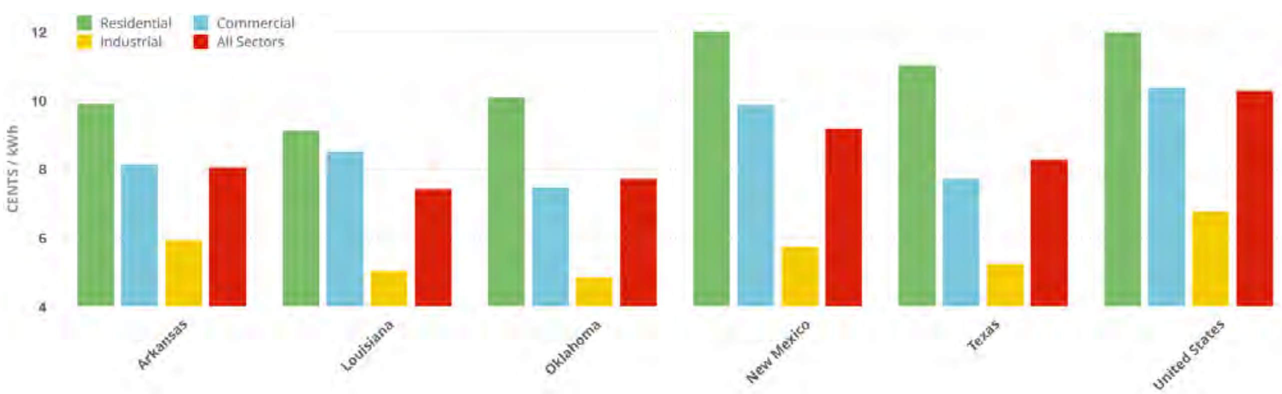
[2] "Deregulated Electricity in Texas," Texas Coalition for Affordable Power, December 2012

Background History

Texans enjoyed residential electricity rates below the national average for many years prior to the adoption of the retail electric deregulation law in 1999[3]. That trend flipped shortly after the law took effect, with average residential prices statewide rising above the national average in 2003 and remaining above the national average until 2011. [See Exhibit 8]

Average Electricity Prices 2016

Exhibit 3: Texas and Adjoining States



Source: United State Energy Information Administration & US EIA Electricity Data Browser

Some observers have said that the increase in statewide electricity prices after the deregulation law took effect is not related to the law, per se, but rather to an increase in natural gas prices. This is because natural gas prices are closely linked to wholesale electricity prices, and natural gas prices hit historically high levels after deregulation[4].

However, fluctuations in natural gas prices alone cannot explain the historic disparity between average electricity prices inside and outside deregulated areas of Texas, particularly during the early years of the law. For every year for which data exist with which to conduct this analysis — that is, between 2002 and 2015 — average residential prices in deregulated areas of Texas have been higher than average prices in deregulation-exempt areas. [See Exhibit 1].

Moreover, average residential prices from 2002 through 2015 have increased more, in percentage terms, in deregulated Texas as compared to areas of the state exempt from deregulation. [See Exhibit 9].

Customer confusion about retail electric shopping, the details of rate offers and other aspects of the deregulated market may have contributed to historically higher prices there. Other contributing factors may include the cost of multi-million dollar marketing campaigns by some retail electric companies and increasing rates charged by monopoly transmission and distribution utilities. These "wires" rates comprise a growing portion of home electric bills in competitive areas.

It remains unclear whether the trend of higher average prices in deregulated areas of Texas has continued in 2016[5] and 2017 given the unavailability of necessary data from those years for which to conduct this analysis. However, the price gap between areas of Texas with electric deregulation and deregulation-exempt areas continues to narrow. In percentage terms, this differential was smaller during 2015 than during any other year since 2002, the first year of the Texas deregulation law.

Possible explanations for this disparity include continued customer confusion about rates and service and relatively high prices charged by the state's legacy electric providers. These legacy providers — that is, companies associated with the former monopoly providers prior to deregulation — serve millions of Texans under deregulation. Their rates are often higher than some of the smaller, low-cost competitors. Multi-million dollar marketing campaigns by retail electric companies also may add to residential electricity costs in deregulated areas. Also, the cost of service of monopoly transmission and distribution utilities operating in deregulated areas may contribute to relatively high electric prices observed in those areas.

In fact, from 2006 through 2015 average residential electricity prices in areas of Texas with electric competition declined by 17.4 percent. During that same 10-year period, average prices in areas exempt from deregulation increased by 5.5 percent. [See Exhibit 1].

A survey of recent competitive pricing offers indicates that many such offers in Houston (the state's largest city operating under the retail electric deregulation) beat the price of electricity in San Antonio (the largest city in Texas exempt from deregulation). [See Exhibit 12]. The number of such offers that meet or beat prices in deregulation-exempt areas appears to be on the rise.

A survey of competitive electricity prices around the Dallas-Fort Worth area reveals many deals there that meet or beat prices in areas of Texas exempt from deregulation. [See Exhibit 13].

[3] "Deregulated Electricity in Texas," Texas Coalition for Affordable Power, December 2012

[4] Public Utility Commission Docket 40000, Item No.447, page 1, Memorandum to Commissioner Kenneth W. Anderson, Jr. from Chairman Donna Nelson.

[5] Rice University researchers, in a corrected May 2017 report, concluded that the average price paid for electricity by residential consumers in competitive areas during 2016 was "roughly equal, in the aggregate" to the average price paid by Texans in non-competitive areas. These findings appear to have been extrapolated from PUC data.

About US EIA Data and PUC Data

This analysis employs data collected by the United States Energy Information Agency, which is the statistical and analytical arm of the U.S. Department of Energy. U.S. EIA data is known to be impartial, and is widely cited by economists, scholars, industry experts, the news media and governmental agencies — including the Public Utility Commission of Texas.

The consistent manner in which the agency calculates electricity prices across all 50 states allows analysts to make apples-to-apples market comparisons. How does the U.S. EIA calculate prices? First, it gathers both revenue and sales data from electricity providers in a given region. It then derives a kilowatt hour or megawatt hour price by dividing revenues in that region by the amount of energy sold there.

TCAP has employed granular U.S. EIA data to calculate average electricity prices inside and outside deregulated areas of Texas, inside and outside areas served by the state's principal power grid (the Electric Reliability Council of Texas) and for the state's residential, commercial and industrial customers.

Employing U.S. EIA data in this fashion allows for calculations of average prices of consumed electricity, as opposed to average prices of individual offers made by electric companies. This distinction is important. The problem with averaging offers by electric companies — but without an understanding of how many customers take each offer — is that such an analysis can lead to conclusions that bear little resemblance to actual market outcomes. For instance, while it may be true that many low-cost offers are available in a given area, it may also be true that most Texans living in those areas do not or cannot avail themselves of those low-cost offers because of restrictions in their existing electricity contracts, or for a number of other reasons.

However, an examination of individual offers is nonetheless useful to gain a sense of commonly available electricity prices in deregulated areas, including prices found in fixed-rate and variable-rate deals. This report examines such individual pricing offers, as included in rate surveys conducted by the Texas Public Utility Commission.

This report also examines charges by the state's two largest transmission and distribution providers, as posted on the PUC website. Transmission and distribution charges by "wires" utilities are non-bypassable, meaning that these charges are imbedded in electricity prices paid by all consumers in the utility's service territory, regardless of the retail electric provider that the consumer selects for service.

THE FINDINGS

Benchmark Analysis: Long-term Trends

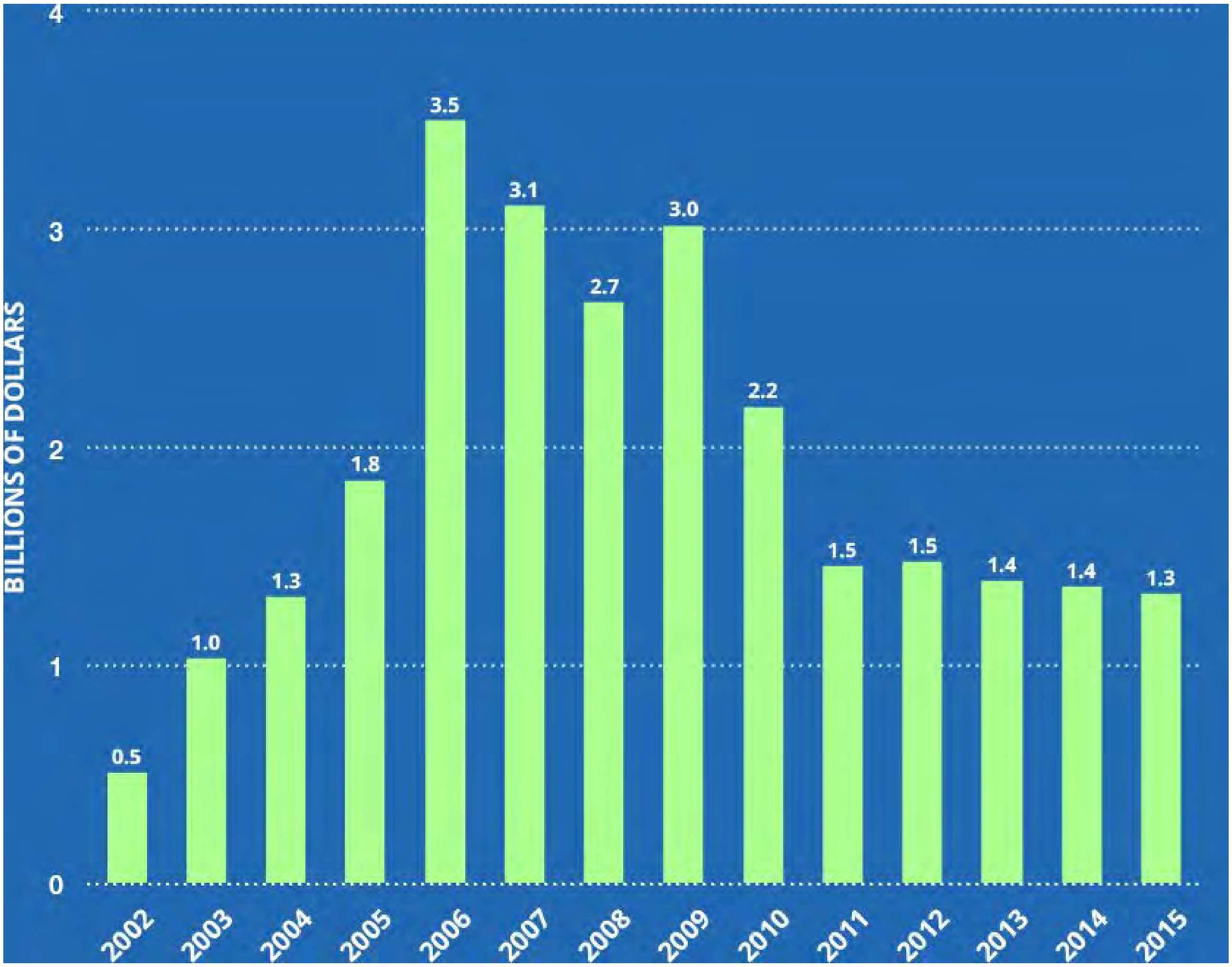
- Texans living in deregulated areas of the state have paid higher average rates for residential electricity than Texans living in areas exempt from deregulation. This is true for 2002 through 2015 — that is, for every year for which U.S. EIA data exists to conduct this analysis. [See Exhibit 1]. Over those years, average residential prices in deregulated areas have been between 9.2 percent (2002) and 46.5 percent (2006) higher than average prices in deregulation-exempt areas.

