FIEC

Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice

2019

BOOK 2

Financial Impact Estimating Conference

Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice

Serial Number 18-10

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FLORIDA . . . *ENERGYWISE!*

A STRATEGY FOR FLORIDA'S ENERGY FUTURE

THE FINAL REPORT OF THE

Florida

ENERGY 2020 STUDY COMMISSION

DECEMBER
2001

FLORIDA ENERGY 2020 STUDY COMMISSION
Knott Building, Room 225-B ◆ Tallahassee, FL 32399-0001
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December 11, 2001

The Honorable Jeb Bush
Governor of Florida
The Capitol
Tallahassee, Florida

The Honorable John McKay
President of the Florida Senate
The Capitol
Tallahassee, Florida

The Honorable Tom Feeney
Speaker of the Florida House of Representatives
The Capitol
Tallahassee, Florida

Dear Governor Bush, President McKay and Speaker Feeney:

On behalf of the Florida Energy 2020 Study Commission, I am pleased to submit our final report for your consideration. As directed by Executive Order Number 00-127, we have developed a comprehensive strategy for assuring that Florida will have an adequate, reliable and affordable supply of electricity.

The 2020 Vision is that "Florida's supply and use of energy promotes economic prosperity, limits environmental impacts, and enhances the quality of life for all Floridians." We adopted five goals relating to energy efficiency, energy supply, energy infrastructure, environmental protection and new technologies. Specific objectives, strategies and tasks were developed to achieve these goals.

The recommendations in the final report are intended to comprise a comprehensive package of interdependent elements. The Study Commission wishes to convey its belief that excluding or changing certain elements of the recommendations, particularly those relating to wholesale competition, may alter their effectiveness in producing the desired results.

Thank you for your support.

Sincerely,

Walter L. Revell
Chairman

Florida Energy 2020 Study Commission

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Internet Access

Florida Energy 2020 Study Commission Final Report,
meeting minutes and task force reports available at

www.myflorida.com/energy

Photo Courtesy of Florida Power and Light Company

I. Florida . . . *EnergyWise!*

The 2020 Vision

A Strategy For Florida's Energy Future

In May of 2000, Florida Governor Jeb Bush recognized the need for a comprehensive state energy policy by creating the Florida Energy 2020 Study Commission. The Study Commission was charged with the responsibility of proposing an energy plan and strategy for Florida. Over the next 20 years, the quality of life, the quality of the business climate and the quality of the environment will be closely linked with how Florida addresses its energy needs.

The Study Commission recommends a comprehensive framework for the industry that is sensitive to consumers and all other stakeholders. The Study Commission's vision for the next 20 years is . . .

Florida's supply and use of energy promotes economic prosperity, limits environmental impacts and enhances the quality of life for all Floridians.

To achieve this vision, the Study Commission sets forth five goals that establish the comprehensive nature of the overall energy strategy. The five goals are:

A. Florida will be a leader in using energy wisely.

B. Florida will have a sufficient energy supply to promote economic development and maximize economic prosperity for all Floridians.

C. Florida will have an energy infrastructure that assures the reliable delivery of electricity to consumers.

D. Florida will have an energy supply and delivery system that preserves Florida's environment.

E. Florida will be a leader in encouraging the future growth and development of next-generation energy technologies and renewable sources of energy.

In support of each goal, the Study Commission recommends a number of objectives, strategies, and tasks. Organized by goal, these objectives, strategies, and tasks follow:

A PROMOTING ENERGY EFFICIENCY AND PUBLIC BENEFITS

OBJECTIVES

A-1 Customers will be knowledgeable about energy efficiency and have access to information that allows them to make informed decisions about the relative efficiency of energy consuming goods.

A-2 Customers have the opportunity to participate in programs aimed at increasing the efficient use of energy resources.

A-3 Low-income customers have access to programs designed to reduce the burden of electricity costs and to increase the efficiency of their homes to reduce energy consumption.

A-4 Customers are encouraged to use electricity during off-peak periods by paying prices for electricity that accurately reflect the real-time cost of production.

A-5 Customers are rewarded for managing their consumption of electricity in a way that contributes to the efficient use of generating resources.

STRATEGY

Revitalize the Florida Energy Office.

TASKS

- The Florida Energy Office should house the office of the state energy director to promote the development of a reliable, efficient, and competitive market to adequately serve consumers.
- The Florida Energy Office should continue seeking federal funding for specific energy research and development activities.
- The Florida Energy Office should conduct a study to identify the potential for savings through energy efficiency and improvements in Florida's building code and appliance standards.
- The Florida Energy Office should promote new investments in energy efficiency, sustainable generating technologies, and energy research and development activities.
- The Florida Energy Office should develop and coordinate implementation of energy policy within the state.

STRATEGY

Expand availability and use of demand-side resources to provide greater reliability and more efficient use of generating plants, lower the cost of electricity, reduce air emissions from power plants, and increase customer satisfaction.

TASKS

- Continue to require load-serving utilities to implement demand-side management programs to maximize the cost-effective contribution of efficiency investments to enhance reliability, lower environmental impacts and lower customer rates.
- Require the Public Service Commission (PSC) to develop innovative rate programs for the residential, commercial and industrial sectors, such as real-time and time-of-use pricing, that send appropriate price signals to customers.
- Require the PSC to consider mechanisms that allow customers to directly respond to high market prices for electricity – "demand responsiveness."
- Require the PSC to investigate mechanisms for instituting "demand bidding," enabling customers to be compensated appropriately for curtailing use during periods of high electricity demand.

STRATEGY

Encourage utilities to conduct research and development on load management and energy efficiency.

TASK

- The PSC should continue to allow cost recovery for research and development of cost-effective load management and energy efficiency programs.

STRATEGY

The State of Florida should encourage energy efficiency and conservation efforts.

TASK

- The State of Florida should undertake a comprehensive evaluation of the energy efficiency of its facilities and develop appropriate goals and standards.

STRATEGY

The State of Florida should increase its support for low-income energy assistance.

TASK

- The State of Florida should provide state funding for the Low-Income Home Energy Assistance Program and the Weatherization Assistance Program.

B ASSURING AN ADEQUATE AND RELIABLE SUPPLY OF ENERGY

OBJECTIVES

B-1 A transition to an effectively competitive wholesale generation market with many buyers and sellers.

B-2 Competitive sellers of generation are subject to consistent regulatory requirements, including standards for access to and use of the bulk power system.

B-3 Load-serving utilities have access to a diversified portfolio of energy resources, including demand-side and renewable resources, acquired through competitive means, with no over-reliance on any particular fuel type, and with appropriate demand-side resources.

B-4 No seller exerts market power.

B-5 Customers enjoy reliable electric service.

B-6 Customers are adequately protected and enjoy stable prices for electricity.

B-7 Utility regulation is aimed at assuring effective competition, regulating prices of monopoly distribution services, and providing proper incentives for minimizing costs, and ensuring operational efficiency and innovation.

B-8 Florida's state and local tax systems are fair with respect to energy providers and individual classes of electric customers.

B-9 Electric industry restructuring is revenue neutral with respect to state and local government revenues derived from taxes and fees levied on electric utilities and customers.

STRATEGY

Provide investor-owned load-serving utilities more flexibility for diversifying their energy resources by creating a competitive wholesale market and establishing a competitive acquisition process for load-serving utilities.

TASKS

- Load-serving utilities should acquire new capacity through competitive bidding, negotiated bilateral contracts, or from the short-term (i.e., spot) market.
- In any review by the PSC of the costs being recovered by the load-serving utilities, the standards for determining whether those costs are prudent would continue to be whether:

- the capacity is needed for reliability;
- the proposed resource acquisition is the most cost-effective alternative;
- the proposed resource alternative contributes to the goal of fuel diversity, and
- the utility has adequately considered cost-effective demand-side alternatives.

- ◆ Competitive bidding for new energy resources should be encouraged by load-serving utilities having the burden of proving that their acquisitions are prudent. Competitive bidding should not be required, though, so that load-serving utilities can act quickly on favorable opportunities.
- ◆ Competitive bidding should be required in situations where load-serving utilities are purchasing new resources from affiliates.
- ◆ Load-serving utilities must be able to demonstrate that their bidding processes are unbiased and preclude advantages to any bidder, including affiliates.
- ◆ The PSC should revise its existing rule on competitive acquisition to be consistent with recommendations made in this report.
- ◆ Time limits should be established on the prudence review process, consistent with due process, in order to maximize market certainty and opportunities.

STRATEGY

Assure adequate fuel diversity.

TASKS

- ◆ The PSC should assure adequate fuel diversity through its regulation of the competitive acquisition process for load-serving utilities.
- ◆ The PSC should place a higher priority on fuel diversity than on whether a resource is the least-cost option when it is determined that there is excessive or imprudent reliance on the fuel of the planned least-cost option.
- ◆ The Governor, the Legislature and the PSC should continue to pursue the safe, efficient and economic disposal of radioactive waste in order to remove a major obstacle to the continued viability of nuclear power.

STRATEGY

Remove barriers to entry for merchant plants and facilitate the development of new generating capacity.

TASKS

- ◆ Eliminate the need-determination process.
- ◆ The recommendation for eliminating the need-determination process should apply to municipal and cooperative utility projects as well.
- ◆ Review the role of the Siting Board.

STRATEGY

Provide for nondiscriminatory access to the transmission system by competitive wholesale providers of electricity by authorizing the transfer of utility transmission assets to a regional transmission organization (RTO).

TASKS

- ◆ Florida's transmission-owning utilities should be authorized to transfer their transmission assets to a FERC-approved RTO, or to allow an RTO to exercise operational control over these assets.
- ◆ Transmission assets transferred to an RTO should be transferred at book value.

STRATEGY

Create a mechanism for transitioning existing generation to a competitive market to further competition in the wholesale market.

TASK

- ◆ Investor-owned utilities should be allowed to transfer or sell existing generating assets under the following terms:
  - Transfers or sales of generating assets should be discretionary on the part of the investor-owned utilities to provide for an appropriate assignment of risk.
  - Transfers of existing generating assets to affiliates should be at book value.
  - Load-serving utilities should have the right to six-year cost-based transition contracts to commit the capacity of existing assets sold or transferred back to the load-serving utilities.
  - Load-serving utilities should be given the right to unilaterally cancel the transition contracts any time during the six-year contract term, subject to reasonable prior notice.
  - Profits from "off-system sales" from plants subject to transition contracts should be shared with customers.
  - Gains on sales of existing generating assets directly from the regulated rate base should be shared with customers.
  - Gains on sales of existing generating assets that have been transferred and are subject to transition contracts should be shared with customers.
  - Losses on sales of existing generating plants should be absorbed by utility shareholders.

STRATEGY

Authorize the PSC to monitor competition in the wholesale market, investigate allegations of market improprieties, and petition the FERC for remedies.

TASKS

- ◆ The PSC should have clear statutory responsibility to monitor and evaluate competition in the wholesale market.
- ◆ The PSC should be given clear authority to petition the FERC for remedies.
- ◆ The PSC should develop expertise in electricity markets, to the extent it does not already exist.
- ◆ The PSC should have access to books and records of all market participants, subject to valid claims of confidentiality.

STRATEGY

Broaden the PSC's responsibility to require utilities to maintain adequate reserves.

TASKS

- ◆ The PSC should continue to assure adequate electrical reserves and to require load-serving utilities to seek additional resources, including power plant construction, when forecasted reserve margins drop below the level deemed necessary by the PSC.
- ◆ The PSC should have access to information of new market participants (Independent Power Producers (IPP) and Regional Transmission Organization (RTO)) to carry out its responsibility of assuring adequate electricity reserves.
- ◆ The PSC should report annually on the status of the state's electric reliability, including a review of fuel availability and fuel mix of Florida's utilities.

STRATEGY

Create mandatory reliability standards for the bulk power system that apply to all market participants and are enforced by the PSC.

TASKS

- ◆ A self-regulating reliability organization (SRRO) should be established to set standards pertaining to the operation of the bulk power system.
- ◆ The SRRO should develop standards applicable to all users of the bulk power system.
- ◆ The PSC should be authorized to adopt these standards as rules and to enforce the standards.

STRATEGY

Assure the PSC's role in protecting against cross-subsidization of competitive services by regulated services.

TASKS

- The PSC should continue to have authority to protect consumers against cross-subsidization of unregulated operations by regulated operations.
- The PSC should have access to books and records of affiliates.
- The PSC should have authority to prescribe a code of conduct regarding affiliate transactions.

STRATEGY

Provide incentives for utilities to provide efficient low-cost electric service.

TASK

- The PSC should consider and implement, if appropriate, performance or incentive rate structures for load-serving utilities to encourage: (1) least-cost supply decisions, (2) cost savings, and (3) reliability.

STRATEGY

Establish a mechanism for long-term monitoring of the development and effectiveness of competition in the electric industry.

TASKS

- Retail competition should not be considered until after the development of an effectively competitive wholesale market.
- The PSC should monitor the development of competition in Florida's wholesale market, in retail markets in other states, and in policy determinations at the federal level.
- The PSC should report biennially to the Governor and the Legislature on the status of competition.
- A study commission, similar to the Florida Energy 2020 Study Commission, should be established in 2004 to assess the status of wholesale competition and make recommendations as to whether retail competition should be allowed.

STRATEGY

Begin the process of transitioning to a tax system that takes into account the changes taking place in the energy industry.

TASKS

- There should be a review of the definition of the taxable commodity of electricity to clarify the applicability of taxes to the separate functions of generation, transmission, and distribution services.
- Consider changes to taxes and fees paid by Florida's utilities and utility customers necessary to assure a system that is fair with respect to energy providers and individual classes of electric customers, and that provides revenue neutrality to state and local governments.

C IMPROVING ENERGY INFRASTRUCTURE

OBJECTIVES

C-1 The energy transmission system provides nondiscriminatory access to sellers of electricity, is independently controlled and operated, and has been relieved of major constraints.

C-2 Transmission pricing provides efficient signals for the siting of new generation capacity and the location of new loads.

STRATEGY

The transmission line siting process should be changed to lead to faster siting of transmission facilities without compromising environmental requirements.

TASKS

- Transmission lines and substations must be recognized as electrical infrastructure necessary for the public health, safety, and welfare that should not be unreasonably prevented from being located where determined necessary for the efficient, reliable delivery of electricity, consistent with existing environmental protections.
- Local governments should be required to adopt reasonable land-use and site condition standards for substations.
- The criteria as approved by the Board of Trustees of the Internal Improvement Trust Fund on January 23, 1996, for the use of natural resource lands by linear facilities should be adopted by rule.
- The existing easement fee exemption for crossing sovereignty lands and lands held for purposes other than conservation (non-natural resource lands) by transmission lines should apply to all state or federally regulated transmission lines.
- Encourage co-location of transmission facilities with linear facilities, such as roads, canals, and railroads. Agencies should be required to allow transmission lines to co-locate within their rights-of-way, provided the transmission line will not interfere with the agency's operations, cause unacceptable environmental harm or unacceptable impacts to natural resource lands. When co-location of a new transmission line within an existing right-of-way is not feasible, incentives should be offered to encourage placement of the transmission line immediately adjacent to the existing right-of-way.
- Encourage co-location of new transmission lines with existing linear facilities by: (1) expanding the exemption from the Transmission Line Siting Act (TLSA) to construction "immediately adjacent" to established linear rights-of-way at the option of the applicant; and (2) replacing the October 1, 1983, deadline for transmission line rights-of-way to be considered "established" for purposes of the exemption with either a requirement that a transmission line already exist within the right-of-way, or that one have existed for a minimum number of years.
- Streamline the licensing of major transmission line projects by eliminating the adjudicatory hearing presently mandated for all TLSA projects unless a party requests one.

- Shorten the post-certification review process by allowing TLSA transmission lines to qualify for a general permit when "best management practices" are used for construction.
- The Department of Environmental Protection (DEP) should undertake a review of the TLSA and other relevant statutory provisions to identify other ways in which Florida's electricity infrastructure can be improved, upgraded and extended, and permitting of transmission line facilities streamlined without compromising environmental requirements.

STRATEGY

Assure that a regional transmission organization can apply for extensions or improvements of the transmission system.

TASKS

- The TLSA should be clarified to indicate that an RTO can be a proper applicant.
- Provide RTOs eminent domain authority.

STRATEGY

The PSC should encourage the FERC-approved RTO to recognize the importance of sending proper short-term price signals reflecting the true costs of generation and consumption.

TASKS

- The PSC should work with the RTO and the FERC to ensure that transmission pricing leads to cost-minimizing decisions by both the RTO and generation companies.
- In conjunction with the RTO and the FERC, the PSC should ensure that the incentives created by transmission pricing lead to the appropriate level and mix of transmission and generation investment.

STRATEGY

Develop long-range planning and policy with regard to transmission infrastructure development.

TASK

- Encourage transmission planners to consult with outside experts and affected parties early in the process to promote the timely resolution of siting issues.

D PRESERVING FLORIDA'S ENVIRONMENT:

OBJECTIVES

D-1 Generating plants and transmission lines are subject to cost-effective environmental requirements that protect and enhance air quality and protect and conserve Florida's water resources.

D-2 Cost-effective environmental control requirements align market incentives with environmental quality goals.

STRATEGY

Continued analysis by DEP on cost-effective methods to reduce emissions of SO2, NOx and Mercury from power plants in Florida.

TASKS

- Consistent with the approach proposed in the National Energy Policy, a multiple-emission control approach is the most promising method of controlling criteria pollutants.
- Any new program for reducing emissions should adhere to certain principles. Programs should: (1) be based on sound science, risk assessment, and cost-benefit analysis, (2) include market-based trading components, (3) maintain fuel diversity, (4) provide certainty and consistency, and (5) allow credit for voluntary early action.

STRATEGY

Develop and maintain an inventory of greenhouse gas (GHG) emissions in Florida.

TASK

- The DEP should develop regulations to inventory and track greenhouse gas emissions within Florida.

S T R A T E G Y

Encourage a collaborative and proactive approach to siting power plants, transmission lines and substations utilizing available natural areas inventories and statewide and regional natural resource maps.

T A S K

- The DEP should consider adopting incentives to encourage applicants seeking to site energy facilities to undergo a pre-application consultative process with affected stakeholders.

S T R A T E G Y

Encourage efficient use and reuse of water in the production of electricity.

T A S K S

- Ensure that Florida's limited water resources are used wisely.
- The DEP, water management districts, and other agencies with jurisdiction over water resources should continue to consider and encourage innovative ways to reuse water.

E PREPARING FLORIDA FOR NEW TECHNOLOGIES AND RENEWABLES

OBJECTIVES

E-1 Renewable resources make up a portion of the state's energy resources, including resources of load-serving utilities used in satisfying customers' demand for electricity, as well as customer-owned applications.

E-2 Consumers have options for cost-effective self-generation, such as micro-turbines, fuel cells and high-efficiency cogeneration.

E-3 New technologies in power electronics and superconductivity should be applied to the transmission grid to achieve the ability to control actively the flow of energy and gain greater efficiency out of existing infrastructure and right-of-way corridors.

STRATEGY

Encourage development and use of renewables.

TASKS

- ◆ The PSC should conduct a study to identify the current level of renewables and prescribe a cost-effective level of new resources.
- ◆ The PSC should have the authority to require a portion of utilities' resources to be from renewable sources available within Florida, including solar, biomass, and waste-to-energy.
- ◆ The PSC should continue to encourage utilities to offer or expand "green pricing" programs.

STRATEGY

Reduce barriers to distributed resources.

TASK

- ◆ Require the PSC to investigate ways of reducing barriers to distributed resources, such as micro-turbines, fuel cells, and high-efficiency cogeneration, including the adoption of interconnection standards.

STRATEGY

Encourage development and application of new technologies to increase the efficiency of the transmission system.

TASK

- Encourage public and private research organizations to investigate and support development and application of new technologies.

STRATEGY

Mitigate, to the extent possible, labor force dislocations associated with new technologies and industry conditions.

TASK

- Encourage job retraining programs by regulated utilities and by electricity producers.

Photo Courtesy of Gulf Power Company

II. Introduction

Electricity is no ordinary commodity. It is the single most important product that drives Florida's economy, maintains our standard of living, and keeps us comfortable. Florida's customers today enjoy reasonable prices and reliable service; however, the electric industry is changing. In an industry that was long considered a monopoly, competition is playing an ever-increasing role in determining prices for electricity. The emergence of competition is forcing state and federal regulatory agencies to examine the industry structure to determine the extent to which the industry should continue to be regulated. With these major national industry-wide changes occurring, no state will be left unaffected. The question for Florida is whether merely to react to the changes or to position the state to take advantage of the technological advances and the benefits of competition.

In recent years, competitive pressures have caused Florida's regulators and lawmakers to question whether changes need to be made in Florida's electric industry. At present, Florida's electric market continues to be a regulated monopoly system. Numerous independent power producers (IPPs) have expressed interest in building generating plants and selling electricity on a wholesale basis in Florida. Some of these providers have proposed to build and operate "merchant" power plants – the capacity for which is not contractually committed to a retail, or "load-serving," utility. While there is a market for short-term energy sales in which merchant power plants could sell energy, Florida's siting laws do not allow the construction of merchant plants.

Competition in the generation market has led to changes in the transmission sector. In response to federal policy initiatives, three of Florida's investor-owned electric utilities are in the process of establishing a regional transmission organization, or RTO, for peninsular Florida. The Federal Energy Regulatory Commission (FERC) views the separation of the transmission function from the generation and marketing functions as critical to an effectively competitive wholesale market. RTOs will enable all participants in the competitive wholesale generation market (investor-owned utilities, municipals, cooperatives, and IPPs) to have fair and open access to the transmission system. There are several forms of RTOs. In Florida, efforts have centered on creating a for-profit transmission company, or "transco," a separate, independent, publicly-traded corporation that will own, lease or operate the electric transmission system.

The recent series of rolling black-outs, power shortages, and electricity price volatility in California provides interesting insights into the restructuring process. The cause of these power shortages has been attributed to a combination of high demand growth, insufficient generation and transmission resources, and poor market design. It is apparent that California's deregulation program, which included giving choice to retail customers, did not include mechanisms designed to prevent shortages from occurring. While competitive markets are capable of maintaining capacity at adequate levels, California's experience points to the need to assure that restructuring efforts are accompanied by market and regulatory mechanisms designed to prevent shortages of generating capacity and excessive price volatility.

States around the nation are examining their regulatory policies. To date, 37 states have either restructured to allow competition or are studying their electric industry to determine whether to further stimulate wholesale generation competition and, in some instances, to pursue retail competition. The restructuring process has also been used as an opportunity to examine policies beyond the issue of competition. It is not uncommon for states to consider making a commitment to energy efficiency and other "public benefits," such as energy assistance for low-income customers. Depending on the nature of the undertaking, the restructuring process can have significant impacts on state and local government revenue sources. The restructuring process also provides an opportunity to address the impact of producing electricity on the environment.

Fueling Florida's Economy

Florida's economy thrives on energy. While the beautiful beaches and moderate climate may attract people here, it is electricity that powers Walt Disney World, produces world famous orange juice, air-conditions hotels, and runs computer systems. Further, Florida's population is growing and, even with the strides continuing to be made in energy efficiency and conservation, more electricity will be needed in the future to serve the growing population. To this end, it is critical that Florida's plan for its future economic growth includes planning for its energy needs. A reliable and sustained source of energy is critical to Florida's prosperity.

Florida has an economic development plan that is prepared and updated annually by Enterprise Florida. The goals of this strategic plan, written by Floridians from across the state, are to ensure that Florida has globally competitive businesses in the state, good-paying jobs for its citizens, and a high quality of life. Enterprise Florida has identified two key elements necessary for Florida's continued success in economic development. The first element is that Florida must compete fiercely and aggressively with other states for investment by wealth-creating businesses, such as manufacturers and service providers. The second element is that Florida has to understand and respond to businesses' needs to be competitive.

Reliability and the cost of energy is critical to companies considering moving into or expanding in Florida. According to a corporate survey conducted by *Area Development*, a leading site and facility planning magazine, energy availability and cost is one of businesses' top ten site selection factors. Enterprise Florida reported at the Study Commission's July 2001 meeting that businesses are concerned about the reliability and cost of electric service. In the area of reliability, businesses are concerned about capacity and long-term availability, redundant feeds to sites, and quality of service. In the area of cost, businesses are concerned about the initial cost to develop site infrastructure, ongoing cost of service and long-term price stability. Enterprise Florida indicated that it had received more questions in the last six months on the issue of electric service reliability than at any other time.

The businesses located in Florida, as well as businesses considering sites within the state, must be competitive in order to sell their products and services. Competition for customers is based on being able to produce products or services at the lowest cost possible. Energy is a significant part of that cost. If Florida wants to grow and prosper in the next 20 years, it must ensure the availability of adequate, reliable and competitively-priced energy. The credibility of these assurances will contribute to the overall economic development of Florida.

Executive Order

In recognition of the changes taking place in the electric industry, Governor Jeb Bush created the Florida Energy 2020 Study Commission (Study Commission) by Executive Order (see Appendix A). The purpose of the Study Commission was to determine what Florida's electric energy needs would be over the next 20 years and how best to supply these needs in an efficient, affordable, and reliable manner. The Study Commission considered all relevant topics, including a number of specific topics outlined by Governor Bush's Executive Order. Specifically, the Executive Order required the Study Commission to consider:

(a) Forecasts through the year 2020 of Florida's population growth, electricity needs and supply, and the expected diversity of fuels and their sources for use in the state;

(b) Current and future reliability of electric supply within and into the state;

(c) Current and future reliability of the natural gas supply into and within the state;

(d) Emerging and projected electric technologies and electric supplies, including solar and renewable energies, and distributed generation technologies, their potential contribution to reliable electric supplies, and their impact upon the state, its environment, and its electric policies;

(e) The experience and impacts upon electricity consumers, generators, and transmitters of all kinds from recent changes in governmental regulation of the electric utility in other states;

(f) Analysis of the impacts of state and local government taxes on government revenues and the electricity supply;

(g) Universal access to electricity and the responsibility to provide it;

(h) Stranded investment costs;

(i) Functional unbundling; or the separation of electricity production, transmission, and distribution;

(j) Impact of restructuring on service to low-income, elderly, and rural consumers;

(k) Renewable energy, energy conservation, and energy efficiency technologies and programs, and the impact of restructuring on the same;

(l) Impact of restructuring on economic development and growth in the state, including potential impact on tourism, agriculture, small business, and industry in the state;

(m) Impact of restructuring on investor-owned electric utilities, municipal electric utilities, rural electric cooperatives, and independent power producers;

(n) Prevention of anticompetitive or unlawful discriminatory conduct or the unlawful exercise of market power by electricity providers;

(o) Environmental impact of electricity supply production, generation, and transmission in the state; and

(p) Impact of restructuring on the current and future electric utility workforce.

Technical Advisory Committees

The Executive Order authorized the Study Commission to establish and appoint any necessary technical advisory committees (TACs). Four TACs were established by vote of the Study Commission to provide guidance on Wholesale Market Restructuring, Public Benefits, Environmental, and Fiscal Impacts. The respective areas of responsibility for each of these TACs were as follows:

Wholesale Market Restructuring -- Energy forecasts through the year 2020, Florida's transmission grid, power plant siting, emerging competition, RTOs, fuel supply and diversity, and stranded investment.

Public Benefits -- Energy conservation and efficiency, emerging technologies (including solar, renewable, and distributed generation technologies), universal service, impacts on low-income, elderly and rural customers.

Environmental -- Environmental impact of electricity production and transmission.

Fiscal Impacts -- Impact of restructuring on state and local taxes and fees paid by the electric industry and electric customers.

TAC members consisted of individuals with expertise in the respective areas of study, and they were not compensated by the Study Commission for their service. The TACs assisted the Study Commission by identifying issues, gathering and analyzing information, and making recommendations to the Study Commission as to appropriate policy actions.

As with regular Study Commission meetings, meetings of the TACs were open to any person wishing to attend, and were noticed to the public.

The Wholesale Market Restructuring TAC members provided valuable input to the Executive Director during the months leading up to the release of the Study Commission's Interim Report. Because of time constraints imposed by the desire of the Study Commission to complete an interim report prior to the 2001 legislative session, the Wholesale Market Restructuring TAC did not formalize its advice in a written report.

The Public Benefits, Environmental and Fiscal Impacts TACs, however, issued written reports to the Study Commission. These reports were presented at the August 30, 2001, meeting of the Study Commission.

Task Force on Stranded Investment

In May of 2001, the Study Commission formed a subgroup of the Study Commission – the Task Force on Stranded Investment – to conduct a more in-depth examination of the stranded investment issue. The Task Force held numerous meetings during the months of May through October, and rendered a recommendation to the Study Commission on October 17, 2001, regarding issues involved in wholesale market restructuring.

All meetings of the Task Force were open to the public and included input from numerous stakeholders.

A further discussion of the Task Force is included in Chapter V (B) of this report.

III. Florida's Electric Industry Today

Florida has an adequate supply of reasonably-priced electricity. However, there are some energy consumers who are concerned about the calculations and forecasts of reserve margins. Nevertheless, Florida continues to grow and the electric industry is changing. Florida needs to adapt to its growth and these changes. Before examining the changes appropriate for Florida, it is necessary to understand Florida's existing electric industry.

FLORIDA'S ELECTRIC INDUSTRY SHOULD BE UNDERSTOOD WITH RESPECT TO ITS:

- Utility profile
- Rate levels
- Customer profile
- Load profile
- Fuel mix and economic dispatch
- Geography and transmission
- Regional reliability councils
- Natural gas pipeline transmission system

Utility Profile

There are numerous participants in the energy market in Florida. Florida has 56 electric utilities, consisting of 5 investor-owned (IOU), 17 cooperatively owned , and 34 municipally owned utilities. In addition to load-serving utilities, there are approximately 60 non-utility generators. These non-utility generators do not have retail obligations; they own generation to serve their own electrical needs (self-service) or sell their output at wholesale to load-serving utilities.

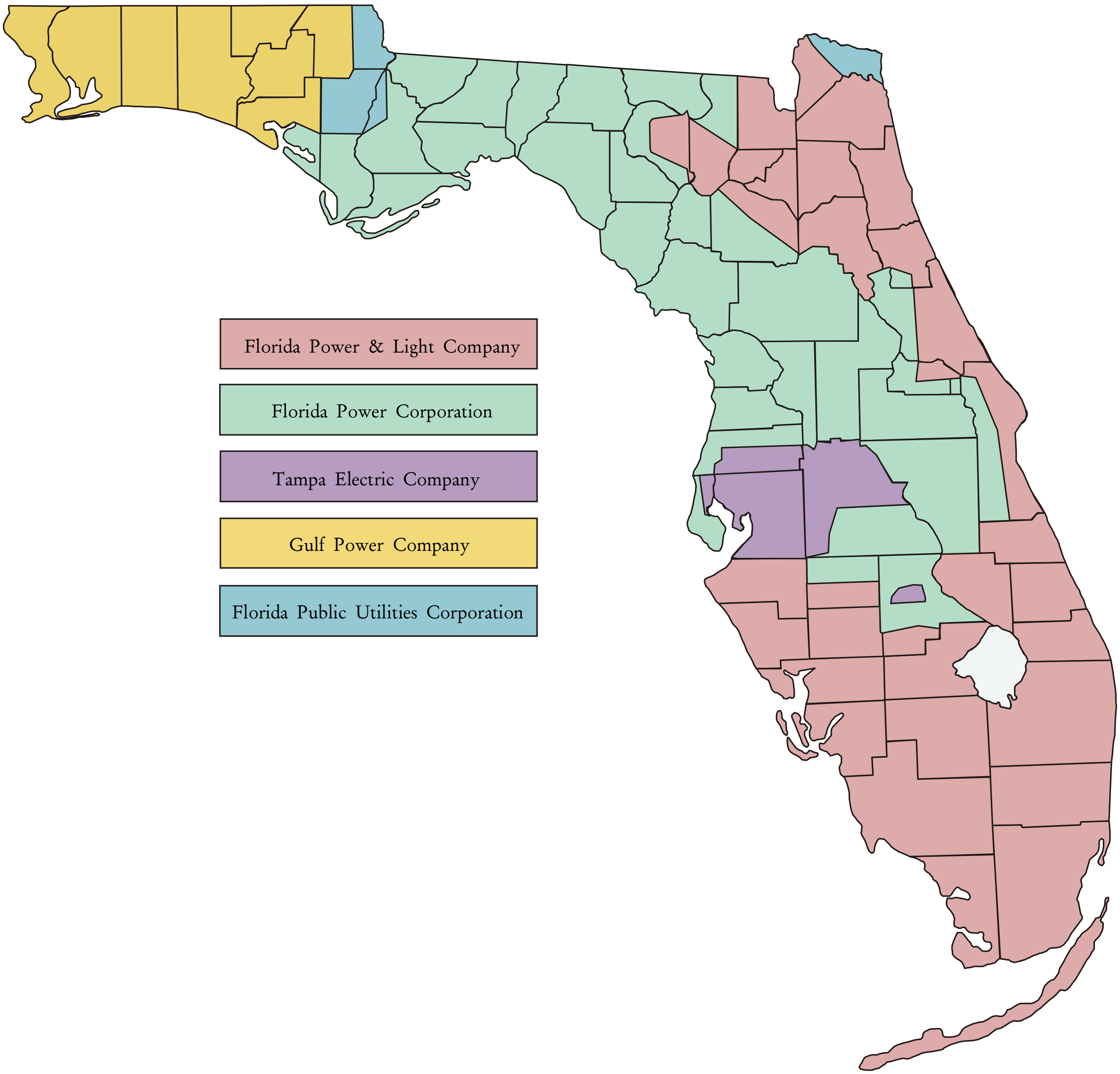
Florida's mix of utilities is typical of what is found nationwide. The largest investor-owned utilities include Florida Power & Light Company (FPL), Florida Power Corporation (FPC), Gulf Power Company (Gulf), and Tampa Electric Company (TECO). The largest cooperatively owned utility is Seminole Electric Cooperative, and the largest municipally owned utilities are Jacksonville Electric Authority, Orlando Utilities Commission, City of Tallahassee, City of Lakeland, and Gainesville Regional Utilities.

The maps on pages 22-24 identify the service areas in which the utilities operate.

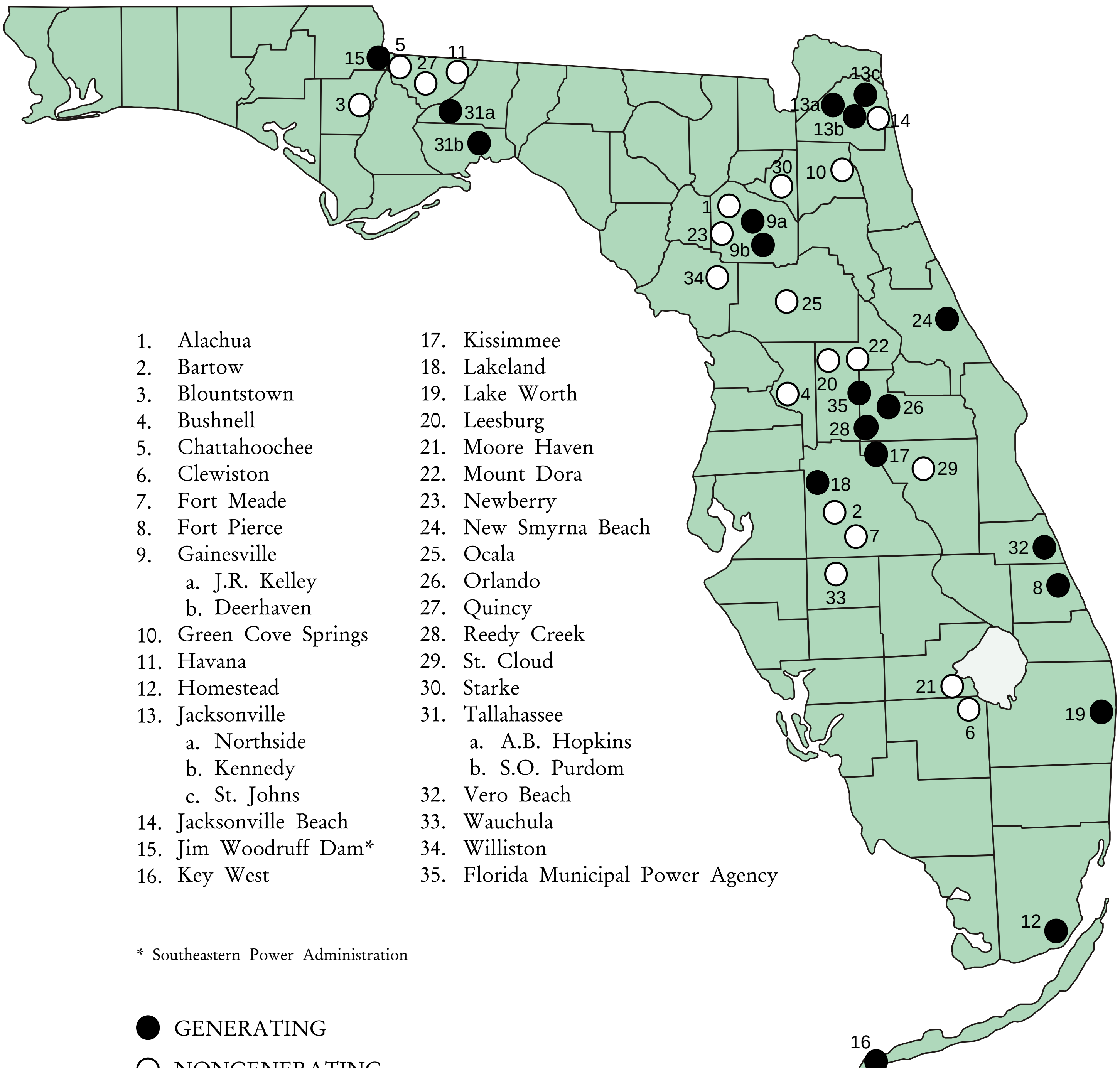
FLORIDA'S ELECTRIC INDUSTRY TYPE

	Load-Serving (Retail) Electric Utilities
5	Investor-Owned Utilities (4 have generation)
32	Municipal Electric Utilities (15 have generation)
1	Improvement District (1 has generation)
16	Rural Electric Cooperatives (1 has generation)
	Wholesale Providers
1	Municipal Power Agency (generation & transmission)
1	Rural Electric Cooperative (generation & transmission)
1	Federal Authority (Jim Woodruff Dam)
60	Non-Utility Generating Facilities

Investor-Owned Utilities



MUNICIPAL ELECTRIC UTILITIES



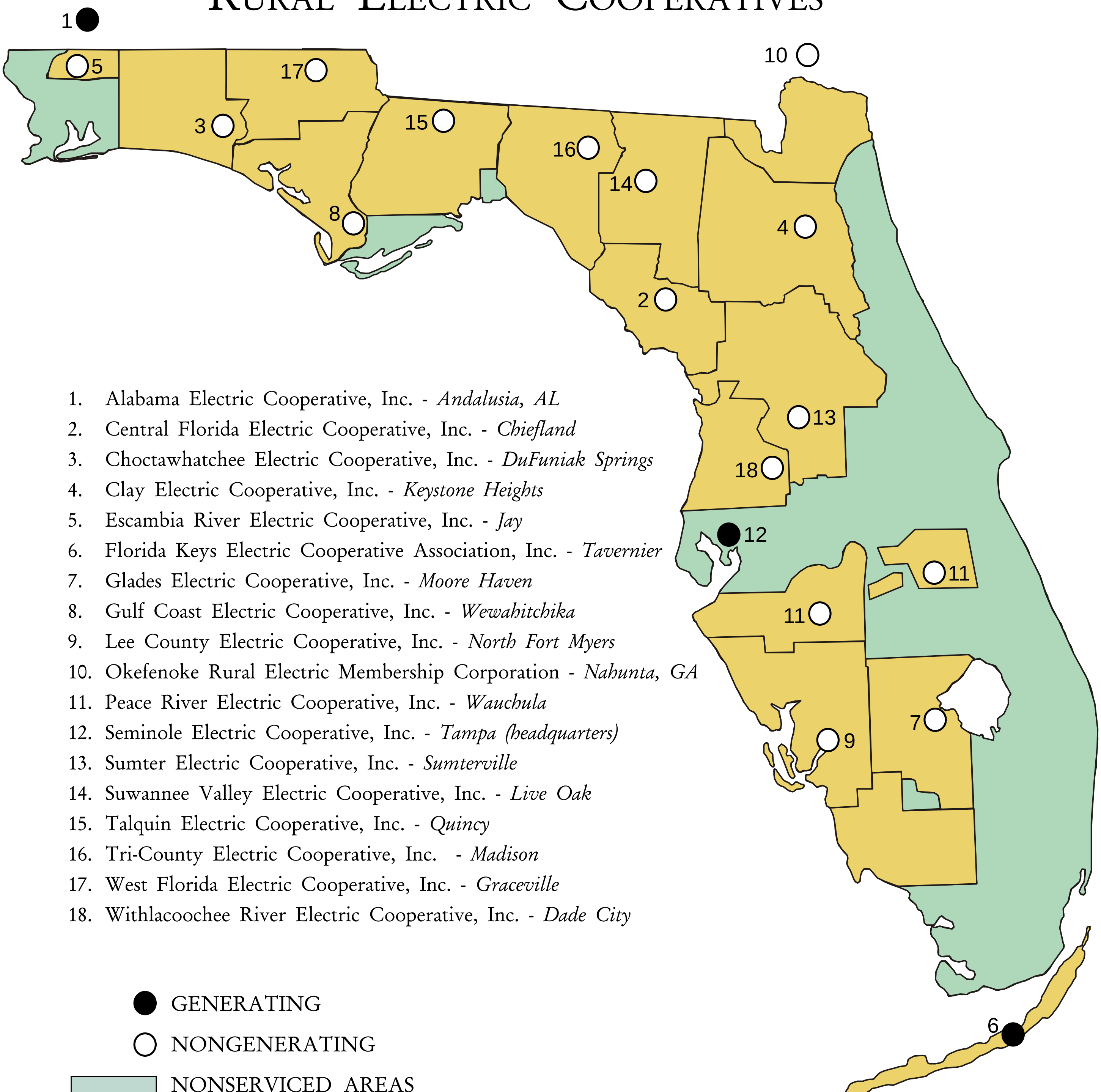
1. Alachua
2. Bartow
3. Blountstown
4. Bushnell
5. Chattahoochee
6. Clewiston
7. Fort Meade
8. Fort Pierce
9. Gainesville
   a. J.R. Kelley
   b. Deerhaven
10. Green Cove Springs
11. Havana
12. Homestead
13. Jacksonville
    a. Northside
    b. Kennedy
    c. St. Johns
14. Jacksonville Beach
15. Jim Woodruff Dam*
16. Key West
17. Kissimmee
18. Lakeland
19. Lake Worth
20. Leesburg
21. Moore Haven
22. Mount Dora
23. Newberry
24. New Smyrna Beach
25. Ocala
26. Orlando
27. Quincy
28. Reedy Creek
29. St. Cloud
30. Starke
31. Tallahassee
    a. A.B. Hopkins
    b. S.O. Purdom
32. Vero Beach
33. Wauchula
34. Williston
35. Florida Municipal Power Agency

* Southeastern Power Administration

● GENERATING

○ NONGENERATING

RURAL ELECTRIC COOPERATIVES



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

GENERATING

NONGENERATING

NONSERVICED AREAS

Only 21 of the 56 utilities in Florida own electric generating plants. As a result, several utilities not only generate for themselves but also sell to others on a long-term basis. Some municipal- and cooperative-owned utilities purchase all of their requirements to serve their customer load.

As of January 1, 2001, the generating capacity within Florida was 42,609 MW (summer ratings) and 44,866 MW (winter ratings).[1]

State of Florida

2001 Generating Capacity - Megawatts

	Summer	Winter
Existing Capacity	39,798	41,975
Non-Utility Generation	2,811	2,891
Total	42,609	44,866

Rate Levels

Florida's electric rates have been stable for more than a decade. Adjusting for inflation, the price of electricity in Florida has actually declined by 38% since 1984. At an average of 7.1 cents per KWH, Florida's electric rates are slightly above the national average of 6.7 cents per KWH. Florida's electric utility industry has provided reliable service at reasonable prices, despite the fact that all generating fuels must be transported long distances to power plants within Florida, and that Florida has experienced rapid growth over the last ten years. The chart on page 26 shows typical residential monthly bills for all Florida electric utilities based on 1,000 KWH usage.

Customer Profile

Florida is somewhat unique in its makeup of customers. Based on 2000 data, approximately 47% of all electric energy is sold to residential customers, 33 % to commercial customers, with another 10% used for street lighting and other uses. Industrial customers account for slightly less than 10% of sales. Florida has a smaller industrial load than the national average, where industrial customers consume 31% of the electricity produced. With respect to actual number of customers, 89% of all accounts on record as of 2000 are residential accounts.

Load Profile

As can be seen in the diagrams on page 27, the energy requirements of customers and businesses vary over the course of the day. In the summer, energy demand begins to climb in the morning hours when hot water heaters come on, people rise and start taking showers and making breakfast. As the temperature rises during the day and air conditioners begin cycling on, the energy demand climbs until about six o'clock in the afternoon when peak demand for the day is reached. Energy load decreases as temperatures cool off during the evening and reaches its lowest point at about one o'clock in the morning. This is a typical summer 24-hour load curve. The winter load curve differs in that it reaches two peaks, the largest occurring at approximately eight o'clock in the morning and the other occurring at approximately seven to nine o'clock in the evening.

[1] The summer and winter capacity values are different because of how weather affects the efficiency of generating units.

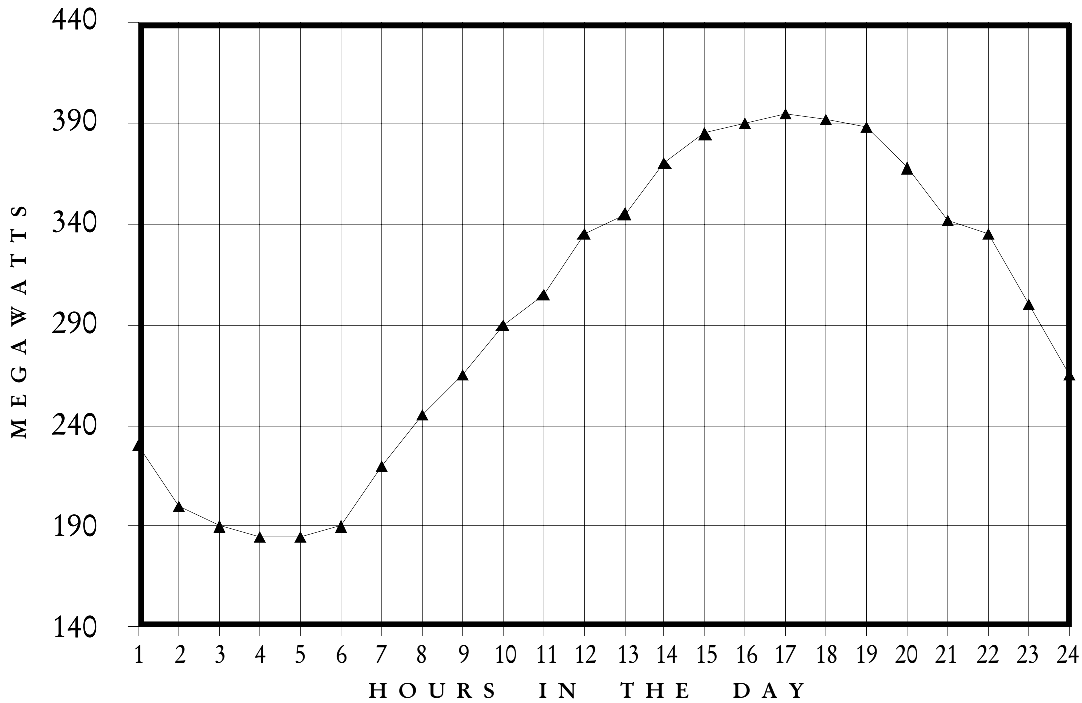
1,000 KWH Residential Monthly Bills for Florida Electric Utilities*

Rank	Utility	Type	Total Bill
1	Fort Meade	Municipal	$ 108.36
2	Lake Worth	Municipal	$ 107.36
3	New Smyrna Beach	Municipal	$ 105.85
4	Alachua	Municipal	$ 105.50
5	Key West	Municipal	$ 102.90
6	Wauchula	Municipal	$ 99.97
7	Homestead	Municipal	$ 99.28
8	Glades	Cooperative	$ 98.50
9	Newberry	Municipal	$ 97.92
10	Bushnell	Municipal	$ 97.32
11	Tri-County	Cooperative	$ 97.02
12	Clewiston	Municipal	$ 96.60
13	Green Cove Springs	Municipal	$ 94.40
14	Havana	Municipal	$ 93.94
15	Williston	Municipal	$ 93.84
16	Peace River	Cooperative	$ 93.00
17	Florida Power Corporation	Invertor-Owned	$ 91.07
18	Suwannee Valley	Cooperative	$ 90.66
19	Starke	Municipal	$ 90.65
20	Bartow	Municipal	$ 90.61
21	Vero Beach	Municipal	$ 90.60
22	Fort Pierce	Municipal	$ 90.22
23	Tallahassee	Municipal	$ 89.69
24	Jacksonville Beach	Municipal	$ 89.68
25	Lakeland	Municipal	$ 89.10
26	Kissimmee	Municipal	$ 88.60
27	St Cloud	Municipal	$ 88.09
28	Central Florida	Cooperative	$ 88.00
29	Quincy	Municipal	$ 87.76
30	Ocala	Municipal	$ 87.22
31	West Florida	Cooperative	$ 86.95
32	Sumter	Cooperative	$ 86.95
33	Florida Power & Light	Invertor-Owned	$ 85.80
34	Tampa Electric Company	Invertor-Owned	$ 85.57
35	Okefenoke	Cooperative	$ 85.00
36	Withlacoochee River	Cooperative	$ 84.67
37	Gulf Coast	Cooperative	$ 84.50
38	Gainesville	Municipal	$ 83.90
39	Moore Haven	Municipal	$ 83.70
40	Orlando	Municipal	$ 83.10
41	Chattahoochee	Municipal	$ 82.05
42	Talquin	Cooperative	$ 82.00
43	Escambia River	Cooperative	$ 81.30
44	Leesburg	Municipal	$ 80.37
45	Lee County	Cooperative	$ 79.60
46	Clay	Cooperative	$ 79.10
47	Choctawhatchee	Cooperative	$ 78.32
48	Florida Keys	Cooperative	$ 76.12
49	Mount Dora	Municipal	$ 74.34
50	Jacksonville Electric Authority	Municipal	$ 68.15
51	Gulf Power Company	Investor-Owned	$ 64.19
52	Blountstown	Municipal	$ 62.08
53	Reedy Creek	Municipal	$ 59.66
54	Florida Public Utilities - Marianna	Investor-Owned	$ 59.58
55	Florida Public Utilities - Fernandina Beach	Investor-Owned	$ 59.55

* *Based on rates as of September 30, 2001. Bills do not include any local taxes or franchise fees. Bills also do not include any gross receipts taxes that are not included in the base rate charges.*

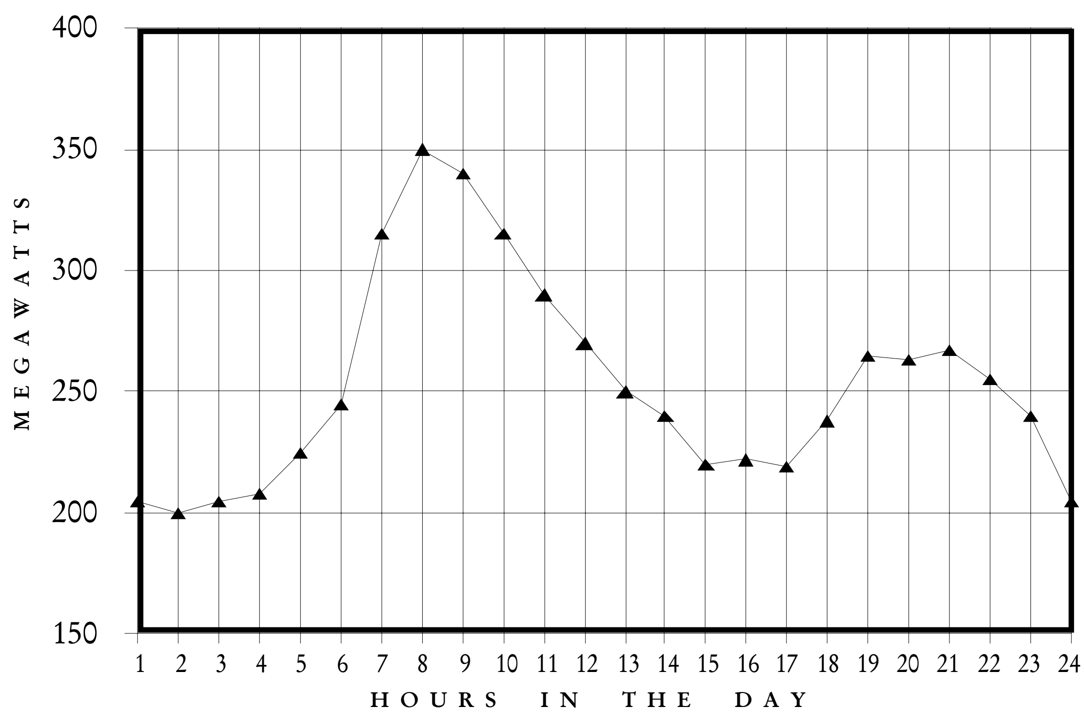
TYPICAL SUMMER PEAK DAY

1991



TYPICAL WINTER PEAK DAY

1991



If each 24-hour load curve was taken throughout the year and plotted over the course of 12 months, it would produce a yearly load demand curve portraying seasonal demand. Between June and September, when air-conditioners are running non-stop, there is a tremendous amount of energy required. During the summer months all generation units are committed to serve that load. Likewise, most generation is available during the winter months, typically December and January, to meet demand spikes caused by unusual weather. Autumn and spring are typically seasons of fairly moderate load levels. For that reason, most generation facility maintenance is performed during the spring and fall. However, these periods are susceptible to energy shortages if there are sudden heat waves or cold fronts.

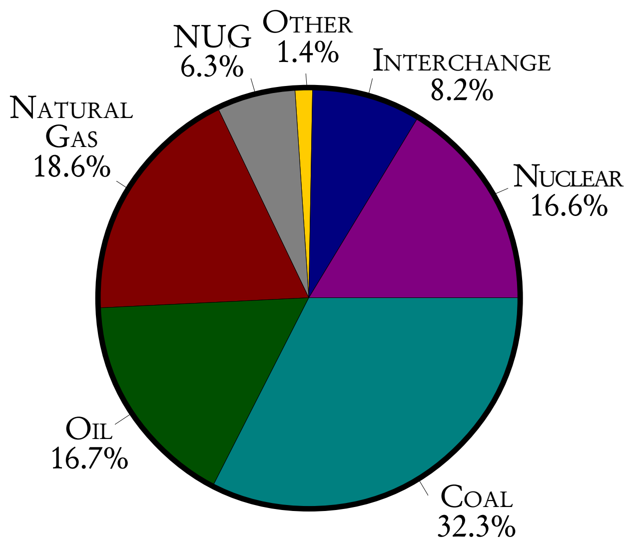
Fuel Mix and Economic Dispatch

Florida has limited native fuel resources. The only energy sources native to Florida are solar, biomass and a small quantity of hydroelectric power in northwest Florida. All other fuels used by Florida's utilities are fossil (natural gas, oil and coal) or nuclear, which must be brought into the state by various transport systems. Natural gas flows into the state primarily through one major pipeline, although another pipeline that will cross the Gulf of Mexico is under construction. Coal is delivered by rail or barge, and oil is delivered by tanker. Nuclear fuel is delivered by truck and rail. The chart below indicates Florida's mix of fuels used to generate electricity.

Peninsular Florida

ENERGY MIX BY FUEL TYPE

2000 (Actual)



The production cost of electricity is affected by the type of fuel used. The following table lists the types of plants operating in Florida with estimates of their average fuel costs. Because of fluctuating fuel prices, these figures are for illustration only and do not reflect actual costs.

FUEL COSTS BY PLANT TYPE

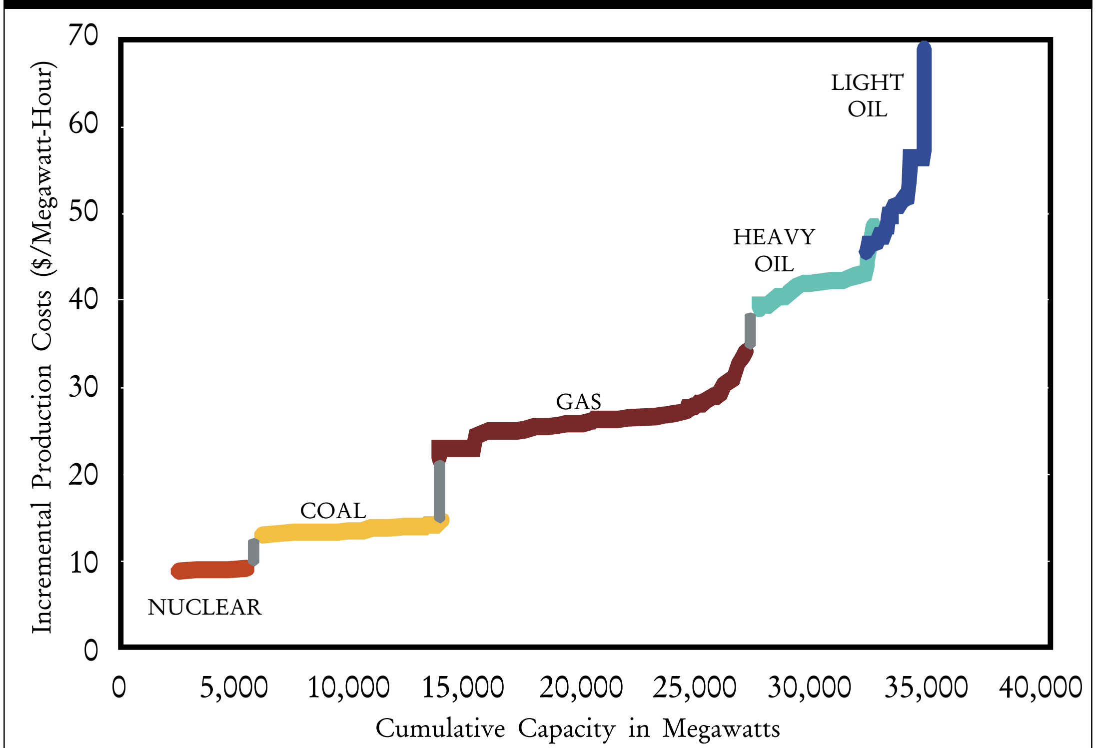
	Fuel ($mmbtu)	Heat Rate (btu/KWH)	Cost ($/MWH)
Nuclear	$ 0.42	11,000	$ 4.62
Coal	$ 2.00	10,000	$ 20.00
Natural Gas	$ 3.50	7,500	$ 26.25
Heavy Oil	$ 4.00	10,000	$ 40.00
Light Oil	$ 4.50	14,000	$ 63.00

In the first column are fuel costs on a dollar-per-million British Thermal Units (BTU) basis. Fuel costs vary, depending on the market price and hedging strategies of the utilities. The heat rate shown in the second column is a measure of efficiency – the amount of heat needed to produce a given amount of electricity. A lower heat rate implies a higher efficiency. A more efficient plant requires fewer BTUs to produce a given megawatt-hour (MWH) of electricity. The third column is the production cost in dollars per MWH (for comparison purposes, a typical home uses approximately one MWH per month). Thus, fuel costs depend on the cost of fuel and plant efficiency. Nuclear, for example, is about $4.62 per MWH while coal is $20 per MWH, and a combustion turbine running on a peak period day could have fuel costs of $63 or higher per MWH.

The following supply stack diagram illustrates how energy production costs determine which fuel and type of generation are deployed to serve customers. The bottom of the chart reflects the amount of energy demanded in Florida on any given day (assuming that cost of production is the sole determinant of deployment), ranging from near zero demand up to 40,000 megawatts, where demand of 35,000 megawatts would be a peak summer or peak winter day. On the left axis is the cost per megawatt hour from the previous diagram. In Florida, because of the low fuel costs, nuclear and coal-fired plants are dispatched first. As load increases, different gas-fired plants are dispatched, then heavy oil, and finally combustion turbines, which are the least efficient and burn the most expensive fuel. On the hottest or coldest days, incremental fuel costs rise to $60 or higher. This diagram is called the economic dispatch, and all utilities that own generation perform this function.

Estimated

PENINSULAR FLORIDA SUPPLY STACK



Geography and Transmission

Florida's geography limits its ability to import power from surrounding states. There are two primary locations where transmission flows between Florida and our neighboring states to the north. Between Florida and Georgia are two 500 KV lines located at the northeast portion of Florida, and between Florida and Alabama are several 230 and 69 KV lines located in the northwest portion of the state.

For the year 2001, the Florida Reliability Coordinating Council estimated that only 6.5% of Florida's electricity demand would be satisfied from sources outside the state. The amount of electricity that can be sent over Florida's interstate transmission wires is limited by thermal conditions and by load conditions.

Under optimal conditions, Florida can import a maximum of 3,600 megawatts (MWs). Approximately 2,600 MWs megawatts of that capacity are committed to deliver generation capacity located in Georgia and owned by FPL, and for other firm purchases. There are some opportunities for non-firm purchases over the interstate transmission interface; however, those opportunities are limited.

Florida's peninsular geography results in reliance on generation resources within the state to ensure the reliability of service. Virtually all the power Florida needs is produced within its boundaries; however, a small but important amount is imported from outside the state. The limits on import capability prevent significant additional capacity from being purchased from outside the state.

Regional Reliability Councils

The North American electric system is comprised of an interconnected network of generating plants, transmission lines, and distribution facilities. Transmission systems are divided into regional grids, which provide electric utilities with alternative power paths in emergencies and allow them to buy and sell power from each other and from other power suppliers. The structure of the grid makes greater reliability possible, but what makes it a reality is the coordination in operations of the electric companies that make up the networks. These operations are coordinated by the North American Electric Reliability Council (NERC).

The NERC is a voluntary membership organization that was created as an alternative to government regulation of reliability. The NERC develops standards, guidelines, and criteria for ensuring system security and evaluating system adequacy. Within the NERC organization are ten Regional Reliability Councils, which adapt the NERC rules to meet the needs of their regions. The reliability coordinating councils were established to ensure and enhance the reliability and adequacy of bulk electricity supply in North America, now and in the future. The members include investor-owned utilities, cooperative systems, municipals, independent power producers, federal systems, and power marketers. Through the work of its ten Regional Reliability Councils, the NERC has largely succeeded in maintaining a high degree of transmission grid reliability throughout the country.

Florida is involved in two Regional Reliability Councils. The portion of Florida west of the Apalachicola River is part of the Southeastern Electric Reliability Coordinating Council (SERC) grid, which covers all or parts of 11 states in the Southeastern United States (Georgia, Alabama, Mississippi, Louisiana, Arkansas, South Carolina, North Carolina, Tennessee, Virginia, Florida, and Missouri). The portion of Florida east of the Apalachicola River and encompassing peninsular Florida comprises the Florida Reliability Coordinating Council.

Natural Gas Pipeline Transmission System

The natural gas industry is critically tied to the electric industry. Natural gas has become the fuel of choice for new electric generators. Over the past decade, the increase in natural gas usage as a fuel has been dramatic. In 1994, 48% of the natural gas brought into Florida was used for electric generation; by 2000, in just six years, that amount had increased to 62%. The actual amount of natural gas used also increased by 50% during that same time.

The gas industry is a capital-intensive industry with much of the cost of operations in underground piping. The existing gas pipeline transmission system that delivers gas to most of Florida is the Florida Gas Transmission Company (FGT) pipeline. The FGT is jointly owned by Enron Corporation and Southern Natural Gas (SONAT). United Gas Pipeline Company also brings gas into Northwest Florida, serving primarily the Pensacola area. South Georgia Natural Gas, a subsidiary of SONAT, delivers gas into the Tallahassee area, and into Hamilton, Suwannee and Columbia counties from the Georgia border.

Natural gas enters the FGT system from the gas and oil-producing areas of Texas and Louisiana. From there, it is transported through parallel 24- and 30-inch pipelines under pressures as high as 990 pounds per square inch (psi) to delivery points throughout the state of Florida. The entire system is approximately 1,500 miles in length.

About 75% of the natural gas entering Florida leaves the FGT system through direct-sales laterals. These are branches from the main pipeline that are owned and operated by FGT. They deliver gas directly to high-volume industrial customers and to electric utility generating stations. The remaining 25% of gas that enters Florida is delivered to local distribution companies and municipally-operated systems.

As of the summer of 2001, a new natural gas pipeline, Gulfstream Natural Gas System, is being constructed through Florida. This new pipeline is originating from Coden, Alabama outside of Mobile Bay and extending across the Gulf of Mexico to Manatee County in Florida, where it will then stretch across the state to Fort Pierce on the East coast. This system is expected to be in service by June of 2002.


Photo Courtesy of Florida Power and Light Company

IV. Future Needs for Electricity

Florida continues to be one of the fastest growing states in the nation. Based on current estimates, Florida's population is expected to increase by an average of 279,000 annually over the next ten years.[2] The electrical needs of Florida must be planned for. This planning must take into account the needs of each household, as well as the needs of grocery stores, gas stations, shopping malls, and other commercial establishments that support our growing population. Florida's industrial sector will also require adequate and reliable supplies of electricity. In this age of personal computers and the Internet, a continued supply of adequate, reliable, and affordable electricity is essential to the continued economic well-being of the state. As Florida's population continues to grow, so does the state's need for sources of electricity.

In 2001, there was 46,254 MWs of resources available to serve a firm summer peak demand of 38,285 MWs, yielding a 21% reserve margin. Based on current utility plans and projections (2001-2010), for the summer of 2002 there will be a total of 48,611 MW of generating resources available in Florida to serve a total firm peak demand of 39,469. This means that a 9,142 MW, or 23%, reserve margin is anticipated next summer to allow for necessary generating unit maintenance and to protect against contingencies, such as unforseen unit outages, unusually severe weather, and unanticipated customer growth. Non-firm demand (load management and interruptible service) represents 2,795 MW of this reserve margin. If non-firm demand, which has been relied on as a cost-effective way of avoiding or deferring power plant construction, is included as part of peak demand, the margin of reserve is 6,347 MW, or 15%.

Florida's aggregate peak demand is expected to rise significantly over the next ten years. Current forecasts show that net summer peak demand will increase by over 9,700 MW (25.4%) between 2001 and 2010. If this growth trend continues, summer peak demand could be expected to increase by over 22,800 MW by 2020, an increase of approximately 59.7% over current levels. Net winter peak demand is forecasted to increase by similar amounts.

Statewide energy consumption is also expected to significantly increase during the ten-year planning horizon. Current forecasts indicate that energy consumption, known as net energy for load, will increase by over 48,600 GWH (22.6%) over the next ten years. If this trend continues beyond 2010, energy consumption can be expected to increase by nearly 111,700 GWH by 2020, a 51.8% increase over current levels.

To meet Florida's growing demand for energy, an acceleration of power plant construction is occurring. Over the next ten years, peninsular Florida's electric utilities have under construction or plan to construct (or acquire) approximately 15,200 MW (summer ratings) of new generating capacity. Looking out over the subsequent ten years to the year 2020, an additional 14,200 MW of generating capacity would need to be built to maintain a 20% reserve. Therefore, to maintain a 20% reserve margin over the next 20 years will require 29,400 MWs of generating capacity.

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[2] Source: Bureau of Economic Business Research, Warrington College of Business Administration, University of Florida.

These forecasts are based on an elaborate statewide energy resources planning process coordinated by the Florida Reliability Coordinating Council (FRCC). The forecasting process is not an exact science, however. A discussion later in this report provides an alternative forecast for 2020 and explains the ramifications of under-forecasting demand growth. For purposes of this section, the discussion relies on the official estimates provided by the FRCC. The following pages describe that process and provide additional discussion on the planning process currently employed to identify and satisfy Florida's energy needs.

Integrated Resource Planning

At present Florida's requirements for electricity are being met by an electric utility industry that is fully regulated. Each year, each utility must submit a Ten-Year Site Plan that forecasts the demand for electricity over a ten-year planning horizon. Utilities must then identify the combination of conservation measures and power plants that will be added to satisfy demand and provide an adequate reserve for contingencies, all at the most affordable cost to consumers. These annual load and resource plans are reviewed by the Public Service Commission (PSC). This annual planning and review process is aimed at ensuring that Florida's electric energy supply meets the needs of the citizens.

Load Forecasting

Load forecasting is the first step in the planning process and is used by electric utilities to estimate future energy needs. From these estimates of customer load, utilities determine how much, and when, additional generating capacity may be needed. Historical data forms the foundation for utility load and energy forecasts. This data include such items as energy usage patterns; number of customers; economic, demographic, and weather patterns; appliance-specific saturation, and energy consumption characteristics. Data is collected from a variety of sources. Utility-sponsored customer surveys are used for residential, commercial, and industrial development. In addition, utility representatives routinely contact area chambers of commerce, residential and commercial building developers, and other businesses to anticipate when and where load growth may occur. Large industrial customers frequently seek out utility suggestions as to where to locate new facilities and what rates are available. Based on this data, the utility prepares models of future economic development, weather patterns, available conservation measures, technology development and impact, and customer use and demographic conditions; all of which effect its forecast of customer demand and energy growth in its service territory.

Demand-Side Management and Energy Efficiency

Utilities employ demand-side management (DSM) and energy efficiency measures to decrease customer peak demand and energy requirements, resulting in the avoidance or deferral of the need for new generating plants. DSM and energy efficiency were mandated by the Florida Legislature in 1980 with passage of the Florida Energy Efficiency and Conservation Act (FEECA).[3] FEECA emphasizes reducing the growth rate of peak demand, controlling the growth rate of energy consumption, and reducing the consumption of fossil fuels.

[3] Sections 366.80 - 366.85, Florida Statutes, and Section 403.519, Florida Statutes.

To meet these objectives, the PSC sets goals for the state's investor-owned and large municipal utilities to reduce the increase of peak demand and energy consumption. The affected utilities implement DSM and energy efficiency plans, consisting of programs and measures designed to meet the goals set by the PSC. Examples of programs contained in utility plans are load management and energy-efficient lighting.

State of Florida

Estimated Savings From Utility DSM Programs

	To Date (Since 1980)	By 2010
Summer Peak Demand	3,761 MW	4,568 MW
Winter Peak Demand	5,451 MW	6,474 MW
Energy Consumption	2,595 GWH	4,543 GWH

Utility DSM programs, referred to collectively as "non-firm service," allow the utility to cycle on and off certain energy-using equipment as needed to maintain reliability during times of system peak demand. In return for this reduced level of service, customers receive a credit or discount on their monthly electric bill. Utilities do not build generation facilities to serve non-firm load. The ability of the utility to manage non-firm customers' demand, therefore, allows the company to avoid the construction of additional plants and provide savings to all customers. Because of the number of participating customers, residential non-firm customers are allowed to return to firm service with as little as 30 days notice. Larger industrial non-firm customers, which have larger individual demands and unique load control arrangements, must agree to give three to five years notice to return to firm service to allow the utility time to put in place additional generating resources to meet the higher demand at system peak.

Utility DSM and energy efficiency programs have resulted in substantial reductions in peak demand and energy consumption since FEECA was enacted in 1980. As noted in the table above, Florida's utilities have reduced peak demand by over 3,700 summer MW (over 5,400 winter MW) and energy consumption by nearly 2,600 GWH. The demand savings alone are equivalent in size to ten modern gas-fired combined-cycle generating units.

Reserve Margin

To provide continuous service to firm customers, utilities must plan for contingencies, such as unforeseen unit outages, unusual weather, maintenance of units, and unexpected customer growth. Utilities use reliability criteria to determine a sufficient level of resources required beyond what is shown to be necessary by the base-case load forecast. The primary criterion used by most Florida utilities is reserve margin, a measure of the amount by which a utility's system capacity exceeds its firm peak demand. Reserve margin is usually evaluated at the time of seasonal peak. Reserve margin has both a supply-side (generating units, firm capacity purchases) and a demand-side (non-firm load) component.

The Florida Reliability Coordinating Council (FRCC) has a planning criterion of 15% reserve margin for peninsular Florida, and the planning criterion used by the state's various electric utilities varies from 15% to 20%. However, peninsular Florida's three large investor-owned electric utilities, which make up nearly 75% of the region's generating capacity, have agreed to increase their planning criterion to 20% by 2004. Gulf Power Company, which is part of the Southern Company system, plans to continue using its 13.5% reserve margin planning criterion.

Florida's utilities forecast an aggregate summer reserve margin of at least 20% for each of the next ten years. Likewise, forecasted winter reserves are expected to meet or exceed 20% during the planning horizon. Florida's forecasted reserve margins do not account for the potential addition of several announced merchant plants, which could add over 5,000 MW of capacity to the state's resources over the next five years.

As mentioned above, non-firm load plays a significant role in the state's reserve margin. The degree of reliance on these non-firm resources has been a subject of controversy at various times. A discussion later in this report recognizes the importance of non-firm load as a cost-effective alternative to constructing additional power plants, but expresses concern about relying too heavily on these resources.

Supply Resource Selection

Having determined the system load and energy requirements, utilities must then select the additional supply-side resources needed to meet these needs in a reliable and cost-effective manner. This process begins by surveying the types of generating technology currently available and identifying their cost and operating parameters (i.e., MW size, heat rate efficiency, start and stop times, load ramping rates, pollution control requirements, water consumption, etc.). Computer analyses are performed to calculate and compare the life-cycle costs of each generating technology. New generating capacity additions are selected for construction based on the most cost-effective combination of capital and operating (fuel) costs to ensure that customer load and energy requirements are met at the lowest practical cost. As a final step in the supply resource selection process, the costs of proposed new generation are compared with the costs of additional demand-side conservation measures to determine if any additional conservation can be implemented as a cost-effective alternative to planned generation.

Generation Mix

Florida's utilities supply electricity from many different generating unit types. Prior to the oil embargoes of the 1970's, Florida's electricity was generated primarily using oil. While oil still accounts for over 17% of the state's energy generation, the generation mix for Florida's utilities as a whole is now more diverse, including coal, nuclear, natural gas, interchange (purchases from out-of-state), and non-utility generation.

The current and forecasted generation mix of Florida's utilities is shown below. Note the forecasted substantial increase in natural gas-fired energy generation over the next ten years. Nearly all generating units planned over the next ten years are expected to be natural gas-fired combined-cycle and combustion turbine units. Two factors are driving this trend: the relatively low cost of natural gas and efficiency improvements in combined-cycle and combustion turbine generating technology. Fuel price is the primary factor affecting the type of generating unit additions.

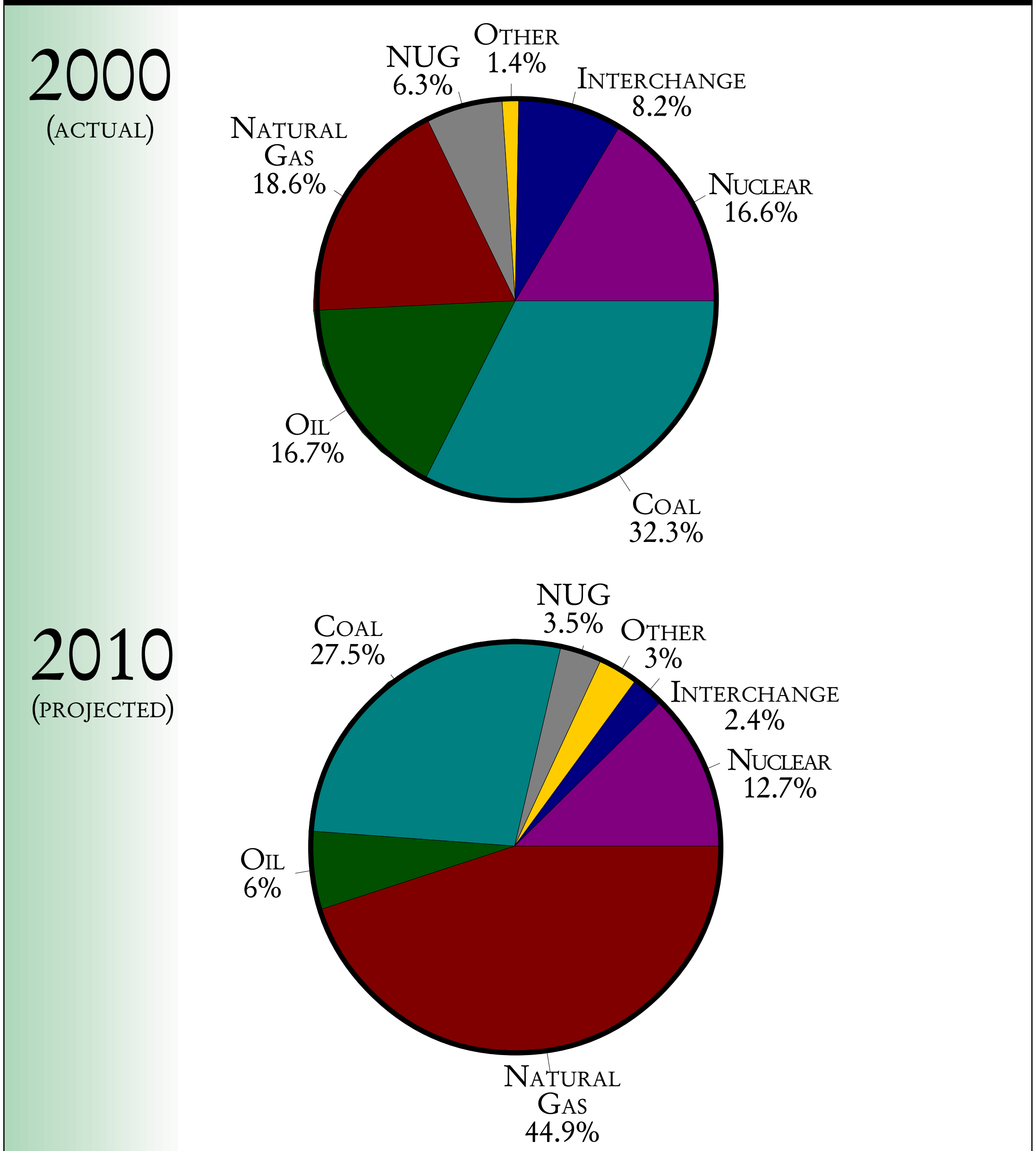
Coal-fired units have not been a viable new generation option for most Florida utilities because of high construction costs and increased concerns over coal plant emissions. However, the City of Lakeland and JEA plan to add coal capacity within the next ten years. If Florida is concerned about becoming heavily dependent upon one fuel type, such as natural gas, it may be necessary to encourage the building of a few coal-fired plants to maintain fuel mix diversity. It may be worth the slightly higher expense of building a coal-fired plant versus a natural gas-fired plant, as insurance against future increases in natural gas prices and over-dependence on one fuel type.

Florida currently has five nuclear generating units – four owned by FPL and one owned by FPC. Nuclear technology is currently out of favor as a way of satisfying new load requirements, primarily because of high capital costs but also because of the federal government's failure to provide a centralized storage facility for spent nuclear fuel. Until the Federal government assumes responsibility for the spent fuel disposal, nuclear generating units are not considered a viable option for future fuel diversification.

Interchange purchases (out-of-state) are expected to decline over the planning horizon because Southern Company expects to have less capacity and energy available for resale.

Peninsular Florida

ENERGY MIX BY FUEL TYPE



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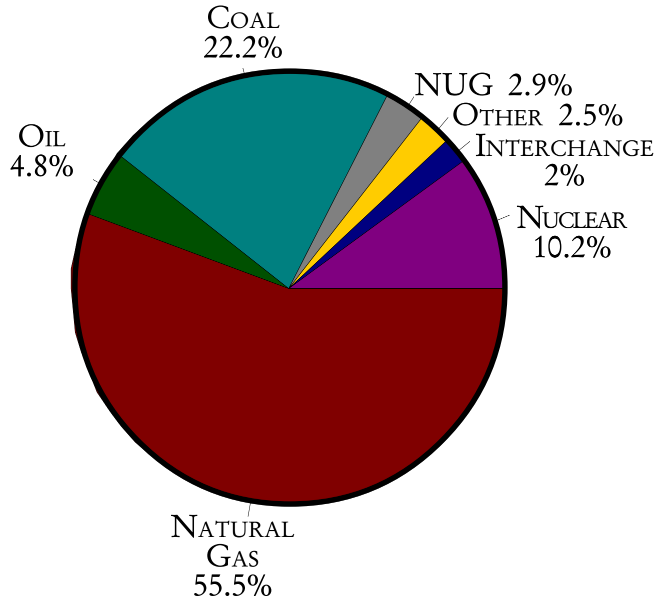
Peninsular Florida

ENERGY MIX BY FUEL TYPE

2020 (PROJECTED)



V. The 2020 Energy Strategy

A PROMOTING ENERGY EFFICIENCY AND PUBLIC BENEFITS

THE GOAL

Florida will be a leader in using energy wisely.

OBJECTIVES

A-1 Customers will be knowledgeable about energy efficiency and have access to information that allows them to make informed decisions about the relative efficiency of energy-consuming goods.

A-2 Customers have the opportunity to participate in programs aimed at increasing the efficient use of energy resources.

A-3 Low-income customers have access to programs designed to reduce the burden of electricity costs and to increase the efficiency of their homes to reduce energy consumption.

A-4 Customers are encouraged to use electricity during off-peak periods by paying prices for electricity that accurately reflect the real-time cost of production.

A-5 Customers are rewarded for managing their consumption of electricity in a way that contributes to the efficient use of generating resources.

REEXAMINING "PUBLIC BENEFITS"

With increased competition leading to the restructuring of the electric industry, many of the traditional roles and responsibilities of regulated electric utilities are being reexamined. There are legitimate questions regarding whether utilities should continue to provide the traditional menu of public benefit-type activities. The restructuring process also provides an opportunity to consider whether certain public benefit-type activities should be increased.

Public benefits typically associated with utilities and the energy industry in general are demand-side management, energy efficiency, research and development, and targeted low-income assistance programs. Many different approaches are available to ensure that public benefit programs remain an essential part of Florida's future energy policy. Some states require that electric utilities offer information to their customers about managing their energy bill, free or low-cost energy audits, or technical and financial assistance to help their customers invest in energy efficient equipment and appliances. Some states require utilities to collect funds or administer programs to provide bill payment assistance to low-income customers. Utilities have also committed resources to research and development activities, often in the area of new technologies, such as renewables and energy efficiency. Collectively, such activities are referred to as public benefit programs because they offer important public services in addition to the business of generating and delivering electricity.

Florida can claim successes in some areas, such as utility demand-side management programs. In other areas, such as energy assistance to low-income customers, Florida is not as progressive. The Study Commission believes there should be a reexamination of these public benefits.

STRATEGY

Revitalize the Florida Energy Office.

TASKS

- ♦ The Florida Energy Office should house the office of the state energy director to promote the development of a reliable, efficient, and competitive market to adequately serve consumers.
- ♦ The Florida Energy Office should continue seeking federal funding for specific energy research and development activities.
- ♦ The Florida Energy Office should conduct a study to identify the potential for savings through energy efficiency and improvements in Florida's building code and appliance standards.
- ♦ The Florida Energy Office should promote new investments in energy efficiency, sustainable generating technologies, and energy research and development activities.
- ♦ The Florida Energy Office should develop and coordinate implementation of energy policy within the state.

Florida Energy Office

The Florida Energy Office (FEO), now housed within Florida's Department of Community Affairs, serves as the central place in state government for information on energy-related issues in Florida. Following the national energy crisis of 1973, the forerunner of the FEO was created in 1974 when responsibilities for petroleum allocation and conservation in Florida were assigned to Florida's Department of Administration. In 1979, following another Middle East oil supply disruption, the executive branch transformed the petroleum allocation office into the Governor's Energy Office within the Executive Office of the Governor.

Beginning in 1982, Petroleum Violation Escrow (PVE) funds became available when federal court cases were settled with oil suppliers who had overcharged consumers during the period of petroleum price controls in the 1970's. These funds were distributed to the states over time to be used for specific energy related initiatives with a broad array of activities. During this period, the Florida Energy Office was staffed at approximately 80 professionals and support personnel engaged in diverse activities. Program efforts were divided into three areas: data acquisition, state energy conservation, and an energy retrofit grant program targeting public and non-profit schools and hospitals and units of local government. In the case of the grant program and the state energy efficiency and conservation program, specific federal guidelines were used to administer these programs.

The Data Acquisition section collected and evaluated energy data on national and statewide supplies, forecasted energy use, published an annual state energy use report, and planned for and directed the response to potential state energy emergencies. The State Energy Conservation Program (SECP) initiated projects and demonstration pilot programs in a wide variety of areas, including ride-sharing, bicycle and pedestrian programs, demonstration projects for renewable energy technology, solar, energy conservation retrofits, education, alternative fuel vehicles, commercial and industrial efficiency, land use and transportation systems, and the building environment. The Institutional Conservation Program (ICP) implemented a 50/50 matching grant program to assist with the replacement of older, inefficient energy consuming equipment in public K-12 schools, community colleges, state universities, not-for-profit public and private schools and hospitals. This program helped reduce these institutions' utility expenses and stretched their financial resources.

In 1991, the FEO was transferred from the Governor's Office to the Department of Community Affairs. Historically, the FEO has not received state general revenue funds to either operate or fund programmatic efforts. All operational funding is federal dollars received through an annual grant from the U.S. Department of Energy.

Over a period of years, the FEO staffing has been reduced with the elimination of the Data Acquisition section and the ICP grant program which ended in 1996. The SECP continues to provide grant funding to all sectors of the state to reduce energy costs in state and local government and private sector buildings through both short- and long-term strategies and activities. The SECP also provides grants for research and development of energy efficient products and technologies. Down from a staff of 80 in the late 1970's, there are currently seven full-time equivalent positions.

Revitalizing the Florida Energy Office

Florida's Statutes currently include authority for a state energy office. Section 377.703(3)(b) and (d), Florida Statutes, states, "The department shall constitute the responsible state agency for performing or coordinating the functions of any federal energy programs delegated to the state, including energy supply, demand, conservation, or allocation. The department shall coordinate efforts to seek federal support or other support for state energy activities, including energy conservation, research, or development, and shall be the state agency responsible for the coordination of multi-agency energy conservation programs and plans."

The Study Commission believes the Florida Energy Office should be revitalized. Specifically, the FEO should:

- House the office of the state energy director to promote the development of a reliable, efficient, and competitive energy market to adequately serve consumers.
- Continue seeking federal funding.
- Conduct a study to identify the potential for savings through energy efficiency and improvements in Florida's building code and appliance standards.
- Manage new investments in energy efficiency, sustainable generating technologies, and energy research and development opportunities.
- Develop and coordinate implementation of energy policy within the state.

The current statutory authority provides an adequate delineation of what the Study Commission believes should be the responsibilities of the FEO. However, the funding sources on which the FEO has been relying are, for the most part, no longer available. The level of resources expected to be available through federal programs is not sufficient to carry out the expanded role contemplated by the Study Commission.

In an effort to expand its resources, the FEO should continue to seek federal funding for projects whose primary objective is to pursue applied research, development and demonstration designed to advance technologies that promote energy efficiency in all sectors of the economy. Such resources may become available with the adoption of President Bush's National Energy Policy. Florida should consider providing additional state resources to expand the FEO's role.

With respect to energy efficiency potential in Florida, the FEO should fund a comprehensive assessment of the statewide opportunities for energy efficiency. In May 1993, a Synergic Resources Corporation (SRC) Report, No. 7777-R8, was submitted to the Florida Energy Office entitled, "Electricity Conservation and Energy Efficiency in Florida: Technical, Economic and Achievable Results." Under the direction of a group of utility, private, state and national energy professionals, it considered 120 demand-side management (DSM) options and provided technical, economic and market penetration information for electricity use for those options. The Codes and Standards unit at DCA was involved in considering the 120 options and listing which were already included within the Florida Energy Efficiency Code For Building Construction (Code) and the potential for including appliance standards and other options within the Code. The FEO should conduct a new study to evaluate potential energy savings.

The evidence in other states shows that one of the most cost-effective means of providing energy with low environmental impact is through adoption of energy efficient building codes and appliance standards. Florida is one of the fastest growing states in the nation, with significant development of new housing and commercial building infrastructure occurring now and for the foreseeable future. Many of Florida's utilities already recognize that it is desirable to build energy efficiency into the design and construction of new buildings, and there are several utility demand-side management programs to encourage energy efficient construction practices. Future revisions to Florida's energy code must be proposed to the Florida Building Commission on a triennial code-change cycle with annual changes as necessary.

Code-change cycles are noticed to the public and must follow a rigorous process to provide time for their review. Energy code provisions specified by section 553.900, Florida Statutes, include those relevant to heating, cooling, and water heating in all new and substantially renovated buildings in Florida, as well as lighting in commercial buildings. Section 553.951, Florida Statutes, covers a limited list of appliances which are covered at the point of sale, including showerheads, lighting fixtures and refrigerators, although it does have provisions to include other appliances if economic criteria are met. State energy codes are required to demonstrate equivalence to national standards when noticed in the Federal Register, while a broad spectrum of appliance efficiencies (including showerheads, lighting fixtures and refrigerators) are covered by U.S. Department of Energy and Federal Trade Commission regulations, which preempt state regulations.

The third area of responsibility for the FEO should be to manage new investments in energy efficiency, sustainable generating technologies, and energy research and development opportunities. There are numerous reasons consumers do not invest in energy efficiency products and services.

Some of the reasons include: high information or search costs, performance uncertainties (difficulties consumers face in evaluating claims about future benefits), hassle or transaction costs, access to financing, misplaced incentives (e.g., landlord-tenant issues), product or service unavailability, long payback periods, regulatory policies that use average (rather than marginal) costs, and lags in receiving real-time price information due to metering and billing practices. In an effort to encourage energy efficiency, the FEO should utilize existing and future resources to manage a broad program of investments in energy efficiency and sustainable generation technology.

The fourth and final area of responsibility is developing and coordinating implementation of energy policy within the state. The Study Commission's Environmental Technical Advisory Committee (E-TAC) noted that there are several competent state agencies with responsibilities relevant to the energy industry. The DCA implements federally-funded programs and targeted energy assistance and weatherization programs. The DEP's role is in the areas of power plant siting, air emission permits, regulation of water, and air pollution laws. The PSC's role is economic regulation. The E-TAC noted that, despite Florida's reliance on the outside world for energy, its growth rate, and the increasing prospect for electricity to become more of a commodity, no entity maintains energy data or coordinates the activities of the DCA, DEP and PSC. The FEO should be given resources and authority to carry out these responsibilities.

Currently, the FEO is housed within the DCA's Division of Housing and Community Development. This division serves needs dealing with human services, housing and energy. The FEO has played a vital role in assisting the Department with its mission. It is co-located in the same division as other energy-related programs, including Weatherization, the Low-Income Home Energy Assistance Program (LIHEAP) and other programs that assist our communities, such as the Community Services Block Grant, the Community Development Block Grant and the Codes and Standards Unit. Co-location of these programs encourages inter-program and governmental coordination and facilitation of delivery of these programs on a statewide basis. Many of these programs are used to leverage each other. This enables the best achievement of the goal of consolidating program services. DCA has significant experience in administering energy programs and well-developed processes for ensuring accountability for use of public funds.

The Study Commission does not make specific recommendations with respect to the location of the FEO, except to note that the coordination and leveraging with many of DCA's existing programs would enable the FEO to efficiently implement energy efficiency programs. Another important consideration is that the role recommended by this report for the FEO would suggest a high priority for its mission, and the need for the FEO to have appropriate authority to assure its ability to carry out this mission.

STRATEGY

Expand availability and use of demand-side resources to provide greater reliability and more efficient use of generating plants, lower the cost of electricity, reduce air emissions from power plants, and increase customer satisfaction.

continued

TASKS

- Continue to require load-serving utilities to implement demand-side management programs to maximize the cost-effective contribution of efficiency investments to enhance reliability, lower environmental impacts and lower customer rates.
- Require the PSC to develop innovative rate programs for the residential, commercial and industrial sectors, such as real-time and time-of-use pricing, that send appropriate price signals to customers.
- Require the PSC to consider mechanisms that allow customers to directly respond to high market prices for electricity -- "demand responsiveness."
- Require the PSC to investigate mechanisms for instituting "demand bidding," enabling customers to be compensated appropriately for curtailing use during periods of high electrical demand.

Florida Energy Efficiency and Conservation Act

Florida was one of the first states to require electric utilities to aggressively pursue programs aimed at reducing the demand and use of energy. In 1980, the Florida legislature passed the Florida Energy Efficiency and Conservation Act (FEECA) which requires the subject utilities to reduce the growth rates of weather-sensitive peak demand, reduce and control the growth rates of electricity consumption, and reduce the consumption of expensive resources such as petroleum fuels. FEECA directed the PSC to adopt goals for each of the jurisdictional utilities every five years.

Since 1980, the nomenclature has changed and the term "conservation" is no longer in vogue, even though the original FEECA act still contains the phrase. Broadly speaking, programs that are directed toward saving energy (kilowatt-hours or KWHs) are called energy efficiency programs. Programs targeted toward reducing peak demand (kilowatts or KWs) are called demand-side management (DSM) programs. Load control is a prime example of a pure demand-side management program. Load control programs allow utilities to cycle on and off individual customer appliances in return for a monthly credit on their bill. It is important to note that the distinction between the two types of programs are not absolutes -- programs can reduce KWs and KWHs. Programs that use variable price signals to alter consumer behavior, particularly at peak periods, are called "price-responsive load" programs. It is the strategic objective of the program that best defines whether it is an energy efficiency program or a DSM program.

Currently, seven Florida electric utilities are required to meet the FEECA standards.[4] This includes the five investor-owned utilities and two municipal utilities. These seven utilities serve approximately 85% of the net energy produced in Florida. The Commission requires investor-owned utility programs for which cost recovery is sought to be "cost-effective." As it has been applied, the test for cost-effectiveness has assured that all utility ratepayers benefit, not just those ratepayers participating in the programs. Thus, cost-effective DSM and energy efficiency programs benefit the general body of ratepayers by reducing current production cost, deferring the need for

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[4] Florida Power & Light Company, Tampa Electric Company, Florida Power Corporation, Gulf Power Company, Florida Public Utilities Company, Jacksonville Electric Authority and Orlando Utilities Commission.

future power plant construction, and improving reliability. In addition, these programs benefit program participants by reducing their electric bills. The standard of cost-effectiveness traditionally applied by the PSC is the "Rate Impact Measurement," or "RIM," test. By ensuring that utility-sponsored conservation programs benefit all customers, the RIM standard assures fairness and equity for utility customers.

Since 1980, utility-sponsored DSM/efficiency programs have reduced year-2000 statewide summer peak demand by an estimated 3,761 MW, winter peak demand by 5,451 MW, and energy consumption by an estimated 2,595 GWH. Florida is recognized as a national leader in the implementation of various load-control programs. Approximately two-thirds of the peak demand savings are attributable to load-control and interruptible-demand programs. By 2010, DSM programs are forecasted to reduce aggregate summer peak demand by an estimated 4,568 MW, winter peak demand by an estimated 6,474 MW, and energy consumption by an estimated 4,543 GWH.

Investor-owned electric utilities are permitted to recover prudent and reasonable expenses, including incentives paid to participating customers, for PSC-approved programs through the Energy Conservation Cost Recovery clause (ECCR). This charge ranges from .05 to .2 cents per KWH on customers' bills. Since the enactment of FEECA, investor-owned electric utilities have recovered over $3.2 billion of conservation program expenditures through the ECCR clause.