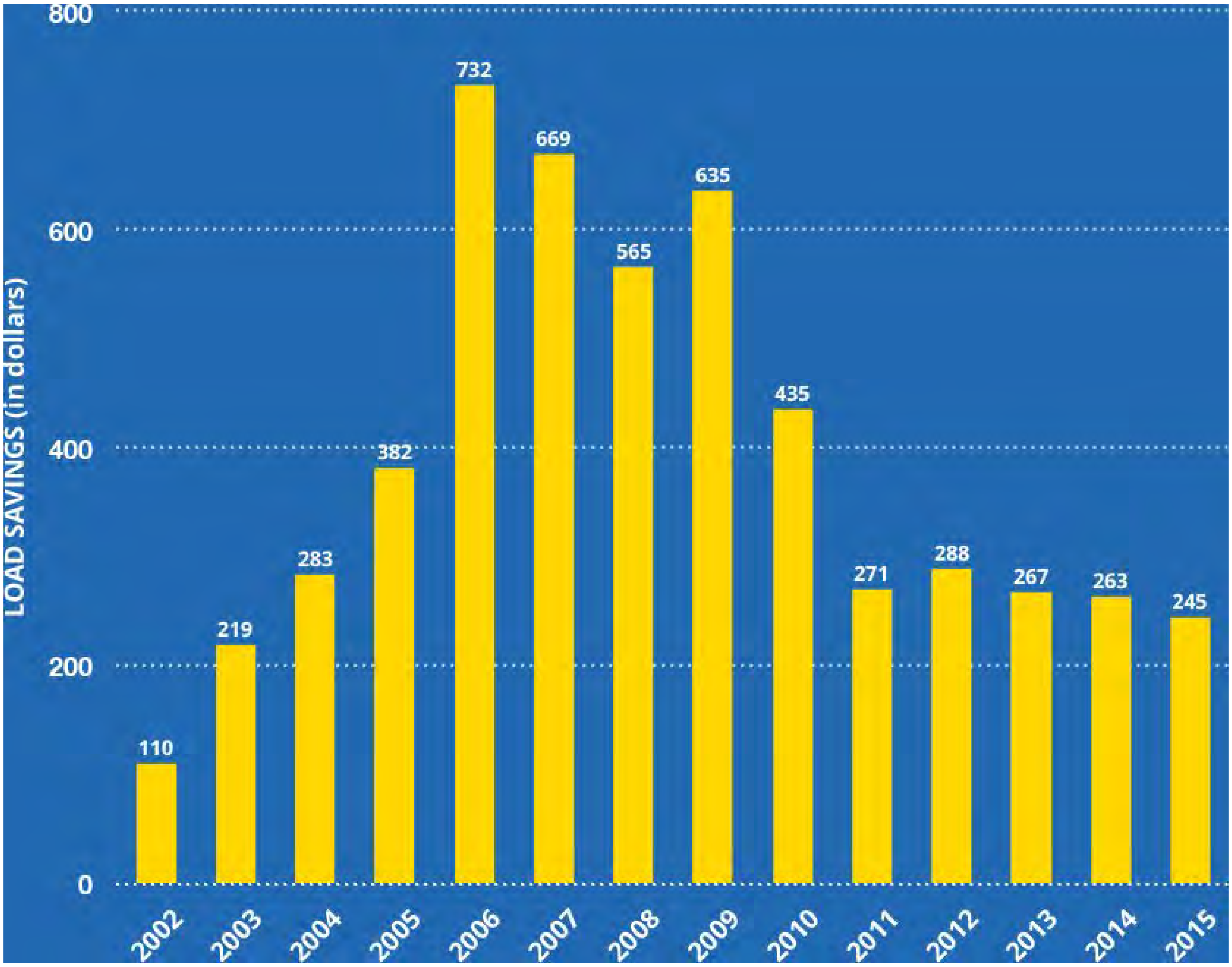
- All told, Texans living in deregulated areas would have saved more than $26 billion in lower residential electricity bills from 2002 through 2015 had they paid the same average prices as Texas living outside deregulation. This imputed higher costs amount to more than $5,300 for a typical household. [See Exhibit 4 and Exhibit 5].
- From 2002 through 2015 average residential electricity prices increased more at the national level than prices increased in both deregulated and deregulation-exempt areas of Texas. During that period, the increase in average residential prices in deregulated Texas was greater than the increase in areas of Texas exempt from deregulation. [See Exhibit 9]
- A shorter view — that is, confining the analysis to the 10 years from 2006 through 2015 — reveals that average residential prices have dropped in deregulated areas by 17.4 percent, while they have increased in areas exempt from deregulation by 5.5 percent. [See Exhibit 1].
- Texas has fared comparatively well in relation to other states with deregulated retail electricity. The average price increase for residential power in deregulated Texas from 2002 through 2015 was the fourth lowest among 15 such states during that period. [See Exhibit 2].
- Annual average residential electricity prices in deregulated areas of Texas have been higher than the nationwide average during 10 of the 14 years included in the benchmark analysis (2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011 and 2014). Annual average residential electricity prices in areas of Texas exempt from deregulation have been higher than the nationwide average once during those 14 years (2005). [See Exhibit 8].
- It remains unclear whether the historic disparity between average electric prices in deregulated and non-deregulated areas continues after 2015 because the necessary data to conduct that analysis has not yet been released. However, rate surveys of more recent competitive offers show an increasing number meeting or beating prices in deregulation-exempt areas. [See Exhibit 12 and Exhibit 13].

The Impact of Higher Residential Rates Under Deregulation: 2002-2015

The Aggregate Impact: Imputed Higher Costs Exceed $26 Billion In the Aggregate.

Exhibit 4: Average electric prices in Texas charged by deregulated providers have been consistently higher than average prices charged by providers exempt from deregulation. The exhibit at right depicts the potential impact of these higher prices. The green bars illustrate the higher costs imputed to Texans in deregulated areas, in the aggregate, when their average rates are compared to averages outside deregulation. These imputed higher costs range from about $500 million per year to more than $3.5 billion. Note, however, that the differential has declined precipitously since the 2006-2010 time period. The aggregate total from 2002 through 2015 exceeds $26 billion in higher costs.


BILLIONS OF DOLLARS
4
3
2
1
0
3.5
3.1
3.0
2.7
2.2
1.8
1.5
1.5
1.4
1.4
1.3
1.3
1.0
0.5
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015



The Individual Impact: Imputed Higher Costs Exceeds $5,300 on Per-Customer Basis.

Exhibit 5: This exhibit depict added costs not in the aggregate, but rather for a hypothetical individual ratepayer. The yellow bars illustrate the higher costs imputed to such a hypothetical Texan who pays average deregulated electricity prices, as compared to average prices for a Texan outside deregulation. Considered in this per-customer fashion, the imputed extra costs range from about a $110 per year to $732 per year. For purposes of comparison, this exhibit assumes per-customer monthly electricity usage of 1,300 kWh. The 2002-2015 total exceeds $5,300 on a per-customer basis.

Source: United States Energy Information Administration

Benchmark Analysis: 2015 Electric Prices

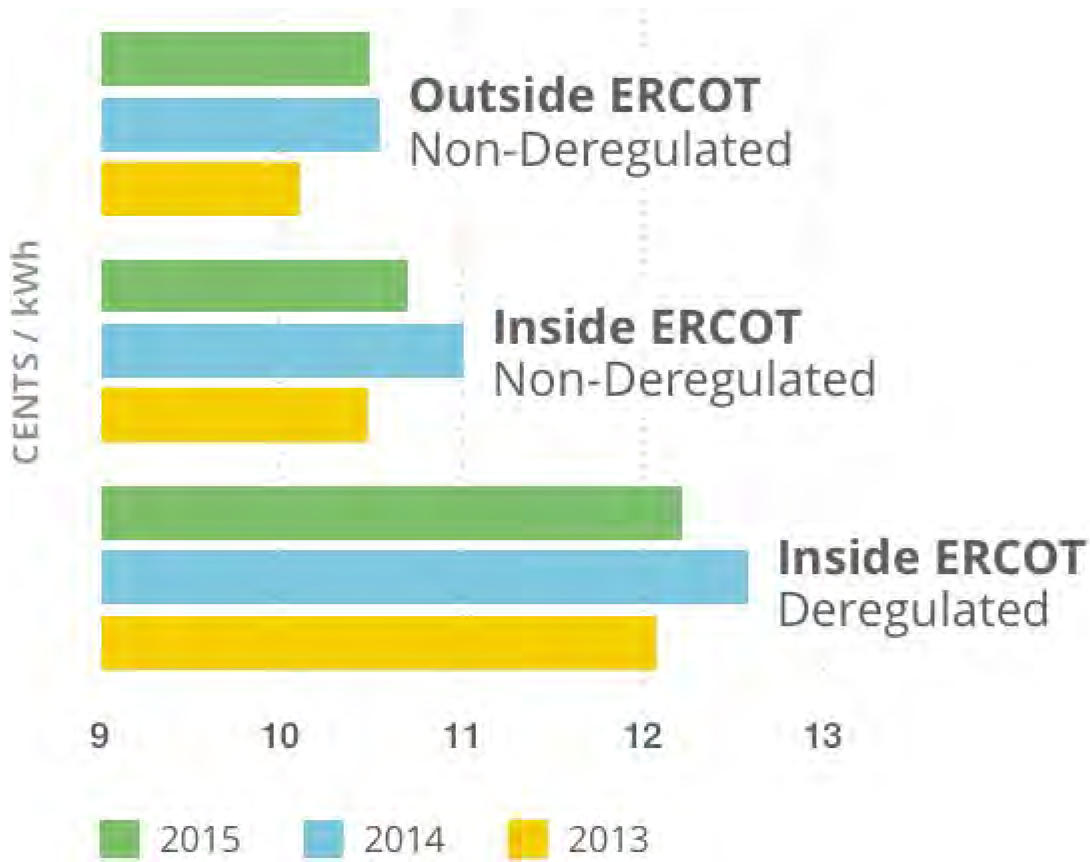
- In 2015 Texans in deregulated areas paid, on average, 12.22 cents per kilowatt hour for residential electricity, while the average price of electricity in areas of Texas exempt from deregulation was 10.65 cents per kilowatt hour. The corresponding nationwide average was 12.55 cents. [See Exhibit 1].

- Had Texans under deregulation paid the same average residential prices for electricity as Texans in areas exempt from deregulation, Texans under deregulation would have saved $1.3 billion in 2015. [See Exhibit 4].

- A typical customer living in a deregulated area of Texas (defined as a customer paying average deregulated prices and consuming 1,300 kilowatt hours of electricity every month) could have saved approximately $244 in 2015 if he or she instead had paid average prices charged to Texans outside deregulation. [See Exhibit 5].

2013-2015: Inside and Outside ERCOT

Exhibit 7: Residential Electric Prices

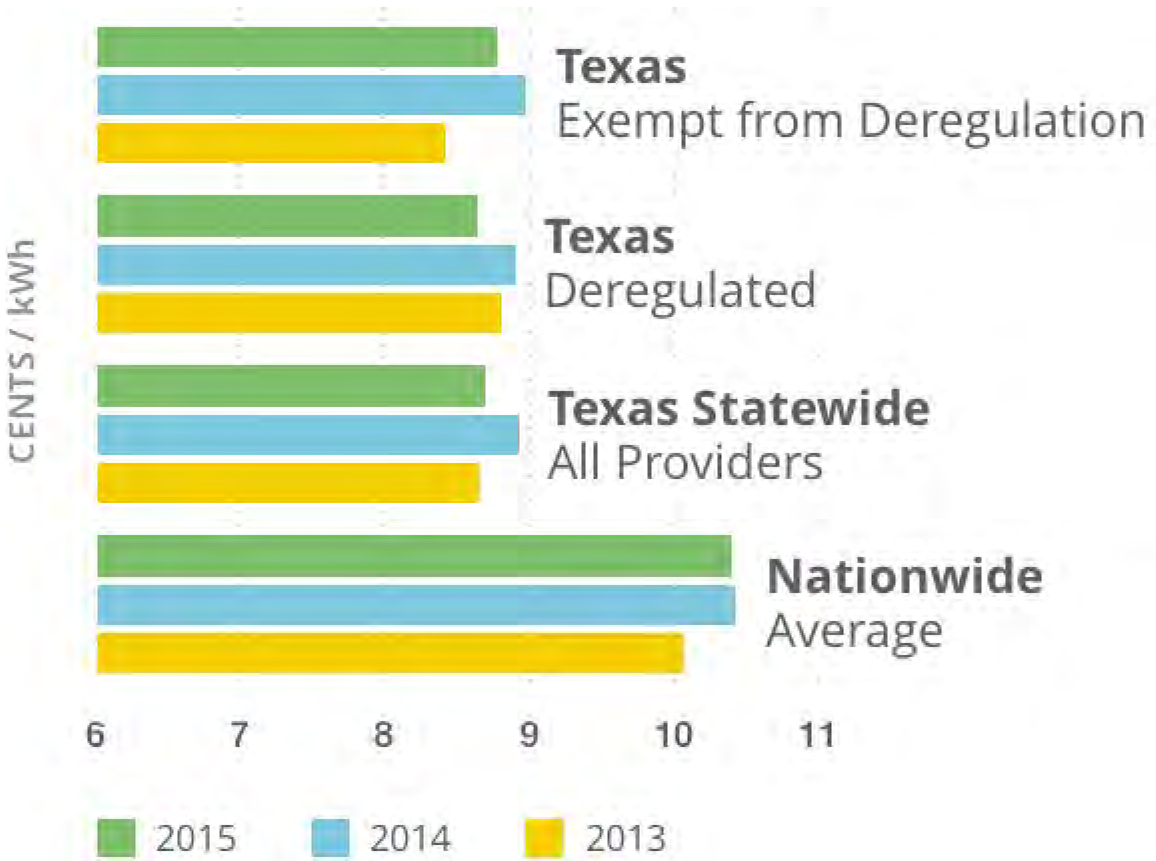


This exhibit depicts three years of average residential prices for areas inside and outside the area of the state's primary power grid. This grid, administered by the Electric Reliability Council of Texas, covers most of the state and includes both deregulated and non-deregulated areas. As shown here, average residential prices in deregulated Texas were higher than average prices in areas of Texas without deregulation — whether those non-deregulated areas were inside or outside ERCOT.

Source: United States Energy Information Administration

2013-2015: All Customer Classes

Exhibit 6: Combined Residential, Commercial and Industrial Prices



This exhibit depicts electricity prices among all customer classes (residential, commercial and industrial) during three years: 2013, 2014 and 2015. Average prices for these customer classes combined were lower in Texas during these years than they were nationwide. This exhibit also shows average prices inside and outside areas of Texas with deregulation.

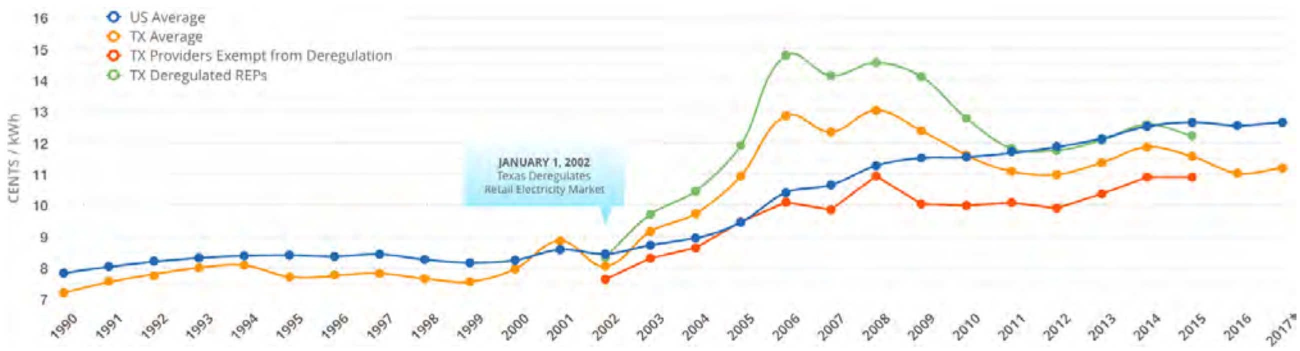
Source: United States Energy Information Administration

- In 2015, the average statewide price of electricity (both inside and outside areas of Texas with deregulation) for all customer classes (residential, commercial and industrial) was 8.7 cents. This beats the 10.41-cent nationwide average price. [See Exhibit 6].
- In 2015, average residential electricity prices charged by deregulated providers within the region served by the Electric Reliability Council of Texas (the state's primary power grid operator) were higher than prices charged by deregulated exempt providers within that region. [See Exhibit 7].

Average Residential Electricity Prices

Exhibit 8: Texas and United States — 1990-2017*

A. 964



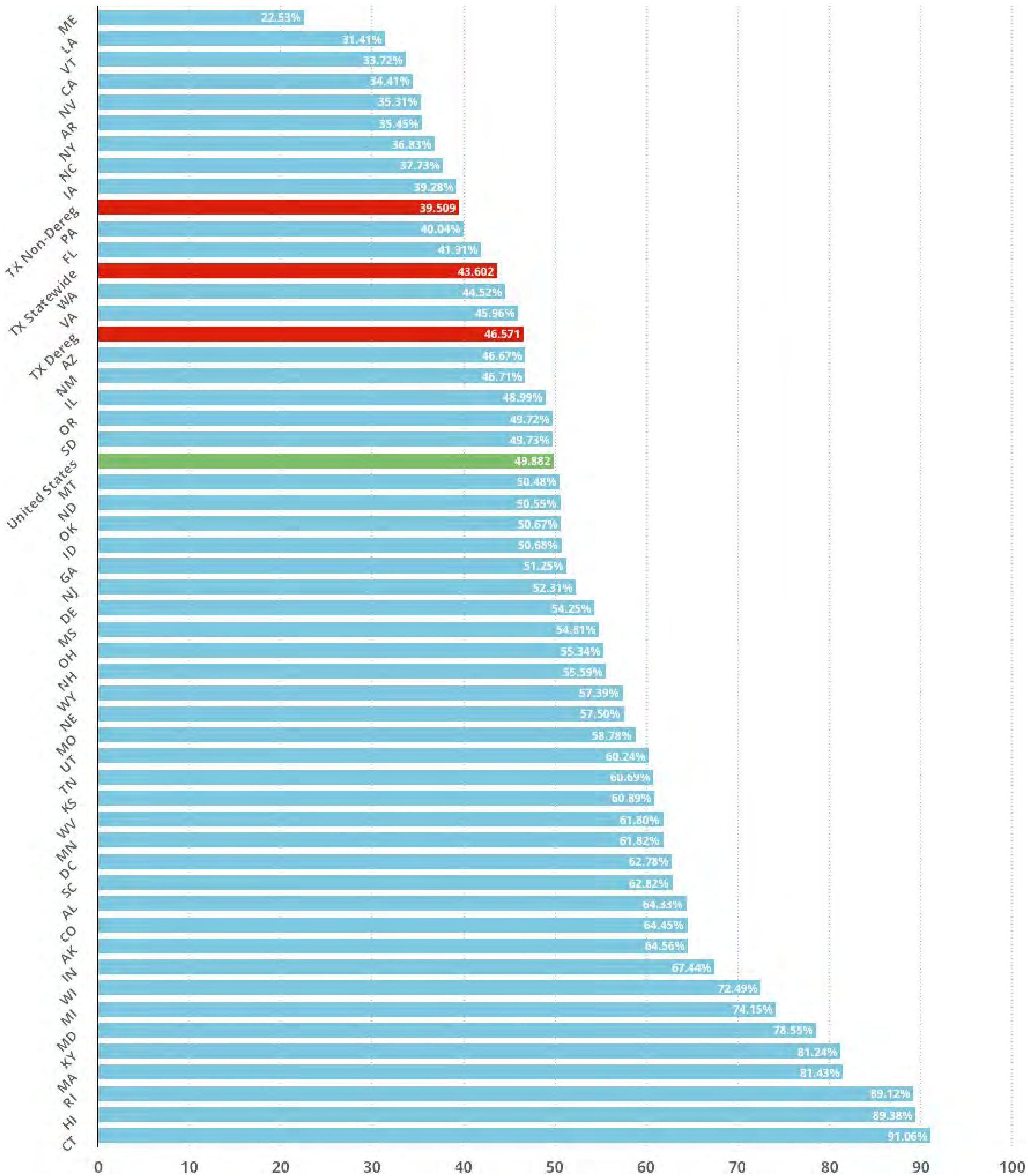
The statewide average price for residential electricity remained below the national average for many years prior to the implementation of the Texas deregulation law. But after Texas deregulated its retail electric market, the statewide average price for residential electricity surpassed the national average. It also remained significantly above that mark for many years. Note, however, that average residential prices in deregulation-exempt areas of Texas remained consistently below the national average after implementation of the deregulation law. By contrast, average prices in deregulated areas remained consistently above the national average (also see Exhibit 1). This dynamic suggests that high residential electricity prices in deregulated Texas contributed to the comparatively high statewide average price after 2002.

Also note that this exhibit shows average statewide residential prices in Texas spiking above the national average in 2001. Although that spike occurred before the deregulation of the state's retail electricity market, it nonetheless was a function of deregulation. This is because the Texas Public Utility Commission allowed utilities in 2001 to collect excess earnings and high fuel surcharges as a down payment on anticipated collections from the restructuring law. Average statewide residential prices in Texas dropped after the deregulated market opened in 2002 because the fuel surcharges expired and because the deregulation law mandated a 6 percent cut in base rates. Average statewide residential prices then remained above the national average through 2010.

This exhibit does not distinguish between prices in areas of the state that are currently deregulated and non-deregulated prior to 2002. This is because the federal data to conduct that granular analysis are not readily available. The same is true for the years 2016 and 2017.

Source: United States Energy Information Administration & Electricity Data Browser

*2017 data through March 2017



Residential Electricity Prices

Exhibit 9: Percentage Increases 2002-2015

Residential electricity prices increased in deregulated areas of Texas from 2002 through 2015 by 46.57 percent, which is less than the 49.88 percent increase registered nationwide. However, electricity prices in areas of the state exempt from deregulation increased by less than 40 percent during that period.

A. 966

Source: United States Energy Information Administration & Electricity Data Browser

Transmission and Distribution Charges

Although monopoly transmission and distribution utilities operate under regulation, their rates impact electricity prices charged by competitive retail electric providers. This is because transmission and distribution utility rates are non-by-passable, which means they are included in a uniform fashion in the rates charged by all retail electric providers that operate in each utility's service territory.

Rate increases since 2003 by the Oncor utility (operating in the Dallas-Fort Worth area) and the CenterPoint Electric utility (operating around Houston) have outpaced inflation. Transmission and distribution charges paid by Oncor and CenterPoint customers also comprise an increasing share of monthly electric bills.

Non-Bypassable Charges: CenterPoint

Exhibit 10: (September 2003 – March 2017)

Transmission and distribution charges
(in dollars, on 1,000kWh monthly bill)

Transmission and distribution utilities operate as regulated monopolies, even in areas of Texas with deregulation. The rates assessed by these utilities continue going up, sometimes at a rate well beyond that of inflation. For instance, rates charged by CenterPoint Electric in the Houston area have increased 67.2 percent since 2003. In 2003, CenterPoint charges comprised 20.2 percent to 29.2 percent of a typical 1,000 kWh electric bill. In 2017, CenterPoint charges comprised 29 percent to 50.1 percent of a typical bill. All electric customers in deregulated areas around Houston must pay CenterPoint's rates, regardless of the retail electric provider the customer chooses for service.

Source: Archived TDU Rate Summaries, PUC

Non-Bypassable Charges: Oncor

A. 967

Exhibit 11: (September 2003 – March 2017)

Transmission and distribution charges
(in dollars, on 1,000kWh monthly bill)

Rates charged by Oncor utility in the Dallas-Fort Worth area increased by nearly 66 percent since 2003. That rate outpaces the rate of inflation. In 2003, Oncor charges comprised 20.1 percent to 27.4 percent of a typical 1,000 kWh electric bill. In 2017, the charges comprised 29 percent to 51.4 percent of a typical bill. All customers in deregulated areas of the Dallas-Fort Worth region must pay Oncor's rates, regardless of the retail electric provider the customers choose for service.