TABLE 1

FEECA Expenditures Year 2000

	Expenditure*
Florida Power Corporation	$ 67,735,835
Florida Power and Light	$ 160,367,518
Florida Public Utilities	$ 275,188
Gulf Power Company	$ 3,804,485
Tampa Electric Company	$ 16,814,182
Total	$ 248,997,208

* *January-August actual; September-December estimated.*

Three Rivers Resource Conservation and Development Council

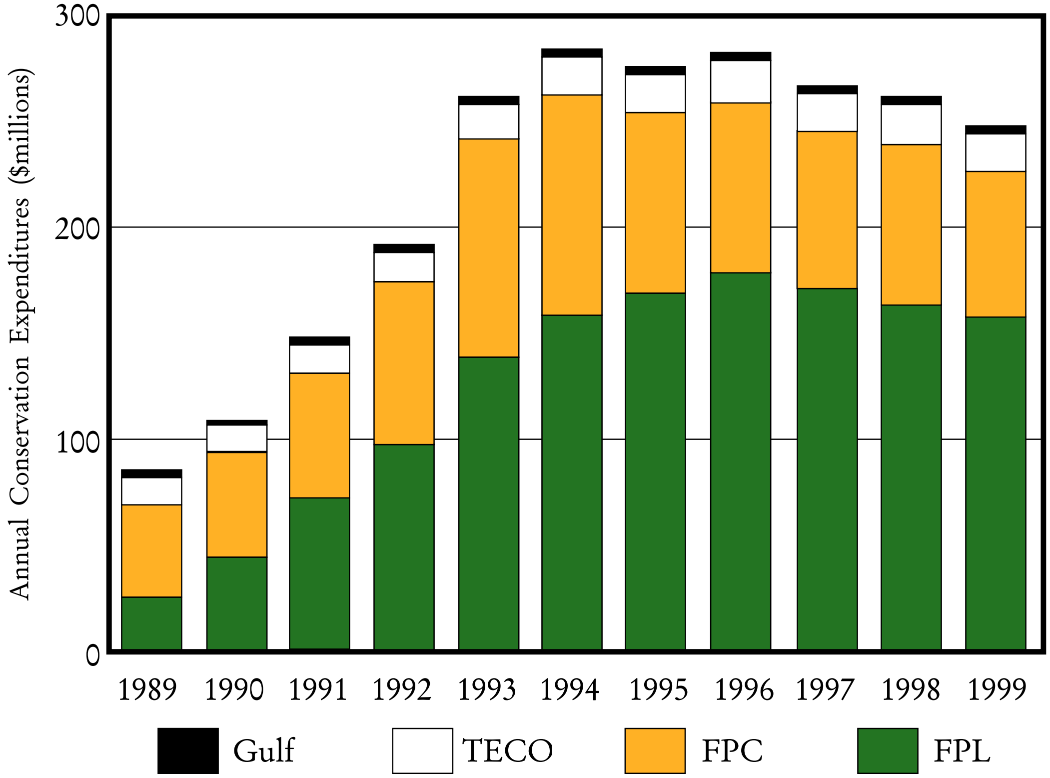
The Three Rivers Resource Conservation and Development Council, with the assistance of the University of West Florida's Small Business Development Center (SBDC) Energy Program Specialist, developed a resource conservation model in their own building located in Milton, Florida. This organization, housed in a 2,400-square-foot historic building that is over 100 years old, is dedicated to developing sustainable economies and resources in rural areas. At the recommendation of the SBDC Energy Specialist, the company has upgraded to Energy Star labeled low-E insulated windows, high efficiency HVAC, programmable thermostats, improved ceiling insulation, T8 fluorescent lamps with electronic ballasts, compact fluorescent lamps (CFLs), LED exit signs, and an induction hot water unit. All retrofits maintained the historic character of the building. It is estimated that millions of BTU's of energy will be saved annually with $1,200 annual cost savings in three years.

Table 1 displays the total expenditures for the year 2000 for the five investor-owned utilities subject to the FEECA. Approximately 68% of these funds are directed toward load-control and interruptible programs. However, included in these funding levels are programs that (1) have an energy efficiency element, and (2) includes some research and development activities. The PSC does not have information on the expenditures for the municipal utilities since they are not rate- regulated, jurisdictional entities.

Table 2 depicts the annual estimated expenditures on DSM and energy efficiency programs which have been recovered from customers by Florida's four largest investor-owned utilities over the past ten years. Annual expenditures peaked soon after numeric goals were set in 1994, primarily due to the start-up costs associated with establishing new programs.

TABLE 2

HISTORICAL FEECA EXPENDITURES



Role of Florida Utilities in Energy Efficiency and Demand-Side Resources

Florida's utilities should continue to play a major role in promoting energy efficiency and load management in at least three ways: (a) by instituting innovative rate designs that will send more accurate price signals to customers, thus lowering the overall cost of electric service; (b) by continuing their responsibility to implement demand-side management programs; and (c) by having the opportunity to implement particular efficiency programs funded through, and on behalf of, the FEO. Utility energy efficiency programs should be focused on the goal of maximizing the cost-effective contribution of efficiency investments to enhance reliability, lower environmental impacts, and lower customer rates. The FEO's goal should be to provide energy efficiency investments and assistance opportunities across a wide range of end-use applications, so that customers in all customer classes will have an opportunity to lower their bills.

Florida is a leader nationally in direct load control or load management. In 1996, data from the U.S. Department of Energy's Energy Information Administration (EIA) showed that demand reduction for Florida represented 64% of the Southeastern Reliability Control (SERC) area[5] and 37% of the contiguous total U.S. demand reduction. That same year, program costs were 66% of the SERC region total and 46% of the U.S. total. The infrastructure for this system currently resides in utility companies' distribution systems. Given past performance and alignment of the financial incentives, it makes sense to maintain program administration by utilities (interpreted to mean the distribution utility). Demand reduction from load management programs also benefits customers by providing a customer-owned resource that can be called upon when generation costs rise, providing an important hedge against the market power of generators in competitive generation markets. In addition, both as a matter of public safety and economic security, state, regional and local governments benefit from the insurance value of demand-side resources in a restructured market.

As competition takes on a greater role in determining prices for electricity, load-management takes on an additional and important role. Electric power markets in the United States today face three related and potentially serious problems: price spikes, loss of reliability, and market power. There is an increasing acknowledgment on the part of policy makers that an effective tool to deal with these problems is to build demand reduction opportunities into wholesale and retail markets. Viable competitive markets depend on the interaction of demand and supply. Unfortunately, in current markets, the demand side is essentially missing. Traditional direct load management programs can improve reliability by reducing peak demands on the power system; however, in today's power markets the economic benefits of reducing load are extended to assist in preventing suppliers exercising market power.

Making demand "price responsive" allows customers to curtail or shift usage of electricity during the hours when electricity prices rise above certain price thresholds. There are a variety of methods to send price signals to the consumer to encourage a demand response to market prices. The demand-response pricing mechanisms, which represent only the beginning of creative thought in this area are:

- **Time-of-use (TOU) pricing**, which establishes different prices for different times during the day; and

- **Real-time pricing (RTP)**, which provides price signals directly to consumers, allowing them to make consumption decisions.

Time-of-use pricing has been used by utilities in Florida and other states for decades, but could be structured with smaller incremental time windows as well as geographical cost components. These changes have not been adopted in most states because of uniform price stabilization plans or price caps implemented to protect consumers from price volatility. The difficulty associated with implementing real-time pricing is getting the price signal to the customer and metering the consumption.

[5] In 1996, the entire state was part of the SERC region. Peninsular Florida has since been separated and is now the Florida Reliability Coordinating Council.

The PSC should be the lead agency to pursue demand response programs. The agency should lead the utilities beyond traditional load control programs and investigate the feasibility of installing metering, billing and communications systems to allow customers to react in real-time to generation production costs. The PSC investigation should explore what customer classes and over what time period this transition should occur.

Good Cents Select

Gulf Power Company's Good Cents Select Program is a residential advanced energy management system that gives customers control over their energy purchases by allowing them to program equipment in their home to automatically respond to varying prices. The Good Cents Select control panel is located in the customer's home and enables customers to program home equipment to fit lifestyle and desired comfort level.

Another way of increasing the responsiveness of electric demand to wholesale prices is to bring about "demand bidding." Demand bidding refers to customers' ability to sell demand reductions back to load-serving utilities when wholesale market prices make it favorable for the customer to do so. For competitive wholesale markets to work efficiently, proper price signals must be known to both purchasers and sellers of electricity. Giving customers real-time price signals is important – especially during periods of extremely tight capacity – to ensure that markets are self-regulating. Linking customer demand to prices in real-time allows customers to respond by lowering loads as prices begin to rise. The ability of demand to respond in this way offers the prospect of reducing the overall volatility of short-term prices, minimizing the average price paid by all customers, and leading to greater reliability in that prices, rather than involuntary curtailments (blackouts), ration scarce electric supplies.

As the state's wholesale market becomes more competitive, demand responsiveness becomes more important. The PSC should be required to investigate and encourage demand bidding mechanisms.

STRATEGY

Encourage utilities to conduct research and development on load management and energy efficiency.

TASK

- The PSC should continue to allow cost recovery for research and development of cost-effective load management and energy efficiency programs.

Research and Development

Utilities have two sources of funding for R&D programs. Historically, the PSC has allowed recovery in base rates of dues paid by investor-owned utilities to the EPRI (formerly known as the Electric Power Research Institute) and for in-house research. The other R&D funding source is the ECCR clause, where specific projects are approved by the PSC and the costs collected via the clause.

R&D expenditures recovered through the ECCR clause in 2000 amounted to $1.018 million. The latter is exclusively focused on energy efficiency, alternative technology and related market research. Based on information contained in the FERC Form 1, Florida utilities spent $4.1 million on other non-efficiency related R&D in 1999. The PSC allows cost recovery through the ECCR clause for expenditures on research and development that is expected to lead to new cost-effective conservation programs. The PSC should continue allowing utilities to recover such expenditures to the extent they are reasonable and prudent.

Florida is also fortunate in having one of the premier research institutions on renewables in the United States – the Florida Solar Energy Center (FSEC). The FSEC's name does not fully describe its mission. Its mission encompasses far more. The FSEC is the largest and most active state-supported renewable energy and energy efficiency research and training organization in the United States. An institute of the University of Central Florida (UCF), FSEC functions as the state's energy research and training center. FSEC annually receives approximately $3 million in operating funds from the State University System of Florida. The Center performs contracted research and training for external sponsors at funding levels that range from $6 million to $10 million per year.

STRATEGY

The State of Florida should encourage energy efficiency and conservation efforts.

TASK

- ♦ The State of Florida should undertake a comprehensive evaluation of the energy efficiency of its facilities and develop appropriate goals and standards.

State Facility Energy Efficiency Standards

Public agencies and facilities are major consumers of energy, including electricity, and it is often cost-effective to invest in technologies that will lower governmental purchasing costs. Lower demand will also have beneficial environmental and reliability impacts generally. This is beneficial to the state, allows state government to lead by example on the conservation front, and encourages the future growth and development of next generation energy technologies in Florida. The State of Florida should undertake a comprehensive investigation into the efficiency of its facilities and develop appropriate goals and standards.

STRATEGY

The State of Florida should increase its support for low-income energy assistance.

TASK

- ♦ The State of Florida should provide state funding for the Low-Income Home Energy Assistance Program and Weatherization Assistance Programs.

Low-Income Home Energy Assistance and Weatherization Assistance Programs

The Low-Income Home Energy Assistance Program (LIHEAP) has been administered by the Department of Community Affairs (DCA) since 1993. Prior to that time, the program was operated by Florida's Department of Health and Rehabilitative Services. The Weatherization Assistance Program (WAP) has been administered by DCA since its inception in 1976.

Within DCA, LIHEAP and WAP are in the Division of Housing and Community Development (HCD), Bureau of Community Assistance. The programs are co-located with other low-income assistance programs including the Low-Income Emergency Home Repair Program (LEHRP), and Community Services Block Grant (CSBG). These programs share close connection in state and federal regulations. Currently, the entire state is served by the LIHEAP and WAP.

The purpose of the LIHEAP is to help low-income households secure and maintain energy sources for heating and cooling their homes. The mission of the WAP is to reduce the heating and cooling costs for low-income families by improving the energy efficiency of their homes while ensuring their health and safety.

Presently, the sole funding source for LIHEAP is the U. S. Department of Health and Human Services. The state receives an annual allocation that is formula-based. Two other allotments may also be received – Leveraging Incentive Funds and Contingency Funds. The Leveraging Incentive Funds are competitive between states and are based on the dollars "leveraged" within the state for low-income energy assistance. Should LIHEAP receive additional support, perhaps from a systems benefit charge, Florida's share of these Leveraging Incentive Funds would significantly increase. Contingency Funds are released by the President as needed to address severe weather conditions or energy supply shortages. The amount varies greatly from year to year as shown below.

LIHEAP FUNDING

Type of Award	Fiscal Year 1997-1998	1998-1999	1999-2000	2000-2001
Grant Award	$ 13,241,770	$ 14,860,812	$ 14,565,607	$ 18,641,042
Contingency	$ 25,937,306	$ 0	$ 7,154,369	$ 4,191,306
Leveraging	$ 153,027	$ 122,622	$ 217,488	$ 151,799
Re-allotment	$ 0	$ 29,960	$ 6,742	$ 0
Total	$ 39,332,103	$ 15,013,394	$ 21,944,206	$ 22,984,147

In Florida, there are 15 local governments and 16 non-profit organizations that provide LIHEAP services. Of these 31 providers, 22 manage both the LIHEAP and WAP. This allocation formula is based primarily on poverty population. Funds are budgeted as follows: DCA retains 2.5% of the federal allocation for administration; 15% of the federal allocation is transferred to the weatherization program also managed by DCA, and 6% of the federal allocation is transferred to Department of Elder Affairs for the Elderly Home Energy Assistance Program, a special energy crisis outreach program for seniors. The balance is distributed by formula statewide to local providers for service to eligible low-income persons, including the elderly. Priority in services is given to households containing members more than 60 years old, children younger than five or disabled persons.

There are 11 local governments and 23 non-profit organizations that provide WAP services in Florida. DCA retains 10% of the federal allocation for state administration, and the remaining 90% is distributed to local service providers. Funds are allocated to each county by a formula that includes the low-income population, heating and cooling degree days, and a base amount. The grants are noncompetitive. Assistance is prioritized toward the elderly, persons with disabilities, families with children younger than 12, and households with repeated high utility bills. Federal law requires that funding be provided through designated agencies unless the agency is defunded or withdrawn.

The WAP is funded by the U.S. Department of Energy (DOE). Florida's fiscal year 2001-2002 DOE allocation is $1,317,877. In the previous years, the WAP has received supplemental funding from Petroleum Violation Escrow (PVE) funds. For the recently commenced fiscal year 2001-2002 agreement period, no PVE funds are allocated for the WAP. The chart below shows funding for the WAP.

WAP FUNDING

Type of Award	Fiscal Year 1997-1998	1998-1999	1999-2000	2000-2001
DOE Grant Award	$ 1,186,000	$ 1,052,473	$ 1,090,617	$ 1,159,000
PVE Fund	$ 5,400,000	$ 5,500,527	$ 3,350,383	$ 2,010,000
Total	$ 6,586,000	$ 6,553,000	$ 4,441,000	$ 3,169,000

LIHEAP and WAP Coordination

Federal and state regulations for these programs encourage coordination of services. The administration of LIHEAP and WAP at DCA encourages inter-program and governmental coordination of the state staff to assist in the delivery of these programs on a statewide basis. DCA is experienced in the management and oversight of the LIHEAP and WAP in addition to the other low-income service programs administered (i.e., CSBG and LEHRP). This enables the low-income population to benefit more efficiently from the program services available.

LIHEAP and WAP Funding

The need for energy assistance is greater than the resources. Especially vulnerable are the low-income elderly on fixed incomes. Of low-income households, 34% have an elderly person in residence. Not being able to adequately heat or cool one's home often results in very serious health and safety consequences. The average energy expenditure in low-income households is $1,140 annually, or approximately, 15% of their annual income. Expenditures on energy for the average family's annual income is 3.5%. With the LIHEAP funds available in a typical year, the program is able to only provide services to approximately 6% of the eligible low-income households.

At the current WAP funding level, only 1% of the low-income population may receive much needed energy efficiency repairs in order to reduce their utility bill. This means that many eligible households go unserved.

To provide the 1999-2000 average benefit of $165 per household to 50% of the eligible LIHEAP population, it would take approximately $123 million or 4.5 times Florida's current award. With respect to WAP, in FY 2000-2001, the national DOE total funding was $150,000,000. New York's allocation was approximately $13,500,000, whereas Florida's allocation was $1,159,000, which places Florida 34th in funding nationwide. In 2000, nationally 68,000 homes were weatherized through the WAP; however, in Florida, only 2,100 low-income households received WAP services. For those 2,100 homes in Florida last year, it is calculated that approximately 30,220.28 mBtus were saved as a result of weatherization measures installed. This equates to an average savings of $369.14 per home/per year realized through weatherization services.

State Commitment to Low-Income and Weatherization Assistance

Most funding for targeted energy efficiency (WAP) and low-income bill assistance (LIHEAP) in Florida is neither sourced nor administered by the energy industry. Utility funding for targeted low-income energy assistance is not significant. In some instances, low-income customers may be eligible for utility conservation programs, such as insulation or air-conditioner upgrades; however, there are no rate-based or dedicated funding sources for low-income assistance or weatherization. Some utilities may have voluntary bill checkoff systems that enable customers to make voluntary contributions to funds administered by the utilities.

The WAP and LIHEAP programs are funded entirely by federal sources. Low-income households typically devote a much larger percentage of their total household income (roughly 15%) to energy bills than customers in general (approximately 3.5%). Heating and cooling bills are a major problem for low-income and elderly customers, often with very serious health and safety consequences.

Florida must find ways to ensure affordable access to electricity. The Study Commission's Public Benefits Technical Advisory Committee (PB-TAC) recommended that efforts to assist low-income households through bill assistance and targeted energy efficiency should be expanded because Florida's efforts lag significantly behind many other states. The PB-TAC recommended increasing low-income programs to a minimum level of funding of .1 mills/kWh, or approximately $18,000,000 per year.

B ASSURING AN ADEQUATE AND RELIABLE SUPPLY OF ENERGY

The Goal

Florida will have a sufficient energy supply to promote economic development and maximize economic prosperity for all Floridians.

Objectives

B-1 A transition to an effectively competitive wholesale generation market with many buyers and sellers.

B-2 Competitive suppliers of generation are subject to consistent regulatory requirements, including standards for access to and use of the bulk power system.

B-3 Load-serving utilities have access to a diversified portfolio of energy resources, including demand-side and renewable resources, acquired through competitive means, with no over-reliance on any particular fuel type, and with appropriate demand-side resources.

B-4 No seller exerts market power.

B-5 Customers enjoy reliable electric service.

B-6 Customers are adequately protected and enjoy stable prices for electricity.

B-7 Utility regulation is aimed at assuring effective competition, regulating prices of monopoly distribution services, and providing proper incentives for minimizing costs and ensuring operational efficiency and innovation.

B-8 Florida's state and local tax systems are fair with respect to energy providers and individual classes of electric customers.

B-9 Electric industry restructuring is revenue neutral with respect to state and local government revenues derived from taxes and fees levied on electric utilities and customers.

Reexamining Policies for Supply

Electricity is an essential part of every day life. When supplies of electricity are not sufficient to meet the demand, consumers experience disruptions that have significant economic and, in some instances, health consequences. As indicated in Chapter IV, Florida's projected need for electricity over the next 20 years will require the installation of significant amounts of generating capacity. There are questions about whether the existing highly regulated system of producing and delivering electricity is the best way to provide this capacity.

During the past three decades, technological, economic and regulatory developments have prompted policy makers to reconsider who the market participants should be and who should bear the risk of investment decisions. This reconsideration has led policy makers to believe increasingly that competition, rather than regulation, should determine the price of electricity. The federal government has policies in place and continues to develop new policies to establish and foster effectively competitive wholesale markets. The President's National Energy Policy contains numerous provisions aimed at enabling competitive markets to develop. Now approximately 25 states have restructured their electric market or are in the process of doing so.

Restructuring programs implemented by states so far have met with mixed results. The lack of an effectively competitive market in California has led to extreme price volatility, while competition in Pennsylvania has been comparatively productive. It is clear, though, that the trend for the electric industry is one in which the three segments – generation, transmission and distribution – are being unbundled.[6] Most new electric generation in the United States is now being built by independent power producers (IPPs). According to the Electric Power Supply Association, since 1990, the competitive power supply industry has accounted for more than half of all the new electric power generation capacity brought on line. The federal government is transitioning control over transmission assets to independent regional transmission organizations (RTOs).

While the results of individual states' retail electric restructuring programs may not be producing compelling evidence of benefits to consumers at this time, there are reasons to believe that competition at the wholesale level can produce benefits. Implemented correctly, competition in the wholesale market should spark innovation and lead to greater efficiencies and lower prices than a regulated market would produce. This will further strengthen Florida's economy and its ability to attract new businesses. A study conducted by Boston Pacific Company, Inc., for the Electric Power Supply Association found that real prices for electricity fell 31% on average over the 1980-1999 period, and by 36% over the 1985-1999 period.[7] The study acknowledged that these price decreases were due in part to declining fuel prices and depreciation of plants, but that there were additional reasons to conclude that competition played a significant role in driving prices down. These additional factors were that: (1) larger price decreases occurred where competitive pressures were the greatest, and (2) that prices across the utilities studied tended to converge. The price convergence is evidence of the success of open access policies, which have allowed suppliers from other regions to compete with native utilities.

The lessons learned from California's unfortunate experience with electric competition demonstrate the importance of restructuring policies and how restructuring the entire market at once – wholesale and retail – compounds the opportunities for unintended consequences. California shows that short-term electricity markets can be volatile and, therefore, that load-serving utilities should not be required to rely solely on these markets to satisfy customer demand. California demonstrates the importance of maintaining adequate generating supplies through proper incentives and clear regulatory and permitting requirements. It also shows the importance of having a mechanism for monitoring the reliability of the system and for bringing additional generating supplies on line when the market fails to bring about those supplies. California has also shown that there is a need for monitoring the interaction between buyers and sellers in the competitive market, and for the appropriate authority to quickly step in when market problems do arise.

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[6] Unbundled means the separation of electric service components for the purpose of offering the components as separately priced elements.

[7] "Assessing the 'Good Old Days' of Cost-Plus Regulation;" Boston Pacific Company, Inc. For the Electric Power Supply Association.

It is in Florida's best interest to transition to a competitive wholesale market with care to minimize the risks of inadequate supply and price volatility. A competitive wholesale market will facilitate the diversification of load-serving utilities' energy resource portfolios. Today, aside from a sizable amount of customer demand managed by the utilities through load-management programs, load-serving utilities' portfolios consist of long-lived generating assets whose fuel sources were determined years before those assets were entered into service. A competitive wholesale market will allow more flexibility for utilities to structure their portfolios with a mix of contractual arrangements of varying contract terms with competitive generating companies. This diversification will shift some of the risk associated with overexposure to longer-term resources from captive customers to the shareholders of those assets.

Natural Monopoly

It is important to realize that the basis for economic regulation of the electric industry was the belief that the industry was a "natural monopoly." A natural monopoly exists in an industry when a single firm can supply the market at a lower per-unit cost than two or more firms. Natural monopoly industries are characterized by high fixed-cost structures. The costs to produce even a small quantity are high, such that once the initial investment has been made, the average cost per unit produced declines with every additional unit produced. Competition in a natural monopoly industry is deemed socially undesirable because the existence of a large number of firms would result in needless duplication of capital equipment. The classic example might be two separate companies providing local water supplies, each constructing a network of mains and distribution facilities.

As a result of demand-side, technological and cost changes in the electric industry beginning in the late 1970s, the traditional regulatory framework designed around the natural monopoly concept has been called into question. There has been a reexamination of both the origins of that regulation and its underlying economic justification. In particular, the "natural monopoly" argument behind extensive price and entry regulation has undergone a reassessment.[8] Today, there is a widespread view that the generation segment of power supply in today's environment would be more efficient and economical in a competitive market. In contrast, transmission and distribution will remain regulated and noncompetitive. The Public Service Commission (PSC) needs to maintain a vital role in energy regulation because energy is an essential commodity for our social and economic well-being. The Public Utility Regulatory Policies Act (PURPA) of 1978, which made it possible for non-utility generators to enter the wholesale power market, demonstrated that the generation segment is not a natural monopoly.

Federal Initiatives

As a result of the changing views toward competition in the electric industry, policy makers have taken steps to ensure a competitive generation market. The federal government, through the Energy Policy Act of 1992 (EPACT), required owners of electric transmission systems to provide fair and open access to the transmission system by IPPs so they can compete with other market participants in the wholesale market. The Federal Energy Regulatory Commission (FERC), pursuant to authority

[8] For a more in-depth explanation of the history of the natural monopoly concept, see *A Historical Perspective on Electric Utility Regulation;* R. Richard Geddes; Regulation, *Volume 15, Number 1, Winter 1992;* The Cato Review of Business & Government.

granted by the EPACT, issued two landmark orders to further promote competition and "open access" to the transmission system. Order No. 888, issued in April 1996, specified the terms under which transmission owners must provide access to their transmission systems by IPPs and other transmission users who desire to sell electricity on a wholesale basis. FERC's Order No. 889, the companion to Order 888, required utilities to provide an Internet-based "OASIS" system. The OASIS, which stands for Open Access Same-Time Information System, provides information in real-time to transmission users about the utilities' available transmission capacity.

Order No. 888 did not achieve the level of reforms desired by the FERC, however. There were lingering concerns that conflicts inherent in vertically integrated utility companies were preventing transmission owners from complying with the spirit of Order 888 -- fair and nondiscriminatory access to independent power producers and other transmission users. At the same time, the FERC recognized that wholesale electricity markets are becoming increasingly regional in nature, and wanted the operation and regulation of transmission systems to reflect that fact. To address these concerns, the FERC issued its second landmark order addressing open access. Order No. 2000, issued December 20, 1999, required that each public utility that owns, operates, or controls transmission facilities make certain filings with respect to forming and participating in RTOs. Order No. 2000 also codified certain minimum characteristics and functions that a transmission entity must satisfy in order to be considered an RTO. The Order required all transmission owners that were not yet part of a FERC-approved RTO to file plans by October 15, 2000, for forming or joining an RTO. The FERC's initial goal was to have all transmission owners in the country operating under an RTO by December 15, 2001.

Florida Regional Transmission Organization -- GridFlorida

The federal policies encouraging open access and RTO development have resulted in changes in Florida's wholesale market. Three of Florida's investor-owned utilities – Florida Power & Light Company, Florida Power Corporation, and Tampa Electric Company – filed an application with the FERC on October 16, 2000, to establish an RTO for peninsular Florida. The RTO has received conditional approval from the FERC.[9] The rates, terms and conditions for its transmission services and other ancillary services will be regulated by the FERC.

GridFlorida was scheduled to be operational in January 2002; however, on May 17, 2001, the joint applicants issued a statement explaining that further RTO development was being halted. This decision was made in response to issues of prudence raised by the Public Service Commission (PSC) in rate cases initiated by the PSC involving FPL and FPC, and in a general review of TECO's participation.[10]

Further complicating the development of a Florida RTO is a FERC order issued on July 12, 2001, initiating mediation for the purpose of facilitating the formation of a single RTO for the Southeastern United States. FERC reasoned that, "in order to successfully encompass the natural market for bulk power in the Southeast, it is necessary that the Southeastern transmission owners combine to

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[9] FERC has approved GridFlorida's governing structure.

[10] See PSC Docket No. 001148-EI for FPL, Docket No. 000824-EI for FPC, and Docket No. 010577-EI for TECO.

form a single RTO."[11] Florida's jurisdictional utilities were not required to participate in the mediation, but were strongly encouraged to do so, and in fact were participants. The decisions by the FERC are consistent with the provisions in President Bush's National Energy Policy relating to the creation of a national transmission grid system to accommodate a competitive wholesale market and to increase the reliability of the transmission system.

Presently, costs for transmission services are included in the utilities' rate bases and are, thus, part of the "bundled" retail rates regulated by the PSC. The establishment of an RTO in Florida would result in changes to the management of Florida's transmission infrastructure, as well as transferring jurisdiction over the majority of bulk power transmission assets from the PSC to the FERC. More to the purpose of this report, though, is that an RTO represents a major enabling mechanism for wholesale competition.

Need for Change

Federal policy initiatives aimed at increasing competition in the wholesale market, and the events thus precipitated, suggest the need for a reexamination of state regulatory policies relative to Florida's wholesale electricity market. Federal policies are succeeding in moving the electric industry toward a more competitive market structure. The generation segment of the industry is no longer a natural monopoly; thus, Florida's policy makers should examine Florida's laws and policies to facilitate a smooth transition to a competitive market. Competitive forces can be expected to minimize electric production costs, lead to better allocation of resources, and provide an impetus for technological and operational innovations that a highly regulated market is unable to achieve.

Competition can be expected to result in lower prices relative to a regulated market, as well as greater innovation – technologically and operationally. At the same time, certain elements of the existing regulatory framework should be retained, but with new direction and emphasis to assure that competition is working and that customers are protected. The changes recommended below are designed to assure that prices for electricity in Florida are reasonable and that Florida will maximize its economic prosperity.

It is important to realize that a path of "no change" will not leave the state in a status quo position. Market participants will continue to search for opportunities within the current regulatory framework. However, the existing legal and regulatory climate in Florida perpetuates uncertainty and risk, and the full benefits of competition will not ultimately be realized. Much of this uncertainty is due to questions arising in the wake of the Supreme Court's decision in the case involving Duke Power Company's need-determination application.

The Supreme Court ruled that a plant must be "fully committed" to serving retail customers in order to be eligible to file for a determination of need. The Court's order did not define the term "fully committed," however, and now there is a question about whether 100% of plant capacity must be committed, or whether some lower percentage can be committed, leaving the rest to be merchant capacity. There is also a question about the length of time for which the capacity must be committed. While the Duke decision appears to render Florida the only state in the nation with a general statutory prohibition against the construction of merchant power plants, IPPs are availing

[11] Order Initiating Mediation, FERC Docket No. RT01-100-000, Issued July 12, 2001.

themselves of the opportunity presented by an exception in the Power Plant Siting Act to construct simple-cycle natural gas-fired combustion turbine "peaking" power plants in Florida.[12] This phenomenon raises questions about whether these efforts may lead to an overabundance of inefficient peaking capacity. An unusual feature of Florida's siting policy is that Florida's general prohibition on merchant plants only applies to the ability to site and construct a merchant plant. It does not prohibit independent power producers from purchasing existing power plants and operating them on a merchant basis.

The uncertainties inherent in Florida's electric market, coupled with the prospect of benefits to be gained by having a competitive wholesale market, suggest that there should be a reexamination of Florida's regulatory policies. Florida should have policies that provide for an orderly transition to a competitive wholesale market, and that assure effective competition beyond the transition. The Study Commission, however, does not believe it is in the best interests of the citizens of Florida to attempt to bring about retail choice at this time. The prevailing logic, with which the Study Commission agrees, is that retail competition should not be attempted until competition in the wholesale market is established.

Florida Energy 2020 Study Commission's Interim Report

The Study Commission released an interim proposal on February 6, 2001, in order to provide information and guidance to the Legislature for its 2001 session on the subject of wholesale market restructuring. The Interim Report provided a comprehensive proposal for removing barriers to entry for merchant plants and other independent power producers, and provided a transition mechanism for moving existing generation assets out of the rate base to become competitive assets.[13]

The Florida Senate Committee on Regulated Industries and the Florida House Committee on Utilities and Telecommunications held committee meetings and workshops to discuss the Interim Report and the subject of wholesale competition. The Committee on Utilities and Telecommunications held workshops on proposed committee bill PCB-OTCO-04-01, which would have implemented the Interim Report's recommendations. No action was taken during the legislative session.

The Study Commission established a Task Force on Stranded Investment to consider additional recommendations with respect to the transfer of existing generating assets. The Task Force addressed the stranded investment issue, as well as aspects of the Interim Report related to the competitive acquisition process to be employed by load-serving utilities, and the transition mechanism for the transfer of existing generating plants out of utilities' rate bases.

The Task Force considered numerous alternative models for achieving a competitive wholesale market. The model recommended by the Task Force, dubbed the "Discretionary Transfer Approach," recognizes the value of providing better means for load-serving utilities to manage the risks associated with changes in fuel prices and technology by diversifying the ownership of new and existing plants, and by encouraging load-serving utilities to employ competitive acquisition methods

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[12] Florida's Power Plant Siting Act requires a need determination for any proposed plant with 75 MWs or more of steam capacity. Applicants proposing plants with less than 75MWs of steam capacity are not required to seek a determination of need and are, thus, free to seek permits necessary to build and operate the plant.

[13] See Interim Report, Florida Energy 2020 Study Commission, February 6, 2001.

for acquiring new generating resources. The discretionary approach does not require the transfer of generation as a matter of law, however. Rather, generation asset transfers would be discretionary on the part of investor-owned utilities. Any transferred asset would be subject to a cost-based transition contract and, to address the stranded benefit concern, there is a provision that would entitle customers to share in gains on sales of plants to third parties. The discretionary approach, however, would preclude utilities from recovering from customers losses on sales to third parties. Finally, the discretionary approach provides a further benefit by allowing customers to continue sharing in any profits from "off-system sales."

STRATEGY

Provide investor-owned load-serving utilities more flexibility for diversifying their energy resources by creating a competitive wholesale market and establishing a competitive acquisition process for load-serving utilities.

TASKS

- Load-serving utilities should acquire new capacity through competitive bidding, negotiated bilateral contracts, or from the short-term (i.e., spot) market.
- In any review by the PSC of the costs being recovered by the load-serving utilities, the standards for determining whether those costs are prudent would continue to be whether:
  - the capacity is needed for reliability;
  - the proposed resource acquisition is the most cost-effective alternative;
  - the proposed resource alternative contributes to the goal of fuel diversity, and
  - the utility has adequately considered cost-effective demand-side alternatives.
- Competitive bidding for new energy resources should be encouraged by load-serving utilities having the burden of proving that their acquisitions are prudent. Competitive bidding should not be required, though, so that load-serving utilities can act quickly on favorable opportunities.
- Competitive bidding should be required in situations where load-serving utilities are purchasing new resources from affiliates.
- Load-serving utilities must be able to demonstrate that their bidding processes are unbiased and preclude advantages to any bidder, including affiliates.
- The PSC should revise its existing rule on competitive acquisition to be consistent with recommendations made in this report.
- Time limits should be established on the prudence review process, consistent with due process, in order to maximize market certainty and opportunities.

Competitive Acquisition of Energy Resources

Today, utilities rely primarily on electricity generated by plants they own, the investment in which is included in their regulated rate bases. Resources from outside the state are limited because the state's import capability is limited to 3,600 MWs. An essential element for a competitive market is a large number of buyers and a large number of sellers. Diversifying the ownership of the state's power plants (new and existing) would have benefits for a competitive market by reducing the market dominance of current generation providers. Requiring load-serving utilities to employ a competitive acquisition process to acquire new resources will exert downward pressure on the cost of electricity required to serve their retail customers by putting the owners of generating plants in a position to compete against each other for sales to the load-serving utilities.

The resource acquisition process begins with the load-serving utilities' integrated resource planning (IRP) process. The IRP process, which utilities in Florida currently employ, identifies the least-cost plan for satisfying the resource needs of the utility. The IRP identifies the amount of generating resources that are needed, as well as the portion of the demand that can be satisfied using cost-effective load management and other conservation programs.

As restructuring of the wholesale market progresses, load-serving utilities will tend to become distribution utilities. New generation will be built outside the rate base – either by IPPs or affiliated generation companies, and existing generation will be sold or transferred to other entities. Transmission assets owned by IOUs will also be separated – functionally or physically – to other entities as well, in accordance with efforts to establish an RTO. What will remain with utilities in the long-run are distribution assets, and an obligation on the part of the load-serving utility to acquire capacity and energy from a competitive market to satisfy its customer demand. Thus, the load-serving utilities will have a crucial role in capturing benefits of competition among wholesale generators for customers.

As this industry transformation takes place, a primary focus of regulation will be on assuring that the load-serving utilities are employing acquisition processes that minimize the costs of energy resources. It is important that this process provide flexibility to allow the load-serving utilities to take advantage of market opportunities. Load-serving utilities should acquire new capacity through competitive bidding, negotiated bilateral contracts, or from the short-term (i.e., spot) market. They should be responsible for demonstrating that the processes followed to acquire resources lead to the lowest cost, taking into account demand-side management (DSM), fuel diversity, and other factors.

The PSC would have an oversight role, as it does today, of the resource selections made by load-serving utilities. Prudence reviews of resource acquisition proposals should be available to utilities to receive cost recovery approval for contracts with IPPs or affiliated generators. Retail rate reviews, which can be initiated by the utility, the PSC, the Office of Public Counsel, or any other affected person, are available on an ongoing basis to review the reasonableness of base rates and other rates and charges. Costs recovered through the various cost recovery clauses would continue to be reviewed by the PSC periodically as part of the normal adjustment clause proceedings. During its reviews, the PSC would have the authority to determine whether the load-serving utility had availed itself of more cost-effective demand-side resources, and whether the mix inherent in the utility's portfolio of energy resources will lead to adequate, efficient service to customers.

In any review by the PSC of the costs being recovered by the load-serving utilities, the standards for determining whether those costs are prudent would continue to be:

- Whether the capacity is needed for reliability,
- Whether the proposed resource acquisition is the most cost-effective alternative,
- Whether the proposed resource alternative contributes to the goal of fuel diversity, and
- Whether the utility has adequately considered cost-effective demand-side alternatives.

These criteria are the same criteria the PSC presently considers in a need-determination proceeding, where the PSC is in the mode of making sure that a proposed generating plant is the most cost-effective alternative. Applying these criteria to the load-serving utilities' acquisitions assures that the economic considerations of the need-determination process continue as a protection to utility customers. Also, applying these criteria to the load-serving utility is consistent with a restructured wholesale market, where there is a policy of allowing merchant plants to be built, and where there is emphasis on having sufficient generating capacity.

One way for load-serving utilities to acquire the lowest-cost resources is to issue requests for proposals (RFPs) for new capacity needs identified in the load-serving utility's planning process. The PSC requires competitive bidding now as a precondition to filing a need-determination application. In a restructured environment, the advantages of bidding are obvious. Competitive bidding provides open opportunities for IPPs, and it minimizes the costs of acquiring energy resources. However, there are instances in which it is not reasonable or practicable for a load-serving utility to issue an RFP and undergo a competitive bidding process, such as the need to act quickly on a favorable opportunity. An RFP process would likely involve a significant amount of time and resources, and may deny the load-serving utilities significant market opportunities. Therefore, competitive bidding should continue to be optional, unless, as discussed below, a load-serving utilities' affiliate is a bidder. The cost-recovery process, in which the load-serving utility has the burden of proof to show that its acquisitions are prudent, will encourage bidding.

The PSC currently has a rule on competitive acquisition that requires utilities to issue RFPs for proposals before filing for a need determination. However, the rule allows some projects to go forward without an opportunity for IPPs to bid on those projects. The exemptions are the same as those included in the need-determination statute – steam capacity less than 75 MWs and repowering projects. Given the recommendation to eliminate the need-determination process, and the desire to encourage utilities to competitively bid, but not require them to do so, the PSC should revise its rule consistent with the recommendations herein.

A significant issue regarding the acquisition of energy resources is self-dealing with affiliated generating companies. Absent measures to safeguard against load-serving utilities favoring resources provided by affiliates, there is a potential for load-serving utilities to engage affiliated resources more often and to pay more for those resources than the market rate. Therefore, in situations where load-serving utilities purchase electricity from affiliates, those purchases should be pursuant to a competitive bidding process. Moreover, utilities must be able to demonstrate that the bidding processes are unbiased and preclude advantages to any bidder, including affiliates.

As mentioned above, utilities should be permitted to seek prior approval of cost recovery for generation resource acquisitions. The prudence review process that accompanies such a review should take place quickly, consistent with due process, in order to maximize market certainty and opportunities. The PSC should be allowed to process petitions for cost recovery of contractual arrangements between load-serving utilities and IPPs under the Proposed Agency Action (PAA) process. The PAA process allows the PSC to render a decision after analysis and recommendation by its staff, and for that decision to go into effect if no affected person petitions for a hearing. Under such a process, the PSC should render its decision within 90 days, and issue its order within 125 days. If instead a case is scheduled directly for hearing, the hearing should be conducted within 90 days, and the PSC should render its order within 150 days. The time frames for the hearing process are consistent with those in the need-determination process.

STRATEGY

Assure adequate fuel diversity.

TASKS

- The PSC should assure adequate fuel diversity through its regulation of the competitive acquisition process for load-serving utilities.
- The PSC should place a higher priority on fuel diversity than on whether a resource is the least-cost option when it is determined that there is excessive or imprudent reliance on the fuel of the planned least-cost option.
- The Governor, the Legislature and the PSC should continue to pursue the safe, efficient and economic disposal of radioactive waste in order to remove a major obstacle to the continued viability of nuclear power.

Fuel Diversity

A significant concern of the Study Commission is the trend of reliance on natural gas as a fuel source for new power plants. Natural gas is favored now because of its relatively low price and its environmental benefits as a cleaner burning fuel. Combined-cycle natural gas-fired power plants are also highly efficient and have low capital costs relative to other options, such as coal. To illustrate this trend, the percentage of energy generated using natural gas has increased from 12.1% in 1990[14] to 18.6% in 2000.[15] Projections indicate that by 2010, 44.9% of Florida's energy will be generated by natural gas. If all generating resource additions between 2010 and 2020 are assumed to be natural gas, the percent of natural gas-fired capacity will be 55.5%.[16]

The issue of fuel diversity has two separate dimensions. The first dimension is the impact on electricity prices due to fluctuations in the price of fuels used to generate electricity. Given the dominant reliance on natural gas to fuel new generation capacity, there are concerns about price fluctuations associated with the dynamics of supply and demand in the natural gas market. The price increase that occurred during the 2000-2001 time frame significantly affected fuel costs for Florida's utilities. As the state's reliance on natural gas increases, the exposure to these price fluctuations will be magnified. This phenomenon is a serious concern and highlights the need for a mechanism to assure the rate impacts of such price volatility can be mitigated significantly. Through the use of hedging instruments such as futures, forwards, options, and contracts-for-differences the rate impacts of extreme volatility in fuels markets can be significantly mitigated. Therefore, the PSC should, as a part of its review of contracts to serve retail load, encourage and emphasize the prudent use of hedging instruments to help counteract the effects of price volatility in fuels markets.

The second dimension regarding fuel diversity is actual physical security of supply. At this time there does not appear to be any significant concern about having adequate pipeline capacity to

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[14] Source: 1990 Ten-Year Plan prepared by the Florida Coordinating Group.

[15] Source: 2000 Regional Load & Resource Plan prepared by the Florida Reliability Coordinating Council (FRCC).

[16] Source: Florida Reliability Coordinating Council supplemental energy forecast prepared at the request of the Study Commission staff. Assumes all new generation beyond 2010 is natural gas-fired.

bring natural gas to points of use within the state. As pointed out earlier in this report, there are several new projects currently in progress to bring about more natural gas to Florida. Nor does there appear to be an immediate concern about the availability of natural gas within the next 20 years. However, as power generators become more dependent upon one fuel source, such as natural gas, any physical supply disruptions of that fuel could have dramatic public safety and statewide economic impacts. Hence there might be the need to consider a more diverse portfolio of generating assets than that indicated by current projections, to guard against the effects of such a supply disruption.

Policy makers, however, should resist the temptation to manage generation expansion by adopting rigid fuel type requirements or portfolio percentages. Rather, there is a need for a more flexible process that can react to developing trends that appear imprudent or excessive from a public safety or statewide economic stability perspective. In a market environment where the PSC continues to regulate retail rates,[17] the competitive acquisition process for load-serving utilities provides the opportunity for the PSC to prevent imprudent or excessive reliance on certain fuel types. When reviewing resource acquisitions of load-serving utilities, the PSC should give a higher priority to those resource acquisitions that would help preserve and maintain fuel diversity, but only after careful deliberation of all the factors supporting the judgement to enhance the state's fuel portfolio.

In the process of mitigating risk, whether it be price risk or supply security risk, there must be a realization that there are costs and environmental impacts associated with hedging against price risk or requiring different fuel types to hedge against physical supply risk. In the case of hedging against price risk, spot market prices for fuel may be less than the hedged price, while at other times the spot price may be greater than the hedge price. Therefore, hedges should be looked upon as an insurance policy that ensures greater certainty.

The case of mitigating physical supply security risk has a similar analogy. A utility's integrated resource plan, for example, may dictate the next increment of capacity be based on natural gas technology because of fuel price forecasts. But because of concerns about fuel diversity, it may be advisable to build a coal plant instead, despite the expectation that the cost may be higher. To achieve the desired fuel diversity, the utility could seek bids for coal capacity. While achieving fuel diversity will result in greater resource expenditures up front, and could result in higher prices, at least in some years, the additional costs should be viewed as an insurance policy against unforeseen physical supply interruptions in fuel markets.

Nuclear Waste Disposal

An energy policy that facilitates the maintenance of a variety of generating fuel sources will help assure energy security, mitigate against price volatility and provide opportunities to address environmental concerns. Nuclear power is, and should continue to be, a viable fuel source for electric generation in Florida and the nation.

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[17] In a competitive retail market, the issue of fuel diversity is complicated by the fact that there would likely be no direct involvement of economic regulation in the prices charged by retail electricity providers. This report does not, however, recommend retail access without further study, and, thus does not attempt to address fuel diversity mechanisms in that context.

Florida has five nuclear units that have provided reliable, low-cost energy for more than 20 years. In Florida and in the nation, nuclear generation provides about 20% of the total generating capacity. However, since the early 1980's, no new nuclear units have been constructed in the United States. The significant capital investment required, the increasing costs of safety requirements, and the delay in providing for the safe and cost-effective disposal of both high- and low-level waste have conspired to cause investment in new plants to cease.

Floridians have paid over $836.5 million for the development of a centralized permanent facility for high-level waste, and continue to pay between $25 and $30 million per year into the Nuclear Waste Fund. The facility was supposed to be operational by January 1998. The current estimate for the facility to become operational is 2010, assuming the site at Yucca Mountain, Nevada is found to be suitable. Similarly, the establishment of a regional low-level facility in North Carolina has not occurred despite the expenditure of millions of dollars.

The safe, efficient and economic disposal of both high-level and low-level waste is essential to ensuring the continued viability of nuclear power. Policy makers and industry representatives in Florida have been working together to realize the establishment of a permanent centralized facility for high-level waste, currently presumed to be located at Yucca Mountain, and to establish appropriate low-level waste facilities. That cooperation and coordination needs to continue. The Governor, the Legislature and the PSC should encourage the federal government to establish these facilities as quickly as possible.

STRATEGY

Remove barriers to entry for merchant plants and facilitate the development of new generating capacity.

TASKS

- Eliminate the need-determination process.
- The recommendation for eliminating the need-determination process should apply to municipal and cooperative utility projects as well.
- Review the role of the Siting Board.

Elimination of the Need-Determination Process

Florida's Power Plant Siting Act (PPSA) requires a determination of need by the PSC for any proposed power plant with more than 75MWs of steam capacity.[18] Upon the filing of an application for a determination of need, the PSC is required to conduct a hearing within 90 days and to render its order within 150 days. While this process has worked well in a regulated monopoly environment, it is inconsistent with the concern about having adequate capacity in a competitive market environment. The determination of need process serves as an unnecessary delay in bringing new capacity on-line. In a competitive market, the concern should be on reducing barriers to entry and providing an environment with less risk and uncertainty to bring about new cost-effective generation

[18] The determination of need is a condition precedent to the conduct of the certification hearing under the PPSA. Chapter 403.508(3), Florida Statutes.

resources in response to market demand. Also, merchant plants are not allowed to avail themselves of the process to construct new capacity; therefore, the need-determination statute acts as a barrier to entry for a whole class of potential market participants.

The need-determination statute came about at a time when there was a concern that the monopoly system and regulation provided incentives for utilities to add investment to their rate bases because they could earn a return on that investment. The need-determination process serves as a check on that tendency by making sure that a proposed power plant is needed for reliability, that it is the most cost-effective alternative, and that the utility has adequately considered conservation alternatives. In a competitive market where new capacity is not being added to the rate base, more of the risk associated with new capacity, especially merchant plants, is born by shareholders.

The appropriate role of regulation in a competitive wholesale market with respect to new capacity additions is to assure that load-serving utilities are managing their risks appropriately and acquiring capacity and energy in the most cost-effective manner, consistent with other objectives, such as fuel diversity and environmental protection. Up-front reviews of the economics of generating plant selection will be of less concern because much of the risk associated with building and owning new generating plants will rest with the shareholders of those plants. Moreover, competitive acquisition processes, such as bidding, will be employed by load-serving utilities to assure that new resources committed to serving retail customers are the lowest-cost resources. Thus, the market structure envisioned in this report includes adequate mechanisms to make sure that new resources are cost-effective.

Concerns about overbuilding capacity are answered by shareholders being more accountable for their investment decisions. Companies that construct power plants must have the expectation that there will be a market for their capacity, either because reserve margins are low or because their production costs will be low enough to displace less efficient capacity. Investors will not invest hundreds of millions of dollars to build a plant unless they can market their electricity. Thus, even though the need-determination process serves to prevent too much capacity from being constructed, a competitive market will not likely result in too much capacity – at least not for prolonged periods – as it would not be profitable for the owners of those plants. A more valid concern is that the marketplace has adequate incentives to attract capital for new capacity, and that generating reserve margins are healthy.

In addition to the time factor involved in bringing new capacity on line, the need-determination process discriminates against merchant plants. Numerous IPPs have demonstrated interest in building generating capacity in Florida. Yet, Florida's law requiring a determination of need by the PSC as a condition precedent to building a power plant does not allow "merchant plants" to be applicants. The need-determination statute, as interpreted by the Florida Supreme Court, requires proposed power plants to be "fully committed" to serving retail customers in Florida.[19] Since merchant plants, by definition, are not fully committed to retail-serving utilities, they cannot apply for a determination of need. Thus, Florida's need-determination statute acts as a major barrier to entry for merchant plant development.

The Study Commission heard testimony that Florida is unique among states in its statutory prohibition against the construction of merchant plants. Florida's power plant siting laws were

[19] Tampa Electric v. Garcia 767 So. 2d 428 (Fla. 2000).

interpreted by the Florida Supreme Court, which ruled on April 20, 2000, that Duke Energy New Smyrna Beach Power Company, Ltd., L.L.P. (Duke), could not be an "applicant" under Florida's need-determination statute. Florida's wholesale market is basically closed to a large segment of potential competitors in the wholesale market. Yet, because retail electric customers are not obligated to pay for the output of merchant plants, but, instead, shareholders bear the risk of construction, it is unnecessary for the state to certify that a capacity need exists in order to protect retail customers. Eliminating the need-determination process would open the market to merchant plants, and provide additional options to Florida's load-serving utilities to reduce costs to customers.

The recommendation for eliminating the need-determination process should apply to all projects, including municipal and cooperative utility projects. The need-determination process is designed to make sure the capacity is necessary for reliability or economic reasons, and that retail customers are not burdened with unnecessary costs. The concern in today's marketplace is not so much whether a utility is building too much capacity, but whether they are building enough. A screen at the state level for municipal and cooperative plants would appear to be superfluous because both municipal and cooperative utilities are "self-regulating" entities. That is, the PSC does not have rate jurisdiction over either type of entity. Rather, the municipalities and the boards of directors representing the members of the cooperatives are directly accountable to the customers of these entities. Therefore, whatever concerns might exist today about building too much capacity, or about a plant being the most economical option, should be presided over at the local government level for municipalities, and at the board of directors level for cooperatives.

While the PSC will no longer decide whether a plant is needed, the Study Commission recommends establishing a process whereby all entities proposing to construct power plants (IPPs, EWGs, municipals and cooperatives) would file copies of their power plant siting applications with the PSC to serve as notification to that agency of the intention to construct a plant. This process would enhance the PSC's oversight over the market and electric system reliability.

Role of the Siting Board

Related to the issue of facilitating the development of new generating capacity is the question of the future role of the Governor and Cabinet, acting as the Siting Board under the PPSA. The Study Commission's recommendation to eliminate the need-determination process raises this question.

The Siting Board makes the final decision as to certification of new power plants, based on the record developed through the PPSA process. The main function of the Siting Board under the current siting process is to balance the need for a power plant with its environmental impacts. The Siting Board may impose conditions of certification, including conditions that constitute variances from non-procedural standards of regulatory agencies. The Siting Board is also authorized to decide issues relating to the use and crossing of agency property, and to grant variances from local land use and zoning requirements consistent with the public interest.

Under a competitive model, the investment community will, in effect, determine the need by its willingness to invest in the facility. The means of protecting the environment should be through a permitting process that spells out in advance the environmental standards that must be met. The PPSA's one-stop siting process already provides a forum for those agencies responsible for each area to assess the impact of the plant and to determine whether the proposal will meet the standards.

The Study Commission believes it is important to address the future role of the Siting Board. Consideration should be given to the unique position of the Governor and Cabinet within state government, as well as to the particular functions of the Siting Board. If the need determination is eliminated, the Siting Board's traditional balancing role would necessarily require revision. The remaining question is whether other facets of the power plant siting process continue to warrant involvement of, and final decision by, the Governor and Cabinet. One option would be to retain the Siting Board, but to authorize the Secretary of the Department of Environmental Protection to issue certification orders for non-controversial power plants. In the case of controversial projects, the Siting Board would continue to make the final decision as to certification, conditions, variances, and use of agency property.

STRATEGY

Provide for nondiscriminatory access to the transmission system by competitive wholesale providers of electricity by authorizing the transfer of utility transmission assets to a regional transmission organization (RTO).

TASKS

- Florida's transmission-owning utilities should be authorized to transfer their transmission assets to a FERC-approved RTO, or to allow an RTO to exercise operational control over these assets.
- Transmission assets transferred to an RTO should be transferred at book value.

Regional Transmission Organizations

The Energy Policy Act of 1992 (EPACT) provided the impetus to wholesale competition by requiring utilities to provide open access to their transmission systems. After the passage of the EPACT, the FERC took steps to bring competition to wholesale electricity markets by opening access to the interstate electricity transmission system to all market participants.

In 1996, the FERC issued Orders 888 and 889, requiring transmission-owning utilities to make their facilities available to others under the same prices, terms, and conditions they charge themselves. They were also required to develop information systems to provide real-time data on the amount of transmission capacity they had available at any given point in time and the prices, terms, and conditions for using it.

The FERC continued its efforts with the issuance of Order 2000 on December 20, 1999. Order 2000 reflects the FERC's belief that operational and reliability issues can best be addressed by regional institutions rather than by individual utilities operating their own systems. The FERC's Order 2000 states that, "Appropriate regional transmission institutions could: (1) improve efficiencies in transmission and grid management, (2) improve grid reliability, (3) remove remaining opportunities for discriminatory transmission practices, (4) improve market performance, and (5) facilitate lighter-handed regulation."

Order 2000 required transmission-owning utilities to file proposals for an RTO by October 15, 2000, and to have the RTO operating by December 15, 2001. In response, Florida's three peninsular investor-owned utilities – FPL, FPC, and TECO – filed a joint petition with the FERC on October 16, 2000, proposing the establishment of GridFlorida, an independent transmission company (Transco) covering peninsular Florida. The FERC issued an order provisionally granting RTO status to GridFlorida on March 28, 2001.[20] Subsequently, in a statement issued May 17, 2001, the three utilities decided to "suspend RTO development activities" until the matters initiated in separate prudence reviews initiated by the PSC with respect to GridFlorida were resolved.

Order 2000 did not attempt to define what the appropriate regions covered by RTOs should be, how many RTOs there should be, or how they should be organized. The details were left to the utilities to propose. However, on July 12, 2001, the FERC issued a series of orders aimed at beginning and expediting the process of creating four large RTOs covering the entire nation. The FERC's Order Initiating Mediation for the Southeast region stated that, " . . . in order to successfully encompass the natural market for bulk power in the Southeast, it is necessary that the Southeastern transmission owners combine to form a single RTO."[21] To accomplish this goal, the FERC's order directed an administrative law judge to mediate settlement discussions for 45 days, and to file a report within 10 days following the conclusion of the mediation. The report is to include an outline of the proposal to create a single Southeastern RTO, milestones for the completion of intermediate steps, and a deadline for submitting a joint proposal. The Order stated that Florida's jurisdictional utilities were not required to participate in the mediation, but "encouraged" them to do so. The GridFlorida companies did participate in the mediation effort.

In a competitive wholesale market, it is critical for generation companies to have fair and open access to the transmission system. The series of decisions by the FERC, coupled by provisions in the National Energy Policy relating to transmission service, are pointing to a strong interest on the part of the Bush Administration to create a national transmission grid system to accommodate a competitive wholesale market as well as to increase the reliability of the transmission system. RTOs are responsible for planning, operating, and monitoring the transmission system under its control. RTOs operate independently of the transmission-owning utilities and ensure that all market participants have equal access to the services of the transmission system.

The future of RTO development in Florida is somewhat unclear at this time. There is a possibility the GridFlorida proposal, which was achieving initial success in receiving regulatory approval by the FERC, could begin moving forward, depending on the outcome of the PSC's prudence review. It is also reasonably foreseeable that Florida utilities could join the larger southeastern RTO. In either event, it is apparent that the FERC is expecting Florida's utilities to participate in an RTO of one form or another.

The development of an RTO for Florida will be an important step in the development of a competitive wholesale market. Allowing an RTO to form in Florida is consistent with the goal of assuring an adequate supply of electricity, and the objective of having a competitive generating market. Therefore, Florida's transmission-owning utilities should be authorized to transfer their transmission assets to a FERC-approved RTO, or to allow an RTO to exercise operational control over those assets.

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[20] Order Provisionally Granting RTO Status, FERC Docket Nos. RT01-67-000 and RT01-67-001, Issued March 28, 2001.

[21] Order Initiating Mediation, FERC Docket No. RT01-100-000, Issued July 12, 2001.

Consistent with the GridFlorida proposal, any assets transferred should be transferred at book value. It is a well-established regulatory axiom that book value is the appropriate transfer value when utility property is transferred from one regulated entity to another[22]. In the case of a transfer of transmission assets to an RTO, transmission assets are being transferred from state-regulated entities (Florida electric utilities) to a FERC-regulated electric utility. Because the FERC's pricing policy for transmission service is cost-based rates, the transfer of regulatory jurisdiction over the transmission assets would not, in and of itself, cause a significant difference in the regulatory approach to setting transmission rates.

STRATEGY

Create a mechanism for transitioning existing generation to a competitive market to further competition in the wholesale market.

TASK

- Investor-owned utilities should be allowed to transfer or sell existing generating assets under the following terms:
  - Transfers or sales of generating assets should be discretionary on the part of the investor-owned utilities to provide for an appropriate assignment of risk.
  - Transfers of existing generating assets to affiliates should be at book value.
  - Load-serving utilities should have the right to six-year cost-based transition contracts to commit the capacity of existing assets sold or transferred back to the load-serving utilities.
  - Load-serving utilities should be given the right to unilaterally cancel the transition contracts any time during the six-year contract term, subject to reasonable prior notice.
  - Profits from "off-system sales" from plants subject to transition contracts should be shared with customers.
  - Gains on sales of existing generating assets directly from regulated rate base should be shared with customers.
  - Gains on sales of existing generating assets that have been transferred and are subject to transition contracts should be shared with customers.
  - Losses on sales of existing generating plants should be absorbed by utility shareholders.

Transfer of Existing Generating Assets

The Study Commission recommends a process be adopted that allows, but does not require, existing generating assets to be part of the competitive wholesale market in Florida. In a competitive market, it is important to have a large number of buyers and a large number of sellers. Presently, for new generation, load-serving utilities build their own plants or contract with IPPs for capacity and energy. Allowing merchant plants will provide load-serving utilities with other options. In

[22] Robert L. Hahne, Gregory E. Aliff, Accounting for Public Utilities, Deloitte & Touche, LLP, Lexis Publishing, Release No. 17, November 2000.

order to achieve the full benefits of competition, though, it will be necessary to diversify the ownership of existing generation assets, especially in the case of investor-owned utilities that would have the ability to exercise market power.

The approach to wholesale restructuring developed by the Task Force on Stranded Investment – the discretionary approach -- is an evolution from the interim proposal that gives the investor-owned utilities more flexibility in timing market entry, clarifies the apportionment of risk, and provides customer protections. It is intended to give IOUs an ongoing opportunity to assume the risk of market success or failure for existing generating assets, while at the same time providing protection from excessive market volatility to customers served by those assets. The approach is also intended to clearly define and settle the stranded cost/stranded benefit issue within a definite time period.

An important consideration associated with creating a transition mechanism for existing plants is the “stranded investment” issue. In virtually all states that have restructured, utilities have been afforded the opportunity to recover costs associated with assets that would not be recoverable in a competitive environment. The theory of stranded cost recovery is that electric industry restructuring imposes a new market structure on incumbent providers and not allowing recovery of stranded costs is tantamount to a regulatory taking. In Florida, the debate on wholesale restructuring has had a different twist. Rather than there being a concern about stranded costs, many stakeholders believe there would be negative stranded costs, or “stranded benefits.” The concern is that transfer of some of Florida’s existing power plants with low book values would allow affiliates to sell the plants to a third party with the resulting “gain on sale” being beyond the jurisdiction of the PSC to capture for the benefit of customers.

The Study Commission did not attempt to quantify the amount of stranded investment associated with Florida’s existing plants. The calculations necessary for such quantification are extensive. More importantly, though, such calculations involve a high degree of reliance on, and are very sensitive to, assumptions about future fuel prices. Accurate fuel price forecasts for even very short periods are difficult. Forecasting fuel prices five, ten, twenty years or more is fraught with inaccuracy. For these reasons, calculating the stranded investment associated with existing power plants was not considered a productive endeavor.

To deal with the concern about the issue of stranded investment, and consistent with the need for a flexible approach to restructuring, an appropriate way to transition existing generation to the competitive market is to allow discretion on the part of the utilities. Creating a voluntary mechanism essentially moots the stranded cost issue. Because the transfers or sales would be voluntary, there would be no regulatory taking that creates the expectation on the part of the utilities to recover stranded costs. The “regulatory compact” would stay in place for those assets that remain in rate base; that is, they would continue to be subject to PSC cost-based regulation as they are today.

Existing assets that are transferred or sold will be subject to a transition contract for up to six years. The transition contract for any given asset would begin at the time of transfer or sale. This approach contemplates that the transition periods for transferred assets may be staggered over time. Thus the transition to a competitive market will take at least six years, unless it is shortened by the load-serving utility, and may involve a substantially longer period of time. Further, if the generator owner has market power or is involved in an affiliate transaction, the output of the generator may be sold at cost-based rates for additional periods of time.

The transition contracts are intended to prescribe the terms and conditions under which the transfer of existing generating plants would be consistent with the public interest. Therefore, the decision to transfer or sell a plant need not be subject to further regulatory review by the PSC. However, the decision of the load-serving utility to purchase capacity pursuant to the transition contract would be subject to review and approval by the PSC.[23]

This report does not spell out all of the terms and conditions of the transition contract, but there are some aspects that are integral to the overall vision of the approach recommended by the Study Commission. First, the transition contracts are intended to account for any stranded benefits associated with a transferred or sold asset. This is accomplished by specifying that transfers from regulated rate base be made at book value, and further specifying that energy and capacity of the assets transferred or sold be available at cost-based rates to the load-serving entity for up to six years. The Study Commission strongly believes this approach to recognizing stranded benefits is preferable to an administrative determination of them. Attempting to quantify stranded benefits beyond the six years of the transition period is fraught with uncertainty, and would unreasonably delay entry of the asset into the competitive market.

Second, the discretionary approach recognizes stranded benefits by providing that if an asset is sold within the transition period, customers would share a portion of any net gain. The sharing percentage should be definitively established in the legislative process so that potential buyers and sellers can adjust their estimate of market value accordingly. The Study Commission recommends, as an appropriate starting point in the legislative process, that consumers receive 50% of any net gains. The Study Commission's report contemplates that an asset may be sold directly from the load-serving utility's regulated rate base or it may be sold at a subsequent point in time by the affiliate of the load-serving utility (generating units under construction that have been included in the load-serving utility's Ten-Year Site Plan as filed with the PSC may be required to enter into cost-based transition contracts for up to six years, but should not be subject to the gain-sharing requirements since the plants were not included in the regulated rate base). It should be noted that the share provision would only be triggered by a cash or cash-equivalent sale; other potential dispositions, such as transfer or trade, would not trigger the sharing provision. However, the provision would apply to any subsequent cash or cash equivalent sale within the six-year time period. The sharing provision would end at the time the transition contract ends. Thus, an asset that was transferred, but not sold within the six-year transition, would not result in any gain-sharing with the load-serving utility's customers.

Third, the transition contracts are intended to preserve the existing apportionment of the benefits of off-system sales between customers and shareholders. Customers would receive the benefits of off-system sales in proportion to the capacity purchased from an existing asset by load-serving utilities under the transition contract.

The length of the transition period is admittedly a matter of judgment. Barring unforeseen developments, the Study Commission anticipates that within three years of passage of restructuring legislation, merchant plant developers will offer significant choices to load-serving utilities. An additional three-year transition beyond that, for a total of six years, represents a fair balance between the interests of customers in recovery of stranded benefits and participation in gains on sales, and the interests of shareholders in business certainty and maximizing market value for its assets.

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[23] The transfer would be subject to review and approval by the FERC under Section 203 of the Federal Power Act.

The other side of the stranded benefit issue is stranded cost. Stranded costs may arise in connection with a transferred or sold asset if market forces value it below its book value, if unforeseen developments require additional investment, or if efficiency improvements by competitive generators displace production. Yet these are risks freely assumed by an IOU in its decision to transfer or sell an asset and thus remove it from regulated rate base, and, therefore, the Study Commission finds it appropriate to place those risks on shareholders. If a transferred asset is sold at a loss, it is borne entirely by shareholders; losses would not be shared between customers and shareholders. In addition, if during the transition period the load-serving utility has an opportunity to obtain capacity or energy at a cost less than that specified in the transition contract, the load-serving utility has the option of terminating the contract on fair notice to the generator. In essence, this assures the load-serving utility an opportunity to obtain capacity at the lower of cost or market-based rates. However, termination of a transition contract would mean the end of an opportunity to share in the proceeds of any gain on a subsequent sale. Moreover, to protect customers from the possibility that a load-serving utility might terminate a transition contract when doing so would not be in the customers' best interest, the PSC would have the ability, as part of its ongoing regulatory responsibilities, to approve or deny the load-serving utility's decision, including prior to the actual termination of the transition contract.

As previously noted, the discretionary approach allows IOUs to time market entry of existing assets. Possible outcomes range from transfer or sale of all generating plants to transfer or sale of none of them. The diversification of ownership of existing generating assets is important for the development of a competitive market. In the case where IOUs transfer or sell all generating assets, those transactions would stimulate the development of a competitive market and minimize the possibility of any particular generation owner having market power. Customers would be protected by the requirement that losses associated with sales must be absorbed by shareholders. Customers are also protected by six-year transition contracts that give load-serving utilities the right to buy the plant's output at cost-based rates or to cancel the transition contracts at any time, subject to fair notice. The contract will allow utilities to take advantage of lower-cost opportunities in the market. It is possible that the discretionary approach would result in no assets being transferred or sold. In that case, assets that remain in rate base remain subject to PSC jurisdiction in traditional cost-based regulation.

All of these decisions – whether to transfer an asset, whether to hold it or sell it, or whether to continue a transition contract – involve strategic assessments that are best made by those who will experience the market results. Moving from a regulated to a competitive market is a fundamental shift in the way prices are set for generation. The outcome is not without risk to customers or the present and future owners of generation assets. The risk to customers can be hedged as much as is practicable by a transition contract that preserves stranded benefits but provides an opportunity to escape stranded costs. The point of restructuring is to create a risk of market-driven success or failure. The existence of those risks will provide an incentive to generators that will ultimately drive down the cost of power to customers.

The load-serving utility will play a pivotal role in a restructured wholesale market. It will be up to the load-serving utility to capture the benefits of price competition for retail customers through effective generation resource acquisition processes. The PSC will be the final arbiter of the load-serving utility's efforts through the Commission's ability to approve or deny cost recovery of the load-serving utility's generation resource selections.

STRATEGY

Authorize the PSC to monitor competition in the wholesale market, investigate allegations of market improprieties, and petition the FERC for remedies.

TASKS

- The PSC should have clear statutory responsibility to monitor and evaluate competition in the wholesale market.
- The PSC should be given clear authority to petition the FERC for remedies.
- The PSC should develop expertise in electricity markets, to the extent it does not already exist.
- The PSC should have access to books and records of all market participants, subject to valid claims of confidentiality.

Market Monitoring

Of the three segments of the electric industry, efforts to establish competition have been focused on the generation segment. Transmission and distribution are expected to remain regulated monopolies in the foreseeable future. In the transition to a competitive generation market, there are concerns about potential market improprieties because of residual concentration of ownership of generating assets. Any time there are heavy concentrations of ownership of production capacity, there are concerns about market power.[24]

As discussed earlier, the process of creating competitive electricity markets results in a greater amount of electrical capacity being bought and sold in the wholesale market. Sales from IPPs to load-serving utilities are wholesale transactions subject to the FERC's jurisdiction. Therefore, the restructuring process results in a greater involvement of the FERC in the market inasmuch as FERC decides the basis for how wholesale prices are determined.[25] The rate at which the FERC's presence comes about will depend on the rate at which existing generating plants are transferred out of the utilities' rate bases.

While wholesale generators are FERC-regulated, the states, nevertheless, have a vital interest in the functioning of wholesale electricity markets. The prices paid for electricity are charged to load-serving utilities, which, in turn, become part of the cost of retail electric service. Excessive prices in the wholesale market have adverse effects on customers and businesses, and can impact the ability of states to attract new businesses for economic development. Thus, it is appropriate for states to have a role in monitoring competition in the wholesale market.

Electricity markets are unique and complicated. The fact that electricity is a commodity that must be produced and consumed in real-time magnifies the problems caused by improper market design. Utilities, in general, have obligations to serve retail customers. In California, this obligation caused

[24] Market power is generally defined as the ability of a firm to profitably raise prices by withholding capacity.

[25] The recovery of these costs from retail customers is subject to state regulation by the PSC.

the utilities, which serve as the provider of last resort, to have to purchase electricity at times when the cost was at extremely high levels. The policies recommended by the Study Commission would not result in such a heavy reliance on the short-term market. However, it is likely that a competitive market would, on its own, establish a spot market; therefore, it is important that there be a mechanism for monitoring the market and for prescribing remedies to preserve effective competition.

Wholesale market transactions are subject to the FERC jurisdiction. For that reason, the PSC may have limited ability to prescribe remedies. However, the PSC is in the best position to monitor Florida's wholesale market and may be able to resolve certain problems. The PSC should, therefore, be given clear responsibility for monitoring the market, and statutory authority to petition the FERC for remedies to problems it is unable to resolve through informal means, such as mediation. Having express authority to petition the FERC for remedies will provide the PSC needed leverage to resolve problems through informal means. This process would have the benefit of allowing problems occurring within the state to be remedied by the PSC without actually having to go through the process of petitioning the FERC. But it would also afford the PSC the ability to invoke the FERC's authority if necessary.

It is important to understand that, while the restructuring process will cause a shift in jurisdiction, the FERC does have policies designed to prevent utilities with market power from being able to exercise their advantage. The FERC is required by statute to assure that wholesale rates for electricity are "just and reasonable." Any rate that is not just and reasonable is unlawful.[26] Sales by a generator must be pursuant to a tariff schedule on file with the FERC or a bilateral contract between designated parties at a rate approved by the FERC (based on the seller's production cost, including a rate of return) or generators may seek approval from the FERC to sell at a "market-based rate." Market-based rate authority allows sales at a price negotiated between the buyer and seller that is not subject to prior approval by the FERC. Generally, to obtain market-based rate authority, a generator must not have, or must have adequately mitigated, any market power – in both generation and transmission. Blanket market-based rate authority is not granted for affiliate transactions and a generator must abide by a code of conduct applicable to affiliate transactions of non-power goods and services.

A generator has market power when it can "significantly influence" price by withholding supply and excluding other sellers from the market for a significant period of time or the seller can hold a price constant and offer inferior service while excluding other competitors.[27] The FERC applies a test, called the "hub and spoke analysis" to determine if a generator has market power in generation.[28] The ability to exercise market power due to transmission constraints within a geographic area has been considered by the FERC in applications for market-based rate authority. Transmission constraints reduce the scope of the market considered in the hub and spoke analysis. The FERC also examines other factors, such ownership of sites, pipeline capacity, and transportation commitments to determine if an applicant could prevent a competitor from entering the market.

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[26] For federal jurisdictional purposes, a public utility is any person who owns or operates a FERC jurisdictional facility, excluding a municipal utility or rural electric cooperative.

[27] TECO Power Services, 52 FERC P61, 191 (1990).

[28] The "hub and spoke analysis" measures the seller's generation market share in the markets for total and uncommitted generating capacity in each of the sellers first-tier and interconnected markets. A market share of 20% or more is an indication that generation market power may be present.

In addition to the market power test for generators, the FERC has developed separate rules to prevent affiliate relationships from interfering with the proper functioning of the market. Sales between affiliates are not permitted under blanket approval of market-based rate authority and are expressly excluded from a market-based tariff; they must be separately approved by the FERC as a just and reasonable rate. In addition, FERC conditions market-based rate authority on the acceptance of a code of conduct if the applicant is affiliated with a public utility with a franchised service territory. The terms of the code of conduct are such that there must be:

- No sale of non-power goods and services at less than cost or greater than market price.
- Separation of employees.
- No information sharing between affiliates that is not available at the same time and on the same terms and conditions to non-affiliates.

The FERC has granted exceptions to this policy in cases where there is no potential for affiliate abuse. For a sale to take place at anything other than a cost-based rate, the seller would have to demonstrate to the FERC on a case-by-case basis that there is no potential for disadvantage to ratepayers. Affiliate sales at market-based rates have been granted where:

- the sale price is pursuant to a market-based tariff that is established independently of the seller or buyer (open market price or regional price index),
- an offer to buy or sell at the same price, terms, and conditions is simultaneously made to non-affiliates,
- there are no captive ratepayers involved (e.g., full retail access or open season), or
- ratepayers are insulated from price effects through a rate freeze or hold harmless provisions.

There has been significant criticism of the FERC's hub and spoke analysis. Based on these criticisms, there appears to be an increasing likelihood of a change in the FERC's policy for determining market power. As this report goes to press, the FERC has informally indicated that it will review the appropriate test of market power in its rulemaking process. In the interim, for those areas that do not have a centralized spot market power exchange, the FERC will apply a supply margin assessment test of generation market power in ruling on individual applications for market-based rate authority. The effect for Florida is, of course, speculative at this time, but it appears reasonably certain that applicants for market-based rate authority to sell in Florida face a greater rather than a lesser degree of scrutiny. Competitive electricity markets are relatively young, and, while the FERC has demonstrated great resolve to assure that competitive markets develop, the FERC itself has acknowledged that it is still learning about how to effectively prevent or remedy problems, such as market power.

The state should be involved in monitoring the market. To carry out this responsibility, the PSC should develop expertise in the area of electricity markets to the extent that expertise does not already exist. Also, the PSC must have access to the books and records of market participants that are in possession of information relative to market problems. Of course, much of the information the PSC might want during an investigation could be confidential in nature, so this proposal suggests that proper mechanisms be created to safeguard this information from disclosure. Currently, the PSC has procedures for handling confidential information, but the providers of that information must go through inordinate hurdles to identify the portions of those documents they wish to protect from disclosure, and to justify the requests for confidentiality. This process consumes significant amounts of PSC staff time spent reviewing the requests and writing orders, not to mention the time spent by the providers of the information preparing the requests.

A successful and efficient manner of addressing confidential records already exists in Florida's telecommunications statute.[29] There, the PSC has access to all records reasonably necessary for the disposition of matters within the Commission's jurisdiction. The information is deemed confidential upon request by the provider and is maintained in that manner until a public records request for the information is received, at which time the confidential nature of the information is reviewed and a ruling is made. This procedure should be followed for the confidential information received pursuant to the PSC's market-monitoring function.

STRATEGY

Broaden the PSC's responsibility to require utilities to maintain adequate reserves.

TASKS

- The PSC should continue to assure adequate electrical reserves and to require load-serving utilities to seek additional resources, including power plant construction, when forecasted reserve margins drop below the level deemed necessary by the PSC.
- The PSC should have access to information of new market participants (IPPs and RTO) to carry out its responsibility of assuring adequate electricity reserves.
- The PSC should report annually on the status of the state's electric reliability, including a review of fuel availability and fuel mix of Florida's utilities.

RELIABILITY

It is critical to the health, safety and welfare of the people of Florida that there be an adequate and reliable source of energy for operational and emergency purposes in Florida through appropriate planning, development and maintenance of a coordinated electric power grid. In competitive markets, forces of supply and demand determine the quantity produced of a particular good or service. In general, this process leads to periods of over-supply and under-supply, with corresponding prices that provide signals for the market to produce more or less. In a purely competitive electric industry, there is no reason to believe that this dynamic would be any different. A purely competitive electricity market may give rise to a boom-bust cycle of generating capacity (and prices) -- periods of low reserve margins (accompanied by higher prices) followed by periods of excess capacity (accompanied by lower prices). The volatility of this cycle may be exacerbated by the lack of ability to inventory electricity.

In today's regulated environment, the PSC has authority aimed at assuring that electric utilities maintain adequate electric reserves. In the competitive wholesale market environment envisioned by this report, load-serving utilities will continue to be monopoly providers, and will be responsible for acquiring adequate resources to meet customer demand. To assure that adequate resources are maintained, it will be critical for the PSC to monitor and periodically report on the status of the reliability of the state's electrical system. It will also be critical for the PSC to have the authority, as it does today, to require load-serving utilities to seek additional resources, including power plant construction if necessary, when forecasted reserve margins drop below the level deemed by the PSC to be sufficient.

[29] Section 364.183, Florida Statutes.

Load-serving utilities would acquire resources from the competitive market. However, if the resources are not available in the competitive market, or if the price at which they are available exceeds the cost if the load-serving utility built a plant, the PSC could order the load-serving utility to build. The Study Commission does not believe it is likely that the PSC would have to avail itself of this option, but the option serves to discipline the competitive market and is the backstop to assure that adequate capacity is available.

Reserve Margins and Capacity Planning

As acknowledged earlier in the report, the planning process is imprecise at best. There is uncertainty associated with predicted values on both the demand and supply sides. On the demand side, the key variables in the forecasts are weather, population growth, and intensity of energy use by end-use residential, commercial and industrial customers. Extremely hot or cold weather can cause extreme peak demands, which may or may not be capable of being met by existing capacity.

Population growth, as projected in the "base" case scenario prepared by the University of Florida's Bureau of Business and Economic Research (BEBR), over the 2000-2010 decade is projected to be significantly less (1.62% per year), than over the previous ten years (2.14% per year). The BEBR also publishes a "high" case scenario for which the predicted growth rate is approximately the same (2.13% per year) as over the 1990-2000 decade. Population growth consistent with this "high" case would mean nearly an additional 1,000,000 Floridians by the year 2010 over the "base" case scenario. Using reasonable estimates of household size and peak demand per household, this would indicate the potential need to plan for an additional 450,000 to 500,000 residential electric customers having peak demand requirements of approximately 1,800 to 2,500 MW, or about four to five additional 500 MW power plants by 2010. The differences in the "base" and "high" case projections for 2020 are correspondingly greater – approximately 1,800,000 more Floridians in the "high" forecast than in the "base" forecast, indicating an additional 750,000 to 900,000 customers needing an additional 3,000 to 4,500 MW of capacity.

The intensity with which Floridians use electricity also affects electricity demand. Over the 1991-2000 decade, energy use per residential customer grew at an average annual growth rate of 1.515% per year. The FRCC's 2001 projections indicate that energy use per residential customer is projected to grow at only .54% per year, or only about one-third of the historical growth rate experienced in Florida over the previous decade. If the actual rate turns out to be 1.0% per year, about halfway between the historical rate and the projected rate, use per residential customer will be 15,465 KWHs per customer, rather than the forecast amount of 14,771 KWHs per customer. This additional energy use will most likely have at least some additional coincident peak demand associated with it, indicating a need for additional generating capacity to serve that peak demand.

The availability or unavailability of power plants also has an obvious and direct effect on the utilities' ability to maintain service to their firm and non-firm customers. If forced or unexpected outages are greater than expected, there will be less capacity available to meet demand. Additionally, if peak demand conditions occur during planned maintenance periods, those power plants that are "down" for maintenance will be unable to serve, and the chance of service interruptions will be correspondingly greater.

Overall, with projected reserve margins increasing to approximately 20%, the likelihood of service interruptions to firm customers in Florida must be regarded as slight. The likelihood of service interruptions to non-firm customers should also decrease. There is significant uncertainty associated with load and usage forecasts, which translates into uncertainty regarding the ability of Florida's utilities to maintain service to their firm and non-firm customers. The Study Commission wishes to emphasize its concerns about reliability and having adequate supplies of electricity. The uncertainty associated with the planning process suggests that the PSC should err on the side of having too much capacity than not enough, realizing, however, that excessive amounts of idle generating capacity translate into higher costs of electricity.

Consistent with the concern about adequate supplies of electricity is the degree of reliance on non-firm resources for reliability. Non-firm load has been viewed as a cost-effective way of avoiding or deferring power plant construction. In the context of reliability, non-firm service is a valuable and proper tool for providing reliable service at lower cost. Non-firm service also has advantages over more conventional supply alternatives inasmuch as it allows utilities to smoothly increase or decrease the number of participating customers and the resulting size of the MW reduction. There are concerns, however, about the potential risk associated with customers discontinuing their participation. While, large customers must provide three to five years prior notice, residential customers may discontinue the program on as little as 30 days notice. The risks associated with customers discontinuing participation is attenuated somewhat by the large number of residential customers who participate in load-management programs, and by its track record. Nevertheless, the Study Commission believes the PSC, in carrying out its responsibilities to maintain reliability, should make sure load-serving utilities do not rely too heavily on load management for reliability, and that they have a sufficient margin of generating capacity over firm demand.

Access to Information

The current vertically integrated structure has facilitated the planning process because utilities have been in possession of both supply and demand forecast information. In the competitive market envisioned by the report, the bulk of the responsibility for providing reliability forecasts will continue to fall on the load-serving utilities; however, due to the disaggregation of the industry, it will be necessary to assure that the PSC has authority to gather information from transmission providers and IPPs since those entities will figure prominently into the reliability equation. The PSC will need to have access to information from these organizations relative to generation and transmission capacity to facilitate the planning and reporting process.

Reliability Reporting

Related to reliability are the issues of fuel availability and diversity, and the overall resource mixes of load-serving utilities. As discussed previously, it is important to maintain a diverse portfolio of energy resources, including resources not typically considered generating resources, such as demand-side resources – load management and energy efficiency programs, and distributed resources. The PSC's responsibility for assuring reliability should include reviews of fuel availability and mix in the annual reliability planning process. The PSC should address these issues in its annual reports with the intention of using this information in connection of prudence reviews associated with resource acquisitions by load-serving utilities.

STRATEGY

Create mandatory reliability standards for the bulk power system that apply to all market participants and are enforced by the PSC.

TASKS

- ◆ A self-regulating reliability organization (SRRO) should be established to set standards pertaining to the operation of the bulk power system.
- ◆ The SRRO should develop standards applicable to all users of the bulk power system.
- ◆ The PSC should be authorized to adopt these standards as rules and to enforce the standards.

Reliability Standards for the Bulk Power System

Another important issue pertaining to reliability is the issue of mandatory reliability standards pertaining to the operation of the bulk power system. Currently, Florida's utilities adhere to voluntary standards developed by the Florida Reliability Coordinating Council (FRCC). This process has worked well in the context of integrated utilities, as evidenced by the high degree of reliability enjoyed by the state. The implementation of wholesale competition, however, will result in independent power producers who may or may not be willing to adhere to these standards. The successful development of a competitive market will, therefore, depend on the existence of mandatory and enforceable electric reliability standards for the electric power grid in Florida.

The issue of mandatory reliability standards has been debated for several years in the national arena, and is addressed in President Bush's National Energy Policy. The National Energy Policy notes that, "Since 1968, the reliability of the U.S. transmission grid has depended entirely on voluntary compliance with reliability standards. There is a broad recognition that voluntary adherence to reliability standards is no longer a viable approach in an increasingly competitive electricity market. There is a need to provide for enforcement of mandatory reliability standards." The National Energy Policy directs the Secretary of Energy to work with the FERC to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight.

While the competitive wholesale market is being established, it would be appropriate to require the establishment of a new self-regulating reliability organization (SRRO). The SRRO should develop reliability standards (taking into consideration existing standards developed by the FRCC) applicable to all users of the bulk power system. The PSC should be authorized to adopt these standards as rules, and to enforce the standards, including the ability to impose penalties for noncompliance. In the event federal legislation passes requiring a national organization (including the possibility of regional organizations) that is responsible for the reliability of the bulk power system, the PSC should continue to have authority to take actions to ensure the safety, adequacy and reliability of electric service in Florida.

STRATEGY

Assure the PSC's role in protecting against cross-subsidization of competitive services by regulated services.

TASKS

- The PSC should continue to have authority to protect consumers against cross-subsidization of unregulated operations by regulated operations.
- The PSC should have access to books and records of affiliates.
- The PSC should have authority to prescribe a code of conduct regarding affiliate transactions.

AFFILIATE TRANSACTIONS

Utility companies have long been affiliated with various types of corporate diversification strategies. Some investments include lines of business associated with the core utility business, such as fuel supply and fuel transportation affiliates. Other investments include businesses unrelated to the core utility business, such as insurance companies. An important responsibility of utility regulation is to make sure that these unregulated operations are not subsidized by the regulated operations. In Florida, the PSC has the authority to prevent such cross-subsidization.

In the competitive wholesale market envisioned by this report, the PSC must continue to have clear authority to protect consumers against cross-subsidization of unregulated operations by regulated operations. Not only is this authority important for protecting consumers, it is important to assure that load-serving utilities are not shifting costs to regulated operations for the purpose of giving competitive generating affiliates an advantage over IPPs. To carry out this responsibility, it is important for the PSC to have access to books and records of affiliates, and the ability to prescribe rules, or "codes of conduct," regarding transactions and resource exchanges between utilities and their affiliates to prevent cross-subsidization and to help assure fair competition between affiliated EWGs and other IPPs.

STRATEGY

Provide incentives for utilities to provide efficient low-cost electric service.

TASK

- The PSC should consider and implement, if appropriate, performance or incentive rate structures for load-serving utilities to encourage: (1) least-cost supply decisions, (2) cost savings, and (3) reliability.

Incentive Regulation

As a complement to restructuring Florida's wholesale market, the PSC should continue to develop alternatives to traditional cost-based regulation for those portions of the industry that remain subject to PSC regulation. From a public policy perspective, traditional rate regulation offers customers a price based on the historical, actual costs to produce power. Reductions in cost are passed on to customers through reductions in rates. The question is whether reducing rates in exact proportion to cost reductions sets up a system in which there is no reward, and, therefore, no incentive to the company providing the service to pursue cost reductions.

Incentive, or performance-based regulation, establishes rates based on cost, but provides an opportunity for the company providing the service to share in the benefits of cost reduction with its customers. Performance-based regulation may, therefore, be a better alignment of management incentives to hold costs down with customer benefits from lower costs. Under traditional regulation, the perspective of the service provider is to describe accurately and justify cost expenditures. Under incentive regulation, the provider's perspective is to drive costs down, relative to those on which rates were set in the regulatory process. This creates additional profits, which, under the sharing mechanism of incentive regulation, can then be shared between customers and shareholders.

Incentive regulation may take a variety of forms. The key characteristic is that a component of the ratemaking formula – price or revenues – is allowed to increase or decrease within a designated range, without regard to the utility's internal costs or rate of return. While Florida and other jurisdictions have used price or earnings caps in this way, Florida has also been something of a pioneer in the development of revenue caps.[30] In a nutshell, a revenue cap allows a utility's revenues to grow to levels set by the PSC, after which revenues are flowed back to customers in the form of rebates. Up to those revenue caps, a provider experiences a direct benefit from its efforts to reduce costs. An additional benefit of revenue cap programs is that they avoid controversy over the determination of a provider's earnings.

Because incentive regulation focuses on performance measured by external standards and gives an incentive to providers to drive costs down, their use would complement the development of competitive pricing in the wholesale market. Incentive regulation could also function as a transition type of regulation to a competitive retail market. For these reasons, the PSC should be encouraged to continue its efforts to develop and implement incentive regulation.

S T R A T E G Y

Establish a mechanism for long-term monitoring of the development and effectiveness of competition in the electric industry.

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[30] The Florida Office of Public Counsel, lead by Study Commission member Public Counsel Jack Shreve, has been instrumental in bringing these programs about. See settlement agreements in Docket Nos. PSC-99-0519-AS-EI and PSC-99-2131-S-EI for Florida Power & Light and Gulf Power respectively.

TASKS

- ♦ Retail competition should not be considered until after the development of an effectively competitive wholesale market.
- ♦ The PSC should monitor the development of competition in Florida's wholesale market, in retail markets in other states, and in policy determinations at the federal level.
- ♦ The PSC should report biennially to the Governor and the Legislature on the status of competition.
- ♦ A study commission similar to the Florida Energy 2020 Study Commission, should be established in 2004 to assess the status of wholesale competition and make recommendations as to whether retail competition should be allowed.

Retail Restructuring and Long-Term Monitoring of Competition

The electric industry is undergoing major changes brought about by several factors. Advancements in power-generating technology, new legislative and regulatory mandates, and regional electricity price variations have caused federal and state policy makers to reconsider regulatory policies. Federal laws and regulatory policies have been adopted that encourage competition in the wholesale market. State policy makers in approximately half the states have undertaken restructuring programs. As of September 2001, 23 states and the District of Columbia have enacted restructuring legislation; and one state (New York) has restructured pursuant to a comprehensive regulatory order.[31]

Not all states have moved with the same zeal toward retail access. The first states to adopt retail access were California and some northeastern states, all of which had high electricity rates. These states promoted competition with the goal of achieving lower rates. Other states have not chosen to open their retail markets. In December 1998, 23 state public utility commissions, including the Florida Public Service Commission, sent Congress a letter expressing concerns that national restructuring legislation may not give states adequate consideration. In general, these state commissions represented southeastern states, which have had lower rates and have been reluctant to implement retail access.

The recommendations in this report will bring about competition in Florida's wholesale market without the problems encountered in California. The recommendations can be expected to result in adequate reliable supplies of electricity, price stability and reasonable costs. The PSC will have the tools to assure that adequate generating capacity will be available by requiring load-serving utilities to secure additional resources if reserve margins become too small. The PSC will prescribe and enforce standards for all users of the bulk power system. The process of restructuring Florida's wholesale market will afford the PSC an opportunity to review all resource additions of the load-serving utilities to assure that load-serving utilities' resource additions are needed; that they are the least-cost resource, consistent with the objective of maintaining fuel diversity; and that reasonable efforts have been made to secure cost-effective demand-side resources. The PSC would also protect against exposure of load-serving utilities to entities with market power by requiring load-

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[31] Energy Information Administration, Status of State Electric Industry Restructuring Activity as of September 2001; http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.

serving utilities to rely more on bilateral arrangements between load-serving utilities and generating companies, rather than on short-term market resources. The PSC will be able to address market issues through informal means, such as mediation, with the ultimate ability to petition the FERC for remedies in cases where the PSC is unable to bring those remedies about.

From the outset, the Study Commission understood the importance of addressing wholesale competition separately from retail competition. The Study Commission's work plan approved at its first meeting in September 2000 reflected this understanding by focusing the initial effort on wholesale restructuring, and considering retail restructuring during the latter part of the study. This approach was predicated on the belief that the wholesale market should be effectively competitive before allowing retail competition. Effective wholesale competition provides the foundation upon which retail competition can be built.

During the course of this study, nothing has come to the Study Commission's attention to change this view. In fact, several presenters appearing before the Study Commission have offered their opinions about the importance of establishing competition at the wholesale level first. Retail competition presents many difficult and challenging issues over and above those that must be resolved to bring about wholesale competition. Adding those issues to the policy agenda compounds the opportunities for mistakes that could have significant adverse consequences on Florida's utility customers.

While the Study Commission is not making any recommendations with respect to retail competition, there are, nevertheless, reasons to believe that when the state's wholesale market is effectively competitive, and when there is a better understanding of some of the difficult issues associated with retail restructuring, that it may be appropriate to give retail customers the ability to choose their supplier. It would, therefore, be appropriate for the state to formally establish a mechanism for long-term monitoring of the development and effectiveness of wholesale competition in the electric industry.

The PSC would be an appropriate entity to monitor the development of wholesale competition, or to at least have a significant role in that function. The future regulatory responsibilities of the PSC, particularly with respect to its role as a market monitor, position the PSC to be knowledgeable about the marketplace. The PSC will also be in the best position to interface with and receive information from the FERC, which has primary regulatory authority over the wholesale market. A representative of the FERC appearing before the Study Commission indicated that the FERC has established a computerized market monitoring office that receives market information in near real-time. The FERC representative indicated that his agency is attempting to make this information available to state regulatory commissions. This information would help the PSC understand the dynamics of the market and the effectiveness of competition.

A natural extension of the PSC's responsibilities as a market monitor would be to help policy makers decide whether and when to implement retail choice. Therefore, the PSC should be required to monitor the development of competition in Florida's wholesale market, as well as developments in retail markets in other states, and policy determinations at the federal level. Using this and other information, the PSC should be required to report biennially to the Governor and the Legislature on the status of competition. This report will keep the Governor and the Legislature apprised of the status and development of competition. It will also will help policy makers make informed decisions on whether conditions are favorable for the state to gain further benefits by allowing customers to choose their electricity supplier.

While the Study Commission believes it is not appropriate to consider retail restructuring at this time, there are reasons to believe that a retail market for electricity could develop. Such a market could eventually provide more of the types of benefits the Study Commission believes will come about from wholesale restructuring. The Study Commission, therefore, recommends that another study commission, similar to the Florida Energy 2020 Study Commission, be formed in 2004 to consider the status of competition and to make recommendations with respect to retail restructuring.

STRATEGY

Begin the process of transitioning to a tax system that takes into account the changes taking place in the energy industry.

TASKS

- There should be a review of the definition of the taxable commodity of electricity to clarify the applicability of taxes to the separate functions of generation, transmission and distribution services.
- Consider changes to taxes and fees paid by Florida's utilities and utility customers necessary to assure a system that is fair with respect to energy providers and individual classes of electric customers, and that provides revenue neutrality to state and local governments.

Fiscal Impacts to State and Local Governments

Electric industry restructuring, particularly retail restructuring, can have significant impacts on the taxes and fees paid by electric utilities to support state and local government programs. In recognition of the potential effects, the Governor's Executive Order requested the Study Commission to consider the impacts of restructuring on the revenues of state and local government. To assist in the analysis of the potential impacts, the Study Commission formed a Fiscal Impacts Technical Advisory Committee (FI-TAC).

The FI-TAC first established an inventory of the major state and local taxes and fees paid by Florida's investor-owned utilities. The FI-TAC then looked for a theoretical framework of a good tax system and adopted the State Tax Reform Task Force's Principles of Taxation. To assess the likely fiscal impacts of restructuring, the FI-TAC developed a qualitative analysis of each tax and fee based on the assumption that restructuring can be expected to result in price decreases, and that demand would not increase by a similar percentage. The FI-TAC also made the assumption that in-state companies would lose market share in Florida, thus becoming less profitable and their property less valuable.[32] The FI-TAC recommended that Florida adopt a competitively neutral tax structure for the electric industry. However, the FI-TAC also recognized that fiscal stability is an important feature of a good tax structure.

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[32] It is noteworthy that the FI-TAC's assumptions seem to be contrary to the concerns expressed by many stakeholders in the stranded investment dialogue. These stakeholders expressed concern that existing utility-owned power plants, on average, would be valued higher in a competitive wholesale market and that utilities would incur significant windfalls absent measures designed to capture these "stranded benefits." The FI-TAC's assumptions, though, are instructive in the analysis of the scenario whereby there are potential adverse impacts on state and local government taxes and fees, and of the tax policies that should be considered to avoid these adverse impacts.

The FI-TAC's report reveals that the bulk of concerns about restructuring with respect to state and local taxes and fees come about under retail restructuring. The Study Commission, though, is not recommending that the state undertake retail restructuring at this time. Rather, the Study Commission recommends that retail restructuring wait until such time as the underlying wholesale market becomes effectively competitive. The Study Commission has recommended policy changes to bring about a competitive wholesale market, and some consideration should be given to the potential tax consequences of those changes.

The FI-TAC advises that, "Changing Florida's regulatory policy to include wholesale open markets for the generation of electricity will not require a full-scale rewrite of its state and local tax system." With respect to wholesale market restructuring, the FI-TAC advises that the primary issue that will need to be addressed is the definition of the taxable commodity by incorporating any potential changes the industry might make in its marketing. These changes include the unbundling of the sale of electricity into separate components, such as generation, transmission, and distribution. Currently, definitions in the tax statutes refer to the purchase of "electricity," which in most cases assumes that electricity is sold at a single price for a bundled service that includes all components. The Study Commission believes that a review of the definition as recommended by the FI-TAC is entirely consistent with the trend in the industry toward separation of the generation, transmission and distribution functions. This review should take place in conjunction with other statutory changes aimed at implementing competition in the wholesale market.

Another impact of wholesale restructuring revealed by the FI-TAC is the impact of competition on ad valorem taxes. Valuation of property is required by the Florida Constitution to be at "just value," which has been interpreted by the courts to mean "fair market value." Traditionally, valuation of utility power plants has been based on the "cost approach." The cost approach uses recorded book values as the basis for determining just value. There is a concern, though, that property appraisers may switch to the "income approach" in a competitive market, in which case property tax collections could become more unpredictable. Under the income approach, valuations would be affected by the competitiveness of the plant, as well as the general price level in the wholesale market.

With respect to the concern about property tax valuations, it appears unlikely that the recommendations of the Study Commission will have any significant near-term impacts, even if the income approach is used to value plants. If plants are transferred to either competitive affiliates or unaffiliated IPPs, the transfers would be accompanied by cost-based transition contracts designed to keep the electricity priced at values based on current book values. Therefore, the transition contracts themselves can be expected to dampen the effect on plant values resulting from any transfers.

The primary effect of any reduction in ad valorem tax revenues would be at the local government level. There could also be a secondary effect on the state funding of education. Grades K through 12 are funded 60% through state general revenues and 40% through property taxes at the local level. Any reduction in local ad valorem taxes could put increased pressure on general revenues. It is important to realize, as did the FI-TAC, that some local governments may actually experience increases in taxable value.