Source: Archived TDU Rate Summaries, PUC

Recent Competitive Offers

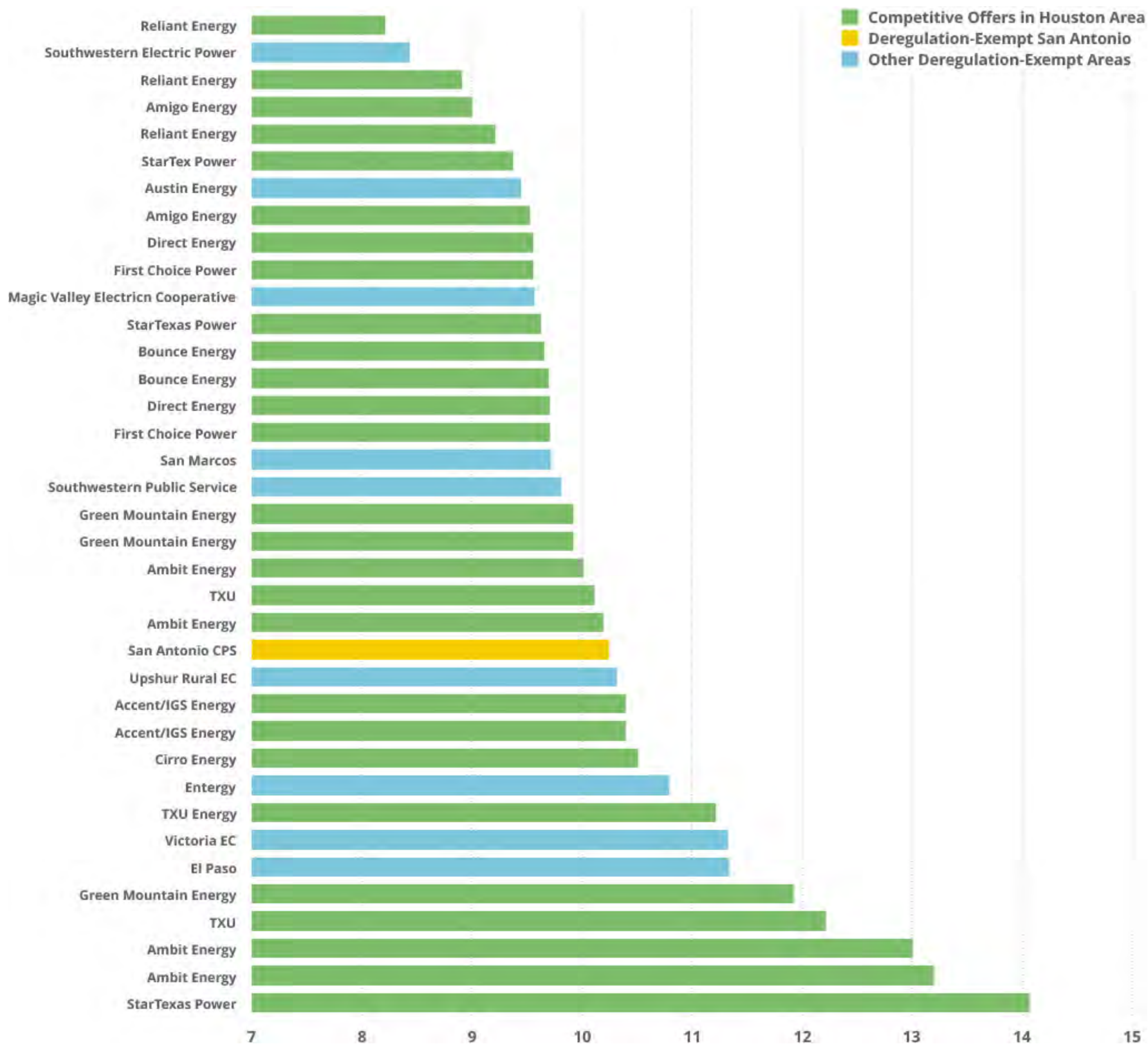
An April 2017 survey of electricity deals in Houston reveals 18 competitive offers with prices lower than the electricity price paid in San Antonio. Houston is the largest city in Texas with deregulation. San Antonio is the largest city exempt from deregulation. This finding is in contrast to previous years, in which Public Utility Commission surveys revealed far fewer deals in Houston with lower prices than in deregulation-exempt San Antonio. [See Exhibit 12].

An April 2017 survey of electricity deals in the Dallas-Fort Worth area reveals 23 competitive offers with prices lower than the electricity price paid in San Antonio. [See Exhibit 13].

Electricity Prices (Houston-Area)

Exhibit 12: Competitive Houston-Area Offers vs. Residential Prices in Deregulation-Exempt Area
(According to PUC Price Surveys, as of March 2017)

A. 968

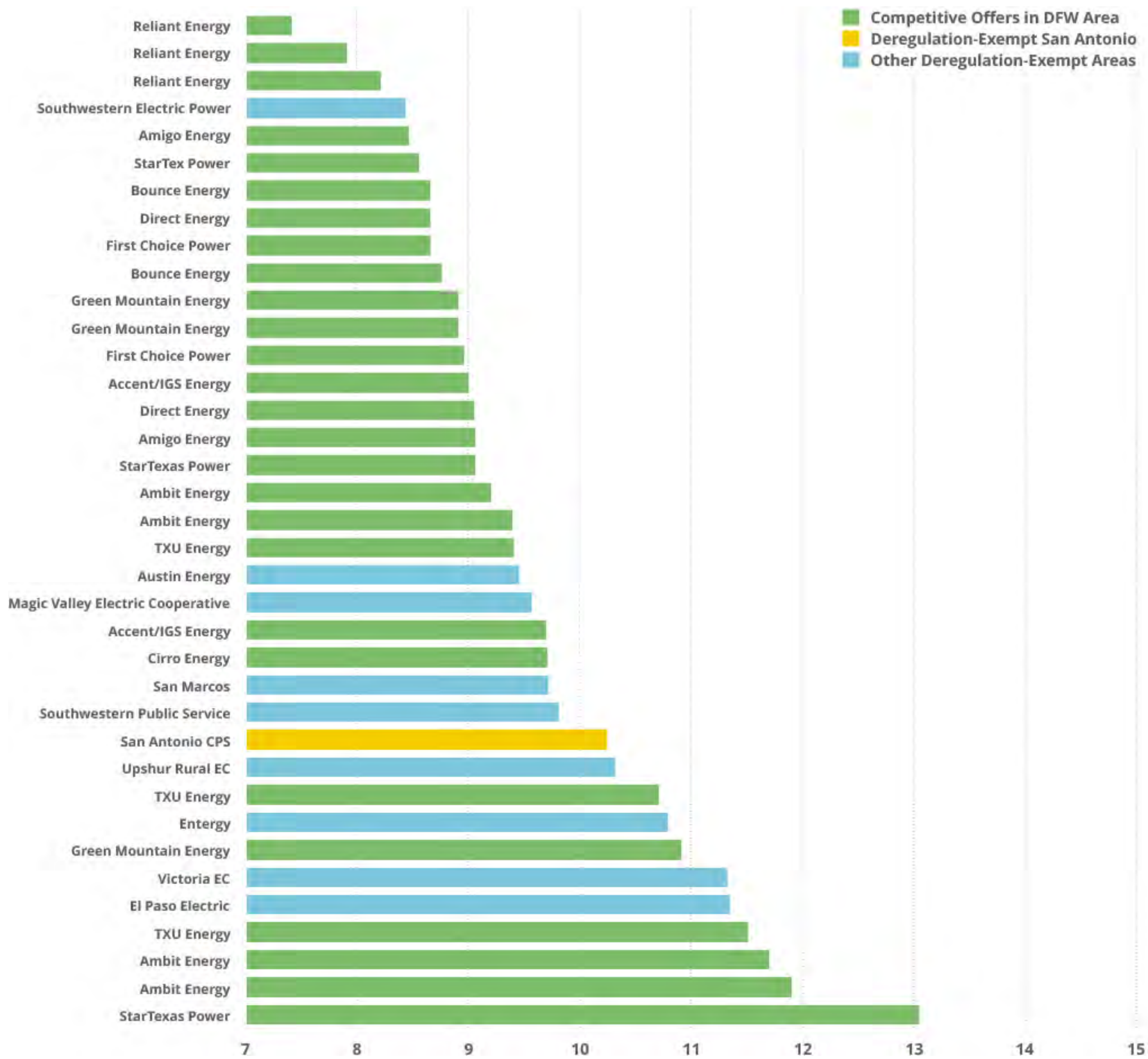


Average electricity prices paid by Texans living in areas outside deregulation have been consistently lower than average prices paid in deregulated areas. But that doesn't mean that Texans can't find plenty of good deals in deregulated areas. This exhibit shows many individual retail offers in the Houston area (as listed in a PUC rate survey for April 2017) that are lower than the residential price of electricity in San Antonio. Houston is the largest city in Texas with deregulation. San Antonio is the largest city exempt from deregulation. This finding is in contrast to the early years of the Texas deregulation law, in which PUC surveys revealed far fewer deals in Houston that were lower than the San Antonio regulated rate. This exhibit also lists electricity prices in other areas of Texas exempt from deregulation. All data has been retrieved from PUC rate surveys.

Electricity Prices (DFW-Area)

Exhibit 13: Competitive DFW-Area Offers vs. Residential Prices in Deregulation-Exempt Area

(According to PUC Price Surveys, as of March 2017)



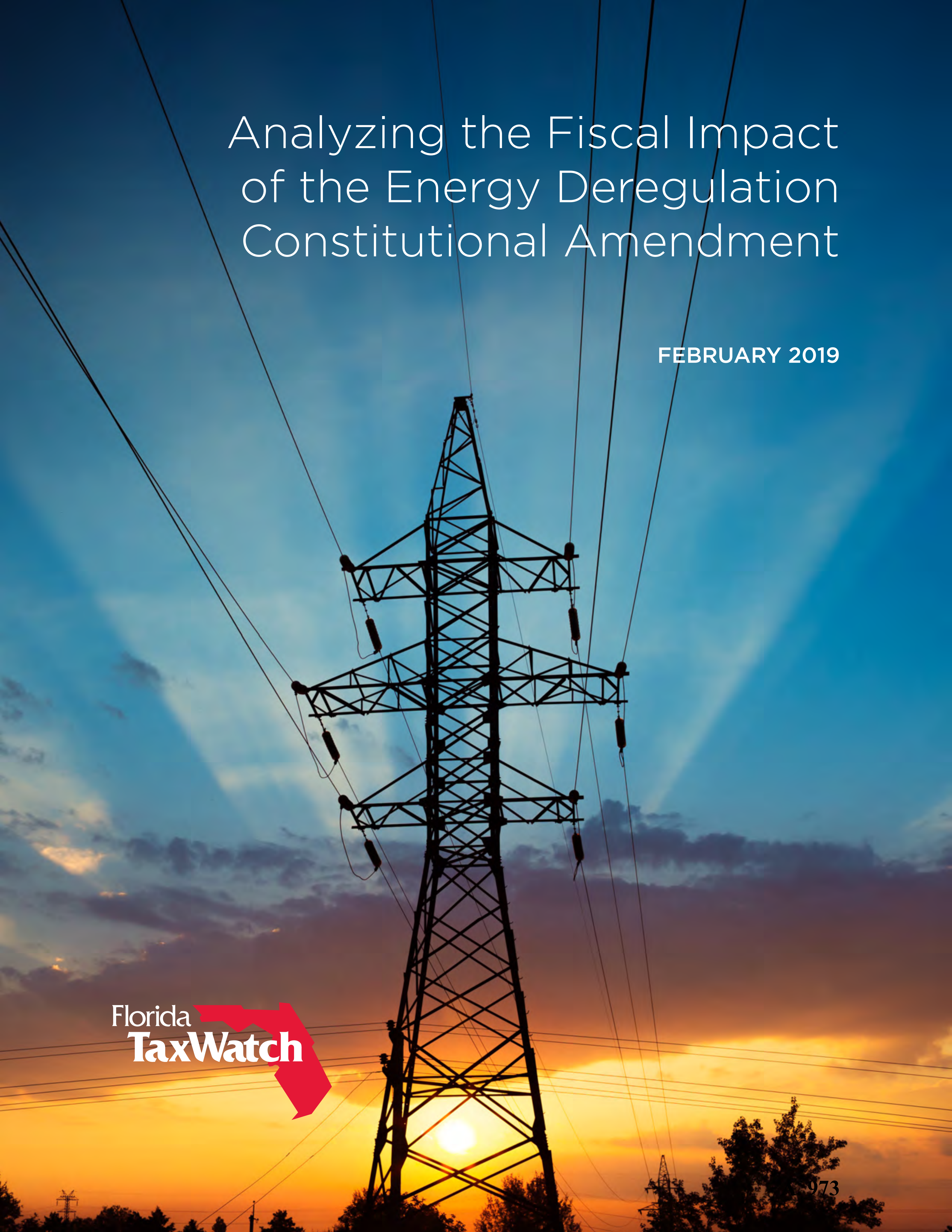
This exhibit shows individual retail electric offers in the Dallas-Fort Worth area, as listed in a PUC rate survey for April 2017. Those offers are shown in green. Exhibit 13 also shows electricity prices in many deregulation-exempt areas of Texas. These are marked in blue. The price of electricity in San Antonio, which is the largest city in Texas exempt from deregulation, is shown in yellow.