The FI-TAC suggested two ways to achieve revenue neutrality for decreased ad valorem tax collections. One way would be to create a new local revenue source for local governments. Another way would be to establish a trust fund to recompense local governments for losses in ad valorem tax receipts due to deregulation, as Texas did. Under the Texas approach, a reimbursement program could be based on a formula calculating the value of plant and equipment in the current market situation compared to the taxable value in a given year, with the difference distributed annually to the various local taxing jurisdictions.

As stated above, the bulk of tax consequences are brought about by retail restructuring. The nature and extent of the potential consequences are such that the Study Commission does not believe that laws allowing retail restructuring should be enacted until these consequences have been considered. Under retail restructuring, the concern is that various suppliers of electricity would be allowed to sell electricity to businesses and residents from locations outside the state. Whether these out-of-state companies can be required to collect or pay Florida taxes and franchise fees is a significant issue. Other states that have enacted retail choice programs have found that energy providers without nexus with their state can easily avoid paying value-based taxes (e.g., sales or gross-receipts taxes). Some states have attempted to overcome this problem by creating nexus through registration requirements. These requirements, however, have not been tested in the courts. Other states have replaced their value-based taxes with volume-based taxes (e.g., tax on gas levied on a cents-per-gallon basis).

While the Study Commission is not recommending retail restructuring at this time, it has recommended monitoring the development of competition in the wholesale market, as well as developments in other areas of the nation and in federal policy arenas, to determine whether and when it will be appropriate to consider retail competition in Florida. To prepare for such an eventuality, policy makers should consider what types of changes are needed to maintain a tax system that is fair with respect to energy providers and individual classes of electric customers, and provides for revenue neutrality to state and local governments. To begin this process, it may be appropriate to establish a task force similar to the Telecommunications Taxation Task Force to build on the work of the FI-TAC. The task force could study the issues in greater depth and make specific recommendations with respect to the tax system.

C IMPROVING ENERGY INFRASTRUCTURE

The Goal

Florida will have an energy infrastructure that assures the reliable delivery of electricity to consumers.

Objectives

C-1 The energy transmission system provides nondiscriminatory access to sellers of electricity, is independently controlled and operated, and has been relieved of major constraints.

C-2 Transmission pricing provides efficient signals for the siting of new generation capacity and the location of new loads.

STRATEGY

The transmission line siting process should be changed to lead to faster siting of transmission facilities without compromising environmental requirements.

TASKS

- Transmission lines and substations must be recognized as electrical infrastructure necessary for the public health, safety, and welfare that should not be unreasonably prevented from being located where determined necessary for the efficient, reliable delivery of electricity, consistent with existing environmental protections.
- Local governments should be required to adopt reasonable land-use and site condition standards for substations.
- The criteria as approved by the Board of Trustees of the Internal Improvement Trust Fund on January 23, 1996, for the use of natural resource lands by linear facilities should be adopted by rule.
- The existing easement fee exemption for crossing sovereignty lands and lands held for purposes other than conservation (non-natural resource lands) by transmission lines should apply to all state or federally regulated transmission lines.
- Encourage co-location of transmission facilities with linear facilities, such as roads, canals, and railroads. Agencies should be required to allow transmission lines to co-locate within their rights-of-way, provided the transmission line will not interfere with the agency's operations, cause unacceptable environmental harm or unacceptable impacts to natural resource lands. When co-location of a new transmission line within an existing right-of-way is not feasible, incentives should be offered to encourage placement of the transmission line immediately adjacent to the existing right-of-way.

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- ♦ Encourage co-location of new transmission lines with existing linear facilities by: (1) expanding the exemption from the Transmission Line Siting Act (TLSA) to construction "immediately adjacent" to established linear rights-of-way at the option of the applicant, and (2) replacing the October 1, 1983, deadline for transmission line rights-of-way to be considered "established" for purposes of the exemption with either a requirement that a transmission line already exist within the right-of-way, or that one have existed for a minimum number of years.
- ♦ Streamline the licensing of major transmission line projects by eliminating the adjudicatory hearing presently mandated for all TLSA projects unless a party requests one.
- ♦ Shorten the post-certification review process by allowing TLSA transmission lines to qualify for a general permit when "best management practices" are used for construction.
- ♦ The DEP should undertake a review of the TLSA and other relevant statutory provisions to identify other ways in which Florida's electricity infrastructure can be improved, upgraded and extended, and permitting of transmission line facilities streamlined without compromising environmental requirements.

Florida's electricity infrastructure consists of a statewide grid of long-distance transmission lines that move electricity from one part of the state to another, as well as the local distribution network that carries electricity to homes and businesses. Florida's transmission grid has strong interties with Georgia. Through these interties, Florida's utilities are able to import a maximum of 3,600 MWs from sources outside the state, which represents approximately 10% of Florida's electrical demand. The peninsular portion of Florida is not strongly interconnected with the portion of Florida's panhandle served by Gulf Power Company.

Nationwide, investment in electric transmission infrastructure has failed to keep pace with the demands placed on the system and the changing nature of the electric industry over the past few years. Policy changes implemented by the FERC have led to the transmission system being increasingly relied on as a way for competitive generating companies to ship power longer distances than the system was originally designed for. Yet, the transmission network was not designed to accommodate these large long-distance power flows across regions – the job it is now being called upon to do with the opening of transmission access.

During the past decade, transmission capacity, as measured by MW miles/MW demand, has declined significantly on the national level. Peninsular Florida's declines were less rapid than the national declines. At the national level, these declines and the fact that the transmission grid has been called upon to perform functions for which it was not designed, have resulted in the flows on many transmission lines exceeding capacity, requiring the operators to curtail buy/sell transactions to bring the power flows within the line's capacity. This curtailment is termed Transmission Line Relief (TLR). Increasing transmission investment would eliminate the need for TLR's, allowing more transactions to take place.

Transmission gridlock is producing rising concerns about the quality and reliability of the nation's power network, the absence of investment incentives, and a strategy and plan for how to correct the logjam. President Bush's National Energy Policy has recognized this problem, and directs that steps be undertaken to alleviate it. The National Energy Policy includes directions to the Secretary of Energy to:

- ◆ Work with the FERC to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight;

- ◆ Expand the Department of Energy's research and development on transmission reliability and superconductivity;

- ◆ Examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove the transmission bottlenecks by December 1, 2001;

- ◆ Work with the FERC to relieve transmission constraints by encouraging the use of incentive rate-making proposals; and

- ◆ Develop legislation, in consultation with appropriate federal agencies and state and local government officials, to grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid (similar to existing authority for natural gas pipelines).

At this time, Florida's transmission infrastructure does not have the types of constraints causing problems in many areas of the country. This is evidenced by the fact that over the last two and one-half years, Florida has experienced two TLRs, while nationally there have been 1,891 TLRs. This is possibly due to the fact that Florida's wholesale electricity market does not have the number of providers that other markets have. Also, Florida's somewhat unique geography does not put Florida between buyers and sellers in different regions; therefore, Florida's transmission network does not have the added stress of providing a path for out-of-state buyers and sellers trying to move power across the state.

Although Florida does not experience many TLRs, the new competitive marketplace will soon utilize the remaining excess capacity in the transmission system and new major transmission will be required. Experience has shown that building new major transmission is a lengthy and difficult process even under the existing Transmission Line Siting Act (TLSA). Changes to the transmission line siting process to allow faster siting of these lines will help to ensure the required new transmission is built in a timely manner.

While Florida does not currently face problems of the same magnitude as other states, there is a need to recognize the importance of making sure that transmission investment keeps pace with the increasing demand for electricity. In addition to the fact that Florida's population is using increasing amounts of electricity, greater competition in the wholesale market is inevitable, and Florida's electricity infrastructure must be able to provide sufficient transmission to accommodate the increased use of the system.

Open transmission access is providing more opportunities for transmission to substitute for generation. Transmission capacity can allow a given region to import electricity that would otherwise have to be generated within that region. In some cases, transmission capacity may allow lower-cost power to be consumed within a region, or it may alleviate market power within a region.

In determining whether to expand transmission capacity to increase access to generation resources outside the state, policy makers should consider the desired degree of reliance on out-of-state resources. Peninsular Florida currently has the ability to import approximately 10% of its generation needs from outside the state. Just as not having enough transmission capacity may be a problem, relying too much on out-of-state resources may be a problem as well. Part of California's problems were due to a heavy reliance on out-of-state purchases, which were suddenly no longer available because of weather conditions and population growth in the northwest. Just as it may be prudent to not become over-reliant upon a particular fuel type, Florida should not become overly dependent on other states for its generation resources.

Transmission line siting currently is the responsibility of state government. It appears that, even under a national transmission line siting scheme, the states may maintain a primary role. There have been proposals to give the federal government eminent domain authority; however, based on news reports of statements from federal energy officials and a high degree of resistance from states, it appears that the Bush Administration's primary interest will be in a scheme whereby the federal government would not intervene unless a state is unable to site a given transmission facility.[33] Therefore, making sure that transmission capacity is adequate and reliable is currently, and will likely remain, the state's responsibility.

The Study Commission believes that Florida should address the concerns about the lack of transmission investment and future expansion of the existing system. Based on testimony received by the Study Commission about transmission line siting, it is apparent that the transmission line siting process could be changed to lead to faster siting of transmission facilities without compromising environmental requirements. Transmission lines and substations must be recognized as electrical infrastructure necessary for the public health, safety and welfare that should not be unreasonably excluded from locations determined necessary for the efficient, reliable delivery of electricity.

Electric providers frequently encounter issues with local governments in siting substations at particular locations. Local governments should be required to adopt reasonable land use and site condition standards for substations. If a substation meets those standards, it should be allowed.

Because of the increasing development of land in Florida, there is less and less undeveloped or non-populated land available for the location of new bulk transmission lines. At the same time, Florida has substantially expanded state ownership of preservation, conservation and recreation lands as a result of land purchases through such programs as Preservation 2000 and Florida Forever Programs. A large investment of public funds has been, and will continue to be, made in the acquisition and management of these lands. At times, electric powerlines may need to be located across these state lands.

A more formal system should be developed to balance the preservation and management of state lands purchased or managed for their natural resources (natural resource lands) with the need for transmission line siting in the State. On January 23, 1996, the Board of Trustees of the Internal Improvement Trust Fund (Trustees) approved a policy for the use of natural resource lands by linear facilities (Appendix B). This policy was developed with input from a range of stakeholders,

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[33] Scientech Issue Alert, September 13, 2001 issue, FERC Qualifies Position on Eminent Domain, New Commission Standards Are Emerging, Will McNamara.

including state land managers, the environmental community, the Department of Transportation, and utility representatives. This policy should be formally adopted by rule under Chapter 120, Florida Statutes, to provide more certainty to all stakeholders.

For easements and other forms of approval to allow electric transmission lines to cross sovereignty lands and state lands held for purposes other than conservation (non-natural resource state lands), the fees charged should reflect that these facilities are "in the public interest" as critical infrastructure. This existing easement fee exemption should be continued and applied to all state or federally regulated transmission lines.

Co-location of transmission facilities with linear facilities, such as roads, canals, and railroads should be encouraged. Co-location minimizes land use impacts by limiting the number of linear features in an area, and reduces environmental impacts because typically less clearing will be required. Some local governments and agencies, such as some water management districts and the Florida Turnpike Authority, have been reluctant to allow co-location within their rights-of-way. Agencies should be required to allow transmission lines to co-locate within their rights-of-way, provided the transmission line will not interfere with the agency's operations, cause unacceptable environmental harm or unacceptable impacts to natural resource state lands. When co-location of a new transmission line within an existing right-of-way is not feasible, incentives should be offered to encourage placement of the transmission line immediately adjacent to the existing right-of-way.

The TLSA (Section 403.52 – 403.5365, Fla. Stat.) establishes a coordinated, one-stop permitting process for large transmission line projects. This process takes approximately 10 to 15 months to complete, which is considerably longer than the otherwise applicable permitting processes. At present, there is an exemption from the TLSA (Section 403.524(2)(c), F.S.) for transmission lines constructed within "established rights-of-way," such as those for roads, railroads, pipelines and transmission lines. For a transmission line right-of-way to be available for use under this exemption, it must have been established prior to October 1, 1983. To encourage co-location of new transmission lines with existing linear facilities, this TLSA exemption should be: (1) expanded to construction "immediately adjacent" to established linear rights-of-way; and (2) amended to eliminate the October 1, 1983, deadline for transmission line rights-of-way to be considered "established" for purposes of the exemption. Instead of the October 1, 1983 deadline, the exemption should require only that another transmission line already exist within the right-of-way to be used, or that the electric transmission line right-of-way have been established for a minimum number of years. This expansion of the TLSA would discourage creation of new linear features in Florida's communities. Electrical facilities exempted from the TLSA, of course, would still be required to obtain all applicable individual permits prior to construction.

Licensing of major transmission line projects (those that are 230 KV or above, are 15 miles or more in length, and cross a county line) under Florida's TLSA should be streamlined. The adjudicatory hearing that is presently required for all TLSA projects should be eliminated unless a party (either an agency or substantially interested person) requests one. For such non-controversial projects, the Secretary of the Department of Environmental Protection should issue the final order of certification rather than the Governor and Cabinet, sitting as the Siting Board. This recommendation is consistent with a suggestion by the Study Commission's E-TAC. This would be consistent with other environmental permitting proceedings and save approximately three months in the permitting process for non-controversial projects. Following certification of a TLSA transmission line, the applicant is typically required to submit detailed design information for post-certification review by regulatory agencies to monitor for compliance with the conditions of certification. The TLSA post-certification review process presently takes about four to six months. This review of the detailed design and construction of a transmission line should be substantially shortened by allowing TLSA transmission lines to qualify for a general permit such as that contained in Section 403.814(6), Fla. Stat., when "best management practices," such as specified limitations on wetlands clearing and construction, are used for construction.

It is possible that there are other steps that could be taken along the lines of the above recommendations. The DEP should undertake a review of the TLSA and other relevant statutory provisions to identify other ways in which Florida's electricity infrastructure can be improved, upgraded and extended, and permitting of these facilities streamlined without compromising environmental requirements.

In the process of the Department of Environmental Protection's review, the Department should be aware that the U.S. Secretary of Energy Spencer Abraham and Governor John Engler of Michigan on behalf of the National Governors Association announced the establishment of a blue-ribbon Task Force on Electricity Infrastructure that will focus on state policies and regional issues that impact the energy sector. The new Task Force will examine current state and federal policies and make recommendations in three key areas:

- Identification of opportunities to streamline generation siting policies and processes, consistent with sound environmental policy, to ensure that generation capacity is in place to facilitate competitive markets;
- Identification of regulatory and institutional barriers to the siting of new transmission infrastructure, and development of a series of recommendations to help states break the siting logjam; and
- Identification of policies and practices that are necessary to support regional electricity markets, and outline principles and parameters for multi-state collaborative approaches to address regional infrastructure issues.

This effort is aimed at implementing a key part of President Bush's National Energy Policy. The DEP should monitor the Task Force's proceedings and give consideration (e.g., through rulemaking or the proposal of statutory revisions) to any recommendations that warrant application in Florida.

STRATEGY

Assure that a regional transmission organization can apply for extensions or improvements of the transmission system.

TASKS

- The TLSA should be clarified to indicate that an RTO can be a proper applicant.
- Provide RTOs eminent domain authority.

Previously in this report, recognition was given to the need to have an independent RTO operate the state's transmission facilities. The existence of the RTO will be a key element of making sure the state has sufficient transmission capacity, since one of its primary functions will be to construct transmission facilities to meet the demands of market participants. The RTO will undoubtedly pursue the upgrade or construction of new major transmission lines that would come under the TLSA. At present, however, the TLSA would not allow an entity in the electrical transmission business, other than an electric utility, municipality, county, electric cooperative, joint operating agency, or a combination thereof, to apply for certification. For the RTO to succeed with its responsibilities, it must be able to apply for permits under the TLSA. Therefore, the TLSA should be clarified to indicate that the RTO is a proper applicant.

Because of the RTO's purpose in the wholesale market, it will also need eminent domain authority with respect to transmission lines. As infrastructure that is needed for the public health, safety and welfare, transmission lines and substations must be capable of being located where they are needed. While electric utilities and other entities granted the power of eminent domain typically attempt to negotiate the land purchase prior to exercising the power, an entity such as an RTO that is authorized to construct transmission lines and substations must also have the power of eminent domain. Otherwise, property owners could prevent the construction of a transmission line or substation, to the detriment of the rest of the community and undermine the reliability of the transmission grid. Of course, eminent domain authority does not give the condemning authority carte blanche to take someone's land. For example, Florida's eminent domain statutes require a circuit court to conduct the eminent domain proceedings to ensure that the condemning authority is properly exercising its power of eminent domain, that alternatives were properly considered and rejected, and, in addition, if requested by the landowner, that a jury of 12 determine the fair market value.

STRATEGY

The PSC should encourage the FERC-approved RTO to recognize the importance of sending proper short-term price signals reflecting the true costs of generation and consumption.

TASKS

- The PSC should work with the RTO and the FERC to ensure that transmission pricing leads to cost-minimizing decisions by both the RTO and generation companies.
- In conjunction with the RTO and the FERC, the PSC should ensure that the incentives created by transmission pricing lead to the appropriate level and mix of transmission and generation investment.

The Study Commission supports the implementation of an efficient mechanism for the pricing of transmission usage. An efficient transmission pricing system will send proper short-term price signals that will indicate the true costs of generation and consumption, and, in conjunction with real-time or time-of-use prices, will allow demand and supply to respond to bottlenecks in the transmission system as they appear. In the long-term, an efficient transmission pricing mechanism will provide new generation and load price signals to locate so that transmission bottlenecks can be avoided or alleviated and will indicate where new transmission capacity is needed. Moreover, efficient transmission pricing should be based upon cost causality and avoid the socialization of costs across all users of the system. Transmission and generation are complements in some cases and substitutes in other situations, so pricing rules provide important incentives affecting the behavior of market participants. Even though the FERC has jurisdiction over this issue, the PSC can work with the RTO and the FERC to ensure that transmission pricing promotes the appropriate level and mix of transmission and generation capacity.

STRATEGY

Develop long-range planning and policy with regard to transmission infrastructure development.

TASK

- Encourage transmission planners to consult with outside experts and affected parties early in the process to promote the timely resolution of siting issues.

The availability of electric energy is a necessary element of economic growth and development, and should be considered in the overall growth management process. The State of Florida should take a long-range view of transmission infrastructure needs and develop basic policies to guide future energy development, considering both current and new technologies.

D PRESERVING FLORIDA'S ENVIRONMENT

The Goal

Florida will have an energy supply and delivery system that preserves Florida's environment.

Objectives

D-1 Generating plants and transmission lines are subject to cost-effective environmental requirements that protect and enhance air quality and protect and conserve Florida's water resources.

D-2 Cost-effective environmental control requirements align market incentives with environmental quality goals.

Preserving Florida's environment is as important to future economic growth as it is to protecting the quality of life of Floridians. In Florida, the environment is the economy. Tourism accounts for approximately 20% of the state's economic activity. Tourists flock to the state for its sandy beaches, freshwater springs, and beautiful environment. The restructuring of Florida's electric industry provides the opportunity to improve its environmental performance.

STRATEGY

Continued analysis by DEP on cost-effective methods to reduce emissions of SO_2, NOx and Mercury from power plants in Florida.

TASKS

- Consistent with the approach proposed in the National Energy Policy, a multiple-emission control approach is the most promising method of controlling criteria pollutants.
- Any new program for reducing emissions should adhere to certain principles. Programs should: (1) be based on sound science, risk assessment, and cost-benefit analysis, (2) include market-based trading components, (3) maintain fuel diversity, (4) provide certainty and consistency, and (5) allow credit for voluntary early action.

Power Plant Emissions

Power plants are among the largest single point sources of air pollution in Florida, particularly those facilities constructed prior to the implementation of the Clean Air Act which are exempted from certain provisions of the act. These "grandfathered" power plants emit large quantities of nitrogen oxides (NOx), which contribute to the formation of ground-level ozone. Ground-level ozone concentrations within the Pensacola and Tampa Bay regions are approaching proposed federal health-based "non-attainment" status under the Clean Air Act.

Significant reductions in NO_x emissions are possible. The State of Florida demonstrated its ability to work with power plant owners to reduce emissions below U.S. EPA-established thresholds. In 1999, the DEP and Tampa Electric Company (TECO) entered into an agreement that will dramatically reduce emissions of both NOx and sulfur dioxide (SO_2), a precursor of acid rain. The emission reductions by TECO at its Gannon and Big Bend power plants should prevent a federal non-attainment designation in the Tampa Bay region. Evidence indicates that the air quality problems in the Pensacola region are not caused by pollutant transport from distant sources. Improving air quality in the Florida panhandle will require significant reductions in the emissions from local power plants that are currently grandfathered and from large industrial sources. The TECO settlement demonstrates that Floridians can have both reliable electricity and clean air.

The Study Commission recommends that the DEP continue to analyze options for the most efficient and cost-effective means to reduce emissions from Florida's power plants. The Study Commission finds that a multiple-emission control approach is the most promising method of controlling criteria pollutants. This strategy is based on improving the performance of technologies used to control emissions of several pollutants simultaneously rather than individually.

The Study Commission concurs with the findings of the National Energy Policy regarding the benefits of multi-pollutant emissions controls. The National Energy Policy directs the Administrator of the U.S. Environmental Protection Agency to propose multi-pollutant legislation. The EPA Administrator is to work with Congress to propose legislation that will establish a flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators. Such a program (with appropriate measures to address local concerns) would provide significant public health benefits, even as electricity supplies are increased. Specifically, the approach included in the National Energy Policy will:

- Establish mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides, and mercury.
- Phase in reductions over a reasonable period of time, similar to the successful acid rain reduction program established by the 1990 amendments to the Clean Air Act.
- Provide regulatory certainty to allow utilities to make modifications to their plants without fear of new litigation.
- Provide market-based incentives, such as emissions trading credits, to help achieve the required reductions.

The Study Commission recommends that certain principles be considered when any new program for reducing emissions is considered. In analyzing options for the most efficient and effective means of reducing emissions from Florida's power plants, the DEP should consider the following principles:

Sound Science, Risk Assessment, Cost-Benefit Analysis -- Identification and definition of air quality-related problems should be based upon and governed by sound science, with open exchange of data and peer review of conclusions. Potential regulatory solutions should be developed using accepted risk assessment techniques and cost-benefit analysis. The preferred regulatory approach should maximize benefits while minimizing costs.

Market-Based Trading Components -- Any new emission reduction program should use market-based trading rather than traditional command-and-control requirements. Market-based reforms have supported a high degree of innovation in air pollution control policy over the past twenty years. Other market-based approaches to multiple-emission control should also be pursued. "Cap-and-trade" programs like the national Acid Rain Program should be encouraged by implementing pricing mechanisms that recognize regional differences and upwind and downwind relations of sources. "Cap-and-trade" systems allow desired overall emission levels to be achieved in the most cost-effective manner. The sulfur dioxide allowance program under Title IV of the Clean Air Act is a successful model of this kind of flexibility. It allows plant owners, and the marketplace, to determine the appropriate emission control strategy for specific plants, consistent with the overall emission reduction goal and the ambient air quality standards. In recognition of the role of air pollutant deposition in the degradation of surface waters, these trading programs should be expanded to allow cross-media trading of credits. This would reward more affordable and efficient pollution control technology while maintaining a net environmental benefit.

Maintain Fuel Diversity -- Electricity in Florida is generated from a diverse mix of fuels. Coal, oil, natural gas and nuclear fuels all play important roles. This fuel diversity provides benefits to Florida's electric utilities and their customers, including mitigation of fuel price volatility and protection from the effects of fuel supply interruptions. In developing any new regulatory program to reduce emissions from power plants in Florida, the benefits of this diverse fuel mix should be recognized and maintained. An emission reduction program that would tend to decrease the diversity of fuel used for electric generation, or to result in over-dependence on any one fuel, should be avoided. Developments in pollution control technologies are resolving the tradeoffs between clean air and diverse fuels. For example, Tampa Electric Company has demonstrated that gasified coal can burn nearly as cleanly as natural gas.

Certainty and Consistency -- Florida must be careful not to adopt a state program that would create conflicting regulatory requirements or inconsistent decision criteria or schedules. Any new Florida program should also seek to provide certainty as to what the additional state requirements will be, how and when they will be applied, and how they fit with other federal and state programs.

Credit for Voluntary Early Action -- Any new emission reduction program should provide incentives for voluntary early compliance actions. Members of the regulated community that choose to reduce emissions prior to regulatory deadlines should be given some credit for their actions. The Study Commission recommends that utilities be allowed to retain ownership and banking rights of expanded air quality increments that result from voluntary emission reductions. Early action incentives could also include tax credits for investments made to achieve emission reductions.

STRATEGY

Develop and maintain an inventory of greenhouse gas (GHG) emissions in Florida.

TASK

- The DEP should develop regulations to inventory and track greenhouse gas emissions within Florida.

Greenhouse Gas Emissions

Because information will be central to possible future emission credit trading programs and evolving clean air strategies, the Study Commission recommends periodic inventorying and tracking of greenhouse gas emissions in Florida.

STRATEGY

Encourage a collaborative and proactive approach to siting power plants, transmission lines and substations utilizing available natural areas inventories and statewide and regional natural resource maps.

TASK

- The DEP should consider adopting incentives to encourage applicants seeking to site energy facilities to undergo a pre-application consultative process with affected stakeholders.

Electric Infrastructure Siting: Transmission Lines

The Commission recommends that, prior to an applicant filing under the PPSA or the TLSA, the applicants engage in a collaborative process to ensure that all affected stakeholders have the opportunity to offer input to identify the most efficient and least intrusive plant site or transmission line corridor. Transmission line projects, in particular, can be massive, impacting many miles of land, and crossing numerous political jurisdictions. In its report, the E-TAC noted that, "transmission lines are difficult to site because they impact multiple property owners, are aesthetically objectionable, impact public lands and waters, and contribute to alteration of habitats." A pre-application collaborative process could identify and resolve complicated issues involved in siting these important infrastructure facilities. This collaborative process should lead to less controversial and faster administrative processing of the application ultimately filed with the DEP. The DEP should consider incorporating incentives, such as streamlined processing, into its siting procedures, or recommending statutory changes, if necessary, to encourage applicants to undertake collaborative processes.

STRATEGY

Encourage efficient use and reuse of water in the production of electricity.

TASKS

- Ensure that Florida's limited water resources are used wisely.
- The DEP, water management districts, and other agencies with jurisdiction over water resources should continue to consider and encourage innovative ways to reuse water.

Water Impacts

The process of generating electric power requires considerable quantities of water. In a state with limited amounts of potable drinking water, the permitting of power plants must consider any new plant's impact on water supplies. The PPSA requires this consideration along with consideration of all other environmental impacts. The permitting of power plants outside the PPSA does not provide a simultaneous, comprehensive process of environmental review by all the relevant agencies that allows for the true balancing of the public interests with respect to water use. Permit conflicts can arise because of water availability issues. For example, the DEP air permitting process may require use of high quality water for control of air pollutants while water management district policies require use of the lowest quality water available. There are also environmental constraints on where cooling water can be obtained and where heated cooling water discharges can occur. Finally, the diverse water management districts have different approaches to the use of fresh water versus marine water for cooling.

The DEP, supported by the Siting Board, has encouraged utilities to use water reclaimed from domestic sewage treatment plants as a primary cooling water source and, in some instances, for internal process uses as well. Similarly, water has been conserved and the discharge of power plant waste waters has been limited or eliminated by the use of advanced brine concentrators, evaporators, and crystallizer systems. Recent coordination of efforts by the DEP, the St. Johns River Water Management District, Orange County, and the Orlando Utilities Commission has resulted in a proposal to capture stormwater from the Orange County solid-waste landfill and use it in the adjacent Stanton Energy Center in lieu of additional ground water. Not only is potable ground water conserved, but a nutrient-rich stormwater discharge to an Outstanding Florida Water, the Econlockhatchee River, is eliminated.

To ensure that Florida's limited water resources are used wisely, the DEP, water management districts and other agencies with jurisdiction over water resources should continue to consider and encourage innovative ways to reuse water. Water policy with respect to the permitting of power plants needs to be reviewed in light of water shortages statewide, and criteria need to be clarified as to power plants.

E PREPARING FLORIDA FOR NEW TECHNOLOGIES AND RENEWABLES

The Goal

Florida will be a leader in encouraging the future growth and development of next-generation energy technologies and renewable sources of energy.

Objectives

E-1 Renewable resources make up a portion of the state's energy resources, including resources of load-serving utilities used in satisfying customers' demand for electricity, as well as customer-owned applications.

E-2 Consumers have options for cost-effective self-generation, such as micro-turbines, fuel cells and high-efficiency cogeneration.

E-3 New technologies in power electronics and superconductivity should be applied to the transmission grid to achieve the ability to control actively the flow of energy and gain greater efficiency out of existing infrastructure and right-of-way corridors.

Industry Trends

The electric industry has seen dramatic changes in the way electricity has been produced over the last few years. For example, the coupling of jet engine technology with traditional steam recovery boilers has led to a new generation of highly efficient combined-cycle and combustion turbine power plants with impressively clean emission profiles. With respect to coal, Florida has a state-of-the-art clean coal power plant whereby coal is converted to a gas and used in a combined-cycle plant. New digital technologies have allowed greater electric throughput over existing lines with greater stability and better system control. The Study Commission anticipates continued development in these traditional generation and transmission sectors.

In addition, the electric industry has also been progressive in less traditional areas of generation and transmission. Over the past few decades, a wide range of new sustainable power generation technologies have emerged, including both clean renewables and other low-emission or highly efficient generation options. These include:

- Cleaner renewable fuels, such as solar, wind, and sustainable forms of bio-energy such as biomass derived fuel and waste-to-energy generation plants,

- Near-zero pollution generation techniques such as fuel cells or power plants running on hydrogen fuels made from fossil fuels where carbon byproducts have been sequestered, and

- Superconducting transmission lines that have the potential for five-fold increases in electric throughput.

Most of these emerging technologies are not yet cost-competitive with traditional forms of electric production. Increased emphasis should be placed on funding research to enhance the ultimate chances of commercial deployment of these resources. Fuel cell development, for example, is heavily supported by the automobile industry looking for the next generation automobile engine. To support emerging technologies, Florida should encourage investment in energy efficiency programs that will accelerate commercialization of the cleanest technologies, including solar and hydrogen-based technologies. Furthermore, Florida must be active at the federal level in encouraging investment in alternative energy resources.

The development path of technology is not always predictable and the ultimate arbiter of the winners and losers is the market place. Technologies once viewed as promising often fail to achieve widespread adoption due to unresolved technical issues, failure of consumers to embrace the technology, or failure to meet cost or performance objectives that make them competitive with alternatives. Because of the dynamics of technological change, it is very difficult for government, with its obligation to protect the public purse, to identify successfully which of the competing industries and industry technologies should be awarded financial support.

STRATEGY

Encourage development and use of renewables.

TASKS

- ♦ The PSC should conduct a study to identify the current level of renewables and prescribe a cost-effective level of new resources.
- ♦ The PSC should have the authority to require a portion of utilities' resources to be from renewable sources available within Florida, including solar, biomass, and waste-to-energy.
- ♦ The PSC should continue to encourage utilities to offer or expand "green pricing" programs.

The development of a Sustainable Portfolio Standard (SPS) would logically have two components. First, a feasibility and evaluation analysis should be undertaken to identify those technologies with near-term commercial application. Since practical deployment of some of these technologies is much further away in time, some type of technical feasibility that includes timeliness, operational characteristics, and contribution to reliability should be undertaken. Upon completion of the feasibility and evaluation study, Florida should implement a SPS to ensure Florida harnesses sustainable generation technologies. Such a program will stimulate a Florida sustainable energy industry. This action will result in funding for, and thereby hasten the deployment of, sustainable energy generation technologies. However, to minimize adverse rate impacts on consumers, formal requests for proposals should be solicited or alternative technology bidding systems should be implemented to allow selection of those sustainable technologies that minimize the acquisition and operation costs of the project. By definition, these resources would not normally be constructed in either a competitive or regulated environment because they do not meet the least-cost resource acquisition standard. Since any SPS will increase electric costs above the level of costs created in a non-SPS mandate, careful analysis should be given to both the level and type of resource that is mandated.

Clean Renewables

Renewable resources are available as input factors in both distributed and central power generators. Such resources include naturally recurring supplies such as sunlight, wind, water, geothermal deposits, and biomass derived fuels. Unfortunately, Florida does not have much potential as a wind area, nor does its geology contain geothermal deposits that can be tapped for power production. Indeed, except for two very small dams in the panhandle, Florida has no potential for traditional hydro power development. However, some preliminary work is being done to explore the possibility of using ocean thermal currents as a driver of generator turbines. When the menu of traditional renewable resources is examined, only solar energy and biomass-derived fuels (bio-energy) are currently viable in Florida or offer the possibility of providing meaningful amounts of electricity in the near term.

Solar energy is clearly Florida's most abundant and cleanest renewable energy supply. Unlike bio-energy, it does not have the potential to produce CO_2 and other harmful emissions. Two major solar power technologies are water heating and photovoltaics (PV).

Solar pool and water heating are viable technologies in widespread use today. A survey conducted over ten years ago indicated more than 250,000 solar hot water systems were installed in Florida. There are an estimated 5,000 new installations of solar water heating per year. For certain specific applications, including pool heating, solar water heating is a cost-effective alternative to traditional water heating technologies. The technology has had difficulty, though, in achieving an even greater share of the market because of its higher initial equipment cost and relatively long payback periods with respect to electric savings.

The other solar technology, photovoltaics, are silicon cells treated with special additives that have the ability to take sunlight and split off electrons to produce direct-current electricity. This DC current passes through an electrical converter where it is converted to 60-cycle alternating current (AC) power. The life-cycle cost of electricity from PV at today's installed cost of $7 per peak watt is $0.22/KWH, according to Dr. David Block of the Florida Solar Energy Center. The U.S. Department of Energy, which invests $76 million/year in PV, has set goals of reducing PV cost to $3 per peak watt by 2010, and $1.50 per peak watt by 2020, and improving the system reliability and lifetimes of these systems. New PV manufacturing technologies have shown potential to meet these cost reductions.

Less than half of one percent of Florida's energy service needs are currently met by solar energy. The "Sunshine State" has potential for generating pollution-free and renewable energy. Solar energy costs will decrease with continued technological improvements and increase in market acceptance, which will lead to lower per-unit installation and infrastructure costs.

Bio-Energy

Bio-energy, or energy derived from plant material, is used for combustion in generating plants. Technologies being developed include gasification and production of energy fuels from crops. Bio-energy projects emit pollutants, including CO_2. Some projects, such as burning harvested trees, are clearly "unsustainable" and may cause more harm than good. Other projects, such as landfill methane recovery, are sustainable only under certain circumstances. Bio-energy involves tradeoffs that merit evaluation in assessing sustainability. Bio-energy is a carbon-neutral energy resource but may pose other risks.

Solid Waste Energy Sources

One existing generation technology currently making a contribution to Florida's generating fleet is municipal solid waste generation. Florida currently has some 362 MWs of firm committed capacity from municipal solid waste generators under contract to the utilities. These contracts were entered into as a result of the requirements of the Public Utilities Regulatory Policy Act (PURPA) of 1978. This federal act requires incumbent utilities to purchase energy and capacity from qualified facilities at full avoided costs. Qualified facilities include plants such as industrial cogenerators, small power producers that use renewable energy, and waste-to-energy plants. There are several bills in Congress that would prospectively repeal PURPA.

Because of limited waste disposal sites and issues related to water table levels, solid waste refuse generation has been one alternative for municipalities to deal with land-filling their solid waste. Moreover, current EPA emission standards require ever stricter emission profiles for refuse generators. To the extent that urban population concentrations continue to produce solid waste streams, this technology can be viewed as a sustainable resource, albeit with its own set of permitting and siting issues.

Brightstar Solid Waste Management and Combustion Process

Brightstar Environmental, an Australian-based company, has created an entirely new solid waste management and combustion process. Brightstar has developed a fully integrated, solid waste energy and recycling system (SWERF). Using a gasification methodology, SWERF allows up to 20% of the waste stream to be recovered and recycled, 70% is converted to electric power, and the remaining 10% requires further processing. This technology is also compatible with existing collection practices.

Sustainability of Resources

Florida presently has waste-to-energy and biomass fueled generation projects in the state's generation mix. While several projects are operational, the amount of existing photovoltaic electric production is insignificant. Moreover, some believe that some of the state's biomass and biogas options may not be sustainable. Bio-energy projects can raise environmental concerns since they involve both pollution from combustion of plant matter (including carbon dioxide) and consumption of natural resources. Some projects, such as burning trees from ecologically valuable or publicly-owned forests to make electricity, are clearly "unsustainable" and do not merit public policy support.

Waste-to-energy generation is a demonstrative technology with identifiable public benefits and is sustainable as long as waste streams are produced. With the possibility of repeal of PURPA, public benefit funding may be necessary to continue to support these projects based on the additional public benefits associated with this technology. Waste-to-energy facilities are valuable in Florida because they reduce waste volumes disposed of in expensive sanitary landfills and by protecting Florida's water supplies.

Other Florida bio-energy resources such as landfill methane recovery may be considered sustainable under certain circumstances. Bio-energy projects involve tradeoffs that merit evaluation in assessing sustainability. Such assessment must weigh the environmental impacts of both the bio-energy project itself and of any electrical generation that project may displace.

Funding for Sustainable Generation Technologies

Florida Photovoltaic Buildings Program Rebates

Florida residential and commercial building owners who choose to install solar photovoltaic (PV) equipment that is connected to their local utility grid may qualify for Florida Solar Energy Center's PV rebate. The Florida Energy Office/Department of Community Affairs has provided this program with $525,000 to fund these rebates. Funds will be available through March 31, 2002 or until they are depleted, whichever occurs first.

Residential applicants can receive up to $16,000 per system at the rate of $4 per installed Watt. Builders and developers are eligible for an additional incentive of $2,000 for installing PV systems on model homes. Commercial applicants can receive up to $40,000 per system at the rate of $4 per installed Watt. All public and educational facilities fall under the commercial portion of the program.

One of the recurring issues with developing technologies is the role of public funding in both the research, development, and commercialization stages of the technology. There are a variety of public funding sources including general appropriations, federal grants, and dedicated funding sources, such as trust funds. A number of states are using public benefit funds to conduct research and development on clean energy technologies such as photovoltaics, coal, and hydrogen fuel cells. The funds also support rebate programs where customers can apply for a rebate to cover a portion of the purchase cost of a photovoltaic system. States are using the funds to conduct studies that identify market barriers to clean energy technologies and formulate strategies for removing the barriers. The funds are also supporting efforts to educate the public about the benefits of clean energy technologies.

Sustainable generation technologies may come to the market more slowly without a public subsidy designed to stimulate innovation and deployment of energy technologies that will most economically yield significant pollution reductions. Investments targeted toward transforming markets for near-zero pollution energy technologies, including both clean fuels and highly efficient generation systems, could yield significant benefits. Solar also would benefit through this type of "buy down." Consideration could also be given for use of such funds for a private/public partnership to begin implementation of superconducting technologies.

Including Sustainable Generation Technologies in Florida's Energy Portfolio

Ten states, including Texas, Arizona, and New York, have adopted a renewable portfolio standard to increase renewable energy capacity. This standard requires retail electricity providers to generate or purchase a specific percentage of their electric capacity from new renewable energy sources. By using "tradable renewable energy credits" to achieve compliance at the lowest cost, such a portfolio standard could function much like the Clean Air Act emission allowance trading system, which permits lower-cost, market-based compliance with air pollution regulations.

These sustainable energy technologies constitute an SPS. An SPS, combined with stringent pollution emission standards for qualifying technologies, is a valuable way to harness market forces to encourage innovation and stimulate reductions in production costs of both commercial and pre-commercial sustainable energy generation technologies. SPS programs are designed to encourage the deployment of new technologies that would not compete on cost-effectiveness with traditional technologies. Nonetheless, public entities may want to fund certain technologies like solar energy or waste-to-energy plants because of other desirable attributes, such as cleaner emission profiles or their contribution to other public purposes. A well-designed SPS could create powerful economic incentives to transform markets for sustainable energy technologies and foster significant pollution reductions.

Green Pricing

Another way to encourage the early deployment of renewable and other sustainable generation resources is by way of voluntary "green pricing" programs. This market and customer-driven strategy offers customers the option to pay a premium for their electric service to purchase qualified renewable and clean energy. Under green pricing programs, utilities purchase electricity from qualified renewable and clean energy suppliers or install such systems themselves. Customers may then elect to pay for some portion of their monthly electric needs from these green resources. Just as some customers in the grocery store prefer to purchase "green" products, the electric industry can offer similar choices.

Utilities around the country have extensive experience with green pricing strategies. Florida utilities have begun to explore how to structure and market green pricing options to their customers. For example, Tampa Electric Company offers 50 KW blocks of green energy to its customers. The energy is generated from either a recently-installed 18 KW photovoltaic array or existing steam generating facilities capable of co-firing coal and biomass. The customer is charged $5.00 for each block of energy. As of April 2001, TECO has signed up 113 residential customers to its green pricing program. Some utilities are using a voluntary check-off system, whereby customers make a contribution each month to the utilities' direct purchase of green power, which is integrated into the total fuel mix of the utility. Regardless of the strategy adopted, voluntary green pricing offers a direct customer choice strategy to encourage these energy sources while avoiding some of the conflict over cost and rate impacts of the utilities being forced to purchase higher-cost renewable or other clean energy resources.

For the reasons noted above, the Study Commission believes the PSC should continue to encourage utilities over which it has retail rate authority to adopt or expand green pricing programs.

S T R A T E G Y

Reduce barriers to distributed resources.

T A S K

- Require the PSC to investigate ways of reducing barriers to distributed resources, such as micro-turbines, fuel cells, and high-efficiency cogeneration, including the adoption of interconnection standards.

Connectivity for Distributed Generation

Electricity customers in Florida who want to install smaller, site-specific power generators, such as photovoltaic systems, micro-turbines, or fuel cells face some regulatory and engineering obstacles if they desire to operate in parallel with their native utility. Collectively, such devices are often referred to as distributed generators, or simply DG. These distribution-side generators have impacts on system reliability, power quality, and can create some safety issues. Therefore, it is necessary that the appropriate safety and interconnection issues be resolved to encourage the safe deployment of DG while ensuring no adverse impact on reliability or safety. In addition, regulatory issues dealing with metering and rate impacts must be addressed for excess electricity to be sold from those systems back to the host utility.

For customers who want to operate in parallel with the host utility, Florida permits DG systems to interconnect under the PSC's cogeneration rules. DG technology did not exist, however, when the cogeneration rules were adopted. The rules were originally designed to accommodate the interconnection of large, multi-megawatt power plants, and did not consider DG technology. Therefore, the interconnection standards in the cogeneration rules act as an obstacle for smaller systems. DG systems are evaluated on a case-by-case basis or under the same standards as large industrial power generators. The additional financial and administrative barriers severely hinder a home or business owner's ability to interconnect smaller DG systems, such as a solar photovoltaic (PV) system to the grid. Customers interested in installing these systems rarely have the resources to overcome these barriers.

Many states have moved to minimize these barriers so that customers who want to install small DG systems do not face the same complex regulatory and technical requirements as larger industrial power generators. These states have addressed the problem by adopting uniform and streamlined interconnection standards and net metering for small clean energy systems. Currently, 36 states provide net metering for small renewable energy systems, and 18 states have established a uniform interconnection standard for renewable energy systems 10 kilowatts and smaller. With uniform connection standards in place, small-system owners no longer face the need to evaluate and settle many complex, technical, contractual, rate and metering issues on a case-by-case basis with the electric utility, and permitting authorities before the system is connected to the utility grid.

On October 2, 2001, the PSC proposed new rules that would facilitate and simplify the interconnection process for solar photovoltaic systems below 10 KW output (Docket No. 010982-EI). The proposed rules would permit these smaller systems to interconnect with very modest insurance requirements, allow parallel operation if the equipment meets agreed upon national standards, and imposes no additional metering costs for customers who wish to install solar PV systems. In addition, the rule gives utilities the option of whether to net meter. Net metering is a billing formula that permits the solar owner to get credit for any power supplied to the utility at retail rates instead of at wholesale rates. While net metering does reduce the cost of installing, reading and billing a second meter, it may not provide the proper price signals to the consumer to sell surplus power, and it may create revenue losses that may be recovered from other customers.

In the future, additional issues of interconnection will arise with respect to larger mechanical equipment distributed generators. With larger machines and the associated electric output, the issues surrounding power quality, distribution reliability, safety, and billing become increasingly complex. These are not trivial issues, but must be addressed in a timely and predictable manner that provides consistent regulatory requirements so as to encourage the increased use of distributed generation.

Florida should continue to remove connectivity barriers by moving forward to examine steps that can be taken to encourage and simplify interconnection of distributed generators. Interconnection requirements should be standardized and metering and billing costs should be equitably allocated between the distribution utility and the customer who is installing distributed generation.

STRATEGY

Encourage development and application of new technologies to increase the efficiency of the transmission system.

TASK

- Encourage public and private research organizations to investigate and support development and application of new technologies.

Advanced Transmission and Energy Management Technologies

Traditionally, transmission and distribution (T&D) systems have been controlled via electro-mechanical devices such as breakers and switches, which are too slow to respond in real-time to a vastly more complex and heavily used grid. Under the auspices of the Electric Power Research Institute (EPRI), great progress has been made to improve existing T&D systems. EPRI has visioned a Technology Roadmap that will lead to a more reliable transmission and distribution system through the use of power electronics, including digital controls, thryristors, and other advanced control technologies. For example, high voltage FACTS (Flexible AC Transmission System) controls have already been deployed on a number of utility systems and frequently represent a simpler, cheaper alternative to siting and constructing high-voltage transmission lines.

In the medium term, superconductivity offers even greater possibilities for transmission improvements. Superconductivity is the ability of certain materials to conduct electrical current with no resistance and extremely low losses. High-temperature superconductivity technologies could be critical to solving transmission bottlenecks, system gridlock and power reliability, since superconducting cables could carry three to five times more power than conventional cables using the same amount of space. About seven percent of electricity is lost in transmission, thus not only could the implementation of superconducting technology prove desirable to increase capacity of transmission rights of way, it could also “provide” energy through efficiency. There are other applications of this technology including transformers, motors and generators.

The Study Commission has been made aware of a number of university-based programs that would assist state government, regulators, local governments, utilities and business entities in responding to the issues of planning and developing the electric power infrastructure for the state. The Study Commission believes that these types of programs, whether offered by public or private institutions, could provide ideal mechanisms to support the development and application of new electric infrastructure technologies. These programs would provide facilities and forums for bringing independent technical, business, public policy and planning expertise together in a single program. Moreover, such programs can leverage financial support from a variety of sources, both private and governmental to support these research and development initiatives.

STRATEGY

Mitigate, to the extent possible, labor force dislocations associated with new technologies and industry conditions.

TASK

- Encourage job retraining programs by regulated utilities and by electricity producers.

Both demand growth and the application of new technologies are likely to lead to an expansion of jobs in the energy industry over the next two decades. These are positive developments from the standpoint of those currently employed in the electricity sector. However, during any transition, changes in job descriptions and in the location of economic activity might lead to labor force dislocations. The Study Commission is sensitive to the concern that adjustments could fall disproportionately upon those currently in the electricity sector work force. The Study Commission encourages firms and educational institutions to offer job retraining programs that would facilitate adjustments to changing technologies and market conditions.

EXECUTIVE ORDER NUMBER 00-127

WHEREAS, it is in the best interest of the People of the State of Florida to ensure for all Floridians an adequate, reliable, and affordable supply of electricity, and

WHEREAS, the location, construction, operation, and decommissioning of electrical power plants may have a significant impact on the welfare of the state's residents, on the natural resources of the state, and on the location and growth of industry, and

WHEREAS, Florida's population is expected to double over the next three decades, with commensurate increases in demand for electricity, and

WHEREAS, it is in the best interest of the people of Florida to promote energy conservation measures and the development of alternate and reasonable supplies of electricity,

NOW, THEREFORE, I, Jeb Bush, as Governor of the State of Florida, by virtue of the authority vested in me by the Constitution and the laws of Florida, do hereby authorize, order and direct that the Energy 2020 Study Commission be created, with membership, term of service, compensation, staff, and scope of inquiry, as follows:

1. The Commission shall be composed of 17 members, 13 of whom are to be appointed by the Governor, 2 of whom are to be appointed by the President of the Senate, and 2 of whom are to be appointed by the Speaker of the House of Representatives. In addition, the Chairman of the Florida Public Service Commission and the Public Counsel shall serve as non-voting members.

2. The appointments must be made by July 17, 2000, and the first meeting of the Commission shall be held in September, 2000. The Chairman of the Commission shall be appointed by the Governor. Any vacancy occurring in the membership of the Commission is to be filled in the same manner as the original appointment.

3. Each member of the Commission is entitled to one vote, and action of the Commission is not binding unless taken by a majority vote of the entire membership of the Commission.

4. The Commission shall determine what Florida's electric energy needs will be over the next 20 years and how best to supply those needs in an efficient, affordable, and reliable manner that will ensure adequate electric reserves. Based on its findings, the Commission shall recommend appropriate electric energy policies for this state, including statutory changes, if necessary. In making its determinations, the Commission shall consider all relevant topics, including, but not limited to:

   a. Forecasts through the year 2020 of Florida's population growth, electricity needs and supply, and the expected diversity of fuels and their sources for use in the state;

   b. Current and future reliability of electric supply within and into the state;

   c. Current and future reliability of the natural gas supply into and within the state;

d. Emerging and projected electric technologies and electric supplies, including solar energy, renewable energy, and distributed generation technologies, their potential contribution to reliable electric supplies, and their impact upon the state, its environment, and its electric policies;

e. The experience and impacts upon electricity consumers, generators, and transmitters of all kinds from recent changes in governmental regulation of the electric utility industry in other states;

f. Analysis of the impacts of state and local government taxes on government revenues and the electricity supply;

g. Universal access to electricity and the responsibility to provide it;

h. Stranded investment costs;

i. Functional unbundling; or the separation of electricity production, transmission, and distribution services;

j. Impact of restructuring on service to low-income, elderly, and rural consumers;

k. Renewable energy, energy conservation, and energy efficiency technologies and programs, and the impact of restructuring on the same;

l. Impact of restructuring on economic development and growth in the state, including potential impact on tourism, agriculture, small businesses, and industry in the state;

m. Impact of restructuring on investor-owned electric utilities, municipal electric utilities, rural electric cooperatives, and independent power producers;

n. Prevention of anticompetitive or unlawful discriminatory conduct or the unlawful exercise of market power by electricity providers;

o. Environmental impact of electricity supply production, generation, and transmission in the state; and

p. Impact of restructuring on the current and future electric utility workforce.

5. The Commission shall, by December 1, 2001, provide to the President of the Senate, the Speaker of the House of Representatives, and the Governor a written report containing specific recommendations for electric energy policies for this state, including legislative recommendations.

6. The Commission may establish and appoint any necessary technical advisory committees. Commission members, and the members of any technical advisory committee may not receive remuneration for their services, but members other than public officers and employees shall be entitled to be reimbursed by the Florida Public Service Commission for travel or per diem

expenses in accordance with chapter 112, Florida Statutes. Public officers and employees shall be reimbursed by their respective agencies in accordance with chapter 112, Florida Statutes.

7. The Governor shall select an executive director and the executive director serves at the pleasure of the Governor. The Florida Public Service Commission, the Department of Environmental Protection, and the Department of Community Affairs shall provide other staff and consultants, after consultation with the Commission. Funding for these expenses will be provided through the Florida Public Service Commission.

8. All agencies under the control of the Governor are directed, and all other agencies are requested, to render assistance and cooperation to the Commission.

9. The Commission shall continue in existence until its objectives are achieved, but not later than December 1, 2001.

10. The Florida Public Service Commission shall provide all funds necessary to implement the provisions of this Executive Order.

IN TESTIMONY WHEREOF, I have hereunto set my hand and have caused the Great Seal of the State of Florida to be affixed at Tallahassee, The Capitol, this 3rd day of May, 2000.

POLICY

Use of Natural Resource Lands by Linear Facilities as Approved by the Board of Trustees of the Internal Improvement Trust Fund

(A) Purpose and Scope.

(1) This policy applies only to linear facilities, including electric transmission and distribution facilities, telecommunications transmission and distribution facilities, public transportation corridors, and related appurtenances.

(2) While it is appropriate to discourage and prohibit most kinds of intrusions on natural resource lands, the Trustees recognize that the expanding ownership of lands by the state and the need to provide services to a growing population through linear facilities and related appurtenances will from time to time require crossings and location on such lands. The goal of the policy is to avoid and minimize conflicts between the acquisition and management of natural resource lands for conservation, recreation, and preservation and activities necessary for the construction, operation and maintenance of linear facilities and related appurtenances.

(B) Definitions.

(1) "Natural Resources" include but are not limited to wetlands, lakes, rivers, streams, estuaries and other surface and ground water resources, flora, fauna, fish and wildlife, natural communities, historical and archaeological resources, scenic vistas and aesthetic values.

(2) "Natural Resource Lands" are those lands owned by the Trustees and which : were acquired with funds from the P2000 or Save Our Coast Bond Program; or were acquired with funds from the CARL or LATF Trust Fund; or are managed for natural resources by the Division of Recreation and Parks, Division of Marine Resources, Game and Fresh Water Fish Commission, Division of Forestry, or Secretary of State.

(3) "Related Appurtenances" include those support facilities necessary to the operation of linear facilities. (Examples include but are not limited to sub-stations and pump-stations.)

(4) "Trustees" means the Board of Trustees of the Internal Improvement Trust Fund

(C) Avoidance.

Owners and operators of linear facilities must avoid locating on natural resource lands unless no other practical and prudent alternative is available and all steps to minimize impacts as set forth below are implemented. The test of practicality and prudence will compare the social, economic, and environmental effects of the alternatives.

(D) Minimizing Impacts.

Applicants must minimize adverse impacts to natural resource lands through reasonable measures where applicable: locating the project in areas where less adverse impacts are expected, such as areas which have already been impacted and are less sensitive than other areas; avoiding significant wildlife habitats, natural aquatic areas, wetlands, or other valuable natural resources; selecting areas to minimize damage to existing aesthetically-pleasing features of the lands; employing best management practices in construction and operation activities; designing access roads and site preparation to avoid interference with hydrologic conditions that benefit natural resources and reduce impacts on other natural resources and public use and enjoyment, and; generally selecting areas that will not increase undesirable human activities on the natural resource lands; and generally, not adversely impacting the management of such lands. However, human activities may be encouraged where linear facility corridors are designated as part of a greenway or trail.

(E) Compensation.

(1) The applicant will pay the Trustees an amount not to exceed the fair market value of the interest acquired in the parcel on which the linear facility and related appurtenances will be located.

(2) In addition to the amount in (E)(1) above, the applicant will provide to the managing agency that measure of additional money, land, or services necessary to offset the actual adverse impacts reasonably expected to be caused by the construction, operation and maintenance of the linear facility and related appurtenances. Such impact compensation will be calculated from the land managing agency's timely presentation of documentation costs which will result from the impacts of the proposed project.

Approved January 23, 1996

ACKNOWLEDGMENTS

Many individuals volunteered their time and expertise to the Florida Energy 2020 Study Commission, for which we are deeply grateful.

Wholesale Market Restructuring Technical Advisory Committee
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Rich Cowart, Regulatory Assistance Project
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Environmental Technical Advisory Committee
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Darrel Graziani, Air Permitting Supervisor, Palm Beach County Health Department
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Task Force on Stranded Investment
Joseph K. Tannehill, Chairman
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The following individuals made formal presentations to the Study Commission:
Jim Alves, Hopping, Green, Sams and Smith
Tom Ballinger, Florida Public Service Commission
David Block, Florida Solar Energy Center
Jack Boatman, Florida Gas Transmission Company
Travis Bowden, Gulf Power Company
Fred Bryant, Florida Municipal Power Authority
Brenda Buchan, Florida Public Service Commission
Shelton Cannon, Federal Energy Regulatory Commission
Ralph Cavanagh, Natural Resources Defense Council
Susan F. Clark, Katz, Kutter, Haigler, Alderman, Bryant & Yon
Armand Cohen, Clean Air Task Force
Gus Colessides, Williams Energy Services
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continued

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Mike Green, Duke Energy North America
Jack Halpern, Post Buckley Schuh & Jernigan (PBS&J)
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Angie Howard, Nuclear Energy Institute (NEI)
Dwight Jenkins, St. Johns Water Management District
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William Johnson, Progress Energy
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Alexander Mack, Florida Department of Community Affairs
Cynthia Marlette, Federal Energy Regulatory Commission
Steve Mayberry, Enterprise Florida
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John McWhirter, Florida Industrial Power Users Group
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Barry Moline, Florida Municipal Electric Association
Mike Naeve, Skadden, Arps, Slate, Meagher & Flom
Margaret Neyman, Gulf Power Company
Mike Oldak, Edison Electric Institute
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David C. Weaver, El Paso Corporation
Joe Wharton, Brattle Group
Ken Wiley, Florida Reliability Coordinating Council
Bill Willingham, Florida Electric Cooperative Association
Mark Wolfe, Energy Program Consortium
The Honorable Pat Wood, III, Chairman, Public Utility Commission of Texas
Tim Woodbury, Seminole Electric Cooperative
Mary Jean Yon, Florida Department of Environmental Protection

BARICE, C.J., DISSENTING

The charge of the Governor to this Study Commission was to think outside of the box, forward 20 years into Florida's future, and not to worry about consensus with the utilities. That would be left to the politicians for another day.[1] At the very core of an energy policy for this great and beautiful state must lie strong protection for our residents, their health, quality of life, and for our environment. The importance of this in a state with an economy dominated by tourism and a housing industry which sells a high percentage of its products to retirees who choose to move here, is hard to overemphasize. The Final Report of this Study Commission covers well a panoply of topics, but when it comes to the protection of our residents' health and our environment, it is thin to the point of transparency.

We have learned much from the pitfalls of other states' deregulation activities. None have enjoyed stellar success, and some have suffered that which we trust Florida will avoid, especially soaring rates and brownouts. Some states have attempted to reverse deregulation, but have not yet found a way to put the genie back in the bottle. That is why I believe we must move cautiously when it comes to divestiture of generating plants. The Final Report would allow utilities to divest themselves of all of their generating plants the day after the legislation passes. Divestiture would be at the sole discretion of the utilities. The plants may be transferred to sister companies at book value, a bargain price. This is the ransom the Study Commission pays for consensus with the utilities to allow merchants into the state.

Once the generating plants are transferred, the state would be largely powerless to correct abuses. We would have to rely on the federal government to do that. The federal government admits that it is not prepared to deal with many foreseeable issues. What little federal oversight exists has not served to prevent sharply higher energy prices from harming consumers, or averted deregulation-related electric energy shortages in some other states.

I do not believe that automatic divestiture of the generating plants at the sole discretion of investor-owned utilities (IOUs) is in the best interests of the residents of the State of Florida. I do not believe that transfer at book value is in the best interest of the residents of the State of Florida. All Florida residents who pay their power bill to an IOU have invested a portion of their electric bills every month, for years and years, to pay for the construction and renovation of these plants. Florida residents have a monetary interest in these plants. The State of Florida has a fiduciary interest in assuring a reliable fleet of plants capable of producing electricity at reasonable rates.

A number of issues need to be addressed before the plants are transferred beyond state control. I do not believe the mere possibility of an unspecified return to the ratepayers of a portion of the profits, if a sale occurs within six years of the date of the legislation, protects the interests of the residents of Florida. Utilities can be expected to sell off the winners (low-cost units) and keep the losers (high-cost units) in the rate base. It is, also, plainly obvious that, should an IOU anticipate a major profit, sales will simply occur in six years and one day, thus depriving ratepayers of a return on their investment.

A more stable, gradual approach would be to leave existing generating plants in the rate base, and to allow all new plants, including those of merchants, to be constructed and compete in the wholesale

[1] Address of Govenor Jeb Bush to Commission, September 13, 2000.

market. Florida's IOU have historically enjoyed a protected rate of return which the Public Service Commission has allowed to be passed on to the residents through their electric bills. The utilities would continue to enjoy the same high rate of return on these existing plants, and Florida's residents would receive the benefit of their bargain. The utilities would, also, compete in the wholesale market with new plants, and enjoy whatever rate is yielded by that market. The IOU's reject this approach, in favor of an all or nothing proposition, which presumably will yield them a higher rate of return. But I, for one, am less interested in consensus with them than in what is best for the residents of Florida.

A less gradual, approach, but one which would allow for careful deliberation, would be for the utility that proposes to transfer generating plants to first demonstrate to the Public Service Commission that consumers will benefit in the short and long term from the transfer. If a low-book-value plant remains in the rate base and is sold, the consumers would receive ALL of the proceeds through rate reductions or rebates. If, however, this same plant were transferred out of the rate base and then sold after the arbitrary six year cut-off proposed in the Final Report, the utility would keep all of the proceeds, and the consumers left with none.

In my view the test for divestiture should be this: The PSC should approve divestiture of generating plants if it determines that consumers will benefit from the transfer. Our Study Commission has moved from an "in the public interest test" through a test that requires "consumers are not harmed," to recommendations which now provide for divestiture with no test at all. Lower pricing may or may not develop under this scheme. Market power is the ability of a plant or group of plants to profitably control the price of power. Once a plant is transferred out of the regulated rate base, the people of Florida will have lost control, likely forever.

While the Final Report recommends giving the Public Service Commission authority to petition the federal government where there is market power abuse, I would respectfully suggest that this frail tool is too little, too late. The time to ensure that the market will be truly competitive, and not simply gamed by one or a few market players, is before the power plants are unleashed from regulation by the Public Service Commission.

The other item of great concern, spanning over the next 20 years of Florida's horizon, is protection of Florida's fragile environment. We have, surprisingly, learned from the experts that a large percentage of the power plants in this state are "grandfathered" and do not have to meet existing regulations designed to protect our air quality through implementation of modern control technology. We have learned of considerable premature deaths and respiratory illnesses caused by power plant emissions. We have learned that power plants emit greenhouse gases that are attributable to respiratory illnesses, rise in sea levels and a threat to the Everglades ecosystem. We have learned that, while Florida's utilities do a good job with energy efficiency, there are a lot of opportunities available for improvement and for development of clean technologies. We received reports and recommendations from the Environmental Technical Advisory Committee (E-TAC) and from the Public Benefits Technical Advisory Committee. I regret that the good advice of these experts has been largely ignored in our Final Report. In fact, portions of the report, as it now stands, have been characterized as a "step backward" by the Chair of the E-TAC Victoria Tschinkel, a former Secretary of the State's leading environmental agency. [2]

[2] Letter of Victoria Tschinkel to Walter L. Revell, October 30, 2001.

Florida's environment is too important to stipulate that its protection must be "cost effective" without carefully defining what that means both for the environment and consumers. And, indeed, what does that mean? How many lives must be lost, coral reefs destroyed, incapacitating respiratory illnesses suffered, to justify the cost of best available technology or the development of renewable technologies? Given the choice, and the vulnerability of the increasing population of elderly in our state, I believe Florida residents would opt for cleaner air and cleaner energy, even at a premium.

The State should, consistent with the ETAC Report, establish an emission reduction program to take the place of the existing grandfathering provisions of the air quality standards for Florida's older power plants. All generating units should be required to periodically update their air quality control systems, with incentives to the utilities for environmental benefits. The state should develop and deploy technologies and emissions cap and trade programs to reduce greenhouse gases.

The recommendations of this Study Commission do not place the same value on efficiency or renewable kilowatts as they do on the construction of new power plants. By endorsing the RIM test, and business as usual, for investment in efficiency and renewables, the Final Report essentially forecloses low-cost, low-risk efficiency investments, while permitting higher-cost new construction alternatives which will increase customers rates and electric bills. The state should recognize that "the cheapest, easiest and fastest kilowatt we generate is the one we can save through efficiencies."[3] The state should join other states in establishing and funding a new entity for aggressive implementation of energy efficiency, sustainable distributed technologies and new or advanced technologies.

The Power Plant Siting Act has served Florida well. All one need do is to look around and see the recently constructed plants of all types, including numerous coal-burning facilities, to know that Florida is far ahead of most other states in assuring timely approval of electric energy facilities.

Recently, the Supreme Court of Florida pointed out a problem with the Siting Act that needs to be corrected so that merchant plants may be built to increase wholesale capacity. This is really quite a simple fix to include merchants as eligible applicants. In a sense, amending this Act to allow the entry of merchant plants is really all we need do to open the marketplace. But, unfortunately an attempt by this Study Commission to recommend that was reversed after intense opposition from the IOU's. The IOU's are willing to tolerate merchant plants and a free marketplace only after we pay their ransom. The ransom they demand is a clever deal to divest power plants to affiliate corporations at book value rather than true market value, and a set of recommendations from this Study Commission aimed at hobbling the protection of our state's precious environment and the health of our citizens by limiting environmental controls to only those which are "cost effective," without defining that term in an open public hearing process.

For these reasons, I must dissent.

[3] Address of Governor Jeb Bush, "Powering the Future Energy Conference", August 19, 2001

STEPHEN J. MITCHELL, CONCURRING

The final report by the Florida Energy 2020 Study Commission (Study Commission) submitted on December 7, 2001 (Final Report), is a report of immense and significant impact. It is a scholarly document that takes into account not only the complexities of the world of energy generation but, also, and more importantly, the practicalities of trying to effect a competitive and robust wholesale energy marketplace in an environment that has been adequately and competently served by existing utilities for over 100 years. Rather than recommend moving vigorously to a fully deregulated marketplace, the Study Commission recommends a very solid low-risk approach whereby the first step would be to expand and move into a competitive market at the wholesale level. The Report is a masterful recognition of the necessity of bringing all of the participants and potential participants in the wholesale energy market into a program that would ultimately lead to the primary goal of the Study Commission, which is to insure adequate, reliable and cost-effective energy for all residents of Florida through the year 2020.

After careful consideration of 15 months of testimony, review of reams of detailed technical material, input from the Study Commission's extremely competent technical advisory committees and the work of the Task Force on Stranded Investment, the Study Commission concluded that to effect and establish a competitive wholesale marketplace in Florida it is necessary to allow the investor-owned utilities to have an opportunity to participate along with the merchant power companies in the wholesale power market. Such competition would lead to great efficiency, innovation, and lower prices to all consumers. This goal was accomplished in the Final Report. It clearly sets forth a process that would allow Florida to move into a competitive wholesale market without falling into the morass and chasms that California did when it established its energy deregulation program.

To accomplish this transition in an effective and expeditious manner, it is important that a level playing field be developed so that the existing investor-owned utilities will be able to enter the wholesale marketplace on an even basis with the very competent merchant power companies that are desirous of developing and expanding their interests in the state. In attempting to develop a program that balances these very strong interests with the goal of insuring adequate, reliable and cost-effective service to consumers, the Study Commission proposes a system that would allow such participation on virtually an equal basis.

The underpinning of this program, and other programs the Study Commission considered, was the absolute requirement that the difficulties of the California effort not be replicated here. In the Report, as well as in the Interim Report filed on February 6, 2001, the Study Commission clearly developed a program that avoids any potential of experiencing the same problems that were experienced in California. From testimony provided by experts who have studied the California market, it was apparent that the underlying causes of California's problems were: (1) mandatory divestiture, (2) lack of capacity, (3) restriction to the "spot" market to acquire power, (4) single fuel source for power generation. While other issues were from time to time discussed, these four concepts were repeatedly described as being the underlying reasons for the debacle experienced in California.

To address the mandatory divestiture issue, the Study Commission endorses a "discretionary" transfer model that permits, but does not require, the transfer of existing generating assets to a competitive status and permits uncommitted merchant generators to independently seek siting approval of new generating capacity. Under the discretionary transfer approach, the investor-owned utilities are allowed to place their generating assets into a competitive wholesale status while new proposed rules address the current prohibition against merchant plants, thereby opening the wholesale market by allowing both the merchants and the investor-owned utilities to compete in the wholesale marketplace against each other.

The discretionary approach contemplates that a load-serving utility would transfer some or all of its generating plants to affiliates, or sell them to third-party purchasers. At the time of the transfers or sales, the generating facilities would be subject to six-year transition agreements whereby the power generated from the generating units would be sold back to the load-serving utility on a "cost basis." This initial transfer to an affiliate would be reviewed by the Federal Energy Regulatory Commission (FERC), pursuant to Section 203 of the Federal Power Act – FERC's merger statute. The PSC's retail rate jurisdiction would be invoked to insure that the transition contract is competitive and serves the best interest of consumers.

The Final Report further recommends that if the transition contract is terminated by the load-serving utility prior to six years, that such termination could be reviewed by the PSC to insure that it was terminated only on the basis that power could be purchased by the load-serving utility from another source at a price less than the "cost-based" price at which the affiliate was required to sell its power back to the load-serving utility. Obviously, the termination of such a contract would only be accomplished in the event that the generating facility is no longer efficient and cost-effective. Any value that the generating unit may have would be reduced to reflect such inefficiency.

When a generating facility previously transferred to an affiliate is sold by the affiliate to a third-party while the six-year transition contract is still in effect, any gain from such sale would be shared between the generating affiliate and consumers. The Study Commission determined that no less than 50% of any gains should be shared with the consumers. Any loss incurred by the generating affiliate would be absorbed by the shareholders of the utility and not passed onto consumers.

The Final Report addresses the need to examine the issue pertaining to the "Duke Power" case, but in conjunction with moving forward on the overall proposal as set forth in the report. The possible elimination of the need determination requirement as suggested in the report could assist in resolving this issue. However, to address only one element of this multi-faceted approach to a competitive wholesale energy market would be detrimental to the dynamics and balance that was carefully established in the proposal. To have only one element of the proposal operating would disturb the contemplated competitive interplay between wholesale suppliers. To establish a viable and true competitive wholesale energy market, all of the competing participants in the wholesale energy market must be in the market. To exclude one segment would preclude the development of the desired competitive model and would impact on the development of a healthy, efficient and competitive wholesale energy marketplace to the detriment of consumers.

The discretionary approach is not, by any stretch of the imagination, an egregious arrangement, nor is it confiscatory or biased toward one side or another as some have characterized it, but rather is an approach that establishes a competitive wholesale energy market in a reasonable period of time with the least risk to consumers. The discretionary transfer approach will result in the production of cost-effective energy by establishing a market with many diverse sellers of power in the marketplace. It is this competitive interplay that will drive down the price of electricity ultimately paid by retail customers.

The Study Commission supported the discretionary approach, not as an accommodation of competing interests, but as the wisest and most practical course of action. It is a stand-alone concept that the members of the Study Commission offer as an enlightened vision of Florida's energy future.

Fuel diversity is also strongly supported by the Study Commission. The Final Report clearly requires that the PSC take into account the necessity for fuel diversity, even if it means that the price of power is higher than what would be produced by a project using the fuel du jour. The Study Commission intended that this be a clear signal that Florida is seeking to insure that it is not and will not be held captive by any one fuel source or any one fuel supplier. The Study Commission strongly believes and clearly sets forth in the report the necessity that fuel diversity be maintained.

The capacity issue, which was a critical factor in California's problems, was exacerbated by the decommissioning of many, if not all, of the oil- and coal-burning generating facilities in California. It was compounded by the fact that the imported energy source, which was primarily hydro-power, was to a great extent not available. The discretionary model will provide the catalyst and the means for insuring that new and more efficient capacity is developed in Florida.

Lastly, by not requiring total divestiture and the purchase of all power on the spot market, we have encouraged the utilization of long-term power contracts as well as hedge agreements and other programs to insure that, under proper management, the load-serving utilities have adequate power to serve the needs of their customers.

As the Final Report discloses, Florida is virtually an energy island. We have limited power importation capabilities. We must produce virtually all of the power that we consume within the state. On the basis of statistics provided by the Florida Reliability Coordinating Council and by the projected growth of the state, which many Study Commission members believe will be exponential rather than linear between now and the year 2020, it is imperative that we provide an environment that encourages increased capacity and energy conservation. This capacity could come in the form not only of additional power plants, as described above, but also by encouragement of clean and renewable energy sources to augment and supplement our current and future supplies of power. The report clearly sets forth methods and mechanisms for continuing to expand research on renewable sources of energy and to develop ways to encourage and promote the same.

Florida's environment drives a great deal of the state's economy, from clean beaches and waters to healthy cities to protected natural areas. The Study Commission seeks to protect and enhance this environment from the impacts of electrical generation and transmission in a rational and comprehensive manner. To accomplish this, the Study Commission did adopt and incorporate into the Final Report many of the recommendations of its Environmental Technical Advisory Committee. In doing so, we also reflected on the statements of the Chair of the Environmental Technical Advisory Committee, whose opening remarks focused on the balancing necessary in implementing environmental measures with the economic impact and practicable result of such implementation. According to her comments, any changes that would result in increased electrical power rates of 10% or more could wreak economic havoc in the state. Keeping that in mind, the Study Commission sought to develop and recommend environmental systems that would protect and promote the state's economy by calling for environmental programs that achieve maximum benefit for our environment and our fellow Floridians without causing economic waste and disruption. Some may disagree with our recommendations, but few can disagree with the goals which we have set, for they are shared by most Floridians. While we embraced many of the issues and have recommended many of the studies suggested by the Environmental Technical Advisory Committee, the Study Commission could not embrace all of the requested elements or that all of the suggested environmental capital improvements be made at a cost of *four billion dollars*. To embrace all of the recommendations could result in possible economic havoc.

The Final Report addresses the major environmental issues associated with existing and future power plants and their supporting infrastructure, including transmission lines, in accordance with the Governor's Executive Order. The Study Commission recognizes that emissions from power plants must be addressed on a multi-pollutant basis as a part of a nationwide effort. This program should allow use of market-based incentives and provide regulatory flexibility to allow targeted changes at existing plants while creating certainty for Floridians that the required reductions will be achieved. The market-based approach to reducing emissions from existing plants is consistent with the Study Commission's efforts to allow the competitive market to direct Florida's energy future. The report recognizes that the Florida Department of Environmental Protection must continue to address emissions from existing power plants, and encourages the State to begin to monitor greenhouse gas emissions in Florida. The latter will allow Florida to be ready if and when any national program to control greenhouse gas is implemented.

The Study Commission benefited greatly from the work of the Environmental Technical Advisory Committee as that group considered in detail many of the environmental issues discussed in the Final Report. Far from ignoring this group of industry experts, we adopted many of their ideas in the final report, including addressing emissions from existing power plants, creating an inventory of greenhouse gases, streamlining the permitting process for non-controversial power plants and transmission lines, and developing policies for siting of new power plants and electrical transmission lines, including over publicly-owned lands.

The Final Report of the Study Commission was developed and decided by individuals who are non-energy stakeholders and who are committed to the great state of Florida. The report is a fair and well-balanced approach that will, if followed, allow for the development of an open competitive wholesale energy market, thereby insuring the development and perpetuation of a reliable, efficient and cost-effective energy system to be enjoyed by all of the residents of the state.

I am honored to be a member of the Study Commission and I totally endorse the contents of its Final Report.

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

Book Value: The original cost of property, plant or equipment minus the balance of accumulated depreciation and other associated reserves, including but not limited to reserves for deferred income taxes, deferred investment tax credits, plant dismantlement and decommissioning.

British Thermal Unit (Btu): The quantity of heat needed to raise the temperature of one pound of water by 1°F at or near 39.2°F.

Bundled Utility Service: All generation, transmission, and distribution services provided by one entity for a single charge. This would include ancillary services and retail services.

Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Cogeneration: The production of electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Cogenerator: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility (QF) under the Public Utility Regulatory Policies Act (PURPA), the facility must produce electric energy and "another form of useful thermal energy through the sequential use of energy," and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC). (See the Code of Federal Regulations, Title 18, Part 292.)

Combined-Cycle Unit: An electric generating unit that consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boiler(s) provided by the exhaust gas of the combustion turbine(s).

Cooperative Electric Utility: A not-for-profit, consumer-owned utility incorporated under the laws of Florida established to provide at-cost electric service. Electric cooperatives are self-regulated and governed by a board of directors elected from the membership.

Demand-Side Management (DSM): The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility-administered programs. It does not refer to energy and load-shape changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards.

Distribution System: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Electric Power Plant: A facility containing prime movers (the engine, turbine, water wheel, or similar machine that drives an electric generator; or a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cell(s)), electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electricity Generation: The process of producing electric energy or transforming other forms of energy into electric energy.

Energy Efficiency: Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption, often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

EPACT: The Energy Policy Act of 1992 addresses a wide variety of energy issues. The legislation creates a new class of power generators, exempt wholesale generators, that are exempt from the provisions of the Public Holding Company Act of 1935 and grants the authority to the Federal Energy Regulatory Commission to order and condition access by eligible parties to the interconnected transmission grid.

Federal Energy Regulatory Commission (FERC): The federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy.

Firm Capacity: Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Fossil Fuel: Any naturally occurring organic fuel formed in the earth's crust, such as oil, coal, and natural gas.

Grid: The layout of an electrical transmission and distribution system.

Hydropower: The production of electricity from the kinetic energy of falling water.

Hydropower Plant: A plant in which the turbine generators are driven by falling water.

Independent Power Producer (IPP): A non-utility wholesale power producer that operates within the franchised service territories of load-serving utilities and is usually authorized to sell at market-based rates. Unlike traditional electric utilities, independent power producers do not possess transmission facilities or sell electricity in the retail market.

Interruptible Load: Refers to a utility program that, in accordance with contractual arrangements, can interrupt consumer load at times of peak demand by direct control of the utility system operator or by action of the consumer at the direct request of the system operator. It usually involves commercial and industrial consumers.

Investor-Owned Utility (IOU): A class of utility whose stock is publicly traded and which is organized as a tax-paying business, usually financed by the sale of securities in the capital market. It is regulated and authorized to achieve an allowed rate of return.

Kilovolt (KV): One thousand volts.

Kilowatt (KW): One thousand watts.

Kilowatthour (KWH): One thousand watthours.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load-Serving Utility: An entity that has the obligation to provide electricity to end-use customers.

Market-Based Rate: Electric service prices determined in an open market system of supply and demand under which the price is set solely by agreement as to what a buyer will pay and a seller will accept. Such prices could recover less or more than full costs, depending upon what the buyer and seller see as their relevant opportunities and risks.

Megawatt (MW): One million watts.

Megawatthour (MWH): One million watthours.

Merchant Plant: A non-utility generator for which the output is not fully contractually committed to a load-serving utility.

Monopoly: One seller of electricity with control over market sales.

Municipal Electric Utility: An electric utility owned and operated by a city, county, or other local district, delivering electricity to local citizens and businesses. Governing decisions, including rates, are set by local city councils or utility boards. They are publicly accountable, with economic benefits returned to the local community. Also referred to as a public power utility.

Non-Firm Capacity: Power or power-producing capacity supplied or available under a commitment having limited or no assured availability.

Non-Utility Generator: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not a load-serving utility. Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area.

Natural Gas: A gaseous mixture of hydrocarbon compounds, primarily methane, delivered via pipeline for consumption. It is used as a fuel for electricity generation, a variety of uses in buildings, and as a raw material input and fuel for industrial processes.

Natural Gas Pipeline: A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters for transporting natural gas and/or supplemental gaseous fuels from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use.

Nuclear Electric Power: Electricity generated by the use of the thermal energy released from the fission of nuclear fuel in a reactor.

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that, when placed in a nuclear reactor, will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Open Access: A regulatory mandate to allow others to use a utility's transmission and distribution facilities to move bulk power from one point to another on a nondiscriminatory basis for a cost-based fee.

Peak Demand: The maximum load during a specified period of time.

Photovoltaic Energy: Direct-current electricity generated from sunlight through solid-state semiconductor devices that have no moving parts.

PURPA: The Public Utility Regulatory Policies Act of 1978, passed by the U.S. Congress. This statute requires states to implement utility conservation programs and create special markets for cogenerators and small producers who meet certain standards, including the requirement that states set the prices and quantities of power the utilities must buy from such facilities.

Rate Base: The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and, in Florida, is calculated based on the utility's prudent investment at original cost. The rate base includes cash, working capital, materials and supplies, and deductions for accumulated provisions for depreciation, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Regional Transmission Organization (RTO): An independent operator of the electric transmission system(s) of a utility or group of utilities, and performs the functions and requirements specified in FERC Order 2000.

Reliability: Electric system reliability has two components – adequacy and security. Adequacy is the ability of the electric system to supply to aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services.

Renewable Energy: Energy obtained from sources that are essentially inexhaustible (unlike, for example, fossil fuels, of which there is a finite supply). Renewable sources of energy include conventional hydroelectric power, wood, waste, geothermal, wind, photovoltaic, and solar thermal energy.

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peakload for a utility system as a percentage of total capability.

Retail: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

Retail Competition: The concept under which multiple sellers of electric power can sell directly to end-use customers and the process and responsibilities necessary to make it occur.

Retail Market: A market in which electricity and other energy services are sold directly to the end-use customer.

Spot Price: The price for a one-time open market transaction for immediate delivery of the specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates.

Sulfur Dioxide (SO_2): A toxic, colorless gas soluble in water, alcohol, and ether. Used as a chemical intermediate in paper pulping and ore refining, and as a solvent. A by-product of coal and other fossil fuel combustion.

Unbundling: The separating of the components of electric power service (generation, transmission, distribution) for the purpose of separate pricing or separate service offerings.

Vertical Integration: An arrangement whereby the same company owns all the different aspects of making, selling, and delivering a product or service. In the electric industry, it refers to the historically common arrangement whereby a utility owns its generating plants, transmission system, and distribution lines to provide all aspects of electric service.

Wholesale Competition: A system whereby load-serving utilities have the option to buy power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of load-serving utilities.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipals for resale to ultimate consumers.

State Energy Management Plan
Annual Summary Report
Fiscal Year 2016-17

FLORIDA DEPARTMENT OF MANAGEMENT SERVICES

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Extract of Pages 1-7

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Executive Summary

The State Energy Management Plan (SEMP) was developed by the Department of Management Services (DMS) to provide a comprehensive system to manage and reduce non-renewable energy consumption and costs in state-owned and metered state-leased facilities. The State Energy Management Plan applies to each executive-branch department or agency of the State of Florida.

The SEMP applies to all state-owned and private-lease facilities for which the agency is contractually obligated to pay for utility consumption based on the utility provider's monthly statement or the facility's sub-meter. The purpose of this report is to summarize energy data submissions provided by each agency for fiscal year 2016-17.

For fiscal year 2016-17, 20 agencies reported energy data for a total of 46.2 million gross square feet of space. The total energy consumption reported for this period translates to a total annual cost of $110 million.

This report contains facility-specific energy consumption and cost data for each state agency, including performance metrics and benchmark comparisons.

The state has acquired facility-specific energy consumption and cost data that can, and should, be used to prioritize energy conservation efforts and capital improvements. This report will assist DMS and other stakeholders in the process of evaluating the energy conservation programs of each agency.

All numbers are subject to minor variations correlated to rounding.

Overview

This report summarizes the SEMP submissions provided by each agency for fiscal year 2016-17. The metrics provided include the total agency-reported gross square footage, annual energy consumption (AEC), energy performance index (EPI), annual utility cost, and cost utilization index (CUI).

The State of Florida is comprised of 21 state agencies that own facilities encompassing approximately 46.2 million gross square feet of space. The combined AEC is approximately 3.7 billion kBTU (thousand British thermal units), at a combined annual cost of approximately $110 million. Table 1 provides a summary of the state's energy performance metrics for each year of SEMP submissions.

Table 1: State of Florida – Energy Performance Metrics

Fiscal Year (FY)	Gross Square Footage (GSF)	Annual Energy Consumption (AEC) [kBTU]	Energy Performance Index (EPI) [kBTU/sf/yr.]	Annual Utility Cost (AUC) [$/yr.]	Cost Utilization Index (CUI) [$/sf/yr.]
FY 2012-13	46,869,556	4,180,908,545	89.2	$110,371,992.88	$2.35
FY 2013-14	48,658,296	3,570,724,059	73.4	$117,092,115.53	$2.41
FY 2014-15	47,947,983	3,853,514,020	80.4	$113,594,247.22	$2.37
FY 2015-16	45,820,611	3,407,807,671	74.4	$111,371,328.88	$2.43
FY 2016-17	46,195,003	3,664,904,210	79.3	$109,583,395.35	$2.37

Figures 1-4 provide five-year comparisons for the state. Green lines represent positive trends, indicating improved performance or reduced costs. Red lines represent negative trends, indicating reduced performance or increased costs.

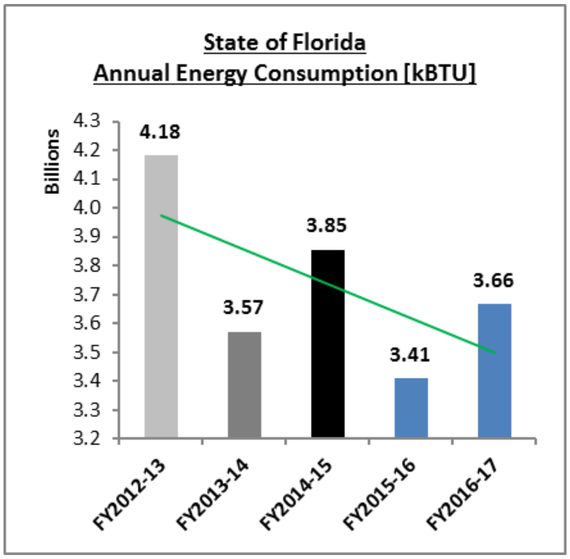

Figure 1: State of Florida
Annual Energy Consumption (AEC)
5-Year Comparison

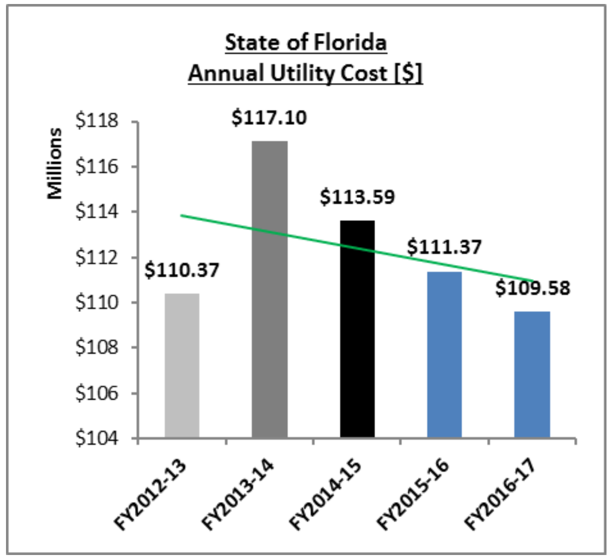

Figure 2: State of Florida
Annual Utility Cost (AUC)
5-Year Comparison

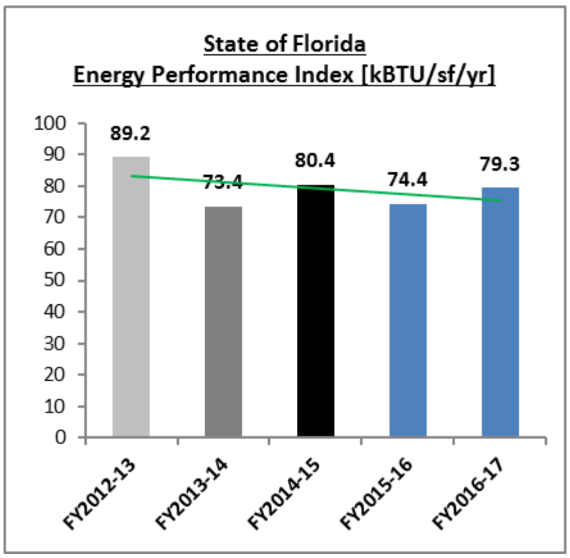

Figure 3: State of Florida
Energy Performance Index (EPI)
5-Year Comparison

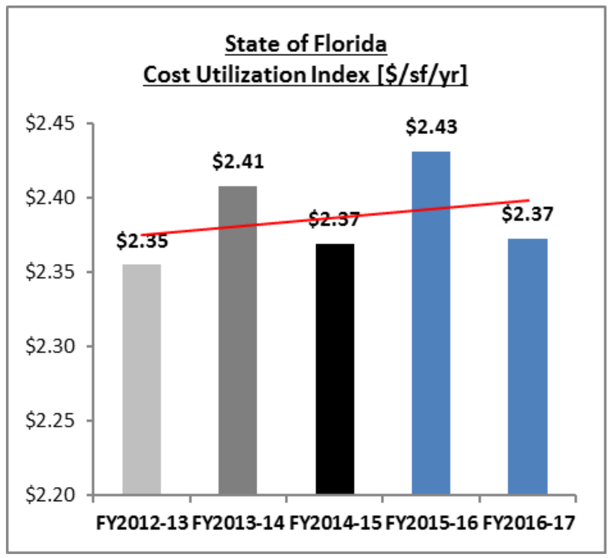

Figure 4: State of Florida
Cost Utilization Index (CUI)
5-Year Comparison

Figures 5-8 provide five-year comparisons for the state by agency. Bars in red indicate agencies whose energy consumption and costs were above the state's calculated EPI and CUI. These increases should be evaluated further to determine ways to reduce consumption and costs.

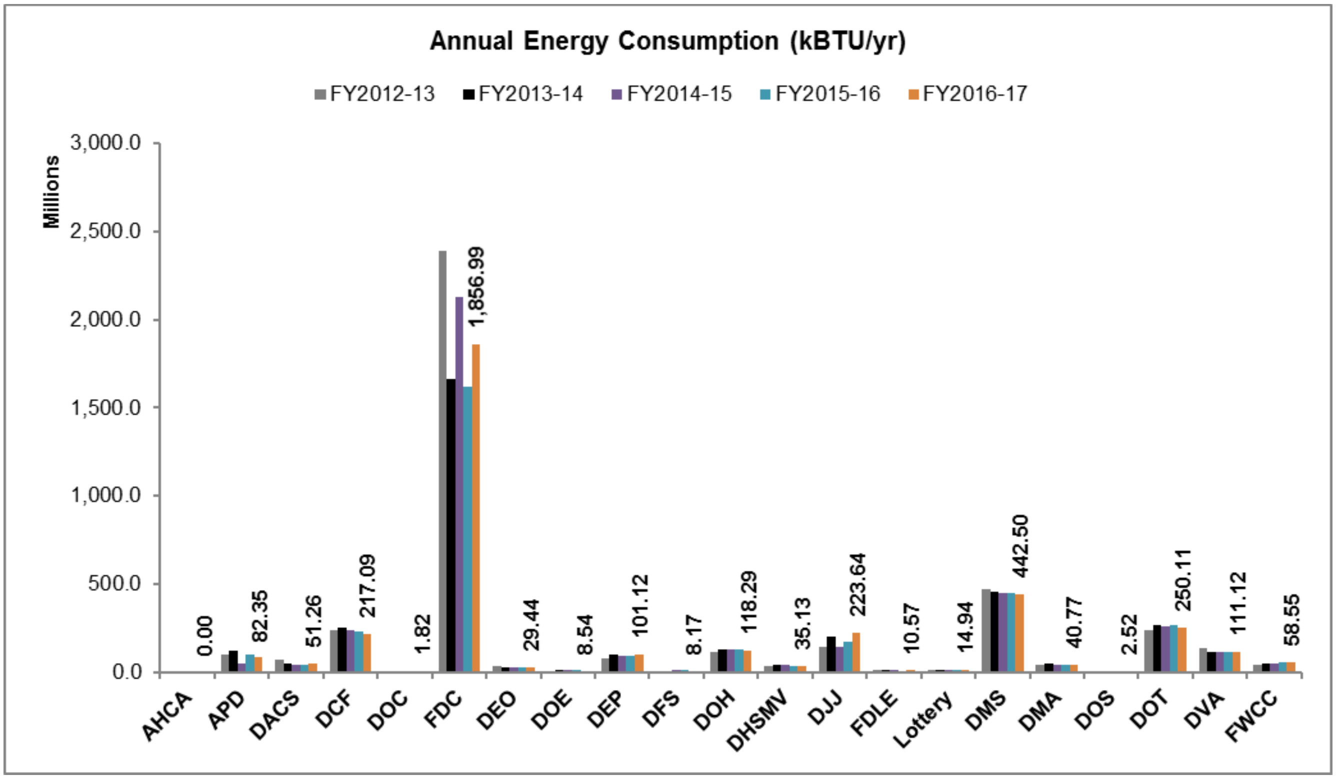

Figure 5: AEC by Agency, 5-Year Comparison
Total AEC = 3,664,904,210 kBTU

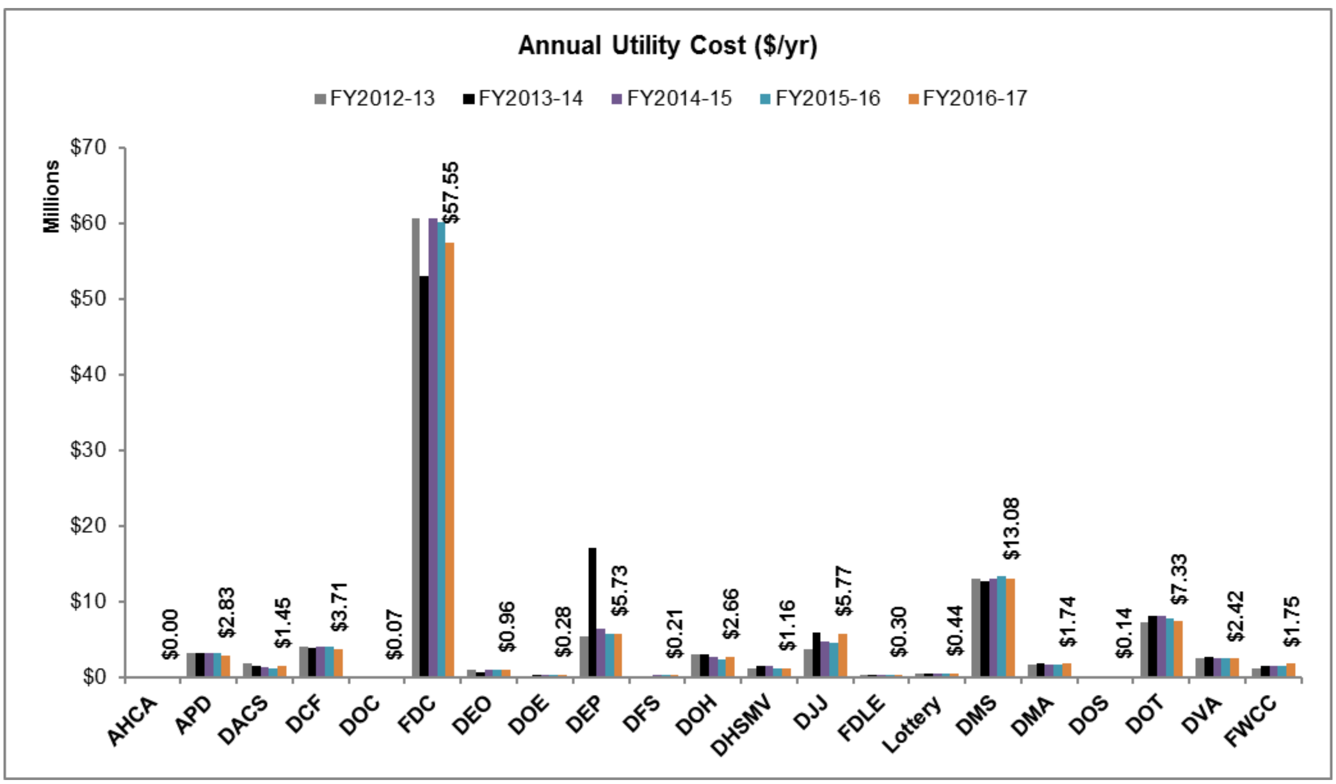

Figure 6: AUC by Agency, 5-Year Comparison
State of Florida AUC = $109,583,395.35

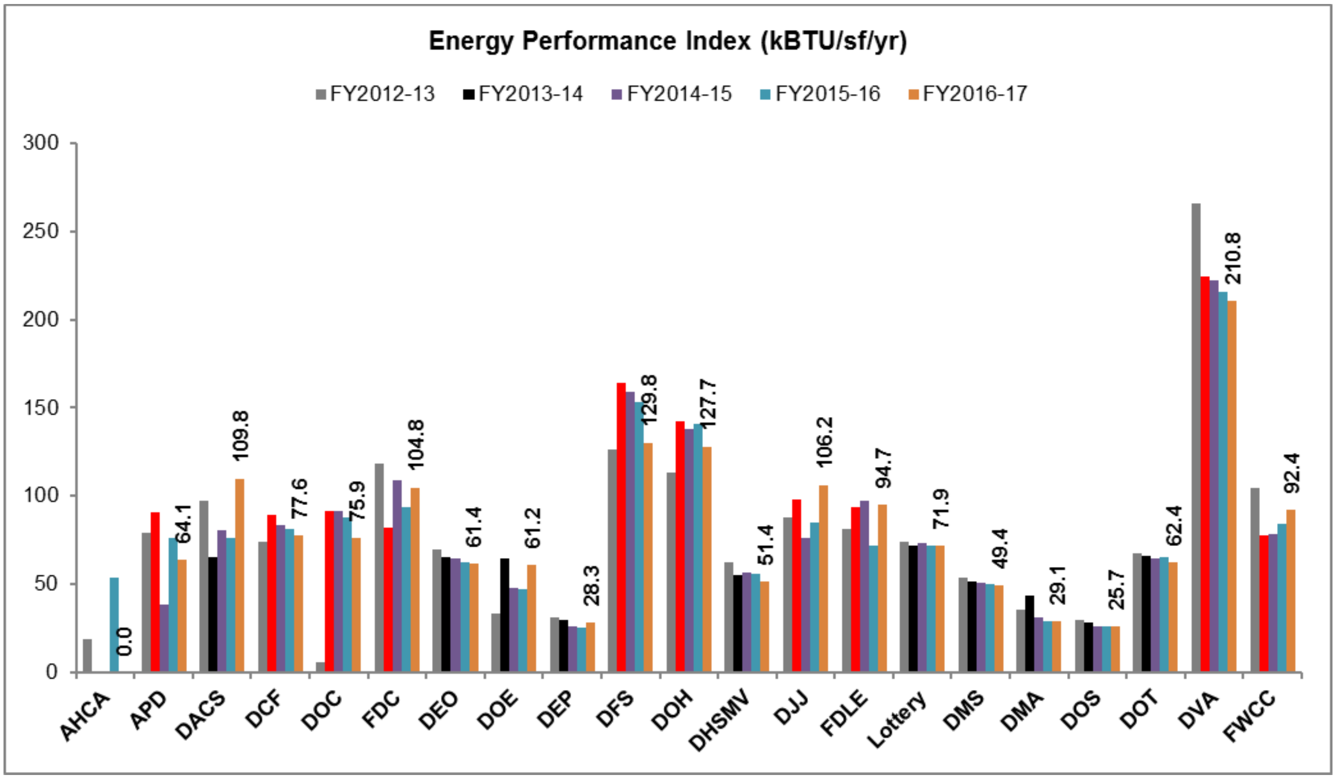

Figure 7: EPI by Agency, 5-Year Comparison
State of Florida EPI = 79.3

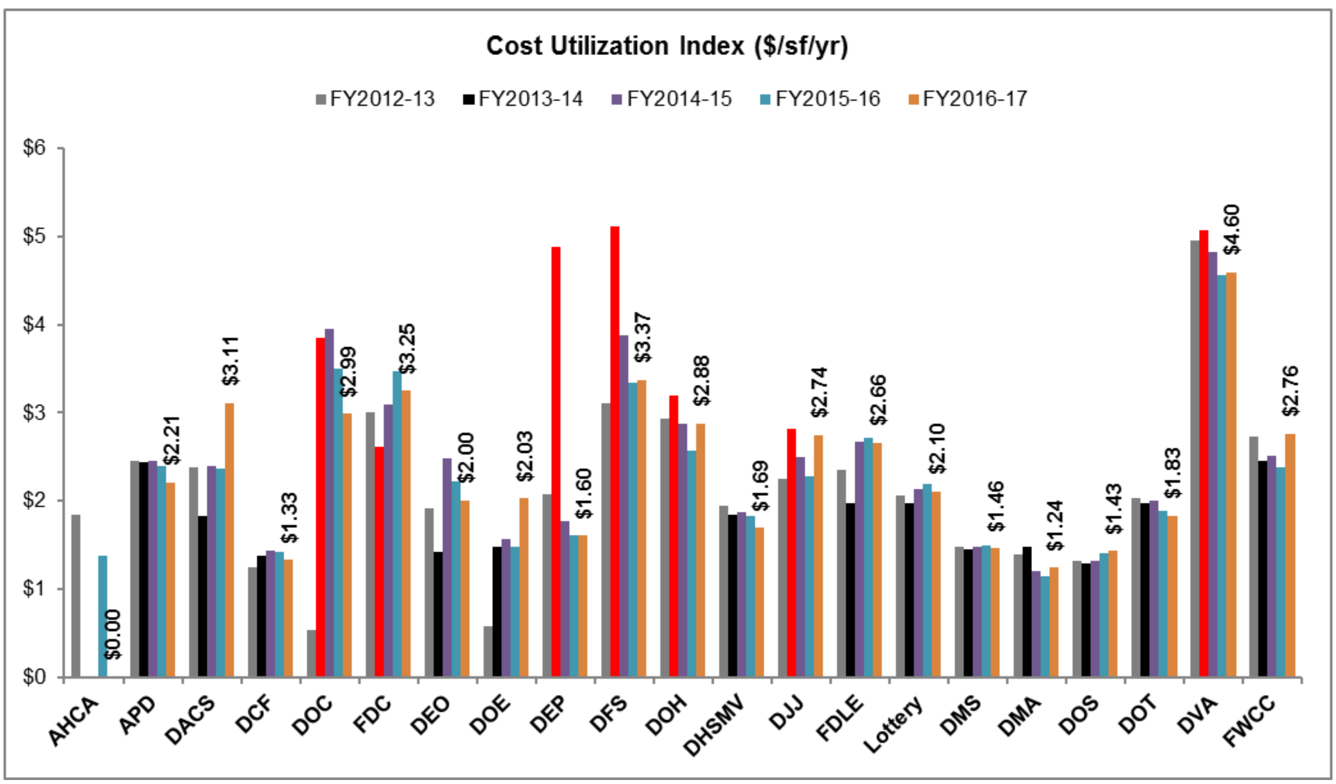

Figure 8: CUI by Agency, 5-Year Comparison
State of Florida CUI = $2.37

Performance Indices & Benchmarking

This report compares each agency's energy performance to the United States Department of Energy's 2012 Commercial Building Energy Consumption Survey (CBECS), which is the latest CBECS data available and serves as the foundation of the federal Energy Star Program. The performance metrics utilized in this analysis are the EPI and the CUI. The energy performance index, measured in kBTU per square foot per year (kBTU/sf/yr.), is the ratio of total energy consumed to the total square footage over the course of one full year. The CUI, measured in dollars per square foot per year ($/sf/yr.), is the ratio of total energy cost to the total square footage over the course of one full year.