About the Author

R.A. "Jake" Dyer

Is a policy analyst for TCAP, a coalition of cities and other political subdivisions that purchase electricity in the deregulated market for their own governmental use. Because high energy costs can impact municipal budgets and the ability to fund essential services, TCAP, as part of its mission, actively promotes affordable energy policies. High energy prices also place a burden on local businesses and home consumers.

TAB 19



Analyzing the Fiscal Impact of the Energy Deregulation Constitutional Amendment

FEBRUARY 2019

Florida TaxWatch

Florida TaxWatch

106 North Bronough Street, Tallahassee, FL 32301 floridataxwatch.org o: 850.222.5052 f: 850.222.7476

Dear Fellow Taxpayer,

Electric power is vital for Florida's residents and businesses. We rely on electricity to power our modern lives and economy, and state and local governments generate significant revenue from the generation, distribution, and sale of electric power.

Currently, Florida electricity customers enjoy prices that are below the U.S. average for residential and commercial electricity. Yet, a proposed constitutional amendment initiative that would destructure Florida's energy market may appear on the November 2020 general election ballot that would (if approved) radically change Florida's energy market.

TaxWatch has undertaken this independent analysis to estimate the financial impacts of deregulation on tax revenues and to help Florida taxpayers better understand the effects of the proposed deregulation.

Discussions about improving such vital systems as Florida's energy market are healthy, and Florida TaxWatch is honored to offer this independent evaluation of this proposal; however, our long-held belief that the venue for considering such policy discussions should be the Legislature and not a constitutional amendment must be noted here.

TaxWatch is pleased to present this report and its findings and looks forward to engaging policymakers and taxpayers in informed discussion.

Sincerely,

Dominic M. Calabro

Dominic M. Calabro
President & CEO

Executive Summary

A proposed 2020 ballot initiative currently making its way through the process, if approved by 60 percent or more of the voters, would deregulate only the segment of Florida's energy market served by the investor-owned utilities (IOUs). Under the proposed language, IOUs would be limited to the construction, operation, and repair of electrical transmission and distribution systems, while municipal and cooperative utilities would have discretion whether to opt into competitive markets. The Florida Legislature would be required to create laws and regulations providing for competitive wholesale and retail markets for electricity generation and supply, and consumer protections, by June 1, 2023 and fully implement the new system by June 1, 2025.

There are a variety of significant tax and revenue implications of this amendment, and this Florida TaxWatch analysis finds that, unless very significant increases in the price of electricity for Floridians result, adoption of the proposed constitutional amendment will have a negative impact on state and local government revenues. These impacts have the potential to be relatively large. Of course, the Legislature and local governments can change the tax structure in an attempt to offset any revenue loss, but that road is fraught with peril.

This analysis provides estimates for both 2018 and 2026. The impacts were first estimated for 2018, the year of the latest tax data. Those estimates were then projected out to 2026—the expected first full year of implementation if the amendment were to pass. The estimates are as follows:

Potential Revenue Impacts by Source

	2018 Revenue Losses			2026 Revenue Losses		
	Low	Middle	High	Low	Middle	High
Electricity Franchise Fees (Local)						
Assumption 1	$171m	$341m	$512m	$190m	$380m	$568m
Property Tax (Local)						
Assumption 1	$18m	$27m	$35m	$26m	$71m	$50m
Assumption 2	$53m	$71m	$88m	$75m	$100m	$125m
Assumption 3	$68m	$95m	$122m	$97m	$135m	$174m
Assumption 4[A]	$105m	$151m[A]	$197m	$149m	$215m[A]	$280m
Gross Receipts Tax (State)						
Assumption 1	$14m	$24m	$33m	$16m	$26m	$37m
Assumption 2		$279m			$310m	
Public Service Tax (Local)						
Assumption 1	$43m	$86m	$129m	$48m	$96m	$144m
Sales Tax (State & Local)						
Assumption 1	$19m (State) $1m (Local) $20m (Total)	$37m (State) $2.5m (Local) $39.5m (Total)	$55m (State) $4m (Local) $59m (Total)	$21m (State) $2m (Local) $23m (Total)	$41m (State) $3.5m (Local) $44.5m (Total)	$61m (State) $5m (Local) $66m (Total)
State Total[B]	**$33m**	**$167m**	**$334m**	**$37m**	**$204m**	**$371m**
Local Total[C]	**$320m**	**$581m**	**$842m**	**$389m**	**$693m**	**$997m**
Potential Total	**$353m**	**$748m**	**$1,176m**	**$426m**	**$897m**	**$1,368m**

[A] Assumption 4 is a combination of the previous assumptions plus a loss of value from non-generation property, therefore the mid-point of assumption 4 represents the mid-point of the combination of the assumptions.

[B] State total includes the Gross Receipts Tax and State Sales Tax

[C] Local total includes the Franchise Fees, Property Taxes, Public Service Tax, and Local Sales Tax

Introduction

There are three major types of electric utility providers: municipal utilities, (rural) cooperative utilities, and investor-owned utilities. Municipal utility companies are "owned and/or operated by a municipality engaged in serving residential, commercial and/or industrial consumers, usually within the boundaries of the municipalities. The rates and revenues from the utilities are regulated by their city commission or an authority appointed by the city commission."[1] Cooperative utilities generally serve Florida's rural areas and are "joint ventures organized for the purpose of supplying electric energy to a specific area. The rates and revenues of rural electric cooperative utilities are regulated by their elected cooperative officers."[2] Investor-owned utilities, which collectively serve the majority of Floridians, are private companies that supply power directly to consumers in all areas not served by municipal or cooperative utilities while also generating power for their customers and to sell to the municipal and cooperative utilities at wholesale. "Investor-owned utility rates and revenues are regulated by the Florida Public Service Commission."[3, 4]

"There are three distinct components to the provision of electricity services: (1) generation (the actual production of electricity); (2) transmission (the transportation of large volumes of electricity at high voltage between the generating plant and the distribution system); and (3) distribution (the delivery of electricity to retail customers in a usable, low voltage form). Over the past century, Florida's electric industry has developed as a vertically-integrated industry, with electric utilities packaging the generation, transmission, and distribution of electricity and providing it to retail consumers in a single rate."[5]

Under Florida's current system, the retail price of electricity for consumers (Residential, Commercial, and Industrial) is below the national average. TaxWatch analysis of data compiled and provided by the U.S. Department of Energy's Information Administration (EIA) shows that Florida's residential rates are the lowest of the ten largest states in the country. Furthermore, the analysis shows that for the twenty years between 1997 and 2017, increases in retail electric prices in states with deregulated electricity markets and regulated states were about the same, and that the prices (per kilowatt-hour) for Residential, Commercial, and Industrial customers in regulated electricity markets (like Florida) are lower than the prices for Residential, Commercial, and Industrial customers in deregulated electricity markets.

"In November 2017, the Public Service Commission's *Review of the 2017 Ten-Year Site Plans* shows that the current supply of electricity in Florida is reliable, even during peak demand periods or unplanned plant outages. Moreover, either by statute or the PSC's approval of territorial agreements, all consumers in the state are assured electricity service regardless of their location or socio-economic status."[6]

1 CRC P51 Proposal Analysis, December 12, 2017.

2 CRC P51 Proposal Analysis, December 12, 2017.

3 CRC P51 Proposal Analysis, December 12, 2017.

4 The Florida Public Service Commission is a state body of appointed officials (with staff) that regulates rates, charges, territorial agreements, need for power plants, and much more regarding the generation, transmission, and sale of electricity. By law (Fla.Admin. Code R. ch. 25-6 (2000)), the Public Service Commission promotes "good utility practices and procedures, adequate and efficient service to the public at reasonable costs, and to establish the rights and responsibilities of both the utility and the customer."

5 CRC P51 Proposal Analysis, December 12, 2017 (page 4)

6 CRC P51 Proposal Analysis, December 12, 2017 (page 5, internal citations omitted from original)

While most states, 33 including Florida, have a regulated energy market, based on the general theory of electric power as an essential service for the well-being of society, buttressed by the industry's inherent propensity toward natural monopoly,[7] 17 states and the District of Columbia have since taken steps to destructure or deregulate[8] their retail markets for electricity since the early 1990s. Under a "deregulated" or "deconstructed" system, the price consumers pay for the transmission and distribution of electricity is generally still regulated but the price they pay for the actual electric power is not and customers choose their electricity provider from among any number of retail electricity suppliers available in their area.

An interest group named Citizens for Energy Choices is promoting a constitutional amendment initiative[9] that may appear on the November 2020 general election ballot. The proposed initiative, if approved by 60 percent or more of the voters, would deregulate only the segment of Florida's energy market served by the investor-owned utilities (IOUs); IOUs would be limited to the construction, operation, and repair of electrical transmission and distribution systems. Municipal and cooperative utilities would have discretion whether to opt into competitive markets. The Florida Legislature would be required to create laws and regulations providing for competitive wholesale and retail markets for electricity generation and supply, and consumer protections, by June 1, 2023 and fully implement the new system by June 1, 2025.[10]

The 2018 Florida Constitution Revision Commission considered a proposal (Proposal 51) similar to this proposed amendment. The Commission's "Proposal Analysis" found:

> *"The majority of states still follow the vertically integrated model that is currently used here in Florida. In those states that have experimented with restructuring their electricity markets, those efforts have typically occurred in states where electricity prices were disproportionately high and which had access to power supply sources from other states. Neither of those dynamics are present in Florida. As noted above, Florida's residential rates are below the national average and are the lowest of the ten largest states in the country. Moreover, Florida's peninsular geography constrains interties with other states and has 'resulted in an interstate interconnection system that has limited the state's competitive generation options (i.e., power sales to and power purchases from out-of-state utilities).'"*[11]

Proposal 51 was rejected by a 5-2 vote and died in the General Provisions Committee of the Constitutional Revision Commission in January 2018.

TaxWatch has undertaken this independent analysis to estimate the financial impacts of restructuring on public revenues, and to help Florida taxpayers better understand the effects of a competitive electric power market on their ability to secure reliable and reasonably-priced electricity.

7 See, e.g., Lazar, J. (2016), Electricity Regulation in the US: A Guide (second edition), Montpelier, VT, The Regulatory Assistance Project, Chapter 1: "The Purpose of Utility Regulation."

8 The terms "deregulate" and "restructure" mean essentially the same thing and are used interchangeably throughout this report.

9 Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice (Initiative Number 18-10).

10 Florida Division of Elections, "Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice (Initiative Number 18-10), retrieved from https://dos.elections.myflorida.com/initiatives/initdetail.asp?account=73832&seqnum=1, January 30, 2019.

11 CRC P51 Proposal Analysis, December 12, 2017 (page 5 internal citations omitted).

Effects of Restructuring Electricity on Tax Revenues

The energy market destructuring proposal would have significant and measurable impacts on the state and local tax revenues and likely even the structure of such taxes. While the impact could easily be measured after the fact, projecting those impacts, especially six years into the future (the proposal requires full implementation of the destructured system by June 1, 2025) is difficult.

The task is complicated by three main factors (in addition to Mr. Yogi Berra's astute observation that "predictions are hard, especially about the future"). First is the magnitude: in total, taxes and fees related to electricity generate nearly $4.5 billion for state and local governments. Second, many of the taxes are dependent on the price of electricity and/or the market value of real assets, both of which are difficult to forecast far into the future. Finally, there are some technical and legal issues that are unclear at this time – since the proposal does not specify the rules and regulations that will govern the destructured system but instead requires the Legislature to create them by June 1, 2023, the resulting revenue of the applicable tax laws and their application must be based on current law and assumptions of likely amendments thereto. It is likely some revenue sources will have to be restructured or new revenue sources implemented, but the response by future Florida Legislatures and local governments is unknown.