For comparison of individual agency properties to national benchmarks, Table 2 provides EPIs and CUIs based on region, square footage, and principal facility activity (occupancy type). Because of the facility-specific energy data collected in the SEMP, the state will be able to benchmark individual facilities' benchmarks to national statistics, such as those provided in Table 2.

Table 2: CBECS Building Classification EPIs & CUIs

Classification	Energy Performance Index (EPI) [kBTU/sf/yr.]	Cost Utilization Index (CUI) [$/sf/yr.]
Census Region & Division:		
South Atlantic	75.5	$1.74
Gross Square Footage:		
1,001-5,000	89.9	$2.03
5,001-10,000	72.6	$1.60
10,001-25,000	62.1	$1.41
25,001-50,000	69.1	$1.45
50,001-100,000	76.7	$1.62
100,001-200,000	83.4	$1.76
200,001-500,000	95.7	$1.95
Over 500,000	108.4	$2.26
Principal Building Activity:		
Education	68.8	$1.37
Food Sales	209.3	$4.93
Food Service	282.6	$5.47
Health Care	172.8	$3.15
Inpatient	**231.3**	**$3.95**
Outpatient	94.9	$2.08
Lodging	96.8	$1.89
Mercantile	89.0	$2.00
Retail (Other Than Mall)	66.9	$1.65
Enclosed and strip malls	109.3	$2.33
Office	**77.8**	**$1.93**
Public Assembly	86.3	$1.84
Public Order & Safety	92.4	$1.92
Religious Worship	38.0	$0.73
Service	58.7	$1.21
Warehouses & Storage	32.8	$0.74
Other	142.9	$2.98
Vacant	12.6	$0.30

Source: U.S. Department of Energy's Commercial Building Energy Consumption Survey (2012)

The state's overall EPI is 79.3 (kBTU/sf/yr.) Figure 9 illustrates the EPI for each of the agencies compared to the state's overall EPI, as well as the Office EPI of 77.8 and the Inpatient EPI of 231.3, according to the CBECS. The state's overall CUI is $2.37 ($/sf/yr.). Figure 10 illustrates the CUI for each of the 21 agencies compared to the state's overall CUI, as well as the Office CUI of $1.93 and the Inpatient CUI of $3.95, according to the CBECS.

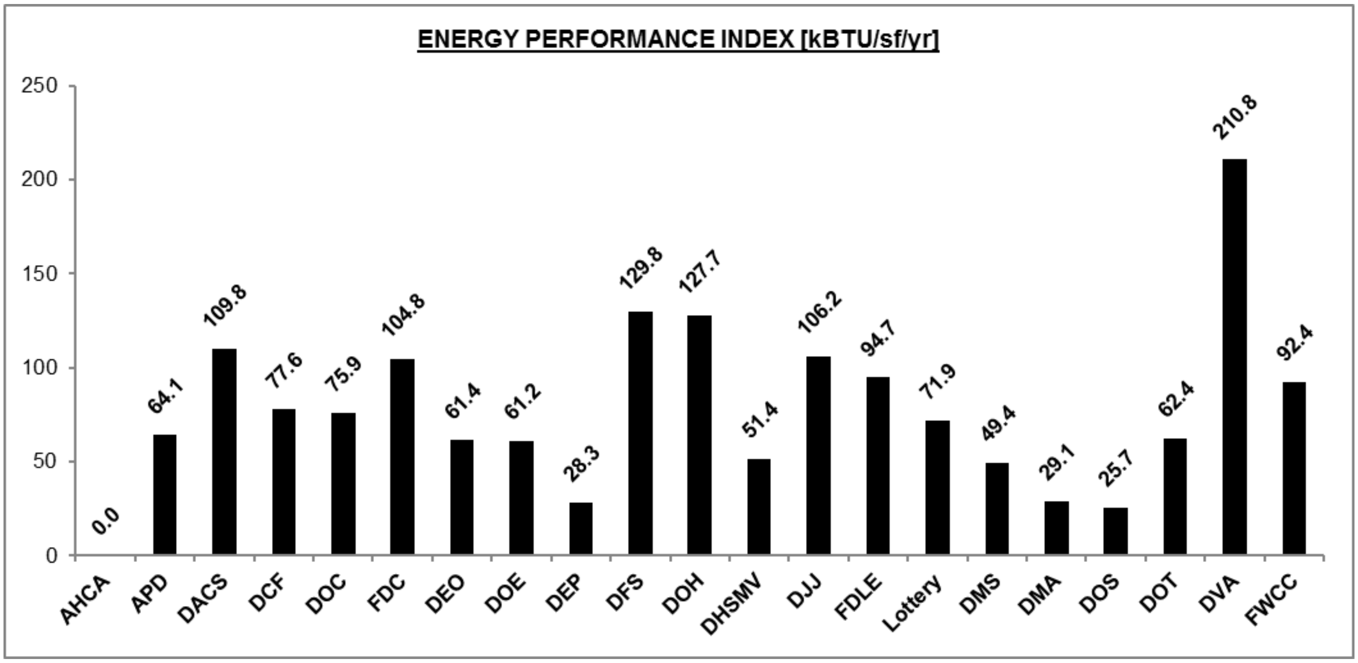

Figure 9: FY2016-17 Energy Performance Index (EPI) by Agency, FY 2016-17
State of Florida EPI = 79.3; CBECS Office EPI = 77.8; CBECS Inpatient EPI = 231.3

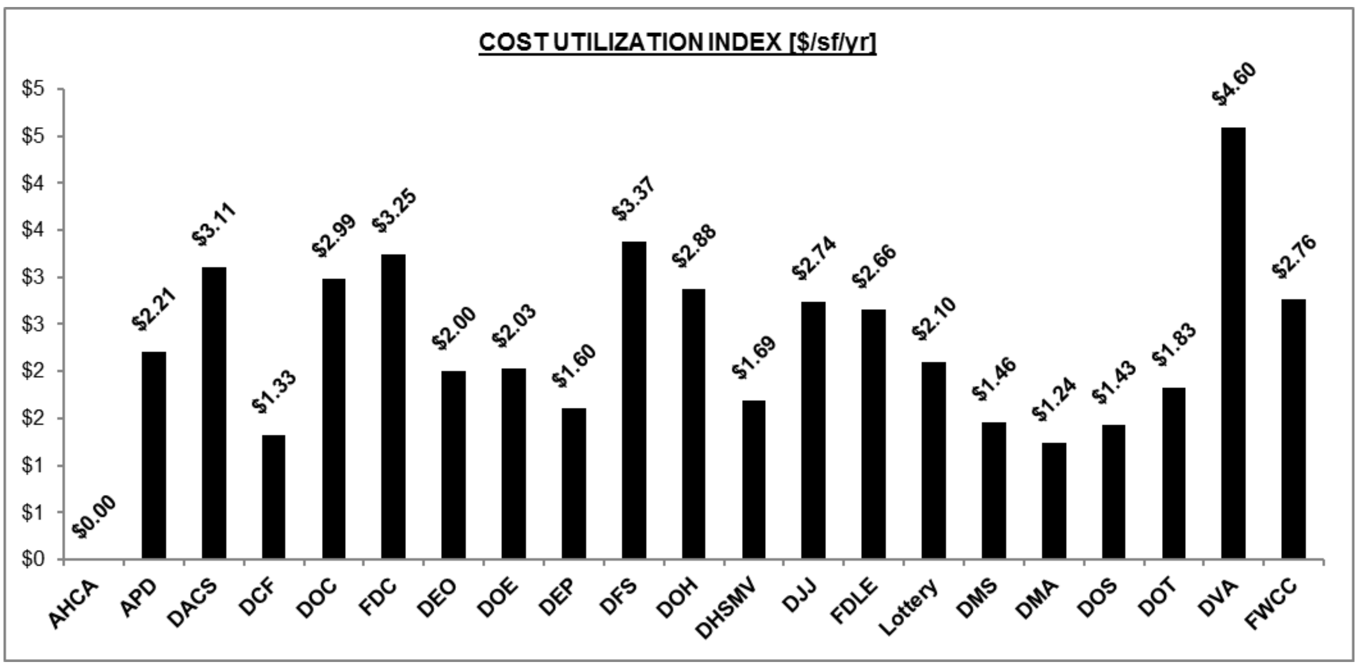

Figure 10: FY 2016-17 Cost Utilization Index (CUI), By Agency, FY 2016-17
State of Florida CUI = $2.37; CBECS Office CUI = $1.93; CBECS Inpatient CUI = $3.95

The purpose of the additional CBECS data is to demonstrate that different facility types have substantially different levels of energy intensity. Although the EPI of 77.8 and CUI of $1.93 may be considered a reasonable benchmark for office space and other space types of similar occupancies, it would not be an appropriate benchmark for hospitals and correctional facilities because of occupancy levels, complexity, operating schedules, and other characteristics. The EPI of 231.3 and CUI of $3.95 would be a more reasonable benchmark for these facility types. AHCA has no facilities requiring SEMP submission for FY 2016-17.

Florida School District
Annual Energy Cost Information

Data Source: 2016-2017
District Financial Report

School District	Natural Gas	Bottled Gas	Electricity	Heating Oil	All Energy	F.I.S.H. GSF	COFTE	Square Foot Cost		Cost Per COFTE	
								All Energy	Elec Only	All Energy	Elec Only
Alachua	$225,623	$56,333	$7,611,150	$0	$7,893,106	5,578,570	25650	$1.41	$1.36	$307.73	$296.73
Baker	0	13,441	923,448	0	936,889	866,818	4750	1.08	1.07	197.26	194.43
Bay	368,606	6,273	6,629,973	0	7,004,852	5,280,694	23073	1.33	1.26	303.59	287.34
Bradford	13,521	3,955	929,824	0	947,300	828,249	3088	1.14	1.12	306.76	301.10
Brevard	165,951	218,430	11,281,354	0	11,665,735	12,803,248	62860	0.91	0.88	185.58	179.47
Broward	179,281	1,041,854	46,701,707	102	47,922,943	39,352,411	229814	1.22	1.19	208.53	203.22
Calhoun	4,136	5,192	629,167	0	638,495	666,012	2144	0.96	0.94	297.80	293.45
Charlotte	22,222	8,292	3,817,762	0	3,848,276	3,399,639	15096	1.13	1.12	254.92	252.90
Citrus	59,853	12,889	3,183,160	0	3,255,902	2,966,986	14976	1.10	1.07	217.41	212.55
Clay	0	4,954	7,171,465	71,498	7,247,917	6,732,822	35059	1.08	1.07	206.73	204.55
Collier	0	25,188	10,807,880	0	10,833,068	8,726,760	44676	1.24	1.24	242.48	241.92
Columbia	16,365	26,341	1,849,796	0	1,892,502	1,991,086	9268	0.95	0.93	204.19	199.58
Dade	589,120	410,494	60,045,190	73,130	61,117,934	48,872,310	284604	1.25	1.23	214.75	210.98
DeSoto	0	14,080	802,162	0	816,242	914,870	4782	0.89	0.88	170.71	167.76
Dixie	0	2,259	507,516	0	509,775	686,143	1974	0.74	0.74	258.28	257.13
Duval	256,290	0	16,494,854	0	16,751,144	17,947,070	111093	0.93	0.92	150.79	148.48
Escambia	846,088	3,990	9,359,909	0	10,209,988	7,811,329	37962	1.31	1.20	268.95	246.56
Flagler	0	14,842	2,219,079	0	2,233,921	2,486,665	11519	0.90	0.89	193.94	192.65
Franklin	0	0	286,831	0	286,831	293,753	924	0.98	0.98	310.42	310.42
Gadsden	0	0	1,661,655	1,238	1,662,893	1,428,456	4701	1.16	1.16	353.71	353.45
Gilchrist	0	8,422	855,065	0	863,487	723,142	2536	1.19	1.18	340.43	337.11
Glades	0	6,291	437,959	0	444,250	385,460	1394	1.15	1.14	318.74	314.23
Gulf	18,208	0	608,736	0	626,944	583,012	1894	1.08	1.04	331.01	321.40
Hamilton	4,461	101,011	564,208	1,180	670,861	688,632	1576	0.97	0.82	425.65	357.98
Hardee	0	0	1,263,413	0	1,263,413	1,201,511	5273	1.05	1.05	239.61	239.61
Hendry	0	12,823	1,423,224	0	1,436,047	1,386,714	7242	1.04	1.03	198.29	196.52
Hernando	14,058	28,091	5,189,157	0	5,231,306	4,406,282	21120	1.19	1.18	247.69	245.70
Highlands	10,684	8,954	2,005,486	0	2,025,123	2,396,385	12071	0.85	0.84	167.77	166.15
Hillsborough	343,417	135,787	33,629,462	0	34,108,667	28,833,584	194318	1.18	1.17	175.53	173.06
Holmes	0	26,708	945,586	0	972,294	1,017,809	3095	0.96	0.93	314.14	305.51
Indian River	7,150	34,194	4,083,269	0	4,124,613	3,152,738	15132	1.31	1.30	272.57	269.84
Jackson	10,283	15,251	2,088,266	0	2,113,800	1,584,120	6330	1.33	1.32	333.96	329.92
Jefferson	0	1,775	302,867	0	304,642	406,364	693	0.75	0.75	439.59	437.02
Lafayette	0	785	209,517	0	210,302	254,819	1193	0.83	0.82	176.26	175.60
Lake	117,837	14,659	7,360,150	0	7,492,646	7,900,228	40121	0.95	0.93	186.75	183.45

Office of Educational Facilities
Florida Department of Education

This report is for cost comparison only, and does not rank districts by the energy used per sq. ft. or by Capital Outlay Full Time Equivalent (COFTE).

Reports are at: http://www.fldoe.org/finance/edual-facilities/annual-energy-maintenance-operations-r.stml

School District	Natural Gas	Bottled Gas	Electricity	Heating Oil	All Energy	F.I.S.H. GSF	COFTE	Square Foot Cost		Cost Per COFTE	
								All Energy	Elec Only	All Energy	Elec Only
Lee	$0	$109,799	$15,654,574	$0	$15,764,373	14,020,351	78164	$1.12	$1.12	$201.68	$200.28
Leon	194,820	26,391	5,893,630	0	6,114,841	6,260,965	32523	0.98	0.94	188.02	181.22
Levy	2,995	23,534	1,116,737	8,388	1,151,654	1,596,600	5123	0.72	0.70	224.79	217.97
Liberty	0	27,950	441,743	0	469,693	410,705	1268	1.14	1.08	370.47	348.42
Madison	41,877	5,998	635,512	0	683,388	546,333	2086	1.25	1.16	327.58	304.63
Manatee	738,268	197,906	10,657,384	0	11,593,558	8,005,792	43360	1.45	1.33	267.38	245.79
Marion	48,803	21,267	7,704,268	42	7,774,380	7,544,787	40914	1.03	1.02	190.02	188.30
Martin	12,038	21,675	4,203,851	0	4,237,564	3,959,706	17869	1.07	1.06	237.15	235.26
Monroe	0	16,205	2,115,373	0	2,131,578	1,901,977	7162	1.12	1.11	297.64	295.37
Nassau	51,575	18,641	1,988,017	7,174	2,065,407	2,416,711	11352	0.85	0.82	181.94	175.12
Okaloosa	336,574	3,344	5,791,835	0	6,131,753	4,605,976	28204	1.33	1.26	217.41	205.35
Okeechobee	0	5,129	1,113,878	0	1,119,007	1,161,914	6162	0.96	0.96	181.60	180.77
Orange	449,931	173,618	40,010,274	0	40,633,823	33,597,233	187886	1.21	1.19	216.27	212.95
Osceola	43,909	64,561	11,600,172	0	11,708,643	8,999,672	50047	1.30	1.29	233.95	231.79
Palm Beach	414,319	167,333	34,663,823	257	35,245,732	31,438,496	168851	1.12	1.10	208.74	205.29
Pasco	36,918	16,659	10,171,768	15,000	10,240,345	12,148,845	65312	0.84	0.84	156.79	155.74
Pinellas	709,665	7,451	21,398,945	0	22,116,061	18,736,379	96161	1.18	1.14	229.99	222.53
Polk	242,633	134,302	12,636,964	0	13,013,899	17,841,651	93947	0.73	0.71	138.52	134.51
Putnam	40,765	58,057	1,735,036	0	1,833,858	2,448,134	10362	0.75	0.71	176.99	167.45
St. Johns	31,101	71,036	5,518,428	13,899	5,634,464	5,980,530	37671	0.94	0.92	149.57	146.49
St. Lucie	19,492	120,390	6,703,610	0	6,843,492	6,691,064	34879	1.02	1.00	196.21	192.20
Santa Rosa	145,269	2,779	5,390,439	0	5,538,488	4,399,388	26578	1.26	1.23	208.39	202.82
Sarasota	65,548	34,282	7,499,853	0	7,599,683	8,450,772	36803	0.90	0.89	206.50	203.79
Seminole	218,219	27,396	12,964,487	0	13,210,102	11,404,265	63619	1.16	1.14	207.64	203.78
Sumter	0	8,527	1,254,610	0	1,263,137	1,326,574	5063	0.95	0.95	249.50	247.82
Suwannee	36,992	22,360	1,171,780	0	1,231,132	1,101,109	5902	1.12	1.06	208.61	198.56
Taylor	11,034	0	717,848	0	728,882	731,225	2806	1.00	0.98	259.73	255.80
Union	0	27,888	517,470	0	545,358	484,672	2197	1.13	1.07	248.18	235.49
Volusia	130,230	0	9,642,356	1,853	9,774,439	10,668,394	58376	0.92	0.90	167.44	165.18
Wakulla	0	28,457	1,062,349	7,455	1,098,261	1,085,212	4939	1.01	0.98	222.36	215.09
Walton	0	0	1,834,206	0	1,834,206	1,942,977	8379	0.94	0.94	218.90	218.90
Washington	2,761	9,587	1,076,019	0	1,088,367	1,070,349	3432	1.02	1.01	317.08	313.48
State Totals	$ 7,298,891	$ 3,716,079	$ 498,767,486	$ 201,216	$ 509,983,672	457,533,449	2,479,395				
State Average								$1.11	$1.09	$205.69	$201.16

This report is for cost comparison only, and does not
rank districts by the energy used per sq. ft.
or by Capital Outlay Full Time Equivalent (COFTE).

From: Keith Hetrick <khetrick@psc.state.fl.us>
Date: February 20, 2019 at 5:59:28 PM EST
To: "'Baker.amy@leg.state.fl.us'" <Baker.amy@leg.state.fl.us>
Cc: Braulio Baez <BBaez@PSC.STATE.FL.US>, Mark Futrell <MFutrell@PSC.STATE.FL.US>
Subject: Letter -- Response to questions asked of Mark Futrell

Dear Ms. Baker,

Please find attached my response, on behalf of our PSC staff, to the questions you asked Mark Futrell during your meeting last week regarding the Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice. Please note that the nature of your questions necessarily require a legal response and that your questions also were directed to our staff. Therefore, the attached letter is intended as a PSC legal staff response to your questions and does not represent any formal legal opinion rendered by or on behalf of the Commission. Please do not hesitate to call or e-mail me, Mark Futrell or Braulio Baez any time for any follow-up questions, or any desired follow-up information related to the topic of this constitutional initiative. Kind regards,

Keith Hetrick
General Counsel
Florida Public Service Commission
850-413-6189
khetrick@psc.state.fl.us

COMMISSIONERS:
ART GRAHAM, CHAIRMAN
JULIE I. BROWN
DONALD J. POLMANN
GARY F. CLARK
ANDREW GILES FAY

STATE OF FLORIDA

KEITH C. HETRICK
GENERAL COUNSEL
(850) 413-6199

Public Service Commission

February 20, 2019

Ms. Amy Baker, Coordinator
Office of Economic & Demographic Research
111 West Madison Street, Suite 574
Tallahassee, FL 32399-6588
Baker.amy@leg.state.fl.us

Dear Ms. Baker,

You have asked Public Service Commission staff to respond to several questions raised at the Monday, February 11, 2019, Financial Impact Estimating Conference, pertaining to the proposed citizen initiative constitutional amendment entitled: Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice. Specifically, you asked: (1) would the proposed constitutional amendment allow Investor-Owned Utilities (IOUs) to own or invest in transmission and distribution systems, and (2) would the ballot proposal allow IOUs to sell or transfer certain facilities to affiliated entities?

The short answer to both questions is that the plain language of the amendment appears to limit IOUs to certain activities, none of which include owning or investing in transmission and distribution systems or selling or transferring certain facilities to affiliated entities. But the ultimate determination will be made by the legislative and judicial branches. The Legislature will implement the amendment by enacting statutes, and the courts will, if asked, review those statutes and determine whether they are consistent with the intent of the voters in passing the amendment. While PSC staff can and has read the plain wording of the amendment, neither the Commission nor its staff can determine the meaning of the amendment until it is enacted pursuant to law; therefore, it is not appropriate for PSC staff to speculate on whether the ballot proposal allows IOUs to own or invest in transmission and distribution systems or sell or transfer certain facilities to affiliated entities until the Legislature adopts implementing language.

As noted above, the Legislature can make any number of policy choices in implementing the amendment. The courts will ultimately determine the meaning of the amendment, if implementing language is challenged. In interpreting the amendment, the courts will look first to the plain text of the amendment and resort to canons of statutory construction only if the court determines that the language is ambiguous. The Public Service Commission implements and interprets statutory provisions that it is charged with enforcing. It can evaluate and interpret statutes to give constitutional validity to the statutes but it cannot determine the constitutionality of a statute. *Carrollwood State Bank v. Lewis*, 362 So. 2d 110, 113–14 (Fla. 1st DCA 1978).

Of particular relevance to the questions asked above is subsection (1) of Section (c). Section (c) deals with implementation language of the amendment and directs the Legislature by June 1, 2023, to "adopt complete and comprehensive legislation to implement this section in a manner fully consistent with its broad purposes and stated terms . . . ." Specifically, subsection (1) provides that the Legislature shall implement language "that entitles electricity customers to purchase competitively priced electricity, including but not limited to provisions that are designed to (1) *limit the activity of investor-owned electric utilities to the construction, operation, and repair of electrical transmission and distribution systems* . . . ." (Emphasis added.) Section (c) also contains other policies the Legislature must implement, but it leaves the door open for the Legislature to achieve these policy goals through any number of methods so long as they are consistent with the text of the amendment.

Without speculating on how the Legislature may choose to implement the amendment, a plain reading of the proposed language in subsection (1) requires or directs the Legislature to "limit the activity of investor-owned utilities to the construction, operation, and repair of electrical transmission and distribution systems." Nowhere does the plain language provide for ownership or investment in transmission or distribution systems or for the sale or transfer of certain facilities, including generating assets, to an affiliated entity of Florida IOUs. Any affiliate of a Florida IOU would have common parent ownership, which by definition would be investor owned. For guidance in analyzing the meaning of a constitutional provision, the Courts will first turn to the plain language of the amendment, just as they would when interpreting a statute. A recent example of a Court's analysis of the plain meaning of a statute occurred in *Citizens of the State of Florida v. Graham*, 213 So. 3d 703 (Fla. 2017), and is illustrative here. There, the Florida Supreme Court reversed a PSC decision that had allowed for cost recovery of a utility for certain activities. The Court explained that under the plain meaning of the Commission's ratemaking statutes, cost recovery is only permissible for costs arising from the "generation, transmission or distribution" of electricity in Florida. The Woodford Project's activities of "exploration, drilling and production" of natural gas in Oklahoma do not constitute "generating, transmitting, or distributing" electricity in Florida, under the plain meaning of the Commission's ratemaking statutes. Here, the constitutional amendatory language expressly and plainly requires the Legislature to adopt provisions that "limit the activity of investor-owned electric utilities to the 'construction, operation, and repair' of electrical transmission and distribution systems."

While PSC staff is comfortable reiterating the express limitations imposed by the plain wording of the proposed constitutional amendment and describing how courts typically analyze or evaluate constitutional provisions, we have no way of knowing how the Legislature or the courts might interpret the amendment. Stated differently, notwithstanding the apparent limiting language, the determination of whether owning or investing in transmission and distribution systems or selling or transferring certain facilities to affiliated entities would be consistent or inconsistent with the proposed limits ultimately resides with the Legislature and the courts.

It is not the role of PSC staff to opine on the intent or meaning of the amendment, and as such, the PSC cannot speculate on whether or not the Legislature would, and if so, lawfully could, interpret the proposed constitutional amendment so as to allow IOUs to own or invest in transmission and distribution systems. While the plain language of the amendment might appear, on its face, to preclude IOUs from doing anything other than constructing, maintaining, and repairing electrical transmission and distribution systems, PSC staff cannot predict or speculate how the Legislature would implement this amendment and how the courts would interpret it.

Sincerely,

Keith Hetrick

Keith C. Hetrick
General Counsel

	A	B	C	D	E	F	G	H	I	J	K
1	Values for Property of Five Investor Owned Electric Utilities (Duke Energy, Florida Power and Light, Florida Public Utilities, Gulf Power, and Tampa Electric)										
2			Tangible Personal Property (TPP)				Real Property				
3	**County #**	**County**	**Just Value**	**Assessed Value**	**Taxable Value**		**Just Value**	**Assessed Value - School**	**Assessed Value NonSchool**	**Taxable Value School**	**Taxable Value NonSchool**
4	11	Alachua	$81,985,349	$81,985,349	$81,912,028		$53,854,100	$53,854,100	$53,854,100	$53,854,100	$53,854,100
5	12	Baker	$16,608,278	$16,608,278	$16,565,552						
6	13	Bay	$519,113,964	$491,320,695	$488,810,361		$16,678,603	$16,678,603	$16,672,945	$16,678,603	$16,672,945
7	14	Bradford	$45,403,624	$45,403,624	$45,359,750		$1,914,882	$1,914,882	$1,914,882	$1,914,882	$1,914,882
8	15	Brevard	$45,246,090	$45,246,090	$45,121,090		$22,482,470	$22,482,470	$20,889,150	$22,482,470	$20,889,150
9	16	Broward	$3,506,394,280	$3,506,394,280	$3,506,344,279		$171,193,610	$171,193,610	$170,303,540	$171,193,610	$170,303,540
10	17	Calhoun	$8,779,496	$8,779,496	$8,729,496		$151,368	$151,368	$151,368	$151,368	$151,368
11	18	Charlotte	$416,179,707	$416,179,707	$416,079,707		$6,586,556	$6,586,556	$5,743,154	$6,586,556	$5,743,154
12	19	Citrus	$2,838,004,397	$1,134,538,764	$1,134,488,764		$344,151,076	$333,940,262	$328,063,757	$333,940,262	$328,063,757
13	20	Clay	$23,508,779	$23,508,779	$23,483,779		$2,032,679	$2,032,679	$1,831,946	$2,032,679	$1,831,946
14	21	Collier	$384,872,163	$384,872,163	$384,847,163		$7,663,491	$7,663,491	$7,059,202	$7,663,491	$7,059,202
15	22	Columbia	$73,819,151	$73,819,151	$73,744,151		$2,157,035	$2,157,035	$2,157,034	$2,157,035	$2,157,034
16	23	Miami-Dade	$414,330,650	$414,330,650	$5,637,685,383		$333,224,058	$333,224,058	$263,400,981	$333,224,058	$263,400,981
17	24	Desoto	$13,581,977	$13,581,977	$414,276,234		$5,171,652	$4,873,464	$4,873,464	$4,873,464	$4,873,464
18	25	Dixie	$307,766,979	$127,382,674	$13,531,977		$76,300	$76,300	$76,300	$76,300	$76,300
19	26	Duval	$710,463,603	$612,649,083	$127,332,674		$19,734,861	$19,734,861	$19,734,861	$19,734,861	$19,734,861
20	27	Escambia	$178,673,409	$178,673,409	$612,624,083		$11,743,919	$11,743,919	$10,460,625	$11,743,919	$10,460,625
21	28	Flagler	$51,923,268	$51,923,268	$178,598,409		$5,592,981	$5,592,981	$5,578,751	$5,592,981	$5,578,751
22	29	Franklin	$25,946,463	$25,946,463	$51,898,268						
23	30	Gadsden	$33,083,007	$33,083,007	$25,896,463		$184,296	$184,296	$184,296	$184,296	$184,296
24	31	Gilchrist	$12,988,258	$12,988,258	$33,054,641		$1,228,766	$1,228,766	$1,228,766	$1,228,766	$1,228,766
25	32	Glades	$40,541,473	$40,541,473	$12,963,258						
26	33	Gulf	$52,311,036	$52,311,036	$40,491,008		$1,487,457	$1,487,457	$1,423,754	$1,487,457	$1,423,754
27	34	Hamilton	$48,255,044	$48,255,044	$52,286,036		$671,682	$671,682	$669,435	$671,682	$669,435
28	35	Hardee	$154,653,901	$154,653,901	$48,180,044		$415,537	$415,537	$415,537	$415,537	$415,537
29	36	Hendry	$299,869,301	$256,355,397	$154,553,901		$5,588,217	$5,588,217	$5,588,217	$5,588,217	$5,588,217
30	37	Hernando	$148,074,091	$148,074,091	$256,305,397		$1,532,864	$1,532,864	$1,524,340	$1,532,864	$1,524,340
31	38	Highlands	$2,347,108,960	$2,347,108,960	$147,998,939		$3,337,155	$3,337,155	$3,326,328	$3,337,155	$3,326,328
32	39	Hillsborough	$18,775,880	$18,775,880	$2,346,963,400		$150,539,487	$150,539,487	$144,310,917	$150,539,487	$144,310,917
33	40	Holmes	$184,677,803	$184,677,803	$18,750,880		$181,606	$181,606	$181,606	$181,606	$181,606
34	41	Indian River	$59,504,073	$59,504,073	$184,602,803		$916,802	$916,802	$912,627	$916,802	$912,627
35	42	Jackson	$43,830,279	$43,830,279	$59,454,073		$3,969,384	$3,969,384	$3,969,384	$3,969,384	$3,969,384
36	43	Jefferson	$6,575,309	$6,575,309	$43,780,279		$2,247,724	$2,247,724	$2,247,146	$2,247,724	$2,247,146
37	44	Lafayette	$232,277,026	$232,277,026	$6,525,309						
38	45	Lake	$1,461,777,988	$1,401,173,498	$232,227,026		$2,947,730	$2,947,730	$2,932,287	$2,947,730	$2,932,287
39	46	Lee	$22,266,592	$22,266,592	$1,401,098,498		$23,801,314	$23,787,751	$19,731,121	$23,787,751	$19,731,121
40	47	Leon	$54,790,921	$54,790,921	$22,187,722		$153,752	$153,752	$122,159	$153,752	$122,159
41	48	Levy	$9,085,499	$9,085,499	$54,740,921		$4,743,972	$4,743,972	$4,743,972	$4,743,972	$4,743,972
42	49	Liberty	$29,181,546	$29,181,546	$9,035,499		$210,147	$210,147	$168,183	$210,147	$168,183
43	50	Madison	$1,309,061,240	$1,106,715,670	$29,155,856		$907,058	$907,058	$867,296	$907,058	$867,296
44	51	Manatee	$223,485,477	$223,485,477	$1,106,565,670		$71,599,702	$71,599,702	$71,096,713	$71,599,702	$71,096,713
45	52	Marion	$2,565,651,640	$2,388,297,683	$223,460,477		$4,675,732	$4,675,732	$3,789,230	$4,675,732	$3,789,230
46	53	Martin	$5,980,656,131	$5,637,813,933	$2,388,176,535		$126,365,250	$126,365,250	$125,183,555	$124,117,034	$122,935,339
47	54	Monroe	$129,584	$129,584	$104,584						
48	55	Nassau	$100,353,780	$100,353,780	$100,278,780		$5,754,430	$5,754,430	$5,484,975	$5,754,430	$5,484,975
49	56	Okaloosa	$170,428,276	$170,428,276	$170,328,276		$2,756,834	$2,756,834	$2,714,730	$2,756,834	$2,714,730
50	57	Okeechobee	$87,208,425	$87,208,425	$87,158,425		$4,402,398	$4,332,012	$4,328,735	$4,332,012	$4,328,735
51	58	Orange	$905,545,307	$905,545,307	$905,420,308		$29,836,045	$29,836,045	$26,807,468	$29,836,045	$26,807,468
52	59	Osceola	$309,899,767	$309,899,767	$309,816,335		$5,822,900	$5,822,900	$5,812,660	$5,822,900	$5,812,660
53	60	Palm Beach	$4,976,898,415	$4,976,898,415	$4,976,523,415		$153,601,117	$153,601,117	$149,148,861	$153,601,117	$149,148,861
54	61	Pasco	$666,152,853	$486,350,457	$486,275,452		$25,913,592	$25,913,592	$25,706,983	$25,913,592	$25,706,983
55	62	Pinellas	$1,442,171,883	$1,442,171,883	$1,442,121,883		$69,475,346	$69,475,346	$67,110,770	$69,475,346	$67,110,770
56	63	Polk	$2,130,232,111	$2,031,306,381	$2,031,150,525		$55,854,588	$55,854,588	$54,660,162	$55,816,707	$54,622,281
57	64	Putnam	$274,527,709	$274,527,709	$274,452,709		$11,972,035	$11,972,035	$11,809,305	$11,972,035	$11,809,305
58	65	Saint Johns	$155,435,459	$155,435,459	$248,816,936		$5,338,945	$5,338,945	$5,056,403	$5,338,945	$5,056,403
59	66	Saint Lucie	$542,671,641	$542,671,641	$2,612,654,980		$280,409,564	$280,409,564	$274,072,096	$261,363,303	$255,025,835
60	67	Santa Rosa	$476,165,942	$476,165,942	$155,410,459		$4,699,558	$4,699,558	$4,689,510	$4,699,558	$4,689,510
61	68	Sarasota	$248,841,936	$248,841,936	$542,596,641		$26,934,000	$26,934,000	$26,497,485	$26,934,000	$26,497,485
62	69	Seminole	$3,326,676,977	$2,773,645,701	$476,065,943		$20,633,067	$20,633,067	$19,767,180	$20,633,067	$19,767,180
63	70	Sumter	$211,561,960	$211,561,960	$211,410,430		$1,473,020	$1,473,020	$1,472,380	$1,473,020	$1,472,380
64	71	Suwannee	$106,537,992	$106,537,992	$106,446,019		$5,202,385	$5,202,385	$5,202,385	$5,202,385	$5,202,385
65	72	Taylor	$47,021,847	$47,021,847	$46,971,388		$1,022,800	$1,022,800	$1,022,800	$1,022,800	$1,022,800
66	73	Union	$5,869,731	$5,869,731	$5,844,140		$205,412	$205,412	$205,412	$205,412	$205,412
67	74	Volusia	$1,452,773,268	$1,452,773,268	$1,452,698,268		$36,219,108	$36,219,108	$35,110,893	$36,219,108	$35,110,893
68	75	Wakulla	$66,645,765	$66,645,765	$66,570,765		$746,413	$746,413	$727,984	$746,413	$727,984
69	76	Walton	$47,476,458	$47,476,458	$47,376,458		$543,456	$543,456	$543,456	$543,456	$543,456
70	77	Washington	$25,069,690	$25,069,690	$25,044,690		$734,891	$734,891	$734,891	$734,891	$734,891
71		**Statewide**	**$42,777,380,878**	**$39,109,503,630**	**$38,941,425,592**		**$2,161,667,179**	**$2,151,074,228**	**$2,036,070,453**	**$2,129,741,870**	**$2,014,738,095**
72											

73–78

Note - Property of the 5 investor owned electric utilities in Florida were identified by first extracting from the Real Property taxrolls all those properties identified as Use Code 91- Utility, gas and electricity, telephone and telegraph, locally assessed railroads, water and sewer service, pipelines, canals, radio/television communication - and all those properties indicated on the TPP Taxrolls as being in the NAICS code 22 - Utilities. After extracting all parcels in use code 91 and NAICS code 22, names of entities were reviewed to identify those properties and accounts of the five investor owned utilities. One additional step was used for the TPP

	A	B	C	D	E	F
1	Tangible Personal Property by 6-Digit NAICS Code					
2						
3	**NAICS Code**	**NAICS Code Description**	**Just Value**	**Assessed Value**	**Taxable Value**	**Percent of Taxable Value**
4	221111	Hydroelectric Power Generation	$6,509,580,488	$5,947,048,217	$5,946,624,393	15.3%
5	221112	Fossil Fuel Elec tric Power Generation	$5,462,209,498	$5,348,358,196	$5,345,493,070	13.7%
6	221113	Nuclear Electric Power Generation	$3,333,256,320	$2,780,225,044	$2,619,209,323	6.7%
7	221114	Solar Electric Power Generation	$598,469,634	$598,469,634	$598,250,588	1.5%
8	221117	Biomass Electric Power generation	$206,720,103	$163,206,199	$163,181,199	0.4%
9	221118	Other Electric Power Generation	$6,060,450,890	$5,711,911,089	$5,711,643,490	14.7%
10	221121	Electric Bulk Power Transmission and Control	$3,966,736,386	$2,165,456,233	$2,165,262,359	5.6%
11	221122	Electric Power Distribution	$16,639,957,559	$16,394,829,018	$16,391,761,170	42.1%
12	**Grand Total**		**$42,777,380,878**	**$39,109,503,630**	**$38,941,425,592**	100%

	A	B	C
1	**Tangible Personal Property**		**Real Property**
2			
3	**Duke Energy**		**Duke Energy**
4	DUKE ENERGY		DUKE ENERGY
5	DUKE ENERGY BUSINESS SERVICES		DUKE ENERGY CENTER
6	DUKE ENERGY BUSINESS SERVICES		DUKE ENERGY FLORIDA INC
7	DUKE ENERGY BUSINESS SVCS		DUKE ENERGY FLORIDA INC A FLOR
8	DUKE ENERGY CENTER		DUKE ENERGY FLORIDA LLC
9	DUKE ENERGY FLORIDA		DUKE ENERGY FLORIDA, INC
10	DUKE ENERGY FLORIDA F/K/A		
11	DUKE ENERGY FLORIDA FKA FLORID		**Florida Power and Light**
12	DUKE ENERGY FLORIDA INC		FLA POWER & LIGHT CO
13	DUKE ENERGY FLORIDA INC (OUTS		FLA POWER & LIGHT CO PROPERTY
14	DUKE ENERGY FLORIDA LLC		FLA POWER & LIGHT COMPANY
15	DUKE ENERGY FLORIDA SOLAR SOLU		FLA POWER CORP
16	DUKE ENERGY SERVICE CO		FLA POWER CORP TAX DEPT -DEC41
17	DUKE ENERY BUSINESS SERVICES		FLA POWER CORP TAX DEPT DEC41B
18	PROGRESS ENERGY SERVICE CO		FLA POWER CORPORATION
19			FLA POWER TAX DEPT DEC41B
20	**Florida Power and Light**		FLORIDA POWER & LIGHT
21	FLA POWER & LIGHT CO		FLORIDA POWER & LIGHT CO
22	FLORIDA POWER &		FLORIDA POWER & LIGHT COMPANY
23	FLORIDA POWER & LIGHT		FLORIDA POWER & LIGHTING CO
24	FLORIDA POWER & LIGHT CO		FLORIDA POWER + LIGHT CO
25	FLORIDA POWER & LIGHT CO.		FLORIDA POWER + LIGHT CO BRAMM
26	FLORIDA POWER & LIGHT COMPAN		FLORIDA POWER + LIGHT CO TRAMM
27	FLORIDA POWER & LIGHT COMPANY		FLORIDA POWER + LIGHT COMPANY
28	FLORIDA POWER + LIGHT CO		FLORIDA POWER AND LIGHT CO
29	FLORIDA POWER + LIGHT COMPAN		Florida Power and Light Compan
30	FLORIDA POWER AND LIGHT		FLORIDA POWER CO
31	FLORIDA POWER CORP		FLORIDA POWER CORP
32	FLORIDA POWER DEVELOPMENT LLC		FLORIDA POWER CORP ETAL TR
33	FLORIDA POWER HOUSE INC		FLORIDA POWER CORP TR ETAL
34	FPL ENERGY SERVICES		FLORIDA POWER CORP C/O TAX DEP
35	FPL ENERGY SERVICES INC		FLORIDA POWER CORP D/B/A
36	FPL ENERGY SERVICES INC		FLORIDA POWER CORP TAX DEPT DE
37	FPL ENERGY SERVICES, INC		FLORIDA POWER CORP.
38	FPL FIBERNET		FLORIDA POWER CORPORATION
39	FPL FIBERNET LLC		FLORIDA POWER CORPORATION AND
40			FLORIDA POWER CORPORATION DBA
41	**Florida Public Utilities Corporation**		
42	FLA PUBLIC UTILITIES CO		**Florida Public Utilities Corporation**
43	FLORIDA PUBLIC UTILITIES CO		FLA PUBLIC UTILITIES CO
44	FLORIDA PUBLIC UTILITIES CO.		FLORIDA PUBLIC UTILITIES
45			FLORIDA PUBLIC UTILITIES CO
46	**Gulf Power**		FLORIDA PUBLIC UTILITIES COMPA
47	GULF POWER CO		
48	GULF POWER COMPANY		**Gulf Power**
49	GULF POWER COMPANY (C)		GULF POWER CO
50	GULF POWER COMPANY (GB)		GULF POWER CO INC
51	GULF POWER COMPANY (M)		GULF POWER CO.
52	GULF POWER COMPANY (NAV BCH)		GULF POWER COMPANY
53			GULF POWER COMPANY INC
54	**Tampa Electric Company**		
55	TAMPA ELECTRIC CO		**Tampa Electric Company**
56	TAMPA ELECTRIC COMPANY		TAMPA ELECTRIC CO
57	TAMPA ELECTRIC DBA PEOPLES		TAMPA ELECTRIC COMPANY
58	TECO SERVICES INC		TAMPA ELECTRIC DBA PEOPLES GAS

Tab 7

Reports

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Appendix A: ECOM Model Annual Average Market Price

Appendix B: ECOM Model Results

Appendix C: Modifications to the ECOM Model

To put the ECOM estimates in perspective, it is useful to use a base for comparison. For the utilities that filed ECOM reports, annual Texas retail cost-of-service generation-related revenues are approximately $10.5 billion dollars per year. Thus, the $12.8 billion expected value for ECOM in the *1998Full* scenario is more than $2 billion greater than the annual generation-related revenues currently collected by utilities. In the *2000Full* scenario, the $7 billion expected value for ECOM is approximately $3.8 billion dollars less than the annual generation-related revenues currently collected by utilities in their regulated rates.

Comparing the estimated ECOM results with total fixed costs is another measure that is helpful to put the ECOM estimates in perspective. Utilities in Texas have a combined net present value of fixed costs[6] of approximately $32 billion. Thus, the $12.8 billion expected value for ECOM in the *1998Full* scenario is approximately 40 percent of the total fixed costs in the utilities' generation costs-of-service.

In comparing ECOM results for utilities of differing sizes and structures, the relative exposure to potentially strandable costs can be examined by *normalizing* the ECOM results, that is, transforming the absolute dollar amount of estimated ECOM to a unit of standard measure. Normalizing the estimates recognizes that the utilities with the largest ECOM may not necessarily be at risk from their potentially strandable investments. Though a large utility may have the largest ECOM, it will also have larger sales and more customers. Thus the *per customer* ECOM burden of a large utility may be much less than that of a smaller utility.

Normalizing the estimates can be achieved in a number of ways. For the purpose of comparison in this report, each utility's estimated dollar amount of ECOM is divided by the utility's installed generating capacity to arrive at a normalized ECOM value in terms of dollars per kilowatt. Figure ES–5 depicts the normalized utility ECOM results for the *1998Full* scenario in terms of ECOM dollars per kilowatt of installed generating

[ES–6] As described in Chapter VI, the fixed generation costs in this analysis include depreciation and return on current investment, federal income taxes, property taxes, nuclear decommissioning costs, and existing purchased power contract costs. The total fixed costs of approximately $32 billion ($1996) is the sum of the net present value of the fixed costs in each utility's ECOM filing.

capacity. As shown, while TU Electric has the greatest amount of ECOM in terms of absolute dollars, the utility ranks in the lower half of the group on a dollars per kilowatt basis. The graph also illustrates the high exposure to potentially strandable costs faced by the municipalities that comprise the Texas Municipal Power Authority, with these four cities showing relatively high normalized ECOM estimates.[7]

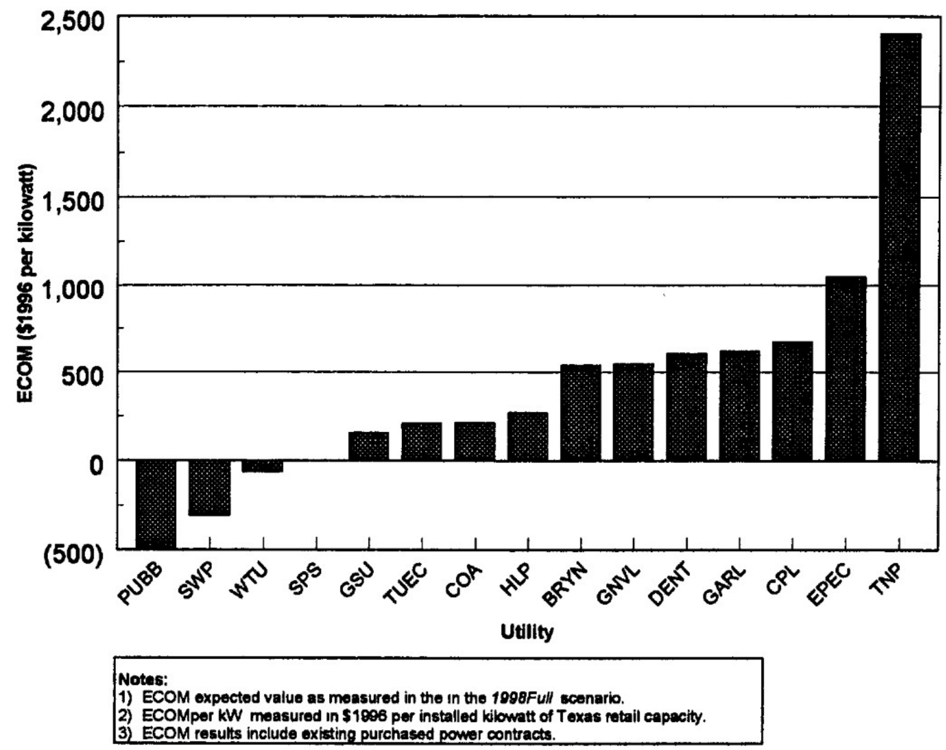

Figure ES–5: Normalized Texas Retail ECOM Model Results for the *1998Full* Scenario

Table ES–5 examines total Texas retail ECOM for the *1998Full* scenario by resource type (natural gas, coal/lignite, nuclear, and other). Nuclear assets comprise a large majority of potentially strandable costs, with an expected value of nuclear-related ECOM in excess of $15 billion. Excluding nuclear assets, the expected value of total Texas retail ECOM in the *1998Full* scenario is reduced to *negative* $2.3 billion.

ES-7 The Texas Municipal Power Authority is comprised of the Cities of Bryan, Denton, Garland, and Greenville.

Table ES–5: Total Texas Retail ECOM Summary by Resource Type (*1998Full* scenario)

Generation Resource Type	Expected Value of Texas Retail ECOM ($1996 million)
Natural Gas	$ 2,020
Coal/Lignite	(4,630)
Nuclear	15,085
Purchased Power/Other	341
Total	**12,816**
Total Excluding Nuclear	(2,269)

Note: See Appendix B for individual utility ECOM results.

In aggregate, the non-nuclear assets of Texas utilities are expected to generate power at average costs that are below the projected market price of electricity, primarily because the original capital investment in these non-nuclear assets is less than the nuclear investment, and the older non-nuclear assets have had time to become more fully depreciated. In addition, the operating costs of most of the non-nuclear assets are low relative to the projected market prices, thus providing a sizable margin in a competitive market that will serve to offset the remaining fixed costs of the non-nuclear generation assets.

The Commission's report on stranded investment presents a number of observations arising from its ECOM estimates:

- *Sensitivity to timing of retail access:* The timing of the implementation of retail access is key to determining the magnitude of ECOM, regardless of the other assumptions incorporated into the analysis.
- *Sensitivity to the market price:* Generally, for every one percent deviation from the projected base case market price, the estimated total Texas retail ECOM results will change by approximately $450 million on a net present value basis.
- *Rate of return:* In the ECOM Model, the rate of return for investor-owned utilities is specified at 10 percent.[8] The 10 percent rate of return is reflective of the various risks to which a utility is currently exposed, and is not reflective of the risk associated with *guaranteed* recovery of investments.

[ES-8] The rate of return for municipals, river authorities and cooperatives was specified at 7.5 percent; however, these entities were allowed to adjust this number to reflect their individual debt service requirements in each year of the forecast period.

- *Utility generation cost projections:* As described in Chapter VI, utilities were required to provide projections of their generation costs and sales for the life of the longest-lived plant in the utility's rate base. While these projections were examined for general consistency, a rigorous analysis of specific aspects of the generation costs was not performed. With the exception of the 10 percent O&M efficiency improvement adjustment, this analysis has not attempted to examine the impact of options that would allow utilities to reduce or mitigate their stranded cost exposure.

G. Rights and Expectations For ECOM Allocation

The Commission's report on stranded investment includes a substantive analysis of the rights and expectations for ECOM allocation. Allocation is the process of assigning all or a portion of ECOM to or among classes of parties, such as firm or interruptible ratepayers, shareholders, and service providers. The allocation issue is highly contentious, and as such, should be considered in careful detail. Some of the key arguments are described below.

1. Wholesale Contracts

One argument maintains that Texas utilities are not subject to a statutory obligation to serve wholesale customers. In wholesale transactions, there is no unwritten or "implied" contract that, in conjunction with the express written wholesale power sales contract, determines the legal rights and expectations of the parties. Because the wholesale transaction is governed by a written agreement, the utility:

1. Does not have a definitive legal right, based on contract law, to demand continued purchases after the lawful termination of the wholesale contract; and
2. Cannot reasonably claim that it must stand ready to serve a wholesale customer that lawfully terminated (or never commenced) service in accordance with its wholesale service contract.

If the contract is silent as to ECOM or continuing cost allocation and recovery issues, and is otherwise unambiguous, the wholesaler arguably does not have a valid legal right or expectation to ECOM recovery from the purchaser beyond the term of the contract. This conclusion is based on the well-settled "parol evidence" rule, which:

> *renders inadmissible any testimony to vary the legal effect of a writing in the absence of any ambiguity, accident, mistake, or fraud shown in connection with the contract.*

Alternatively, one may adopt the "rebuttable presumption" course taken by the FERC in its Order No. 888. If this rebuttable presumption approach is adopted, a party to a wholesale contract would be permitted to rely on parol evidence in an attempt to prove that an apparently clear and unambiguous wholesale contract does not absolutely reflect the parties' expectations.

2. Retail Transactions.

Unlike the written contracts in wholesale transactions, the State (through the Commission) regulates public utility *retail* (or final use) rates and services. Except for a few large customers, there are no written contracts between utilities and their retail customers. Instead, the current arrangement in Texas between consumers and their municipality, cooperative, river authority, or IOU suppliers is predicated on a form of unwritten "implied contract" that requires the consumer to pay for service taken from the utility at the rate established in the ordinance then in effect. In addition to an implied contract to pay for power actually taken, a *regulatory compact* arguably exists between the State and utility. This regulatory compact requires the utility to provide adequate and reliable service at fair rates to all consumers within the utility's certificated service area. In return for this *public* service, the State, through the Commission (or municipal authority), agrees to set rates that provide a reasonable opportunity to earn a reasonable return on its invested capital as well as reasonable and necessary operating expenses. Because the implied contract and the regulatory compact are not bilateral written agreements, it is more difficult to determine the legal rights and expectations arising from retail transactions, as compared to wholesale transactions.

In addition, ECOM allocation issues that apply to IOUs do not necessarily pertain to cooperatives, river authorities, and municipal utilities. A cooperative's or municipal utility's owners, "shareholders," ratepayers, and customers are generally one-and-the-same. Accordingly, cooperatives and municipalities argue that, regardless of the allocation, the members/citizens, as also the "shareholders"/owners, must foot the entire bill.

3. Summary of Allocation Conclusions

Regardless of the allocation method adopted, ECOM should be allocated and recovered in a way that places the lowest possible cost burden on the parties. To reach this goal, the public interest would appear to require an allocation method that:

1. Does not inhibit the transition to competition;
2. Provides benefits if possible (such as providing incentives to shut down inefficient generation facilities that may otherwise continue to operate in a regulated market);
3. Allocates only verifiable, non-mitigatable ECOM; and
4. Provides incentives to ensure that the utilities' ECOM is reduced to the lowest amount possible.

The Legislature may also consider whether utility divestiture of generation plant will further the public interest and enhance competition. If so, an allocation method could be adopted that provides a utility and its shareholders with significant ECOM recovery if it agrees to divest its generation plant. This approach has the added benefit of clearly defining that utility's ECOM—the difference between the present book value of the plant, and the purchase price paid by the entity that acquires the divested plant.

An allocation method may also best serve the public interest, both equitably and legally, if it ensures that ECOM is allocated to the broadest possible base. For example, if ECOM is allocated to all constituencies, it should be allocated in an appropriate manner to: (1) all ratepayers, regardless of whether they are firm or interruptible, high or low load factor, industrial, commercial, or residential ratepayers; and (2) the utilities. If ECOM is allocated only to ratepayers, it should be allocated in an appropriate manner to all ratepayers regardless of class. If ECOM is to be allocated solely to the utilities, the utilities can be left with the discretion to determine how to deal with the allocation encompasses. Table IV-2 identifies Texas investor-owned utilities by NERC region. Figure IV-1 is a map of the State of Texas that shows the boundaries of the Electric Reliability Council of Texas, the Southwest Power Pool and the Western Systems Coordinating Council.

Table IV-2: Texas Investor Owned Utilities

Utility Name	Acronym	NERC Region
Central Power and Light Co.	CPL	ERCOT
El Paso Electric Company	EPE	WSCC
Gulf States Utilities	GSU	SPP
Houston Lighting and Power Co.	HL&P	ERCOT
Southwestern Electric Power Company	SWEPCO	SPP
Southwestern Public Service Company	SPS	SPP
Texas Utilities Electric Co.	TUEC	ERCOT
Texas-New Mexico Power Co.	TNP	ERCOT
West Texas Utilities	WTU	ERCOT

Source: Office of Regulatory Affairs, *1996 Statewide Electrical Energy Plan for Texas,* Austin, TX: Public Utility Commission of Texas (June 1996).

The remainder of this chapter is organized as follows: Section A discusses Moody's stranded cost study; Section B explains S&P's lost revenue approach; Section C describes DRI's estimated stranded investment results; Section D discusses Fitch's utility generation costs; Section E compares the different results estimated for Texas; and Section F describes RII's asset-by-asset stranded investment study of Massachusetts utilities.

A. MOODY'S ESTIMATE OF STRANDED COST

Moody's Investors Service published a study estimating stranded costs for U.S. investor-owned utilities in August 1995. Moody's top-down analysis begins with the determination of a utility's break-even price.[47]

[47] Fremont, Paul B., Rogihn K. Hornstra, Susan D. Abbott, and M. Douglas Watson, Jr., *Stranded Costs Will Threaten Credit Quality of US Electrics*, New York, NY: Moody's Investors Service, Special Comment (August 1995).

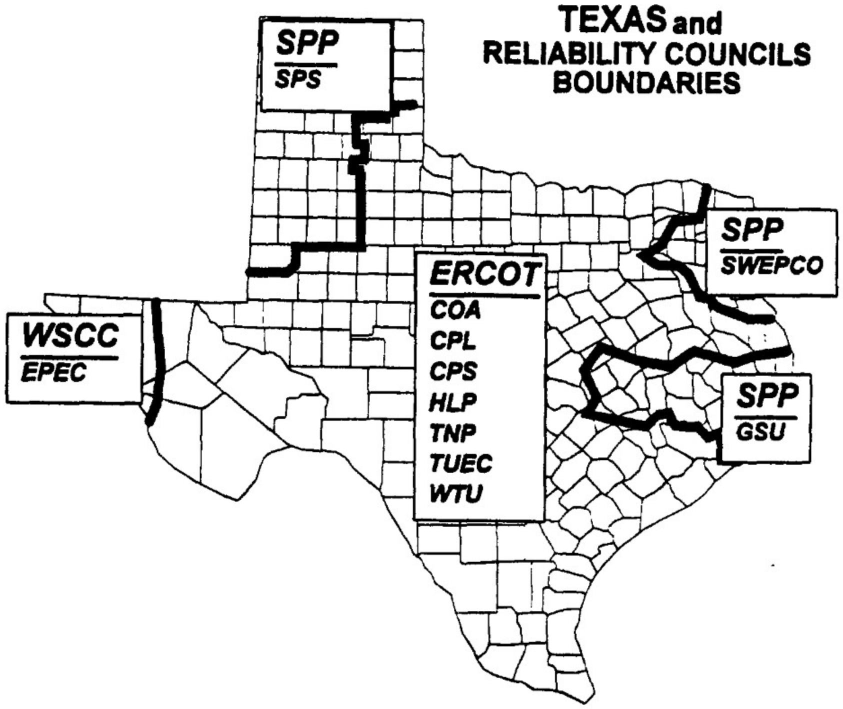

Figure IV-1: Utilities in Texas with NERC Region Boundaries

Moody's defines the break-even price as the minimum price at which a company must sell electric capacity, both owned and purchased, to recover all of its fixed production costs. Moody's argues that if a company's margin from selling electric energy does not cover all fixed costs, it must make up the difference by charging customers for electric capacity. The size of the gap between total fixed costs and the amount recovered by margins determines the amount of revenue a company must generate from capacity sales in order to break-even or cover its total generating costs.[48] The total amount of potentially stranded costs for any electric utility is equal to the difference between its break-even price and the market price for capacity, times the amount of the company's capacity.[49]

[48] Moody's defines fixed costs to include current cash expenditures such as non-fuel operating and maintenance expenses, fixed payments under long-term power contracts, interest, property taxes, and depreciation. Adjusted break-even prices and equity for each company were calculated using 1993 FERC Form 1 reports.

[49] Fremont, *supra* at 1 - 6.

Table IV-3: Moody's Market Price Assumptions

NERC Region	Energy (cents/kWh)	Capacity ($/kW)
ECAR	1.7	$ 40
ERCOT	1.8	30
MAAC	1.9	45
MAIN	1.7	40
MAPP	1.3	45
NPCC	2.0	45
SERC	2.0	30
SPP	1.7	20
WSCC	2.4	35

Source: *Stranded Costs Will Threaten Credit Quality of US Electrics*, Moody's Investors Services, Special Comment at 10 - 18 (August 1995).

Table IV-3 shows Moody's energy and capacity pricing assumptions for each NERC region. Under Moody's pricing assumptions, ERCOT is almost exactly at the median price for both energy and capacity. ERCOT's energy prices reflect the region's diverse fuel mix. The lower capacity prices reflect the fact that there are only four operating nuclear plants in ERCOT. Nuclear plants tend to have higher costs than other types of plants because of the high capital costs associated with them. Moody's asserts that the "forces of supply and demand" determine the value of capacity. Moody's contends that in a surplus situation, capacity has little or no value; when capacity is in short supply, the value is determined by the cost of a new plant. Moody's believes that there will be surplus capacity in every region of the country and that utilities will close plants with higher operating costs if they are not needed to satisfy demand.[50]

Moody's analysis uses a 10-year transition period to competition beginning in 1996. Moody's assumes that companies would be able to fully write-off plant values and deferred assets over the 10 years. Each year that the break-even price for a company is above the regional market price for capacity, the company incurs stranded costs. The losses during the 10-year period are discounted using present value calculations and a 9 percent discount rate.[51]

Moody's estimates that stranded costs in the United States will total about $135 billion with losses concentrated in the northeastern and western United States. Moody's

[50] *Id.* at 1 - 6.

[51] *Id.* at 1 - 6.

results rest on the current and previously incurred fixed costs associated with production such as purchase power contracts and nuclear power plants. Moody's concludes that the NERC regions with exposure to stranded costs are those whose utilities have high break-even prices for owned and purchased generation, large amounts of deferred assets, and low market prices for capacity. ERCOT is in a good position to incorporate market-based pricing of electricity relative to other NERC regions. Table IV-4 shows Moody's stranded cost estimates for each NERC region.

Table IV-4: Moody's Estimated Stranded Costs in NERC Regions

NERC Region	Estimated Capacity (kW)	Equity ($ millions)	Stranded Costs ($ millions)	Stranded Costs/ Equity
ECAR	92,516,139	$ 22,330	$ 20,164	90 %
ERCOT	42,485,969	11,638	10,307	89
MAAC	52,105,651	19,838	13,303	67
MAIN	47,666,966	12,351	5,984	48
MAPP	19,245,520	4,515	632	14
NPCC	57,242,833	18,124	29,544	163
SERC	100,183,491	26,066	11,261	43
SPP	50,124,441	12,159	14,384	118
WSCC	79,224,938	26,501	28,863	109
TOT/AVG	540,795,948	153,522	134,442	88

Source: *Stranded Costs Will Threaten Credit Quality of US Electrics*, Moody's Investors Services, Special Comment at 10 - 18 (August 1995).

Moody's estimates stranded costs for Texas to total about $12 billion. Table IV-5 summarizes the results of Moody's stranded cost study of Texas IOUs. TUEC has the highest estimated stranded costs, about $5 billion. TNP has the highest break-even price ($136/kW) and the highest stranded cost relative to equity (337 percent) of all the Texas utilities included in the study. SWEPCO has the lowest break-even price, and has the second lowest estimated stranded cost. WTU is in the best position; it faces no stranded costs, and has a break-even price that is lower than the calculated ERCOT market price for capacity.

Moody's indicates that the $135 billion estimate for stranded costs is probably understated because current fixed payments made under long-term fuel contracts were not included in the calculations. In addition, the estimated average market price for

Table IV-5: Moody's Estimated Stranded Costs for Texas IOUs

Company	Break-Even ($/kW)	Estimated Capacity (kW)	Equity ($ millions)	Stranded Costs ($ millions)	Stranded Costs/ Equity
CPL	$ 67	4,206,869	$ 1,424	$ 999	70 %
EPE	109	1,043,559	(239)	497	N/A
GSU	94	2,760,673	851	1,320	155
HL&P	71	14,279,796	3,705	3,737	101
SWEPCO	22	1,532,076	220	21	9
SPS	26	2,210,248	377	88	23
TNP	136	1,065,667	214	722	337
TUEC	65	21,568,573	6,029	4,849	80
WTU	25	1,365,064	266	0	0
TOT/AVG		50,032,525	12,847	12,233	95

Note: The break-even price includes an adjustment for deferred assets. Texas jurisdiction of capacity, equity, and stranded costs calculated by Commission Staff based on a generation demand allocator of 67 percent for EPE, 44 percent for GSU, 54 percent for SPS, and 34 percent for SWEPCO.

Source: *Stranded Costs Will Threaten Credit Quality of US Electrics*, Moody's Investors Services, Special Comment at 10 - 18 (August 1995).

capacity may be higher than what could actually result because there is currently excess generation capacity. Finally, the utilities may be forced to write-off plant values and deferred assets immediately. According to the study, if regulators do not allow incremental write-off over the full 10-year period, stranded costs will increase due to the time value of money.[52]

B. STANDARD & POOR'S ESTIMATED LOST REVENUES

S&P published an administrative study estimating lost revenues for US utilities in November 1995. S&P used a top-down approach to measure the annual revenues that electric utilities would lose if retail markets were opened to direct access. Under direct access, wholesale and retail customers would be able to choose their power generator, and electricity prices would be determined by the market.

[52] *Id.* at 1-6.

Table IV-6: S&P Estimated Production Costs for Texas IOUs (cents/kWh)

Utility	Generation Costs				Purchased-Power Costs	Total Generation & Purchased Power Costs
	Residential	Commercial	Industrial	Total		
CPL	6.94	7.10	3.55	5.55	1.78	5.14
EPE	9.18	8.09	4.89	6.37	2.66	5.79
GSU	7.25	6.43	3.95	5.26	2.84	4.81
HL&P	6.97	5.72	3.27	4.85	4.30	4.88
SWEPCO	5.14	4.15	3.14	3.42	.70	3.17
SPS	4.68	4.19	2.75	3.13	1.76	3.12
TUEC	6.38	5.33	3.41	5.15	4.33	5.13
TNP	10.78	10.15	5.54	8.45	4.31	5.55
WTU	5.32	3.98	2.93	3.47	1.76	3.40

Source: Bilardello, John, and Michael Cole, Standard & Poor's, Utilities and Perspectives, Special Edition, *Direct Access Threatens Electric Utility Revenues*, Vol. 2, No. 48 at 4 - 5 (November 27, 1995).

S&P derived generation costs by multiplying the total net income contribution from owned generation by the portion of total assets dedicated to generation. Production costs were segmented by customer type based on the relationship between actual residential, commercial, and industrial rates to average rates. Table IV-6 summarizes S&P's estimation of production costs for major Texas IOUs.

S&P based the lost revenues estimate on assumptions about unregulated electricity prices and load factors shown in Table IV-7. A load factor compares average demand to peak demand, and is always shown as a percentage. Industrial customers typically have a high load factor, indicating that they use more electricity relative to their expected peak use than other customers. "Higher load factors tend to reduce average power costs because the investment costs for equipment are spread over more energy consumption."[53] S&P's higher price for residential customers reflects their lower load factor. The prices in Table IV-7 do not include any services associated with transmission and distribution, which S&P estimates to add about 1.5 cents per kWh to

[53] Fink, Donald G., and H. Wayne Beaty, *Standard Handbook for Electrical Engineers*, Eleventh Edition, New York, NY: McGraw-Hill Book Company at 12 - 17 (1978).

rates for all customer segments. The prices used in the model are for illustrative purposes only. S&P was not trying to predict market prices.[54]

Table IV-7: S&P's Lost Revenue Assumptions

Customer Class	cents/kWh	Load Factor
Industrial Rate	2.50	80 %
Commercial Rate	3.75	60
Residential Rate	5.00	40

Source: Bilardello, John and Michael Cole, Standard & Poor's Utility Perspectives, Special Edition, *Direct Access Threatens Electric Utility Revenues* at 3 (November 27, 1995).

The difference between the assumed market rates for generation and each utility's production costs was multiplied by the three-year average sales volume for each utility to arrive at an estimate of potential lost revenues. The S&P study calculated lost revenues for two scenarios: a Reasonable Case and a Severe Case. The Reasonable Case Scenario assumes that competition will not occur in residential markets for several years, and contains estimates of potential lost revenues from the commercial and industrial sectors only. The Reasonable Case also assumes recovery of 50 percent of lost revenues. The Severe Case Scenario estimates potential lost revenues occurring if all three customer segments were opened to competition at the same time. This study determined that lost revenues would range from $10 billion to $26 billion per year for the entire country. The result translates into 6 to 16 percent of annual utility revenues. S&P identifies utilities with high generation costs and a heavy industrial customer base to be most at risk.

S&P estimates that Texas utilities could lose $700 million to $2 billion in revenues because of competition. Table IV-8 shows S&P's result for Texas' nine major IOUs. Under the Reasonable Case Scenario, TUEC could lose $266 million in revenues, suffering the most from competition in commercial and industrial customer classes. WTU could be much better off, losing only $3 million. A comparison of lost revenues to total revenues shows that GSU and TNP tie for the worst position, with 8.2 percent of total revenues lost to competition.

[54] Bilardello, John, and Michael Cole, *Direct Access Threatens Electric Utility Revenues*, Standard & Poor's at 1 - 8 (November 27, 1995)

Table IV-8: S&P Lost Revenues for Texas IOUs

Utility	Severe Case: Total Lost Revenues ($ millions)	Severe Case: Total Lost Revenue as Percent of Total Revenues	Reasonable Case: Total Lost Revenues ($ millions)	Reasonable Case: Total Lost Revenue as Percent of Total Revenues
CPL	242.51	20.8	83.04	7.1
EPE	85.74	23.4	26.38	7.2
GSU	174.61	23.0	62.14	8.2
HL&P	761.87	19.6	226.91	5.8
SWEPCO	5.29	2.0	4.45	1.6
SPS	10.32	2.4	7.59	1.8
TUEC	894.11	16.9	266.13	5.0
TNP	117.11	25.7	37.44	8.2
WTU	8.85	2.7	3.01	0.9
TOTAL	2,300.41		717.09	

Note: Total lost revenues include purchased power. Texas jurisdiction of potential lost revenues calculated by Commission Staff based on a generation demand allocator of 67 percent for EPE, 44 percent for GSU, 54 percent for SPS, and 34 percent for SWEPCO.

Source: Bilardello, John, and Michael Cole, *Direct Access Threatens Electric Utility Revenues* at 6 - 7 (November 27, 1995).

S&P also estimated lost revenues by customer segment. Table IV-9 shows the figures for Texas IOUs. The largest estimated loss is by TUEC in the residential sector, close to $350 million. In contrast, S&P estimates that SPS will have a negative loss, or a gain of $4.4 million from its residential customers.

C. DRI/McGraw-Hill Stranded Costs

DRI published its *Electricity Outlook for Spring-Summer 1996* incorporating an estimation of stranded investments.[55] DRI uses a top-down approach with very general assumptions in its methodology.

DRI assumes that electricity prices would decline between the years 1995 and 2020 due to declining coal prices and improvements in generating plant heat rates. DRI also expects increased competition to lead to decreases in industry reserve margins, peak

[55] Yanchar, Joyce, and Michael Mendelsohn, *Electricity Outlook*, DRI/McGraw-Hill World Energy Service U.S. Outlook, (Spring-Summer 1996).

Table IV-9: S&P Lost Revenues from Generation for Major Texas IOUs by Customer Segment ($ millions)

Utility	Residential	Commercial	Industrial	Total
CPL	$ 96.08	$ 126.68	$ 58.29	$ 281.04
EPE	34.57	40.61	13.14	88.32
GSU	56.93	54.84	75.38	187.14
HL&P	272.59	211.24	190.43	674.27
SWEPCO	1.76	3.99	11.98	17.73
SPS	(4.40)	6.09	9.90	11.58
TUEC	347.16	325.42	171.28	843.87
TNP	35.06	29.90	23.46	88.42
WTU	4.34	2.44	5.02	11.80
TOTAL	386.56	801.21	558.88	2,204.17

Note: Total does not include purchased power. Texas jurisdiction of potential lost revenues calculated by Commission Staff based on a generation demand allocator of 67 percent for EPE, 44 percent for GSU, 54 percent for SPS, and 34 percent for SWEPCO.

Source: Bilardello, John, and Michael Cole, *Direct Access Threatens Electric Utility Revenues* at 6 - 7 (November 27, 1995).

demands, administrative and operating costs, and write-offs of uneconomic assets. The DRI model anticipates that all states will allow utilities to recover 80 percent of their stranded costs. DRI based its stranded cost on the difference between the region's industrial electricity price (less transmission and distribution costs) and the long-run marginal generation cost in the base-load generation, multiplied by the volume of electricity demand expected to be at risk in the region. The long-run marginal cost is the weighted average of the levelized costs associated with new coal or gas generation units. The price of natural gas or coal and the technology available in each region accounts for the variation in costs between regions. Average electricity prices are assumed to be 5 to 6 cents per kWh above long-run marginal costs in the highest-price regions, and 2 to 4 cents per kWh above the long-run marginal costs in most other regions. Table IV-10 shows DRI's forecast for long-run marginal costs and average electricity prices for the West South Central Region that consists of Texas, Oklahoma, Louisiana, and Arkansas.[56]

[56] Yanchar *supra* at 49-51.

Table IV-10: DRI Generating Costs and Price of Electricity for the West South Central Region of the United States

	Long-Run Marginal Cost (cents/kWh)			Average Electricity Price
Year	Base	Peak	Average	(cents/kWh)
1995	4.9	9.3	5.6	6.0
2005	6.4	11.3	7.1	7.1
2020	10.7	18.1	11.8	11.3

Source: Yancher, Joyce and Michael Mendlesohn, *Electricity Outlook,* DRI/McGraw-Hill World Energy Service U.S. Outlook (Spring-Summer 1996).

DRI estimates that stranded costs for the United States will total about $87 billion. The model assumes functional but not structural unbundling of generation from transmission and distribution activities.[57] The results from the Reference Case analysis are shown in Table IV-11. DRI's calculation was performed on a regional level and its results do not indicate which individual utilities would have stranded costs. The results indicate that the coastal regions of New England and Pacific II (California and Hawaii) are at risk for more than one-third of their rate base. The study indicates that the West South Central region, which includes Texas, will have no stranded costs.

D. FITCH REPORT

The Fitch Report is a top-down administrative study that measures companies' fixed and variable costs. While this study does not estimate stranded investment, it provides insight into the relative cost positions of IOUs in the United States. The authors chose to use FERC data because reporting is conducted at the individual operating utility level, has a high degree of compliance,[58] and cost information could be identified by cost elements and business sectors.

[57] DRI/McGraw-Hill, *The Future of the Electric Power Industry Around the World, Volume IV, North America* at 20.

[58] Only three utilities did not file in 1995: Central Hudson Gas & Electric Corp., Consolidated Edison Co. of New York, Inc., and San Diego Gas & Electric Co. The utilities argued that filing would expose competitive data, placing them at a disadvantage in the marketplace.

Table IV-11: DRI Estimated Stranded Costs

Region	Stranded Costs ($ billions)	Present Value of Stranded Costs ($ billions)	Present Value as Share of Current Rate Base (%)
New England	$16.6	$12.7	59 %
Middle Atlantic	21.5	16.5	13
South Atlantic	12.2	9.3	13
East North Central	0.0	0.0	0
West North Central	2.7	2.0	0
East South Central	7.5	5.8	36
West South Central	0.0	0.0	0
Mountain 1	0.0	0.0	0
Mountain 2	3.4	2.6	18
Pacific 1	0.0	0.0	0
Pacific 2	24.0	18.4	54
U.S.	87.9	67.3	17

Note: DRI's present value calculation assumes assets are stranded in equal portions between 1997 and 2002.

Source: Yancher, Joyce and Michael Mendlesohn, *Electricity Outlook*, DRI/McGraw-Hill World Energy Service U.S. Outlook (Spring-Summer 1996).

Fitch used an embedded cost model because of the belief that investment in fixed assets valued at historical cost drives the electric utilities' existing cost structures.[59] The model estimates a utility's current fixed and variable costs associated with power supply, transmission and distribution functions. Fitch's model estimates a company's underlying cost structure; it is not a detailed utility-specific cost study. Fitch uses the following simplifying assumptions:

1. Utility plant assets are valued at historical cost less depreciation;
2. Return of capital and return on capital invested in utility plant are based on embedded costs;
3. Each utility is entitled to earn a return on all net electric plant equal to the return authorized in the utility's last electric rate case; and
4. Recovery of regulatory assets and deferred assets are not included as a cost.[60]

[59] Lapson, Ellen, and Edward J. King, *Electric Utility Competitive Operating Statistics*, Fitch Research at 2 (October 30, 1995).

[60] *Id.* at 3.

Table IV-12: Fitch Estimated Embedded Cost of Electric Service for NERC Regions (cents/kWh)

NERC Region	Power Supply	Transmission	Distribution	General and Administrative	Total Embedded Cost
ECAR	3.74	0.30	0.90	0.54	5.48
ERCOT	4.41	0.32	1.02	0.66	6.42
MAAC	4.92	0.38	1.54	0.84	7.68
MAIN	3.56	0.24	1.08	0.60	5.49
MAPP	3.19	0.48	1.01	0.57	5.25
NPCC	5.56	0.52	1.89	0.88	8.79
SERC	3.87	0.30	1.12	0.71	6.53
SPP	3.52	0.32	0.92	0.57	5.32
WSCC	4.04	0.46	1.21	0.73	6.44

Note: Estimate is for year ended 12/31/95.

Source: Lapson, Ellen, and Edward J. King, *Electric Utility Competitive Operating Statistics*, Fitch Investors Service, LP, Special Report at 10 - 13 (October 30, 1995).

Fitch's results indicate that power supply costs make up the majority of the utilities' embedded costs, followed by distribution, then general and administrative costs, with transmission costs being the smallest part. Table IV-12 shows that ERCOT's embedded costs are about average when compared to the other NERC regions. General and administrative costs for ERCOT are lower than in other regions but power supply and transmission costs are slightly above average. Table IV-13 contains Fitch's embedded cost results for Texas IOUs. At 8.09 cents per kWh, TNP has the highest total embedded cost, while SPS enjoys the lowest at 4.07 cents per kWh.

E. Comparison of Texas Results in National Studies

The studies discussed in the previous sections used different approaches to arrive at an estimate of the effect of competition. To the extent that these studies are all measuring the end result of a transition to a competitive electric generation market, a broad comparison of the final numbers can be made. Because of the very different assumptions and methodologies used in each study, a more detailed comparison is not appropriate. Further caution is necessary when comparing the results from the studies because Moody's estimates are stated in terms of net present value, while S&P's and DRI's estimates are stated in terms of nominal values.

Table IV-13: Fitch Estimated Embedded Cost of Electric Services for Major Texas IOUs (cents/kWh)

Utility	Power Supply	Transmission	Distribution	General and Administrative	Total Embedded Cost
CPL	4.37	0.33	0.85	0.70	6.25
EPE	5.28	0.47	0.72	1.01	7.48
GSU	4.06	0.29	0.60	0.87	5.82
HL&P	4.01	0.19	0.90	0.85	5.95
SWEPCO	2.76	0.28	0.71	0.39	4.13
SPS	2.90	0.32	0.51	0.35	4.07
TUEC	4.96	0.24	0.92	0.43	6.55
TNP	5.54	0.43	1.46	0.65	8.09
WTU	3.17	0.43	0.99	0.67	5.26

Note: Estimate is for year ended 1995.

Source: Lapson, Ellen, and Edward J. King, *Electric Utility Competitive Operating Statistics*, Fitch Investors Service, LP, Special Report at 10 - 13 (October 30, 1995).

Table IV-14 summarizes the estimates from Moody's, S&P, and DRI studies. These very different estimates of the effects of competition illustrate the level of uncertainty that *ex ante* administrative studies are attempting to quantify. The large variance of the results also points to the potential error involved in this type of analysis.

Table IV-14: Estimated Effects of Competition on Texas, ERCOT and United States ($ millions)

Study	ERCOT	Texas	U.S.
Moody's Stranded Costs Estimate	$ 10,307	$ 12,233	$ 134,442
S&P's Lost Revenue Estimate (Reasonable Case Scenario)	616	717	10,000
DRI's Stranded Costs Estimate (Reference Case Scenario)	Not Available	Not Available	87,800

Note: DRI estimates $0 stranded costs for the West South Central Region, which includes Texas, Oklahoma, Louisiana, and Arkansas. The West South Central Region is the smallest regional breakdown that includes Texas provided in DRI's study.

Despite the large variance in the absolute losses estimated by the administrative studies, the *relative* positions of Texas utilities are fairly constant: Texas' higher cost utilities will probably have the highest amounts of potentially strandable assets. Table IV-15 displays the relative ranking of each Texas IOU; a ranking of 1 indicates least losses/least cost and a ranking of 9 indicates the most losses/highest cost. The rankings were determined by normalizing Moody's and S&P's results in order to compare them with Fitch's embedded cost of service estimates. Normalization was achieved by dividing the study results by 1995 sales as reported to the Commission.

The uniformity of the normalized results between Moody's, S&P and Fitch studies may serve as a general indicator of which Texas utilities may have the largest quantities of potentially strandable investment. The fifth column in Table IV-15 lists the utilities' reported 1995 sales in the state of Texas and indicates that utility size does not appear to be a determinant for relative success in a competitive market. EPE, GSU, TNP and TUEC share the 7, 8, and 9 ranking, indicating that they may have higher relative strandable investment than the other Texas utilities. The rankings for EPE, GSU and TUEC reflect large investments in nuclear plants. The high costs of a fluidized-bed generation plant may be the primary cause of TNP's low rank.

WTU, SWEPCO, and SPS consistently rank 1, 2, or 3, indicating that these three utilities could have an easier transition to a market pricing environment. This situation is probably due to the fact that SPS, SWEPCO, and WTU generate electricity by burning coal and natural gas only; they have no nuclear capital or decommissioning costs. Section C of Chapter VII contains additional information about each utility.

Table IV-15: Relative Position of Texas IOUs

Utility	Moody's Stranded Investment	S&P Lost Revenue (Reasonable Case)	Fitch Embedded Cost of Service	1995 Sales (MWh)
CPL	4	6	6	19,592,050
EPE	8	8	8	4,348,559
GSU	7	7	4	13,679,884
HL&P	6	5	5	60,384,443
SPS	3	3	1	13,786,346
SWEPCO	2	1	2	9,805,580
TNP	9	9	9	5,082,191
TUEC	5	4	7	89,062,760
WTU	1	2	3	6,400,437

Note: 1995 sales are as reported for the Texas jurisdiction only.

Source: Office of Regulatory Affairs, *1996 Statewide Electrical Energy Plan for Texas*, Austin, Texas: Public Utility Commission of Texas (June 1996).

F. MASSACHUSETTS STUDY

Resource Insight, Inc. (RII), published the results of a study prepared for the Massachusetts Attorney General that estimated potentially strandable investment for five major Massachusetts utilities in April 1996. The five utilities studied were: Boston Edison (BECo); Cambridge Electric; Commonwealth Electric (ComElectric); the portion of New England Electric System's (NEES) attributable to Massachusetts; and Western Massachusetts Electric Company (WMECo). This study is a bottom-up analysis that attempts to quantify the sale price of individual utility assets. The stated objective of the study is to "estimate the price that would be paid by the high bidder for each generation asset in a competitive market."[61]

RII defines stranded investment as the difference between net plant and the present value of future operating profits, as of January 1, 1998. RII used data from the utilities' 1994 FERC Form 1 to estimate net plant. Operating profits were calculated as the present value of the market value of energy and capacity, less annual expenditures for fuel, operations and maintenance expenses, and nuclear capital additions (including taxes). The *New England Power Pool's 1995 Capacity, Energy, Load and Transmission Report*, which predicts a capacity deficiency by the year 2003, was used to develop forecasts of market prices of capacity and energy.[62] Because the Massachusetts study was based on the analysis of individual generating plants, RII made many assumptions regarding plant operations. The assumptions are necessary because the utilities in the study do not maintain plant level data of the type necessary for a bottom-up stranded investment study. Table IV-16 summarizes the assumptions RII used in its base case scenario.

[61] Chernick, Paul, Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster, *Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities*, Resource Insight, Inc. at 1 - 12 (April 17, 1996).

[62] Chernick, *supra* at 6.

Table IV-16: The Massachusetts Study, Base-Case Assumptions & Inputs

	Global Assumptions
General and Administrative Expenses	Non-fuel operations and maintenance expenses adjusted upwards by 20 percent
Discount Rate	10 percent - similar to utility embedded and marginal costs of capital
Bidders' Beliefs that Underlie their Behavior	• Plant performance and costs can continue at historical levels as they did under incumbent management • Market values of capacity and energy will bear the same relationship to the plants' operating costs as described above • Bidders can finance the plants at costs similar to utility costs of capital
	Nuclear Inputs
Capacity Factors	65 to 85 percent
Capital Additions	Set at average of recent costs for each unit and continued at that rate through the plants' scheduled operating life
Non-fuel Operations and Maintenance Expenses	Increase annually at 1 percent in real terms
Nuclear Fuel Costs	Held constant at 6 mills/kWh in 1996 dollars
Operating Life	Operate until the end of its license
	Non-Nuclear Inputs
Fossil Fuel Prices	• Interruptible gas will reach $2.98/MMBtu and #2 oil will reach $4.60/MMBtu by 2003 (in 1996 dollars) • For dual-fuel plants, assumed average fuel price would be 90 percent of the price of residual oil
Capital Additions	Not considered significant for non-nuclear plants, therefore assumed to be zero
Operating Life	• 18 years for fossil units • 38 years for hydroelectric units
Peaking Capacity	Fossil peakers are treated as having no fuel costs and no energy benefits
Capacity Factor	• 50 percent for oil and dual-fuel steam plants, except Canal 1 (60 percent) and West Springfield 3 (20 percent) • 80 percent for coal plants • 50 percent for firm gas plants • 40 percent for NEES and 60 percent for WMECo conventional hydroelectric plants • 8 percent for pumped-storage hydroelectric
	Market Prices
Capacity	Trending upwards from $10.56 in 1996 to $51.75/kW in 2003.
Energy	Trending upwards starting from $25/MWh in 1995 to $42.75/MWh (the cost of a new gas combined-cycle plant) in 2003.

Source: Chernick, Paul, et al., *Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities*, Resource Insight, Inc. (April 17, 1996).

Under the base case scenario, all the generation assets studied produced positive present values of operating profits except Millstone 1 & 2 and Pilgrim.[63] The two plants were considered uneconomical to operate, and RII stated that they should be retired regardless of whether the electric industry is restructured. In the base case, the two plants have no value to any potential bidder. For the remaining plants, the present value of the operating profit represented the market value of the utility's plant investment.

The RII study predicted stranded investment for the Millstone 3 unit and the shares of the Seabrook nuclear plant owned by Cambridge and ComElectric. The study predicted that the Maine and Vermont Yankee nuclear plants, NEES's share of Seabrook and each utility's groups of fossil steam plants, combustion turbines and hydroelectric plant would produce a restructuring gain.[64] RII expects net profit from selling generation at market prices to be $250 to $500 million for each Massachusetts utility, except NEES, which will be about $2.7 billion. According to RII, NEES's restructuring gain is higher because it owns more generation assets, will receive a small net gain from its nuclear assets, and has large hydroelectric resources which are very valuable.[65]

To test the robustness of the study, RII ran four alternative scenarios: improved nuclear performance; increased discount rate; lower fuel prices; and extremely low market price. The results from the base case scenario were maintained for all of the alternative scenarios except the extremely low market price. Under the extremely low market price scenario the long-term market price for electricity is approximately $32/MWh.

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[63] The Millstone plant consists of three units located in New London County, Connecticut. Millstone is owned by the Northeast Nuclear Energy Company. Millstone 1 began operation in 1970 and has a nameplate capacity of 661.5 mw. Millstone 2 began operation in 1975 and has a nameplate capacity of 909.9 mw. Millstone 3 began operation in 1986 and has a nameplate capacity of 1,253.1 mw. Pilgrim is a Boston Edison Company nuclear power plant located in Plymouth County Massachusetts. Pilgrim began operation in 1972 and has a nameplate capacity of 678 mw.

[64] More recently, Northeast Utilities (NU) announced the closure of its Connecticut Yankee nuclear power station. The president of NU's nuclear division stated, "It's all about economics . . . We looked at the value of the plant to our customers over its remaining lifetime and concluded that the right economic choice was to leave the unit shut down." Reukin, Andrew C., "Connecticut Reactor to Close, A Victim of Economic Change," *New York Times,* at 18 (December 5, 1996).

[65] Chernick, *supra* at 12.

With such a price, which RII claims is very unlikely, most of New England's nuclear generation would be retired, as well as many older fossil fuel plants.[66]

RII acknowledges that its results are "strikingly different" from those filed by the major Massachusetts electric utilities in February 1996. The utilities all attested that their generation assets would have zero market value in a restructured industry, and requested stranded investment charges to fully recover the net plant investment. RII states that "large levels of stranded investment are the result of poor plant performance or low market prices, either of which would also result in retirement of large amounts of capacity, regardless of industry structure."[67] RII concludes that the market valuation of most utilities' generation assets will exceed their net investment, resulting in large restructuring gains. RII also states that divestiture appears to be the most promising method for determining potentially stranded investment.

[66] *Id.* at 17.

[67] *Id.* at 2.

A. Objective of the ECOM Model

As noted in Chapter I, ECOM is a measure of the magnitude of a utility's potentially strandable investments. These investments are properly described as "potentially strandable" for two reasons. First, no investment is stranded so long as it is still subject to regulated cost-based rates. Second, stranded investment is a consequence of market prices being lower than regulated cost-based rates, and with no competitive market from which to base a comparison, estimates of competitive market prices must be used to gauge the magnitude of excess costs over market.

The ECOM Model estimates the magnitude of *excess* generation-related cost-of-service revenues relative to the market-based revenues that a utility may experience under various market access, or deregulation, scenarios.[97] This analysis is performed for both the Texas retail and wholesale jurisdictions. All ECOM estimates presented in this report are calculated under varying assumptions regarding (1) the timing of the introduction of competition in Texas, and (2) the market price that may prevail in the competitive market.

The purpose of quantifying the potential effect of deregulation is *not* to provide a conclusive determination or point-estimate of the magnitude of stranded costs to be used in setting utility rates.[98] Rather, the objective is to provide a range of information that will be beneficial to decision makers in the analysis of electric industry restructuring alternatives. The ECOM Model is an administrative method of determining the magnitude of potentially strandable investments. Alternative measurement methods are discussed in Chapter III of this report.

B. Overview of the ECOM Model

The ECOM model is an electronic workbook in Microsoft Excel 5.0 software. The model estimates the after-tax net present value of the change in generation-related

[97] ECOM estimates are calculated on a net present value basis.

[98] In the event retail markets are eventually opened to competition and a method is selected to quantify the financial impact of such competition on utilities, evidentiary hearings would likely be required on a utility-by-utility basis.

revenues that a utility may experience as a result of selling electricity at market-based prices rather than at regulated prices. In the model, ECOM is defined as the present value of the difference between a utility's fixed costs and the contributions to capital of utility sales under competitive conditions (i.e., revenues in excess of ongoing operating costs). The model, as distributed to the utilities, was developed to provide estimates of Texas retail ECOM. However, generation cost and sales data were also collected in the utilities' filings, enabling the Commission Staff to develop estimates of Texas jurisdictional wholesale ECOM.

Texas utilities that own generation plants were required to provide forecasted data on capital and production costs associated with generation resources. In the ECOM Model, reporting utilities allocate these costs by resource type (gas, coal/lignite, nuclear, or other) and by customer class (industrial, commercial, residential on the retail side; and Texas jurisdictional wholesale) for each year for the projected life of the plants. The utilities also provided projections of their sales (in MWh) allocated by resource type and by customer class.[99] Using these utility cost and sales projections, the ECOM Model calculates the regulated price of electricity for each customer class under continued cost of service regulation. Based upon a range of projected competitive market prices developed by Staff (low, base, and high),[100] the model calculates a corresponding range of competitive market-based revenues for each utility by customer class. ECOM is then calculated as the present value of the difference between the regulated and the market-based revenue streams.[101]

As stated previously, ECOM is defined as the present value of the difference between fixed costs and the contributions to fixed costs of utility sales under competitive conditions. Utilities recover a contribution to fixed costs by selling electricity at a

[99] All generation cost and sales data were projected and provided by the utilities pursuant to the Order Initiating Investigation in Project No. 15001 for the forecast period of 1996 to 2035. Commission Staff has reviewed the filings for accuracy and general consistency, however Staff has not audited the utility filings nor were the data made available to all interested parties for review because of confidentiality concerns.

[100] A table containing the ECOM Model market prices is contained in Appendix A. The competitive market price of electricity is discussed further in Section B(1) of this chapter.

[101] Some minor modifications to the ECOM Model were performed by Staff subsequent to the filing date of June 24, 1996. See Appendix C for a discussion of these changes.

competitive price that exceeds the variable cost of operation. In the ECOM Model, fixed costs consist of the following:

1. Return on existing generation-related invested capital (net of deferred taxes and other rate base deductions);[102]
2. Depreciation of existing generation assets;
3. Nuclear decommissioning expense;
4. Property tax payments;[103]
5. Existing purchased power contracts; and
6. Generation-related federal income tax (FIT) payments.

Operating costs (or variable costs) in the ECOM Model consist of the following:

1. Return on incremental generation-related investment (net of deferred taxes and other rate base deductions);
2. Depreciation of incremental generation investment;
3. Operations and maintenance expense;
4. Fuel expense;
5. Taxes other than FIT; and
6. Miscellaneous expense.

Combining fixed costs, operating costs and competitive operating revenues, ECOM can be represented by the following equation:

$$\text{ECOM} = \sum pv\{\text{FC} + \text{OC} - \text{R}\}, \text{ where}$$

pv = present value;

FC = Fixed costs in the regulated cost-of-service;

OC = Operating costs;

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[102] The return and FIT components of the cost-of-service are treated as fixed costs in the ECOM Model. If a different rate of return were specified for ECOM recovery, the return and FIT components would become variable costs. See discussion in Chapter VIII, Section B.3.

[103] Property tax payments are treated as fixed costs in the ECOM Model. In the event the market value of generation is less than current book values, the ECOM portion of the current book value would have to be taxable by the various property taxing districts for this assumption to hold. Data contained in the utilities' ECOM filings indicate that approximately $275 million in property taxes were levied upon investor-owned utility generation assets in 1995. Using the base case *1998Full* scenario as an example, the ECOM portion of the $275 million would be approximately $100 million. Thus, given the assumptions of this example and all other variables held constant, if the ECOM portion were not taxable, property tax receipts from utilities would decrease by approximately $100 million per year on a Statewide basis.

R = Revenues from electricity sales at the market price.; and

Σ = Sum from the first year of retail access through 2035.

As stated previously, the difference between the market price of electricity (R) and a firm's average variable cost of electricity production (OC) is the firm's contribution to capital. When the market price is greater than variable costs, the firm will collect revenues that at least partially offset fixed costs. This revenue offset of fixed costs is reflected in the calculation of ECOM. If projections of variable costs are greater than the expected market revenues over the life of a plant, then the firm will not operate the plant (except perhaps in the very short-run). Once that plant is shut down, no further contribution to capital is received, and ECOM is equal to the fixed costs remaining at the time the plant ceases operation.[104]

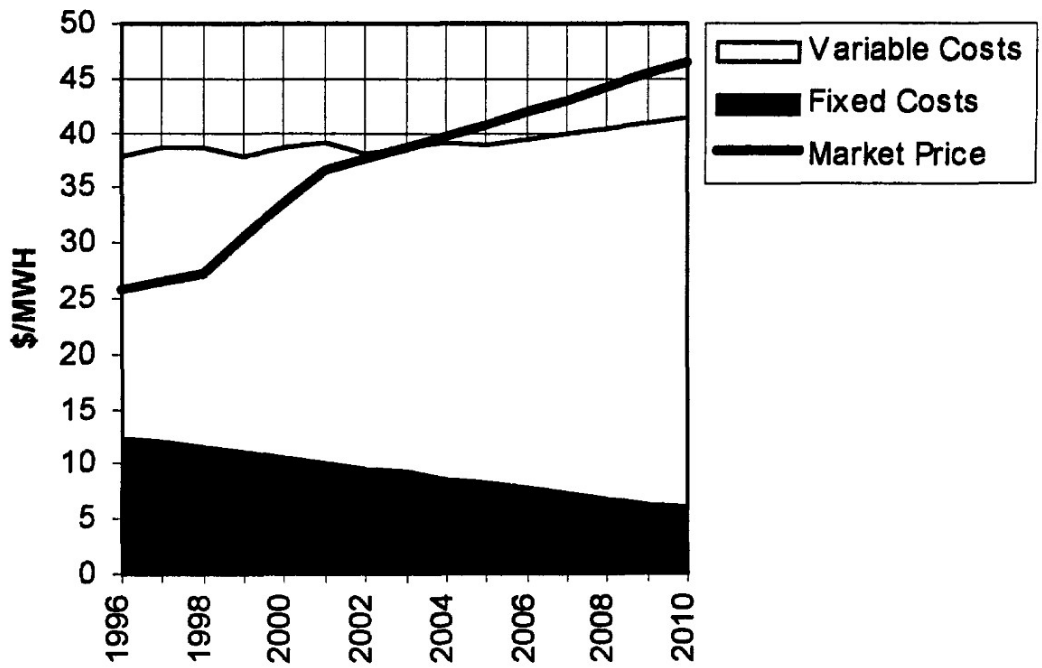

Figure VI–1: Illustration of the ECOM Methodology (1)

[104] The ECOM Model can be classified as an *ex ante* administrative approach that is a blend of the top-down and bottom-up methods. The ECOM Model does not value assets and liabilities individually (bottom-up) nor is the total generation function valued as an undivided whole (top-down). Rather, the ECOM Model analyzes potentially strandable investment by resource type, and is therefore a blend of the two methods. See Chapter

Figure VI–1 and I–2 illustrate the ECOM Model methodology. In Figure VI–1, the utility generation cost-of-service is represented by the sum of the variable costs and the fixed costs. In the illustration, the utility's generation cost-of-service is greater than the projected market price of electricity for the years 1996 to 2004. From 1996 to 2004, ECOM is equal to the vertically hatched area representing the difference between the market price and the generation cost-of-service. For the years 2005 to 2010, the generation cost-of-service is less than the market price and therefore results in a reduction to ECOM. It is important to note in this example that, even if the positive and negative ECOM areas were of identical size, ECOM would not net to zero as the ECOM that results in the near years will have a greater present value than the reduction to ECOM that may occur in later years.

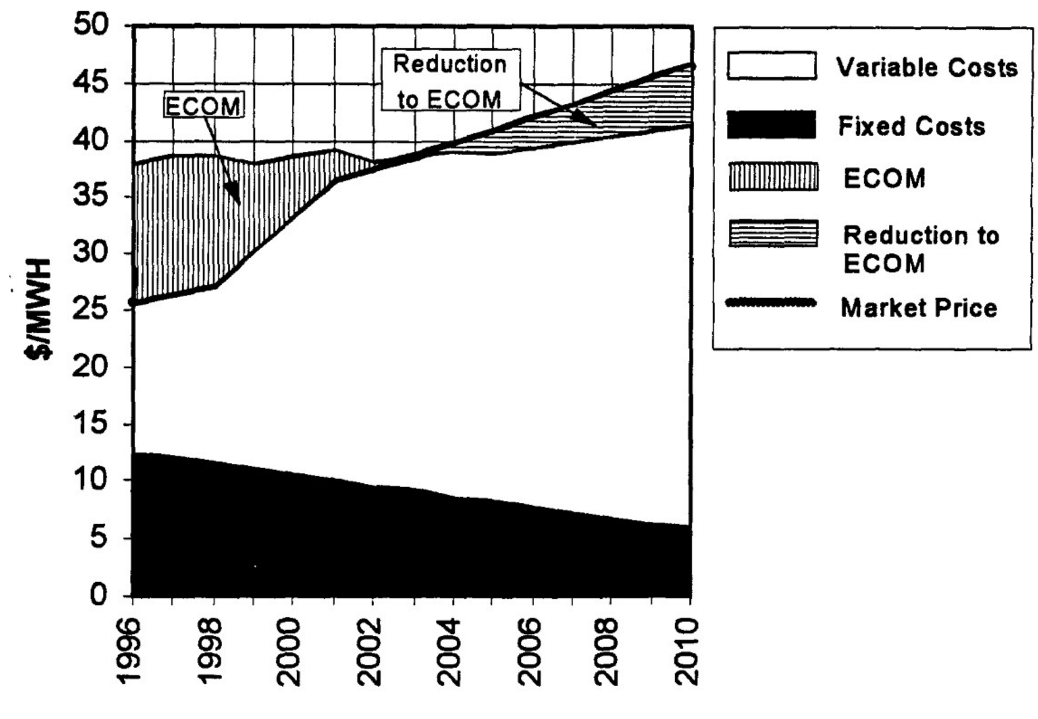

Figure VI–2: Illustration of the ECOM Methodology (2)

III(B) for a discussion of methods and approaches for estimating the magnitude of potentially strandable investments.

Worth noting is the effect of using a *present value* in presenting ECOM results as opposed to nominal year-by-year ECOM results. As shown in Figure VI–1 and Figure VI–2, ECOM levels will vary from year to year as the market price and the components of the regulated generation revenue requirement change. For example, in Figure VI–1, the generation revenue requirement exceeds the projected market revenues in the early years, producing positive ECOM values. However, in the later years, the generation revenue requirement is less than projected market revenues, producing *negative* ECOM values. By using a present value, the ECOM values (positive or negative) calculated for the nearest years are weighted more heavily than the ECOM values calculated for later years. Thus, in this example, the positive ECOM values in the early years have a greater effect on the total ECOM result than do the *negative* ECOM values in the later years.

Additionally, inspection of Figure VI–1 reveals that the market price is greater than the variable cost in each year. This indicates that, from an economic standpoint, the plant should continue to operate. Even though the total cost is not recovered in the early years, the plant should continue to operate from an economic perspective because the revenue obtained by selling power at the market price is greater than the variable cost of operation, thus creating a positive operating margin.[105] In this example, although the firm is unable to recover its total cost in the early years, it is able to offset at least a portion of its fixed costs with the positive operating margin.

Inspection of the ECOM Model equation reveals that ECOM equals total costs—composed of fixed costs and variable costs in the regulated generation cost-of-service—net of total revenues received under market-based rates. In the model, ECOM can never be greater than the present value of the utility's fixed costs as defined in the Model. If a plant ceases to operate because it is uneconomic to operate in a competitive environment, ECOM will equal the present value of only the fixed costs. If it is economic to continue operating a plant, then ECOM will be *less* than the present

[105] Over the long-run, a firm generally cannot continue to operate in a condition in which it does not recover its average total cost of production.

value of fixed costs because the firm will collect revenues greater than its operating expenses which will offset the total amount of fixed costs.

1. The Competitive Market Price of Electricity

A critical variable in any analysis of potentially strandable investment is the projected future market price of electricity. The ECOM Model includes a range of annual average market price estimates—low, base, and high.[106] In projecting the market price of electricity, the goal was to calculate a reasonable range for the annual average equilibrium price that would exist in a truly competitive generation market, i.e., a market in which no company possesses market power. If one or more companies were able to exercise market power in a deregulated market, the prevailing price of electricity would be higher than the price that would prevail in a truly competitive market. In that case, higher market prices would yield reduced utility ECOM levels relative to that of a truly competitive generation market.[107]

a) Short- and Long-run Marginal Cost

The development of market prices for electricity is based upon the premise that the market price in a competitive market will be determined by the cost marginal unit necessary to satisfy market demand. The determination of which costs to include as costs associated with the production of the marginal unit (the marginal costs) depends on the time-frame of the analysis, i.e., either the short-run or long-run. In this analysis, the short-run is the period in which existing capacity is sufficient to meet market demand. The long-run is the time period in which capacity additions are required to satisfy market demand.

Over the short-run, the marginal cost of operating a generating unit consists primarily of fuel and variable O&M costs. Therefore, the short-run market price is determined

[106] In an effort to reduce the number of variables in the estimation of ECOM, the market price used in the ECOM Model is based upon the assumption of a single market price for the Texas market.

[107] A quantitative analysis of the effect of market power is not provided in this report. However, an analysis of the effect of market power on Texas ECOM results is provided by J. Kennedy and Associates, Inc. in *Electric Utility Restructuring Issues For ERCOT: Prices, Market Power and Market Structure*, prepared on behalf of the Office of Public Utility Counsel of Texas (October 1996). This document is referenced solely as an additional resource, as the Commission has not engaged in a critical analysis of the study.

by summing the fuel and variable O&M costs of the most costly generating unit operating in a particular market at a particular time (the short-run marginal cost, SRMC). Under this pricing structure, all units in operation, except the marginal unit, are guaranteed at least some contribution to fixed costs. For the Texas market, the marginal unit at any point in time is likely to be either a natural gas steam or combustion turbine unit; thus, the short-run market price will be highly sensitive to the price of natural gas.

In the long-run, *all* of the costs of a new unit in the market comprise the relevant marginal costs. That is, all fixed and all variable costs attributable to an incremental unit sum to equal the long-run marginal cost (LRMC) or the long-run market price. Projection of the total cost of future generating technologies is vital to the calculation of LRMC. Analysis of current capital, O&M, and fuel projections indicate that combined-cycle combustion turbine (CCCT) technology is and will continue to be the most economic new generation resource in the Texas market for the foreseeable future.

Modeling the transition from SRMC to LRMC market prices requires an assessment of the timing of future capacity additions and a judgment as to when the costs of such additions will be fully reflected in the market price. It is reasonable to expect a period of transition in which the market price is reflective of a blend of SRMC and LRMC. Without any capacity additions, the reserve margin from existing units in ERCOT is projected to fall below 15 percent in the year 1999 or 2000 due to the projected growth in demand for energy across the State. By using the projected date of reserve margin requirements as a decision point in the transition of market price from short-run to long-run, reserve margins can be implicitly accounted for in the market price calculation. The Commission developed market price estimates based upon SRMC for the years 1996 through 1999, with a linear transition to full LRMC in the year 2001 and thereafter.

b) Natural Gas Prices

A key input variable in the projection of market prices is the future price of natural gas. Because of the high degree of uncertainty associated with future natural gas prices, inputs to the ECOM Model use a range of projected natural gas prices to account for the uncertainty associated with this variable. Following the deregulation of the natural gas market at the wellhead and the development of a spot market for natural gas in the mid-1980s, annual average spot market natural gas prices as delivered to utilities on the Texas Gulf Coast averaged \$2.11 per MMBtu and ranged from a low of \$1.77 to a high of \$2.46 per MMBtu (\$1996).[108] The 1996 base case natural gas price is set at the \$2.11 per MMBtu historical average. The high and low cases were calculated by adding/subtracting two standard deviations (i.e., 2.0 times \$0.21 = \$0.42) from the base case. Thus, the high and low natural gas price estimates in 1996 were \$2.53 and \$1.69 per MMBtu, respectively. This range establishes a 95 percent confidence interval for prices in 1996. The base, high and low cases are each escalated each year at the assumed inflation rate of 3 percent (i.e., a zero percent real growth rate). Historical and projected natural gas prices for the years 1986 to 2010 are presented in Figure VI–3.[109]

[108] MMBtu stands for Million British thermal units. Historical natural gas price data as reported in *Natural Gas Week* for the years 1986 to 1995.

[109] Historical price data from 1986 to 1995, projected thereafter (nominal dollars per MMBtu).

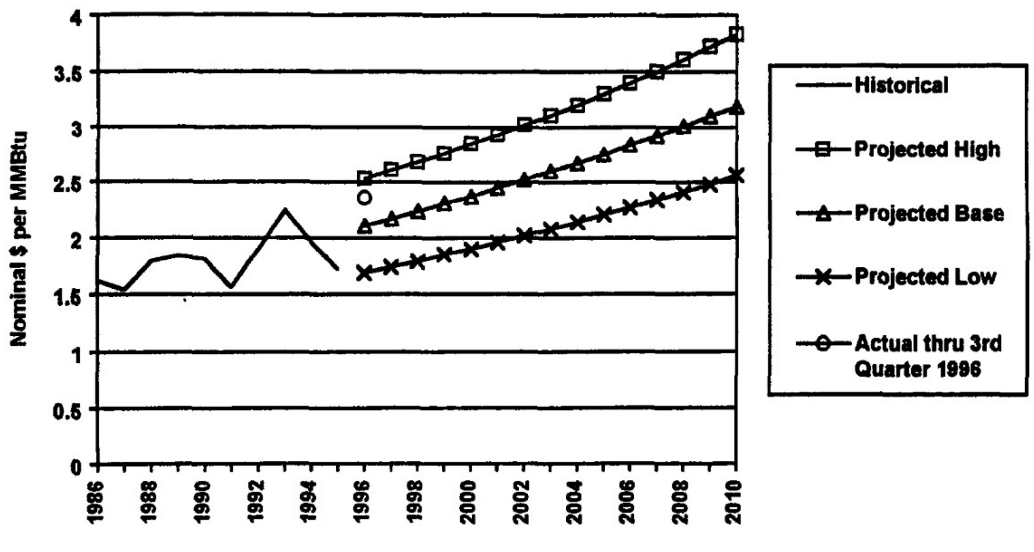

Figure VI–3: Historical and Projected Natural Gas Prices

The base case natural gas price projection is conservative compared to other published forecasts of natural gas prices because it incorporates a relatively lower growth rate. The base case forecast for natural gas prices is escalated at the general rate of inflation, incorporating 0 percent real growth over the forecast horizon. Among other published forecasts, the only forecast with a comparable growth rate is that of the Gas Research Institute (GRI), which projects a 0 percent real growth rate for the period 2000 to 2015. The remaining natural gas price forecasts contain positive real growth projections over the same period ranging from approximately 1 to 3 percent.[110] All else equal in the ECOM analysis, *higher* natural gas prices have the effect of *decreasing* the estimated level of ECOM; and likewise, *lower* natural gas prices *increase* the estimated level of ECOM.

[110] Published forecasts are from the *DOE/EIA Annual Energy Outlook 1996*, Appendix F, and include: Energy Information Administration; The WEFA Group, *Natural Gas Service Long Term Forecast, Spring 1995*; Gas Research Institute, *GRI Baseline Projection of U.S. Energy Supply and Demand, (August 1995)*; DRI/McGraw Hill, *World Energy Service U.S. Outlook (Spring-Summer 1995)*; and American Gas Association; *1995 AGA-TERA Base Case (January 1995)*.

c) Market Price by Customer Class

Electricity market prices have also been projected by customer class. Over the forecast period, industrial customers are projected to continue receiving a lower price than commercial customers; and commercial customers are projected to receive a lower price than residential customers. This price disparity is based on the higher average load factor of large customers relative to small customers.[111] Not only is a high load factor a desirable characteristic from the viewpoint of an electricity supplier, but in a competitive market, larger customers will likely have the ability to consume a higher percentage of energy during off-peak hours. In contrast, smaller customers, while consuming a share of energy during off-peak hours, will likely consume a significant portion of their overall requirements during the higher-priced on-peak hours. Still, in a competitive generation market, the price differential among customer classes is projected to be relatively modest. In the short-run, the industrial and residential classes are projected to be 96 and 104 percent, respectively, of the commercial class price. In the long-run, the differential is projected to increase slightly to 93 and 107 percent, respectively, of the commercial class price.[112]

Market prices as projected for the commercial class for the years 1996 through 2020 are contained in Figure VI-4. A tabular representation of the market price projections for all customer classes from 1996 though 2035 is contained in Appendix A.

[111] Load factor for a customer is the ratio of the average customer load to the peak customer load over a specified period of time. Generally, a higher load factor requires less "excess" capacity be reserved to serve the peak load.

[112] The projected competitive price differentials are based upon annual average projections for *generation only*. The prices do not include transmission losses, transmission costs, or distribution costs. The increase in the price differential over the long-run is due to a projected increase in the difference in the average efficiency of the marginal on-peak unit and the average efficiency of the marginal-off peak unit.

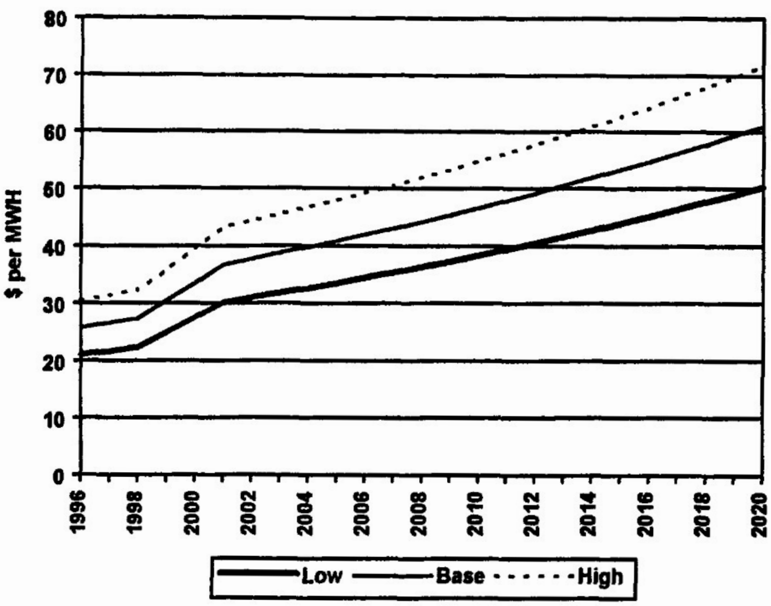

Figure VI–4: Market Prices for Electricity Used in the ECOM Model (Commercial Class)

2. Probabilistic ECOM Analysis

Although the price range incorporated in the ECOM Model captures a wide range of potential market prices, the range does not adequately reflect the probability of incurring the low or high market price in consecutive years. While it is possible that the high (or low) market price will occur in consecutive years, it is highly unlikely that these extreme values will continue to occur repeatedly. As a simple illustration, consider the toss of a coin. For any fair coin, there is a 50 percent chance of landing heads and likewise for tails. Assume you toss the coin 50 times, choosing either heads or tails on each toss.

Obviously, the number of tosses for which you will choose correctly is between zero and 50, including these two extreme values. However, the likelihood of choosing either always correctly or always incorrectly is extremely remote. In fact, your odds are better at correctly picking all six winning numbers in the Texas Lottery on two separate attempts! Statistically, you are most likely to select 25 tosses correctly, and you should be more than 90 percent confident that you will select between 19 and 31 tosses correctly (inclusive). An analogous probabilistic approach has been implemented in the ECOM Model.

In the ECOM Model, the extreme high and low ECOM estimates are calculated by using the projected low and high market prices, respectively, for consecutive years throughout the forecast period, even though a stream of consecutive years of extreme market prices is statistically unlikely. To more properly reflect the probability of occurrence of the projected market prices, a simulation has been incorporated into the ECOM Model using @RISK risk analysis software.[113] @RISK is used to determine the relative likelihood of each possible ECOM outcome. From a public policy perspective, knowledge of the relative likelihood of outcomes provides more useful information upon which to base decisions. Note, however, that probabilities *are not* certainties, and there is always a chance, albeit small, of ending up at either of the extremes.[114]

Performing a probabilistic ECOM analysis requires assigning a probability distribution to the projected market price of electricity. Because the market prices for electricity in Texas are largely a function of natural gas prices and the capital cost of new electric generating units, a probability distribution for future market prices is used that accounts

[113]@RISK, copyright 1996 by Palisade Corporation, is an add-in program to Microsoft Excel that uses simulation, sometimes called Monte Carlo, to perform risk analyses. See Appendix C for further discussion of the capabilities of the @RISK software.

[114] Probabilistic analyses require the specification of probability distributions for outcomes that are subject to uncertainty, e.g., future natural gas prices. Unlike in the coin toss and lottery examples in which the distribution of outcomes is known (binomial and hypergeometric, respectively), the distributions of variables such as natural gas prices must be estimated. This analysis incorporates reasonable assumptions regarding the various probability distributions; however, to the extent actual future outcomes vary from the assumed distributions, the actual ECOM levels will vary as well and may well fall outside the bounds of the specified confidence intervals.

The Office of Public Utility Counsel comments that "[t]he accuracy of the probabilistic percentiles associated with specific ECOM values is dependent upon the validity of the base case market price forecast and the assumptions which underlie that forecast. For example, assumptions regarding the exercise of market power by dominant suppliers or the potential for real gas price increases would result in higher probability estimates for the occurrence of lower ECOM values." Staff notes that it is not the *potential* for real gas price increases that would result in higher probability estimates for the occurrence of lower ECOM values, as the *potential* for real gas price increases is captured in the range of market prices used in the ECOM Model. Rather, it is an *expectation* of real gas price increases that would shift the probability distribution for natural gas prices, thus resulting in higher probability estimates for the occurrence of lower ECOM values.

for uncertainty in both of these inputs.[115] In addition, the cost of natural gas in each utility's embedded generation cost projection was varied in the same manner as the natural gas price used in the market price estimate.

The results of the probabilistic ECOM analysis are similar to the results in the coin toss example. While the basic ECOM Model provides the expected value, the extreme low, and the extreme high estimates of ECOM, the probabilistic ECOM analysis reveals the range of most likely ECOM outcomes for a particular scenario.

Table VI–2: Example of the Effect of Probabilistic Analysis on the Range of ECOM Outcomes ($1996 millions)

	Extreme High	95th Percentile	Expected Value	5th Percentile	Extreme Low
TUEC ECOM	$ 7,181	$ 5,600	$ 4,090	$ 2,580	$ 195

Note: See Chapter VII for complete Texas retail ECOM results.

As an illustration of the effect of the probabilistic ECOM approach on the range of outcomes, consider the case of the Texas Utilities Electric Company (TUEC). In the analysis of the effect of full retail access in the year 1998, the ECOM Model produces the results shown in Table VI–2 for TUEC. Examining only the extreme cases, TUEC's ECOM could vary by $7 billion. However, using a probabilistic approach that identifies a range of likely outcomes, the extreme range is reduced by more than 55 percent to approximately $3 billion.[116] The probability-based ranges presented in this report are representative of the 90 percent confidence interval of ECOM outcomes. Note that the outcomes labeled as *extreme high* and *extreme low* are well outside the 90 percent confidence band, and therefore can be considered to have an extremely low

[115] Probabilistic natural gas prices are modeled assuming a truncated normal distribution with zero as a lower limit. The historical mean of $2.11 per MMBtu on a delivered to utility basis in 1996 is incorporated with a growth rate equal to the projected inflation rate of 3 percent. The natural gas price standard deviation is assumed to be 10 percent of the mean, consistent with historical data. This natural gas standard deviation percentage is adjusted in future years by multiplying by $(T - 1996)^{1/2}$, where T is equal to the year, to account for forecast uncertainty. In the development of the ECOM Model market price, capital costs for combined-cycle combustion turbine units range from $400 to $600 per kilowatt for a turn-key project ($1996). In the probabilistic market price, capital cost was assigned a uniform distribution ranging from $400 to $600 per kilowatt ($1996).

[116] $7 billion is equal to the extreme high case minus the extreme low case. $3 billion is equal to the 5th percentile value minus the 95th percentile value.

probability of occurrence. A similar relationship holds for all of the ECOM scenarios presented in this report.

The high, base, low and probabilistic market prices used in the ECOM Model produce the following five ECOM outputs for each scenario:[117]

1. **Extreme High ECOM Estimate** - The extreme high ECOM estimate is obtained by using the low market price in every year of the forecast period. The low market price incorporates the low projected natural gas price for every year and the low projected capital cost for new combined-cycle generating units. The extreme high ECOM estimate has a very low probability of occurrence.
2. **95th Percentile ECOM Estimate** - The 95th percentile ECOM estimate is less than the extreme high ECOM estimate and greater than the expected value ECOM estimate. The 95th percentile ECOM estimate is obtained by using a probability-weighted market price distribution to calculate a probability distribution of ECOM results for each competitive scenario. The probabilistic ECOM analysis indicates with 95 percent confidence that the actual ECOM level will be less than the 95th percentile ECOM estimate.
3. **Expected Value ECOM Estimate** - The expected value ECOM estimate is obtained by using the base market price in each year of the forecast period. The base market price incorporates the base projected natural gas price for each year and the base projected capital cost for new combined-cycle generating units. The expected value ECOM estimate is the most likely or best estimate of the actual ECOM level in each competitive access scenario.
4. **5th Percentile ECOM Estimate** - The 5th percentile ECOM estimate is greater than the extreme low ECOM estimate and less than the expected value ECOM estimate. The 5th percentile ECOM estimate is obtained by using a probability-weighted market price distribution to calculate a probability distribution of ECOM results for each competitive scenario. The probabilistic ECOM analysis indicates with 95 percent confidence that the actual ECOM level will be greater than the 5th percentile ECOM estimate.
5. **Extreme Low ECOM Estimate** - The extreme low ECOM estimate is obtained by using the high market price in every year of the forecast period. The high market price incorporates the high projected natural gas

[117] The low, base, and high capital cost estimates for a new CCCT are $400, $500 and $600 per kilowatt ($1996), respectively, escalated annually at the projected inflation rate of 3 percent. The low, base and high delivered to utility natural gas price estimates are $1.69, $2.11 and $2.53 per MMBtu, respectively, escalated annually at the projected inflation rate of 3 percent.

price for every year and the high projected capital cost for new combined-cycle generating units. The extreme low ECOM estimate has a very low probability of occurrence.

As described previously, these five outputs effectively band the range of ECOM outcomes. Furthermore, the probabilistic ECOM analysis establishes a 90 percent confidence interval representing the range of the most likely ECOM outcomes for each utility under each competitive scenario.

3. Market Price Indicators as Projected by Utilities

With the wholesale market in its competitive beginnings, very little pricing data is available from market-based transactions. In fact, most such transactions are subject to strict confidentiality because of their competitive nature. However, some proceedings have been conducted at the Commission that provide some insight into the expected future cost of generating electricity.

a) Competitive Pricing Proceedings

Figure VI–5 displays pricing data submitted in three separate competitive pricing-related proceedings at the Commission. The utility-filed data consist of actual competitive wholesale transaction prices, utility projections of marginal cost, and the projected cost

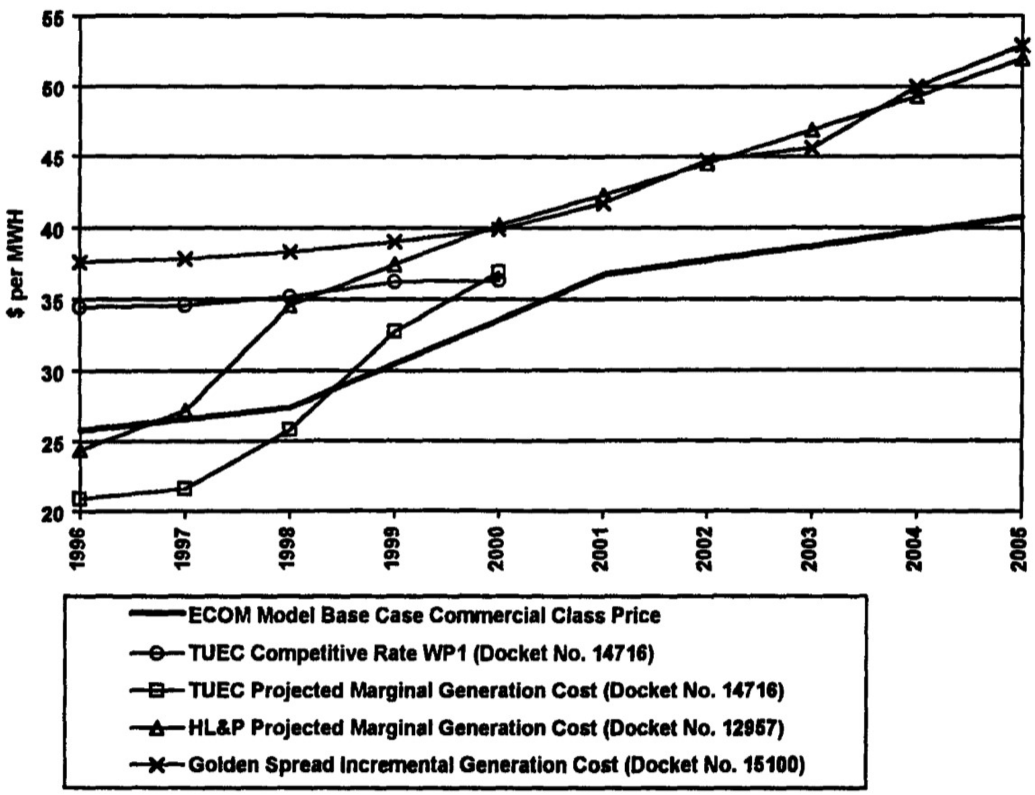

Figure VI–5: The ECOM Market Price as Compared to Utility Market Price Indicators[118]

of power from new generation resources.[119] While the available data are limited, Figure VI–5 shows the utility projections to be, on average, higher than price projected in the commercial class base case (the "Base Price"), especially after 1998 (the first year in which retail access is assumed in the ECOM Model scenarios).

[118] *Application of Texas Utilities Electric Company for Authority to Implement Rate WP1 to Lyntegar Electric Cooperative, Inc. and Taylor Electric Cooperative, Inc.*, Docket No. 14716 (Mar. 21, 1996)(not yet reported). Testimony of Stephen Houle, Exhibits SJH-4, 5, 6, and 7 (Rate WP1 adjusted to remove transmission costs). *HLP Tariff, Sheet No. D6.5*, approved Aug. 30, 1995. (HLP projects energy cost in dollars per MWh and capacity costs in dollars per kW. To convert to dollars per MWh for comparison, a conservative estimate of the capacity factor of 100 percent was assumed in converting the capacity costs). *Request of Golden Spread for Determinations Required by Section 32(K) of the Public Utility Holding Company Act and for Certification of Contract,*, Docket No. 15100, Rebuttal testimony, Exhibit AGH-4, Schedule AB-01.1, at 2.

[119] By law, the utility's negotiated competitive rate must be greater than or equal to the utility's marginal cost. See PURA95 §§ 2.001(b), 2.052(b), and 2.2011(p).

b) Utility Avoided Cost Filings

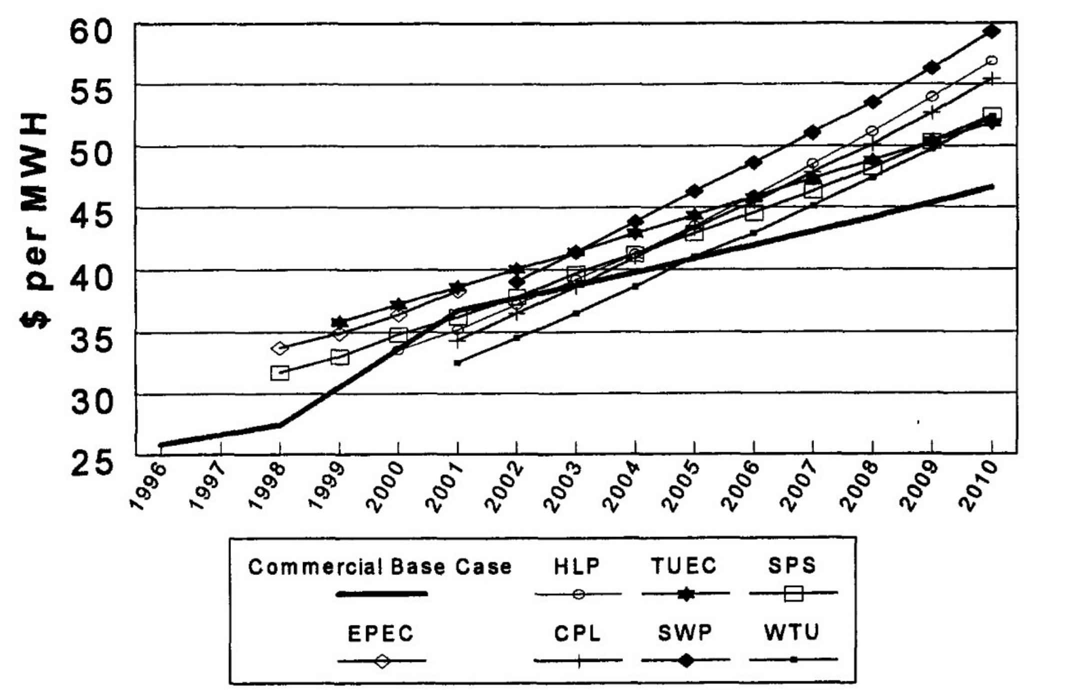

Figure VI–6: Utility Projected Avoided Cost Payments as filed at the Commission

In accordance with P.U.C. SUBST. R. 23.66(h), utilities in Texas are required to submit a biannual filing detailing projected capacity and energy payments that each utility projects to incur as the result of adding new generation resources over the coming 5 to 15 years. These data are used as a basis for calculating the price a utility should pay to a qualifying facility as a result of deferring generation requirements and planned capacity additions. The most recent avoided cost filing was in December 1994. Figure VI–6 shows the avoided cost projections of several utilities along with the Base Price used in the ECOM Model.[120] As indicated in Figure VI–6, the utility avoided cost projections compare favorably with the Base Price through the year 2004, after which the avoided cost projections exceed the Base Price.

[120] Capacity payments projected by the utilities were reported in dollars per kW and were converted to dollars per MWh by assuming a 100 percent capacity factor. A 100 percent capacity factor is a conservative capacity factor that results in a lower cost per MWh than if a capacity factor less than 100 percent were used.

B. Retail ECOM Trends and Observations

A detailed review of the ECOM filings of the utilities in Texas reveals a number of interesting observations. Among these are the sensitivity of the ECOM estimate to the timing of retail access; the sensitivity of the ECOM estimate to the future market price of electricity; and the effect of including a risk-adjusted versus a risk-free rate of return in the ECOM calculation.

1. Sensitivity of ECOM to the Timing of Retail Access

The timing of the implementation of retail access is key in determining the magnitude of ECOM, regardless of the other assumptions incorporated into the analysis. Obviously, if retail access is never implemented, a utility will have no stranded costs as the utility will continue to collect revenues from ratepayers at cost-based rates.

However, as explained in Chapters I and II, ECOM can be identified even without retail access because the utilities' book costs differ from a competitive market value. As time passes, depreciation and retirement of generation assets cause the magnitude of ECOM to decrease as the utility's generation cost-of-service declines. This discussion will focus on the magnitude of ECOM as it changes over time, regardless of the retail market structure.

For utilities whose production costs exceed projected market prices, time alone is the single greatest factor affecting the level of retail ECOM. For every year that a utility can continue collecting cost-of-service based rates, it can further depreciate its over-market assets with the regulated revenue stream, thus reducing the level of generation investment remaining at risk in a competitive retail market. For the Texas retail market, the expected value of ECOM for the *1998Full* scenario is approximately $12.8 billion ($1996); but, with retail access delayed only two years, the expected value of ECOM for the *2000Full* scenario falls to approximately $7.2 billion ($1996). Thus, in just two years of continued utility collection of traditional cost-based rates, utility fixed costs (and ECOM) are reduced by $5.6 billion ($1996), or 44 percent, for the total Texas retail market. By delaying retail access an additional two years to the year 2002, the expected value of total Texas retail ECOM is reduced by an additional 36 percent to approximately $4.6 billion ($1996).[151] Thus, on a total Texas retail basis, delayed retail access has the effect of reducing ECOM by about 20 percent per year.

An important observation in the above analysis is that the estimates are all presented in $1996. Thus, the analysis implicitly assumes that ECOM is "settled"[152] in 1996, and that regulated rates continue to the year of deregulation. For example, the Statewide Texas retail ECOM estimate for the *1998Full* scenario of $12.8 billion ($1996) assumes that ECOM is "settled" in 1996, and that regulated rates continue until retail access is implemented beginning in 1998. Likewise, the Statewide Texas retail ECOM estimate of $7.2 billion ($1996) for the *2000Full* scenario assumes that ECOM is "settled" in 1996, and that regulated rates continue until retail access is implemented beginning in the year 2000.

If ECOM levels are "settled" in years other than 1996, the dollar amounts will change due to the time value of money. For example, it may be more appropriate to assume that ECOM is "settled" in the year in which retail access is implemented rather than in 1996. If the estimate of Statewide Texas Retail ECOM for the *1998Full* scenario of $12.8 billion ($1996) is "settled" in 1998 rather than in 1996, the value in $1998 increases to $15.1 billion solely because of the time value of money.[153] Likewise, if the estimate of Statewide Texas Retail ECOM for the *2000Full* scenario of $7.2 billion ($1996) is "settled" in the year 2000 rather than in 1996, the value increases to $10.0 billion ($2000). Table VIII–5 contains a matrix of ECOM estimates for the *1998Full* and *2000Full* scenarios with varying ECOM "settlement" dates.

[151] Delayed retail access is actually detrimental to low-cost producers (or the current customers of the low-cost producers in the instance that *negative* ECOM is flowed-through to the utility's customers) in that such utilities may actually sell power at cost-based rates that are *lower* than what they might otherwise receive in a competitive market.

[152] The term "settled" refers to the date at which the level of ECOM is determined and a mechanism is implemented for the recovery of the percentage of ECOM that is appropriately allocated to the customers of a utility.

[153] In this case, a growth rate of 8.5 percent (the generic after-tax weighted average cost of capital used in the ECOM Model) is applied for two years to transform $12.8 billion in $1996 to $15.1 billion in $1998.

Table VIII–5: Statewide Texas Retail ECOM Estimates with Varying ECOM "Settlement" Dates (billions)

	$1996	$1997	$1998	$1999	$2000
Statewide Texas Retail ECOM Estimate for the *1998Full* Scenario	$ 12.8	$ 13.9	$ 15.1	n/a	n/a
Statewide Texas Retail ECOM Estimate for the *2000Full* Scenario	7.2	7.8	8.5	$ 9.2	$ 10.0

Note: Results table incorporate a 10 percent O&M efficiency improvement.

2. Sensitivity of ECOM Estimates to the Market Price

As noted previously, the estimation of ECOM is also very sensitive to the projection of the future market price of electricity. In the ECOM Model, the sensitivity of the results to the market price is effectively captured through the presentation of a range of ECOM values as discussed in Chapter VI.

Roughly speaking, for every 1 percent deviation from the projected base case market price, the estimated total Texas retail ECOM results will change by approximately $450 million on a net present value basis. Thus, if the base case annual average market price were increased by 1 percent *in each year of the forecast period*, the resulting total Texas retail ECOM estimate would be reduced by approximately $450 million. Likewise, if the base case annual average market prices were reduced by 1 percent *in each year of the forecast period*, the resulting total Texas ECOM estimate would be increased by approximately $450 million.

As an illustration of this effect, assume that the actual annual average market price were 5 percent *higher* than the base case annual average market price in each year of the forecast period. Applying this assumption to the *1998Full* scenario results in a reduction in the estimated total Texas retail ECOM of approximately $2.3 billion, from $12.8 billion to $10.5 billion. Likewise, if the annual average market price were 5 percent *lower* than the base case annual average market price in each year of the forecast period, the total Texas retail ECOM estimated in the *1998Full* scenario would be increased by approximately $2.3 billion, from $12.8 billion to $15.1 billion.

It is important to emphasize that the sensitivities discussed above are premised upon a reduction/increase in the market price *in each year of the forecast period.* If actual market prices were higher than the projected market price in some years and less than the projected market price in other years, the effect of such variations would likely net out to produce a level of ECOM comparable to the base case result. Furthermore, the presentation of a range of ECOM values in each scenario is intended to incorporate and account for the uncertainty associated with the future market price of electricity.[154]

3. Rate of Return on Equity

Utility generation cost-of-service ratemaking allows the opportunity to recover a return on utility investment. In the ECOM Model, the rate of return for IOUs is specified at 10 percent.[155] The 10 percent rate of return reflects the various risks to which a utility is currently exposed, not the risk associated with *guaranteed* recovery of investments. Some methods of ECOM recovery have been proposed that would guarantee a utility recovery of a percentage of its measured stranded costs through some type of non-bypassable charge. If such a guaranteed recovery mechanism were implemented, it may be appropriate to reduce the utility's rate of return on equity (and, thus, the overall rate of return) in accordance with its reduced risk profile.[156] Lowering the return component of the cost-of-service will reduce the utility's total generation cost-of-

[154] The development of the market price of electricity is based upon an economic analysis in which the future market prices were "constructed" using various cost components such as fuel and capital costs. In addition, the market price projections include a 5 percent adder resulting from the value that fuel diversity may add to a competitive market price. The exclusion of the fuel diversity portion of the market price would have the effect of reducing the market price, and therefore increasing ECOM estimates. The quantitative effect of removing the fuel diversity component of the projected market price would be comparable to the 5 percent reduction in market price discussed above on a Statewide Texas retail basis. Noteworthy, however, is that actual data and utility projections indicate market prices that are ***higher*** than the prices projected in the ECOM Model, including the fuel diversity component (see discussion at Chapter VI(B)(3) of this report).

[155] The rate of return on equity is a component of the overall utility rate of return. The rate of return for municipal utilities, river authorities, and cooperatives was specified at 7.5 percent; however, procedures were adopted to allow these entities to adjust this number to reflect their individual debt service requirements in each year of the forecast period.

[156] It has also been suggested in comments on the draft report that risk premia that previously have been collected by utilities in rates charged customers "could be considered to represent an excess recovery. This amount could be applied to mitigate the impact of any 'stranding' by consumers . . . A true-up of these amounts would be possible at the time of an IOU's final recovery of stranded costs." See comments of Marta Greytok on behalf of the Aluminum Company of America (ALCOA), "A Practical Solution to the 'Stranded Cost' Dilemma," Project No. 15001, at 5 (November 25, 1996).

service, and thus the level of ECOM. Quantification of the magnitude of a reduction in the rate of return is beyond the scope of this analysis, but could be estimated using the ECOM Model.[157]

4. Utility Generation Cost Projections

As described in Chapter VI, utilities were required to provide projections of their generation costs and sales for the life of the longest-lived plant in the utility's rate base. While these projections were examined for general consistency, a rigorous analysis of specific aspects of the generation costs was not performed. With the exception of the 10 percent O&M efficiency improvement adjustment, this analysis has not attempted to examine the impact of options that would allow utilities to reduce or mitigate their stranded cost exposure, such as aggressive cost-cutting measures, economic capital additions to enhance plant performance, and economic extension of plant lives, among others. Such measures would either reduce a utility's cost relative to market prices or provide increased revenues and contributions to fixed costs, thereby reducing the magnitude of assets at risk of under-recovery in a competitive market.

C. Individual Utility Retail ECOM Model Results

This section graphically portrays the Texas Retail ECOM Model results for each of the six competitive retail access scenarios. The graphical representation of each scenario can be interpreted as follows:[158]

- **Extreme High ECOM Estimate** - Represented by the top of the vertical line.
- **95th Percentile ECOM Estimate** - Represented by the right tick mark on the vertical line.
- **Expected Value ECOM Estimate** - Represented by the square in the middle of the vertical line.

[157] Federal income tax (FIT) payments are a function of the return component in the cost-of-service. Therefore, a reduction in the return will result in a reduction in the projected FIT payments as well, although the reduction in FIT will not be directly proportional to the reduction in the return. Analysis of the effect of a reduction in the return on the projected FIT payments would require an extensive analysis conducted on a utility-by-utility basis.

[158] For a more detailed discussion regarding the interpretation of the ECOM presentation figures, see Chapter VI(B)(2).

- **5th Percentile ECOM Estimate** - Represented by the left tick mark on the vertical line.
- **Extreme Low ECOM Estimate** - Represented by the bottom of the vertical line.

Table VIII–6 summarizes utility-by-utility results for the *1998Full* and *2000Full* scenarios. Detailed results for individual utilities are contained in Appendix B.

Table VIII–6: Individual Utility Texas Retail ECOM Model Results for Scenarios *1998Full* and *2000Full*

Utility	*1998Full* Expected Value of ECOM ($1996 million)	*2000Full* Expected Value of ECOM ($1996 million)	*1998Full* Expected Value of ECOM per kW	*2000Full* Expected Value of ECOM per kW	Utility Sales as a Percent of Texas Retail MWh Sales
Total Texas Retail	$ 12,816	$ 6,985	$ 253	$ 141	100.0
WTU	(63)	(122)	(63)	(123)	1.7
TUEC	4,090	1,913	211	99	32.8
CPL	2,251	1,611	568	406	7.5
HL&P	3,587	2,084	263	153	24.2
EPEC	1,051	778	1,048	776	1.7
GSU	426	181	156	66	5.2
SWP	(470)	(457)	(311)	(302)	3.0
SPS	(8)	(145)	(4)	(67)	4.2
TNP	707	518	2,406	1,760	2.1
COA	519	305	213	125	2.9
PUBB	(100)	(107)	(496)	(528)	0.3
BRYN	178	147	536	443	0.3
DENT	171	147	601	516	0.3
GARL	401	322	616	513	0.6
GNVL	82	68	545	456	0.2

Note: Individual utility percentage of Texas retail sales do not add to 100 percent because certain municipalities that did not file ECOM reports are not included in the list. Utility generation capacity is measured as the current installed Texas retail generation capacity in kilowatts.

REPORT TO CONGRESS ON COMPETITION IN WHOLESALE AND RETAIL MARKETS FOR ELECTRIC ENERGY

Pursuant to Section 1815 of the Energy Policy Act of 2005

The Electric Energy Market Competition Task Force

The Electric Energy Market Competition Task Force

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This report was prepared by the Task Force with the assistance of the Department of Justice, Federal Energy Regulatory Commission, Federal Trade Commission, Department of Energy, and Department of Agriculture. The Task Force assumes full responsibility for the report and the views expressed herein.

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EXECUTIVE SUMMARY

A. Congressional Request

The Energy Policy Act of 2005 (EPAct 2005)[1] was designed to provide a comprehensive long-range energy plan for the United States. Section 1815 of the Act[2] created an "Electric Energy Market Competition Task Force"[3] (Task Force) to conduct a study of competition in wholesale and retail markets for electricity in the United States. Section 1815(b)(2)(B) required the Task Force to publish a draft final report for public comment at least 60 days prior to submitting the final report to Congress. The Task Force published the draft final report in June 2006 and sought comment on the preliminary observations contained in the draft. Based on those comments, and other input received earlier, the Task Force hereby submits this final report to Congress.

B. Task Force Activities

In preparing this report, the Task Force undertook several activities, as follows:

- Section 1815(c) of the EPAct 2005 required the Task Force to "consult with and solicit comments from any advisory entity of the Task Force, the states, representatives of the electric power industry, and the public." Accordingly, the Task Force published a Federal Register notice seeking comment on a variety of issues related to competition in wholesale and retail electric power markets. Over 80 commenters provided a variety of opinions and analyses in response. These comments are available online for public review in the Task Force docket maintained by the Federal Energy Regulatory Commission (FERC) under Docket No. AD05-17-000. The list of parties who submitted comments is attached as Appendix A.[4]

- The Task Force met and discussed competition-related issues with a variety of representatives of the states, the electric power industry, and other stakeholders in October-December 2005. These groups are listed in Appendix B.

- The Task Force prepared an annotated bibliography of the public cost/benefit studies that have attempted to analyze the status of wholesale and retail competition. Appendix C contains this bibliography.

- The Task Force reviewed the status of retail competition in the states and examined in detail the experiences of seven states with active retail competition programs: Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas. These

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[1] Pub. L. No. 109-58, 119 Stat. 594 (2005).

[2] Pub. L. No. 109-58, § 1815, 119 Stat. 594, 1128 (2005).

[3] The Task Force consists of five members: (1) one employee of the Department of Justice, appointed by the Attorney General of the United States; (2) one employee of the Federal Energy Regulatory Commission, appointed by the Chairperson of that Commission; (3) one employee of the Federal Trade Commission, appointed by the Chairperson of that Commission; (4) one employee of the Department of Energy, appointed by the Secretary of Energy; and (5) one employee of the Rural Utilities Service, appointed by the Secretary of Agriculture.

[4] Abbreviations for those parties are also listed in Appendix A.

states have taken a variety of approaches to introducing retail competition. Appendix D profiles these retail competition programs, updating information prepared by the Federal Trade Commission (FTC) staff.

- ❖ The Task Force published the draft final report in the Federal Register for public comment on June 13, 2006, 71 Fed. Reg. 34,083 (2006). The notice accompanying the draft requested comments on the Task Force observations. About 80 different entities provided comments and suggestions on the draft report. These commenters are listed in Appendix A. Draft report comments are available for public review online in the Task Force docket maintained by FERC under Docket No. AD05-17-000.

- ❖ In preparing the draft report, the Task Force conducted further research and reviewed the information from comments and interviews.

C. The Goal of Increasing Competition in Electric Power Markets

Federal and several state policymakers generally introduced competition in the electric power industry to overcome perceived shortcomings of traditional cost-based regulation. In competitive markets, prices are expected to guide consumption and investment decisions, leading to more economically efficient investments and lower prices than under traditional cost of service monopoly regulation. More specifically, market-based, as compared to regulated, pricing of electricity would be expected to more accurately reflect the underlying costs of production. These prices should thus align the price of electricity with the value customers place on electricity, leading to a more efficient allocation of electrical resources and lower overall prices than would be the case in the absence of market-based prices. These price signals should also serve to increase price during periods of scarcity, thereby eliciting reductions in consumption, moderating market power and improving reliability.

D. Observations on Competition in Wholesale Electric Power Markets

Congress has taken a number of steps to facilitate competition in wholesale electric power markets. The Public Utility Regulatory Policies Act of 1978 (PURPA),[5] the Energy Policy Act of 1992 (EPAct 1992),[6] and EPAct 2005 promoted competition by lowering entry barriers and increasing transmission access. Federal electricity policies have sought to strengthen competition but continue to rely on a combination of competition and regulation.

In assessing wholesale competition, the Task Force addressed the following question: Has competition in wholesale markets for electricity resulted in sufficient generation supply and transmission to provide wholesale customers with the kind of choice that generally is associated with competitive markets?

To answer this question, the Task Force examined whether competition has elicited the consumption and investment decisions generally associated with competitive wholesale markets.

[5] Pub. L. No. 95-617, 92 Stat. 3117 (codified in U.S.C. titles 15, 16, 26, 30, 42, and 43) (1978).

[6] Pub. L. No. 102-486, 106 Stat. 2776 (1992).

The Task Force found this question challenging to address due to a number of complicating factors. The various U.S. regional wholesale electric power markets developed differently since the introduction of widespread wholesale competition. There were significant regional regulatory and structural differences in the electric power industry when Congress enacted EPAct 1992 and when FERC adopted Order No. 888[7] in 1996, mandating nondiscriminatory access to the transmission grid. Even today, the regional markets have different features and characteristics. As discussed in Chapter 3, these differences make it difficult to identify and separate the determinants driving consumption and investment decisions and thus make it difficult for the Task Force to evaluate the degree to which more competitive markets have influenced such decisions.

Despite the difficulty of directly answering the question at hand, the Task Force's examination of wholesale competition did yield useful observations, as outlined below.

1. <u>Wholesale Market Structures</u>

Wholesale markets exhibit regional differences and generally rely on one of two types of market structures to support wholesale transactions.

a. One approach to competition in wholesale markets is to base trades exclusively on bilateral sales negotiated directly between suppliers and scheduled through individual, non-regionalized transmission owners. This approach predominates in the Northwest and Southeast. This traditional trading format allows for somewhat independent operation of transmission control areas and, in the view of some market participants, better accommodates historical contracts. However, prices and terms are more transaction-specific and, for some timeframes, less publicly available than in organized markets, which may result in less efficient generation dispatch. It can be difficult for system operators to coordinate transmission efficiently in these systems, as congestion costs and impacts are not readily apparent. A lack of centralized, shared information about generation dispatch and trades on interconnected systems requires a transmission owner to hold part of its transmission capacity as unused "reserves" to ensure reliable system operation. In some of these markets, wholesale customers have difficulty gaining unqualified access to the transmission needed to access competitively priced generation, thus limiting their ability to shop for least-cost supply options.

b. Another approach to wholesale competition relies on entities that are independent of market participants to control operation of all transmission facilities across a wide region and to operate trading markets – regional transmission organizations (RTOs) or independent system operators (ISOs). Variations of this approach predominate in the Northeast, Mid-Atlantic, Midwest, Texas, and California. The market designs in these regions provide participants with guaranteed physical access to the transmission system (subject to transmission security constraints). These customers are responsible for the cost of that access (if they choose to

[7] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540, FERC Stats. & Regs. ¶ 31,036, 31,639 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997); *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F. 3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) [hereinafter Order No. 888].

participate), and thus are exposed to congestion price risks. This more open access to transmission can increase competitive options for wholesale customers and suppliers as compared to most bilateral markets. The price transparency in these regional organized markets can increase the efficiency of the trading process for sellers and buyers and can give clear price signals indicating the best place and time to build new generation. Concerns have been raised, however, about the inability to obtain long-term transmission access at predictable prices in these markets and the impact that this can have on access to competing suppliers and incentives to construct new generation. Some customers have raised concerns about high and sometimes volatile commodity price levels in these markets.

2. <u>Generation Investment in Competitive Wholesale Markets</u>

New generation investment has varied significantly by region since the adoption of open access transmission and the growth of competition. The Task Force examined comments on how competition policy choices have affected investment decisions of both buyers and sellers in wholesale markets. A number of issues emerged. One was the difficulty of raising capital to build facilities whose revenue streams are affected by changing fuel prices, demand fluctuations, and the potential for regulatory intervention. A related theme was the investment dampening effects of a perceived lack of long-term contracting options for generation and transmission. Overall, the Task Force identified several factors that affect investment decisions in wholesale power markets.

a. Availability of Long-Term Contracts. Both generators and wholesale customers cited long-term contracts as critical in obtaining financing for new generation and ensuring adequate supplies for retail loads at predictable prices. Several explanations were offered for a perceived lack of long-term contracting opportunities. First, short-term market conditions, particularly in organized markets with uniform price auctions, may be affecting the availability, pricing, and terms for long-term power supplies under bilateral contracts. Base-load and mid-merit generators may see relatively high profits in short-term markets where clearing prices are often set by higher cost mid-merit and/or peaking plants reliant on oil or natural gas, particularly when fuel prices rise. Second, generators and marketers may be unwilling to enter into long-term supply contracts because of limited opportunities to hedge the potential risks of long-term commitments in highly volatile electricity markets. Third, both generators and customers cited continuing uncertainties over availability and certainty of long-term delivery options (transmission). Fourth, long-term contracts may be difficult to arrange because of inherent uncertainties associated with federal and state regulation of these contracts. Finally, the uncertainty that distribution utilities face over how much supply they will need to procure for customers that have an option to switch can also discourage utilities from signing long-term contracts.

b. Capital Investment. Potential entrants to generation markets must be able to convince capital markets that generation is a viable profitable undertaking. The availability of long-term contracts, as noted above, is critical to the ability of nonutility generators to secure capital for new investment. Transmission access can be vital to supporting competitive options for market participants. Recently, capital for large investment projects has flowed to traditional utilities more than to merchant generators. This shift in part reflects reduced profitability of many merchant generators in recent years.

c. *Transmission Infrastructure.* The availability of transmission is often key in determining whether a generating facility is likely to be profitable and, thus, elicit investment. Despite legislative and regulatory efforts to expand transmission access for competitive generation and to reduce the potential for discrimination, the perception of discrimination persists. Commenters reported that such discrimination can increase delivery risk because purchasers fear their transmission transactions could be terminated for anticompetitive reasons. One response to this risk is to turn over operation of the regional transmission grid to ISOs and RTOs. Another is to adopt additional reforms to the Order 888 Open Access Transmission Tariff (OATT). New federal authorities provided by EPAct 2005 also address transmission infrastructure issues.

3. <u>Pricing and Entry in Wholesale Markets for Electricity</u>

Several options may be used to elicit adequate supply in wholesale markets:

a. One possible, but controversial, way to spur entry is to allow wholesale price spikes when supply is short. The profits realized during these price spikes can provide incentives for generators to invest in new capacity. However, if wholesale customers have not hedged (or cannot hedge) against price spikes, then these spikes can lead to adverse customer reactions. Unfortunately, it can be difficult to distinguish high prices due to the exercise of market power from those due to genuine scarcity. Past price spikes have caused regulators and various wholesale market operators to adopt price caps in certain markets. Although price caps may limit price spikes and some forms of market manipulation, they can also limit legitimate scarcity pricing and impede incentives to build generation in the face of scarcity. Not all the caps in place may be necessary or set at appropriate levels.

b. "Capacity payments" also can help elicit new supply and help moderate price volatility. Wholesale customers pay suppliers to assure the availability of generation when needed. Where there are capacity payments in organized wholesale markets, however, it is difficult for regulators to determine the appropriate level of capacity payments to spur entry without over-taxing market participants and customers. Also, capacity payments may elicit new generation when transmission or other responses to price changes might be more affordable and equally effective. Depending on their format, capacity payments also may discourage entry by paying uneconomical generation to continue running when market conditions otherwise would have led to not running, or even decommissioning.

c. Expanding transmission capacity may encourage entry of new generation and/or the more efficient use of existing generation. However, transmission owners may resist building transmission facilities if they also own generation and if the proposed upgrades would increase competition in their sheltered markets. Another challenge is that it is often difficult to assess the beneficiaries of transmission upgrades, who should pay for the upgrades, and how regulators should provide for recovery of the investment through rates. This regulatory challenge may cause uncertainty about the price for transmission and about return on investment both for new generators and for transmission providers.

d. Another option for ensuring adequate generation supply is to exercise traditional regulatory authority over electricity generators/suppliers. In this situation, regulated monopoly utility providers operate under an obligation to plan and secure adequate generation to meet the needs of their customers. Regulators allow the utilities to earn a fair rate of return on their investment, thereby encouraging utility investment. This approach is not without risk to the utility, as regulators have authority to disallow excessive costs. Furthermore, these traditional methods are imperfect and can in some cases lead to overinvestment, underinvestment, excessive spending and unnecessarily high costs. These methods can distort both investment and consumption decisions.

E. Observations on Retail Market Competition

In the early 1990s, several states with high electricity prices began exploring opening retail electric service to competition. While customers would choose their supplier, the local distribution utility would still handle the delivery of electricity. Retail competition was expected to result in lower retail prices, innovative services and pricing options. It also was expected to shift the risks of assuring adequate new generation construction from ratepayers to competitive market providers. By 2006, 16 states and the District of Columbia had restructured retail electric service and allowed competitive suppliers to provide service to some, if not all, retail customers at prices set in the market.

Most restructured states required the local utility to continue to offer service under regulated "provider of last resort" (POLR) rates for all retail customers who did not switch suppliers or who lost or discontinued competitive service. These POLR rates were typically fixed for extended periods of time. In many of these states, vertically integrated utilities divested or transferred their generation assets as part of restructuring plans. As a result, in these states the retail load serving utilities obtain electricity from wholesale markets to meet the needs of their retail customers, including POLR obligations. Some states also required that the utilities join RTOs.

1. Retail Competition Experience in Profiled States

The Task Force examined in detail the implementation of retail competition in Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas. Common goals for retail competition included:

- lower electricity prices than under traditional cost of service regulation through retail suppliers' (and eligible customers') access to competitive wholesale markets;
- better service and more options for customers;
- technological innovation and new products and services for consumers; and
- environmental improvements.

In most profiled states, retail competition has not developed as expected for all customer classes. Few residential customers have switched to alternative providers. (Exceptions include Massachusetts, New York, and Texas.) In most of the profiled states, few residential customers have a wide variety of alternative suppliers and pricing options. Commercial and industrial (C&I) customers have more choices and options, but in several states large industrial customers have become increasingly dissatisfied with retail market prices. To the extent that multiple suppliers serve retail customers, prices have not decreased as expected, and the range of new options and services is often limited.

At the same time, there is some evidence that alternative suppliers have offered new retail products, including "green" products that are more environmentally friendly for residential and non-residential customers and customized energy management products for large C&I customers.

Legislative or regulatory limits on POLR prices have hampered entry by competitive suppliers in retail markets. In the profiled states, regulators often capped the POLR electricity price for "transitional" multi-year periods that are now just ending. Several states also required price reductions for POLR service below existing regulated rates (in order to proxy the expected benefits of competition). Over time, these capped and discounted POLR prices fell below prevailing wholesale market price levels. These POLR price caps have the unintended effect of dampening competitive price signals and discouraging entry by competitive suppliers.

The POLR rate caps and the sharp increase in fossil fuel costs affecting all retail suppliers across the country, complicate Task Force efforts to discern any price differences attributable to the introduction of competition. The implementation of retail competition is a relatively new exercise, and retail competition policies involve a number of unresolved issues (including regulatory issues) that can inhibit vigorous competition. It should be easier to evaluate the impact of restructuring in retail electricity markets once some of these issues have been resolved.

2. <u>State Retail Competition Issues</u>

Initial POLR rate discounts, freezes and caps have been lifted in several states, and caps in several more expire in 2006 and 2007. When the rate caps expire, states must decide whether to continue POLR for all customer classes, how POLR providers will secure adequate generation supplies, and how to price POLR service for each class. The Task Force identified some key issues that states may wish to consider as they evaluate their retail competition and POLR policies.

a. *Function of POLR Pricing*. If regulated POLR service is to be a proxy for efficient price signals, POLR rates must closely approximate a competitive price, which is based on supply and demand at any given time. If the POLR service price does not closely match the competitive price, it is likely to distort consumption and investment decisions.

b. *Adjustments to POLR Rates*. If POLR prices remain fixed while prices for fuel and wholesale power are rising, customers may experience rate shock when the transition period ends. This can create public pressure to continue the fixed POLR rates at below-market levels. One regulatory response may be to phase in the price increase gradually, by deferring recovery of part of the supplier's costs. This approach reduces rate shock, but it is likely to distort retail electricity markets both in the short term (when costs are deferred) and in the long term (when the deferred costs are recovered). The better practice is to make frequent adjustments to the cap (at least to reflect changes in fuel costs) or to abandon the cap altogether and use a competitive process to procure supply.

c. *Nature of POLR Service*. States have different policy goals for establishing and maintaining POLR service in competitive retail markets. These policies can affect entry of competitive retail suppliers. POLR service (or an equivalent provision) that is limited to an obligation to serve customers of a supplier that has left the market, while the customer obtains another supplier, is the least intrusive form of POLR service. It also is consistent with protecting consumers against unanticipated loss of electric service. POLR service that goes beyond short-term access to the wholesale spot market involves providing a bundle of services that electricity marketers also could provide. A more expansive version of POLR service may hamper development of alternative suppliers. The economic rationale for maintaining a POLR service obligation usually is limited to trying to correct market imperfections. If a state adopts a more expansive version of POLR service, it should periodically review the rationale for continuing the service.

d. *Treatment of Different Customer Classes*. States may find that effective retail competition programs require different POLR service designs for different customer classes. Large C&I customers are logical leaders for retail choice because of their familiarity with energy procurement processes and because they are comfortable with decisions to adjust input use based on input prices. State policies have allowed POLR rates for these large customers to reflect wholesale spot market prices more than POLR rates for residential customers. This approach generally has led large customers to switch suppliers more than small customers have. Also, more suppliers have tried to solicit these large customers.

e. *Consumer Education*. Customers may find it difficult to find competitive supplier offers in the first place and to understand the terms and conditions of those offers. It also is unclear whether the perceived potential cost savings are sufficient to give customers incentives to undertake the effort to find this information. For these smaller, less sophisticated shoppers, issues of awareness and access to comparative pricing information should be addressed as retail customer choice is implemented.

f. *Customer Aggregation*. Competitive provider interest in residential and small business customers has been slow to develop in most states. While POLR policies have dampened price signals, the higher per-unit costs of marketing and switching for small customers may also be a disincentive for providers. Retail aggregation programs can reduce shopping burdens and uncertainties for individual customers and lower customer acquisition costs for competitive providers. Several states have approved customer aggregation plans as an alternative approach to developing retail competition. Opt-out customer aggregations may be worth considering because they can minimize transaction costs without limiting customer choice.

g. *Procurement of POLR Supply*. In all retail competition states, a substantial number of retail customers continue to depend on POLR service. Some states have used, or are proposing to use, auctions to procure POLR supply. Auctions may allow retail customers to get the benefit of competition in wholesale markets as suppliers compete to supply the necessary load. Various auction processes have been suggested.

h. *Switching Costs*. Switching is important for retail electricity competition to work. Rules and procedures for switching should allow customers to switch easily but should deter unauthorized switching (slamming).

Section E of Chapter 4 presents a description of various approaches to overcoming some of the above-mentioned difficulties and to encouraging competition in retail electricity markets.

CHAPTER 1
INDUSTRY STRUCTURE, LEGAL AND REGULATORY BACKGROUND, TRENDS AND DEVELOPMENTS

For almost all of the 20th Century, the electric power industry was dominated by regulated monopoly utilities. Beginning in the late 1960s, a number of technological, economic, regulatory, and political developments led to fundamental changes in the structure of the industry.

In the 1970s, vertically integrated utility companies (investor-owned, municipal, or cooperative) controlled over 95 percent of the electric generation in the United States. Typically, a single local utility sold and delivered electricity to retail customers under an exclusive franchise regulated under state law. Today, the electric power industry includes both utility and nonutility entities, including many new companies that produce, market and deliver electric energy in wholesale and retail markets. As a result of industry changes, by 2004 electric utilities owned less than 60 percent of electric generating capacity. Increasingly, decisions affecting retail customers and electricity rates are split among federal, state, and new private, regional entities. This chapter highlights structural changes in the industry since the late 1960s. It provides an overview of the important legislative and regulatory changes, as well as trends that have contributed to increased competition.

A. Industry Structure and Regulation

Participants in the electric power sector in the United States include investor-owned utilities and electric cooperatives; federal, state, and municipal utilities, public utility districts and irrigation districts; cogenerators and onsite generators; and nonutility independent power producers (IPPs), affiliated power producers, power marketers, and independent transmission companies that generate, distribute, transmit, or sell electricity at wholesale or retail.

In 2004, 3,276 regulated retail electric providers supplied electricity to over 136 million customers, with retail sales totaling almost $270 billion. Retail customers purchased more than 3.5 billion megawatt hours (MWhs) of electricity. Active retail electric providers include utilities, federal agencies, and power marketers selling directly to retail customers. These entities differ greatly in size, ownership, regulation, customer load characteristics, and regional conditions. These differences are reflected in policy and regulation. Tables 1-1 to 1-5 provide selected statistics for the electric power sector by type of ownership in 2004 based on information reported to the Department of Energy (DOE), Energy Information Administration (EIA).

1. <u>Investor-Owned Utilities</u>

Investor-owned utility operating companies (IOUs) are private, shareholder-owned companies ranging from small local operations serving a retail customer base of a few thousand to giant multi-state holding companies serving millions of customers. Most IOUs are or are part of a vertically integrated system that owns or controls generation, transmission, and distribution facilities/resources to meet the needs of retail customers in their franchise service areas. Many IOUs have undergone significant restructuring and reorganization under state retail competition plans over the past decade. As a result, many IOUs no longer own generation, but those that sell electric power to retail customers must procure electricity from wholesale markets. See Chapter 4 and Appendix D of this document for details on state experience with retail competition. IOUs continue to be a major presence. In 2004 there were 220 IOUs serving approximately 94 million retail distribution customers, accounting for 68.9 percent of all retail customers and 60.8 percent of retail electricity sales. IOUs directly owned about 39.6 percent of total electric generating capacity and accounted for 44.8 percent of generation for retail and wholesale sales in 2004. IOUs provide service to retail customers under state regulation of territories, finances, operations, services, and rates. States that have not restructured retail service generally regulate retail rates under traditional bundled cost-of-service rate methods. In states that have restructured IOUs, distribution services continue to be provided under monopoly cost-of-service rates, and retail customers obtain generation service either at market rates from alternative competitive providers or at regulated "provider of last resort" (POLR) rates from the distribution utility or another designated POLR service provider. IOUs serve retail customers in every state but Nebraska.

Under the Federal Power Act (FPA),[8] the Federal Energy Regulatory Commission (FERC) regulates wholesale electricity transactions (sales for resale) and unbundled transmission activities of IOUs as "public utilities" engaged in interstate commerce. The exceptions are IOUs that do not have direct interconnections with utilities in other states that allow unimpeded flow of electricity across systems. Thus, IOUs in Alaska, Hawaii, and the Electric Reliability Council of Texas (ERCOT) region of Texas generally are not subject to FERC jurisdiction.

2. Public Power Systems

The more than 2,000 publicly owned power systems include local, municipal, state, and regional public power systems. These providers range from tiny municipal distribution companies to large systems such as the Los Angeles Department of Water and Power. Publicly owned systems operate in every state but Hawaii. About 1,840 of these systems are cities and municipal governments that own and control the day-to-day operation of their electric utilities.[9] Public power systems served over 19.6 million retail customers in 2004, or about 14.4 percent of all customers. Together, they generated 10.3 percent of the nation's power in 2004, accounted for 16.7 percent of total electricity sales and owned about 9.6 percent of total generating capacity. Many public systems are distribution-only utilities that purchase, rather than generate, power. According to the American Public Power Association, about 70 percent of public power retail sales were met from wholesale power purchases, including purchases from municipal joint action agencies by the agencies' member systems. Only about 30 percent of the electricity for public power retail sales comes from power generated by a utility to service its own native load.[10] Publicly owned utilities, thus, depend overwhelmingly on transmission and the wholesale market to bring electricity to their retail customers.

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[8] 16 U.S.C. §§ 791a et seq. (2000).

[9] APPA comments.

[10] *Id.*

Regulation of public power systems varies among states. In some, the public utility commission exercises jurisdiction in whole or part over operations and rates of publicly-owned systems. In most states, public power systems are regulated by local governments or are self-regulated. Municipal systems usually are governed by a local city council or an independent board elected by voters or appointed by city officials. Other public power systems are operated by public utility districts, irrigation districts, or special state authorities.

On the whole, state retail restructuring initiatives did not affect retail services in public systems. However, some states allow public systems to adopt retail choice alternatives voluntarily.

3. Electric Cooperatives

Electric cooperatives are privately-owned, non-profit electric systems owned and controlled by the members they serve. Members vote directly for the board of directors. In 2004, 884 electric distribution cooperatives provided retail electric service to almost 16.6 million customers. In addition, another 65 generation and transmission cooperatives (G&Ts) own and operate generation and transmission and secure wholesale power and transmission services from others to meet the needs of their distribution cooperative members' retail customers and other rural native load customers. G&T systems and their members engage in joint planning and power supply operations to achieve some of the savings available under a vertically integrated utility structure. Electric cooperatives operate in 47 states. Most were originally organized and financed under the federal rural electrification program and operate in primarily rural areas. Cooperatives provide electric service in all or parts of 83 percent of the counties in the United States.[11]

In 2004, electric cooperatives sold more than 345 million MWhs, served 12.2 percent of retail customers, and accounted for 9.7 percent of electricity sold at retail. Nationwide electric cooperatives generate about 4.7 percent of total electric generation and own approximately 4.2 percent of generating capacity.

While some cooperative systems generate their own power and sell power in excess of their members' needs, most G&Ts and distribution cooperatives are net buyers. Cooperatives nationwide generated only about half of the power needed by their retail customers. They secured approximately half of their power needs from other wholesale suppliers in 2004. Although cooperatives own and operate transmission facilities, almost all rely to some extent on transmission owned by others to deliver power to their customers.

Regulatory jurisdiction over cooperatives varies among states. Some states exercise considerable authority over rates and operations, while others exempt cooperatives from state regulation. In addition to state regulation, cooperatives with outstanding loans under the Rural Electrification Act of 1936[12] are subject to financial and operating requirements of the Rural Utilities Service (RUS), Department of Agriculture. RUS must approve borrowers' long-term wholesale power

[11] NRECA comments.

[12] 7 U.S.C. 901 *et seq.*

contracts, operating agreements, and transfers of assets. Cooperatives that have repaid their RUS loans and that engage in wholesale sales or provide transmission services to others have been regulated by FERC as public utilities under the FPA. EPAct 2005 gave FERC additional discretionary jurisdiction over transmission services provided by larger electric cooperatives.

4. Federal Power Systems

Federally-owned or chartered power systems include the federal power marketing administrations (PMAs), the Tennessee Valley Authority (TVA), and facilities operated by the U.S. Army Corps of Engineers, the Bureau of Reclamation, the Bureau of Indian Affairs, and the International Water and Boundary Commission. Wholesale power from federal facilities (primarily hydroelectric dams) is marketed through four federal power marketing agencies: Bonneville Power Administration, Western Area Power Administration, Southeastern Power Administration, and Southwestern Power Administration. The PMAs own and control transmission to deliver power to wholesale and direct service customers. They also may purchase power from others to meet contractual needs and may sell surplus power as available to wholesale markets. Existing legislation requires that the PMAs and TVA give preference in selling their generation to public power systems and to rural electric cooperatives.

Together, federal systems have an installed generating capacity of approximately 71.4 gigawatts (GW) or about 6.9 percent of total capacity. Federal systems provided 7.2 percent of the nation's power generation in 2004. Although most federal power sales are at the wholesale level, some are made to end users. Federal systems nationwide directly served 39,845 retail customers in 2004, mostly industrial customers and about 1.2 percent of retail load.

5. Nonutilities

Nonutilities are entities that generate, transmit, or sell electric power but do not operate regulated retail distribution franchises.[13] They include wholesale nonutility affiliates of regulated utilities, merchant generators, and qualifying facilities (QFs).[14] They also include power marketers that buy and sell power at wholesale or retail but that do not own generation, transmission, or distribution facilities. Independent transmission companies that own and operate transmission facilities but do not own generation or retail distribution facilities or sell electricity to retail customers are also included in this category for EIA reporting purposes.

Non-QF wholesale generators engaged in wholesale power sales in interstate commerce are subject to FERC regulation under the FPA. Power marketers selling at wholesale are also subject to FERC oversight. Power marketers selling only at retail are subject to state jurisdiction and oversight in states where they operate. FERC regulates interstate transmission services of independent transmission companies under the FPA. Such companies also may be organized and regulated as utilities where they are located for planning, siting, permitting, and other purposes.

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[13] "Nonutilities" – as that term is defined for EIA reporting purposes and as used here – may still be characterized as "utilities" and subject to public service regulation under state law and regulated as "public utilities" by FERC.

[14] QFs are small power producers using eligible alternative electric generating technologies and industrial and commercial cogenerators (combined heat and power producers) that have special status under PURPA.

As retail electric providers, 152 power marketers reporting to EIA served about 6 million retail customers or about 4.4 percent of all retail customers and reported revenues of over $28 billion, on about 11.6 percent of retail electricity sold.

Nonutilities are a growing presence in the industry. In 2004, nonutilities owned or controlled approximately 408,699 megawatts (MWs) or 39.6 percent of all electric generation capacity, compared to about 8 percent in 1993. About half of nonutility generation capacity is owned by nonutility affiliates or subsidiaries of holding companies that also own a regulated electric utility.[15] Nonutilities accounted for about 33 percent of generation in 2004. Tables 1-1 through 1-5 summarize this information.

Table 1-1. U.S. Retail Electric Providers, 2004

Ownership	Number of Electricity Providers	Percent of Total	Number of Customers			Percent of Total
			Full-Service	Delivery only*	Total	
Publicly-owned utilities	2,011	61.4	19,628,710	6,125	19,634,835	14.4
Investor-owned utilities	220	6.7	90,970,557	287,9114	93,849,671	68.9
Cooperatives	884	27	16,564,780	12,170	16,576,950	12.2
Federal Power Agencies	9	0.3	39,843	2	39,845	0.03
Power Marketers**	152	4.6	6,017,611	0	6,017,611	4.4
Total	3,276	100	133,221,501	2,897,411	136,118,912	100.0

Notes:
*Delivery-only customers represent the number of customers in a utility's service territory that purchase energy from an alternative supplier.

** Ninety-eight percent of all power marketers' full-service customers are in Texas. Investor-owned utilities in the ERCOT region of Texas no longer report ultimate customers. Their customers are counted as full-service customers of retail electric providers (REPs), which are classified by the Energy Information Administration as power marketers. The REPs bill customers for full-service and then pay the IOU for the delivery portion. REPs include the regulated distribution utility's successor affiliated retail electric provider that assumed service for all retail customers that did not select an alternative provider. Does not include U.S. territories.

Source: American Public Power Association, *2006-07 Annual Directory & Statistical Report*, from Energy Information Administration Form EIA-861, 2004, data.

[15] EEI comments.

Table 1-2. U.S Retail Electric Sales, 2004

Sales to Ultimate Consumers in Thousands of MWhs

Ownership	Full-Service	Energy only	Total	Percent
Publicly-owned utilities	525,596	65,466	591,062	16.7
Investor-owned utilities	2,148,351	3,359	2,151,720	60.8
Cooperatives	344,267	890	345,157	9.7
Federal Power Agencies	41,169	352	41521	1.2
Power Marketers	207,696	203,202	410,898	11.6
Total	3,267,089	27,3269	3,540,358	100.0

Source: American Public Power Association, *2006-07 Annual Directory & Statistical Report*, from Energy Information Administration Form EIA-861, 2004 data.

Table 1-3. U.S. Retail Electric Providers, 2004, Revenues from Sales to Ultimate Consumers

Ownership	Sales in $ millions			
	Full-Service	Energy only *	Delivery	Total **
Publicly-owned utilities	$37,734	$5,787	$27	$43,548
Investor-owned utilities	$162,691	$128	$8,746	$171,565
Cooperatives	$25,448	$37	$7	$25,492
Federal Power Agencies	$1,211	$13	$1	$1,224
Power Marketers	$17,163	$11,000	0	$28,162
Total	$244,247	$16,965	$8,761	$269,992

Notes:
* Energy-only revenue represents revenue from a utility's sales of energy outside of its own service territory.

** Total shows the amount of revenue each provider group receives from both bundled (full-service) and unbundled (retail choice) sales to ultimate customers. Eighty-five percent of the energy-only revenue attributed to publicly-owned utilities represents revenue from energy procured for California's investor-owned utilities by the California Department of Water Resources Electric Fund. Ninety-eight percent of power marketers' full-service sales and revenues occur in Texas. IOUs in the ERCOT region of Texas no longer report sales or revenue to ultimate consumers on EIA 861.

Source: American Public Power Association, *2006-07 Annual Directory & Statistical Report*, from Energy Information Administration Form EIA-861, 2004 data

Table 1-4. U.S. Electricity Generation, 2004

Thousands of MWhs and Percent of Total

Ownership	Generation (thousands of MWhs)	Percent of Total
Publicly-owned utilities	397,110	10.3
Investor-owned utilities	1,734,733	44.8
Cooperatives	181,899	4.7
Federal Power Agencies	278,130	7.2
Power Marketers	42,599	1.1
Nonutilities	1,235,298	31.9
Total	3,869,769	100.0

Source: American Public Power Association, *2006-07 Annual Directory & Statistical Report*, from Energy Information Administration Form EIA-861 and EIA-906/920 for generation. Data are for 2004, adjusted for joint ownership.

Table 1-5. U.S. Electric Generation Capacity, 2004

Ownership	Nameplate Capacity (in MWs)	Percent of Total
Publicly-owned utilities	98,686	9.6
Investor-owned utilities	408,699	39.6
Cooperatives	43,225	4.2
Federal Power Agencies	71,394	6.9
Nonutilities	409,689	39.7
Total	1,031,692	100.0

Source: American Public Power Association, *2006-07 Annual Directory & Statistical Report*, from Energy Information Administration Form EIA-860 for capacity, including adjustments for joint ownership. Data are for 2004.

B. Growth of the Electric Power Industry

For a variety of legal, economic, and technological reasons, the electric utility industry in the United States developed as a collection of separate, mostly vertically-integrated monopoly franchises with wholesale and retail prices and services extensively regulated under state and federal law. Many states have elected to maintain this model. The legacy of this vertically-integrated monopoly structure creates substantial challenges for state and federal efforts to restructure the industry and to create new institutional arrangements to facilitate increased reliance on competitive market prices. This section provides a brief overview of the evolutionary changes in the electric power industry.

1. The Rise of Electric Utility Monopolies and Public Utility Regulation

In the late 19th Century, electric utilities developed as small central station power plants with limited local distribution networks. Franchise rights granted by manufacturers and by municipal governments allowed use of public streets and rights of ways. These franchises were often exclusive, but in some cities there was head-to-head competition among competing electric lighting companies.[16] In addition, because lighting, electric motors, and traction were the major uses of electricity, customers could turn to alternatives – natural gas lighting or self-generation in the case of street railway, commercial, and industrial customers.[17] Many municipalities elected to create and operate their own electric utility systems.

Certain characteristics of providing electric service were recognized early on. Utility systems incurred high fixed costs for investments in generating plants needed to meet peak load and to extend the delivery system. Because they had relatively low operating costs, their profits were determined by the percent of time the power plant was in use. Complementary load diversity – such as balancing daytime traction and electric motor loads with evening lighting loads – could raise generating plant use and revenues to offset fixed costs and boost profits. The high capital costs of electric generating plants made investments risky. Steady gains in generation, transmission, and distribution economies of scale provided incentives to expand the electric networks. Larger plants produced cheaper electricity than many smaller plants. The substantial investment required for electric utility plants also spurred creation of long-term financing structures and the corresponding interest in providing assurances to investors that the entity would be profitable and would remain financially viable long enough to repay the debt.

These characteristics led some to suggest that a single monopoly provider of integrated generation, transmission and distribution service could provide electric service most economically and safely. To avoid abuses of this monopoly power, it was suggested that impartial state agencies should be created to award franchises and establish rates and service standards. An early associate of Thomas Edison, Samuel Insull of Chicago Edison was among them and proposed state regulation of private utilities in a speech before the National Electric Light Association in 1898.[18] Insull characterized electricity production as a "natural monopoly."[19] Initially, the proposal for state regulation was poorly received, but as private

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[16] LEONARD S. HYMAN, AMERICA'S ELECTRIC UTILITIES: PAST, PRESENT AND FUTURE 64 (Public Utility Reports, Inc. 1988) [hereinafter HYMAN]. In the City of Chicago, the city council granted 29 different electric franchises between 1882 and 1905; three of them were citywide.

[17] For more on the history of electric utilities, see also U.S. Department of Energy, Energy Information Administration, *The Changing Structure of the Electric Power Industry: 1970-1991*, at 57 (March 1993), *available at* http://tonto.eia.doe.gov/FTPROOT/electricity/0562.pdf [hereinafter *EIA 1970-1991*]; U.S. Department of Energy, Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update,* Appendix A (October 2000), *available at* http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/update2000.html [hereafter *EIA Update 2000*].

[18] HYMAN at 68.

[19] In economic literature, the concept of a "natural monopoly" developed over time as a rationalization for the regulation of electric utilities. In brief, a "natural monopoly" is an industry characterized by long-run decreasing costs where a single provider can supply product or service at a lower cost than competition. ALFRED E. KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS, Volume 1, at 11-12 (John Wiley & Sons, Inc. 1970). Kahn also notes the substantial legal and historical "public interest" rationale for regulation of the electric utility industry. Economists have debated whether the electric utility industry or segments of it are natural monopolies for several decades. This debate

electric companies began to grow and consolidate and concerns were raised over trusts in many industries, the concept began to gain support. In 1907, Wisconsin adopted legislation regulating electric utilities and was quickly joined by two other states. By 1916, 33 states had established state agencies to oversee private electric utilities.[20]

Generally, under this approach, the state regulatory commission granted exclusive retail electric franchises to private companies within specified territories, protecting the utility from competition. In return, the utility assumed an obligation to provide safe and adequate service to all retail customers within its territory under just and reasonable rates, terms and conditions overseen by the state. Often the utility was authorized to use public rights of way and eminent domain for electric facilities. To meet this obligation to serve, most private utilities built and controlled the generation, transmission, and distribution facilities needed to provide service to customers. Rates were set to cover the companies' reasonable costs plus a fair return on shareholders' investment. The utility could expect a right to reasonable compensation for its services, although a specific rate of return was not guaranteed. Retail rates (price) were based on the average historical system cost of production (including the investors' fair return on investment).

In the early 20th Century, private electric utilities continued to expand under this system of state regulation. Most continued to build their own generation plants and transmission systems, primarily due to the cost and technological limitations of transmitting electricity over distances.[21] Initially, there was little wholesale trade among utilities. As the industry grew, continued improvements in technology allowed expansion beyond central cities, and prices for electricity fell at the same time that demand increased substantially.

Over the same period, electric utility holding companies were created and began to acquire local private and municipal utilities. While a holding company's local utility operating companies were regulated by the state, the holding company and its other affiliates and subsidiaries were not, and often did business in several states. The proliferation, consolidation, and complexity of such companies coincided with a number of financial and securities abuses that were documented in an investigation by the Federal Trade Commission (FTC). These holding companies often became the sole providers of various services and products to their affiliated utilities, and their sometimes inflated costs were passed through to the retail customers. By 1932, the eight largest utility holding companies controlled 73 percent of the investor-owned electric industry.[22]

This pattern of consolidated ownership and holding company abuses led to calls for federal involvement in the electric power industry. As a result of the FTC findings, Congress passed the Public Utility Holding Company Act of 1935 (PUHCA 1935),[23] which required the breakup and

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focuses on the economic theory rationalization for regulation and not the public policy or legal basis for electric power regulation. *See, e.g.*, Vernon Smith, *Regulatory Reform in the Electric Power Industry* (1995) (working paper, on file with the Department of Economics, University of Arizona); RICHARD F. HIRSCH, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN UTILITY SYSTEM (MIT Press 1999); SHARON BEDER, POWER PLAY: THE FIGHT TO CONTROL THE WORLD'S ELECTRICITY (W.W. Norton 2003).

20 HYMAN at 68.

21 *See EIA Update 2000*.

22 HYMAN at 74.

23 15 U.S.C. §§ 79a *et seq.* (2000).

stringent federal oversight of the large utility holding companies. The FPA expanded the Federal Power Commission's authority to include oversight and regulation of interstate sales of wholesale power (e.g., sales of power between utility systems) and interstate electricity transmission at wholesale by "public utilities" (i.e., investor-owned utilities). FPA jurisdiction over interstate sales closed a gap in electric industry regulation that the Supreme Court had identified in 1927.[24]

When the FPA was enacted, wholesale and interstate sales of electricity were limited. Most wholesale transactions were long-term power supply contracts by investor-owned utilities to sell and deliver power to neighboring public power and cooperative utilities. Over time, utilities became more interconnected via high-voltage transmission networks. Constructed primarily for reliability, these networks also facilitated more opportunities for interstate trade. However, wholesale trade was slow to develop.

Until the late 1960s, the vertically integrated monopoly utility model appeared to work reasonably well. Utilities were able to meet increasing demand for electricity at decreasing prices as advances in generation technology and transmission provided increased economies of scale with larger units and decreased costs.[25]

2. The Energy Crisis of the 1970s, PURPA, and the Expansion of Nonutility Generation and Wholesale Power Markets

The shift toward a more competitive marketplace for electricity was precipitated by industry changes that began in the late 1960s and accelerated throughout the 1970s. Resulting financial stresses challenged the continued profitability of the large vertically integrated utility model. They also provoked criticisms of the traditional cost-of-service regulatory model that allowed the pass-through of higher costs and risks of construction to consumers.

By the end of the 1960s, electricity demand and generation were increasing at an annual rate of 7.5 percent, and residential rates were declining at an average annual rate of 1.5 percent.[26] At the same time, the new large nuclear and coal plants built in the 1970s did not yield the dramatic improvements in economies of scale that earlier technological advances in generating plant size had produced. The industry's characterization as a long-term decreasing cost industry came into question. Periods of rapid inflation and higher interest rates substantially increased the completion costs of large, base load generating plants.[27] New environmental and safety regulations required addition of pollution controls and design features that added to costs and construction time. Moreover, once in operation, many of the new, larger units required more maintenance and longer downtimes than expected. Thus, by the late 1970s, a newer, larger, generation facility no longer could be assumed to be more cost-efficient than a smaller plant.[28]

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[24] In *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Co*., 273 U.S. 83 (1927), the Supreme Court ruled that state regulators were barred by the Commerce Clause from setting the prices of electricity sold across state lines.

[25] *See EIA 1970-1991*.

[26] *EIA Update 2000* at 114-15.

[27] The costs of constructing new nuclear plants quadrupled between 1971 and 1976. Over 63 nuclear units were canceled between 1975 and 1980. *EIA Update 2000* at 114-15.

[28] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,640-41.

This experience stimulated interest in smaller, modular, more energy-efficient generating units. One expression of this interest resulted in commercialization of aeroderivative gas turbine technology. This technology allowed smaller generation units to be constructed at lower costs, more quickly, and at less financial risk than large base-load coal and nuclear plants.[29] Thus, construction of low-cost generation became an option for utilities that were formerly captive to high-cost generators and emerged as a viable path for new nonutility generators to enter the market.

As the difficulties plaguing utilities' generation construction programs were playing out, utility fuel prices were escalating rapidly in response to the Arab oil embargo of 1973-1974 and subsequent world oil market disruptions. Significantly higher energy prices added to inflation and increased electric rates.[30] Other developments also substantially contributed to the growing interest in electric utility reforms. First, the 1965 Northeast power blackout raised concerns about the reliability of weakly coordinated bulk power system operating arrangements among utilities.[31] The nuclear accident at the Three Mile Island plant in Pennsylvania on March 28, 1979, heightened concerns over safety and led to stringent new regulatory requirements for nuclear plants.

Criticism of the traditional cost-of-service utility regulation model by economists and policy analysts also increased during the 1970s with suggestions for alternate approaches to regulation and changes in industry structure. Critics of cost-based regulation argued that the industry structure limited opportunities for more efficient suppliers to expand, placed insufficient pressure on less efficient suppliers to improve performance, and insulated customers from the cost impacts of energy use.[32]

Congress enacted the Public Utility Regulatory Policies Act (PURPA) as a response to the energy crises of the 1970s. PURPA's major goal was to promote energy conservation and alternative energy technologies and to reduce oil and gas consumption through use of improved technology and regulatory reforms. A perhaps unanticipated side effect was that PURPA prompted a number of parties to see potential profits in developing competitive generating plants, creating an opportunity for nonutilities to emerge as important electric power producers.[33]

PURPA required electric utilities to interconnect with and purchase power from cogeneration facilities and small power producers that met statutory criteria for a qualifying facility (QF). A utility had to pay the QF at the utility's incremental cost of production. In a departure from cost-based rate approaches, FERC defined this as the utility's avoided cost of power.[34] Box 1-1

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29 *Id.* at 31,641.

30 *Id.* at 31,639, n.9.

31 The response to the blackout included the formation of regional reliability councils and the North American Electric Reliability Council (NERC) to promote the reliability and adequacy of bulk power supply. *EIA Update 2000* at 109.

32 Paul L. Joskow, *The Difficult Transition to Competitive Electricity Markets in the U.S.* 6-7 (AEI-Brookings Joint Ctr. for Regulatory Studies, Working Paper No. 03-13, 2003), *available at* http://www.aei-brookings.org/admin/authorpdfs/page.php?id=271 [hereinafter Joskow, *Difficult Transition*].

33 See *EIA 1970-1991* at 22.

34 PURPA specifically set forth criteria on who and what could qualify as QFs (mainly technology, size, and ownership criteria). Two types of QFs were recognized: cogenerators, which sequentially produce electric energy and another form of energy (such as heat or steam) using the discusses how implementation of PURPA encouraged nonutility generation suppliers by guaranteeing a market for the electricity produced.[35] PURPA changed prevailing views that vertically integrated public utilities were the only reliable sources of power[36] and showed that nonutilities could build and operate generation facilities effectively and without disrupting the reliability of the electric grid. PURPA contributed substantially, both directly and indirectly, to the creation of an independent competitive generation sector.[37]

Box 1-1
State Implementation of PURPA

PURPA required states to determine each utility's avoided costs of production. This cost was used to set the price for purchasing a QF's power. To encourage renewable and alternative energy generation, several states, including California, New York, Massachusetts, Maine, and New Jersey, required utilities to sign long-term contracts with QFs at prices that eventually ended up being much higher than the utilities' actual marginal savings of not producing the power itself (avoided costs). As a result, many utilities in these states entered into long-term purchase contracts at prices higher than those available in the competitive wholesale markets. The costs of these QF contracts were reflected in retail rates as cost pass-throughs. The experience added to the dissatisfaction with retail rate regulation.

Before passage of PURPA, nonutility generation was confined primarily to commercial and industrial facilities that generated heat and power for onsite use where it was advantageous to do so. Although nonutility generation facilities were located across the country, development was heavily concentrated geographically, with about two-thirds of such facilities located in California and Texas. Nonutility generation development advanced in states where avoided costs were high enough to attract interest and where natural gas supplies were available. Federal law largely precluded electric utilities from constructing new natural gas plants during the decade following enactment of PURPA, but nonutility generators faced no such restriction and quickly turned to the new smaller gas turbines as the preferred generating technology.

The response to PURPA was dramatic. Annual QF filings at FERC rose from 29 applications covering 704 MW in 1980 to 979 in 1986 totaling over 18,000 MW. From 1980 to 1990, FERC received a total of 4,610 QF applications for a total of 86,612 MW of generating capacity.[38]

Following PURPA, continued improvement in generating technology lowered costs and further contributed to an influx of new entrants in wholesale markets. They could sell electric power

same fuel source, and small power producers, which use waste, renewable energy, or geothermal energy as a primary energy source. *See EIA 1970-1991* at 5.

35 *Id.* at 24.

36 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,642.

37 *See* Paul L. Joskow, *Deregulation and Regulatory Reform in the U.S. Electric Power Sector*, at 17 (February 16, 2000) (revised discussion draft prepared for the Brookings-AEI Conference on Deregulation in Network Industries, Dec. 9-10, 1999) [hereinafter Joskow, *Deregulation*].

38 CONG. RESEARCH SERV., COMM. ON ENERGY AND COMMERCE, 102D CONG., ELECTRICITY: A NEW REGULATORY ORDER? 92 (Comm. Print 1991).

profitably with smaller scale generators, including renewable energy technologies and more efficient, modular gas turbines.[39] Other nonutilities that could not meet QF criteria began building new capacity to compete in bulk power markets to meet the needs of utilities.[40] These new entities were known as merchant generators or independent power producers (IPPs).[41] By 1991, nonutilities (QFs and IPPs) owned about 6 percent of the electric generating capacity and produced about 9 percent of the total electricity generated in the United States.[42] Nonutility facilities accounted for one-fifth of all additions to generating capacity in the 1980s.[43] Beginning in the 1980s, FERC allowed many new utility and nonutility generators to sell electricity at rates negotiated in wholesale markets, rather than established under cost-of-service formulas.[44]

In 1988, FERC solicited public comments on three notices of proposed rulemaking (NOPRs) dealing with electricity pricing in wholesale transactions. These NOPRs addressed the following issues: (1) competitive bidding for new power requirements; (2) treatment of independent power producers; and (3) determination of avoided costs under PURPA.[45] These proposals would have moved FERC towards greater use of a "non-traditional" market-based pricing approach in ratemaking as opposed to the agency's "traditional" cost-based approach. The NOPRs, however, proved controversial, and efforts to establish formal rules or policies were abandoned. However, the overall policy goals were still pursued on a case-by-case basis.