Changes in the price of electricity would impact revenues, since so much of the billions in taxes and fees paid by IOUs are based on the amount consumers pay or on the gross revenues of utilities, but the inconsistent outcomes across other states that have initiated deregulation and the probable allowance for recovering stranded costs further cloud the future. If electricity prices fall, so will government revenues and the cost of energy for public entities. Conversely, electricity price increases would boost revenue, offsetting some of the revenue loss that is due to other factors, but also increase the cost of energy for public entities. Since our extensive literature review finds little evidence that deregulation will significantly reduce Florida's electricity prices, TaxWatch does not attempt to quantify the impact electricity prices would have on government revenues.

An added degree of uncertainty results from Florida Constitutional Amendment 5,[12] approved by the voters in November 2018. The amendment requires that any state tax or fee increase be approved by at least a two-thirds vote of the membership of both the House and Senate, and that each increase be in a separate bill containing no other subject. Historically, tax increases in Florida that have been approved by majority vote have generally reached the two-thirds threshold;[13] however, with such a complicated and interrelated utility tax and fee structure, and so many competing interests, reaching a broad consensus may be difficult.

There are multiple factors resulting from a deregulated electricity market besides price that can impact revenues. These include the migration of energy generation outside of the state, the loss of property tax values of electricity assets, the need to distribute tax burden among more (and no longer similar) companies, tax and fee bases that might no longer be appropriate, and the revenues and profits of electricity providers. In addition to these factors, there are two issues that will significantly affect public revenues in a destructured system that must be addressed first. One is the stranded costs associated with the change from the current system; the second is the state's ability to exercise jurisdiction over new providers in the collection of taxes.

12 Article VII, s. 19, Florida Constitution.

13 Florida TaxWatch, 2018 Voter Guide to Florida's Constitutional Amendments. https://floridataxwatch.org/Research/Full-Library/ArtMID/34407/ArticleID/17819/2018-Voter-Guide.

Stranded Costs

Stranded costs represent the quantified losses that will be incurred by the IOUs as a direct result of the destructuring policy. If the proposed constitutional amendment were to pass, IOUs would be required to sell all generation assets within a fixed time period, which would likely lead to discounted prices for the assets, which are termed stranded costs. Essentially, stranded costs are the difference between book value to the current owner of an asset versus value of that asset sold at auction. Additionally, the costs of any legal obligations (such as breaking long-term purchase or service agreements) could count as stranded costs. Typically, IOU's are reimbursed for these costs.[14]

The market value of the generation asset cannot be known with certainty until a competitive auction has occurred; however, taxable values of real property are intended to represent the likely market value of that property. TaxWatch has examined the taxable value of Florida generation assets for IOUs[15] as well as the book value[16] and compared those values. That comparison shows as much as approximately $5.153 billion in potential stranded costs.

The U.S. Energy Information Administration reports that 2017 retail sales of electricity by Florida utilities was 233,154,549 MWh.[17] If the Florida PSC were to allow 100 percent recovery of this calculated difference, and charge it to ratepayers over a three year period, then the nominal charge per kilowatt-hour would be about $7.37 per 1,000 KWh. The average residential customer in Florida in 2017 is reported by EIA to have used an average of 1,089 KWh per month. If reimbursable stranded costs were to be larger, then this monthly charge to ratepayers would need to be larger. If instead asset auctions generated higher sale prices than implied by taxable valuations, then the stranded cost charge-off borne by ratepayers could be proportionately smaller.

Nexus

The introduction of competition is likely to attract new electricity suppliers, some of which may be located outside Florida. Whether these out-of-state suppliers may be held responsible for paying or collecting Florida taxes depends on whether "nexus" can be established. "Nexus" refers to the authority of a state to levy taxes on any out-of-state seller, historically based on physical presence (e.g., an out-of-state provider has sufficient physical property, employees or other assets in the state that would justify taxation).[18] "Physical presence" generally means there is a continuous and regular presence of employees or the presence of an office or other place of business within the taxing state.

Several taxes discussed below could be affected by nexus. Nexus issues arise when federal and state laws prohibit either taxing companies that have no physical presence (nexus) in the state or requiring them to collect taxes from purchasers on behalf of the government. This issue has received a lot of attention for many years in relation to the collection of sales and use taxes by remote sellers with no nexus in the state that sell products to residents of the state. Several U.S. Supreme Court decisions have held that companies with no nexus were not required to collect

14 Appendix A provides a detailed examination of stranded costs and their applicability.

15 Taxable values adjusted for recently completed construction.

16 Book values adjusted for accumulated reserves for depreciation.

17 U.S. EIA, "Florida Electricity Profile 2017, Table 1. 2017 Summary Statistics (Florida)". A MWh is 1,000 KWh.

18 Research Triangle Institute, "State and Local Tax Considerations in Electric Industry Restructuring, Volume 1-Task 3 Final Report, September 1998, retrieved from www.rti.org/sites/default/files/resources/7135-321.pdf, January 30, 2019.

and remit to the state any tax from purchasers. Mail order and phone sales have made this an issue for a very long time, but the explosion of Internet shopping has made this a serious revenue concern for many states, with Florida likely losing out on hundreds of millions of dollars of sales and use taxes annually. These taxes are legally due from the purchasers, but if the seller is not required to collect the tax, it is largely up to the purchaser to voluntarily pay the tax to the state.

A recent Supreme Court decision (*Wayfair vs. North Dakota*) threw out the physical presence requirement; however, the Court cautioned that complying with a state's tax law could not overburden an out-of-state seller. While this decision may pave the way for Florida to start collecting some of this missing sales and use tax revenue, the Legislature will have to take steps to facilitate such collections and Florida's resulting taxing scheme would have to pass constitutional muster. As this report discusses the various taxes on electricity, nexus will be a recurring issue. Since IOUs paid or remitted nearly $1.8 billion in these taxes in 2018, even a small percentage loss of these taxes due to nexus issues would constitute a significant negative fiscal impact for state and local governments.

Tax and Fee Tax Impacts

The electricity industry is a very important source of revenue for Florida's state and local governments. Multiple taxes and fees are levied against the sale of electricity and the operations of utilities. Providing electricity to Florida's citizens and businesses raises $4.4 billion[19] annually in taxes and fees for Florida governments (not including $2.8 billion from the sales of electricity by municipal-owned utilities).[20] Most of the tax and fee revenue is provided by private utilities. Florida's IOUs[21] pay or collect approximately $3.6 billion annually in franchise fees and public services, property, income, gross receipts, and sales and use taxes.

More than one-half of that revenue goes to local governments. This revenue is especially critical for municipalities where the public service tax on electricity is by far the largest municipal non-ad valorem tax source --- its nearly $800 million in annual revenues exceed discretionary sales tax and communications services tax revenue combined.

Charter counties collect an additional $260 million in public services taxes. Similarly, the nearly $600 million in electric franchise fees collected by municipalities represents their largest permit and fee revenue source, more than double that of all impact fees combined. Counties collect another $160 million in electricity franchise fees.

Schools are also big beneficiaries of utilities taxes. Approximately 40 percent of property taxes statewide go to school districts and the gross receipts tax funds construction, renovation, and maintenance of educational capital facilities.

19 Florida TaxWatch estimate from multiple sources, including utility companies, the Florida Legislature, the Revenue Estimating Conference and the Federal Energy Regulation Commission.

20 Florida Legislature, Office of Economic and Demographic Research, Municipal Revenue Account Totals, 2017. http://edr.state.fl.us/Content/local-government/data/revenues-expenditures/stwidefiscal.cfm.

21 Florida Power & Light, Tampa Electric Company, Duke Energy, Gulf Power, and Florida Public Utilities Company.

Franchise Fees

The taxing power of local governments is tightly restricted by the state constitution. Besides property taxes, which are authorized by the constitution,[22] local governments may only levy taxes authorized in law by the state Legislature. The constitution says: "No tax shall be levied except in pursuance of law… All other forms of taxation shall be preempted to the state except as provided by general law."[23] Under broad home rule authority granted by the constitution, however, local governments may levy fees. Fees are largely governed by case law; the guiding principle is that the fee is reasonable in relation to the government-provided privilege or service or that the fee-payer receives a special benefit.

Franchise fees are an example. These fees are negotiated between the municipal or county government and a utility. The adopted franchise agreement grants a utility a license to provide electric service to the residents and businesses within that city's limits or the unincorporated portion of a county. It also grants the privilege of using local government's rights-of-way to conduct the utility business (installing lines and poles and providing truck access). Franchise agreements also contain a promise that the local government will not provide competing utility services. Franchise fees are critical to local governments and they are the utility-related revenue source that carries the largest risk under the proposed amendment. Franchise fees are levied on other utilities, but the one on electricity is by far the most lucrative, bringing in $750 million annually to city and county governments. IOUs pay $682 million of that amount (Rural Electric Cooperatives also pay franchise fees). These fees are passed on to the purchasers of electricity as embedded costs (i.e., not identified by line-item as a source of public revenue).

Franchise agreements typically are long-term agreements, often 30 years. Deregulation would surely make the existing agreements obsolete. Typically, franchise fees are based on the gross revenues received by the utility from the customers in the local government's boundaries. With the loss of vertical integration, the revenue attributable to one company will be reduced. If IOUs no longer bill consumers for all costs (generation, transmission and distribution), the tax base will be greatly reduced. Many, including the Florida League of Cities, believe all franchise fee revenue could be at risk. It is likely the franchise fee agreements, as they exist now, would no longer be workable (or enforceable) after deregulation. A revised structure with new revenue source could be devised, but it would be a complex task, one that politics would make even more difficult.

Franchise fees could be restructured, such as being based on the value of energy distributed through a facility, but will franchises be as valuable as they are now? Surely not---while ostensibly payment of fair rent for the use of public rights of way, the true value to utilities is the granting of the right to be the exclusive seller. In a competitive marketplace, that value is lost. Even if franchise fees can be retained in some form, significant revenue losses are a distinct possibly. Moreover, since franchise fees can be included in the base for sales, gross receipts and public service tax levies, any reduction in franchise fees could impact those taxes as well.

22 Article VII, s. 9(a), Florida Constitution.

23 Article VII, s. 1(a), Florida Constitution.

Property Taxes

Property taxes are local governments' most important revenue source. Property taxes are reserved for local governments --- the state constitution prohibits the state from levying the tax.[24] Florida's cities, counties, school districts and special districts depend on the $31.4 billion this tax provides annually. Forty percent of the revenue ($12.6 billion) goes to schools. Counties collect 38 percent of the revenue ($11.9 billion; cities collect 15 percent ($4.8 billion); and independent special districts collect 7 percent ($2.1 billion).[25]

Property taxes are levied on both real and tangible personal property (TPP). Since household goods and personal effects are exempt, TTP taxes are generally paid only by businesses on their machinery, equipment, furniture, computers, signs, supplies, and other such property. The taxable value of real and tangible personal property is its fair market value minus any exclusion, differential, or exemption allowed by Florida laws. Millage rates (the tax rate) vary from jurisdiction to jurisdiction and are subject to various caps. The average millage rate paid by property owners in Florida is 17.46 mills ($17.46 per $1,000 of taxable value).[26]

Utilities are capital intensive and have significant real and tangible personal property tax obligations. Florida's IOUs paid $1.1 billion in property taxes in 2018. IOU generation sites accounted for $352 million of that amount. Many counties rely heavily on property tax revenue from utilities, especially small, rural counties where utility property can comprise a significant portion of the tax base. A sizable reduction in utility property value could have a profound impact on schools as well.

The proposed utility constitutional amendment would likely reduce property tax revenues. If deregulation and the required divestiture of generation property result in more out-of-state generation of electricity, there would likely be corresponding loss in in-state generation property, reducing Florida's property tax base. Factors including Florida's geography at the cost of interstate transportation of electricity will likely limit this impact.

A much more significant reduction in Florida's property tax base could result from the forced divestiture of generating facilities. This would be due in part to the IOUs stranded costs, which is largely the amounts by which the book values of utility generation assets exceed their market values. Sales of IOU property at below book value would reduce the appraised and taxable values of those properties. If the required divestitures were to result in "fire sale" prices, this will further reduce the selling price and thus the appraised and taxable values of IOU property.

It has been noted that the language of the proposed constitutional amendment is ambiguous as to whether the current IOUs would be able to own the transmission and distribution system.[27] The proposed amendment requires the Legislature to pass a law to "limit the activity of investor-owned electric utilities to the construction, operation, and repair of electrical transmission and distribution systems." It does not specify that the IOUs can own the systems. If this is interpreted as requiring the divestiture of ownership of the transmission and distribution system, then the value of these components of the IOUs' total tax base would be compromised.

24 Except for intangible personal property.

25 Florida Department of Revenue, Millage and Taxes Levied Report, 2017.

26 Florida Revenue Estimating Conference, 2018 Florida Tax Handbook. http://edr.state.fl.us/Content/revenues/reports/tax-handbook/taxhandbook2018.pdf.

27 Testimony and discussion at the Financial Impact Estimating Conference, February 11, 2019.

Public Service Tax

Municipalities and charter counties are authorized to levy a public service tax on the purchase of electricity, metered natural gas, liquefied petroleum gas (either metered or bottled), manufactured gas (either metered or bottled), and water service. Charter counties may only levy the tax on customers in the unincorporated area of the county. The tax cannot exceed 10 percent of the payments received by the utility from the sale of taxable items and the majority of governments levy the maximum. It is a tax on the consumer and the utility collects it and remits it to the local government.

The public service tax, sometimes called the municipal utility tax, is a critical revenue source for local governments, especially cities. It is by far their largest non-ad valorem tax source, supplying 13 percent of tax revenue (39 percent of non-ad valorem taxes). Of the $1.2 billion in public service taxes collected annually by cities and counties on all utilities, the sale of electricity contributes just over $1 billion.[28] Florida IOUs collect $856 million in public service taxes for cities and charter counties.

Since this is a tax on the consumer and utilities collect it, it could be impacted by nexus issues and be subject to an erosion of revenue collections. Due to the large amount of revenues collected, even if there is relatively small amount of electricity sales to Florida customers made by out-of-state companies with no nexus in Florida, and the sellers do not collect and remit the taxes, local governments could see significantly reduced revenues.

Gross Receipts Tax

The 2.5 percent gross receipts tax on electricity produces $634 million annually. The gross receipts tax is a state tax and is deposited into the Public Education Capital Outlay (PECO) Trust Fund to pay for construction and maintenance of Florida's educational facilities. Florida's IOUs pay $465 million annually in gross receipts taxes. All electric utilities must pay the gross receipts tax, including municipally-owned utilities and rural electric cooperatives.

Prior to 2014, the gross receipts tax was 2.5 percent and the sales tax on electricity used by commercial customers was 7 percent. In an effort to increase revenue for the PECO Trust Fund, the 2014 Legislature added a 2.6 percent gross receipt tax on the electricity sales tax base (commercial customers) and decreased the sales tax by 2.65 percent to 4.35 percent. This analysis considers the gross receipts tax as only the original 2.5 percent tax and the sales tax on electricity as 6.95 percent (4.35 percent plus 2.6 percent).

The state's gross receipts law will have to change under deregulation. A significant potential revenue impact arises because the gross receipts tax is levied on the receipts of electricity distribution companies.[29] Currently, since services are bundled under one company, tax is levied on both the charge for distribution and the charge for the electricity. Under the proposed amendment (and current statutory law) the distribution company would only be liable for the tax, while the receipts of the generators and the marketers would not be taxed. This would have to be addressed or a significant portion of the tax base (up to two-thirds)[30] could be compromised.

28 Florida Revenue Estimating Conference, 2018 Florida Tax Handbook.

29 Section 203.01(c)1., Florida Statutes

30 The cost of delivery electricity's compromises about 1/3 of the total price.

In 2005, the Legislature changed the gross receipts tax law in response to the deregulation of the natural gas market, which resulted in a significant increase in amount of gas provided from out-of-state. In addition to addressing the taxation of natural gas, the law changed the way an electricity transmission company is taxed if S. 203.01(c)1 does not apply. Presumably, this would be the case if the distribution company only receives payment for the delivery of electricity. Under this alternate provision[31], the tax would be based on the number of kilowatt-hours delivered multiplied by an "index" price: the average Florida price per kilowatt-hour for retail consumers in the previous calendar year.[32]

This has not been an issue for IOUs since both the charge for distribution and the charge for the electricity are included in the price. If this provision comes into play under the proposed amendment, generators and retailers would not be (directly) liable for the gross receipts tax and distribution companies would pay tax on the (estimated) total cost of electricity. The distribution companies might be able to recoup the cost through charges for the use of the system, but the effect on gross receipts revenues could be high. Florida TaxWatch performed a comparison of the index prices with the actual prices at various levels of usage and classification of services and found that index prices were between 3 percent and 7 percent below actual prices. In addition, since the index price is from the previous calendar year, the index price would lag behind the actual price, assuming actual electricity prices rise (after accounting for any effects of deregulation on price). It is likely that gross receipts tax collections would be less than it taxed at the actual price.

There is a use tax provision in the gross receipts tax law that requires a Florida purchaser of electricity that did not pay the tax to the seller to pay the tax directly to the Department of Revenue.[33] The provision also provides that if the purchaser paid a like tax to the seller, the amount of gross receipts tax owed to Florida is reduced by the amount of like tax paid. Even with the use tax language, as is the case with the sales tax, it may be difficult to collect the gross receipts tax on the sale of electricity by a company with no Florida nexus. Moreover, if the state in which the company is located levied a gross receipts tax which the Floridian paid in an amount at least equal to Florida's tax, no tax would be due to Florida. Under deregulation, therefore, the percentage of sales made by companies with no Florida nexus should result in a similar reduction in gross receipts tax revenue.

Sales Taxes

Florida has a state general sales tax rate of 6 percent, but electricity is taxed at 6.95 percent. Local option sales taxes also apply to electricity sales. The local rate varies from county to county, but it can add up to 2.5 percent. There is an exemption for residential electricity, which comprise a five-year average of 59 percent of total retail sales by IOUs[34]. Florida's IOUs collect $369 million in state sales taxes annually, and another $28 million in local sales taxes. Nexus has always been a problem for Florida's sales tax collections, and while the *Wayfair* decision may make future collections easier, the state is not there yet. If deregulation results in more sales by out-of-state companies, some loss in sales tax revenues should be expected.

31 Section 203.01(d)1., Florida Statutes

32 Florida Department of Revenue, Tax Information Publication No:18B06-01, Gross Receipts Tax Index Prices for the Period July 1, 2018 through June 30, 2019. https://revenuelaw.floridarevenue.com/LawLibraryDocuments/2018/05/TIP-121726_TIP%2018B06-01%20FINAL%20RLL.pdf

33 Section 203.01(f), Florida Statutes

34 Florida Public Service Commission, Statistics of the Florida Electricity Utility Industry, October 2018. http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/Statistics/2017.pdf.

Corporate Income Taxes

Corporations doing business in Florida must pay a tax of 5.5 percent on net income earned in Florida.[35] Florida "piggybacks" the federal income tax code in its determination of taxable income, annually adopting most federal changes. This makes federal taxable income the starting point for determining Florida taxable income. Any federal change Florida decides to "de-couple" from is then added or subtracted from federal income. Taxable income earned by corporations operating in more than one state is taxed in Florida on an apportioned basis using a formula that is based on the percentage of three factors that are located in Florida: 25 percent on property, 25 percent on payroll and 50 percent on sales. The first $50,000 of net income is exempt from taxation.

Reduced income of IOUs under a deregulated environment would decrease their income tax liability. Presumably, at least some of that lost liability would be offset by liability of the new companies that replaced IOU services; however, if some of the lost income moves to out-of-state companies, nexus issues would arise. Previous studies in Florida[36] and North Carolina[37] have estimated corporate income tax losses in a deregulated electricity market of 36.3 percent and 30.3 percent, respectively. Both estimates assume a decline in electricity prices and no recovery of stranded cost.

The Florida estimate assumed no significant entry into the market by out-of-state companies but noted that interstate transmission of electricity could raise questions as to how the apportionment formula will be applied for utility companies. The North Carolina study attributed approximately 19 percent of the reduction in corporate income tax revenue to lack of nexus.

As is often the case with corporate income taxes, tax payments vary considerably from year to year.[38] Coupled with the uncertainty created by the federal Tax Cuts and Jobs Act and how Florida will deal with the impacts, a base estimate of annual state income tax revenue by IOUs could not be produced.

Use Tax Paid by Utilities

Generally, utilities self-accrue sales taxes on their purchases. Instead of paying the tax to the vendor (regardless of where the vendor is located), they remit a use tax (same rate as the sales tax) directly to the state. Florida's IOUs' annual use tax payments exceed $100 million, the vast majority of which is due on distribution and transmission activities. Machinery and equipment used to generate electricity are exempt from the sales tax. Assuming purchases related to distribution and transmission activities remain in Florida, deregulation should not result in a significant loss of utility-paid use taxes.

Potential Revenue Impacts by Source

As discussed earlier, the complicated nature of utility taxation and the unknown manner in which the Legislature would implement the proposed amendment make reliable estimates of the proposed amendment's impacts unattainable. The purpose of this analysis is not to create a specific estimate of the revenue impact of electricity

35 The income tax applies to C corporations. S corporations, non-profit corporations, master limited partnerships and limited liability companies are exempt.

36 Florida Legislature, Office of Economic and Demographic Research, Potential Fiscal Impact of Electric Utility Deregulation on Florida's Public Education Capital Outlay (PECO) Program, December 1999.

37 Research Triangle Institute, State and Local Tax Considerations in Electric Industry Restructuring, Volume 1—Task 3 Final Report, September 1999.

38 Federal Energy Regulatory Commission, FERC Financial Report Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others. Reports for each Florida IOU, multiple years.

deregulation, but to highlight potential impacts and magnitudes for the Financial Impact Estimating Conference, the Legislature, local governments, and other stakeholders to consider.

Florida TaxWatch analysis finds that, unless very significant increases in the price of electricity for Floridians result, adoption of the proposed constitutional amendment will have a negative impact on state and local government revenues. These impacts have the potential to be relatively large. Of course, the Legislature and local governments can change the tax structure in an attempt to offset any revenue loss, but that road is fraught with peril.

It should be noted that the way the Legislature chooses to handle stranded costs could impact revenues. If at least some of the stranded costs recovery is done through an assessment on customers' bills or through an artificially high retail rate imposed by law, and the Legislature chooses to make those consumer payments taxable, it could have a positive revenue impact on taxes such as the gross receipts tax, the sales tax, and the public service tax, and would reduce some of the potential negative impacts discussed below.

Estimates are given for both 2018 and 2026. The impacts were first estimated for 2018, the year of the latest tax data. Those estimates were then projected out to 2026—the expected first full year of implementation if the amendment were to pass. The estimates do not change drastically over time, as electricity prices are not expected to increase much in the next several years. Most estimates were grown using the future growth rates for electricity gross receipts taxes adopted by the Gross Receipts Tax Revenue Estimating Conference.[39] Property tax revenues were estimated using the future taxable value growth rates adopted by the Ad Valorem Assessment Revenue Estimating Conference,[40] reduced slightly due to the downward trend in average millage rates.[41]

Electricity Franchise Fees (Local)

Total Annual Revenue (Local): $750 million, with $682 million paid by IOUs

If deregulation rendered all current franchise agreements obsolete and unenforceable, the entire $682 million could be lost.

- Assumption 1: Local governments and utilities could agree on changes to salvage 25 percent to 75 percent of revenue. Franchises would be less valuable due to loss of monopoly.
  2018 Revenue Loss: $171 million to $512 million
  2026 Revenue Loss: $190 million to $568 million

Property Tax (Local)

Total Revenue from IOUs: $1.1 billion
Tax Revenue from IOUs Generation Sites: $352 million

- Assumption 1: Loss of 5 percent to 10 percent of the taxable amount of generation property due to movement out-of-state and plant closure for other economic reasons, including lack of profitability.
  2018 Revenue Loss: $18 million to $35 million
  2026 Revenue Loss: $26 million to $50 million

39 Revenue Estimating Conference, Gross Receipts Tax Conference Results, November 29, 2018. http://edr.state.fl.us/Content/conferences/grossreceipts/grossreceiptsresults.pdf

40 Revenue Estimating Conference, Ad Valorem Assessments Conference Package, December 11, 2018. http://edr.state.fl.us/Content/conferences/advalorem/adval_results.pdf

41 Florida Revenue Estimating Conference, 2018 Florida Tax Handbook. http://edr.state.fl.us/Content/revenues/reports/tax-handbook/taxhandbook2018.pdf.