Between 1983 and 1991, FERC was asked to approve more than 30 non-traditional market-based rate proposals. These proposals were brought by IPPs, power brokers/marketers, utility-affiliated power producers, and traditional franchised utilities. FERC approved all but four.[46] In explaining its approach, FERC staff wrote: "The Commission has accepted non-traditional rates where the seller or its affiliate lacked or had mitigated market power over the buyer, and there was no potential abuse of affiliate relationships which might directly or indirectly influence the market price and no potential abuse of reciprocal dealing between the buyer and seller."[47] In determining whether the seller could exercise market power over the buyer, FERC considered

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39 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,644.

40 Joskow, *Deregulation* at 19.

41 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,642.

42 *EIA 1970-1991* at vii.

43 *Id.* at 27.

44 *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,643.

45 *See Regulations Governing Bidding Programs*, Notice of Proposed Rulemaking, 53 Fed. Reg. 9,324 (Mar. 22, 1988), FERC Stats. & Regs. ¶ 32,455 (1988) (modified by 53 Fed. Reg. 16,882 (May 12, 1988)). This proposal would have adopted competitive bidding into the process of acquiring and pricing power from QFs and would have largely abandoned the prior avoided cost purchase rates.

See Regulations Governing Independent Power Producers, Notice of Proposed Rulemaking, 53 Fed. Reg. 9,327 (Mar. 22, 1988), FERC Stats. & Regs. ¶ 32,456 (1988) (modified by 53 Fed. Reg. 16882 (May 12, 1988)). This proposal would have relaxed rate review and regulation of wholesale sales by independent power producers, and other public utilities that did not operate retail distribution systems.

See Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, Notice of Proposed Rulemaking, 53 Fed. Reg. 9,331 (Mar. 22 1988), FERC Stats. & Regs. ¶ 32,457 (1988) (modified by 53 Fed. Reg. 16882 (May 12, 1988)). This proposal would have revised the elements used in making administrative determinations of avoided costs for rates for utilities' PURPA QF purchases.

46 *Hearing on National Energy Security Act of 1991 (Title XV) Before the S. Comm. on Energy and Natural Resources*, 102d Cong. 97 (1991) (statement of Cynthia A. Marlette, Associate General Counsel for Hydroelectric and Electric, Federal Energy Regulatory Commission).

47 *Id.* at 100.

whether the seller or its affiliates owned or controlled transmission that might prevent the buyer from accessing other power sources. A seller with transmission control might be able to force the buyer to purchase from the seller, thus limiting competition and significantly influencing price. The FPA does not allow rates to reflect an exercise of such market power.[48]

FERC recognized the potential for control of transmission to create market power and the challenge such control created in moving to greater reliance on market-based rates. FERC staff told Congress, "Because the Commission's very premise of finding market-based rates just and reasonable under the FPA is the absence or mitigation of market power, or the existence of a workably competitive market, and because the FPA mandates that the Commission prevent undue preference and undue discrimination, we believe the Commission is legally required to prevent abuse of transmission control and affiliate or any other relationships which may influence the price charged a ratepayer."[49]

Despite these developments, two limitations at that time were perceived to discourage competitive wholesale generation markets. First, IPPs and other generators of cheaper electric power could not easily access the transmission grid to reach potential customers.[50] Under the FPA as then written, FERC had limited authority to order access. FERC would subsequently find that "intervening" transmitting utilities would deny or limit transmission service to competing suppliers of generation to protect demand for wholesale power supplied by their own facilities.[51] Second, unlike QFs that enjoyed a statutory exemption under PURPA, IPPs were subject to PUHCA 1935, which discouraged nonutilities from entering the generation business.[52]

3. <u>The Energy Policy Act of 1992 and FERC Orders Nos. 888 and 889</u>

EPAct 1992 amended the FPA and PUHCA 1935 to address what were then seen as the two major limitations to the development of a competitive generation sector.

First, EPAct 1992 created a new category of power producers, called exempt wholesale generators (EWGs).[53] An EWG is an entity that directly, or indirectly through one or more affiliates, owns or operates facilities dedicated exclusively to producing electric power for sale in wholesale markets.[54] EWGs are exempted from PUHCA 1935 regulations, thus eliminating a

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48 *Id.*

49 *Id.* at 102.

50 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,642-43.

51 Joskow, *Deregulation* at 21. *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,644.

52 Joskow, *Deregulation* at 23. Under PUHCA 1935, those public utility holding companies that did not qualify for an exemption were subject to extensive regulation of their financial activities and operations. These regulations limited the availability of exemptions and the growth and expansion of electric utility companies. PUHCA 1935 restricted utility operations to a single integrated public-utility system and prevented utility holding companies from owning other businesses that were not reasonably incidental or functionally related to the utility business. Further, registered holding companies had to obtain Securities and Exchange Commission (SEC) approval for the sale and issuance of securities, for transactions among their affiliates and subsidiaries and for services, sales, and construction contracts, and they were required to file extensive financial reports with the SEC.

Although PUHCA 1935 provided for limited exemptions, it was long criticized as discouraging new investment in the electric utility industry by nonutility entities. Mergers and acquisitions of utilities subject to PUHCA 1935 have largely been by other domestic and foreign utilities. Investment by entities outside the industry has been limited, as these entities avoid the extensive regulations imposed by PUHCA 1935.

53 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,645.

54 Joskow, *Deregulation* at 24.

major barrier for utility-affiliated and nonaffiliated power producers that wanted to build or acquire new non-rate-based power plants to sell electricity at wholesale.[55]

Second, EPAct 1992 expanded FERC's authority to order transmitting utilities to provide transmission service for wholesale power sales to any electric utility, federal power marketing agency, or any person generating electric energy.[56] It provided for orders to be issued on a case-by-case basis following a hearing if certain protective conditions were met. Although FERC implemented this new mandatory wheeling authority, it ultimately concluded that procedural limitations restricted its reach and a broader remedy was needed to eliminate pervasive undue discrimination in transmission service that hindered competition in wholesale markets.

In April 1996, FERC adopted Order No. 888 in exercise of its statutory obligation under the FPA to remedy undue transmission discrimination. The goal was to ensure that transmission owners do not use their transmission facility monopoly to unduly discriminate against IPPs and other sellers of electric power in wholesale markets. In Order No. 888, FERC found that undue discrimination and anti-competitive practices existed in transmission service provided by public utilities in interstate commerce. FERC determined that non-discriminatory open access transmission service was an appropriate remedy and one of the most critical components of a successful transition to competitive wholesale electricity markets. Accordingly, FERC required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to file open access transmission tariffs (OATTs) containing certain non-price terms and conditions. They also were required to "functionally unbundle" wholesale power services from transmission services.[57] This meant that a public utility was required to: (1) take wholesale transmission services under the same tariff of general applicability as it offered its customers; (2) define 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 the utility's transmission system.[58]

Concurrent with Order No. 888, FERC issued Order No. 889[59] that imposed standards of conduct governing communications between a utility's transmission and wholesale power functions to prevent the utility from giving its power marketing arm preferential access to transmission information. Order No. 889 requires each public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce to create or participate in an Open Access Same-Time Information System (OASIS). OASIS must provide information regarding available transmission capacity, prices, and other information that will

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55 *See EIA 1970-1991* at 30; Joskow, *Deregulation* at 23.

56 Pub. L. No. 102-486, §§ 721-26, 106 Stat. 2776 (1992).

57 Order No. 888, FERC Stats. & Regs. ¶ 31,036, at ¶ 31,654.

58 *Id.* Order No. 888 also clarified FERC's interpretation of the federal/state jurisdictional boundaries over transmission and local distribution. While it reaffirmed that FERC has exclusive jurisdiction over the rates, terms, and conditions of unbundled retail transmission in interstate commerce by public utilities, it nevertheless recognized the legitimate concerns of state regulatory authorities for the development of competition within their states. FERC therefore declined to extend its unbundling requirement to the transmission component of bundled retail sales and reserved judgment on whether its jurisdiction extends to such transactions. The United States Supreme Court affirmed this element of Order No. 888. *New York v. FERC*, 535 U.S. 1 (2002).

59 *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, Order No. 889, 61 Fed. Reg. 21,737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 at 31,583 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

enable transmission customers to obtain open access to non-discriminatory transmission service.[60]

In Order No. 888, FERC also encouraged grid regionalization through the formation of independent system operators (ISOs). Participating utilities would voluntarily transfer operating control of their transmission facilities to the ISO to ensure independent operation of the transmission grid.[61] The expectation was that ISO regional control would lead to improved coordination, reliability, and efficient operation.[62] However, ISO participation was voluntary and was not embraced in all regions.[63] Together, Order Nos. 888 and 889 serve as the primary federal regulatory foundation for providing nondiscriminatory transmission service and information about the availability of transmission service.[64]

4. Retail Electricity Competition and State Electric Restructuring Initiatives

In the early 1990s, several states with high electricity prices began exploring opening retail electric service to competition. While customers would choose their supplier, the delivery of electricity would still be done by the local distribution utility. Retail competition was expected to result in lower retail prices, innovative services and pricing options. It also was expected to shift the risks of new generation construction from ratepayers to competitive market providers. The substantial rate disparity among and between utilities in different states spurred state interest in retail competition. For example, in 1998, customers in New York paid more than two and one-half times the rates paid by customers in Kentucky. Rates in California were well over twice the rates in Washington.[65] Some of this disparity can be attributed to different natural resource endowments across regions, such as the availability of hydroelectric resources in the Northwest and of abundant coal reserves in Kentucky and Wyoming– which were reflected in the low cost of electricity in these states. In contrast, in more urban states without these resources, utilities invested heavily in large, new nuclear and coal plants, which often turned out to be more expensive than anticipated, adding to retail rates. Some utilities in high-cost states also had entered into long-term PURPA contracts that subsequently resulted in higher prices than in the wholesale power market.[66] These QF contract costs were ultimately reflected in the regulated retail rates.[67]

Many large industrial customers viewed these rate disparities among states as a competitive disadvantage and looked to retail competition as a way to secure lower cost electricity supplies. Many industrial customers had long objected that they subsidized lower rates for residential customers under state regulated rates. For example, a survey by the Electricity Consumers Resource Council in 1986 contended that industrial electricity consumers paid more than $2.5

[60] Joskow, *Deregulation* at 29.

[61] *EIA 2000 Update* at 66.

[62] *Id.* at 66, 68, 80.

[63] *Id.* at 67.

[64] Joskow, *Deregulation* at 27-28.

[65] *EIA 2000 Update* at ix.

[66] *See* discussion *infra*, Box 1-1.

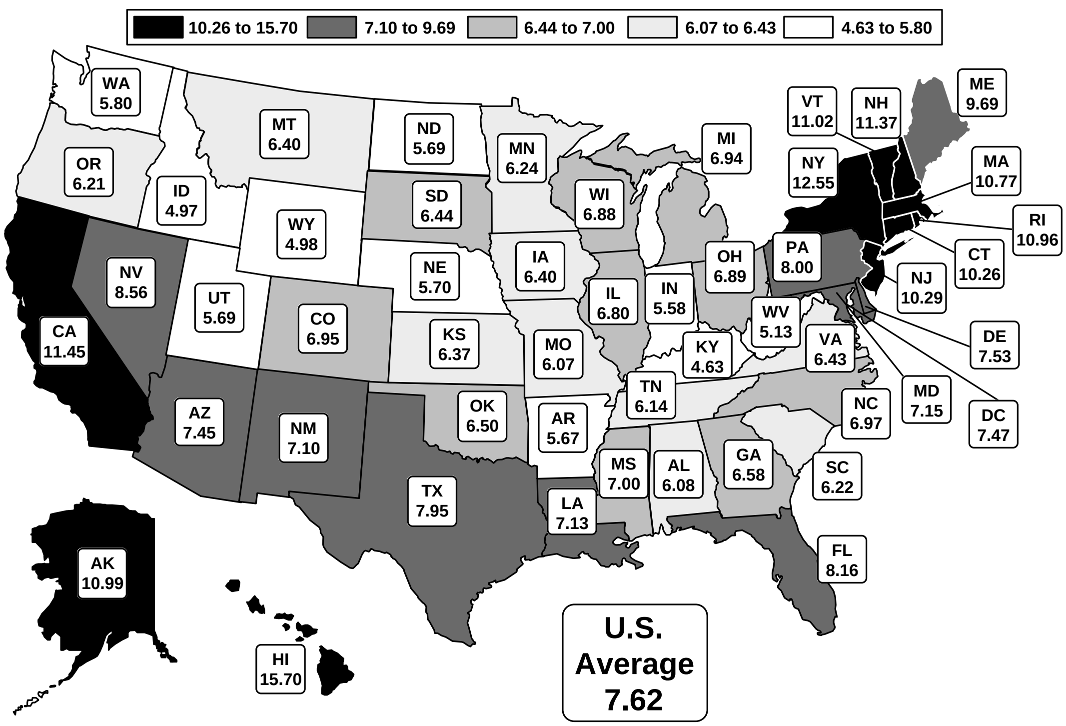
[67] Joskow, *Deregulation* at 19.

billion annually in subsidies to other electricity customers (e.g., commercial and residential customers).[68] It was presumed that allowing industrial customers to choose a new supplier would avoid these subsidies, thereby resulting in lower electricity prices for such customers.

Thus, it was not surprising that many states adopting plans to restructure retail electric service were those with higher prices.[69] (Figure 4-1 in Chapter 4 shows average retail electricity prices in 1995.) States with high electricity rates, such as California and those in New England and the mid-Atlantic region, were among the most aggressive in adopting retail competition and restructuring electric service in the hope of lowering retail rates. As of 2004, the disparity in retail prices among the states persisted, as illustrated in Figure 1-1, below.

Figure 1-1. U.S. Electric Power Industry, Average Retail Price of Electricity by State, 2004

Cents per kWh



Source: EIA, *Electric Power Annual 2004*, Figure 7.4

Most states considered the merits and implications of competition and industry restructuring, but not all adopted retail competition plans. As of July 2000, 24 states and the District of Columbia had enacted legislation or passed regulatory orders to restructure their electric power industries. Two states had legislation or regulatory orders pending, while 16 states had ongoing legislative or regulatory investigations. Only eight states did not formally initiate restructuring studies.[70]

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[68] Electricity Consumers Resource Council, *Profiles in Electricity Issues: Cost-of-Service Survey* (Mar. 1986).

[69] *EIA 2000 Update* at 43.

[70] *Id.* at 81-82.

The meltdown of California's electricity markets and the ensuing Western Energy market crisis of 2000-2001 are widely perceived to have halted interest by states in restructuring retail markets. Since 2000, no additional states have announced plans to implement retail competition programs, and several states that had introduced such programs have delayed, scaled back, or repealed their programs entirely (see Figure 1-2 below).[71]

In 2006, retail customers in 30 states continue to receive service almost exclusively under a traditional regulated monopoly utility service franchise. These states include 44 percent of all U.S. retail customers, representing 49 percent of electricity demand. However, 20 states and the District of Columbia have state restructuring plans in force that allow competitive retail providers to provide service to some if not all retail customers at prices set in the market.

State retail restructuring plans often involved divestiture of generating assets by local vertically integrated utilities. As a result, the distribution utilities that sell electricity to retail customers must procure power from wholesale markets under long- or short-term bilateral contracts and from wholesale spot markets. These jurisdictions include many of the most populous states, accounting for over half of all retail customers and loads. With some exceptions, retail competition has been slow to develop in many of these states, particularly for residential customers. Without a competitive provider option, most customers continue service under regulated "provider of last resort" (POLR) rates. In some states, freezes and caps on POLR rates approved by state regulators under retail restructuring cases are expiring, and POLR rates are being revised sharply upward to reflect higher market-based wholesale electricity costs. State experience with electric competition and related issues is discussed in Chapter 4, Retail Competition, and in Appendix D.

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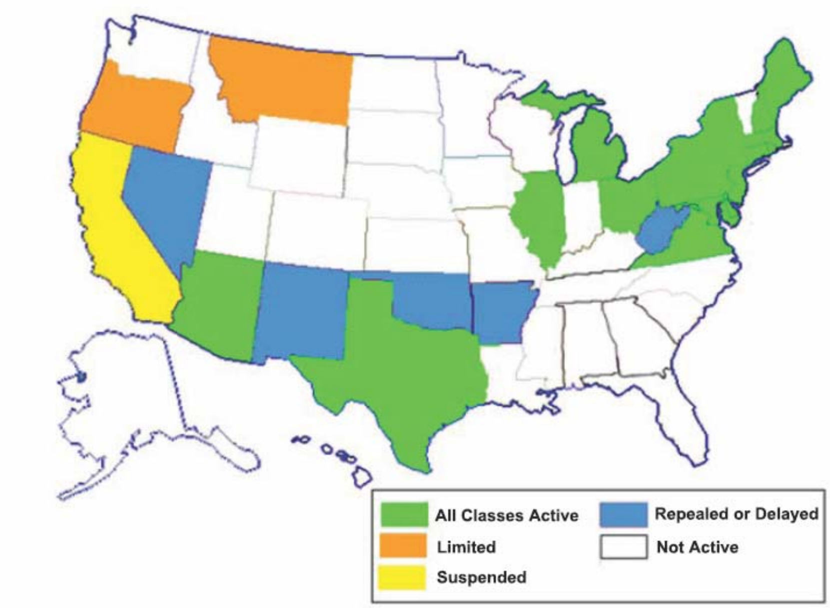
[71] Paul L. Joskow, *Markets for Power in the United States: An Interim Assessment*, ENERGY J. 2 (forthcoming 2006), *available at* http://stoft.com/metaPage/lib/Joskow-2006-power-market-assessment.pdf [hereinafter Joskow, *Interim Assessment*].

Figure 1-2. Status of State Electric Industry Restructuring Activity and Retail Competition, July 2006



Note: Nevada repealed its retail choice legislation in 2001. It subsequently enacted legislation allowing state regulators to approve requests from very lareg C&I customers to procure electricity from alternative suppliers if the contract is found to be in the public interest.

Source: Task Force Comments and EIA, *Status of State Electricity Industry Restructuring Activity 2003*, February 2003, *available at* http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf.

5. <u>The Western Energy Market Crisis 2000-2001.</u>

California opened its retail markets to competition and started spot markets for wholesale electricity in 1998. In response to the state plan, the three major investor-owned utilities divested most of their non-nuclear generation and turned over operation of transmission facilities to the new California Independent System Operator (CAISO). The IOUs were required to sell into and purchase power through the new California Power Exchange (CalPX) and the CAISO. Retail rates were reduced but remained well above the national average. Rates were then frozen until the utilities recovered their stranded costs. At that point, competitive markets were expected to drive prices lower. San Diego Gas and Electric (SDG&E) fully recovered its stranded costs by summer of 1999, and its retail rates were then allowed to reflect the utility's cost of obtaining power in the wholesale markets. Retail rates for the other two major utilities remained frozen.

In late May 2000, the CAISO called its first Stage 2 power alert as system reserves fell below 5 percent. PX prices that had averaged about $27 per MWh in April spiked to over $50 in May and continued upwards, eventually reaching a high of $450 per MWh in January 2001. These higher prices were quickly passed through in San Diego, where average customer bills tripled by mid-summer. California's other major utilities, Pacific Gas and Electric (PG&E) and Southern California Edison (SCE), were forced to pay the unexpectedly higher PX wholesale prices, but could not pass increases on to retail customers as they were still under a rate freeze.

Price spikes were not California's only problems. On June 14, 2000, the CAISO imposed rolling blackouts in PG&E's San Francisco service area because of shortages attributed to the maintenance shutdown of several generating plants. These were the first of many power emergencies and blackouts affecting the state that did not end until July 2001.

Responding to public concern, the California Public Utilities Commission, the state's attorney general, and FERC all launched investigations. On August 2, 2000, SDG&E filed a complaint at FERC against all sellers in the PX and ISO markets and asked for a price cap of $250.[72] FERC opened a formal investigation of wholesale pricing in California and the West in general. A preliminary FERC staff report in November 2000 found that the market rules and structure were "seriously flawed" and, coupled with supply and demand imbalance, could result in rates that were not "just and reasonable."[73] The staff report concluded that the state's market structure created the potential for abuse of market power when supplies were tight. FERC proposed interim emergency remedies that were instituted in December 2000.[74]

As the state's market problems continued and spread, price spikes affected electricity pricing hubs and utilities across the West, including states that had not adopted retail competition and that were not included in the CAISO. The region's increased power costs were estimated in the tens of billions and led to retail rate increases in many Western states.[75] California declared multiple power emergencies in December 2000, followed by blackouts in January and March 2001. High wholesale market prices that utilities were not allowed to recover through retail rates threatened the solvency of the state's three major IOUs. California sought to end the procurement difficulties faced by IOUs in the state by entering into long-term contracts to secure power on behalf of the utilities and to preserve service to retail customers. Contract prices were set at some of the highest prices prevailing over this period.[76] As a condition of assuming responsibility for power procurement, the state suspended retail competition for all but large customers that already had contracts with competitive suppliers. In April, PG&E's retail electric utility subsidiary, one of the largest in the nation, filed for bankruptcy protection, later joined by a number of wholesale seller-creditors, because the financially distressed distribution utilities did not make timely payments to these generators. Power prices did not return to "normal" ranges until fall of 2001.

Over this period, FERC issued a number of orders setting and lowering price caps, establishing market monitoring requirements, and opening an investigation of possible market manipulation in the run-up of natural gas prices in the West. State, federal, and private investigations ultimately uncovered a number of market abuses and regulatory gaps.[77] Many FERC and other

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[72] Federal Energy Regulatory Commission, *The Western Energy Crisis, the Enron Bankruptcy, and FERC's Response*, *available at* http://www.ferc.gov/industries/electric/indus-act/wec/chron/chronology.pdf.

[73] *Id.*

[74] *Id.*

[75] For example, the Idaho PUC commented that the pass-through power cost adjustment portion of retail rates increased between 30 to 50 percent as a direct result of the impacts of the Western energy crisis. Idaho PUC comments.

[76] *See* discussion *infra*, Box 4-3.

[77] *See, e.g., California Attorney General, Energy White Paper: A Law Enforcement Perspective on the California Energy Crisis, Recommendations for Improving Enforcement and Protecting Consumers in Deregulated Energy Markets* (April 2004), *available at* http://ag.ca.gov/publications/energywhitepaper.pdf [hereinafter Cal. Atty Gen. White Paper]; Federal Energy Regulatory Commission, *Final Report on Price Manipulation in Western Energy Markets: Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas*

proceedings arising out of the dysfunctional California markets continue today.[78] A number of energy traders eventually faced criminal charges. The 2000-2001 Western Energy Crisis had wide repercussions as other regions adapted their market rules and structures to avoid the problems encountered in the West.

6. Development of Regional Transmission Organizations and Regional Wholesale Markets

After issuing Order Nos. 888 and 889, FERC continued to receive complaints about transmission owners discriminating against independent generating companies. Transmission customers remained concerned that implementation of functional unbundling did not produce complete separation between operating the transmission system and marketing and selling electric power in wholesale markets. There were also concerns that Order No. 888 made some discriminatory behavior in transmission access more subtle and difficult to identify and document.

After FERC issued Order Nos. 888 and 889, the electric industry continued to evolve in response to competitive pressures and state retail restructuring initiatives. Utilities today purchase more wholesale power to meet load than in the past and are relying more on availability of other utility transmission facilities to deliver power. Retail competition increased significantly, and state initiatives brought about the divestiture of generation plants by traditional electric utilities. In addition, there were a number of mergers among traditional electric utilities and among electric utilities and gas pipeline companies. The number of power marketers and independent generation developers increased dramatically, and ISOs were established to manage large parts of the transmission system. Trade in wholesale power markets has increased significantly, and the nation's transmission grid is now used more heavily and in new ways.

In December 1999, responding to continuing complaints of discrimination and lack of transmission availability, FERC issued Order No. 2000.[79] This order recognized that Order No. 888 set up the foundation for competitive electric markets, but did not eliminate the potential to engage in undue discrimination and preference in providing transmission service.[80] FERC concluded that regional transmission organizations (RTOs) could eliminate transmission rate pancaking,[81] increase region-wide reliability, and eliminate any residual discrimination in transmission services where operation of the transmission system remains in the control of a vertically integrated utility. Accordingly, FERC encouraged voluntary formation of RTOs.

Prices, Docket No. PA02-2-000 (March 26, 2003); U.S. General Accounting Office, *Restructured Electricity Markets, California Market Design Enabled Exercise of Market Power* (June 2002), *available at* http://www.gao.gov/new.items/d02828.pdf; Lockyer v. FERC, 383 F.3d 1006 (9th Cir., 2004); U.S. Senate, Committee on Governmental Affairs, *Committee Staff Investigation of the Federal Energy Regulatory Commission's Oversight of Enron Corp* (November 2002), *available at* http://hsgac.senate.gov/_files/111202fercmemo.pdf.

78 For more on FERC proceedings, see the FERC webpage, "Addressing the 2000-2001 Western Energy Crisis," at http://www.ferc.gov/industries/electric/indus-act/wec.asp.

79 *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, 65 Fed. Reg. 809 (Jan. 6, 2000), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092, 65 Fed. Reg. 12,088 (March 8, 2000), *aff'd, Public Utility District No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) [hereinafter Order No. 2000].

80 In Order No. 2000, FERC found that "opportunities for undue discrimination continue to exist that may not be remedied adequately by [the] functional unbundling [remedy of Order No. 888]." Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,105.

81 The term "rate pancaking" refers to circumstances in which a transmission customer must pay separate access charges for each utility service territory crossed by the customer's contract path.

RTOs are entities set up in response to FERC Order Nos. 888 and 2000 encouraging utilities to voluntarily enter into arrangements to operate and plan regional transmission systems on a nondiscriminatory open access basis. RTOs are independent entities that control and operate regional electric transmission grids for the purpose of promoting efficiency and reliability in the operation and planning of the transmission grid and for ensuring non-discrimination in the provision of electric transmission services. RTOs currently do not own transmission.[82]

FERC has approved RTOs or ISOs in several regions including the Northeast (PJM, New York ISO, ISO-New England), California, the Midwest (MISO) and the Southwest (SPP), as shown in Figure 1-3 below. By the end of 2004, regions accounting for 68 percent of all economic activity in the United States had chosen the RTO option.[83] In 2004 and 2005, the PJM RTO grid expanded substantially to include several additional service territories in the Midwest. In 2004, the territories served by Commonwealth Edison (ComEd), American Electric Power (AEP), and Dayton Power and Light joined PJM. The expansion continued in 2005 with the addition of Duquesne Light and Dominion Resources. PJM now covers about 18 percent of total electricity consumption in the United States and includes utility service territories in the Mid-Atlantic, Midwest, and parts of the Southeast.[84]

In most cases, RTOs have assumed responsibility to calculate the amount of available transfer capability (ATC) for wholesale trades for member systems across the footprint of the RTO. RTOs also are responsible for coordinating regional planning, at least for facilities necessary for reliability above a certain voltage. As of 2004, all RTOs coordinate dispatch of generators in their systems and provide transmission services under a single RTO open access tariff. In addition to operating the regional transmission grid, RTOs operate regional organized energy markets, including a short-term market which prices energy, congestion, and losses. RTOs in the East offer day-ahead and real-time markets, while California and Texas offer real-time markets alone. All current RTOs use or plan to use some form of locational pricing to manage transmission congestion and have independent market monitors that assess and report on market activities.[85] RTOs and regional wholesale markets are described in more detail in Chapter 3.

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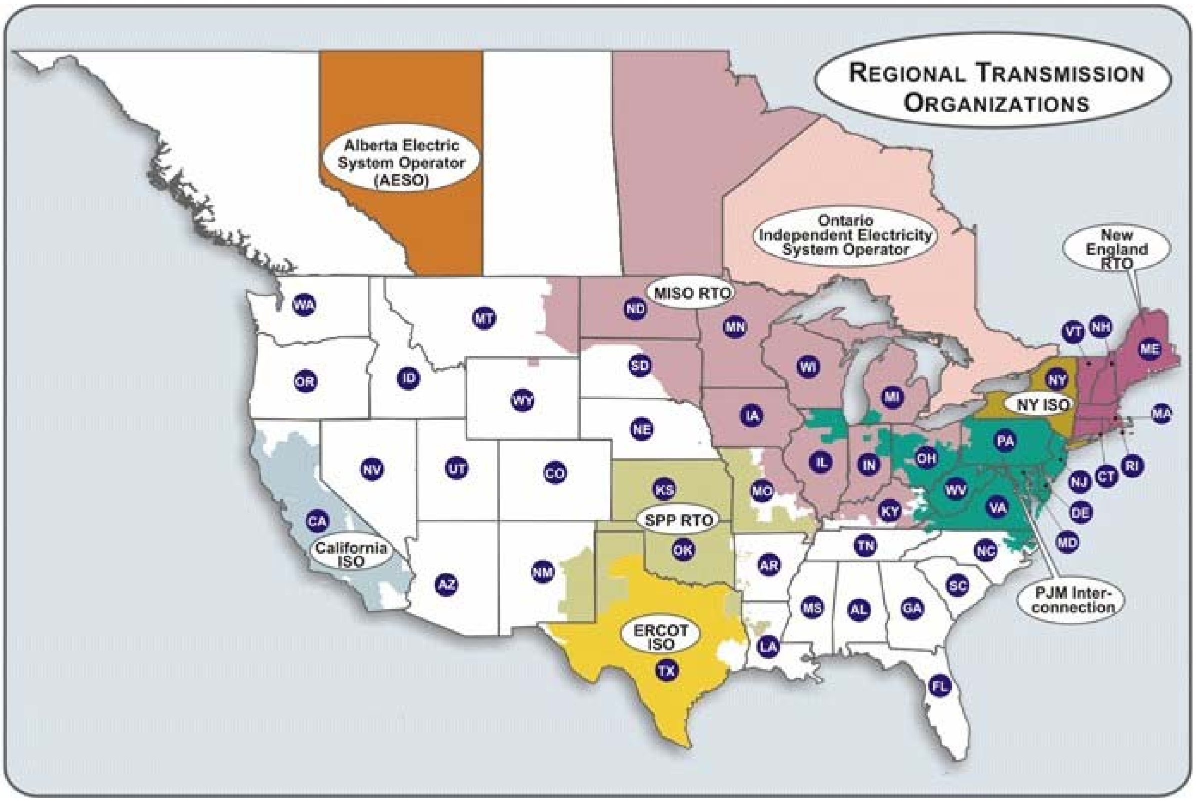
82 Although RTOs do not now own transmission facilities, they are not precluded by regulation from doing so. FERC's Order No. 2000 allows RTOs that are independent transcos – transmission-owning RTOs that do not own or operate generation and are not affiliated with generation owners or operators. Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,036-37.

83 Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, *State of the Markets Report: An Assessment of Energy Markets in the United States in 2004*, at 51 (2005) [hereinafter *FERC State of the Markets Report 2004*], *available at* http://www.ferc.gov/legal/staff-reports.asp.

84 *Id.* at 53.

85 *Id.* at 52.

Figure 1-3. RTO Configurations in 2006



Note: The above map shows the general location of approved RTOs. Not all transmitting utilities within the shaded area of an RTO are necessarily members of the RTO and some RTO members are not shown in this map.

Source: FERC RTO Regional Map, 2006, created using Platts POWERmap, *available at* http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp

The RTO model and regional organized wholesale markets have been voluntarily adopted by utilities and market participants in the Northeast, Mid-Atlantic, California, and parts of the Midwest and Southwest. Some states required RTO participation as part of restructuring under the state retail competition plan. RTO members include utilities in states that have not adopted retail competition. State regulators often serve on RTO advisory bodies and have been active in FERC proceedings involving RTOs. Although RTOs enjoy broad participation by utilities and competitive power suppliers, some comments filed with the Task Force[86] raised concerns over perceived high costs of RTO implementation and operations and oversight of RTO markets.

In other regions, including most of the Southeast, the West outside of California, and other parts of the Midwest, RTOs have been considered, but formation has stalled. State regulators and utilities in these regions have found it difficult to assess the potential benefits and costs of establishing RTOs. They have been reluctant to create new institutional arrangements that could diminish local control over transmission facilities and could impose additional costs on retail customers.

[86] *See, e.g.*, APPA comments (2); NRECA comments (2); Alliance of State Leaders Protecting Electricity Consumers comments (2); Wisconsin Load Serving Entities comments (2); Progress and Santee Cooper comments (2).

7. <u>August 2003 Blackout</u>

On August 14, 2003, an electrical outage in Ohio precipitated a cascading blackout across seven other states and as far north as Ontario, Canada, leaving more than 50 million people without power.[87] The August 2003 blackout was the largest in United States history, leaving some parts of the nation without power for up to four days and costing between $4 billion and $10 billion.[88] It affected large portions of the Midwest and Northeast United States and Ontario and an estimated 61,800 MWs of load. It was the eighth major blackout in North America since the 1965 Northeast Blackout. A Joint U.S.-Canada Power System Outage Task Force issued a final Blackout Report in April 2004. The report identified factors that were common to some of the eight major outages from 1965 through the 2003, as shown below:

> (1) conductor contact with trees; (2) overestimation of dynamic reactive output of system generators; (3) inability of system operators or coordinators to visualize events on the entire system; (4) failure to ensure that system operation was within safe limits; (5) lack of coordination on system protection; (6) ineffective communication; (7) lack of "safety nets;" and (8) inadequate training of operating personnel.[89]

In addition to the Joint Study, affected states and NERC[90] carried out their own investigations.

8. <u>The Energy Policy Act of 2005</u>

In August 2005, Congress passed EPAct 2005, which amended the core statutes (FPA, PURPA, PUHCA 1935) governing the electric power industry. Among the notable provisions of EPAct 2005 are the following:

- *Reliability*: Section 1211 authorizes FERC to certify an Electric Reliability Organization to propose and enforce reliability standards for the bulk power system. EPAct 2005 authorized penalties for violation of these mandatory standards.

- *Transmission Siting*: Section 1221 requires the Secretary of Energy to conduct a study of electricity congestion within one year of the enactment of EPAct 2005 and every three years thereafter. It authorizes the Secretary of Energy to designate certain areas experiencing congestion as "National Interest Electric Transmission Corridors" based on these studies. In certain limited circumstances, FERC is authorized to approve construction permits for transmission facilities in designated corridors when states either lack such authority, or withhold approval for more than one year after filing of an application or corridor designation. Proponents of this new federal authority argue that it

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87 U.S. Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (April 2004), at 1.

88 *Id.* In contrast, the November 1965 Northeast Blackout resulted in the loss of over 20,000 MWs of load and affected 30 million people.

89 *Id.* at 107.

90 *See, e.g.*, New York State Public Service Commission, *NYPSC Staff Second Report on the August 13-14, 2003 Blackout* (November 2005), *available at* http://www.dps.state.ny.us. Also, see the NERC blackout website materials, *available at* http://www.nerc.com/~filez/blackout.html, and the reports of the Michigan Public Service Commission, *available at* http:www.michigan.gov/mpsc.

will facilitate construction of new transmission and help alleviate transmission congestion that can impair competition in electric markets.

- *Transmission Investment Incentives*: Section 1241 requires FERC to establish incentive-based rate treatments for public utilities' transmission infrastructure to promote capital investment in transmission infrastructure, attract new investment with an attractive return on equity, encourage improvement in transmission technology, and allow for recovery of prudently incurred costs related to reliability and improved transmission infrastructure. Proponents contend this will encourage the expansion of transmission capacity and, thus, help foster greater competition in electric markets.

- *PURPA Reform*: Section 1253 permits FERC to terminate, prospectively, the obligation of electric utilities to buy power from QFs, such as industrial cogenerators. FERC may do so when the QFs in the relevant area have adequate opportunities to make competitive sales, as defined by EPAct 2005. The premise is that growth in competitive opportunities in electric markets negates the need for PURPA's "forced sale" requirements.

- *PUHCA 1935 Repeal*: Title XVII, subtitle F repeals PUHCA 1935 and replaces it with new PUHCA 2005. It provides FERC and state access to books and records of holding companies and their members. It also provides that certain holding companies or states may obtain FERC-authorized cost allocations for non-power goods or services provided by an associate company to public utility members in the holding company. PUHCA 2005 also contains a mandatory exemption from the federal books and records access provisions for entities that are holding companies solely with respect to EWGs, QFs or foreign utility companies. The goal is to reduce legal obstacles to investment in the electric utility industry and, thereby, help facilitate the construction of adequate infrastructure.

C. Recent Trends Related to Competition in the Electric Energy Industry

This section discusses several more recent electric industry policy developments and characteristics.

1. <u>Increases in Generation and Growth of Nonutility Generation Suppliers</u>

Electric power industry restructuring has been sustained largely by technological improvements in gas turbines. It is no longer necessary to build a larger generating plant to gain operating efficiencies. Combined-cycle gas turbines reach maximum efficiency at 400 MW, while aero-derivative gas turbines can be efficient at sizes as low as 10 MW. These new gas-fired combined cycle plants can be more energy efficient and less costly than the older oil and gas-fired plants.[91] Because of their smaller footprint and low emissions, gas turbine generators can often be located close to load, avoiding the need for additional transmission. Coupled with greater transmission access as a result of Order No. 888, it became feasible for generating plants hundreds of miles apart to compete with each other, giving customers more choices in electricity suppliers.[92]

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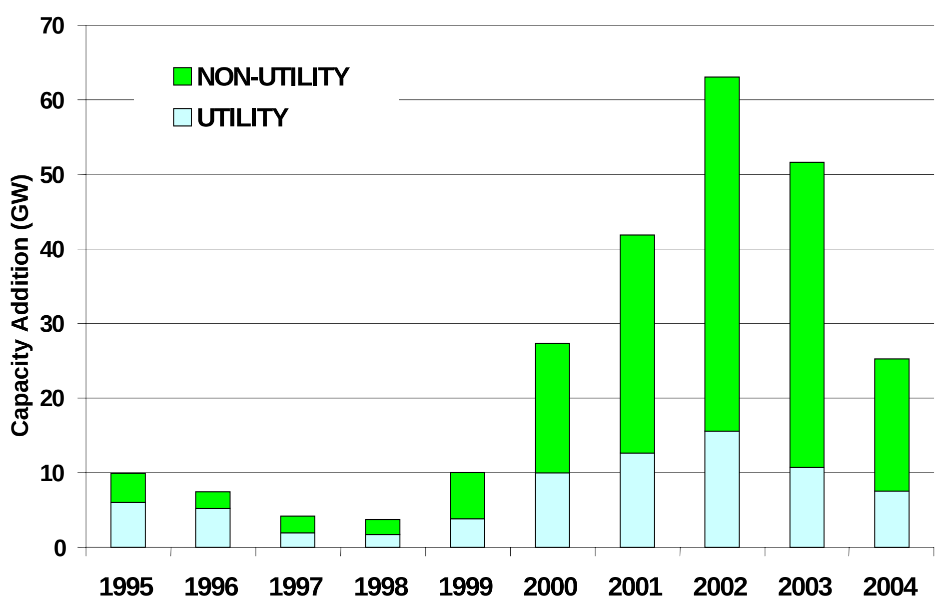
[91] *EIA 2000 Update* at ix. The size of the cost improvements depends on the underlying fuel prices.

[92] *Id.*

The market participation of utilities and other generation suppliers began changing in response to increases in energy costs in the 1970-1990s and the passage of PURPA, which facilitated entry of nonutility QFs as energy-efficient, environmentally-friendly, alternative sources of electric power. The change continued through Order No. 888, which opened up the transmission grid to competing wholesale electricity suppliers.[93] Until the early 1980s, electric utilities' share of electric power production increased steadily, reaching 97 percent in 1979.[94] By 1991, however, the trend had reversed itself, and the utilities' share declined to 91 percent.[95] By 2004, regulated electric utilities' share of total generation continued to decline (63.1 percent in 2004 versus 63.4 percent in 2003) as nonutilities' share increased (28.2 percent versus 27.4 percent in 2003).[96]

This trend is illustrated by comparing increases in capacity additions for utility and nonutility generation suppliers, as shown in Figure 1-4 below. While most of the existing capacity and most of the additions to capacity through the late 1980s were built by electric utilities, their share of capacity additions declined in the 1990s. Between 1996 and 2004, roughly 74 percent of electricity capacity additions were made by nonutility power producers.

Figure 1-4. Utility and Nonutility Generation Capacity Additions, 1995-2004



Source: FERC analysis of Platts PowerDat data.

However, the pattern of merchant generation investment outpacing utility investment may be shifting. Traditional regulated utilities, including public power and cooperative utilities,

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93 *Id.* at 23.

94 *EIA 1970-1991* at vii.

95 *Id.*

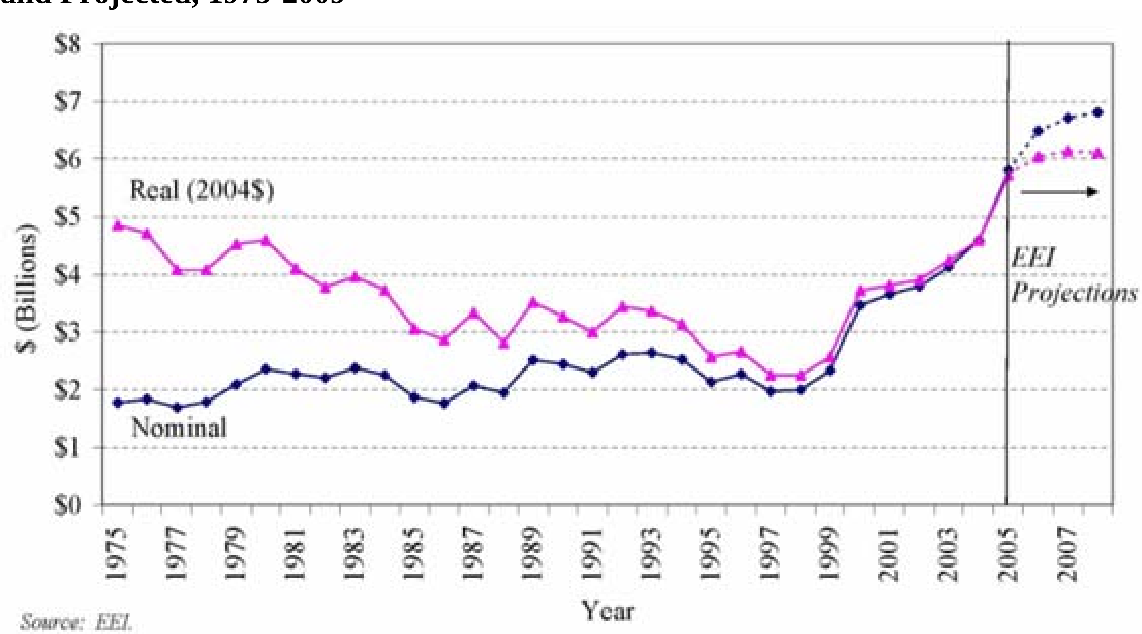
96 U.S. Department of Energy, Energy Information Administration, *Electric Power Annual 2004*, at 2 (November 2005), *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epa.pdf [hereinafter *EIA Electric Power Annual 2004*].

accounted for about 60 percent of capacity additions from 2005 through May 2006. In California, six new power plants began operations, including four owned by public utilities and two owned by IOUs.[97]

2. Transmission Investment

Despite these increased investments in new generation, the Edison Electric Institute (EEI) reports that IOU investment in transmission declined from 1975 through 1999. See Figure 1-5. Over that period, electricity demand more than doubled, resulting in a significant decrease in transmission capacity relative to demand. Box 1-2 suggests reasons for this trend. Since 1999, according to EEI surveys, transmission investment has increased annually. From 1999 to 2003, IOU investment increased 12 percent annually.[98] For 2004 to 2008, IOUs expect to invest about $28 billion in transmission, an almost 60 percent increase over the prior five-year period.

Figure 1-5. Transmission Construction Expenditures by Investor-Owned Utilities, Actual and Projected, 1975-2009



[97] APPA comments (2).

[98] Edison Electric Institute, *EEI Survey of Transmission Investment: Historical and Planned Capital Expenditures*, at 1 (May 2005).

Box 1-2
Decline in Transmission Investment

Transmission is the physical link between electricity supply and demand. Without adequate transmission capacity, wholesale competition cannot function effectively.

Some reasons suggested for the decline in transmission investment between 1975 and 1997 (see Figure 1-5) are a decline in investment in large base-load generating plants requiring associated new large transmission additions, an overbuilt system prior to 1975, lack of available capital due to other investment activities by vertically integrated utilities, the protection of vertically integrated utility generation from competition, and regulatory uncertainty over recovery of new transmission investment.

Another explanation for the decline in investment is the difficulty of siting new transmission lines. Siting can bring long delays and negative publicity. Local opposition can be significant. Also, some states may require a showing of benefits to the state for approval of a transmission line. This creates challenges for interstate transmission facilities proposed to primarily benefit interstate commerce.

3. Retail Prices of Residential Electricity

As seen in Figure 1-6 below, between 1970 and 1985, national average residential electricity prices more than tripled in nominal terms and increased by 25 percent in real terms (adjusting for inflation).[99] U.S. real retail electricity prices began to fall after the mid-1980s until 2000-2001 as fossil fuel prices and interest rates declined and inflation moderated significantly.[100] Real retail prices stayed flat through 2004, but have begun to increase in all regions reflecting higher fuel prices and operating costs.

According to the latest information from EIA, residential electric prices in 2005 averaged 9.43 cents per kilowatthour (kWh), an increase of about 5 percent from 2004. Retail electric prices continue to increase, and the national average price for residential customers in April 2006 was 10.31 cents per kWh, up 12 percent from a year earlier.[101] These increases reflect substantially higher fuel and purchased power costs.[102]

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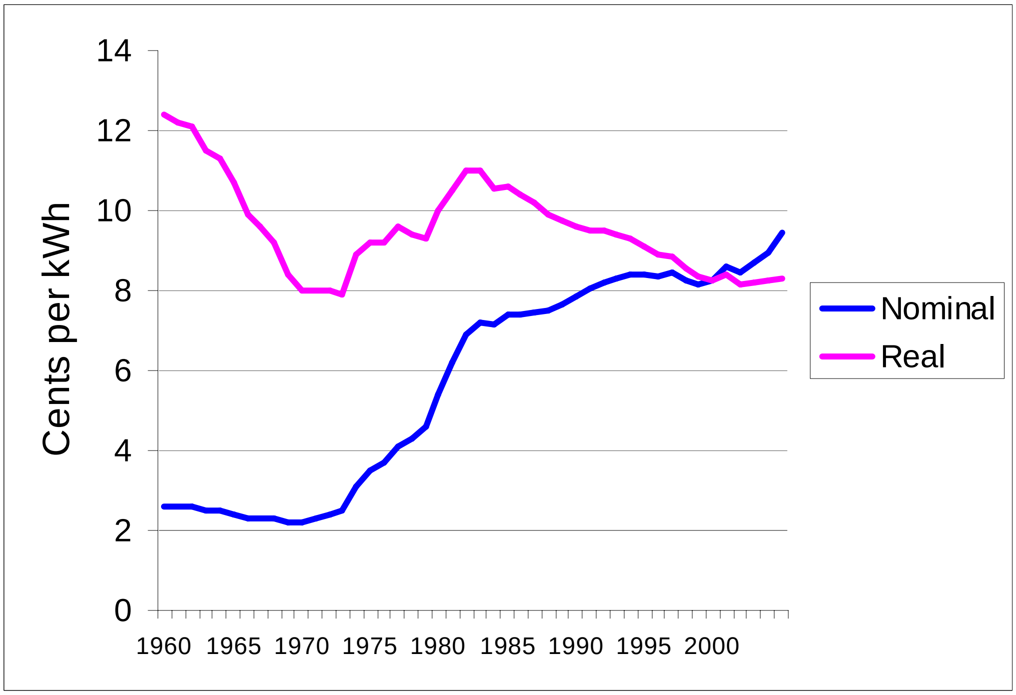
99 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,640.

100 Joskow, *Difficult Transition* at 7.

101 U.S. Department of Energy, Energy Information Administration, *Electric Power Monthly*, Table 5.3 (July 2006), *available at* http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.

102 According to an analysis for EEI, "Fuel and purchased power costs have risen substantially and are by far the largest cause of recent electricity price increases. On an industry-wide basis, these account for roughly 95 percent of increases in total operations and maintenance (O&M) costs experienced by electric utilities in the last five years." Peter Fox-Penner, *et al.*, *Behind the Rise in Prices: Electricity Price Increases Are Occurring Across the Country, Among all types of Electricity Providers. Why?*, ELEC. PERSPECTIVES 53 (July/August 2006).

Figure 1-6. National Average Retail Prices of Electricity for Residential Customers, 1960-2005



Note: Real prices are shown in chained (2000) dollars, calculated by using gross domestic product implicit price deflators.

Source: EIA, *Annual Energy Review 2004*, Table 8.10 Average Retail Prices of Electricity, 1960-2004, and EIA, Monthly Energy Review, July 2006, Table 5-3.

4. <u>Changing Patterns of Fuel Use for Generation – Reaction to Increased Oil Prices and Clean-Air Environmental Regulations</u>

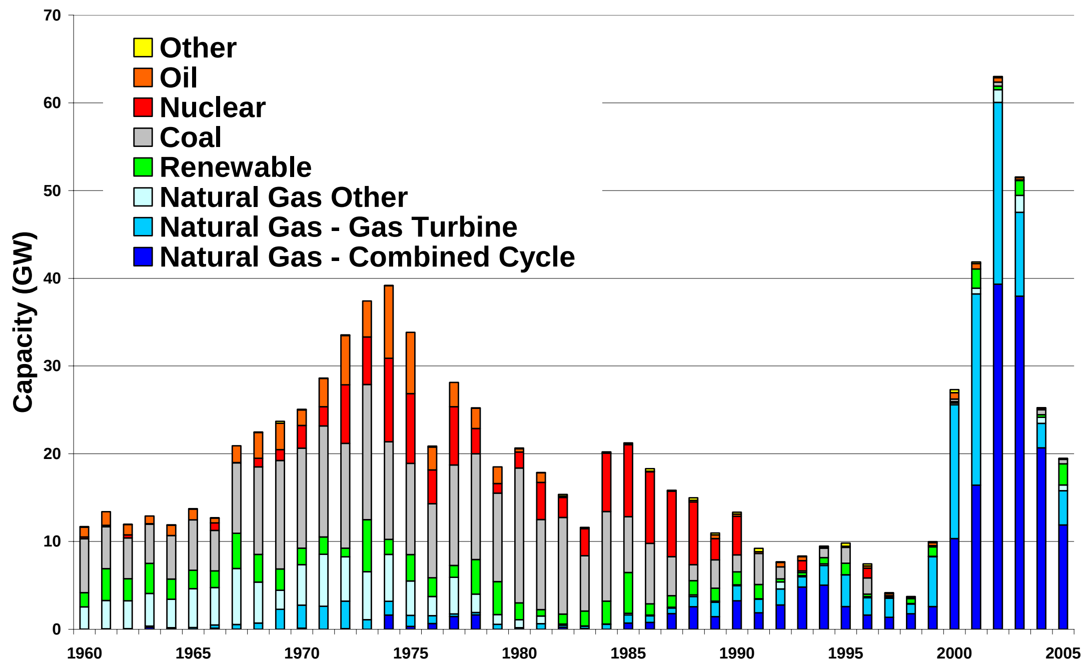
For many years, coal was the fuel most commonly used to generate electricity, providing 46 percent of utilities' generation in 1970 and more than 50 percent since 1980. As world oil prices escalated in the 1970s, oil-fired and gasoline-fired generation's share of electricity supply began decreasing and utilities' use of oil and gas for new generation was restricted by federal law.

Hydroelectric power also has played a large role in the supply of electric power, but its share has declined relative to other major fuels mainly because there are a limited number of suitable sites for hydroelectric projects. Nuclear power emerged as the second largest fuel source in 1991 but was not expected to increase.[103]

[103] *EIA 1970-1991* at 20.

For nonutilities, natural gas has been the major fuel for new plant additions.[104] Indeed, in recent years, new capacity additions reflect the prevalence of natural gas.[105] As shown in Figure 1-7, recent plant additions illustrate this change. The Clean Air Act Amendments of 1990 (CAA) and state clean air requirements also contributed to increased use of natural gas. The CAA sought to address the most widespread and persistent pollution problems caused by hydrocarbons and nitrogen oxides, both of which are prevalent with traditional coal and petroleum-based generation. The CAA fundamentally changed the generation business because emission of air pollutants would no longer be cost-free. As a result, many generation owners and new plant developers turned to cleaner-burning natural gas as the fuel source for new generation plants. California has depended heavily on gas-fired generation because of its specific air quality standards.[106]

Figure 1-7. Natural Gas Plants Dominate New Generating Unit Additions



Source: FERC analysis of Platts PowerDat data.

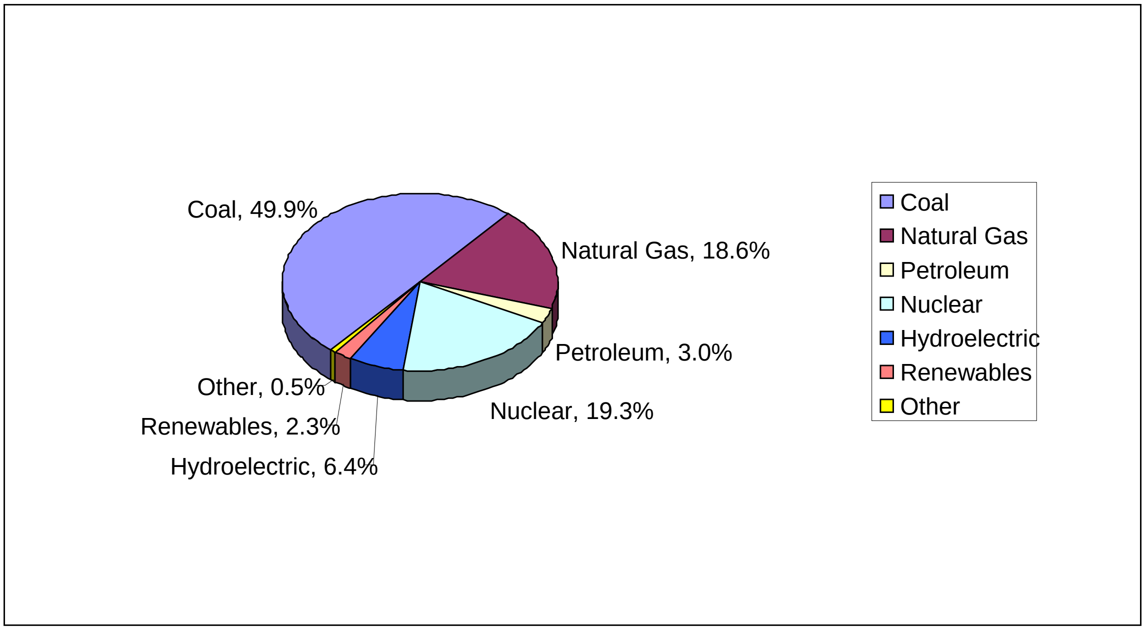
[104] During the 1990s, with natural gas prices at an all time low and availability of efficient, modular gas turbines, many nonutilities built natural-gas generation facilities to enter wholesale markets. Today, as a result of restructuring-related asset sales and divestitures, nonutilities own and operate a broad mix of nuclear, coal, natural- gas and renewable generation facilities that supply wholesale markets. Natural-gas-fired generating capacity was 57 percent of nonutility generating capacity in 2004. According to EPSA, based on EIA data, 36 percent of electricity produced by competitive generators was coal-fired, 30 percent natural gas, 24 percent nuclear, 6 percent hydroelectric and other renewables, and four percent oil-fired. EPSA comments (2).

[105] *EIA Electric Power Annual 2004* at 2.

[106] Federal Energy Regulatory Commission, *The Western Energy Crisis, The Enron Bankruptcy, & FERC's Response*, at 1, *available at* http://www.ferc.gov/industries/electric/indus-act/wec/chron/chronology.pdf.

The result of these plant additions through December 2005 is that 49.9 percent of the nation's electric power was generated at coal-fired plants (Figure 1-8). Nuclear plants contributed 19.3 percent; 18.6 percent was generated by natural gas-fired plants, and 2.5 percent was generated at petroleum liquid-fired plants. Conventional hydroelectric power provided 6.6 percent of the total, while other renewables (primarily biomass, but also geothermal, solar, and wind) and other miscellaneous energy sources generated the remaining electric power.

Figure 1-8. Net Generation Shares by Energy Source: Total (All Sectors), January-December 2005



Source: EIA, *Electric Power Monthly*, July 2006, Table 1-1.

The trend toward gas-fueled capacity additions may be changing. There is renewed interest in coal-fired generation as reflected in utilities' and nonutilities' announcements of new coal plant construction projects. Two major reasons may explain coal's resurgence: (1) the relative price of natural gas compared to coal has increased substantially and (2) the cost of environmental equipment for coal plants, such as scrubbers, has decreased. "Over the past decade, many merchant combined-cycle gas-fired units were built on the assumption that natural gas would be relatively inexpensive and that cleaning technology for coal plants would drive the price of coal plants significantly higher. Sharp increases in natural gas prices in recent years have challenged these assumptions." DOE's EIA estimated that 573 MWs of new coal generation would be added nationally in 2005, which compares with an estimate of 15,216 MWs of gas-fired additions for the same year. For 2009, however, predicted trends shift; the EIA projects that 8,122 MWs of new coal generation will be added that year, whereas only 5,451 MWs of gas-fired generation additions are predicted.[107] DOE predicts a resurgence of coal-fired generation as far into the future as 2025.[108]

[107] *See EIA Electric Power Annual 2004* at 17, table 2.4, *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epat2p4.html.

[108] *See* U.S. Department of Energy, National Energy Technology Lab, *Tracking New Coal-Fired Power Plants*, at 3-4, *available at* http://www.netl.doe.gov/coal/refshelf/ncp.pdf (predicting 85 GWs of new coal capacity created by 2025).

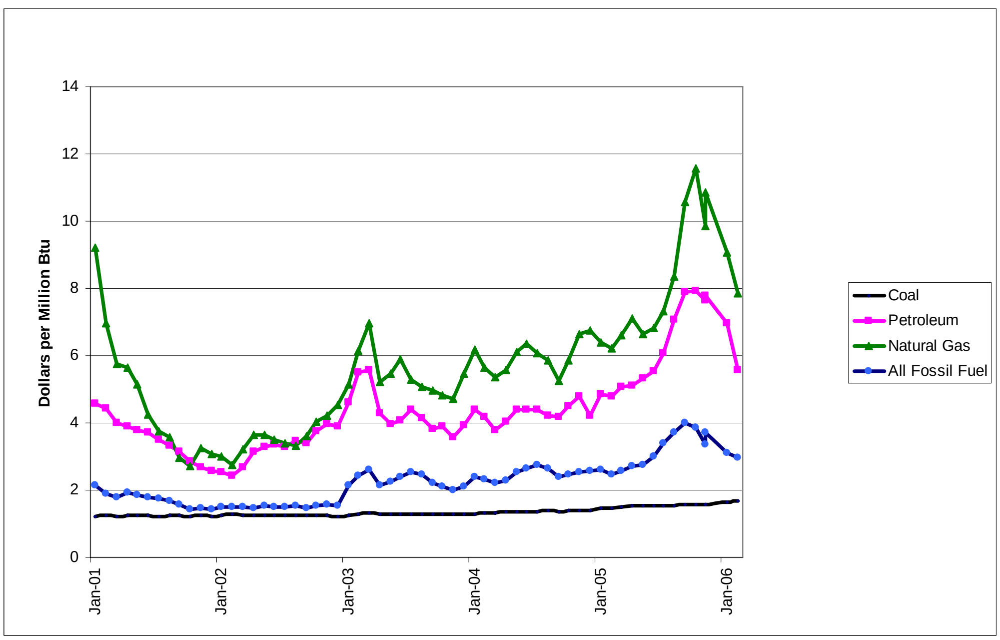
Higher gas prices and environmental concerns have also spurred renewed interest in nuclear generation. EPAct 2005 includes a number of provisions intended to encourage and facilitate a new and improved generation of nuclear power plants.

5. Fuel Price Trends

Natural gas prices have been increasing in recent years, due in part to historically high petroleum prices. Natural gas prices increased 51.5 percent between 2002 and 2003, 10.5 percent between 2003 and 2004, and 37.6 percent between 2004 and 2005. Strong demand for natural gas, as well as natural gas production disruptions in the Gulf of Mexico, contributed to these increases. As shown in Figure 1-9, for December 2005 the overall price of fossil fuels was influenced by the price increases in natural gas. In December 2005, the average price for fossil fuels was $3.71 per million Btu (MMBtu), 10.1 percent higher than for November 2005, and 44.4 percent higher than in December 2004. As natural gas prices increase relative to coal prices, the change may make development of clean-burning coal plants more economically attractive than they were when natural gas fuel prices were lower.

Figure 1-9. Fossil Fuel Costs for Electric Generators, 2001-2006

Dollars per Million Btu



Source: EIA, *Monthly Energy Review*, July 2006, Table 9.10. Cost of Fossil-Fuel Receipts at Electric Generating Plants.

6. Mergers, Acquisitions, and Power Plant Divestitures of Investor-Owned Electric Utilities[109]

Many IOUs have fundamentally reassessed their corporate strategies to function more like competitive, market-driven entities than in their more regulated past.[110] One result is that there was a wave of mergers and acquisitions in the late 1980s through the late 1990s between traditional electric utilities and between electric utilities and gas pipeline companies.

IOUs also have divested a substantial number of generation assets to IPPs or transferred them to an unregulated nonutility subsidiary within the company.[111] Even though FERC-regulated IOUs have functionally unbundled generation from transmission, and some have formed RTOs and ISOs, many utilities have divested their power plants because of state requirements. Some states that opened the electric market to retail competition view the separation of power generation ownership from power transmission and distribution ownership as a prerequisite for retail competition. For example, California, Connecticut, Maine, New Hampshire, and Rhode Island enacted laws requiring utilities to divest their power plants. In other states, the state public utility commission may encourage divestiture to arrive at a quantifiable level of stranded costs for purposes of recovery during the transition to competition.[112]

Since 1997, IOUs have divested power generation assets at unprecedented levels,[113] and these power plant divestitures have also reduced the total number of IOUs that own generation capacity.[114] A few utilities have decided to sell their power plants, as a business strategy, deciding that they cannot compete in a competitive power market. In a few instances, an IOU has divested power generation capacity to mitigate potential market power resulting from a merger.[115] As described in Table 1-6 below, between 1998 and 2001, over 300 plants, representing nearly 20 percent of U.S. installed generating capacity, changed ownership.

Since 2001 the merger trends have shifted slightly, as financial difficulties of the merchant generating sector have prompted the sale or transfer of a substantial share of the merchant fleet. Some purchasers have been traditional utilities, including public power and cooperative utilities.[116]

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109 The information provided in this section is current as of July 2006 and does not reflect any subsequent changes.

110 *See* U.S. Congress, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition*, at 47, OTA-E-409 (Washington, DC: U.S. Government Printing Office, May 1989).

111 *EIA 2000 Update* at 91.

112 *Id.* at 105-06.

113 *Id.* at 105.

114 *Id.* at 91.

115 *Id.* at 106.

116 The EIA periodically reports on generation plant transfers. For a list of plants transferred in 2003- 2006, *see* the *EIA Electric Power Monthly* (July 2006), *available at* http://www.eia.doe.gov/cneaf/electricity/epm/tablees4.html.

There were no significant electric power company mergers from 2001 to 2004, but in 2004 utilities and financial institutions exhibited growing interest in mergers and acquisitions, prompting many analysts to herald 2004 as a new round of consolidation in the power sector.[117] One utility-to-utility acquisition closed,[118] and three were announced.[119] Most electric acquisitions in 2004 involved the purchase of specific generation assets. Many companies strove to stabilize financial profiles through asset sales. In aggregate, almost 36 GW of generation, or nearly 6 percent of installed capacity, changed hands in 2004.[120]

Table 1-6. Power Generation Asset Divestitures by Investor-Owned Electric Utilities, as of April 2000

GWs and Percent of Total and U.S. Generating Capacity

Status Category	Capacity (GW)	Percent of Total	Percent of Total U.S.Generation Capacity
Sold	58.0	37	8
Pending Sale (Buyer Announced)	28.2	18	4
For Sale (No Buyer Announced)	31.9	20	4
Transferred to Unregulated Subsidiary	4.1	3	1
Pending Transfer to Unregulated Subsidiary	34.2	22	5
Total	156.5	100	22

Source: EIA, *The Changing Structure of the Electric Power Industry 2000: An Update,* (October 2000), Table 19.

117 *FERC State of the Markets Report 2004* at 30-32.

118 Announced in December 2003, Ameren closed its acquisition of Illinois Power Co. in September 2004. *Id.* at 31.

119 In January 2004, Black Hills Corp announced the acquisition of Cheyenne Light, Fuel & Power from Xcel Energy. In July 2004, PNM Resources, the parent of Public Service Company of New Mexico, announced the intention to acquire TNP Enterprises, the parent of Texas New Mexico Power Company from a group of private equity investors. *Id.* at 31-32. In December 2004, Exelon announced its intent to merge with PSEG, a plan that would create the nation's largest utility company by generation ownership, market capitalization, revenues, and net income. *Id.* at 32.

120 *Id.* at 30.

CHAPTER 2
CONTEXT FOR THE TASK FORCE'S STUDY OF COMPETITION IN WHOLESALE AND RETAIL ELECTRIC POWER MARKETS

This chapter provides context and theoretical underpinnings to the Task Force's study of competition in wholesale and retail electric power markets. It describes (1) perceived shortcomings of traditional cost-based regulation that motivated restructuring and regulatory reform, (2) the theoretical role competitive market price signals play in guiding consumption and investment decisions,[121] and (3) a brief discussion of expected benefits of shifting from cost-based rate regulation to market-based pricing of electricity.

A. Overview of Perceived Shortcomings of Cost-Based Rate Regulation

State and federal policymakers regulated providers of the generation, transmission, and distribution of electric power as vertically-integrated monopolies for approximately 70 years. For much of this period it was considered economically inefficient and technologically challenging to have multiple sources of generation, transmission, and distribution facilities serving customers in the same geographic area. Competition was considered impractical and not in the public interest because it would require costly duplication of facilities and likely engender competition that would not be sustainable due to economies of scale. Under this model, competition was expected eventually to result in ratepayers paying for failed facilities without benefiting from alternative sources of supply.

The traditional "regulatory compact" required an electric power utility to serve all retail customers in a defined franchise area in exchange both for the opportunity to earn a reasonable return on its investment and for protection against entry by potential rivals. Consumer prices or "rates" were based on the regulated utilities' average historic cost of production plus an adder for a fair return on investment and often adjustments for changing fuel prices. Regulators used this "cost-based" regulation to try to ensure adequate supplies at reasonable prices for consumers, as required by state laws. Under most state regulatory policies, utilities could not recover new investments in rates until regulators determined that the investment was "prudent" and the facilities were "used and useful" (actually being used to serve customers). Historically, some states allowed large nuclear cost overruns to be included in the rate base, while other states did not. In general, disallowances of investments have been rare.

As described in Chapter 1, beginning in the 1970s, the combined effects of a number of changes – improvements in smaller-scale generation technology, transmission, communications and control technologies, rising energy prices, environmental policy concerns, increased concerns about the effectiveness of traditional utility rate regulation, and favorable experience with the introduction of increased competition in other network industries – began to transform the structure and regulation of the electric power sector.

[121] For a full discussion of the theory of competition in wholesale electricity markets, *see* STEVEN STOFT, POWER SYSTEM ECONOMICS: DESIGNING MARKETS FOR ELECTRICITY (IEEE Press 2002).

1. Effects on Electricity Demand and Prices

Under cost-based regulation, end-use, and sometimes wholesale, customers often paid prices for their electricity that were based on average costs calculated over extended periods of months or years so that the prices did not vary with consumption or the marginal cost of generation. These rates were stable and often only varied by season. Although time-based rates and certain regulated products such as interruptible or curtailable services had been used within the electric power industry for decades, they had not been applied to the vast majority of retail customers.

The average cost-based pricing formula precludes economically accurate price signals from guiding consumption decisions.[122] Inefficiency has resulted as consumers purchased either too much electricity (when the average price was below the efficient price) or too little electricity (when the average price exceeded the efficient price). Inefficient resource use can translate to higher production costs and prices. Historical average cost electricity prices, for example, gave consumers no economic reason to conserve electricity when supplies were short or demand was high. Similarly, suppliers did not receive economically accurate price signals to guide their short- and long-term sales of generation. In addition, many industrial customers among others have objected that retail rate structures frequently contained cross-subsidies among customer classes and thus, further distorted prices.[123]

2. Effect on Investment Decisions

Regulators' influence over generation construction decisions likely also contributed to inefficiency. Historically, regulators had encouraged local utilities to build or contract for sufficient generation to serve customers within their territories. Regulators blocked entry by independent generators or allowed the utilities to do so. This resulted in utilities owning nearly all generation assets within their service territories and discouraged competition among generators. While the intent of these policies was partly to keep price down, the unintended effect was to dampen incentives for cost reduction, investment in new capacity and innovation.[124] More competition might have led earlier to technological innovation and lower generation costs.

The fact that regulators had to agree that a capital investment was necessary and prudent before rate recovery was allowed[125] further discouraged innovation. Utilities were reluctant to take investment risks that might end up being unrecoverable if regulators deemed their cost unreasonable. Thus, long-term planners and regulators had significant influence over when and where generation would be built. In making decisions, regulators struggled to strike a balance between reasonable rates and providing utilities with incentives to make necessary and sufficient investments.

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[122] From an economic perspective, retail electricity prices (or rates) that do not closely track wholesale price trends do not send economically "accurate" price signals when they do not reflect temporal variations in production costs and wholesale market prices within days, across seasons, or even across years (except after long lags).

[123] Electricity Consumers Resource Council, *Profiles in Electricity Issues: Cost-of-Service Survey* (March 1986).

[124] *See, e.g.*, KIP VISCUSI ET AL., ECONOMICS AND REGULATION OF ANTITRUST 6-7 (MIT Press, 4th ed. 2005) [hereinafter VISCUSI, ET AL.].

[125] Most states also regulate the siting of major electric power facilities.

This regulatory oversight also possibly encouraged an overcapitalization of the industry, as generators were assured a rate of return on any approved capital project. It might also have led to undercapitalization if a regulator was too conservative. Further, if rates were set too high, utilities could earn a higher return on new generation investments than would be warranted by the cost of capital. If regulators were unlikely or unable to identify and disallow excessive construction costs, utilities had little incentive to design new generation plants cost-effectively. At the same time, regulatory disallowances of some costs imposed risk on utility decisions to elicit capital and build new generation, and investors sought compensation for this risk when they supplied capital to utilities.[126]

Ultimately, ratepayers were left to bear much of the investment risk, as they had to pay for regulator-approved projects resulting in overinvestment as well as any subsequent higher costs from underinvestment (for example, costs of running higher cost generation more often than is economically efficient).

A 1983 DOE analysis of electric power generation plant construction showed that electric utilities (regulated under a cost-based regulatory regime) had limited ability to control construction costs of coal and nuclear plants. During the 1970s and early 1980s, the cost range per MW to build a nuclear plant varied by nearly 400 percent and by 300 percent for coal plants. The study showed that some companies were not competent to manage such large-scale, capital-intensive projects. In addition, they tended to custom design plants, as opposed to using a basic design and then refining it.[127]

One alternative to traditional cost-based rate-of-return regulation is price cap regulation. Under this approach, the regulator caps the price a firm is allowed to charge.[128] This alternative may remedy some of the incentive problems of cost-based regulation, but comes with its own costs. Another alternative is the addition of an open, transparent Integrated Resource Planning process by utilities to consider and support choices about building new generation procuring supplies from wholesale markets, and/or investing in demand-side options to meet projected load growth. In some states, regulators are involved in the utility IRP process and may approve the resulting plan. Even with this oversight mechanism, regulators have few reference points to determine if a builder's choices about design, efficiency, and materials for the IRP selected plant are prudent.

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126 In the academic literature, the risk of utility overinvestment has been explained by the Averch-Johnson Effect. The Averch-Johnson Effect reflects that "a firm that is attempting to maximize profits is given, by the form of regulation itself, incentives to be inefficient. Furthermore, the aspects of monopoly control that regulation is intended to address, such as high prices, are not necessarily mitigated, and could be made worse, by the regulation." KENNETH E. TRAIN, OPTIMAL REGULATION 19 (1991) [hereinafter TRAIN]. The Averch-Johnson Effect also predicts that if a regulator attempts to reduce a firm's profits by reducing its rate of return, the firm will have an incentive to further increase its relative use of capital. *Id.* at 56. Thus, the most obvious regulatory control within cost-base rate regulation creates further distortions. The Averch-Johnson Effect is sometimes thought to explain why a regulated firm is led to "gold plate" its facilities, i.e., incur excessive costs so long as those expenses can be capitalized.

127 U.S. Department of Energy, *The Future of Electric Power in America: Economic Supply for Economic Growth* (June 1983) (DOE/PE-0045).

128 Under price cap regulation, a firm can theoretically "produce with the cost-minimizing input mix [and] invest in cost-effective innovation." TRAIN at 318. However, this dynamic only occurs where the price cap is fixed over time and the utility receives the benefit of cost reductions and cost-effective innovations. Further, the benefit of this increased efficiency "accrues entirely to the firm: consumers do not benefit from the production efficiency." *Id.* Where the price cap is adjusted over time, firms are induced to engage in strategic behavior. Additionally, "if, as . . . expected, the review of price caps is conducted like the price reviews under cost-base rate regulation, then the distinction blurs between price-cap regulation and cost-base rate regulation." *Id.* at 319. One way for consumers under a rate cap system to share the benefits of efficiency improvements without eliciting strategic behavior from the regulated firm is to include periodic, automatic reductions in rates based on general trends in productivity.

3. Motivation for Change

In part, the struggles of regulators to ensure adequate supplies of power at reasonable rates led policymakers to examine whether competition could provide more timely and efficient incentives for what to consume and build. Advances in technology also allowed the entry of a variety of new, nonutility generators and demand response alternatives and weakened the argument for preserving utilities' monopolies on generation services. These developments set the stage for considering competitive pricing as an option for eliciting entry by new generators or expansion by existing generators. Generally, transmission and distribution have continued to be regulated services.

B. Overview of the Role of Price in Competitive Wholesale and Retail Electric Power Markets

How much a supplier will produce at a given price is determined by many things, including (in the long run) how much it must pay for the labor it hires, the land and resources it uses, the capital it employs, the fuel inputs it must purchase to generate the electric power, the transmission it must use to deliver the electric power to end users, and the risks associated with its investment. Consumers' overall willingness to pay for a product also is determined by a large variety of factors, such as the existence and prices of substitutes, income, and individual preferences.

The following is a review of expectations based on economic theory of how competition might determine prices and discipline investment in the electric utility industry. Chapters 3 and 4 examine how well actual wholesale and retail electricity market structures are meeting these expectations.

1. Price Affects Customer Consumption

Price changes play an important economic function by encouraging customers and suppliers to respond to changing market conditions. Price changes signal to customers in wholesale and retail markets that they should change their decisions about how much and when to consume electric power. Price increases signal customers to reduce consumption. The more consumers reduce their consumption in response to an increase in prices, the less market power sellers are likely to have. Lower prices encourage customers to increase consumption. Consumer price responsiveness is often referred to as "demand response."[129]

The primary purpose of incorporating market driven prices into wholesale and retail electric power markets is to provide price signals that accurately reflect underlying costs of production and thereby encourage efficient consumption patterns. Economic analysis suggests that the market dynamics of this type of pricing will result in lower overall production costs, which will translate into lower consumer prices.

[129] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005* (February 2006) [hereinafter *DOE EPAct Demand Response Report*]. The *DOE EPAct Demand Response Report* discusses the benefits of demand response in electric power markets and makes recommendations to achieve these benefits.

Accurate price signals are expected to improve the efficiency of electric power production by more closely aligning the price that customers pay *for* and the value they place *on* electricity. In particular, by exposing customers to prices based on marginal production costs, resources can be allocated more efficiently.[130] Accurate price signals also reduce cross subsidies between customers and among customer classes.[131] Flat electricity prices based on average costs can lead customers to "over-consume – relative to an optimally efficient system in hours when electricity prices are higher than the average rates, and under-consume in hours when the cost of producing electricity is lower than average rates."[132] Efficient price signals also have the benefit of increasing price response during periods of scarcity and high prices, which can help moderate generator market power and improve reliability.

Box 2-1
Market Prices

Market prices reflect myriad individual decisions about prices at which to sell or buy. They act as a mechanism that equalizes the quantity demanded and the quantity supplied. Rising prices signal consumers to purchase less and producers to supply more. Falling prices signal consumers to purchase more and producers to supply less. Prices will stop rising or falling when they reach the new equilibrium price: the price at which the quantity that consumers demand matches the quantity that producers supply.

When there are many close substitutes for a particular commodity, a relatively small price increase will result in a relatively large reduction in consumption. For example, if natural gas were a very good substitute for electric power at prevailing prices, then even a relatively small increase in electricity prices could persuade many consumers to switch in part or entirely to natural gas. To induce those consumers to return to electricity, electricity prices would not need to fall by very much. However, where there are no close substitutes for electric power, the price of electricity may have to rise substantially to reduce consumption by a significant amount.

Empirical literature shows that, even if the retail price of electricity increases by a large percentage, consumption of electricity does not decline much. In economic terms, it is said that the short-run demand for electricity is "inelastic" with respect to price. See Box 2-2. This inability to substitute other products for electricity in the short run means that changes in supply conditions (price of input fuels, etc.) are likely to cause wider price fluctuations than would be the case if customers could easily reduce consumption when prices rise. Furthermore, electric power has few viable substitutes for key end uses such as refrigeration and lighting, and thus the

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[130] There is substantial literature on setting rates based on marginal costs in the electric sector. *See, e.g.*, M. CREW & P. KLEINDORFER, PUBLIC UTILITY ECONOMICS (St. Martin's Press 1979); B. MITCHELL, W. MANNING, & J. PAUL ACTON, PEAK–LOAD PRICING (Ballinger 1978). Other papers suggest that setting rates based on marginal costs will result in a misallocation of resources. *See* S. Borenstein, *The Long-Run Efficiency of Real-Time Pricing*, 26:3 ENERGY J. (2005). Nevertheless, the literature also indicates that marginal-cost pricing may result in a revenue shortfall or excess, and standard rate-making practice is to require an adjustment (presumably to an inelastic component) to reconcile with embedded cost-of-service. Various rate structures to accomplish marginal-cost pricing include two-part tariffs and allocation of shortfalls to rate classes. *See* VISCUSI, *ET AL.*

[131] The reduction of cross subsidies can be seen as having both positive and negative implications for society as a whole – depending on one's perspective and whether the cross-subsidy supports publicly acceptable goals, such as rural electrification.

[132] *DOE EPAct Demand Response Report* at 7.

consequences for supply shortfalls can be significant.[133] In the long run, this effect may be somewhat muted as customers may have more ability to adjust consumption and fuel sources in response to price changes.

Box 2-2
Price Elasticity of Demand

The desire and ability of consumers to change the amount of a product they will purchase when its price increases is at the core of the concept of price elasticity of demand for that product. The price elasticity of demand is the ratio of the percent change in the quantity demanded to the percent change in price. That is, if a 10 percent price increase results in a 5 percent decrease in the quantity demanded, the price elasticity of demand equals -0.5 (-5 percent ÷ 10 percent). If the ratio is close to zero, demand is considered "inelastic," and demand is more "elastic" as the ratio increases. Short-run elasticities are typically lower than long-run elasticities.

Experience with retail pricing experiments in New York, Georgia, California, and other states have demonstrated that customers are able to adjust their electricity consumption and are at least somewhat responsive to short-run price changes (i.e., have a non-zero short-run price elasticity of demand). Georgia Power's Real Time Pricing (RTP) tariff option found that certain large industrial customers who receive RTP based on an hour-ahead market are somewhat price-responsive (short-run price elasticities ranging from approximately -0.2 at moderate prices, to -0.28 at prices of $1/kWh or more). Among day-ahead RTP customers, short-run price elasticities range from approximately -0.04 at moderate prices to -0.13 at high prices. National Grid also found limited responsiveness to price in its pricing program.[134] A critical peak pricing (CPP) experiment in California in 2004 determined that a test group of residential and small business customers responded to price and significantly reduced consumption (13 percent on average, and as much as 27 percent when automated controls such as controllable thermostats were installed) during critical peak periods. In addition, the California pilot found that most customers on the CPP tariffs had a favorable opinion of the rates and would be interested in continuing in the program.[135]

Customer response to prices requires the following conditions: (1) that time-differentiated price signals are communicated to customers; (2) that customers have the ability to respond to price signals (e.g., by reducing consumption and/or turning on an on-site generator); and (3) that customers have interval meters (i.e., so the utility can determine how much power was used at

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[133] Estimates of the total costs in the United States due to the August 14, 2003, blackout range between $4 billion and $10 billion. Electricity Consumers Resource Council, *The Economic Impacts of the August 2003 Blackout* (Feb. 2, 2004).

[134] Chuck Goldman, *et al.*, *Does Real-Time Pricing Deliver Demand Response? A Case Study of Niagara Mohawk's Large Customer RTP Tariff*, Lawrence Berkeley National Laboratory (August 2004), *available at* http://drrc.lbl.gov/pubs/54974.pdf; Nicole Hopper, Charles Goldman and Bernie Neenan, *Demand Response from Day-Ahead Hourly Pricing for Large Customers*, 19:3 ELECTRICITY J. 52 (Apr. 2006) [hereinafter Hopper, *et al.*].

[135] Charles River Associates, *Final Report on the Impact Evaluation of the California Statewide Pricing Pilot* (March 16, 2005), *available at* http://www.energy.ca.gov/demandresponse/documents/group3_final_reports/2005-03-24_SPP_FINAL_REP.PDF. Customers on a similar CPP program at Gulf Power also have high satisfaction with the program, which incorporates automated response to CPP events.

what time and bill accordingly).[136] Most conventional metering and billing systems are inadequate for charging time-varying rates, and most customers are not used to considering price changes in making consumption decisions on a daily or hourly basis. There is, however, a significant effort underway to improve metering technology and infrastructure to better facilitate end-use price responsiveness.[137]

2. Supplier Responses Interact with Customer Demand Responses to Drive Production

Generation supply responses are equally important in the theoretical determination of an appropriate market price. The extent of supply responses will depend on the cost of increasing or decreasing output. Generally, the longer industry has to adjust to a change in demand, the lower the cost of expanding output will be. With more time, firms have more opportunity to change their operations or invest in new capacity.

If the cost of increasing production is small, a relatively small price increase may be enough to encourage producers to increase production in response to increased demand. If the cost of increasing electricity output is high, however, suppliers will not increase production unless the price increases enough to cover the higher costs. In that case, customers would be compelled to pay significantly higher prices for additional supply. Additionally, when suppliers are already delivering as much electric power as they physically can, increased demand can be met only from new capacity. If prices are to provide incentives for resource additions, suppliers must be confident that prices will remain high enough for long enough to justify building a new generating plant.

These supply decisions are complicated because electric power cannot be stored economically, thus there are generally no inventories of electricity. Therefore, electricity generation must always exactly match electricity consumption.[138] The lack of inventories means that wholesale demand is nearly completely determined by end-use demand.[139] Moreover, any distant generation must "travel" over a transmission system with its own limiting physical characteristics.[140] Transmission capability must allow customers access to distant generation sources. The system is further complicated by the dynamics of the AC transmission grid, which can create network effects and can produce positive externalities (depending on the method used in accounting for transmission costs).[141] That is to say, where transmission users are not charged for the congestion impacts of their use patterns, users' actions can cause costs to others which the causal party is not obligated to pay. This dynamic can distort the effect of price signals on dispatch efficiencies.

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[136] *See* EEI comments. Pepco cautions that many customers, particularly residential and commercial customers, are relatively inflexible in responding to price changes due to constraints imposed by their operations and equipment. *See* Pepco comments.

[137] *See DOE EPAct Demand Response Report*; Mercatus Center comments (2).

[138] APPA comments.

[139] While the demand for surplus energy in wholesale markets can vary as a function of the cost of owned generation and existing contracts, the ultimate demand for energy is entirely a function of end-use load.

[140] Alcoa comments.

[141] TAPS comments.

Another complication derives from the fact that aggregate retail demand fluctuates throughout the day and over seasons, with typically higher demand during the day than at night. System operators must maintain a sufficient mix of generating capacity and demand response (plus a margin of standby generation and demand response for system support and reliability purposes) to meet peak customer demands at all times – even if a substantial share of that resource mix is only used during a small portion of the day or year. Thus, load-serving entities must supply or procure (through long-term contracts and/or short-term "spot" market purchases) sufficient "energy" *and* demand response to meet varying loads. Generating resources designed to meet these load changes are generally categorized as "base" load, "intermediate" load and "peak" load. Base load generation runs more or less constantly and can be expensive to build but inexpensive to run once it is built (i.e., large coal and nuclear plants). Intermediate load plants are designed to be brought online and shut down quickly to meet fairly predictable daily changes in load above the base level and below peak. A variety of generating plants can be used for intermediate loads, including gas turbines, gas- and oil-fired steam boilers and hydro-electric plants. Peak load generation tends to come from units such as combustion turbines that can respond rapidly to changes in load, are quick and inexpensive to build, but are often expensive to run. The costs of generating electricity for these different applications can differ substantially.

In any case, a higher price driven by resource scarcity should signal a legitimate opportunity for economic profit, attracting new resource construction where it is most highly valued. At the same time customer demand may decrease in response to rising prices. The increase in resources coupled with a demand response should work together to bring prices down.

3. <u>Customer and Supplier Behavior Responding to Price Changes in Markets</u>

In sum, the combined impact of consumer and supplier responses to changed market conditions should produce a new market equilibrium price. Current prices must change when they create an imbalance between the quantity demanded and the quantity supplied. For example, when demand spikes, short-run prices might have to swing sharply higher to provide incentives for short-run supply increases. However, consumers do not have many good substitutes for electric power, and suppliers usually cannot increase output instantly or transport distant available generation to increase the quantity supplied to a market. Even if higher prices give incentives to change behavior, consumers and producers may have little ability to do so in the short term. Over longer time frames, however, they have more options to react to higher prices. The result is that long-run price increases usually will be much smaller than the short-run price increases needed to induce additional generation.

C. Comparing the Benefits to the Costs of Restructuring Markets for Electricity

While the shortcomings of cost-based regulation played a major role in the shift toward competitive electricity market structures, some market participants question whether the benefits outweigh the costs associated with establishing such markets. Some question whether electricity markets are, by nature, sufficiently competitive to warrant expected price reductions.[142] They note the cost of operating ISOs and the cost to consumers of market manipulations and failures. Respondents to these concerns suggest that these markets are too new to warrant passing such

[142] APPA comments.

judgment. They note that these failures may be a result of ill-advised market designs, and they find benefits despite such failures.

As various regulatory bodies considered whether to deregulate electricity markets, some conducted formal cost-benefit studies to address the relative benefits of the status quo versus proposed policy changes. The Task Force received many comments identifying, endorsing, or criticizing such studies. The Task Force did not, however, have the resources or time to fully examine, critique, or draw definitive conclusions from these widely varying studies. An annotated bibliography of many of these studies is attached as Appendix C. The Task Force also refers the reader to the summary conclusion of a recent DOE review of RTO benefit cost studies. See Box 2-3.

Box 2-3
Review of Cost-Benefit Studies

In December 2005, the Department of Energy released a study reviewing recent RTO Cost/Benefit analyses. This study provides a review of the state of the art in RTO Cost/Benefit studies and suggests methodological improvements for future studies. Following is a summary of this study's conclusions.

In recent years, government and private organizations have issued numerous studies of the benefits and costs of regional transmission organizations (RTOs) and other electric market restructuring efforts. Most studies have focused on benefits that can be readily estimated using traditional production-cost simulation techniques, which compare the cost of centralized dispatch under an RTO to dispatch in the region without an RTO, and on the costs associated with RTO start-up and operation. Taken as a whole, it is difficult to draw definitive conclusions from these studies because they have not examined potentially much larger benefits (and costs) resulting from the impacts of RTOs on reliability management, generation and transmission investment and operation, and on wholesale electricity market operation.

Existing studies should not be criticized for often failing to consider these additional areas of impact, because for the most part neither data nor methods yet exist on which to base definitive analyses. The primary objective of future studies should be to establish a more robust empirical basis for ongoing assessment of the electric industry's evolution. These efforts should focus on impacts that have not been adequately examined to date, including reliability management, generation and transmission investment and operational efficiencies, and wholesale electricity markets. Systematic consideration of these impacts is neither straightforward nor possible without improved data collection and analysis.

J. Eto, B. Lesieutre, & D. Hale, *A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies* (December 2005) (prepared for the Department of Energy).

CHAPTER 3
COMPETITION IN WHOLESALE ELECTRIC POWER MARKETS

A. Introduction and Overview

As described in the preceding chapters, prior to the introduction of wholesale market competition, vertically integrated utilities sold their excess electric power to other utilities and to wholesale customers such as municipalities and cooperatives that had little or no generating capacity of their own.[143] FERC and its predecessor agency, the Federal Power Commission, regulated prices, terms and conditions of interstate wholesale sales by investor-owned utilities. Wholesale purchasers' desire to escape being captive to a vertically integrated monopoly supplier of electricity was a fundamental impetus to opening the generation sector to competition.[144] Sellers of wholesale power were also interested in accessing more customers. This desire for competition to play a greater role in determining supply and demand is consistent with standard economic theory, which asserts that effective competition ensures an economically efficient allocation of resources.

As described in Chapter 2, an important effect of a competitive market operation is that it provides customers with prices that reflect market conditions (abundance, scarcity, etc.). These market-based prices are an essential component of effective competition, as they discipline both consumption and production such that the cost of generating electricity is minimized. However, the demand for wholesale power is derived entirely from consumption choices at the retail level. In electricity there has been an impediment to efficiency in that prices of electricity to retail customers often are not directly connected to the wholesale prices in the market in which supplies are sold. This is because states have jurisdiction over retail prices, and state regulators generally set retail rates based on average costs. Thus, unlike wholesale market-based prices, retail prices did not vary with consumption or the cost of production.[145]

The effects of this regulated price disconnect are heightened by one of the shortcomings of cost-based rate regulation: its difficulty in providing incentives for investors to make economically efficient decisions concerning when, where, and how to build new generation.[146] If competition is to allocate resources in an economically efficient manner, customers must have access to a sufficient number of competing suppliers either via transmission, incumbent generation, demand response, or new local generation.[147]

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143 Wholesale markets involve sales of electric power among generators, marketers, and load serving entities (i.e., distribution utilities and competitive retail providers) that ultimately resell the electric power to end-use customers (e.g., residential, commercial, and industrial customers).

144 *U.S. v. Otter Tail Power Company*, 410 U.S. 366 (1973) (the United States sued a vertically integrated utility when it refused to deal with the Town of Elbow Lake, MI, a town that was seeking alternative sources of wholesale power for a planned municipal distribution system).

145 *See* discussion *infra* Chapter 1.

146 Retail price impacts of competition are discussed in this report's Chapter 4.

147 In a 2002 report, the then-named General Accounting Office made a related point, connecting increasing competition to structural changes. U.S. General Accounting Office, GAO-03-271, *Lessons Learned From Electric Industry Restructuring*, at 21 (2002) ("Increasing the amount of competition requires structural changes within the electric industry, such as allowing a greater number of sellers and buyers of electricity to enter the market").

Competitive policies in electricity markets were introduced to alleviate these disconnects between retail demand, wholesale demand, and investment incentives and to create more efficient markets.[148] In EPAct 1992, Congress determined that competition in wholesale electric markets would benefit from two changes to the traditional regulatory landscape: (1) expansion of FERC's authority to order utilities to transmit, or "wheel," electric power on behalf of others over their own transmission lines and (2) reduction of entry barriers so additional nonutilities could enter the market. The former change permitted wholesale customers to purchase supply from distant generators, while the latter provided customers with competitive alternatives from independent entrants.[149]

In examining the experience with competition to date, a fundamental question to ask is whether competition in wholesale markets has resulted in sufficient generation supply and transmission to provide wholesale customers with the kind of choice that is generally associated with competitive markets. This is the primary question the Task Force attempts to address in this chapter. Answering this question has been challenging due to difficulties in identifying determinants of investment decisions. Each region was at a different regulatory and structural point when Congress enacted EPAct 1992. For example, some regions began with tight power pools, while others operated transmission and generation in a less centralized manner. Some regions had higher population densities and thus more tightly configured transmission networks than did others. Some regions had access to fuel sources unavailable or less available in other regions (e.g., natural gas supply in the Southeast, hydropower in the Northwest). Currently, some regions operate under a transmission open-access regime that has not changed since the early days of open access, while other regions have well developed independent providers of transmission services and organized day-ahead exchange markets for electric power and ancillary services.

This chapter discusses the question at hand anecdotally – by addressing whether and how entry has occurred in several regions with different forms of competition (i.e., the Midwest, Southeast, California, the Northwest, Texas, and the Northeast). It includes a discussion of how long-term purchase and supply contracts, capital requirements, regulatory intervention, and transmission investment affect supplier and customer decisions. The chapter concludes with observations on various regional experiences with wholesale competition.[150] These observations highlight the trade-offs involved with various policy instruments used to introduce competition.

B. Background

One of the overall purposes of EPAct 1992 was "to use the market rather than government regulation wherever possible both to advance energy security goals and to protect consumers."[151] Policymakers recognized that vertically integrated utilities had market power in both

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148 It is important to note that competition in wholesale electric markets may not lead to an efficient allocation of resources involving the services that prevent network collapse. Where there are "public good" aspects to the delivery of a good or service, such as with reliability, regulation may be the best way to ensure that the correct level of the good or service is provided. In some circumstances, however, market remedies may be available that are superior to regulation.

149 *See* EPAct 1992 House Report, H.R. REP. NO. 102-474(I), at 138.

150 The New York State Public Service Commission correctly commented that another metric with which to measure competition is its effect on production efficiencies. The Task Force did not seek to quantify this effect, given the constraints of the Report.

151 EPAct 1992 House Report, H.R. REP. NO. 102-474(I), at 133.

transmission and generation because they owned all transmission and nearly all generation plants within certain geographic areas. Congress enhanced FERC's ability to reduce monopoly power by enhancing its authority to order utilities, case by case, to transmit power for alternative sources of generation supply.

Today, vertically integrated utilities and other entities that operate transmission systems generally are required to offer transmission service under the terms of the standard Open Access Transmission Tariff (OATT) adopted by FERC in Order No. 888.[152] Transmission providers offer two types of long-term transmission service under the OATT: network integration transmission service (network service) and point-to-point transmission service. Box 3-1 describes both types of transmission service. The OATT seeks to put market participants on equal footing when it comes to transmission access – making competition more viable. Price has been predictable and stable for both OATT services over the long term.[153]

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[152] *See* discussion *infra* Chapter 1 for more information on FERC Order No. 888.

[153] The demand charge for long-term point-to-point transmission service is known in advance. For network service, the transmission customer pays a load-ratio share of the transmission provider's FERC-approved transmission revenue requirement. Thus, even if redispatch to relieve transmission congestion occurs and the costs are charged to customers, or expansion is necessary and the expansion costs are added to the revenue requirement, the distribution over the whole system has allowed the charges to individual customers to remain relatively stable. Customers who take either service have a right to continue taking service when their contract expires, although point-to-point customers may have to pay a different rate (up to the maximum rate in the transmission provider's tariff) if another customer offers a higher rate.

Box 3-1
How Transmission Services Are Provided Under the OATT

OATT contracts can be for point-to-point (PTP) or "network" transmission service. Network integration transmission service allows transmission customers (e.g., load-serving entities) to integrate their generation supply and load demand with that of the transmission provider.

A transmission customer taking network service designates "network resources," which include all generation owned, purchased or leased by the network customer to serve its designated load, and individual network loads to which the transmission provider will provide transmission service. The transmission provider then provides transmission service as necessary from the customer's network resources to its network load. The customer pays a monthly charge for this basic service, based on a "load ratio share" (i.e., the percentage share of the total load on the system that the customer's load represents) of the transmission-owning and operating utility's "revenue requirement" (i.e., FERC-approved cost-of-service plus a reasonable rate of return).

In addition to this basic charge, there may be additional charges. For example, when a transmission customer takes network service, it agrees to "redispatch" its generators as requested by the transmission provider. Redispatch occurs when a utility, due to congestion, changes the output of its generators (either by producing more or less energy) to maintain the energy balance on the system. If the transmission provider redispatches its system due to congestion to accommodate a network customer's needs, the costs of that redispatch are passed through to all of the transmission provider's network customers, as well as to its own customers, on the same load-ratio share basis as the basic monthly charge.

The transmission provider must plan, construct, operate and maintain its transmission system to ensure that its network customers can continue to receive service over the system. To the extent that upgrades or expansions are needed to maintain service to a network customer, the costs are included in the transmission-owning utility's revenue requirement, thus impacting the load-ratio share paid by network customers.

Point-to-point transmission service, which is available on a firm or non-firm basis and on a long-term (one year or longer) or short-term basis, provides for transmission between designated points of receipt and designated points of delivery. Transmission customers that take this kind of service specify a contract path. A customer taking firm point-to-point transmission service pays a monthly demand charge based on the amount of capacity it reserves. Generally, the demand charge may be the higher of the transmission provider's embedded costs to provide the service, or the incremental costs of any system expansion needed to provide the service. If the transmission system is constrained, the demand charge may reflect the higher of the embedded costs or the transmission provider's "opportunity" costs, with the latter capped at incremental expansion costs.

Comments to the Task Force raised several concerns over transmission-dependent customers' access to alternative generator suppliers via OATTs. In particular, some commenters noted the continued possibility of transmission discrimination in their regions and that the ability for transmission suppliers to discriminate can block access to alternative suppliers.[154] Commenters concluded that transmission discrimination can increase delivery risk because purchasers fear their transmission transactions might be terminated for anticompetitive reasons by their vertically integrated rival, if they purchase from a generator that is not affiliated with the transmission provider. The facts that electricity cannot be stored economically and electricity demand is very inelastic in the short term heighten delivery risk.

One response to this risk is to turn over operation of the regional transmission grid to an independent operator, such as the ISOs and RTOs that now operate in New England, New York, the Mid-Atlantic, the Midwest, Texas, and California (organized markets).[155] RTOs address deliverability concerns in several ways.[156] The market designs in these regions provide participants with guaranteed physical access to the transmission system (subject to transmission security constraints). See Box 3-2 for a discussion of how transmission is provided in organized wholesale markets.

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[154] APPA comments; TAPS comments. *See also* Midwest Stand-Alone Transmission Companies comments.

[155] Prior to wholesale competition, several of the regions listed had "power pools" of utilities that undertook some central economic dispatch of plants and divided the cost savings among the vertically integrated utility members.

[156] For example, RTOs using LMP pricing address physical deliverability concerns by giving physical access to all users willing to pay the market-determined price. The potential for high LMPs due to limited transmission availability presents a risk that many market participants prefer to hedge. Financial transmission rights (FTRs) have been developed as a means for transmission users to hedge against transmission pricing risk. The amount of FTR MWs available for hedging are determined by the transmission capabilities of the grid, so that a holder of an FTR generally can depend on being able to use the transmission service covered by the FTR. In some RTOs, FTRs are allocated on the basis of historic transmission use. In others, FTRs are allocated either through an auction or through a process that awards FTRs in proportion to the total requests for FTRs for a particular transmission service. Under the latter two approaches, some historic transmission users may have to acquire additional FTRs from other parties in order to hedge their previous levels of transmission use. In particular, in circumstances where certain transmission paths have become highly congested, historic transmission users may have to make significant expenditures to maintain traditional levels of transmission rights.

Box 3-2
How Transmission Is Priced in an ISO or RTO

ISOs and RTOs (hereinafter RTOs) provide transmission service across a region under a single transmission tariff. They also operate organized electricity markets for the trading of wholesale electric power and/or ancillary services. Transmission customers in these regions schedule with the RTO injections and withdrawals of electric power on the system, instead of signing contracts for a specific type of transmission service with the transmission owner under an OATT.
The pricing for transmission service is substantially different in these regions than under a standard OATT. RTOs generally manage congestion on the transmission grid through a pricing mechanism called Locational Marginal Pricing (LMP). Under LMP, the price to withdraw electric power (whether bought in the exchange market or obtained through some other method) at each location in the grid at any given time reflects the cost of making available an additional unit of electric power for purchase at that location and time. In other words, congestion may require the additional unit of energy to come from a more expensive generating unit than the one that cannot be accessed due to the system congestion. In the absence of transmission congestion, all prices within a given area are the same at any given time. However, when congestion is present, the prices at various locations typically will not be the same, and the difference between any two locational prices represents the cost of transmission system congestion between those locations. This congestion cost constitutes the only significant "variable cost" of transmission – the fixed costs of infrastructure investment are recovered through a standard transmission access fee.

Because congestion on the grid changes constantly, a transmission customer may be unable to determine beforehand the price for electric power at any location. To reduce this uncertainty, RTOs make a financial form of transmission rights available to transmission customers, as well as other market participants. Generally known as financial transmission rights (FTRs), they confer on the holder the right to receive certain congestion payments. Generally, an FTR allows the holder to collect the congestion costs paid by any user of the transmission system and collected by the RTO for electricity delivered over the specific path. In short, if a transmission customer holds an FTR for the path it takes service over, it will pay on net either no congestion charges (if the FTR matches the path exactly) or lower congestion charges (if the FTR partially matches), providing a financial "hedge" against the uncertainty.

In general, FTRs are now available for one-year terms (or less) and are allocated to entities that pay access charges or fixed transmission rates. Pursuant to EPAct 2005, FERC has adopted rules to ensure the availability of long-term FTRs.

In regions with RTOs, wholesale electricity can be bought and sold through negotiated bilateral contracts, through "standard commercial products" available in all regions, and through various products offered by the organized exchange market.

For bilateral contracts, the contract can be individually negotiated with terms and conditions unique to a single transaction. Standard products are available through brokers and over-the-counter (OTC) exchanges such as the NYMEX and InterContinental Exchange (ICE).[157] Standard products have a standard set of specifications so that the main variant is price. Finally, some RTOs also operate organized exchange markets that offer various products including electric power and ancillary services. These markets typically involve both real-time and day-ahead sales. Ancillary services include various categories of generation reserves such as spinning and non-spinning reserves in addition to Automatic Generation Control (AGC) for frequency control.

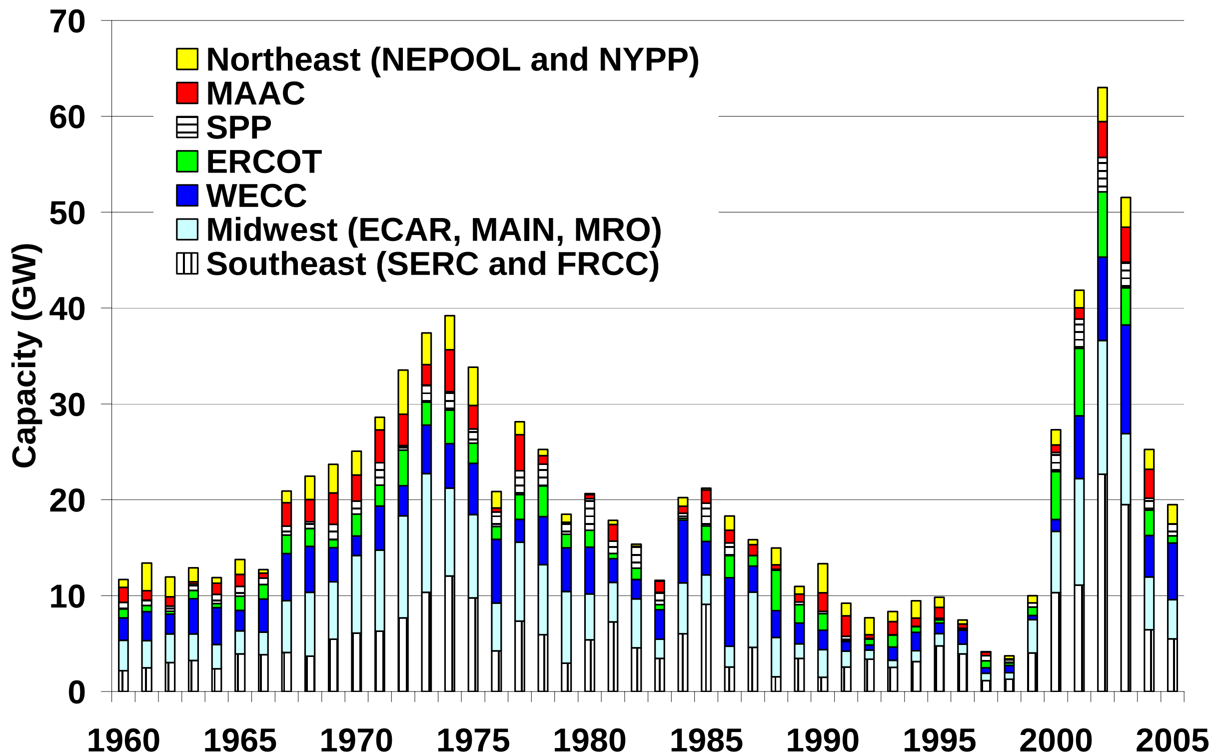
As described above, there is a question as to whether the price signals described in Chapter 2 have functioned to elicit the consumption and investment decisions that were expected to occur with wholesale market competition.

C. Wholesale Electric Power Markets and Generation Investment by Region

New generation investment has varied significantly by region since the adoption of open access transmission and the growth of competition. Figure 3-1 shows the overall pattern of new investment by region. There has been substantial new investment in the Southeast, Midwest, and Texas, while other regions have not experienced as much investment. Each region has different pricing formats for transmission services. Moreover, regions that operate exchange markets for electric power and ancillary services use different forms of locational pricing, price mitigation, and capacity markets.

[157] Companies can also limit their exposure to price swings through financial instruments rather than contracts for physical delivery of electricity. Such contracts are essentially a bet between two parties as to the future price level of a commodity. If the actual price for power at a given time and location is higher than a financial contract price, Party A pays Party B the difference; if the price is lower, Party B pays Party A the difference. In fact, in the United States electricity markets, such agreements are sometimes called "contracts for differences." Purely financial contracts involve no obligation to deliver physical power. In this report, the Task Force discusses contracts for physical delivery rather than financial contracts, unless otherwise noted.

Figure 3-1. U.S. Electric Generating Capacity Additions, 1960 – 2005



Source: FERC analysis of Platts PowerDat Data

These regional differences provide some insight into the impact of different policy choices on creating markets with sufficient supply choices to support competition and to allocate resources efficiently.

1. <u>Midwest</u>

a. Wholesale Market Organization

In 2004, the Midwest RTO began providing transmission services to wholesale customers in its footprint. On April 1, 2005, the Midwest Independent System Operator (MISO) commenced its organized electric power market operations. Prior to that, there were no centralized electric power exchange markets and wholesale customers obtained transmission under each utility's OATT.

b. New Generation Investment

Wholesale prices spiked in the Midwest in the summer of 1998,[158] as an increase in demand due to unusually hot weather combined with unexpected generation outages. A significant amount of

[158] Federal Energy Regulatory Commission, *Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998* (1998).

new generation was built in response to the price spike, as shown in Table 3-1. For example, from January 2002 through June 2003, the Midwest added 14,471 MW in capacity.[159]

Most of the new generation was gas-fired, even though the region as a whole relies primarily on coal-fired generation.[160] More recently, new generation has been coal fired, in part because of rising natural gas prices.[161] This entry and the subsequent drop in wholesale power prices has resulted in (1) merchant generators in the region declaring bankruptcy and (2) vertically integrated utilities returning certain generation assets from unregulated wholesale affiliates to rate-base.

2. Southeast

a. Wholesale Market Organization

Wholesale customers in the region obtain transmission under each utility's OATT (e.g., Entergy or Southern Companies). There are no centralized electric power markets specific to the region.

b. New Generation Investment

Due to the Southeast's proximity to natural gas in the Gulf of Mexico and pipelines to transport it, natural gas is a popular fuel choice for those building plants in the region. The Southeast has seen considerable new generation construction, as shown in Figure 3-1. More than 23,000 MW of capacity were added in the Southern control area between 2000 and 2005,[162] and several generation units owned by merchants or load-serving entities have been built in the Carolinas in the past few years.

A significant portion of the region's new generation was nonutility merchant generation, and a number of merchant companies that built plants in the 1990s have sought bankruptcy protection. Often, the plants of bankrupt companies have been purchased by local vertically integrated utilities and cooperatives, such as Mirant's sale of its Wrightsville plant to Arkansas Electric Cooperative Corporation and NRG's sale of its Audrain plant to Ameren.[163] Even apart from bankruptcies, some independent power producers have withdrawn from the region.

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159 Federal Energy Regulatory Commission, Office of Market Oversight and Investigations, *State of the Markets Report: Assessment of Energy Markets for the Period January 1, 2002 through June 30, 2003*, at 109 (2004), available at http://www.ferc.gov/legal/staff-reports.asp [hereinafter *FERC State of the Markets Report 2002-2003*].

160 *Id.* at 50.

161 *FERC State of the Markets Report 2004* at 77.

162 Southern comments.

163 *See* Fitch Ratings, *Wholesale Power Market Update* (Mar. 13, 2006), *available at* http://www.fitchratings.com/corporate/sectors/special_reports.cfm?sector_flag=2&marketsector=1&detail=&body_content=spl_rpt.

3. California

a. Wholesale Market Organization

The California ISO began operation in 1998 to provide transmission services. Concurrently, a separate Power Exchange (PX) operated electric power exchanges. After the 2000-2001 energy crisis, the PX was dissolved.[164]

b. New Generation Investment

Even before the California energy crisis, California depended on imported electric power from neighboring states. Much of the generation capacity that serves load in Southern California was built a substantial distance away from the population it serves, making the region heavily dependent upon transmission. In the past few years, much of the generation in California has operated under long-term contracts negotiated by the state during the energy crisis.[165] Since 2000-2001, California's demand has increased, but construction of local generation has not kept pace. Over 6,000 MW of new generation capacity entered California in 2002-2003, but very little was built in congested, urban areas such as San Francisco, Los Angeles, and San Diego.[166] Most new generation projects have been in Northern California.[167] In the past five years, transmission investments have improved links between Southern and Northern California, and accessible generation investment in the Southwest has increased.

4. New England

a. Wholesale Market Operation

The New England ISO (ISO-NE) provides transmission services as well as a centralized electric power market. Under the electric power pricing mechanism adopted by ISO-NE, certain units used to maintain local resource adequacy must bid into the energy markets at marginal costs under must-run reliability contracts. The fixed costs of these high-priced units are recovered from users in the pertinent reliability zone.

b. New Generation Investment

Much of New England's net new generation has been built in less populated areas of the region, such as Maine, while most of the demand for power is in southern New England. From January 2002 through June 2003, ISO-NE added 4,159 MW in capacity.[168] There were fewer capacity additions in 2004 than in the two previous years. In 2004, four generation projects came on line. Generation retirements in 2004 totaled 343 MW, of which 212 MW are deactivated reserves.

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164 Currently, the CAISO operates only an imbalance energy market.

165 *See* discussion *infra* Chapter 1, for a more extensive discussion of the Western Energy Crisis of 2000-2001.

166 *FERC State of the Markets Report 2004* at 69; *FERC State of the Markets Report 2002-2003* at 41-43.

167 CAISO comments.

168 *FERC State of the Markets Report 2002-2003* at 109.

Demand growth in the organized New England markets has led to "load pockets," areas of high population density and high peak demand that lack adequate local supply to meet demand and for which transmission congestion prevents use of distant generation. These pockets have not seen entry of generation to meet local demand, and transmission has not always been adequate to bridge this gap. In general, New England needs new generation in the congested areas of Boston and Southwest Connecticut, increased demand response, or increased transmission investment to reduce congestion. Significant transmission upgrades were expected to go into operation in Boston and Southwest Connecticut during 2006.[169]

Theoretically, locational prices should elicit generation investment where needed, but this has been inadequate in load pockets. The ISO-NE pricing methodology often did not allow the market clearing price to reflect the cost of generation used to serve the congested areas.[170] The resulting locational prices were not sufficient to attract significant new entry. Several policies have been adopted to provide the needed incentives. In 2003, ISO-NE implemented a temporary measure known as the Peaking Unit Safe Harbor (PUSH) mechanism, which was intended to enable greater cost recovery for high-cost, low-use units in designated congestion areas; however, PUSH units were not able to recover all their fixed costs.[171] In June 2006, FERC approved a settlement establishing a forward capacity market in New England that will project demand three years in advance and hold annual auctions to purchase power resources for the region's needs.[172] The forward capacity market includes a locational component to account for areas where transmission congestion limits the ability to import capacity necessary to meet local demand.

5. New York

a. Wholesale Market Operation

NYISO provides transmission services as well as a centralized electric power market. NYISO uses price mitigation to guard against wholesale price spikes, but, in contrast to early ISO-NE practice, it includes high-cost generators in marginal locational pricing.

b. New Generation Investment

New York traditionally has built generation in less populated areas and transmitted the power to more populated areas. For example, the New York Power Authority was created, in part, to get hydroelectric power from the Niagara Falls area into more congested areas of the state. From January 2002 through June 2003, NYISO added 316 MW in capacity.[173] Three generating plants

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[169] ISO New England Inc., *Forecast Report of Capacity, Energy, Loads, and Transmission*, at 76 (2006), *available at* http://www.iso-ne.com/trans/celt/report/2006/2006_CELT_Report.pdf.

[170] *FERC State of the Markets Report* 2002-2003 at 83 ("These load pockets did not exhibit materially higher locational prices in 2004, probably because the cost of expensive units used to ensure resource adequacy and transmission security in these areas are frequently not eligible to set the clearing price").

[171] *Id.* at 36.

[172] *Devon Power LLC*, 115 FERC ¶ 61,340 (2006); Press Release, ISO New England Inc., ISO New England Announces Broad Stakeholder Agreement on New Capacity Market Design (Mar. 6, 2006), *available at* http://www.iso-ne.com/nwsiss/pr/2006/march_6_settlement_filing.pdf.

[173] *FERC State of the Markets Report 2002-2003* at 109.

with a total summer capacity of 1,258 MW came on line in 2004. Three plants totaling 170 MW retired in 2004.[174]

Currently, transmission constraints in and around New York City limit competition in the city and lead to greater use of expensive local generation, which results in high prices. NYISO uses price mitigation measures designed to avoid mitigating prices resulting from genuine scarcity. NYISO has separate mitigation rules for New York City. In an effort to lessen distortion of market signals, NYISO includes the cost of running generators to serve load pockets in its calculation of locational prices. Thus, potential entrants get a more accurate price signal regarding investment in the load pocket.

In a further effort to spur new construction, NYISO also sets a more generous “reference price” for new generators in their first three years of operation (bids above the reference prices may trigger price mitigation).[175] Unlike New England, New York is seeing new generation investment in at least one congested area. Approximately 1,000 MW of new capacity entered commercial operation in the New York City area in 2006. The fact that New York is better able than New England to match locational need with investment is likely due to New York’s clearer market price signals, both in energy markets and capacity markets. However, the Public Utility Law Project of New York commented that it is the public power agencies and traditional investor-owned utilities – rather than merchants responding to NYISO prices – that have invested in new infrastructure.

The effect of load pockets on prices is shown in Figure 3-2, which estimates the annual value of capacity based on weighted average results of three types of auctions run by the NYISO. Capacity prices are higher in the tighter supply areas of NYC and Long Island.

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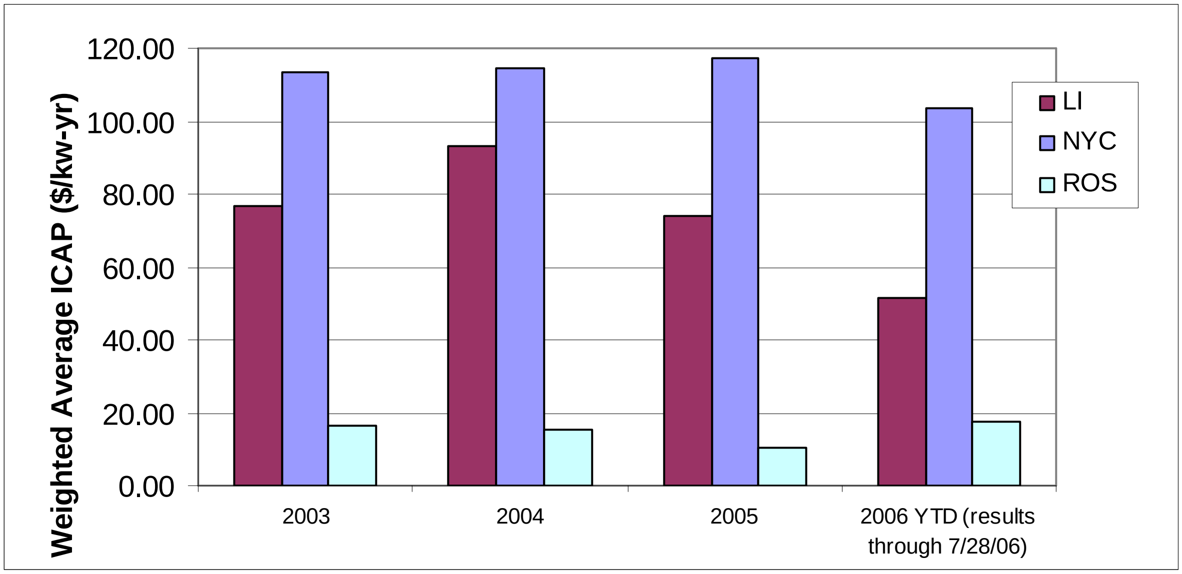
[174] *FERC State of the Markets Report 2004* at 97.

[175] *FERC State of the Markets Report* 2002-2003 at 39.

Figure 3-2. Estimate of Annual NY Capacity Values

Dollars per kilowatt-year ($/kW-yr)



Source: FERC analysis of NYISO data

6. PJM

a. Wholesale Market Operation

The PJM Interconnection provides transmission services as well as a centralized electric power market. PJM has both energy and capacity markets. Its energy market has locational prices, and FERC recently approved, in principle, PJM's proposal to shift to locational prices in its capacity markets.[176] The locational capacity market has not yet been implemented.

b. New Generation Investment

PJM capacity includes a broad mix of fuel types. Recent PJM expansion into new territories has added significant low-cost coal resources to PJM's overall generation mix, although the National Rural Electric Cooperative Association (NRECA) commented that other parts of PJM lack sufficient generation as a result of inadequate capacity additions. From January 2002 through June 2003, PJM added 7,458 MW in capacity.[177] Capacity additions in 2004 were lower than in the two previous years, especially considering that PJM added significant new territory in 2004. In 2004, 4,202 MW of new generation was completed in PJM. During the year, 78 MW of generation was mothballed and 2,742 MW was retired.[178]

[176] *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, at 61,236, *reh'g denied*, 117 FERC ¶ 61,331 (2006).

[177] *FERC State of the Markets Report 2002-2003* at 109.

[178] *FERC State of the Markets Report 2004* at 112.

Like other areas, PJM depends on transmission to move power from areas of low-cost generation to areas of high demand. The flow is generally from the western part of PJM, an area with significant low-cost coal-fired generation, to eastern PJM. The easternmost part of PJM is limited by transmission line capacity constraints, which at times limit the deliverability of generation from the west. This means that higher-cost generation must be run in the eastern region to meet local demand. Furthermore, within the eastern region, there are areas of even more limited transmission. As a result, in some areas generation that is not economical to run is given reliability must-run (RMR) contracts to prevent it from retiring and possibly reducing local reliability.[179] Recently, three utilities in PJM proposed major transmission expansions to increase capacity for moving power into eastern parts of PJM.[180] In its comments, PJM contends that it is experiencing a "robust" level of new transmission investment for reliability upgrades.

7. Texas

a. Wholesale Market Operation

The Electric Reliability Council of Texas (ERCOT) manages power scheduling on an electric grid consisting of about 77,000 MWs of generation capacity and 38,000 miles of transmission lines. It also manages financial settlement for market participants in Texas's deregulated wholesale bulk power and retail electric market. The Public Utility Commission of Texas regulates ERCOT. ERCOT generally is not subject to FERC jurisdiction because its operations are not integrated with other electric systems outside of Texas (i.e., there is no interstate electric transmission). ERCOT is the only market in which regulatory oversight of the wholesale and retail markets is performed by the same governmental entity.

Each year, ERCOT determines the set of transmission constraints within its system that it deems Commercially Significant Constraints (CSCs). Once approved by the ERCOT Board, the CSCs and the resulting Congestion Zones are used by the ERCOT dispatch process for the next year. In 2005, ERCOT had six CSCs and five Congestion Zones. When the CSCs bind, ERCOT economically dispatches generation units' bids against load within each zone. To balance the system in real time, ERCOT issues unit-specific instructions to manage Local (intra-zonal) Congestion, then clears the zonal Balancing Energy Market. The balancing energy bids from all the generators are cleared in order of lowest to highest bid.[181]

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[179] *Id.* at 188.

[180] AEP proposes to build a new 765-kilovolt (kV) transmission line stretching from West Virginia to New Jersey, with a projected in-service date of 2014. *AEP Interstate Project Summary, available at* http://www.aep.com/newsroom/resources/docs/AEP_InterstateProjectSummary.pdf. Allegheny Power (Allegheny) proposes to construct a new 500-kV transmission line, with a targeted completion date of 2011, which will extend from southwestern Pennsylvania to existing substations in West Virginia and Virginia and continue east to Dominion Virginia Power's Loudoun Substation. *Allegheny Power Transmission Expansion Proposal, available at* http://www.alleghenypower.com/TrAIL/TrAIL.asp. More recently, Pepco has proposed to build a 500-kv transmission line from Northern Virginia, across the Delmarva Peninsula and into New Jersey.

[181] *ERCOT Response to the DOE Question Regarding the Energy Policy Act 2005, available at* http://www.oe.energy.gov/DocumentsandMedia/ercot2.pdf.

At least one study asserts that when there is local congestion, local market power is mitigated in ERCOT by ad hoc procedures aimed at keeping prices relatively low while maintaining transmission flows within limits. The study concludes that, as a result, prices may be too low to elicit needed investment when there is local scarcity. Since it is difficult for new entrants to enter local markets at these prices, local monopoly positions are essentially entrenched.[182]

b. New Generation Investment

In the late 1990s, developers added more than 16,000 MW of new capacity to the Texas market.[183] Certain aspects of this market may make it attractive to new investment. Texas consumers directly pay (via their electricity bills) for transmission system updates made to accommodate new plants. In other states, FERC often requires developers to pay for system upgrades upfront and recoup the cost over time through credits against their transmission rates.[184] In addition, the Texas PUC plans to implement an energy-only resource adequacy market design in the fall of 2006 that requires incrementally raising the energy offer caps over time. More than 13,000 MWs of new capacity is scheduled to be online in 2009-2011.[185]

c. Hybrid Wholesale/Retail Demand Response

ERCOT has a competitive market-based demand response program that allows competitive retailers, along with willing customers, to respond to market-based price signals. Under the Load Acting As a Resource Program (LAAR), customers bid demand response into ERCOT's ancillary services market for responsive reserves through their scheduling agent.[186] If needed by ERCOT, the load is then paid the market-clearing price for responsive reserve. The LAAR program is fully subscribed at 1,150 MWs.

8. <u>The Northwest</u>

a. Wholesale Market Organization

Wholesale customers obtain transmission service through agreements executed pursuant to individual utility OATTs. There are no centralized exchange markets specific to the region, but there is an active bilateral market for short-term sales within the Northwest and to the Southwest and California, which makes use of centralized electronic exchange platforms (such as the InterContinental Exchange). Several trading hubs with significant levels of liquidity provide price information. Multiple attempts to establish a centralized Northwest transmission operator have proven unsuccessful for a variety of reasons, including difficulties in applying standard restructuring ideas to a system dominated by cascading (i.e., interdependent nodes) hydroelectric generation and difficulties in understanding the potential cost shifts that might result in

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182 Ross Baldick and Hui Niu, *Lessons Learned: The Texas Experience, available at* http://www.ece.utexas.edu/~baldick/papers/lessons.pdf.

183 U.S. General Accounting Office, GAO-02-427, *Restructured Electricity Markets, Three States' Experiences in Adding Generating Capacity*, at 9 (2002) [hereinafter GAO, *Restructured Electricity Markets, Three States' Experiences*].

184 *Id.* at 19.

185 Public Utilities Commission of Texas comments (2).

186 For more information regarding LAAR, *see* http://www.ercot.com/services/programs/load/laar.

restructuring contract-based transmission rights. A nascent organization created to enhance coordinated regional reliability and planning, ColumbiaGrid, has recently seated a board and begun development of various "functional agreements."[187]

b. New Generation Investment

The Northwest's generation portfolio is dominated by hydroelectric generation, which comprises roughly half of all generation resources in the region on an energy basis.[188] Coal and natural gas resources make up most of the remaining generation, with smaller contributions from wind, nuclear, and other resources. The hydroelectric share has decreased steadily since the 1960s.

The Northwest's hydroelectric base allows the region to meet almost any capacity demands within the region, but the region is susceptible to energy limitations (given the finite amount of water available to flow through dams). This ability to meet peak demand buffers incentives for building new generation, which might be needed to assure sufficient energy supplies during times of drought. In three out of four years, hydro generation can displace much of the existing thermal generation in the Northwest. However, generation was added in recent years to meet load growth and to attempt to capitalize on high-prices during the Western energy crisis of 2001-2002. Due to high power purchase costs during this crisis, some utilities have added thermal resources as insurance against drought-induced energy shortages and high prices. Altogether, over 3,800 MWs of new generation has been added to the Northwest Power Pool since 1995. Of that, 75 percent was commissioned in 2001 or later.

D. Observations on Current Wholesale Market Options

One of the most diffiult questions federal regulators currently face is whether the different forms of competition in wholesale markets have resulted in an efficient allocation of resources. The various approaches used by the different regions show the range of available options.

1. <u>Open Access Transmission without an Organized Exchange Market</u>

One option is to rely on the OATT to make generation options available to wholesale customers. No centralized transmission operator or exchange market for electric power operates in regions that rely on this option (the Northwest and Southeast). However, active trading platforms can be found in these regions. These platforms provide liquidity and price transparency in some day-ahead or longer-term markets – although the prices do not directly reflect the costs of congestion. For long-term sales in these markets, wholesale customers shop for alternatives through bilateral contracts with suppliers. In both cases, customers separately arrange for transmission via the OATT. With a range of supply options to choose from, long-term bilateral contracts for physical supply can provide price stability for wholesale customers and send them a rough price signal so they can determine whether to build or buy. However, prices and terms can be unique to each transaction and may not be publicly available. Furthermore, the lack of centralized information about trades leaves transmission operators with system security risks that constrain transmission

[187] *Available at* http://www.columbiagrid.org

[188] For a complete discussion of generation characteristics of the Northwest, *see* NW Power & Con. Council, *The Fifth Northwest Power and Conservation Plan*, Ch. 2 (2005), *available at* http://www.nwcouncil.org/energy/powerplan/plan/Default.htm.

capacity. The lack of price transparency can add to the difficulty of pricing long-term contracts in these markets.

This model depends significantly on the availability of transmission capacity that is sufficient to allow buyers and sellers to connect. Thus, it also depends on the accurate calculation and reporting of available transmission capacity. Short-term availability is not sufficient, even if accurately reported, to form a basis for long-term decisions such as contracting for supply or building new generation. Not only must transmission be available, it also must be seen to be available on a nondiscriminatory basis. As FERC noted in Order 2000, persistent allegations of discrimination can discourage investment even if they are not proven. Without the assurance of long-term transmission rights, wholesale customers may remain dependent on local generation owned by one or only a few sellers, because they cannot access competitive options supplied by more distant generation. Similarly, new suppliers may have no means of competing with incumbent generators located close to traditional load.

2. Organized Wholesale Markets

In organized markets, market participants have access to an exchange market where prices for electric power are set in reference to supply offers by generators and demand by wholesale customers (including Load-Serving Entities or LSEs). While prices can be set by a number of mechanisms, all U.S. exchange markets have a uniform price auction to determine the price of electric power. Uniform price auctions theoretically provide suppliers an incentive to bid their marginal costs, to maximize their chance of getting dispatched.

The principal alternative to uniform price auctions is a pay-as-bid market.[189] Research on whether pay-as-bid auctions result in lower prices than do uniform price auctions has been evolving and the results are, at best, mixed. Theoretically, pay-as-bid auctions do not result in lower market-clearing prices and may even raise prices as suppliers base their bids on forecasts of market-clearing prices instead of their marginal costs. Recent research suggests that pay-as-bid can sometimes result in lower costs for customers.[190] But the pay-as-bid approach may reduce dispatch efficiency, to the extent generator bids deviate from their marginal costs.[191] From a practical perspective, academics and market designers generally agree that uniform price auctions in competitively structured markets produce economically efficient prices.

Currently, in uniform price auction markets some generators (e.g., coal- or nuclear-fueled units) may be earning a return above those typically allowed under cost-based regulation. But other generators (e.g., natural gas-fueled units) are earning returns below those typically allowed under cost-based regulation. In a competitive market, a unit's profitability in a uniform price auction will depend on whether, and by how much, its production costs are below the market clearing price. A uniform price auction thus may produce very high prices compared with the costs of

[189] Under a pay-as-bid market, sellers are paid their actual bid prices, while under a "single price" or uniform price market, all sellers are paid the single market-clearing price.

[190] Par Holmberg, *Comparing Supply Function Equilibria of Pay-as-Bid and Uniform Price Auctions* (2005) (Uppsala University, Sweden Working Paper 2005:17); G. Federico & D. Rahman, *Bidding in an Electricity Pay-As-Bid Auction* (Nuffield College Discussion Paper No 2001-W5, 2001); Joskow, *Difficult Transition* at 6-7.

[191] Alfred E. Kahn, *et al.*, *Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond* (Blue Ribbon Panel Report, study commissioned by the California Power Exchange, 2001).

some generators and yet not high enough to give investors an incentive to build new generation that could moderate prices going forward. The uniform price auction creates strong incentives for entry by low-cost generators that will be able to displace high-cost generators in the merit dispatch order. The sufficiency of entry in uniform price auction markets has been a topic of discussion among policymakers and market participants. Four policy options have been suggested.

a. Unmitigated Exchange Market Pricing

One possible, but controversial, way to spur entry is to let wholesale market prices rise with scarcity.[192] As discussed in Chapter 2, the market likely will respond in two ways. First, the resulting price spikes will attract capital and investment. To assure that the price signals elicit appropriate investment and consumption decisions, they must reflect the differences in prices of electricity available to serve particular locations. The costs of supplying customers within the region may vary where transmission capacity limits the availability of electric power from some generators within a regional market. Without locational prices, investors may not make wise choices about where to invest in new generation.

Unfortunately, it is difficult to distinguish high prices due to the exercise of market power from those due to genuine scarcity. High prices due to scarcity are consistent with the existence of a competitive market, and therefore perhaps suggest less need for regulatory intervention. High prices stemming from the exercise of market power in the form of withholding capacity may justify regulatory intervention. Being able to distinguish between the two situations is therefore important in markets with market-based pricing.[193]

Second, higher prices likely will influence customer decisions about how much and when to consume. Price increases signal customers to reduce the amount they consume. Indeed, during the Midwest wholesale price spikes in the summer of 1998, consumption fell when prices rose as customers purchased little supply during those periods.[194] To reduce consumption efficiently, retail customers must have the ability to react to accurate price signals. As discussed in Chapter 4, customers often have limited incentive, even in markets with retail competition, to reduce their consumption when the marginal cost of electricity is high. This is because retail rates in the short term do not vary to account for the costs of providing the electricity at the actual time it was consumed.

b. Moderation of Price Volatility with Caps and Capacity Payments

To date, the alternative to unmitigated exchange market pricing has been price and bid caps in wholesale exchange markets. Although price and bid caps may moderate wide swings in

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192 In theory, a pivotal supplier could bid $1 million or more and set the clearing price, so in practice the ISO would have still set a cap, albeit a high one. In its comments, the Public Utilities Commission of Texas describes a plan it expects to adopt in summer 2006, to raise offer caps incrementally in its energy-only market. The Public Utilities Commission of Texas expects to ultimately pay $3000 per MWh for energy in some hours of the year.

193 *See generally Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964 (D.C. Cir. 2005).

194 Robert J. Michaels and Jerry Ellig, *Price Spike Redux: A Market Emerged, Remarkably Rational*, 137 PUB. UTIL. FORTNIGHTLY 40 (1999). Wholesale customers with supply contracts for which the prices were tied to the market price paid higher prices for electric power during those hours.

market-clearing prices, there is disagreement as to the appropriate level of the caps. Higher caps may strike a balance between a policy of smoothing out the peaks of the highest price spikes and one of demonstrating where capital is required and can recover its full investment. Some argue, however, that high price caps may burden consumers with high prices and yet not allow prices to rise to the level that will actually ensure that investors will recover the cost of new investment.[195] Thus prices can rise significantly and yet not attract additional supply that could eventually moderate price.

Capacity payments are one way to ensure that investors recover fixed costs. Such payments can provide a regular payment stream that, when added to power market income, can make a project more economically viable. Like any regulatory construct, however, capacity payments have limitations. It is difficult to determine the appropriate level of capacity payments to spur entry without over-taxing market participants and consumers. In addition, because capacity payments include a reserve margin added on to demand, capacity markets may be more susceptible to market power than energy markets. These markets may not be viable unless there is some mitigation policy, but determining the appropriate mitigation policy is a challenge.[196]

To the extent that capacity rules change, there is a perception of risk about capacity payments that may limit their effectiveness in promoting investment and ultimately new generation. When rules change, builders and investors may take advantage of short-term capacity payment spikes in a manner that is inefficient from a longer-term perspective.

If capacity payments are provided for generation, they may prompt generation entry when transmission or demand response would be more affordable and equally effective. Capacity payments also may reward traditional utilities and their affiliates disproportionately by providing significant revenues for units that are fully depreciated. Capacity payments also may discourage entry by paying uneconomical units to keep running instead of exiting the market. These concerns can be addressed somewhat by appropriate rules – e.g., NYISO's rules giving capacity payment preference to newly-entered units. In general, however, it is difficult to tell whether capacity payments alone would spur economically efficient entry.

One issue is whether capacity prices should be locational, similar to locational electric power prices. PJM, ISO-NE and NYISO have either proposed or implemented locational capacity markets that may increase incentives for building in transmission-constrained, high-demand areas. The combination of high electric power prices and high capacity prices in these areas may create adequate incentive to build generation in load pockets.[197]

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195 Sometimes, in fact, entry may not be justified, even in the face of high prices. Potential entrants must consider the benefits as well as the costs of entry. Some areas may be so costly to enter, that it is more efficient for society as a whole to pay the higher prices rather than pay the high investment costs to build lower cost generation, institute price-responsive demand programs, or invest in transmission access to lower-cost generation.

196 Making demand response eligible to meet reserve margins may ease these concerns.

197 In the areas that need capacity the most – densely populated areas significantly bounded by topographical barriers such as oceans – land prices, environmental restrictions, aesthetic considerations, and other factors may make new generation more (or even prohibitively) expensive. In fact, there are some environmental restrictions that serve as de facto bars to new generation entry.

c. Encouraging Additional Transmission Investment

Building the right transmission facilities may encourage entry of new generation or more efficient use of existing generation located near, but outside, load pockets. But transmission expansion to serve increased or new load raises the difficulty of creating a rate structure that ties the economic and reliability benefits of transmission to particular consumers. Because transmission investments can benefit multiple market participants, it is difficult to assess who should pay for the upgrade, particularly when some market participants do not require the transmission to meet their needs. This regulatory challenge may cause uncertainty about the price for transmission and about return on investment both for new generators and for transmission providers.

Merchant transmission lines, built by nonutilities, once were thought to be a solution to the need for long distance transmission lines. However, few merchant lines have been built. Uncertainties about revenue have made financing difficult. In addition, difficulties in obtaining needed rights-of-way and environmental approvals have chilled potential merchant projects.[198] Provisions of EPAct 2005 that allow for federal permitting of transmission projects under certain circumstances appear to have encouraged interest in new transmission projects, including merchant projects.[199]

Building or expanding transmission capacity, where possible, may remove the congestion that contributes to higher electricity prices in load pockets and other transmission-constrained areas. However, the potential for building new transmission may reduce the incentive to build new generation in the load pockets or develop demand response and thus may sustain the high prices there. Once new transmission capacity is built, it will increase supply options and decrease or dampen prices just as newly built generation or demand response would. Building or expanding transmission may increase supply more cost effectively than building new generation in load pockets and other constrained areas.

Both generation and merchant transmission builders must deal with an existing transmission owner or an RTO/ISO to obtain permission to interconnect their facilities. Moreover, there are substantial difficulties in siting new transmission lines. It is difficult to assess whether these risks are higher for transmission builders than for generation builders or demand response programs.

d. Governmental Control of Generation Planning and Entry

The final alternative is a regulatory, rather than market, mechanism to assure that adequate generation is available to wholesale customers. As a method to spur investment, regulatory oversight of planning has some positive aspects, but it also has costs. Using regulation through governmentally determined resource planning to encourage entry could result in more entry than through market-based solutions, but that entry may not occur where, when, or in a way that most

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[198] PJM Interconnection, L.L.C., *PJM Regional Transmission Expansion Plan*, at 20 (2006), *available at* http://www.pjm.com/planning/reg-trans-exp-plan.html.

[199] *See supra* note 180. AEP and Allegheny are both requesting that their proposed transmission projects be designated as a National Interest Electric Transmission Corridor under EPAct 2005.

benefits customers. Regulatory oversight of investment also means regulators can bar entry for reasons other than efficiency. The stable rate of return on invested capital under rate regulation can encourage investment. On the other hand, rate regulation can lead to overinvestment, excessive spending and unnecessarily high costs. Regulation also does not provide the same market discipline that effective competition provides. Under regulation, ratepayers may bear the risk of mistakes resulting from where and how investments are made. In competitive markets, the penalties for such mistakes fall on management and shareholders. Future accountability for investment decisions can lead to better decision-making at the outset.[200]

Some commenters strongly supported Integrated Resource Planning or other governmentally supervised planning processes to provide optimal fuel diversity.[201] In particular, they were concerned that the market acting alone creates boom-bust cycles where investors overreact to market signals and too many parties invest in one region. This creates overcapacity, which in turn leads to lower prices. Regulatory oversight of planning could result in greater fuel diversity, and thus less exposure to risks associated with changes in fuel prices or availability. Although IRP often includes consideration of future fuel prices, it is difficult to determine in advance the appropriate mix of fuels given the difficulty of projecting fuel prices. Regulators and planners too can make flawed resource decisions and have done so in the past.

3. Market Oversight of Wholesale Energy Markets

Under current law, market oversight to prevent anticompetitive behavior is an important feature of organized wholesale electricity markets. There is consensus about the need for market oversight and rules to ensure that wholesale electricity markets function efficiently and provide benefits to consumers. FERC's Office of Enforcement and state regulators perform this service by reviewing wholesale electricity markets and the reports of internal and independent market monitors.[202] Organized markets also are subject to ongoing scrutiny by state regulators and the independent market monitoring arms of RTOs.[203] In sum, market oversight continues to be a vital element of organized wholesale markets, and efforts are ongoing to strengthen the oversight process.

E. Factors that Affect Investment Decisions in Wholesale Electric Power Markets

The Task Force examined comments on how competition policy choices have affected investment decisions of buyers and sellers in wholesale markets. A number of issues emerged. One was the difficulty of raising capital to build facilities whose revenue streams are affected by changing fuel prices, demand fluctuations, and the potential for regulatory intervention. A related theme was the investment dampening effects of a perceived lack of long-term contracting options. Some commenters asserted that significant problems still exist in organized markets, including steep price increases in some locations without the moderating effect of long-term

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[200] Regulatory solutions, more so than market-based outcomes, may outlive the circumstances that made them seem reasonable.

[201] New York G&E comments; Idaho PUC comments.

[202] FERC's efforts are not limited to the organized markets, and extend to other markets as well. Also, federal and state antitrust enforcement agencies have jurisdiction to challenge anticompetitive conduct in electricity markets.

[203] NYPSC comments.

contracting and new construction.[204] Alternately, the comment was made that in some markets prices are so low that they discourage entry by new suppliers, despite growing projected demand relative to supply.[205] Overall, the Task Force identified six factors that affect investment decisions in wholesale power markets.

Commenters cited long-term contracts as a critical prerequisite in obtaining financing for new generators.[206] Both generators and consumers said they were unable to arrange long term contracts.

1. <u>Unavailability of Long-Term Supply Contracts - Wholesale Buyer Perspective</u>

Many wholesale buyers said they had sought to enter into long-term contracts but found few or no offers.[207] The Task Force attempted to determine whether the available data supported these allegations by examining 2004-2005 data collected by FERC through its Electric Quarterly Reports for three regions – New York, the Midwest, and the Southeast. Appendix E contains this analysis. Although inconclusive (due to data limitations described in Appendix E) the analysis showed that contracts of less than one year predominated in each of the three regional markets examined. In two of the markets, longer contract terms were observed to be associated with lower contract prices on a per MWh basis.

Three reasons may explain why buyers perceive they cannot enter long-term purchase power contracts.[208]

First, the APPA commented that its members in RTO regions who attempt to procure power under long-term bilateral arrangements have found it difficult to arrange contracts with base-load and mid-merit generators at prices that reflect the generators' long-term total cost structure. Base-load and mid-merit generators may see relatively high profits when gas-fueled generators are the marginal units, particularly when natural gas prices rise. Natural gas-fueled generators in a uniform price auction may see lower profits as their fuel costs rise, to the extent other generation becomes relatively more economical.[209] When natural gas units set the market price, these units may recover only a small margin over their operating costs, while nuclear and coal units recover larger margins. Under the competitive model, entry will occur if long-term prices exceed long-term costs. In fact, recent proposals for new generation show a significant number of proposals to build base-load and mid-merit generation.[210] In addition, at least some wholesale customers may have the option of investing in their own generation projects - either directly or through affiliates or joint ventures with other interested parties - if they are dissatisfied with the

204 ELCON comments; NRECA comments; APPA comments.

205 *E.g.*, PJM comments; EPSA comments.

206 Constellation comments; Mirant comments.

207 ELCON comments.

208 In competitive markets, customers also have the ability to build their own generation facility if they are unable to obtain the long-term purchase contracts that they seek.

209 *See, e.g.*, Maine Public Advocate comments; NASUCA comments.

210 The July 2006 Energy Velocity database shows that of the 165,163 MW of generation that is permitted, proposed, application-pending or has had a feasibility study performed, 110,964 MW, about two-thirds, is nuclear, combined cycle, coal-fired steam or integrated coal gasification technology (generation types typically considered base-load or mid-merit).

terms offered by incumbent suppliers. Indeed, in some regions, public power and cooperative utilities have announced plans to participate in new base-load generating plants. Because of the long lead times and considerable uncertainties involved, it will be some years before electricity from any of these plants can enter the market.

There are additional theoretical problems with the effectiveness of competition in providing investment incentives in that the very competitiveness of these markets cannot be assumed. For example, over 10 years ago, FERC requested comments on a wholesale "PoolCo" proposal, the predecessor to today's organized electricity market with open transmission access.[211] At the time, the U.S. Department of Justice generally supported the emerging market form but warned:

> The existence of a PoolCo cannot guarantee competitive pricing, since there may be only a small number of significant sellers into or buyers from the pool. The Commission should not approve a PoolCo unless it finds that the level of competition in the relevant geographic markets would be sufficient to reasonably assure that the benefits of eliminating traditional rate regulation exceed the costs.[212]

These concerns are heightened by the fact that the market-clearing price in organized exchange markets may be established by a changing subset of generators depending upon fluctuations in consumer demand and transmission congestion.[213] Indeed, some commenters specifically cited recent studies that argue that electricity markets need a larger number of suppliers to sustain competitive pricing than are needed for other commodities.[214]

A second explanation for the perceived lack of long-term purchase contracts may be related to limited trading opportunities to hedge the potential costs of long-term commitments. Long-term contracts in other commodities are often priced with reference to a "forward price curve." A forward price curve graphs the price of contracts with different maturities. The forward prices graphed are instruments that can be used to hedge (or limit) the risk that market prices at the time of delivery may differ from the price in a long-term contract. In a market with liquid forward or futures contracts, parties to a long-term contract can buy or sell products of various types and durations to limit their price risk. Currently, liquid electricity forward or futures markets often do not extend beyond two to three years.[215] In some markets, one-year contracts are the longest available. In markets where retail load is served by contracts of fixed durations, such as the three-year obligations in New Jersey and Maryland, contracts for the duration of the obligation are growing slowly in number. But the relative lack of liquidity may discourage parties from

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211 *See Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act*, Notice of Inquiry, 59 Fed. Reg. 54,851 (Oct. 26, 1994), FERC Stats. & Regs. ¶ 35,529 (1995) (FERC Docket No. RM94-20-000).

212 Comments of U.S. Department of Justice, *Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act*, at 6 (Mar. 2, 1995) (FERC Docket No. RM94-20-000). *See also* Reply Comments of the U.S. Department of Justice, *Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act* (Apr. 3, 1995) (FERC Docket No. RM94-20-000).

213 *See* Comment of the Federal Trade Commission, *Market-Based Rates for Public Utilities*, at 7-8 (Jul. 16, 2004) (FERC Docket No. RM04-7-000), *available at* http://www.ftc.gov/os/comments/ferc/v040021.pdf.

214 APPA comments; Carnegie Mellon comments.

215 Nodir Adilov, *Forward Markets, Market Power, and Capacity Investment* (2005) (Cornell Univ. Dep't of Econ. Job Mkt. Papers), *available at* http://www.arts.cornell.edu/econ/na47/JMP.pdf.

signing long-term contracts, because they lack the ability to "hedge" these longer-term obligations.

Finally, the availability of long-term purchase contracts depends on the availability and certainty of long-term delivery options (transmission). Box 3-2 above describes how transmission prices are set in organized exchange markets. Wholesale customers have argued that the inability to secure firm transmission rights for multiple years at a known price, particularly in organized markets, introduces unacceptable uncertainty in resource planning, investment, and contracting.[216] They say this financial uncertainty has hurt their ability to obtain financing for new generation projects, especially new base-load generation.

Congress addressed the issue of insufficient long-term contracting in the context of RTOs and ISOs in EPAct 2005. In particular, section 1233 of EPAct 2005 provides that:

> [FERC] shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, <u>and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs</u>.[217]

To implement this provision in RTOs and ISOs, FERC adopted new rules regarding FTRs in July 2006. The rules require such organizations to offer long-term firm transmission rights. FERC did not specify a particular type of long-term firm transmission right, but instead established guidelines for the design and administration of these rights, such as the length of terms and the allocation of those rights to transmission customers.

2. <u>Unavailability of Long-Term Supply Contracts – Generator/Investor Perspective</u>

Commenters cited long-term contracts as a critical prerequisite in obtaining financing for new generators.[218] Comments from generation investors suggested that their ability to arrange long-term contracts is inhibited by several uncertainties. Most of these uncertainties arise from the unpredictability of state and federal regulation. Finally, the nascence of market structures for the sale of electricity can make it difficult for market participants to have settled expectations about the risk of long-term contracts. A description of the uncertainties associated with regulatory risk follows.

One type of regulatory uncertainty derives from the fact that most wholesale contracts are subject to regulation by FERC, and a party to a contract can ask FERC to change prices and terms, even

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216 APPA comments; TAPS comments.

217 Pub. L. No. 109-58, § 1233, 119 Stat. 594, 958 (2005) (emphasis added).

218 Constellation comments; Mirant comments.

if the specific contract has been approved previously.[219] For example, in 2001-2002, several wholesale power purchasers asked FERC to modify certain contracts entered into during the California energy crisis. They alleged that problems in the California electricity exchange markets had caused their contracts to be unreasonable. The sellers argued that if FERC overrides existing contracts, market participants would not be able to rely on contracts when transacting for power and managing price risk. In declining to change the contracts,[220] FERC cited its obligation to respect contracts except when other action is necessary to protect the public interest.[221]

A second type of regulatory uncertainty involving bankruptcy may limit future market opportunities for merchant generators and thus reduce their ability to raise capital. In recent years, several merchant generators (NRG, Mirant and Calpine) have sought to use the bankruptcy process to break long-term power contracts.[222] This bankruptcy risk may create an additional incentive to favor construction of generation by load-serving entities or to purchase from utility affiliates over wholesale purchases from merchant generators.[223] These disputes have spawned conflicting rulings in the courts. In particular, these cases have centered on separate, but intertwined issues. First, there is a question of where jurisdiction over efforts to end power contracts properly lies, as between FERC and the bankruptcy courts, and to what extent courts may enjoin FERC from acting to enforce power contracts. Second, there is an issue of what standard applies to such efforts (what showing must a party make to rid itself of a contract). The law remains unsettled, as do parties' expectations.

A third type of regulatory uncertainty concerns regulated retail service in states with retail competition.[224] The uncertainty over how much supply a distribution utility will need to serve its customers, who have the option to switch, can prevent or discourage utilities from signing long-term contracts.[225] The extent of this disincentive is unclear if competitive options are available for distribution utilities to purchase needed supply or sell excess supply.

A fourth type of uncertainty relates to a general concern about institutional instability. Some market participants argue that they cannot count on current rules and trading mechanisms

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219 In December 2005, FERC proposed to adopt a general rule on the standard of review that must be met to justify proposed modifications to contracts under the FPA, except transmission service agreements executed under an open access transmission tariff as provided for under Order No. 888, and under the Natural Gas Act, except agreements for the transportation of natural gas executed pursuant to the standard form of service agreement in pipeline tariffs. *Standard of Review for Modifications to Filed Agreements*, Notice of Proposed Rulemaking, 71 Fed. Reg. 303 (January 4, 2006), FERC Stats. & Regs. ¶ 61,317 (2005) (Comm'r Kelly, dissenting). Specifically, FERC proposed that, in the absence of specified contractual language permitting the Commission to act on proposed modifications to an agreement on its own motion or on behalf of a signatory or non-signatory under the "just and reasonable" standard, the Commission, a signatory or a non-signatory seeking to change a contract must show that the change is necessary to protect the public interest. FERC explained that its proposal recognized the importance of providing certainty and stability in energy markets, and helped promote the sanctity of contracts. A final rule is pending.

220 *Nevada Power Company v. Enron*, 103 FERC ¶ 61,353, *order on reh'g*, 105 FERC ¶ 61,185 (2003); *Public Utilities Commission of California v. Sellers of Long Term Contracts*, 103 FERC ¶ 61,354, *order on reh'g*, 105 FERC ¶ 61,182 (2003); *PacifiCorp v. Reliant Energy Services, Inc.*, 103 FERC ¶ 61,355, *order on reh'g*, 105 FERC ¶ 61,184 (2003).

221 *See Northeast Utilities Service Co., v. FERC*, 55 F.3d 686, 689 (1st Cir. 1995).

222 *See* Howard L. Siegel, *The Bankruptcy Court vs. FERC- The Jurisdictional Battle*, 144 PUB. UTILS. FORTNIGHTLY 34 (2006).

223 Another factor creating a potential preference for self-built generation as opposed to long-term purchases is the treatment by some credit rating agencies of power purchase contracts as imputed debt. If a utility's self-built generation is treated as an asset but long-term purchase contracts are treated as imputed debt, it may cause utilities and state regulators to favor constructing and owning over purchasing. *See* EPSA comments.

224 *See infra* Chapter 4 for a discussion of regulated service offerings in states with retail competition.

225 Mirant comments; Constellation comments.

because market rules and institutions change so frequently. This can serve to deter new entry.[226] At the same time, many market participants continue to advocate changes in regulatory policy, even long-settled policy.

3. Capital Requirements - Risk and Reward in the Face of Price and Cost Volatility

New generation construction in wholesale markets depends on the ability of a company to acquire capital, either from internal sources or external capital markets. There is no federal regulation of generation entry, and most states that have permitted retail competition have eliminated any "need-based" showing to build a generation plant.

In the United States, private capital has funded most electric generation investment. Under traditional cost-base rate regulation, utility investment decisions were based in part on the promise of a regulated revenue stream with little associated risk to the utility. Ratepayers often bore the risk, and money from capital markets was generally available when utilities needed to fund new infrastructure. One significant problem, however, was that regulators had limited ability to ensure that utilities spent their money wisely.[227] Investors view regulatory disallowances of imprudent expenditures as regulatory risk. Some believe that Integrated Resource Planning processes with opportunities for public and regulator participation in advance of resource procurement decisions will reduce the risks of later regulatory disallowances.[228]

In competitive markets, project funding is based on anticipated market-based projections of costs, revenues, and relevant risks factors. The ability to obtain funding is impacted by the degree to which these projections compare with projected risks and returns for other investment opportunities.[229] Using this information, potential entrants to generation markets must be able to convince capital markets that new generation is a viable profitable undertaking. In the late 1990s, investors appeared to prefer market investments to cost-based rate-regulated investments, as merchant generators were able to finance numerous generation projects, even without a contractual commitment from a customer to buy the power.[230]

Recently, capital for large investment projects has flowed to traditional utilities more than to merchant generators.[231] In part, this preference reflects the reduced profitability of many merchant generators in recent years and the relative financial strength of many traditional utilities. It also may reflect a disproportionate impact of the collapse of credit and thus trading capability of nonutilities after Enron's financial collapse.[232] As shown in the Table in Appendix G, virtually all electric companies rated A- or higher are traditional utilities, not merchant generators.

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[226] Paul L. Joskow, *Competitive Electricity Markets and Investment in New Generating Capacity* (April 28, 2006) (MIT Working Paper).

[227] CONG. BUDGET OFFICE, FINANCIAL CONDITION OF THE U.S. ELECTRIC UTILITY INDUSTRY (1986), *available at* http://www.cbo.gov/showdoc.cfm?index=5964&sequence=0.

[228] Southern comments; Duke comments.

[229] Commodity Futures Trading Commission, *The Economic Purpose of Futures Markets, available at* http://www.cftc.gov/opa/brochures/opaeconpurp.htm.

[230] APPA comments.

[231] Task Force Meetings with Credit Agencies, *see* Appendix B.

[232] GAO, *Restructured Electricity Markets, Three States' Experiences* at 13.

Investor preference for traditional utilities also may be affected by increasing volatility in electric power markets. As wholesale markets opened to competition, investors recognized that income streams from the newly-built plants would not be as predictable as in the past.[233] Under cost-based regulation, vertically integrated utilities' monopoly service territories significantly limited the risk of not recovering the costs of investments. Once generators had to compete for sales, generation plant investors were no longer guaranteed that construction costs would be repaid or that the output from plants could be sold at a profit.[234] Financing was easier to obtain for projects such as combined cycle gas and particularly gas turbines that can be built relatively quickly. At the time, they were thought to have a cost advantage over existing generation, including less efficient gas-fueled generators.[235] In 1996, the EIA projected that 80 percent of electric generators between 1995 and 2015 would be combined cycle or combustion turbines.[236] Base-load units, such as coal plants, with construction and payout periods that would put capital at risk for a much longer time, were harder to finance.[237]

The increasing amount of new generation fueled by natural gas, however, has caused electricity prices to vary more frequently as natural gas is a commodity subject to wide swings in price.[238] With input costs varying widely, but merchant revenues often limited by contract or by regulatory price mitigation, investors may worry that merchant generators may not recover their costs and provide an attractive rate of return. Commenters suggest that competitive suppliers are beginning to focus on developing facilities fueled by other sources. They cite 2006 announcements by NRG Energy, Inc. (investing $16 billion to develop 10,500 MW of nuclear, wind, and coal facilities), TXU (investing in multiple coal-fired plants), Constellation Energy and Exelon Corp. (developing a nuclear plant), BP and Edison Mission Group (investing $1 billion in a hydrogen-fueled plant), and AES (investing $1 billion in renewable technologies).[239]

4. Regulatory Intervention May Affect Investment Returns

Economic theory says that, in an unregulated world, needed generation investments will be made and generation investors will recover not only their variable and fixed costs but also make an adequate return on these needed investments to maintain long-term financial viability. The mechanism for this cost recovery of the correct level of generation investment is allowing the highest cost generator being dispatched at a particular time and place to determine the market clearing price. The mechanism works as follows: As resources become scarce relative to demand, market prices are set by more and more expensive resources. Generators with variable

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233 Connecticut DPUC comments.

234 GAO, *Restructured Electricity Markets, Three States' Experiences* at 13.

235 U.S. Department of Energy, Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, at 38 (December 1996), *available at* http://tonto.eia.doe.gov/FTPROOT/electricity/056296.pdf.

236 *Id.*

237 *Hearing on Nuclear Power, Before the Subcomm. on Energy of the S. Comm. on Energy & Nat'l Res.* (Mar. 4, 2004) (statement of Mr. James Asselstine, Managing Director, Lehman Brothers). *See also* Nuclear Energy Institute, *Investment Stimulus for New Nuclear Power Plant Construction: Frequently Asked Questions*, *available at* http://www.nei.org/documents/New_Plant_Investment_Stimulus.pdf.

238 *Natural Gas Factors Affecting Prices and Potential Impacts on Consumers: Testimony Before the Permanent Subcommittee on Investigations, Committee on Homeland Security and Governmental Affairs*, United States Senate; GA-06-420T (Feb. 13, 2006), at 7.

239 EPSA comments.

costs below the market clearing price receive “scarcity rents” that cover their fixed costs and provide a return on investment. If high prices in a particular energy market reflect scarcity, these economic rents generally are efficient and serve to provide incentives for construction.

However, regulators may limit recovery of high prices during these periods due to the unpalatability of even temporarily high prices and/or suspicion of inappropriate market gaming. Thus regulators may deter suppliers from making needed investments in new capacity by imposing price caps and limiting recovery of legitimate costs and delivery of adequate returns.

This dynamic leads to a chicken-and-egg conundrum: if there were efficient investment, wholesale price or bid caps might not be needed. More investment in capacity would lead to less scarcity, and thus fewer or shorter episodes of high prices that may require mitigation. By contrast, it may be that price regulation during high-priced hours diminishes investors' confidence that market forces (rather than regulation) will set prices. That diminished confidence in their ability to earn sufficient investment returns thus deters entry of new generation supply, thereby limiting competition and giving cause for price caps.

Price mitigation through price or bid caps has become an integral component of most organized markets. The use of price mitigation has led generators to seek adequate returns through implementation of supplemental revenue streams (capacity credits) to encourage entry of new supply. See Box 3-3 for a discussion of capacity credits. In practice, however, the presence or absence of capacity credits has not always resulted in predicted outcomes. California did not have capacity credits and did not experience much new generation, but two regions (Southeast and Midwest) experienced significant new generation entry without capacity credits. Northeast RTOs with capacity credits continue to have some difficulty attracting entry, especially in major metropolitan areas.

Box 3-3
The Use of Capacity Credits in Organized Wholesale Markets

In theory, capacity credits could support new investment because suppliers and their investors would be assured a certain level of return even on a marginal plant that ran only in times of high demand. Capacity credits might allow merchant plants to be sufficiently profitable to survive even in competition with the generation of formerly-integrated local utilities that may have already recovered their fixed costs.

As noted, much of the new generation in the Southeast was nonutility merchant generation that relied on the region's proximity to natural gas supplies. In the Midwest, in the late 1990s, largely uncapped prices were allowed to send price signals for investment. In California, price caps of various kinds have been used for a number of years, limiting price signals for new entry. In the Northeast, organized markets have offered capacity payments for long-term investments in addition to electric power prices that are sometimes capped in the short term. There is no conclusive result from any of these approaches – no one model appears to be the perfect answer for how to spur efficient investment with acceptable levels of price volatility.

Net revenue analyses for centralized markets with price mitigation suggest that price levels are inadequate for new generation projects to recover their full costs. For example, in the last several years, net revenues in the PJM markets have been, for the most part, too low to cover the full costs of new generation in the region.[240] Based on 2004 data, net revenues in New England, PJM and California would have allowed a new combined-cycle plant to recover no more than 70 percent of its fixed costs.

Regulation also may interfere with efficient exit of generation plants due to the use of reliability-must-run requirements. In some load pockets in organized markets, plant owners are paid above-market prices to run plants that are no longer economical at the market-clearing price. For example, in its Reliability Pricing Model filing with FERC, PJM states, "PJM also has been forced to invoke its recently approved generation retirement rules to retain in service units needed for reliability that had announced their retirement. As the Commission often has held, this is a temporary and suboptimal solution. Such compensation, like the RMR contracts allowed elsewhere, is outside the market, and permits no competition from, and sends no price signals to, other prospective solutions (such as new generation or demand resources) that might be more cost effective."[241] To the extent that market rules allocate the cost of keeping these plants running for customers outside of the load pocket, such payments may distort price signals that, in the long run, could elicit entry. Graduated capacity payments that favor entry of efficient plants may be a partial solution to retiring inefficient old plants.

5. Investment in Transmission: A Necessary Adjunct to Generation Entry

Transmission access can be vital to supporting competitive options for market participants. For example, merchant generators depend on the availability of transmission to sell power, and transmission constraints can limit their range of potential customers. Small utilities, such as many municipal and cooperative utilities, depend on the availability of transmission to buy wholesale power, and transmission constraints can limit their range of potential suppliers. Much of the transmission grid is owned by vertically-integrated, investor-owned utilities. Some have alleged that these utilities have an incentive to limit grid use by others to the extent that such use conflicts with sales by their own generation. In short, the availability of transmission is often key in determining whether a generating facility is likely to be profitable and, thus, elicit investment.

Since Order No. 888, questions have arisen concerning the efficacy of various terms and conditions governing transmission availability. For example, customers have raised concerns regarding the calculation of Available Transfer Capacity (ATC). Another concern has been a lack of coordinated transmission planning between transmission providers and their customers. Finally, customers have raised concerns about some aspects of transmission pricing. Based on these concerns, in May 2006 FERC proposed modifications to Order 888 open access transmission tariffs to further limit undue discrimination in transmission services. FERC is soliciting public comments on its proposed modifications.

[240] Occasionally in the past few years net revenues have been sufficient to cover the costs of new peaking units, and in 2005 they were enough to cover the costs of a new coal plant. PJM Interconnection, LLC, Market Monitoring Unit, *2005 State of the Market Report*, at 118 (2006), *available at* http://www.pjm.com/markets/market-monitor/som.html

[241] *PJM Interconnection*, 115 FERC at 61,236.

As discussed above, generation that is built where construction costs are low and fuel supplies readily available, but not necessarily near demand, relies heavily on readily available transmission. The Connecticut DPUC noted that, while generation growth may have been sufficient for some regions such as New England as a whole, some localized areas saw demand grow without increases in supply, raising prices in load pockets. If transmission access to the load pocket were available, a large base-load plant outside the load pocket might become an attractive investment.

Less regulatory intervention in wholesale markets for generation may be necessary if transmission upgrades, rather than unrestricted high prices or capacity credits, are used to address the concerns about future generation adequacy. Although capacity credits may spur generators within a load pocket to add additional capacity, capacity credits may not be required for base-load plants outside the load pocket. Those base-load plants would not have the problem of average revenues falling below average costs because they would have access to more load, and would be able to run profitably during more hours of the day. Similarly, price caps may be unnecessary if improved transmission brought power from more base-load units into the congested areas. Prices would be lower because there would be less scarcity, and high-cost units would run for fewer hours.

6. Some Types of Generation Investment May Not Be Adequate without Government Intervention

System reliability, the prevention of network collapse, is a public good.[242] The market may not elicit enough generation that has the technical capability (i.e., the ability to generate MWs within a very short period of time in a critical location) to prevent network collapse. An administrative process may be needed to provide the correct level of generation technically capable of responding to reliability needs. Some argue that perceived inadequate generation entry[243] may be due to competitive policies that are inadequate for eliciting appropriate levels of technically capable generation.

7. The Level of Investment in Demand Response Can Affect the Need for Generation and Transmission Investment

Chapter 2 described the typical disconnect between wholesale and retail prices in electric markets. This disconnect can lead to wider price fluctuations than would be the case if customers could easily reduce their demand when prices rise. There are several means to influence the level of demand for power, including energy efficiency and demand response. Examples of energy efficiency include giving customers incentives to replace inefficient refrigerators and air conditioners and imposing appliance standards or more energy-efficient

[242] Public goods have two characteristics – "nonexclusiveness" and "nonrivalry." Nonexclusiveness means that others cannot be excluded from the use of the good (e.g., if one person refuses to pay taxes, that person still can enjoy public parks) and nonrivalry implies that one person's consumption of the good does not diminish another person's consumption (e.g., the fact that one person enjoys the increased safety engendered by military spending doesn't decrease another person's safety.) "Preventing network collapse" is nonexclusive because if the network collapses there is nothing one can do to escape it (unless one constructs freestanding on-site generation) and it is nonrivalrous because one person being protected from collapse does not preclude another person's being protected.

[243] Joskow, *op. cit.*

building codes. Tools for eliciting demand response include time-based rates and incentive-based programs. Time-based rates include time-of-use pricing (i.e., a peak price and an off-peak price), critical peak pricing (i.e., similar to time-of-use rates, but with a critical peak component invoked during system emergencies or periods of high wholesale prices), and real-time pricing (e.g., Georgia Power's RTP tariff). Incentive-based demand response programs include interruptible rates, air-conditioner cycling, and independent system operator emergency demand response programs.

By influencing demand, energy efficiency and demand response programs can affect pricing in the short term and in the long term by affecting the amount of generation and transmission needed as well as the composition (i.e., composition of base load, mid-merit and peaking generation) of investment. For instance, programs that aim to reduce electricity consumption that is fairly constant – such as refrigerator efficiency programs – reduce the need for base-load plants. Similarly, programs that improve the efficiency of appliances that contribute to peaking load (i.e., air conditioners) can reduce demand for mid-merit generation. Demand response programs that curtail demand at peak times may resolve constraints that cause load pockets. Even when constraints persist, demand response can also serve to reduce prices in load pockets whether these high prices are the result of scarcity rents or market power. DSM also holds the potential to defer the need for new transmission enhancements. To date, energy efficiency has provided important benefits, but additional capability can be achieved. Demand response capability has been modest, between 3 and 7 percent in most regions.[244] The use of energy efficiency and demand response is expected to increase significantly in the next few years, especially after advanced smart metering is installed.

[244] Federal Energy Regulatory Commission, *Staff Report on the Assessment of Demand Response and Advanced Metering* (August 2006).

CHAPTER 4
COMPETITION IN RETAIL ELECTRIC POWER MARKETS

A. Introduction and Overview

This chapter examines the development of competition in retail electricity markets and discusses the status of competition in the 16 states and District of Columbia that currently allow customers to choose their electricity supplier.[245]

Although it has been almost a decade since states started implementing retail competition, residential customers in most of these states still have little choice among suppliers. In most of these states, few residential customers have a wide variety of alternative suppliers and pricing options. Commercial and industrial (C&I) customers have more choices and options, but in several states large industrial customers have become increasingly dissatisfied with retail prices.

The lack of incentives for alternative suppliers and marketers to enter the market at the retail level has been a major impediment to market-based competition. Most states required the distribution utility to offer electricity at a regulated price as a backstop or default if the customer did not choose an alternative supplier or if the chosen supplier went out of business.[246] States argued that this was needed to ensure universal access to affordable and reliable electricity.

States often set the price for the regulated service at a discount below then-existing rates and capped the price for multi-year periods. In some states, these initial discounts sought to approximate anticipated benefits of competition for residential customers. Since then, wholesale prices have increased. More than any other policy, this requirement that distribution utilities offer service at low prices unwittingly impeded entry by alternative suppliers to serve retail customers. New entrants cannot compete against a below-market regulated price.

States with prices regulated at below-market levels now face "rate shock." On the one hand, rate caps for the regulated service most residential customers use expired or will expire within a few years, and states are faced with raising their regulated customer rates. These higher prices are particularly painful to customers that have limited ability to adjust consumption in response to price increases and also lack competitive supply options (other than possibly to install their own onsite generation). On the other hand, if states continue to require distribution utilities to offer

[245] The Task Force adopts the convention of designating states as permitting retail competition on the basis of whether a state allows alternative suppliers to enter and obtain multiple, geographically dispersed customers. An even broader potential definition of retail competition would take into account policies that allow individual retail customers to provide some or all of their own generation needs (*i.e.,* to make rather than buy electricity). Onsite generation is common in some industries in some sections of the country. Small onsite generation projects – often referred to as "Distributed Generation" or "Distributed Resources" projects – are gaining popularity as well. Many states that do not have retail choice in the conventional sense do have provisions for various forms of onsite generation and net metering. Another broader form of retail competition involves municipal utilities or cooperatives. NRECA comments (2). These entities can be carved out of existing private utility distribution areas, or can be added back into them if the municipality decides to do so (or if the cooperative disbands). The *Otter Tail Power* case, 410 U.S. 366 (1973), was decided on the basis of this form of retail competition. If these broader definitions of "retail competition" were used, all (or nearly all) states would be designated as retail competition states.

[246] In this report, the Task Force refers to state-mandated and -regulated electrical service in states with consumer choice programs as POLR service. A broad range of terms is used in different states to denote this type of service. Some states have more than one form of mandated service or have changed the form of POLR service over time. In many states, POLR service originated as an element in arrangements to pay the stranded (*i.e*., non-recovered) costs of vertically integrated utilities – costs that may have become unrecoverable when the state adopted a retail customer choice approach.

regulated service at below-market rates, then retail entry – and thus competition – will not occur. Moreover, below-market rates put the distribution utility's solvency at risk and do not provide appropriate incentives for conservation.[247]

This conundrum is further complicated by the fact that most distribution utilities offering regulated service no longer own generation assets. Most of the supply contracts that were part of the agreements under which they divested generating assets were set to expire at the end of a finite transition period.[248] Many distribution utilities sold or transferred their generation assets to unregulated affiliates when retail competition began. If they offer regulated service, they must purchase supply in wholesale markets. Their former generation assets may be more expensive now than when they were divested. If the utility repurchases these assets at current prices, it is likely to have "sold low and bought high."

The competitiveness of wholesale prices directly affects retail prices,[249] except where retail prices are set by regulation without regard to current wholesale prices. For example, retail prices usually will reflect imperfections in the wholesale market, such as some wholesale suppliers' ability to exercise market power,[250] problems in market design that increase wholesale suppliers' costs, government subsidies to some suppliers for reasons other than addressing market failures, transmission discrimination that prevents low-cost suppliers from reaching customers, or restrictions that delay or prevent entry and diffusion of low-cost generation technologies. Distortions in wholesale prices that lead to distortions in retail prices can cause economic inefficiencies both in retail customers' consumption patterns and in investment decisions. Ultimately these distortions can reduce consumer welfare and raise private and social costs of producing goods made with electricity as an input.

This chapter addresses the status and impact of retail competition in seven states that the Task Force examined in detail: Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas.[251] These states represent the various approaches to retail competition.[252] The chapter also discusses why it is difficult to determine whether retail prices

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247 Debt rating agencies may downgrade the creditworthiness of utilities in states that require utilities to sell at prices below their costs. For example, Moody's Investors Services reportedly has downgraded the creditworthiness of utilities in Maryland – in particular, Baltimore Gas & Electric, due to that firm's inability to pass on increased input costs to consumers, which "leaves BGE in a weakened state that makes it vulnerable to further downgrades and even insolvency if it faces further energy price shocks or other costs that the legislature deems cannot be passed on to customers." Patricia Hill, *Maryland Utilities Designated Near Junk*, WASH. TIMES (July 12, 2006), *available at* http://www.washingtontimes.com/functions/print.php?StoryID=20060711-103048-5690r.

248 In most retail customer choice states, supply contracts (vesting contracts) have been used to enable distribution utilities to offer POLR service at the capped price level after they have divested generating plants or transferred them to unregulated affiliates. The "rate shock" anticipated in these states is due in part to the lack of laddering in the vesting contracts beyond the end of the transition period, as defined in the legislation. There are two exceptions worth noting. In California, vesting agreements were de-emphasized in favor of procurement at spot market prices. In upstate New York, vesting agreements were longer term and continue to have a moderating effect on average procurement prices for POLR service. Public Utility Law Project of New York comments (2) at 36.

249 Several commenters emphasized the potential spillovers from problems at the wholesale level to the retail level, including NYPSC comments (2) at 3-4; APPA comments (2) at 4, 21-25; New York Companies comments (2) at 2, 4-5; Direct Energy comments (2) at 7; Alliance for Retail Energy Markets comments (2) at 3-4; Industrial Consumers comments (2) at 9-10, 21-22; Allegheny comments (2) at 15, 19.

250 Retail competition and options for onsite generation can provide opportunities for a customer to find alternative supply sources, including self-generation, if the customer's present supplier tries to raise prices above the competitive level (*i.e.*, attempts to exercise market power).

251 *See* Appendix D *infra* for each state profile.

252 Restructured states as of May 2006 include Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia, plus the District of Columbia. The states profiled in Appendix D display a range of conditions that are similar to the other states with retail competition. Virginia is similar to Pennsylvania in that its transition to retail competition evolved over a 10-year period. Maine and Rhode Island are similar to New York and Texas in that prices for are higher or lower than they would have been absent the move to retail competition. Also included are several observations based on experiences of states that have implemented retail competition, with an emphasis on how states can minimize market distortions once rate caps expire.

B. Background on Provision of Electric Service and the Emergence of Retail Competition

For most of the 20th century, local distribution utilities typically offered electric service at rates that varied among customer classes (e.g., residential, commercial, and industrial). State regulatory bodies set these rates based on the utility's costs. Locally elected boards oversaw the rates for customers of public power and cooperative utilities. For investor-owned systems, the regulated rate included an opportunity to earn an authorized rate of return on investments in utility plants needed to serve customers. Public power and cooperative systems operate under a nonprofit, cost-of-service structure. Their rates typically include a margin to cover unanticipated costs and support new investment.

With minor variations, monopoly distribution utilities deliver electricity to retail customers.[253] Industrial customers sometimes can choose from more options than can small business and residential customers for service and rate structures (e.g., "time-of-use" rates, which are lower when demand is lower during "off-peak" periods).[254]

Beginning in the early 1990s, several states with high electricity prices began to explore opening retail electric service to competition. As discussed in Chapter 1 and Figure 4-1, rates varied substantially among utilities, even within a single state. Some of the disparity was due to different natural resource endowments across regions, the most important of which are the hydroelectric resources in the Northwest and the abundant coal reserves in such states as Kentucky and Wyoming. Moreover, some states required utilities to enter into PURPA contracts at prices much higher than the utilities' avoided costs. In addition to these rate disparities, some industrial customers contended that their rates subsidized lower rates for residential customers.

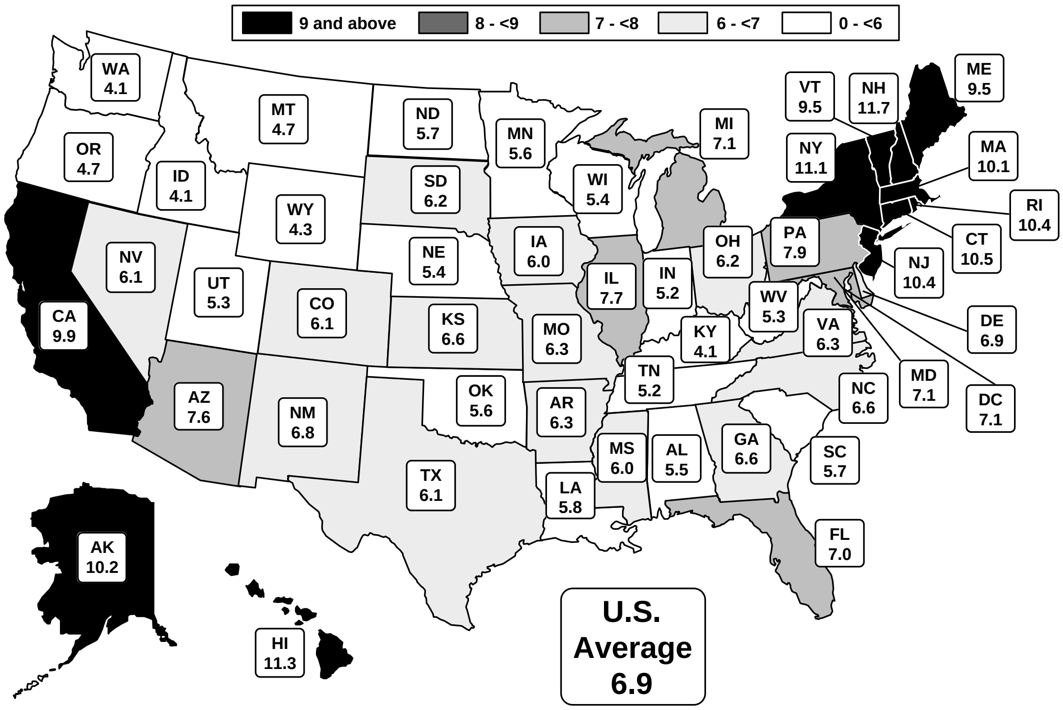
"provider of last resort" (POLR) service have been adjusted regularly to reflect changes in wholesale prices. Delaware, the District of Columbia, Illinois, Michigan, New Hampshire, Ohio, and Rhode Island share the situation faced by Maryland, where the transition period of fixed prices for residential and small C&I POLR service will end in the near future. Massachusetts's rate cap period ended recently. Many of the states poised to end the transition period are developing approaches to bring POLR prices for residential and small C&I customers up to market rates in stages rather than all at once. Several of these states also share Maryland's and New Jersey's interest in auctions for procuring POLR service supplies. Oregon's situation differs from the other states in that only nonresidential customers can shop, and that shopping is limited to a short window of time each year.

[253] Retail electric customers in 30 states continue to receive service almost exclusively under a traditional regulated monopoly utility service franchise. These states include 44 percent of all U.S. retail customers, accounting for 49 percent of electricity demand.

[254] For example, Georgia law allows any new customers with loads of 900 kilowatts or more to make a one-time selection from among competing eligible electric suppliers. Southern comments.

Figure 4-1. U.S. Electric Power Industry, Average Retail Price of Electricity by State, 1995

Cents per kWh



Source: EIA, *The Changing Structure of the Electric Power Industry*, Figure 11 (Dec. 1996).

Retail competition allowed customers to choose their electric supplier or marketer, but their electricity would still be delivered by the local distribution utility.[255] The idea was that customers could obtain electric service at lower prices if they could choose among suppliers. For example, they could buy from suppliers outside their local market, from new entrants into generation, or from power marketers, any of which might charge lower prices than the local distribution utility. The ability to choose among alternative suppliers was intended to reduce market power that local suppliers might otherwise have, so that customers might see lower prices from local suppliers. Also, it was thought that new suppliers might offer innovative price and other terms to purchase electricity that could improve the quality of service.

In 1996, California enacted a comprehensive electric restructuring plan to allow customers to choose their electricity supplier. To accommodate retail choice, California extensively restructured its electric power industry. The legislation:

(1) established an Independent System Operator (ISO) to operate the transmission grid throughout much of the state, so that all suppliers could access the transmission grid to serve their retail customers;

[255] FERC and the states will continue to regulate the price for transmission and distribution services, and the local distribution utility will continue to deliver the electricity in most states, regardless of which generation supplier the customer chooses.

(2) established a separate wholesale trading market for electricity supply, so that utilities and alternative suppliers could purchase electricity to serve their retail customers;
(3) mandated an immediate 10 percent rate reduction for residential and small commercial customers that did not choose an alternative supplier;
(4) authorized utilities to collect stranded costs related to generation investments that were unlikely to be as valuable in a competitive retail environment; and
(5) implemented an extensive public benefits program funded by retail ratepayers.[256]

Other states also enacted comprehensive retail competition legislation: New Hampshire (May 1996), Rhode Island (August 1996), Pennsylvania (December 1996), Montana (April 1997), Oklahoma (May 1997), and Maine (May 1997). By January 2001, 22 states and the District of Columbia had adopted retail competition legislation. Regulatory commissions in four other states (including Arizona, which also enacted legislation) had issued orders requiring or endorsing retail choice for retail electric customers.

Several states – primarily those with low-cost electricity generation, such as Alabama, Colorado, North Carolina, and Wisconsin – concluded that retail competition would not benefit their customers.[257] For example, Colorado was concerned that limitations on transmission access and high concentration among generation suppliers would lead suppliers to exercise market power to the detriment of customers. These states opted to keep traditional utility service.

States adopting retail competition plans generally did so to advance several goals, including:

- lower electricity prices than under traditional regulation through access to lower-cost power in competitive wholesale markets where generators compete on price and performance;
- better service and more options for customers through competition from new suppliers;
- innovation in generating technologies, grid management, use of information technology, and new products and services for consumers; and
- improvements in the environment through displacement of dirtier, more expensive generating plants with cleaner, cheaper natural-gas-fired and renewable generation.

Under the restructured model, legislatures and regulators affirmed their support for making electricity available to all customers at reasonable rates, with continued safe and reliable service and consumer protections under regulatory oversight. Boxes 4-1 and 4-2 describe the Pennsylvania and New Jersey legislatures' findings and the expected results of retail competition.

[256] A.B. No. 1890, 1995-1996 Sess. (Cal. 1996) (enacted), *available at* http://www.leginfo.ca.gov/pub/95-96/bill/asm/ab_1851-1900/ab_1890_bill_960924_chaptered.pdf.

[257] Wisconsin regulators apparently believed that retail competition might increase the cost of capital for new generation and transmission projects. PSC Wisconsin Comments (2) at 3.

Box 4-1
Findings of the Pennsylvania Legislature

The findings of the Pennsylvania General Assembly demonstrate these varied goals:

(1) Over the past 20 years, the federal government and state government have introduced competition in several industries that previously had been regulated as natural monopolies.
(2) Many state governments are implementing or studying policies that would create a competitive market for the generation of electricity.
(3) Because of advances in electric generation technology and federal initiatives to encourage greater competition in the wholesale electric market, it is now in the public interest to permit retail customers to obtain direct access to a competitive generation market as long as safe and affordable transmission and distribution is available at levels of reliability that are currently enjoyed by the citizens and businesses of this Commonwealth.
(4) Rates for electricity in this commonwealth are on average higher than the national average, and significant differences exist among the rates of Pennsylvania electric utilities.
(5) Competitive market forces are more effective than economic regulation in controlling the cost of generating electricity.

Source: Pennsylvania HB 1509 (1995), *available at* http://www.legis.state.pa.us/WU01/LI/BI/BT/1995/0/HB1509P4282.HTM

Box 4-2
Findings of the New Jersey Legislature

"The [New Jersey] Legislature finds and declares that it is the policy of this State to:

(1) Lower the current high cost of energy, and improve the quality and choices of service, for all of this State's residential, business and institutional consumers, and thereby improve the quality of life and place this State in an improved competitive position in regional, national and international markets;

(2) Place greater reliance on competitive markets, where such markets exist, to deliver energy services to consumers in greater variety and at lower cost than traditional, bundled public utility service; . . .

(4) Ensure universal access to affordable and reliable electric power and natural gas service;

(5) Maintain traditional regulatory authority over non-competitive energy delivery or other energy services, subject to alternative forms of traditional regulation authorized by the Legislature;

(6) Ensure that rates for non-competitive public utility services do not subsidize the provision of competitive services by public utilities; . . ."

C. Meltdown and Retrenchment

From late spring 2000 and into the spring of 2001, California experienced high natural gas prices, a strained transmission system, and generation shortages (due to hydro shortages and operating restrictions) that resulted in blackouts. Wholesale electricity prices soared during this time. Existing state law had capped residential "provider of last resort" (POLR) service rates at levels that were soon below the market price for wholesale electric power. After a large investor-owned utility declared bankruptcy because it was unable to increase its retail rates to cover high wholesale power prices, the state stepped in to buy electricity on behalf of two of the state's three IOUs.[258] California eventually suspended retail competition for most customers while it reconsidered how to assure adequate electric supplies and continuation of service at affordable rates in a competitive wholesale market environment. Although that suspension continues today, 12 percent of load in the state is supplied by alternative suppliers, some additional consumers remain eligible to switch to alternative suppliers, and new initiatives for municipal aggregation are being pursued.[259] Box 4-3 describes California's role in purchasing electricity and the all-time-high prices it paid, and continues to pay.

Box 4-3
California's Electricity Purchases at All-Time-High Prices

In 2001, California spent over $10.7 billion to purchase electricity on the spot market to supply customer's daily needs. The state also signed long-term contracts worth approximately $43 billion for10 years. These contracts represented about one-third of the three utilities' requirements for the same period (2001–2011). Viewed with the benefit of perfect hindsight, the state entered these long-term contracts when prices were at an all-time high. Future prices hovered in the range of $350-$550 per MWh during the time California negotiated its long-term contracts, and in April future prices peaked at $750/MWh as the state finalized its last contract. By August 2001, future prices had dropped below $100. Thus, as of May 2006, the state is obligated to pay well over market prices for at least five more years. *See* Southern California Edison.

The California experience sent ripple effects throughout the Western region and prompted several states to defer or abandon efforts to implement retail competition. No new states have adopted retail competition since 2000, and some states – including Arkansas and New Mexico – repealed retail competition plans they previously had adopted.

Other populous states, such as Illinois, New Jersey, New York, Pennsylvania, and Texas, moved ahead with retail competition. Some of these states ended, or are about to end, their POLR

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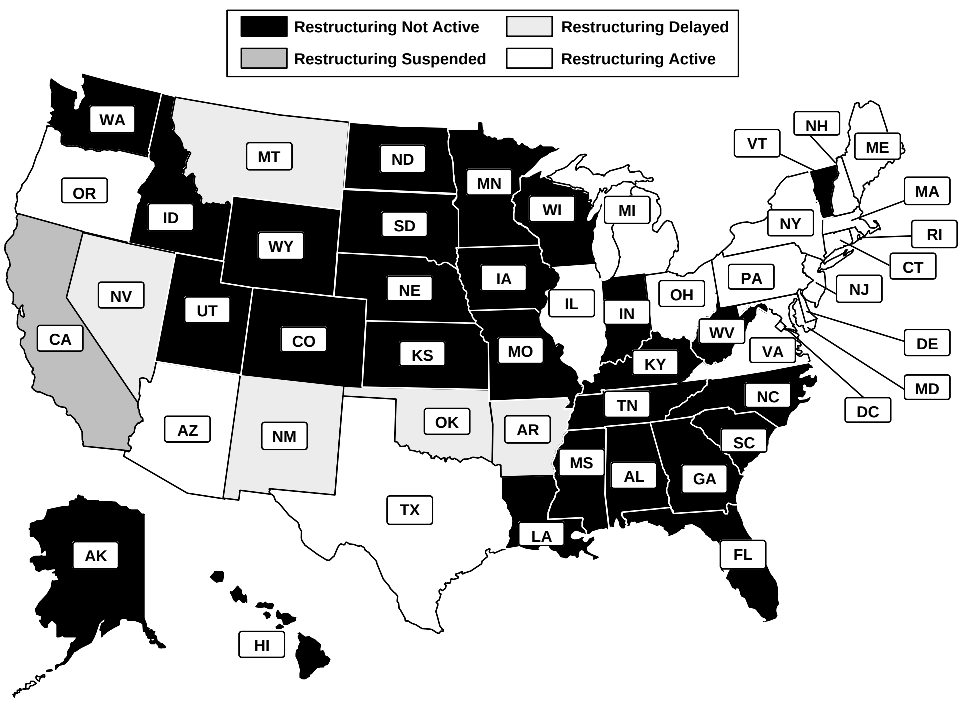
[258] *See, e.g.*, Cal. Atty Gen. White Paper; Federal Energy Regulatory Commission, *Final Report on Price Manipulation in Western Energy Markets: Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices* (March 26, 2003) (Docket No. PA02-2-000); U.S. General Accounting Office, *Restructured Electricity Markets, California Market Design Enabled Exercise of Market Power* (June 2002), *available at* http://www.gao.gov/new.items/d02828.pdf.

[259] CPUC comments; Alliance for Retail Energy Markets comments (2).

service rate caps and will soon purchase wholesale supplies for POLR service at market prices (although several of these states are developing approaches to slow the adjustment to market-based procurement). States such as New York and Texas, which have adjusted POLR prices to approximate market rates on an ongoing basis, do not face a potentially significant increase in POLR service prices.

As shown in Figure 4-2, 16 states and the District of Columbia have restructured at least some electric utilities in their states and allow at least some retail customers to purchase electricity directly from competitive retail suppliers. Restructured states as of April 2006 include Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia, as well as the District of Columbia.

Figure 4-2. United States Map Depicting States with Retail Competition, 2003



Source: EIA, *available at* http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf

D. Experience with Retail Competition

With the expected benefits of retail competition in mind, the Task Force examined seven states in depth. These "profiled states" – Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas – represent the different approaches to retail competition.

In most profiled states, competition has not developed as expected for all customer classes. In general, few alternative suppliers currently serve residential customers. Where there are multiple suppliers, prices have not decreased as expected, and the range of new options and services often is limited. Development of retail competition has been impeded to a considerable extent by the fact that several states still have capped residential POLR rates. C&I customers generally have more choices in both suppliers and of customized services, than do residential customers.[260] However, most large C&I customers do not have the option to take POLR service at discounted, regulated rates. Alternative suppliers may find C&I customers to be more attractive because the ratio of sales to marketing costs is often perceived to be higher for these customers.

This section reviews the status of retail competition in the profiled states, with an emphasis on entry of new suppliers, migration of customers to alternative suppliers,[261] and the difficulty of drawing conclusions about the effect of retail competition on prices due to the capped POLR service.[262] It then discusses how regulated POLR service has distorted entry decisions by alternative suppliers. Lessons learned from the use of POLR that may assist states as they decide how to structure future POLR service are included.

1. States Have Allowed Distant Suppliers to Access Local Customers and Have Encouraged Distribution Utilities to Divest Generation

Each profiled state adopted measures to encourage entry of new suppliers to compete with the incumbent utility. Each adopted policies to allow suppliers other than the local distribution utility to gain access to retail customers by requiring the utilities to join an ISO or an RTO. As discussed in Chapter 3, larger geographic markets for wholesale electricity enable retail suppliers and marketers to buy generation supplies from a wider range of local and distant sources (e.g., neighboring utilities with excess generation, independent power producers, cogenerators, etc.). Even if no new generation facilities are built, independent operation and management of the transmission grid increases retail customers' choices and makes it more difficult for local generators to exercise market power.

Some states, including Massachusetts, New Jersey, and New York, ordered or encouraged utilities to divest generation assets to independent power producers (IPP) to eliminate possible transmission discrimination or to secure accurate stranded cost valuations.[263] Although these divestitures generally did not require a utility to sell its generation assets to more than one company to eliminate the potential for the exercise of market power, generating facilities frequently have been sold to more than one IPP.[264] In other states, such as Illinois and

[260] Many alternative suppliers reportedly have developed customized time-of-use and other forms of energy management contracts for large C&I customers. Wal-Mart comments at 10-11; Commercial End-Users comments at at 3; Direct Energy comments (2) at 3.

[261] The degree to which customers switch to alternative suppliers sometimes is used to measure the extent of retail competition. States with retail customer choice usually report these switching statistics. This can be a useful measure when the greatest concern is that the POLR service provider is obstructing switching, or that certain features of regulation (including lack of information about the retail choice process and below-market pricing of POLR service) are discouraging entry and active consumer shopping for electricity service. Another way to gauge the success of retail competition policy is to survey consumers about their awareness of retail choices and perceptions of the difficulty of switching between suppliers. However, surveys are expensive and results are not available systematically. More generally, consumers can obtain the benefits of competition if existing competition, entry, or the threat of entry prevents incumbent suppliers from exercising market power manifested in the form of higher prices, lower product quality, or reduced innovation. In this sense, retail competition could be effective even without any switching to alternative suppliers. NASUCA comments (2).

[262] There is no reason to believe, however, that retail competition in this market will not function as competition does in any market, by reducing quality-adjusted prices.

[263] *See infra* Massachusetts, New Jersey, and New York profiles, Appendix D. See also Federal Trade Commission, Staff *Report on Competition and Consumer Protection Perspectives on Electric Power Regulation Reform: Focus on Retail Competition*, at 43 (2001), *available at* http://www.ftc.gov/reports/elec/electricityreport.pdf [hereinafter *FTC Retail Competition Report*].

[264] The prices of generation assets have been volatile since these divestitures occurred. Asset prices often are keyed not only to the cost of the fuel necessary to generate the electricity, but also to the location of the asset on the transmission grid.

Pennsylvania, several utilities voluntarily sold or transferred generation assets to unregulated affiliates.[265]

As a result of these divestitures, regulated distribution utilities in profiled states operate fewer generation plants than in the past. Distribution utilities that are required to serve customers must purchase generation in the wholesale market to serve their customers. Table 4-1 shows the amount of a state's generation operated by the state's utilities (i.e., not operated by IPPs or as combined heat and power facilities), both before and after the start of retail competition.

Table 4-1. Percentage of Utility Ownership of Generation Assets by State

State	Prior to Restructuring (1997)	2002
Illinois	97.0	9.1
Maryland	95.4	0.1
Massachusetts	86.6	9.0
New Jersey	81.2	6.8
New York	84.3	32.4
Pennsylvania	92.3	12.3
Texas	88.3	41.2

Note: The utility ownership percentage for New York in 2002 is higher than for other states with divestiture policies because it includes the hydroelectric and nuclear facilities of the Power Authority of the State of New York (even though that body is not a retail distribution utility).

Source: EIA, *State Profiles*, Table 4 in each state profile, *available at* http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html.

Other states, such as Texas, limited the market share any one generation supplier can hold in a region, to provide opportunities for other suppliers to enter.[266] Still others, such as New York, helped organize introductory temporary discounts from alternative suppliers, thus providing customers an incentive to try out these new suppliers.[267]

2. <u>Alternative Suppliers Serving Retail Customers and Migration Statistics</u>

Many generation suppliers serve large industrial and large commercial customers in the profiled states. For example, in Massachusetts, over 20 direct suppliers provide service to C&I customers, along with over 50 licensed electricity brokers or marketers.[268] However, only four active suppliers serve residential customers in the state.[269] In New Jersey, C&I customers can

[265] *See* Illinois and Pennsylvania profiles, Appendix D. *See also FTC Retail Competition Report*, Appendix A (profiles of Illinois and Pennsylvania).

[266] *See infra* Texas profile, Appendix D.

[267] *See infra* New York profile, Appendix D.

[268] Massachusetts Department of Telecommunications and Energy, *List of Competitive Suppliers/Electricity Brokers*, *available at* http://www.mass.gov/dte/restruct/company.htm.