- Assumption 2: 15 percent to 25 percent loss of generation property value due to forced sales at less than book value.
  2018 Revenue Loss: $53 million to $88 million
  2026 Revenue Loss: $75 million to $125 million

- Assumption 3: Assumptions 1 and 2 (15 percent loss from Assumption 2 applied to 90 percent of generation property).
  2018 Revenue Loss: $68 million to $122 million
  2026 Revenue Loss: $97 million to $174 million

- Assumption 4: Scenario 3 plus 5 percent to 10 percent loss of value of non-generation property.
  2018 Revenue Loss: $105 million to $197 million
  2026 Revenue Loss: $149 million to $280 million

Gross Receipts Tax (State)

Total GRT Collections on Electricity: $634 million
GRT paid by IOUs: $465 million

- Assumption 1: If Section 203.01(d)1., Florida Statutes applies, the difference between index prices and actual prices would reduce collections by 3 percent to 7 percent.
  2018 Revenue Loss: $14 million to $33 million
  2026 Revenue Loss: $16 million to $37 million

- Assumption 2 *(low probability)*: Since the tax is currently levied on distribution companies, if only distribution costs are taxed, only approximately 40 percent of the base would be taxed.
  2018 Revenue Loss: $279 million
  2026 Revenue Loss: $310 million

Public Service Tax (Local)

Total PST Revenue: $1.0 billion
Revenue Collected by IOUs: $860 million

- Assumption 1: 5 percent to 15 percent of sales are made by out-of-state companies and lack of nexus results in non-collection by seller and no use tax from purchaser.
  2018 Revenue Loss: $43 million to $129 million
  2026 Revenue Loss: $48 million to $144 million

Sales Tax (State and Local)

Revenue Collected by IOU: $369 million (state) and $28 million (local)

- Assumption 1: 5 percent to 15 percent of sales are made by out-of-state companies and lack of nexus results in non-collection by seller and no use tax from purchaser.
  2018 Revenue Loss: $18.5 million to $55 million (state) and $1.4 million to $4.2 million (local)
  2026 Revenue Loss: $21 million to $61 million (state) and $1.6 million to $4.7 million (local)

Corporate Income Taxes (State)

Reduced income of IOU's under a deregulated environment would decrease their income tax liability. Presumably, at least some of that lost liability would be offset by new companies; however, if some of the lost income moves to out-of-state companies, nexus issues would arise. CIT payments by IOUs fluctuate too greatly to estimate losses.

Potential Revenue Impacts by Source

	2018 Revenue Losses			2026 Revenue Losses		
	Low	Middle	High	Low	Middle	High
Electricity Franchise Fees (Local)						
Assumption 1	$171m	$341m	$512m	$190m	$380m	$568m
Property Tax (Local)						
Assumption 1	$18m	$27m	$35m	$26m	$71m	$50m
Assumption 2	$53m	$71m	$88m	$75m	$100m	$125m
Assumption 3	$68m	$95m	$122m	$97m	$135m	$174m
Assumption 4[A]	$105m	$151m[A]	$197m	$149m	$215m[A]	$280m
Gross Receipts Tax (State)						
Assumption 1	$14m	$24m	$33m	$16m	$26m	$37m
Assumption 2		$279m			$310m	
Public Service Tax (Local)						
Assumption 1	$43m	$86m	$129m	$48m	$96m	$144m
Sales Tax (State & Local)						
Assumption 1	$19m (State) $1m (Local) $20m (Total)	$37m (State) $2.5m (Local) $39.5m (Total)	$55m (State) $4m (Local) $59m (Total)	$21m (State) $2m (Local) $23m (Total)	$41m (State) $3.5m (Local) $44.5m (Total)	$61m (State) $5m (Local) $66m (Total)
State Total[B]	**$33m**	**$167m**	**$334m**	**$37m**	**$204m**	**$371m**
Local Total[C]	**$320m**	**$581m**	**$842m**	**$389m**	**$693m**	**$997m**
Potential Total	**$353m**	**$748m**	**$1,176m**	**$426m**	**$897m**	**$1,368m**

[A] Assumption 4 is a combination of the previous assumptions plus a loss of value from non-generation property, therefore the mid-point of assumption 4 represents the mid-point of the combination of the assumptions.

[B] State total includes the Gross Receipts Tax and State Sales Tax

[C] Local total includes the Franchise Fees, Property Taxes, Public Service Tax, and Local Sales Tax

Note: local estimates do not include any revenue from the state 6% sales tax (local government half-cent sales tax, county and municipal revenue sharing, and fiscally constrained counties).

Conclusion

Overall, this TaxWatch analysis clearly shows that deconstructing Florida's electricity market through the proposed constitutional amendment will likely have a significant negative impact on state and local revenues.

This analysis uses the best available evidence to estimate that this amendment has the potential to cause a loss of state and local revenue ranging from $426 million to $1.368 billion in 2026, the expected first full year of implementation.

Appendix A

Stranded costs fall into five main categories:[42]

- Unrecoverable costs of generation-related assets—in a competitive market, if electricity prices are lower than the level necessary to repay the investments and provide a fair return, and if the assets cannot be sold for use elsewhere, those costs will be stranded.
- Long-term contracts for power or fuel that would be money losers with lower market prices for power—long-term contracts that might have made good business sense in a regulated environment or that might have served some public purpose may become net liabilities in a competitive market. Two examples that may result in stranded costs are contracts that require utilities to buy power from other generators and contracts to buy fuel.
- Unrecoverable regulatory assets—in the electric power industry, a regulatory asset is essentially a promise from a public utility commission to let a regulated utility recover a cost it has already incurred (e.g., deferred income tax liability) by charging higher rates in the future than it would otherwise. If electricity rates are no longer regulated, the ability to recover that money may be impaired, and the regulatory asset becomes worthless.
- Unrecoverable investments in social programs—the costs of programs designed to encourage energy conservation and efficiency, assist low-income customers, etc., that have not been recovered by the time the retail electricity market is deregulated would not be recovered in a competitive market.
- Employment transition costs—employee-related expenses prompted by restructuring, such as the costs of offering early retirement, job training, etc., would not be recovered in a competitive market.

If restructuring occurs without provisions to compensate utilities for stranded costs, then the utilities will have to absorb all of these costs. How Florida treats these stranded costs may provide some relief; however, investors are likely to view the electricity generation market as riskier.

Consequently, the cost of capital would rise for new investment, thus raising the future cost of electricity.[43] Others claim that compensating utilities for stranded costs would slow the benefits of competition and keep electricity prices higher than otherwise. Permitting utilities to recover all stranded costs from ratepayers and taxpayers would reward utilities for making poor choices about electricity generation in the past and would not encourage them to make good choices in the future.[44]

42 Congressional Budget Office, "Electric Utilities: Deregulation and Stranded Costs," CBO Paper, October 1998, retrieved from www.cbo.gov/sites/default/files/105th-congress-1997-1998/reports/stranded.pdf, February 3, 2019.

43 A. Lawrence Kolbe and others, "Regulatory Risk: Economic Principles and Applications to Natural Gas Pipelines and Other Industries," (Boston, Mass.: Kluwer Academic Publishers, 1993).

44 Kenneth Rose, "An Economic and Legal Perspective on Electric Utility Transition Costs," NRRI 96-15, National Regulatory Research Institute, 1996.

Whether utilities should be compensated for all or some portion of their stranded costs is essentially a question of fairness. What is fair depends on how the following questions are answered:

- Does restructuring violate the regulatory compact between a utility and its regulators, under which a utility provides universal electricity service to all customers in a specified area at a price determined by the state in exchange for a guaranteed return and recovery of their costs?
- If implementation of state and federal laws led utilities to incur higher costs, should the utility be permitted to recover those costs?
- If restructuring does not permit a utility to recover its stranded costs, does that constitute a legal "taking" which is prohibited by the Fifth Amendment of the U.S. Constitution?
- If a regulated electricity market precluded a utility from earning a higher rate of return, should a competitive electricity market exempt a utility from earning abnormally low rates of return?[45]

The Federal Energy Regulatory Committee (FERC) in 1996 issued guidance via Rule 888 and subsequent determinations suggesting that IOUs generally should be able to recover stranded costs to the extent that the generation facilities in question were required by state regulatory authorities to be built and these costs incurred.[46] Some of the changes envisioned by Rule 888, however, have not been fully implemented.[47]

The Florida Energy 2020 Study Commission produced a report describing a comprehensive strategy for assuring that Florida would have an adequate, reliable and affordable supply of electricity.[48] This Commission advocated an approach called the "Discretionary Transfer Approach," which would have allowed IOUs to continue to own generating capacity and recommended allowing recovery of stranded costs over a six-year period.[49] The Commission advocated sharing any benefits from sales for existing generating assets with customers. Their report notes that "in virtually all states that have restructured, utilities were afforded the opportunity to recover costs associated with assets that would not be recoverable in a competitive environment."[50]

The Commission recognized that restructuring would have fiscal impacts to both state and local government, particularly with respect to existing local government property tax revenues.[51] No attempt was made to quantify what that impact might be, but there was a recommendation that policy makers consider what changes would be necessary to maintain a tax system that is fair to both producers and consumers while providing revenue neutrality for state and local governments.[52]

45 Congressional Budget Office, "Electric Utilities: Deregulation and Stranded Costs," CBO Paper, October 1998, retrieved from www.cbo.gov/sites/default/files/105th-congress-1997-1998/reports/stranded.pdf, February 3, 2019.

46 FERC, "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities." Order No. 888, FERC Stats & Regs. 1996.

47 See discussion in Florida Energy 2020 Study Commission. "Florida...EnergyWise! A Strategy for Florida's Energy Future." December 2001. http://edocs.dlis.state.fl.us/fldocs/commissions/energy/2001report.pdf Last accessed February 15, 2019.

48 Florida Energy 2020 Study Commission. "Florida...EnergyWise! A Strategy for Florida's Energy Future." December 2001. http://edocs.dlis.state.fl.us/fldocs/commissions/energy/2001report.pdf Last accessed February 15, 2019.

49 Ibid.

50 Ibid.

51 Ibid.

52 Ibid.

ABOUT FLORIDA TAXWATCH

As an independent, nonpartisan, nonprofit taxpayer research institute and government watchdog, it is the mission of Florida TaxWatch to provide the citizens of Florida and public officials with high quality, independent research and analysis of issues related to state and local government taxation, expenditures, policies, and programs. Florida TaxWatch works to improve the productivity and accountability of Florida government. Its research recommends productivity enhancements and explains the statewide impact of fiscal and economic policies and practices on citizens and businesses.

Florida TaxWatch is supported by voluntary, tax-deductible donations and private grants, and does not accept government funding. Donations provide a solid, lasting foundation that has enabled Florida TaxWatch to bring about a more effective, responsive government that is accountable to the citizens it serves since 1979.

This Report and its findings are based on an independent analysis by Florida TaxWatch experts and renowned economist *Richard Harper, Ph.D.*, a senior member of the Florida Council of Economic Advisors at Florida TaxWatch.

The findings in this Report are based on the data and sources referenced. Florida TaxWatch research is conducted with every reasonable attempt to verify the accuracy and reliability of the data, and the calculations and assumptions made herein. Please feel free to contact us if you feel that this paper is factually inaccurate.

The research findings and recommendations of Florida TaxWatch do not necessarily reflect the view of its members, staff, Executive Committee, or Board of Trustees; and are not influenced by the individuals or organizations who may have sponsored the research.

Florida TaxWatch

Stay Informed:

www.floridataxwatch.org facebook.com/floridataxwatch @floridataxwatch youtube.com/floridataxwatch

106 N. BRONOUGH ST., TALLAHASSEE, FL 32301 O: 850.222.5052 F: 850.222.7476