[269] Massachusetts Department of Telecommunications and Energy, *Active Licensed Competitive Suppliers and Electricity Brokers*, *available at* http://www.mass.gov/dte/restruct/competition/index.htm#Licensed%20Competitive%20Suppliers%20and%20Electricity%20Brokers.

choose among nearly 20 suppliers, but residential customers only have a choice of one or two competitive suppliers.[270]

Texas and New York have more options for residential customers. In Texas, residential customers can choose from approximately 15 suppliers.[271] In New York, between six and nine suppliers offer services to residential customers in each service territory.[272] With the notable exception of the Ohio municipal aggregation program described in Box 4-4, few if any suppliers have provided continuous service to residential customers in the other profiled states or in other retail competition states prior to the end of the respective transition periods.

Box 4-4
Customer Choice through Municipal Aggregation in Ohio

In New York, Texas, and most other states, retail customer switching occurs primarily through individual customer decisions to pick a specific alternative retail supplier. In Ohio, however, most switching activity has occurred through aggregations of customers seeking a supplier under the statewide "Community Choice" aggregation option. The Ohio retail competition law provides for municipal referendums to seek an alternative supplier and allows municipalities to work together to find an alternative supplier. The largest aggregation pool, the Northeast Ohio Public Energy Council, has 100 member communities and served approximately 500,000 residents at its peak. The Ohio program allows individual customers to opt out of the aggregation. In most other states, aggregation programs require customers to specifically opt in to participate. Participation rates generally are much higher in opt-out than in opt-in programs. (NOPEC recently had to contract for supply with an affiliate of the distribution utility after the original supplier withdrew from the market).

The percentage of residential customers switching from the POLR service to an alternative competitive supplier is greatest where there are more available generation suppliers. For example, in Massachusetts, 8.5 percent of residential customers had migrated to a competitive supplier as of December 2005.[273] Approximately 41 percent of large C&I customers switched to alternative suppliers, representing 57.5 percent of the C&I load.[274] In states with several

[270] New Jersey Board of Public Utilities, *List of Licensed Suppliers of Electric, available at* http://www.bpu.state.nj.us/home/supplierlist.shtml. For example, in the Connectiv territory, there are 18 C&I suppliers and only one residential supplier. Eighteen suppliers serve C&I customers and one serves residential customers in the PSE&G service territory.

[271] Texas Public Utility Commission, *Texas Electric Choice Compare Offers from Your Local Electric Providers*, *available at* http://www.powertochoose.org/default.asp.

[272] New York State Public Service Commission, *Competitive Electric and Gas Marketer Source Directory*, *available at* http://www3.dps.state.ny.us/e/esco6.nsf/. The NYPSC reports that this range has moved to between 6 and 16 alternative suppliers, and the agency expects the number and variety of services offered by alternative suppliers to increase as New York State moves forward with retail competition. NYPSC comments (2). Some listed suppliers may not be actively marketing to residential customers. Public Utility Law Project of New York comments (2) at 41-42.

[273] A substantial number of these switches are the result of community aggregations (principally the Cape Light Compact) rather than individual residential switches. Cape Light Compact comments (2) at 1-2.

[274] *See infra* Massachusetts profile, Appendix D.

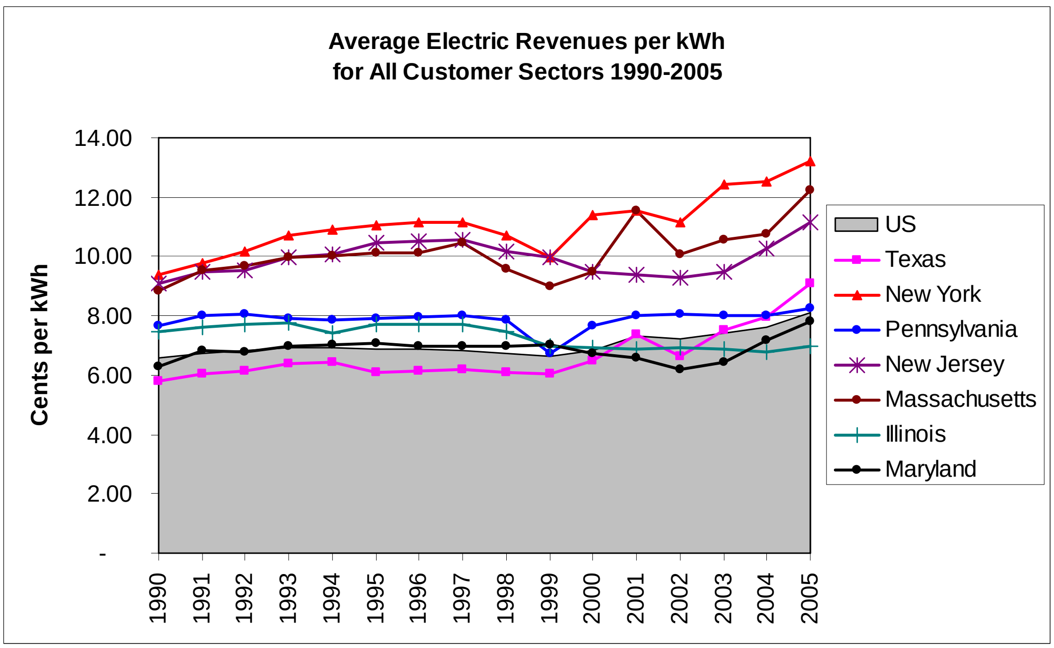
suppliers serving residential customers, higher percentages of residential customers switched to a new supplier (e.g., approximately 26 percent chose a new supplier in Texas).[275]

3. Retail Price Patterns by Type of Customer

Figure 4-3 shows average revenues per kilowatt hour for all customer types in the profiled states against the national average for 1990-2005. The U.S. national average was generally flat at 8 cents per kWh during this period. Rates in New York, Massachusetts, and New Jersey generally have been higher than the national average, while those in Texas, Pennsylvania, Maryland, and Illinois have been lower. In 2004 and 2005, retail prices in all states began to increase.

Figure 4-3. Average Revenues per kWh for Retail Customers, 1990-2005

Profiled States and National Average



Source: EIA Form 861 data, and Monthly Electricity Report for average electric revenues per kWh all sectors, all retail providers.

a. Residential and Commercial Customers

It is difficult to draw conclusions about how competition has affected retail prices for residential customers in states in which a substantial share of such customers continues to take service under capped POLR rates (e.g., Maryland, Illinois, Pennsylvania, and Texas). Comparisons of regulated prices shed little light on price patterns resulting from retail competition.

POLR prices have increased recently in states in which residential rate caps have expired. In New Jersey, residential rate caps on POLR service expired in the summer of 2003. Since then,

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275 *See infra* Texas profile, Appendix D. There likely is a "chicken-or-egg" problem about whether more switching over time is attributable to a prior increase in suppliers or vice-versa (or whether both effects interact).

the state has conducted an internet auction to procure POLR supply of various contract lengths (one- and three-year contracts). The state holds annual auctions to replace suppliers with expiring contracts and to acquire additional supply. Rates for the generation portion of POLR service were flat in 2003 and 2004 after adjusting for deferred charges, but increased in 2005 and 2006, with rates increasing approximately 13 percent between 2005 and 2006.[276]

In Massachusetts, capped POLR rates expired in February 2005. Since then, customers who did not choose an alternative supplier still have been able to obtain POLR service. Massachusetts based the generation portion of its POLR service on the price of supply procured in wholesale markets through fixed-priced, short-term (three- or six-month) supply contracts. Rates for the generation portion of POLR service in the Boston Edison (north) territory increased from 7.5 to 12.7 cents per kWh from 2005 to 2006.[277]

b. Large Industrial Customers

Examining large industrial customers that continue to use a fixed price POLR service also sheds little light on price patterns. A number of states have revised their POLR policies for large customers. Their POLR price for generation is a pass-through of the hourly wholesale price for electricity plus a fixed administrative fee. For example, Maryland, New Jersey, and New York have adopted this type of POLR pricing for large industrial customers.[278] Many customers have switched to alternative suppliers in these states.

Large industrial customers described how their rates have increased since the beginning of retail competition.[279] Some commenters suggested that the Task Force should compare prices of a utility operating in a state that did not implement retail competition against prices of the same utility in a state that implemented retail competition.[280]

The difficulty with this comparison is that many factors unrelated to retail competition may simultaneously influence prices. For example, one state may have reduced cross-subsidies among customer classes while other states increased them. As a result, a price comparison between two states for a class of customers would conflate competition and cross-subsidization effects. Transmission congestion also may affect access to different generators (with low or high prices), so that comparing two states as if they were in the same physical location would be misleading. The timing of rate adjustments may differ between states, so that a single snapshot of rates would show a lower price in one state at one point in time, but a lower price in the other state at a different point in time – even if the net present values of typical bills in the two states were identical over a long observation period. Finally, some states may defer recovery of costs, whereas other states choose not to. Thus, without accounting for these and other factors, a

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276 *See infra* New Jersey profile, Appendix D. *See also* Kenneth Rose, *2003 Performance of Electric Power Markets* (Aug. 29, 2003), at II-19 (review conducted for the Virginia State Corporation Commission).

277 *See infra* Massachusetts profile, Appendix D.

278 Although the POLR service price is based on the hourly wholesale price of electricity, customers in Maryland and New Jersey who purchase this service are unaware of the price until they consume the power or until they are billed. Galen Barbose, Charles Goldman, and Bernie Neenan, *The Role of Demand Response in Default Service Pricing*, 19:3 ELEC. J. 64 (Apr. 2006) [hereinafter Barbose et al.].

279 *See, e.g.,* ELCON comments; Portland Cement comments; Alliance of State Leaders comments; Alcoa comments.

280 Portland Cement comments; Lehigh Cement comments.

simple price comparison between two states may not reveal whether retail competition has benefited customers. At this point the Task Force does not have sufficient data to provide a definitive explanation of price differences between states.[281]

4. <u>Results of Efforts to Bring Accurate Price Signals into Retail Electric Power Markets</u>

There is mixed evidence concerning the degree to which retail competition has resulted in efficient price signals to customers. Residential POLR service rate caps have not increased customer exposure to time-based rates.[282] In contrast, real-time pricing is the POLR service available to the largest customers in New Jersey, Maryland, and New York.[283] The shift to real-time pricing has been eased by technical advances in metering that have increased the sophistication (and decreased the prices) of meters that record the volume of consumption in each small block of time.[284]

Commenters argue that POLR rate structure can significantly affect customer response to price, especially among larger customers. A broad spectrum of utilities, state regulators, and ISOs argue that variable rates permit customers to react to price changes by enabling them to see clearly how much they can save.[285] The experience of the largest customers in National Grid USA's New York area suggests that customers using real-time pricing demonstrate price sensitivity.[286]

In states with traditional cost-based regulation, utilities have used various incentives to induce customers to reduce consumption when demand is high or transmission is congested (e.g., hot summer days). In other instances, such as in New York State, ISOs have successfully implemented demand response programs available to retail customers. In some instances, retail competition has discouraged these traditional types of programs, particularly when distributing utilities are no longer responsible for POLR service.[287] When distribution utilities are required to maintain a portfolio of resources to meet POLR loads, they may no longer value these types of programs as a resource to ensure reliable and efficient grid operation. Shifting the responsibility of grid operation and reliability to regional organizations such as ISOs/RTOs further decreases distribution utilities' interest in these products.

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281 *See infra* Appendix C for reference to some price comparisons by other parties.

282 Rates for residential POLR service in the Consolidated Edison distribution areas in New York State, however, are reported to vary by month rather than being averaged over longer periods of time. Public Utility Law Project of New York comments (2) at 35-36.

283 For discussion of the exposure to hourly prices among the entire class of the largest C&I customers, rather than just the customers still taking POLR service, *see* Barbose et al.; Hopper, *et al.* The authors report that although most customers switch away from POLR service when it is an hourly price, they often select offers from alternative suppliers that contain elements of hourly pricing. Further, they report that the proportion of customers accepting hourly price aspects in their supply contracts – over 90 percent – is far higher when the price is set on the day-ahead spot market. The authors believe that the higher participation rates in hourly pricing under this circumstance are due to the early warning that customers get in the day-ahead market and the customers' consequently greater ability to respond to these pricing signals.

284 Direct Energy comments (2) at 7; Mercatus Center comments at 2; CP Consulting comments at 2. Results from trial programs using advanced meters for residential customers indicate that residential demand for air conditioning is more price sensitive than other uses, particularly if the response is automated. Robert Earle and Ahmad Faruqui, *Toward a New Paradigm for Valuing Demand Response*, 19:4 ELEC. J. 21 (May 2006).

285 Constellation comments; Pepco comments; Southern comments; EEI comments; IURC comments; NYPSC comments; ISO-NE comments.

286 National Grid comments.

287 For example, Pepco stopped actively supporting its air-conditioner direct load control program when it divested its generation assets.

5. Retail Competition in Rural America

Many rural areas are served by small non-profit electric cooperative and public power utilities. They were among the last to be electrified and the most costly to serve. Customers are scattered over large geographic areas, with residential and small loads predominating. Although electric distribution cooperative service areas have been opened to competition under some state plans, no state has required municipal and/or public power utilities to implement retail competition.

Eight states with retail competition – Arizona, Delaware, Maine, Maryland, Michigan, New Hampshire, Pennsylvania, and Virginia – required cooperatives to implement retail competition in their service territories. With the exception of Pennsylvania, state public utility commissions regulated electric cooperatives' retail rates and approved their competition plans. Pennsylvania left the design and implementation of retail competition to the individual distribution cooperatives. The Pennsylvania Public Utility Commission is responsible for licensing competitive retail providers in cooperative service territories. Cooperative retail competition plans have been fully implemented in Delaware, Maine, New Hampshire, Pennsylvania, and Virginia. Some aspects of cooperative retail competition plans are still in administrative or judicial proceedings in Arizona and Michigan. Michigan has allowed electric cooperatives to offer retail competition to a portion of their very large C&I customers, but has deferred extending competition to other customers.

Other states – including Illinois, Montana, New Jersey, Ohio, and Texas – allow electric cooperatives to opt into retail competition on a vote of their boards or membership. None of these states regulates cooperatives' rates or services. They leave the design and implementation of retail competition to the individual cooperative. The state licenses competitive providers, but providers must enter into agreements with the cooperative to begin enrolling retail customers. A handful of individual cooperatives in Montana and Texas elected to provide retail competition options for their members.

It is difficult to track the progress of retail competition in rural areas because most states do not make switching data available or maintain up-to-date information on active suppliers in cooperative service territories. Nevertheless, the Task Force determined that there were few alternative competitive providers, if any, for residential customers of rural systems open to retail competition. No competitive providers were enrolling customers in cooperative systems in Arizona, Maine, Maryland, New Hampshire, Pennsylvania, or Virginia in May 2006. In Delaware and Montana, competitive providers had been licensed to serve cooperative customers, but it is unclear whether any is currently enrolling customers. Licensed provider and switching information for Texas cooperatives is not yet available.

E. POLR Service Price Significantly Affects Entry of New Suppliers

Each profiled state required local distribution utilities to offer a POLR service for customers who do not select an alternative generation provider or whose supplier has exited the market. The price that the distribution utility charges for regulated POLR service is usually "fixed" for an extended period – that is, it does not vary with increases or decreases in wholesale prices.

Generation accounts for the most significant portion of the POLR service price. This component constitutes the amount that the customer avoids paying to the distribution utility by choosing (and paying) an alternative provider. Many states denote this as the "price to beat" or the "shopping credit."

Commenters say that the price of POLR service is the most significant factor affecting whether new suppliers will enter the market and compete to serve customers.[288] The POLR price is the price against which new suppliers, including unregulated affiliates of the distribution utility, must compete if they are to attract customers.[289] The frequency with which the POLR service price changes, among other features of POLR service, can affect the competitive dynamics between different suppliers.

1. Contrasting Visions of POLR Service

The comments revealed two visions of how POLR service should function in the long term.[290] In the first vision, POLR is a long-term option for customers. Under this view, POLR service closely approximates traditional utility service, but in a market place with other sources of supply. Under this vision, POLR service often features prices that are fixed over extended periods. Government-regulated POLR service competes head-to-head with private, for-profit retail suppliers.[291] (An analogy would be the U.S. Postal Service providing parcel postage service in competition with for-profit package delivery services by United Parcel Service, DHL, and FedEx). Alternative suppliers may grow as they find additional approaches to attract customers, but POLR service will likely retain a substantial portion of sales, particularly to residential customers. This type of POLR service serves as a yardstick against which alternative suppliers compete. Most states have adopted this vision of POLR service.[292]

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288 In addition to the policies surrounding POLR service discussed above, the comments identified other factors that depress or delay entry into retail markets. For example, the Pennsylvania Consumer Advocate identified several factors that depressed retail entry by suppliers to serve residential customers, including "the acquisition costs associated with marketing programs to reach residential customers, the costs of serving such customers once acquired, and the rising prices for generation supply service in the wholesale market." PA Consumer Advocate comments at 3. The Maine Office of Public Advocate echoed these factors and also identified the "miscalculation by some suppliers as to the risks and rewards for retail electricity competition." Maine Public Advocate comments at 3. The Industrial Consumers observed that retail markets are not fully competitive because of insufficient generation divestitures that left suppliers with market power. ELCON comments at 2. Another factor identified by Industrial Consumers is the inability of alternative suppliers to gain access to necessary transmission services to serve their customers. ELCON comments at 6. Others customers suggested that the lack of uniform rules throughout every service territory hinders entry for suppliers. Wal-Mart comments at 13. Other commenters argued that alternative suppliers need access to customer use data from utilities to be able to market to prospective customers. Constellation comments at 43. Still others argued for no minimum stay requirements at POLR and constrained shopping windows, which can dampen entry. RESA comments at 30-31; Strategic comments at 10; Wal-Mart comments at 13. The lack of entry in most states makes it difficult for the Task Force to evaluate which additional factors are the most important.

289 There is one potential exception: a supplier that offers a substantially different product – for example, "green" power from wind turbines – may be able to charge a higher price and still attract customers.

290 Although state utility regulators often require that POLR service be provided or procured by the incumbent distribution utility, the task of providing or procuring POLR service could be carried out by other entities. New York Companies comments (2). For example, it could be assigned to one or more alternative suppliers, awarded through a competitive bidding process, or assumed directly by the state utility regulator (as in Maine). In any case, the firm assigned to provide or procure POLR service may be exposed to the risk that this responsibility will be unprofitable because costs and demand are volatile or because state utility regulators impose costs on the provider of POLR service (such as switching incentives) during the transition to retail customer choice. This risk can create financial difficulties for the distribution utility or another entity with this responsibility. New York Companies comments (2).

291 *See, e.g.,* Illinois Commerce Commission comments; PPL comments; PA Office Consumer Advocate comments.

292 *See, e.g.,* PA Office Consumer Advocate comments; NASUCA comments.

In the second vision, POLR is a barebones, temporary service consisting of retail access to wholesale supply, primarily for customers that are between suppliers. In this vision, alternative suppliers serve the bulk of retail customers. They compete primarily against each other with a variety of price and service offerings designed to attract different types of customers. This type of POLR service acts as a stopgap source of supply that ensures electric service is not interrupted when an alternative supplier leaves the market or is no longer willing to serve particular customers. Wholesale spot market prices, or prices that vary with each billing cycle, may be acceptable as the price for POLR service.[293] (A supply arrangement comparable to this version of POLR service is the high-risk pool for automobile insurance operated in several states).[294] Texas and Massachusetts are current examples of this vision of POLR service, as is Georgia in its design for retail natural gas sales.[295]

Some profiled states incorporated aspects of both visions of POLR service for different types of customers. For example, New Jersey adopted the first approach for residential customers and the second approach for large C&I customers.[296] Large C&I customers are generally expected to be well-informed buyers with wide energy procurement experience. Accordingly, some states determined they are more likely to quickly obtain the benefits of retail competition without additional help from state regulators in the form of fixed POLR prices.

2. <u>Key POLR Service Design Decisions</u>

The profiled states took different approaches to designing their POLR service offerings. Key design decisions involved pricing of the POLR, duration of the POLR obligation, and how to acquire POLR supply. Each of these can affect entry conditions that alternative suppliers face. This section describes each of the decisions.

a. Pricing of POLR Service

The profiled states generally set the POLR price at the regulated price for electric power prevailing before the onset of retail competition, less a discount. Discounts usually persist over a specified multi-year period. Assuming that competition generally lowers prices, one rationale for the discounts was to provide a proxy for the effects of competition on customers less able to quickly obtain such savings for themselves. The Illinois POLR service discount, for example, was developed to bring local prices into line with regional prices. When retail competition began, Illinois customers in areas with relatively low prices before customer choice did not receive discounts below the previously regulated rates. In contrast, customers in the

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293 *See, e.g.*, RESA comments; Wal-Mart comments; National Energy comments; SUEZ comments.

294 Most states have a mechanism by which high-risk drivers can obtain insurance. Often insurers in a state are assigned a portion of the pool of high-risk drivers based on each firm's share of drivers outside the pool. AIPSO manages many of the pools and maintains links with individual state programs at https://www.aipso.com/adc/DesktopDefault.aspx?tabindex=0&tabid=1. Similar plans are available in many states for individuals with prior health conditions who are seeking health insurance coverage. *See* COMMUNICATING FOR AGRICULTURE AND THE SELF-EMPLOYED, COMPREHENSIVE HEALTH INSURANCE OF HIGH-RISK INDIVIDUALS (19th ed. 2005).

295 Texas will end its "price to beat" system in 2007 (*See infra* Texas profile, Appendix D). Massachusetts ended its rate-capped POLR service in February 2005 (*See infra* Massachusetts profile, Appendix D). In the Atlanta Gas Light distribution territory, the distribution utility petitioned the Georgia Public Service Commission to withdraw from retail sales. In Georgia, under the amended Natural Gas Competition and Deregulation Act of 1997, a customer who does not choose an alternative supplier is randomly assigned an alternative supplier. Discussion and documentation about the Georgia natural gas retail competition program are available at http://www.psc.state.ga.us/gas/ngdereg.asp.

296 *See infra* New Jersey profile, Appendix D.

Commonwealth Edison territory – the area with the highest cost-based rates – received 20 percent discounts to bring retail POLR prices there into line with the regional average bundled service prices prevalent prior to the restructuring legislation.[297]

b. The Extent and Timing of Pass-Through of Fuel Cost Changes

States also have considered the extent to which they should adjust the regulated POLR price to allow for changes in the cost of fuel to generate electricity. Some states separated fuel costs from other cost components, because fuel costs have been more volatile than other input prices. (Fuel costs are the largest variable cost component and can be calculated for each type of generation unit on the basis of public information.) These factors also suggest that a generation firm has little control over its fuel costs once it has invested in generation. For example, Texas instituted twice-yearly adjustments in the POLR service (price to beat) price calculations. By adjusting POLR prices for changes in fuel costs, Texas regulators have prevented the POLR price from slipping too far away from competitive price levels, thus maintaining the POLR price as a closer proxy for the competitive price.[298] If retail prices fall too far below wholesale prices, the POLR supplier may have financial difficulties, and alternative suppliers will be unlikely to enter or remain as active retailers.[299]

c. POLR Price and the Shopping Credit

When a retail customer picks an alternative supplier, the distribution utility with a POLR obligation avoids the costs of procuring generation supply for that customer. The distribution utility therefore "credits" the customer's bill so that the customer pays the alternative supplier (rather than the utility) for the electricity supplied.[300] This avoided charge – the "shopping credit" – equals the regulated POLR service price. States have used two approaches to determine the level of the shopping credit. One view is that the shopping credit equals the avoided cost or the proportion of POLR procurement costs attributable to a departing customer. Maine, for example, estimated avoided costs on this basis, with no additional estimated avoided costs.[301] This approach results in a lower shopping credit and lower total POLR price.

An alternative perspective is that the distribution utility also avoids "adders" (costs that are in addition to avoided procurement costs), including marketing and administrative costs.[302] This view results in a higher shopping credit and higher total POLR price, creating "headroom" for

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297 *See infra* Illinois profile, Appendix D.

298 *See infra* Texas profile, Appendix D. In contrast, a state with long lags in fuel cost adjustments would have retail prices well below market rates during periods of increasing fuel prices, and prices well above market rates during periods of declining fuel prices. A single snapshot comparison of prices would be misleading in these circumstances.

299 *See* discussion *infra* of the California energy crisis, in which one of the state's utilities declared bankruptcy because, among other reasons, capped POLR rates were substantially below wholesale prices.

300 The distribution utility continues to charge the customer a delivery charge (a "wires" charge) to cover the transmission and distribution expense.

301 Thomas L. Welch, Chairman, Maine Public Utilities Commission, *UtiliPoint PowerHitters interview* (Jan. 24, 2003), *available at* http://mainegov-images.informe.org/mpuc/staying_informed/about_mpuc/commissioners/ph-welch.pdf.

302 See Kenneth Rose, *Electric Restructuring Issues for Residential and Small Business Customers*, National Regulatory Research Institute Report NRRI 00-10 (June 2000), *available at* http://www.nrri.ohio-state.edu/dspace/bitstream/2068/610/1/00-10.pdf, for a discussion of adders and their relationship to wholesale prices and headroom for entrants in Pennsylvania and other states.

potential entrants. In Pennsylvania, the POLR shopping credit included several other elements, such as avoided marketing and administrative costs.[303] Some observers attributed Pennsylvania's early high volume of switching to the additional avoidable costs included in its shopping credit calculations.[304]

d. The Multi-Year Period for POLR Service

States that implemented retail competition also determined how long POLR service should continue at a discount from prior regulated prices. This period generally corresponded to the distribution utility's collection of stranded generation and other costs. In a competitive retail environment, utilities no longer were assured they could recover costs of all of their state-approved generation investments. Most states faced claims of stranded costs associated with generation facilities that were unlikely to earn enough revenues to recover fixed costs once customers could seek out alternative, lower-priced retail suppliers. States allowed utilities to recover stranded costs through charges on distribution services that cannot be bypassed.[305]

Each state that authorized the collection of stranded costs had to determine these costs and the duration of the collection period. These decisions fundamentally altered the electric power industry and were at the center of some of the most contentious issues state regulators faced. Some states (for example, Maine and New York) required some or all generation to be sold to obtain a market-based determination of the level of stranded costs.[306] In other states, such as Illinois, utilities voluntarily divested generation assets. As noted above, the result of these divestitures is that generation no longer is primarily in the hands of regulated distribution utilities.[307]

e. Procurement for POLR Service

Because most distribution utilities no longer own generation to satisfy all of their POLR obligations, they took different approaches to acquire generation supply. For example, New Jersey utilities that offer residential POLR service acquire generation supply through three overlapping three-year contracts, with each contract covering approximately one-third of the projected load.[308] This "laddering" of supply contracts reduces the volatility of retail electricity prices but does not assure that the prices paid by POLR service consumers are competitive in the short term.[309] Other states used different ways to hedge the volatility in short-term energy prices. For example, New York distribution utilities have long-term supply contracts with the purchasers of their generation assets (vesting contracts) based on pre-divestiture average generation prices.[310]

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303 *Id.*

304 Over time, the shopping credit in Pennsylvania faded in significance as the competitive rates increased relative to POLR service prices due to fuel cost increases. *See* the pattern of customer switching in the Pennsylvania profile in Appendix D *infra*.

305 *FTC Retail Competition Report*, State Profiles, Appendix A.

306 *See infra* New York profile, Appendix D; *FTC Retail Competition Report*, Appendix A (profile of New York).

307 *See infra* Illinois profile, Appendix D.

308 *See infra* New Jersey profile, Appendix D.

309 *See, e.g.,* Maine Public Advocate comments.

310 *See infra* New York profile, Appendix D.

F. Observations on How POLR Service Policies Affect Competition

One of the most contentious issues state regulators currently face is how to price POLR service once rate caps expire. This situation is especially vexing for those states that had stranded cost recovery periods during which fixed POLR prices were substantially lower than wholesale prices. Rate caps expire this year in Delaware, Illinois, Maryland, Ohio, and Rhode Island, and customers in those states that did not choose an alternative supplier face potentially substantial price increases.

Rapid increases in fuel prices in recent years – leading to increases in wholesale prices – have made it difficult fully to discern best practices regarding retail competition. The price increases interacted dramatically with POLR service rate caps, clouding the experiences most states have had with other retail competition issues. As a result, the range of experience regarding other aspects of retail competition is narrow, primarily limited to what has occurred in New York, Texas (within ERCOT), the Duquesne distribution area within Pennsylvania, Maine, Massachusetts (recently), and the large C&I customers in New Jersey, Illinois, and Maryland. Because each state faces different electricity supply and demand conditions, it is not possible to recommend a single approach for all states considering retail customer choice. Nonetheless, given these limitations, the Task Force offers the following observations on what appears to work well (and not to work well) in retail customer choice programs.

- **Minimum POLR Service:** POLR service (or an equivalent provision) to serve customers of a supplier that has left the market, while the customer obtains another supplier, is the least intrusive form of POLR service, yet it is consistent with concerns about potentially life-threatening effects of unanticipated loss of electric service.

- **Treatment of Different Customer Risk Preferences:** POLR service that goes beyond short-term access to the wholesale spot market involves providing a bundle of services that electricity marketers also can provide. States that embrace a more expansive version of POLR service should recognize that this step may hamper the development of alternative suppliers. The economic rationale for taking this step usually is limited to trying to correct some identifiable and substantial market imperfections. If a state adopts a more expansive version of POLR service, it should periodically review the rationale for continuing it.

- **POLR Service Price Caps:** It is difficult to establish a POLR service price cap that will not distort retail electricity markets and the associated development of effective competition. The best practice is to make frequent adjustments to the cap (at least so as to reflect changes in fuel costs), or to abandon the cap altogether and use an objective, competitive process to procure supply.

- **Treatment of Different Customer Classes:** Large customers are logical pioneers for retail choice because of their familiarity with energy procurement processes and because they are comfortable with decisions to adjust input use based on input prices. For smaller, less sophisticated customers, including residential customers, issues of awareness and access to comparative pricing information should be addressed as retail customer choice is introduced.

- **Switching Costs:** Switching is important for retail electricity competition to work. States should strive to avoid rules that make switching more expensive or slower than is necessary to avoid unauthorized switching (slamming).

- **Consumer Education:** Becoming an informed and responsive consumer in an unfamiliar market requires that the customer be informed that he or she has choices and be provided with information about how to compare available choices and how to switch suppliers (including any constraints on switching). Texas maintains a well-organized website that appears to work well for residential price comparisons. New York's program to encourage customers to try out alternative suppliers that agree to offer a temporary discount appears to educate many residential customers effectively about the ease of switching, without subsidizing alternative suppliers.

- **Customer Aggregation:** Customer aggregation is an approach that can reduce per-customer search and switching costs and thus generally can help to develop retail competition. Opt-out customer aggregations may be worth considering because they can minimize transaction costs without limiting customer choice.

- **Entry:** Entry is a key concept in retail electricity competition. States should attempt to avoid rules that make entry more expensive or slower than is required to avoid fraudulent marketing activities. Areas to consider include registration fees and delays, costs and delays in interacting with the distribution utility (metering, billing, treatment of receivables), security deposits for suppliers, rules regarding disconnecting retail customers for non-payment, and exit penalties.

1. POLR Service Price to Approximate the Market Price

The POLR service price must closely approximate a competitive market price if it is to provide economically efficient incentives for consumption and supply decisions and thereby maximize welfare. This price will vary over time as supply and demand change.[311] If the POLR service

[311] Because the marginal cost of supplying electricity varies over the course of the day and season and because fuel costs sometimes are volatile, efficient retail prices for electricity are more volatile than the prices that customers are used to paying under traditional regulation. Electricity prices under traditional regulation typically reflect average costs for electricity and risk management over extended periods. In a retail choice environment, alternative suppliers can offer a variety of risk management (hedging) levels that range from full, immediate pass-through of wholesale spot market prices to fixed rates for extended periods. For a discussion of how much hedging is required to eliminate portions of volatility, *see* Severin Borenstein, *Customer Risk from Real-Time Retail Electricity Pricing: Bill Volatility and Hedgability*, (June 6, 2006) (University of California Energy Institute CSEM Working Paper 155), *available at* http://www.ucei.berkeley.edu/PDF/csemwp155.pdf. It is important to note that these bundles of electricity and risk management also can constitute efficient retail prices, although they contain a cost component associated with the risk management services. If POLR service prices become more volatile, a customer who prefers less risk will have incentives to search for an alternative supplier that offers a price/risk tradeoff – slightly higher prices but less volatility.

Alternative suppliers will have incentives to offer preferable price/risk alternatives to gain customers. Retail customers can also consider whether onsite generation or other forms of upstream vertical integration offer a preferable price/risk combination.

In general, so long as customers are served by alternative suppliers or upstream vertical integration is an option, the POLR price is only one component of the average market price.

In a traditional regulatory setting, utilities sometimes offer customers a discount if they agree to have their service interrupted during peak demand periods. Removing restrictions to interruptible service rates would allow more customers to improve the match between their risk preferences and their electric service. Industrial Coalitions comments (2) at 25.

price does not closely match the competitive price, it will distort consumption and investment decisions[312] leading to an inferior allocation of resources.[313] Competitive market prices align consumers' willingness to pay for a service with the marginal cost of providing it (where, in the long run, the marginal cost includes a competitive rate of return on investments). This alignment leads to the most economically efficient allocation of resources.[314]

Experience within the profiled states shows that it is not easy to approximate the competitive price. Not only does the competitive price change when prices of inputs change, but the price also acts as an investment signal for new generation. The short-term competitive price for the electric generation component can move quickly and dramatically. Over the past several years, the initial fixed discounts for POLR service have resulted in below-market prices or occasionally above market prices, but never at the short-term market price for long.[315] When POLR prices are below competitive levels, even efficient alternative suppliers cannot profit by entering or continuing to serve retail customers.[316] Firms with the POLR obligation can become financially distressed, as they did in California during its energy crisis.[317]

Fuel prices are responsible for a substantial percentage of the change in the market price. A POLR service should adjust the retail electricity price for changes in the prices of fuels used by generators (at the margin). This is more efficient than using a fixed price as a proxy for the market price. Moreover, a POLR price that is adjusted only infrequently to incorporate underlying fuel price changes will usually be either above or below the competitive market price.[318] A fixed or infrequently updated price creates incentives for customers to move back and forth from POLR service to alternative suppliers, based on which offers a lower rate. This repeated switching may create additional costs for both POLR and alternative suppliers. It also can reduce the certainty about procurement quantities which suppliers need to make long-term supply arrangements. Including other identifiable cost components that fluctuate widely in POLR service price adjustments will increase the likelihood that the POLR service price will be a reasonable proxy for the competitive price.

2. Lack of Market-Based Pricing Distorts Development of Competitive Retail Markets

A second issue arises when below-market POLR service prices persist during a period of rising fuel prices and correspondingly increasing wholesale supply prices. In these circumstances,

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[312] Some commenters observed that cost averaging, cost deferrals, inaccurate cost allocations, double counting of costs, and price caps all can distort consumption and investment that result in loss of consumer welfare. Strategic Energy comments (2) at 6; Constellation comments (2) at 8.

[313] The electricity industry has traditionally provided discounts or other forms of assistance to low-income families. States may need to examine whether the level of this assistance should be increased in response to price increases or greater price volatility. National Association of State Utility Consumer Advocates (2). Similarly, firms whose competitors are in areas with stable or declining prices or diminishing price volatility could face financial distress, just as if they experienced other types of increased or more volatile input costs relative to their rivals. Firms with electricity-intensive production processes are likely to be particularly sensitive to increased prices or price volatility. Alcoa comments (2); Industrial Coalitions comments (2) at 26.

[314] This statement would need to be qualified to the extent there is market power and to the extent there are unpriced externalities such as pollution.

[315] *See, e.g.*, Wal-Mart comments; WPS comments; Illinois Commerce Commission comments; PPL comments; RESA comments.

[316] *See, e.g.*, Wal-Mart comments; RESA comments.

[317] *See, e.g.*, EEI comments.

[318] *See, e.g.*, RESA comments.

customers are likely to experience a shock when POLR service prices are adjusted to reflect prevailing wholesale prices. This can create public pressure to continue the fixed POLR rates at below-market levels. For example, some jurisdictions have considered a gradual phase-in of the price increase to bring POLR prices to the market level. The shortfall between the market POLR price and the price that customers actually pay is usually deferred and collected later from the POLR provider's customers.

Although this approach reduces rate shock, it is likely to distort retail electricity markets. First, a phase-in of the price increase continues to send inaccurate price signals and undermines incentives to reduce consumption. Second, it prevents entry of alternative suppliers by keeping the POLR rate below market levels for additional years. Third, it results in higher prices in future years as the deferred revenues are recovered, so that customers who purchase electricity later are unfairly penalized (overcharged). Fourth, if surcharges to pay for deferred revenues are not designed carefully, the charges can disrupt existing competition by forcing customers with alternative suppliers to pay for part of the deferred revenues. Fifth, if wholesale prices decline, customers will choose alternative suppliers, and this migration will create a stranded cost problem as the POLR provider loses customers it had counted on to pay the higher prices. Moreover, if the state prevents the stranded cost problem by imposing large exit fees, POLR service customers will be locked in to the POLR provider, so that competition may not develop even after POLR service prices rise to market levels. Finally, continued POLR service price caps in an environment of increasing wholesale prices can endanger the financial viability of the distribution utility.

3. Different POLR Services Designed for Different Classes of Customers

Some states have different POLR service designs for different customer classes. POLR service prices offered to large C&I customers generally entail less discounting from regulated rates or competitive market-based procurement and have been based on wholesale spot market prices. Large C&I customers generally have a good understanding of price risk and of the means and costs required to reduce that risk. In addition, suppliers often can customize service offerings to the unique needs of these large customers.[319] With their larger loads, large C&I customers also may be better equipped to respond to efficient price signals than other classes of customers. The result of this price response may be to improve system reliability and dissipate market power in peak demand periods.[320]

Large C&I customers have engaged in more switching to competitive providers in states that have implemented this division between POLR service for large C&I customers and for residential and small C&I customers.[321] Many alternative suppliers reportedly have developed

[319] *See, e.g.*, Wal-Mart comments at 10-11; Commercial End-Users comments.

[320] In Case 03-E-0641, the New York State Public Service Commission required New York utilities to file tariffs for mandatory real-time pricing (RTP) for large C&I customers. The order observed that "average energy pricing reduces customers' awareness of the relationship between their usage and the actual cost of electricity, and obscures opportunities to save on electric bills that would become apparent if RTP were used to reveal varying price signals." It further notes that "if a sufficient number of customers reduced load in response to RTP, besides benefiting themselves, the reduction in peak period usage would ameliorate extremes in electricity costs for all other customers."

[321] *See infra* New Jersey profile, Appendix D; RESA comments.

customized time-of-use contracts for large C&I customers.[322] Moreover, the profiled states show that a substantial number of suppliers actively serve large C&I customers. Box 4-5 describes Oregon's unique sign-up period for its nonresidential customers.

Box 4-5
Oregon's Annual Window for Switching for Nonresidential Customers

Oregon has a unique process by which nonresidential customers of the two large investor-owned distribution utilities in Oregon can switch to an alternative supplier. Nonresidential customers must make their selections during a limited annual window. The window must extend at least five days in duration, but usually a month is allowed. In addition to picking the alternative supplier, the largest customers must select a contract duration. One option specifies a minimum duration of five years, with an annual renewal after that. As of 2005, alternative suppliers were anticipated to serve about 10 percent of load in one distribution area and about 2.1 percent in the other. One utility offered choice beginning in 2003, while the other began customer choice in 2005. Detailed descriptions are available at http://www.oregon.gov/PUC/electric_restruc/indices/ORDArpt12-04.pdf.

It is not necessary to expose *all* customers to time-based prices to introduce price-responsiveness into retail markets.[323] As a first step, customers who are the most price-sensitive could be exposed to time-based rates. Niagara Mohawk in upstate New York took this approach for its largest customers, as did Maryland and New Jersey. California is considering setting real-time pricing as the default rate for medium-sized and larger C&I customers. Another means to introduce price responsiveness is to provide customers with voluntary time-based rate programs, along with assistance in equipment purchases or financing. For example, the New York State Public Service Commission requires voluntary time-of-use pricing for residential customers, and the Illinois Legislature requires that residential customers be offered real-time pricing as a voluntary tariff. Ideally, competition provides incentives for suppliers to offer customers the mix of products and services that matches their potentially diverse preferences.

4. Use of Auctions to Procure POLR Service

As discussed above, New Jersey has used an auction process to procure POLR supply for both residential and C&I customers. Illinois proposed a similar auction for when its rate caps expire. Auctions may bring retail customers the benefit of competition in wholesale markets as suppliers compete to supply load. However, as discussed in Chapter 3, if there is a load pocket, an auction is unlikely to help this process, resulting in fewer benefits of competition.

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[322] *See, e.g.*, New York Companies comments; Alliance for Retail Energy Markets comments; Constellation comments; PPL comments; RESA comments; NYPSC comments; Direct Energy comments; Reliant comments; PA Office Consumer Advocate comments; Wal-Mart comments; Commercial End-Users comments.

[323] Steven Braithwait and Ahmad Faruqui, *The Choice Not to Buy: Energy Savings and Policy Alternatives for Demand Response*, PUB. UTILS. FORTNIGHTLY (Mar. 15, 2001).

5. Consumer Awareness of Customer Choice and Engendering Interest in Alternative Suppliers

Experience with restructuring in other industries indicates that consumer switching from a traditional supplier to a new one can be a slow process. It took 15 years before AT&T lost half of its long-distance service customers to alternative suppliers.[324] One reason retail electric competition could be slow to develop is that expected gains from learning more about market choices may be too small to make the learning worthwhile,[325] particularly for residential customers with small loads.[326]

Pricing of POLR service and helping consumers compute the "shopping credit" may encourage more rapid development of retail competition by motivating residential consumers to search for market choices. Some states that have low "shopping credits" have had little retail entry. Some states with retail competition have had substantial consumer education programs, including websites with orientation materials and price comparisons.[327] These initiatives help promote learning about market alternatives.

New York is encouraging retail competition by helping organize temporary discounts from alternative suppliers and ordering distribution utilities to make these discounts known to customers who contact the utility.[328] These efforts have increased residential switching and reduced prices, at least for the short term. Experience indicates that once residential customers switch to alternative suppliers, they seldom return to POLR service even after the temporary discounts expire.[329]

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[324] James Zolnierek, Katie Rangos, and James Eisner, Industry Analysis Division, Common Carrier Burerau, Federal Communications Commission, *Long Distance Market Shares, Second Quarter 1998*, at 19-20 (Sept. 1998), *available at* http://www.fcc.gov/Bureaus/Common_Carrier/Reports/FCC-State_Link/IAD/mksh2q98.pdf; Thomas L. Welch, Chairman, Maine Public Utilities Commission, *UtiliPoint PowerHitters interview* (Jan. 24, 2003) *available at* http://mainegov-images.informe.org/mpuc/staying_informed/about_mpuc/commissioners/ph-welch.pdf.

[325] Economists refer to this phenomenon as "rational ignorance." Clemson University, *The Theory of Rational Ignorance* (The Community Leaders' Letter, Economic Brief No. 29), *available at* http://www.strom.clemson.edu/teams/ced/econ/8-3No29.pdf.

[326] Joskow, *Interim Assessment*.

[327] *See, e.g.,* ELCON comments; Progress Energy comments; Constellation comments; Pepco comments; PA Office Consumer Advocate comments.

[328] In Case 05-M-0858, the New York State Public Service Commission adopted the "PowerSwitch" alternative supplier referral program (first developed by Orange & Rockland) as the model for all utilities in the state.

[329] New York State Consumer Protection Board, *Comment to the New York State Public Service Commission*, Case 05-M-0334, Orange & Rockland Utilities, Inc., Retail Access Plan, at 5 (May 2, 2005). The Consumer Protection Board indicated that retail customers who have participated in "PowerSwitch" are returning to POLR service at a rate of less than 0.1 percent per month. The Board applauded PowerSwitch because it is completely voluntary and provides assured initial savings to consumers.

APPENDIX A
LIST OF COMMENTERS WHO RESPONDED TO TASK FORCE NOTICES REQUESTING COMMENTS*

** Two notices were published in the Federal Register as FERC Docket Number AD05-17-000: (1) Notice Requesting Comments on Wholesale and Retail Electricity Competition, issued on October 13, 2005, and (2) Notice Requesting Comments on Draft Report to Congress on Competition in the Wholesale and Retail Markets for Electric Energy, issued on June 5, 2006. The actual comments can be found at FERC.gov*

The following parties filed comments in response to the notice issued October 13, 2005:

Alcoa, Inc. (Alcoa)

Allegheny Energy Companies (Allegheny)

Alliance for Retail Energy Markets

Ameren Services Company (Ameren)

American Antitrust Institute (AAI)

American Public Power Association (APPA)

Association of Large Distribution Cooperatives (Large Distribution Cooperatives)

BlueStar Energy Services, Inc. (BlueStar)

BP Energy Company (BP Energy)

California Independent System Operator Corporation (CAISO)

California Public Utilities Commission (CPUC)

Cape Light Compact

Carnegie Mellon Electricity Industry Center (Carnegie Mellon)

CenterPoint Energy Houston Electric, LLC (CenterPoint)

Los Angeles Department of Water and Power (LADWP)

7-Eleven, Inc, Big Lots Stores, Inc., Crescent Real Estate Equities, Federated Department Stores, Hines, JC Penney, Wal-Mart Stores, Inc. (collectively, Commercial End-Users)

COMPETE, Electric Power Supply Association (EPSA), Alliance for Retail Choice (ARC)

Connecticut Department of Public Utility Control (Connecticut DPUC)

Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. (together, New York Companies)

Constellation Energy Group, Inc. (Constellation)

Council of Industrial Boiler Owners (CIBO)

Demand Response and Advanced Metering Coalition (DRAM Coalition)

Direct Energy Services, LLC (Direct Energy)

Dominion Resources Services, Inc. (Dominion)

Duke Energy Corporation (Duke)

Duquesne Light Company (Duquesne)

Edison Electric Institute (EEI)

Electric Power Supply Association (EPSA)

Electricity Consumers Resource Council (ELCON) and American Chemistry Council, American Iron and Steel Institute, Coalition of Midwest Transmission Customers, PJM Industrial Customer Coalition, Illinois Industrial Energy Consumers, Industrial Energy Users - Ohio, and Multiple Intervenors (collectively, Industrial Consumers)

EnerNOC, Inc. (EnerNOC)

Exelon Corporation (Exelon)

Governor of the State of Rhode Island

Idaho Public Utilities Commission (Idaho PUC)

Illinois Commerce Commission

Independent Power Producers of New York, Inc. (IPP NY)

Indiana Utility Regulatory Commission (IURC)

Industrial Consumers: Portland Cement Association, American Forest and Paper Association, American Iron and Steel Institute, California Large Energy Consumers Association, Coalition of Midwest Transmission Customers, National Lime Association, PJM Industrial Customer Coalition

ISO New England Inc. (ISO-NE or ISO New England)

ISO/RTO Council

Large Public Power Council (LPPC)

Lehigh Cement Company (Lehigh)

Maine Office of Public Advocate (Maine Public Advocate)

Midwest Independent Transmission System Operator Inc. (Midwest ISO or MISO)

Midwest Stand-Alone Transmission Companies

Mike Holly; Sorgo Fuels, Inc.

Mirant Corporation (Mirant)

Missouri Public Service Commission (Missouri State Commission)

National Association of Regulatory Utility Commissioners (NARUC)

National Association of State Utility Consumer Advocates (NASUCA)

National Energy Marketers Association (National Energy)

National Grid USA (National Grid)

National Rural Electric Cooperative Association (NRECA)

New Mexico Attorney General

New York Independent System Operator, Inc. (NYISO or New York ISO)

New York State Department of Public Service (NYPSC or New York PSC)

New York State Electric & Gas Corporation (New York G&E) and Rochester Gas & Electric Corporation (Rochester G&E)

North Carolina Utilities Commission, Public Staff - North Carolina Utilities Commission, and the Attorney General of the State of North Carolina (collectively, North Carolina Agencies)

Northeast Utilities

NUCOR Corporation, Blue Ridge Power Agency, and the East Texas Electric Cooperative (collectively, Large Power Buyers)

Orlando Utilities Commission (Orlando Utilities)

Pennsylvania Office of Consumer Advocate (PA Consumer Advocate)

Pepco Holdings, Inc. (Pepco)

PJM Interconnection, LLC (PJM)

PNM Resources, Inc. (PNM)

PPL Companies (PPL)

Progress Energy, Inc. and South Carolina Public Service Authority (together, Progress and Santee Cooper)

Public Utilities Commission of Ohio

Reliant Energy Inc. (Reliant)

Retail Energy Supply Association (RESA)

South Carolina Electric and Gas Company (South Carolina E&G)

Southern California Edison Company (SoCal Edison)

Southern Companies (Southern)

Southwest Transmission Dependent Utility Group (Southwest Transmission)

Steel Manufacturers Association (Steel Manufacturers)

Strategic Energy, LLC (Strategic Energy)

SUEZ Energy North America (SUEZ)

The Alliance of State Leaders Protecting Electricity Consumers (Alliance of State Leaders)

Transmission Access Policy Study Group (TAPS)

Transmission Agency of Northern California (TANC)

Virginia State Corporation Commission

Wal-Mart Stores, Inc. (Wal-Mart)

WPS Resources Corporation (WPS)

Xcel Energy Services, Inc. (Xcel)

The following parties filed comments in response to the notice issued June 5, 2006:

Alcoa, Inc. (Alcoa)

Allegheny Power and Allegheny Energy Supply Company, LLC (together, Allegheny)

Alliance for Retail Energy Markets

Alliance of State Leaders Protecting Electricity Consumers

American Public Power Association (APPA)

Attorney General of California

Attorney General of New Mexico

California Department of Water Resources; State Water Project

Cape Light Compact

City of Seattle; City Light Department

Coalition of Midwest Transmission Customer, NEPOOL Industrial Customer Coalition, PJM Industrial Customer Coalition, Industrial Energy Users-Ohio, Industrial Energy Consumers of Pennsylvania, and West Virginia Energy Users Group (collectively, Industrial Coalitions)

Community Power Alliance

COMPETE, Electric Power Supply Association (EPSA), Alliance for Retail Choice (ARC)

Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. (together, New York Companies)

Constellation Energy Group, Inc. (Constellation)

CP Consulting

Direct Energy Services, LLC (Direct Energy)

Duquesne Light Company (Duquesne)

Edison Electric Institute (EEI) and the Alliance of Energy Suppliers

Electric Power Supply Association (EPSA), Independent Power Producers of New York (IPP NY), Independent Energy Producers of Maine (IEPM)

Electricity Consumers Resource Council (ELCON) and American Iron and Steel Institute, Association of Businesses Advocating Tariff Equity, Coalition of Midwest Transmission Customers, PJM Industrial Customer Coalition, Industrial Energy Users – Ohio, Multiple Intervenors, and Wisconsin Industrial Energy Group, Inc. (collectively, Industrial Consumers)

Industrial Consumers: Portland Cement Association, American Forest and Paper Association, American Iron and Steel Institute, California Large Energy Consumers Association, Coalition of Midwest Transmission Customers, National Lime Association, PJM Industrial Customer Coalition

ISO New England Inc. (ISO New England)

ISO/RTO Council

Mercatus Center; George Mason University (Mercatus Center)

Midwest Independent Transmission System Operator, Inc. (MISO)

Midwest Stand-Alone Transmission Companies

Mike Holly; Sorgo Fuels, Inc.

National Association of State Utility Consumer Advocates (NASUCA)

National Grid USA (National Grid)

National Rural Electric Cooperative Association (NRECA)

New York State Electric & Gas Corporation (New York G&E) and Rochester Gas & Electric Corporation (Rochester G&E)

OMB Professionals, Inc.

Pacific Gas & Electric Company (PG&E)

PJM Interconnection, LLC (PJM)

Portland Cement Association (Portland Cement)

PPL Companies (PPL)

Progress Energy, Inc. and South Carolina Public Service Authority (together, Progress and Santee Cooper)

Public Service Commission of New York (PSC New York)

Public Service Commission of Wisconsin (PSC Wisconsin)

Public Utility Law Project of New York

Public Utilities Commission of Texas

Reliant Energy Inc. (Reliant)

Strategic Energy, LLC (Strategic Energy)

SUEZ Energy North America (SUEZ)

Transmission Access Policy Study Group (TAPS)

William D. Steinmeier

Wisconsin Power & Light, Madison Gas & Electric Company, Wisconsin Electric Power Company, Wisconsin Public Power Incorporated, and WPS Resources Corporation (collectively, Wisconsin Load Serving Entities).

APPENDIX B
TASK FORCE MEETINGS WITH OUTSIDE PARTIES

American Public Power Association – October 27, 2005
ArcLight Capital Partners LLC– November 9, 2005
Compete Coalition – October 27, 2005
Edison Electric Institute – October 26, 2005
Electric Power Supply Association – October 27, 2005
Electricity Consumers Resource Council – October 26, 2005
Fitch Ratings – November 9, 2005
Lehman Brothers – November 9, 2005
Merrill Lynch Commodities, Inc. – November 9, 2005
Moody's Investors Service – November 9, 2005
National Association of Regulatory Utility Commissioners – October 27, 2005
National Association of State Energy Officials – October 27, 2005
National Governors Association – October 26, 2005
National Rural Electric Cooperative Association – October 26, 2005
Public Utility Law Project – October 27, 2005
Standard & Poor's – November 9, 2005
SUEZ Energy North America – December 8, 2005

APPENDIX C
AN ANNOTATED BIBLIOGRAPHY OF QUANTITATIVE COST BENEFIT ASSESSMENTS OF ELECTRIC INDUSTRY RESTRUCTURING PROPOSALS

Commenters on the section 1815 study highlighted a wide variety of cost-benefit studies that seek to evaluate the electric power industry. Both proponents and opponents of electric industry restructuring have armed themselves with these types of analyses to support their respective positions. It can be challenging to understand these studies' sometimes contradictory results.

The Task Force reviewed roughly 30 cost-benefit analyses[330] in an attempt to better understand what they reveal. Based on this review, together with a review of the recent DOE Report (J. Eto, B. Lesieutre, and D. Hale, *A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies* (December 2005) [hereinafter Eto]), the Task Force has made the following observations:

1) **Many of the existing studies address only the benefits of restructuring proposals**. To the extent studies overlook the costs associated with institutional changes, they can provide an incomplete picture of impacts, and their results should be juxtaposed to cost estimates. (*See* Appendix C: RTO West Benefits and Costs, *Economic Assessment of RTO Policy*, and *Putting Competitive Power Markets to the Test The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies*).

2) **The benefits associated with some of the most significant motivations behind restructuring –** the maintenance of system reliability and the facilitation of lowest-cost electricity production (via incentives for innovation and low-cost construction) - **are very difficult to quantify** using current technology and are often left out of benefit assessments. "It is important that technically limited studies not be interpreted to suggest that impacts that they do not analyze are not significant." Eto at 21.

3) **Existing methods and models used to estimate benefits are limited in what they can measure.** Many of these models also employ simplistic and often misleading assumptions about market behavior. Improving the models used to derive quantitative benefits is technically difficult – significant improvements would involve marrying the complexity of adequately modeling a 10,000+ bus transmission/generation system to the complexity of modeling realistic human behavior in markets. The capabilities of existing models are likely to be fairly static until computer technology advances enough to accommodate the memory needs associated with this complex modeling task.

[330] This review focuses on original studies – responses and critiques to these studies are listed under the "Alternate Views" table category.

4) **Modeling energy transmission and markets necessarily requires making a great deal of assumptions** given the significant limitations in data needed to "feed" these models. Thus, outputs of RTO modeling attempts vary widely based on the assumptions made by the parties doing the modeling – assumptions as to transmission configurations, weather, imports/exports, market behaviors, generation costs, etc. (*See* Appendix C: *Study of Costs, Benefits and Alternatives to Grid West,* versus *The Estimated Benefits of Grid West*).

5) **Another limitation of the studies is that they often only estimate the benefits to society as a whole. Determining the distribution of benefits and costs - who wins and who loses, or who wins the most - is an important piece of the decision making puzzle.** Unfortunately, it is much more difficult to measure the distribution of benefits than it is total social costs. Some efforts have been made in this direction with estimates of the end-use price impacts that restructuring has had or might have and with estimates of benefits that individual participants in electricity markets might accrue (*See* Appendix C: *Beyond the Crossroads, the Future Direction of Power Industry Restructuring* and *Competition Has Not Lowered Electricity Prices*).

6) **Characteristics of the best restructuring cost-benefit studies**, given existing technology/data, include:

- Provision of clear and precise descriptions of assumptions, data sources, methods and technical detail.
- Where econometric models are used, study write-ups should provide regression methods and equations, goodness of fit measures, and results of any tests done to detect analytical flaws.
- An attempt to address all potential costs and benefits.
- An effort to address the distribution of impacts.

STUDIES OF BENEFITS IN THE US

Beyond the Crossroads: The Future Direction of Power Industry Restructuring

Region	US
Report Date	2005
Sponsor	Cambridge Energy Research Associates
Author/Contractor	Cambridge Energy Research Associates
Model/Method	CERA constructs average counterfactual prices as an econometric function of fuel prices and return on the rate base, for residential and industrial customers in four geographic territories based on 1992-1197 data.
Scope of Inquiry	Real price impacts on consumers of electric industry restructuring (study also addresses other restructuring policy issues on a non-quantitative basis)
Period Studied	1997-2004
Conclusion	U.S. residential electric consumers paid about $34 billion less for the electricity they consumed over the past seven years than they would have paid if traditional regulation had continued. Regional distribution of these benefits: NE $ 8 billion Midwest: $ 8 billion South: $24 billion West: -$7 billion
Alternate Views	• APPA thinks figures are inflated: http://www.appanet.org/newsletters/washingtonreportdetail.cfm?ItemNumber=14977&sn.ItemNumber=0 • Comments to Electric Energy Market Competition Task Force by NRECA, November 18, 2005 • H. Spinner, *A Response to Two Recent Studies that Purport to Calculate Electric Utility Restructuring Benefits Captured by Consumers,* ELECTRICITY JOURNAL, Volume 19, No. 1 (January/February 2006) at 42-47.

Electricity Markets: Consumers Could Benefit from Demand Programs, but Challenges Remain

Region	US
Report Date	August, 2004
Sponsor	Report to the Chairman, Committee on Governmental Affairs, U.S. Senate
Author/Contractor	US GAO
Model/Method	Reviewed the literature, analyzed industry and participant data, and conducted interviews with state and federal officials (in FERC, the DOE , and the GSA), industry experts, representatives from utilities, and customers
Scope of Inquiry	Examines the current and potential role for demand-response programs.

	Identifies (1) the types of demand-response programs currently in use; (2) the benefits of these programs; (3) the barriers to their introduction and expansion; and (4) where possible, instances in which these barriers have been overcome.
Period Studied	
Conclusion	Demand-response programs can benefit customers in regulated and restructured markets by improving market functions and enhancing the reliability of the electricity system Recent studies show that demand-response programs have saved millions of dollars—including about $13 million during a heat wave in New York State during 2001. A FERC-commissioned study reported that a moderate amount of demand-response could save about $7.5 billion annually in 2010.
Web Reference	http://www.gao.gov/new.items/d04844.pdf

Staff Report on Cost Ranges for the Development and Operation of a Day One RTO (FERC Docket No. PL04-16-000)

Region	Based on data from PJM, MISO, SWPP, and ERCOT
Report Date	October, 2004
Sponsor	FERC
Author/Contractor	FERC Staff
Model/Method	The analytical base for this Study rests largely on information gleaned from audit staff, FERC Form No. 1 data and interviews with and data responses from existing RTOs and Independent System Operators (ISOs).
Scope of Inquiry	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 to operate as an RTO. Also estimates operating cost of a Day One RTO.
Period Studied	Various
Conclusion	• The average annual operating expense of a new Day One RTO would impact the average retail customer by approximately 0.02¢/KWh, or less than 0.3 percent of the customer's total bill. • Day One RTOs have required an investment outlay of between $38 million and $117 million and an annual revenue requirement of between $35 million and $78 million**.** • Cost overruns can result from changing plans mid-course, poor project management and extensive delays. • Cost data are not accounted for in a standardized way.
Web Reference	http://www.ferc.gov/EventCalendar/Files/20041006145934-rto-cost-report.pdf
Alternate Views	• M. Lutzenhiser, *RTO Dollars and Sense: Financial Data Raises*

	Doubts About Whether Deregulation Benefits Outweigh Costs, PUBLIC UTILITIES FORTNIGHTLY (December, 2004). • Alliance of State Leaders Protecting Electricity Consumers, *Commentary on FERC Staff Report on Day-1 RTO Cost* (November, 2004), *available at* http://www.pacifier.com/~ppcpdx/Tx/Alliance%20Cost%20Study%20Report%2011-22-04%20FINAL.pdf

Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design

Region	United States
Report Date	April 30, 2003
Sponsor	US DOE Report to Congress
Author/Contractor	In addition to DOE staff, participants included contractors who supported the modeling (GE Power Systems Energy Consulting, OnLocation, Inc) and those who supported the analysis (Charles River Associates, Neenan Associates, and Ken Rose of NARUC).
Model/Method	DOE's Policy Office Electricity Modeling System (POEMS) was used to assess wholesale and retail price impacts of SMD. GE MAPS was used to assess how the use of transmission networks will change under SMD. POEMS is an amalgam of several economic models (including EIA's National Energy Modeling System and TRADELEC) which forecasts trading volume and prices by NERC region. GE MAPS is an engineering model used to simulate the effects of a security constrained LMP market model on transmission patterns.
Scope of Inquiry	Assess the impacts of implementing FERC's Standard Electricity Market Design (SMD), as presented in FERC's July 31, 2002 proposed rule
Period Studied	
Conclusion	1. Estimated annual cost of implementing FERC's SMD Rule: $760 million ($.21/MWhr) 2. Average wholesale prices under SMD are estimated to decrease by 1 percent in 2005, increasing to 2 percent by 2020, relative to the non-SMD case. 3. The net benefit to all consumers of implementing SMD is estimated to be $1 billion/year for the first six years, dropping to $700 million by 2020. These figures are net of the $760 million estimated annual cost. (This implies total annual benefits of $1.46 to $1.76 billion, though this figure is not cited in the document). 4. Positive results are not consistent across regions – modeling suggests that end-use prices would rise in some regions and decrease in others.
Alternate Views	Alliance of State Leaders Protecting Electricity Consumers, *Commentary on DOE's Study of Standard Market Design* (June, 2003), *available at* http://www.pulp.tc/Alliance_Commentary_on_DOE_Study.pdf

Impact of the Creation of a Single MISO/PJM/SPP Power Market

Region	Midwest & Northeastern US
Report Date	2002
Sponsor	MISO-PJM-Southwest Power pool
Author/Contractor	Energy Security Analysis, Inc. (ESAI)
Model/Method	ZPM
Scope of Inquiry	Analyzes the impact of establishing a joint, common electricity market encompassing 26 states, the District of Columbia and the Canadian province of Manitoba (baseline is 2002 mix of ISOs and vertically integrated utilities
Period Studied	2002-2012
Conclusion	Benefits : $1.7 billion/year

Economic Assessment of RTO Policy

Region	United States
Report Date	2/26/2002
Sponsor	FERC
Author/ Contractor	ICF Consulting
Model/Method	ICF's IPM (Integrated Planning Model) computer simulator. • Simulates current inefficiencies through cross-CA hurdle rates, then eliminates those hurdle rates and measures the efficiency impacts. • Assumes 5 percent improvement in transmission transfer capability and measures production cost impacts. • Capacity sharing benefits simulated. • Decreased reserve requirements (from 15 percent to 13 percent) • Assumes generator efficiency improvements in RTO Policy case.
Scope of Inquiry	Assesses economic costs and benefits of a national move toward RTOs, including improvements in transmission system operations with resulting enhancements to inter-regional trade, congestion management, reliability and coordination, and improved performance of Energy markets.
Period Studied	2002-2021
Conclusion	* $1-$10 billion/year in system production cost savings * NPV of production cost savings over 20 years: about $1 trillion • About 4 percent savings off of base case for 20 year period • NPV of start up costs: $4.2-$7.3 billion (based on start up comparison of operating ISO/RTOs). Net operating costs (as compared with base case) assumed to be near zero .
Web Reference	http://www.ksg.harvard.edu/hepg/Papers/FERC%20ICF%20rtostudy_final_0226.pdf
Alternate Views	• Comments of the California Electricity Oversight Board Proposed Pricing Policy for Efficient Operation and Expansion Of the Transmission Grid, FERC Docket No. PL03-01-000 (March 13, 2003), *available at*

	http://www.eob.ca.gov/attachments/PL03-1-000Comments.doc • Comments of the New England Conference of Public Utilities Commissioners on Electricity Market Design and Structure, FERC Docket No. RM01-12-000. • Comment of the Staff of the Bureaus of Economics and Competition and the Office of the General Counsel of the Federal Trade Commission on Electricity Market Design and Structure, FERC Docket No. RM01-12-000, http://www.ftc.gov/be/v020014.pdf

STUDIES OF BENEFITS IN THE MIDWEST

An RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon

Region	PJM / Northern Illinois
Report Date	October 18, 2005
Sponsor	Illinois Citizens utility Board
Author/Contractor	Synapse Energy Economics / Ezra Hausman, Paul Peterson, David White, and Bruce Biewald
Model/Method	Comparison of baseline capacity revenues (derived from historical market data) with proposed RPM PJM price
Scope of Inquiry	Determine potential wealth transfer effects of proposed Reliability Pricing Model (RPM) by examining capacity revenues that might accrue to Exelon's Nuclear facilities in Northern Illinois if RPM is implemented.
Period Studied	June 2004 – June 2005
Conclusion	At the target RPM price, Exelon's nuclear plants in northern Illinois stand to gain almost $390 million in additional capacity revenues, compared to the 2004 capacity market price, at ratepayers' expense. At the maximum RPM price, these plants would receive a $1.2 billion increase in capacity revenues. At PJM's target price, RPM would amount to a rate increase for PJM ratepayers as a whole of over $5 billion every year, paid mostly to existing base load generation.
Web Reference	http://www.synapse-energy.com/Downloads/SynapseReport.2005-10.IL-CUB.RPM-Study--Higher-Costs-Windfall-Profits-for-Exelon.04-20.pdf

The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets

Region	Wisconsin
Report Date	March 26, 2004
Sponsor	MISO
Author/Contractor	Science Applications International Corporation
Model/Method	Production Cost/ Power Flow Modeling: PROMOD IV
Scope of Inquiry	Evaluates proposed financial transmission right allocations and overall impact of market participation on Wisconsin consumers.
Period Studied	2005 Calendar Year
Conclusion	Wisconsin and Michigan Upper Peninsula customers to save $51 million annually in wholesale power costs, net of costs of participating in markets.
Web Reference	http://www.midwestmarket.org/publish/Document/573257_ffe0fcee0f_-7f570a531528/_.pdf?action=download&_property=Attachment
Alternate Views	See comments of Wisconsin Load Serving Entities to Draft EPAct 2005 Section 1815 Report on Competition – FERC Docket AD05-17 – 6/26/06

STUDIES OF BENEFITS IN THE NORTHEAST

Putting Competitive Power Markets to the Test The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies

Region	Eastern Interconnection
Report Date	July, 2005
Sponsor	BP Energy Company, Constellation Energy, Exelon Corporation, Mirant Corporation, NRG Energy, Inc., PSEG, Reliant Energy Inc., Shell Trading Gas and Power Company, Williams, and Suez Energy North America
Author/Contractor	Global Energy Decisions
Model/Method	Global Energy calculated the benefits of wholesale competition for the Eastern Interconnection as they occurred. Those results were compared with a simulation of market conditions without the changes in market rules that enabled wholesale competition. Consumers benefited if the study showed a positive difference between current market conditions and the simulation of the traditional market rules prior to wholesale competition. Model: EnerPriseTM Strategic Planning *powered by MIDAS Gold®* software
Scope of Inquiry	To identify and quantify the existing and foreseeable consumer benefits of competitive electricity markets.
Period Studied	1999-2003
Conclusion	Wholesale customers in the Eastern Interconnection have realized a $15.1 billion benefit during the time period measured due to electricity competition. This benefit derives primarily from differences in the cost of generation construction under the two scenarios.
Web Reference	http://www.globalenergy.com/competitivepower/competitivepower.pdf
Alternate Views	Global Energy Decision, *Putting Competitive Power Markets to the Test: An Alternative View of the Evidence, available at* http://www.nreca.org/Documents/PublicPolicy/NRECAAD0517final.pdf

Electricity Prices in PJM: A Comparison of Wholesale Power Costs in the PJM Market to Indexed Generation Service Costs

Region	PJM Interconnection
Report Date	June 3, 2003
Sponsor	PJM
Author/Contractor	Synapse Energy (Biewald, Steinhurst, White, Roschelle)
Model/Method	estimates and compares two sets of annual prices: (1) the actual wholesale power costs (WPC) in the PJM market, and (2) prices in a scenario with economic regulation continued from the mid-1990s to today so that the

	generation service costs (GSC) are the unbundled generation portion of the pre-restructuring cost-of-service rates
Scope of Inquiry	To illuminate the effect of restructuring on prices in the PJM interconnection.
Period Studied	1999-2003
Conclusion	while PJM deregulated costs fluctuate year-to-year, on average, the wholesale power costs over the five year period 1999 to 2004 have been lower than the indexed generation service costs.
Web Reference	http://www.pjm.com/documents/downloads/reports/synapse-report-pjm-electricity-prices.pdf

Erecting Sandcastles From Numbers: The CAEM Study of Restructuring Electricity Markets

Region	PJM
Report Date	Dec. 3, 2003
Sponsor	NRECA
Author/Contractor	Christiansen Associates (Moray, Kirsch, Braithwait, Eakin)
Model/Method	Analysis of CAEM study assumptions/ inputs
Scope of Inquiry	To review and critique the Center for Advancement of Energy Markets' (CAEM) study entitled *Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region* (Sept. 22, 2003) (hereinafter CAEM Study).
Period Studied	1997-2002
Conclusion	The CAEM Study's quantitative results fail to demonstrate any relationship between these price changes and the economic effects of restructuring.
Web Reference	http://www.ksg.harvard.edu/hepg/Papers/Christensen.crit.restruct.mkts.in .pjm.03-Dec.03.pdf
Alternate Views	See below: *Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region, available at http://www.caem.org/website/pdf/PJM.pdf*

Estimating the Benefits of Restructuring Electricity Markets: An Application to the PJM Region

Region	PJM
Report Date	October, 2003
Sponsor	CAEM
Author/Contractor	R. Sutherland, CAEM
Model/Method	Measures decline in electricity prices during restructured period.
Scope of Inquiry	Estimates benefits of restructuring the electricity market in the PJM region.
Period Studied	1997-2002
Conclusion	Ultimate customers in the PJM region saved about $3.2 billion in 2002 from current restructuring efforts
Web Reference	http://www.caem.org/website/pdf/PJM.pdf
Alternate Views	Erecting Sandcastles From Numbers: The CAEM Study of Restructuring Electricity Markets (see above at *http://www.ksg.harvard.edu/hepg/Papers/Christensen.crit.restruct.mkts.in.pjm.03-Dec.03.pdf)*

Northeast Regional RTO Proposal: Analysis of Impact on Spot Energy Prices

Region	Northeast
Report Date	April, 2002
Sponsor	PJM
Author/Contractor	PJM
Model/Method	Market Simulation – GE MAPS
Scope of Inquiry	Estimates the impact of implementing a Northeast RTO on regional spot market prices in the near term.
Period Studied	Simulation year: 2001
Conclusion	Net Benefits of $299 million. $188 to PJM <$22> to NYISO $96 to NE

Assessing Short Run Benefits from a Combined Northeast Market

Region	Northeast
Report Date	October 23, 2001
Sponsor	NYISO
Author/Contractor	A. Hartshorn, S Harvey – LECG Consulting
Model/Method	Replicated Mirant methods: Statistical / econometric analysis using historic prices and flows. Looked at unconstrained transmission to determine correlation between prices. Extended the EEA analysis in time, improved on some elements of their methodology, and undertook some sensitivity analysis of Mirant

	estimates.
Scope of Inquiry	Potential benefits from implementing an interregional real-time dispatch in the Northeast. (Response to Mirant study of 2001)
Period Studied	10/00-8/01
Conclusion	Found that improvements in data and assumptions in Mirant study led to a material overstatement of the short-run benefits to New York consumers. Found large price impact benefits to PJM customers but little or negative price impacts for New York energy customers. Found overall decrease in energy payments for the combined region of $139 million for New York and $50 million for PJM on an annual basis.
Web Reference	http://www.ksg.harvard.edu/hepg/Papers/Assessing%20Short-Run%20Benefits%20from%20Combined%20NE%20Market%2010-23-011.pdf

Mirant Study*

Region	Northeast
Report Date	September 2001
Sponsor	Mirant
Author/Contractor	Energy and Environmental Analysis, Inc.
Model/Method	Statistical / econometric analysis using historic prices and flows. Looked at unconstrained transmission to determine correlation between prices. Assumes centralized dispatch would eliminate measured uneconomic flows.
Scope of Inquiry	Potential efficiency benefits that could be achieved by creating a single market for electricity in the Northeast. Model does not address net costs of establishing/operating a single Northeast RTO.
Period Studied	6/00-12/00
Conclusion	Net benefit of $440 million. $76 to PJM, $256 to NYISO, $108 to NE ISO.

** Not publicly available. Review based on secondary references.*

Competition Has Not Lowered U.S. Industrial Electricity Prices

Region	Connecticut, Massachusetts, Maine, New Hampshire, New York, and Rhode Island
Report Date	2005 (Published in the Electricity Journal, Vol. 18, No. 2 (2005) at 52-61)
Sponsor	Jay Apt
Author/Contractor	Jay Apt, Carnegie Mellon University
Model/Method	Used EIA price data to perform regression analysis on prices before and after competition.
Scope of Inquiry	Examines the effect of restructuring on prices paid by US industrial customers for electricity
Period Studied	1990-2004
Conclusion	Competition does not produce statistically significant price effects – rates

	in all states studied other than Maine increased an average of .8 percent per year prior to competition and they increased by 2 percent per year after competition.
Web Reference	http://wpweb2.tepper.cmu.edu/ceic/papers/ceic-05-01.asp

Economic Assessment of AEP's Participation in PJM

Region	PJM combined with AEP
Report Date	December, 2003
Sponsor	AEP
Author/Contractor	Cambridge Energy Research Associates
Model/Method	?
Scope of Inquiry	Quantifies the costs and benefits of AEP's integration into PJM markets.
Period Studied	?
Conclusion	$245 M in 2004 declining to $188M in 2008

Economic and Reliability Assessment of a Northeastern RTO

Region	NYISO, ISO-NE
Report Date	August 23, 2002
Sponsor	NYISO, ISO-NE
Author/Contractor	NYISO/ISO-NE
Model/Method	GE MAPS
Scope of Inquiry	Assesses wholesale electricity market impacts and organizational impacts of establishing a Northeastern RTO (NERTO), including expected costs of implementation, savings from market efficiencies, savings from operational consolidation.
Period Studied	?
Conclusion	$220M/yr in 2005 $150M/yr in 2010

STUDIES OF BENEFITS IN THE NORTHWEST

Bonneville Power Administration Grid West Benefit Assessment for Decision Point 2

Region	Northwest US
Report Date	August 4, 2005
Sponsor	Bonneville Power Administration
Author/Contractor	Internal Bonneville Power Administration staff report
Model/Method	Partially based on modeling conducted by Grid West (see "Estimated Benefits of Grid West") – Power World model used to derive benefits of control area consolidation and economic redispatch. Other analytical methods used to determine value of common regulation, reliability improvements, economic reserve markets, increased transmission usage, (measured in Gridview model), etc.
Scope of Inquiry	Potential benefits of adopting proposed Grid West design as compared with status quo.
Period Studied	Various – primarily examined 1 year historical period.
Conclusion	Reliability Benefits: $27 - $62 million annually Increased Transmission Capacity: $9 to $15 million annually Regulating Reserve benefits: $5-$8 million annually Redispatch Efficiencies: $41-$56 million annually Contingency Reserve Market Efficiencies: $20 to $30 million/year De-pancaking of transmission rate efficiencies: $4-$10 million **TOTAL**: $106 to $108 million
Web Reference	http://www.bpa.gov/corporate/business/restructuring/Docs/2005/benefit%20assessment/BPA_Grid_West_Benefit_Assessment.pdf

The Estimated Benefits of Grid West

Region	Pacific Northwest
Report Date	July, 2005
Sponsor	Grid West Regional Representatives Group
Author/Contractor	Grid West Risk Reward Workgroup
Model/Method	PowerWorld, Gridview, miscellaneous spreadsheet analyses, surveys
Scope of Inquiry	Estimate the benefits related to Grid West formation
Period Studied	Various
Conclusion	Results presented as a menu: • The capacity cost savings associated with Grid West-managed contingency reserves range from $20 million to $73 million per year. • The estimated capacity cost savings associated with Grid West reducing the amount of regulating reserves range from $5 million to

	$26 million per year • The estimated production cost savings associated with Grid West-managed real-time energy balancing redispatch range from $41 million to $385 million per year • The estimated annualized value to the region of avoiding cascading disturbances ranges from $27 million to $83 million per year. • Avoiding momentary (less than 5 minutes) or sustained events (longer than 5 minutes but shorter than 12 hours) related to non-cascading transmission events has an estimated annualized value to the region ranging from $17 million to $203 million per year • The estimated increase in production costs from the existing practice of charging multiple or pancaked rates ranges from $4 million to $61 million per year. • The estimated reduction in production costs from more efficient prescheduled interchange facilitated by the RCS ranges from $18 million to $52 million per year. • The estimated savings associated with energy conservation, non-wires expansion, and demand-side measures facilitated by Grid West range from $1 million to $61 million per year.

Study of Costs Benefits and Alternatives To Grid West

Region	Northwestern US
Report Date	October 15, 2004
Sponsor	Snohomish PUD
Author/Contractor	Henwood Energy & Margot Lutzenhiser of the Public Power Council
Model/Method	*Benefits*: MarketSym used to estimate the short term dispatch benefits associated with rate de-pancaking and more liquid operating reserve markets *Costs*: Applies apply the average cost/MWh of operating PJM, NYISO, ISO NE, CAISO and ERCOT to Grid West's projected annual demand.
Scope of Inquiry	Study the costs, benefits and alternatives to forming Grid West
Period Studied	2004
Conclusion	Gross annual benefits to the region of $78 million Grid West Annual costs of $200 million. Net Benefits of <122 million>
Web Reference	http://www.snopud.com/content/external/documents/gridwest/henwood_gridwestfinal.pdf

RTO West Benefit/Cost Study

Region	Northwestern US
Report Date	March 11, 2002
Sponsor	RTO West
Author/Contractor	Tabors Caramanis and Associates

Model/Method	GE MAPS
Scope of Inquiry	This study looked at the impacts that removing pancaked transmission rates and sharing reserves would have on the cost of generation in the Northwest.
Period Studied	2004
Conclusion	• The net benefits of eliminating transmission rate pancakes and sharing reserves would be $305 million/year in the RTO West footprint, and $410 million for all of RTO West. • 40 percent of this benefit can be attributed to the elimination of rate pancaking, 60 percent to reserves sharing.

RTO West Potential Benefits and Costs

Region	Northwest
Report Date	October 23, 2000
Sponsor	RTO West
Author/Contractor	RTO West Benefits/Cost Team
Model/Method	Aurora for production cost modeling, spreadsheet analyses for others
Scope of Inquiry	Identify and quantify benefits and costs to the regional electric power system that would occur as a result of implementing RTO West
Period Studied	Various
Conclusion	• Inconclusive production cost savings • Regulating reserve savings of $28 million annually over the RTO footprint. • Reliability benefits of anywhere from $33 million to $328 million annually • RTO Annual Costs of $63-$76 million • Misc. qualitative benefits

STUDIES OF BENEFITS IN THE SOUTHEAST

Cost Benefit Study of the Proposed GridFlorida RTO

Region	Peninsular Florida
Report Date	December 12, 2005
Sponsor	Grid Florida, LLC
Author/Contractor	ICF Consulting
Model/Method	Production cost modeling using GE MAPS
Scope of Inquiry	Examined the costs and benefits to Peninsular Florida consumers of transforming the current decentralized market to a centrally organized market under two modes of operation – a Day-1 only RTO and a Delayed Day-2 RTO.
Period Studied	2004-2016
Conclusion	• The quantitative benefits to Peninsular Florida consumers of Day-1 Only RTO operation is $71 million over this period, while the quantitative start-up and operating costs of a "greenfield" Day-1 RTO is $775 million. Thus, the Day-1 RTO configuration reflects an estimated net loss of $704 million. • Whereas the quantifiable benefits under Delayed Day-2 RTO operation were substantial, and ranged from approximately $810 million in the Market Imperfection Case to almost $968 million in the Reference Case, the cost of a "greenfield" Delayed Day-2 RTO with wholly new systems, physical facilities and personnel, designed along FERC's Standard Market Design principles, is also very significant at $1.25 billion. • The GridFlorida Delayed Day-2 RTO could breakeven under the scenarios examined in this study if the net benefits from the qualitative factors and the change in utility operational costs should be within the range of $285 million and $443 million over the 13-year forecast period. • This study also indicates that the non-jurisdictional consumers would receive net positive benefits of $798 million from the implementation of a GridFlorida Delayed Day-2 RTO while jurisdictional consumers would receive a net loss of $1.1 billion.
Web Reference	http://www.icfi.com/Markets/Energy/doc_files/gridflorida-rto-report.pdf

Cost Benefit Analysis Performed for the SPP Regional State Committee

Region	Southwest Power Pool
Report Date	April 23rd, 2005, revised July 27, 2005
Sponsor	SPP Regional State Committee
Author/Contractor	Charles River Associates
Model/Method	a) Wholesale Energy Modeling using GE MAPS

	b) Allocation of Energy Market Impacts and Cost Impacts c) Qualitative Assessment of Energy Imbalance Impacts d) Qualitative Assessment of Market Power Impacts e) Aquila Sensitivity Cases
Scope of Inquiry	(1) an analysis of the probable costs and benefits that would accrue from consolidated services and functions (which include reliability coordination and regional tariff administration) and (2) the costs and benefits of SPP's implementation of an Energy Imbalance Service (EIS) market.
Period Studied	2006-2015
Conclusion	* In the Stand-Alone case, implementation of intra-SPP wheeling rates leads to a less efficient dispatch and thereby increases system-wide production costs in comparison with the Base case. * The EIS market is estimated to provide considerably more benefits than costs, with the net benefits being $373 million to the transmission owners under the SPP tariff over the 10-year study period
Web Reference	http://www.spp.org/Publications/CBARevised.pdf

Electric Competition in the States of Arkansas, Louisiana and Mississippi - Is There An Opportunity?

Region	Arkansas, Louisiana and Mississippi
Report Date	2004
Sponsor	Tractebel
Author/Contractor	Tractebel
Model/Method	Spreadsheet
Scope of Inquiry	?
Period Studied	?
Conclusion	Fuel savings: $610M/yr Fixed O&M savings: $280M/yr

The Benefits and Costs of Dominion Virginia Power Joining PJM

Region	Virginia
Report Date	June 25, 2003
Sponsor	Dominion Virginia Power (DVP
Author/Contractor	Charles River Associates
Model/Method	GE MAPS
Scope of Inquiry	Assesses net benefits (to VG retail customers & to all retail and wholesale customers in DVP control) of DVP joining PJM to
Period Studied	2005-2014
Conclusion	Net Benefit to Virginia Retail Customers: $110.3 million for '05-'10: $476.6 million for '05-'14. Net Benefit to DVP customers: $127.4 million for '05-'10: $557.2 million for '05-'14.

The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast

Region	SE (SeTrans, Grid South, Grid Florida)
Report Date	11/6/02
Sponsor	Southeastern Association of Regulatory Commissioners
Contractor	Charles River Associates / GE Power Systems Engineering
Model/Method	GE MAPS (OPF/Production cost model) and a Financial Evaluation Module.
Scope of Inquiry	Net benefits of instituting SMD in SE (GridSouth, SeTrans & GridFlorida) of the US.
Period Studied	2004 – 2013
Conclusion	Mixed +150 to +$1,421for SeTrans; -$286 to +$84 for Grid South; -$25 to +248 for Grid Florida: ($Million 2003 dollars, PV over 10 years) *Note: Total Benefits are Net of Estimated Costs of Operating RTO*
Web Reference	http://www.crai.com/pubs/pub_2901.pdf

STUDIES OF BENEFITS IN TEXAS

Electric Reliability Council Of Texas, Market Restructuring Cost Benefit Analysis.

Region	ERCOT/ Texas
Report Date	11/30/2004
Sponsor	ERCOT
Author/Contractor	TCA/KEMA
Model/Method	a) **Energy Impact Assessment (EIA)—**quantified impacts to the energy market, system dispatch, energy prices, and resulting production system costs. (GE MAPS) b) **Backcast—**quantified optimized generation dispatch results for the ERCOT system for 2003 for comparison with those actually experienced. c) **Implementation Impact Assessment (IIA)—**provided quantitative and qualitative treatment of implementation startup costs, ongoing costs, and other transition-related impacts for ERCOT and its market participants. d) **Other Market Impact Assessment (OMIA)—**provided qualitative treatment of a variety of other measures of impact of market designs not captured directly in the EIA.
Scope of Inquiry	focused on two alternative market design choices: a zonal market design (extant at the time of the study) and a nodal market design
Period Studied	2005-2014
Conclusion	Did not draw single conclusion – "the potential savings found in the Energy Impact Assessment, relative to the Implementation costs found in the Implementation Impact Assessment, suggest that the benefits of the TNM could outweigh the costs for the ERCOT region as a whole.
Web Reference	http://oldercot.ercot.com/TNT/default.cfm?func=documents&intGroupId=83&b

APPENDIX D
STATE RETAIL COMPETITION PROFILES[331]

Illinois: Overview of Retail Competition Plan and Market Response

Administrator and Start Date: Customer choice in Illinois began in December 1997 with the enactment of the Electric Service Customer Choice and Rate Relief Act of 1997 (HB 362). HB 362 required a phase-in of retail competition, with larger customers able to choose an alternate generation supplier earlier in the transition. Specifically, customers eligible to choose their electric supplier as of October 1, 1999, included industrial and commercial customers with a demand of greater than 4 MW,[332] commercial customers with businesses at ten or more sites with an aggregate coincident peak demand of 9.5 MWs or greater, and non-residential customers accounting for one-third of the remaining electricity use of their customer class. All other non-residential customers were allowed to choose a supplier as of December 31, 2000, and all residential customers as of May 1, 2002.[333] The mandatory transition period ends January 1, 2007.[334]

The Illinois Commerce Commission (ICC) oversees the transition to competition in the electric industry. On January 24, 2006, the ICC approved proposals from Commonwealth Edison, the Ameren companies, Central Illinois Public Service, Central Illinois Light Company and Illinois Power, to procure generation (for retail customers who do not switch to an alternative retail supplier) through a joint competitive reverse auction process. In order to reduce price increases after the transition period ends, the utilities have offered to phase in price increases at the end of the transition period for residential customers.

Services Open to Competition: Generation and metering services: The ICC promulgated rules that permit non-residential customers to choose a meter service provider other than the distribution utility.

The ICC permitted Commonwealth Edison to designate customers with a demand exceeding 3 MW as a competitive customer class.[335] No other classes of customers have been declared competitive to date. Competitive services are defined as those services provided under special contract, not provided under tariff, and any tariffed service that the ICC decides is competitive. A service is declared competitive only if it is offered by a provider other than the utility or its affiliate, to a defined customer group or area, at a competitive price, if the utility is likely to or has lost business to the competitor, and if there is adequate transmission system capacity.[336]

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[331] Information in this appendix is derived in large part from – and updates information contained in the *FTC Retail Competition Report*. Because economic circumstances and state laws and regulations change, regulatory authorities in each state and market participants should be consulted for more detailed and up-to-date information on state retail choice programs.

[332] Average monthly maximum electrical demand on the electric utility's system during the 6 months equals the customer's highest monthly maximum demands in the 12 months ending June 30, 1999.

[333] 220 ILL. COMP. STAT. 5/16-104 (West 2001).

[334] S.B. 2081 (Ill. 2002) (extending the transition period from January 1, 2005, to January 1, 2007).

[335] *Commonwealth Edison Company*, Illinois Commerce Commission, Docket No. 02-0479 (March 28, 2003), *available at* http://eweb.icc.state.il.us/e-docket/reports/view_file.asp?intIdfile=83392&strc=bd.

[336] 220 ILL. COMP. STAT. 5/16-113.

Consumer Options: Consumers have two options for service:

(1) They may either remain with the utility as a bundled customer (i.e., receiving generation, transmission and distribution services); or

(2) They may choose to become a delivery services customer (i.e., they only take distribution and transmission services from the utility). Delivery services customers may purchase generation services from another electric utility, from a competitive supplier, or from their own utility using the power purchase option (PPO).[337]

The PPO is a transitional option that is provided by distribution utilities as long as they are recovering stranded costs from customers (*see* Recovery of Stranded Costs/Transition Costs). Under PPO service, a non-residential delivery services customer (such as an industrial customer) can purchase electric power from the utility at a price that reflects wholesale costs. These customers may then assign the power purchased under the PPO to an alternative supplier. Under this option, the suppliers to whom customers have assigned PPO rights are, in effect, purchasing electricity from the utility and selling it to their customers.

Alternative Suppliers Licensed to Provide Service: All suppliers wishing to provide competitive supply service must have a certificate of service authority. In order to receive certification, a supplier must show technical, financial, and managerial capability.[338] A competitive supplier is required to maintain a license or permit bond in the amount of $30,000 if the supplier intends to serve only non-residential customers with maximum demand greater than 1 MW; $150,000 if the supplier intends to serve non-residential customers with annual electric consumption greater than 15,000 kWh; or $300,000 if the supplier wishes to be certified to serve all eligible retail customers.

In general, retail competition is much more active in the Commonwealth Edison territory than elsewhere in the state. In 2005, the number of active suppliers in each distribution utility's territory ranged from zero for MidAmerican, to nine for ComEd.[339] Over the 2000 to 2005 period, the number of suppliers increased in the AmerenCIPS service territory from 3 to 4. An alternative supplier entered the AmerenCILCO area for the first time in 2003 and the only alternative supplier left the MidAmerican area in 2001. The retailers have focused only on non-residential customers.

[337] *Id*. at 5/16-110.

[338] *Id.* at 5/16-115.

[339] Illinois Commerce Commission, *Competition in Illinois Retail Electric Markets in 2005*, Table 2 (May 2006), *available at* http://www.icc.illinois.gov/docs/en/060524garpt16120b.pdf.

Retail Pricing Trends: As Table 1 shows, retail prices for the residential sector rose about 7 percent from 1988 to 1997. Commercial and industrial prices rose by lesser amounts during that decade. Prices for all classes of customers declined after that decade through 2004, with the largest declines taking place in the residential sector due to mandatory rate reductions.

Table 1. Average Annual Price per KWh by Sector
(nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Residential	9.7	10	9.9	9.9	10.3	10.3	10	10.4	10.3	10.4	9.9	8.8	8.8	8.7	8.4	8.4	8.4
Commercial	7.5	7.8	7.8	7.9	8.1	8	7.7	7.9	8	7.9	7.8	7.4	7.2	7.4	7.5	7.3	7.5
Industrial	5.2	5.4	5.4	5.5	5.5	5.5	5.2	5.3	5.2	5.3	5.1	5	4.2	4.7	4.9	4.9	4.7
All Sectors	7.3	7.5	7.5	7.6	7.7	7.8	7.4	7.7	7.7	7.7	7.5	7	6.6	6.9	6.9	7.1	6.8

Source: Energy Information Administration

Price Changes for POLR Service for Residential Customers: In accord with the restructuring legislation, there were mandatory residential POLR service rate reductions instituted in 1998, which depended on how the utility's residential rate compared to the residential rate for all large investor owned utilities in the region at the time of the restructuring legislation. The rationale behind the restructuring legislation was that competition would tend to bring higher local rates down to the regional average, but there was uncertainty about whether residential customers would obtain these benefits of competition in a timely manner because of the relatively high expected marketing costs associated with residential customers. No mandated retail price reductions were applied to POLR service for non-residential customers.

There are six major utilities in Illinois with required residential rate reductions for customers that have not selected an alternative supplier. Rate reductions were designed to bring residential rates in line with regional rates at the time of the restructuring legislation and are shown in Table 2.[340] The larger discount rates were applied in two phases.

Table 2. Price Reductions from 1997 Cost-Based Rates by Distribution Utility

Distribution Utility	**Reduction from 1997 Regulated Prices**
Commonwealth Edison	20% (15% August 1999, 5% October 2001)
AmerenIP	20% (two increments)
AmerenCILCO	5%
AmerenCIPS	5%
AmerenUE	5%
MidAmerican Energy	1.7%

Non-residential customers were able to elect "real-time pricing" beginning on October 1, 1998; residential customers were able to elect real-time pricing beginning on October 1, 2000.[341] Real-

[340] *See* S.B. 24 (Ill. 1999) (amending H.B. 362). Illinois Commerce Commission comments at 17-18.

[341] 220 ILL. COMP. STAT. 5/16-107.

time pricing is defined as pricing which varies hour by hour for non-residential customers, and on a periodic basis during the day for residential customers.[342] The largest residential real-time pricing effort is a pilot program involving 1,500 customers in the Commonwealth Edison territory operated by the Community Energy Cooperative.[343] Some non-residential customers may also have real-time pricing or other time of use rates, but statistics are unavailable.

POLR Service Provider: Utilities must provide traditional, bundled service for those customers who choose not to shop for a competitive supplier.[344] The POLR (standard offer) price is the price for bundled service (i.e., service including generation, transmission, and delivery), which was set by the utility's last rate proceeding, less the amount of any rate reduction required in the restructuring law. This rate is frozen until January 1, 2007.

Recovery of Stranded Costs/Transition Costs: Utilities collect stranded costs from both POLR service customers as part of the rates and through a separate charge from retail customers with an alternative supplier.[345]

Switching Restrictions and Minimum Stay Requirements: Customers purchasing power from an alternate supplier are allowed to return to the utility after paying an administrative fee. A utility may require a returning customer with usage less than 15,000 kWh annually to stay with the utility for two years.[346]

Switching Activity: The degree to which customers have switched to delivery service from bundled service varies greatly between distribution franchise territories and classes of customers. Table 2 provides the switching statistics for the largest utility franchise areas, separated by customer type, as of November 2005. As Table 3 indicates, the vast majority of switching activity is centered on the Commonwealth Edison distribution territory (which also has the largest load in the state). Lower levels of switching have taken place in the AmerenCILCO and AmerenIP areas, and there has been very little switching outside of these three areas.

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342 *Id*. at 5/16-102.

343 Robert Lieberman (ICC Commissioner), *Ruminations on Demand Response – a View from Chicago* (Oct. 28, 2005), *available at* http://www.raabassociates.org/Articles/Lieberman_10.28.05.ppt#299.

344 220 ILL. COMP. STAT. at 5/16-103.

345 *Id*. at 5/16-108.

346 *See* 220 ILL. COMP. STAT. 5/16/-103(d).

Table 3. Illinois Switching to Alternative Suppliers as of November 30, 2005 % of Customers and (% of Load)				
Firm and Usage In million kWh	Residential	Small C&I	Large C&I	Total
AmerenCILCO 461	0.0% (0.0%)	0.0% (0.1%)	2.2% (33.3%)	0.0% (15.4%)
AmerenCIPS 952	0.0% (0.0%)	0.2% (0.8%)	7.1% (4.1%)	0.0% (2.2%)
AmerenIP 1,496	0.0% (0.0%)	0.8% (8.9%)	29.8% (41.7%)	0.1% (23.2%)
AmerenUE 265	0.0% (0.0%)	0.0% (0.0%)	2.5% (0.2%)	0.0% (0.1%)
ComEd 91,508	0.0% (0.0%)	6.0% (36.6%)	73.9% (58.3%)	0.6% (32.8%)
MidAmerican 139	0.0% (0.0%)	0.0% (0.0%)	0.0% (0.0%)	0.0% (0.0%)
Source: Illinois Commerce Commission				

Table 4 shows the patterns of switching for the 2003 to 2006 period. Residential switching has remained dormant over the whole period while large non-residential customers have switched much of their load to alternative suppliers. Small non-residential customers have been slower in switching to alternative suppliers and the load served declined slightly in 2006, but the share of alternative suppliers continue to be well above the levels in 2003.

Table 4. Illinois Retail Aggregate Customer Migration Statistics, 2003 to January 2006 % of Customers and (% of Load) Served by Alternative Suppliers				
	2003	2004	January 2005	January 2006
Residential	0.0% (0.0%)	0.0% (0.0%)	0.0% (0.0%)	0.0% (0.0%)
Small C&I	3.8% (30.2%)	4.4% (31.5%)	5.7% (38.4%)	5.9%) (36.7%)
Large C&I	58.6% (54.6%)	64.1% (56.6%)	73.0% (58.3%)	71.9% (58.7%)
Note: The 2003 and 2004 figures are annual aggregates while the 2005 and 2006 figures are for the month of January. The 2005 and 2006 figures are estimated from the statistics for the Commonwealth Edison territory. Load in Commonwealth Edison accounts for approximately 96.5 percent of the load of IOUs. To be conservative, it was assumed that there was no switching outside of Commonwealth Edison, hence the Commonwealth Edison statistics for 2005 and 2006 were reduced by 3.5 percent to create the proxy for the state-wide value. *Source*: Illinois Commerce Commission				

Public Benefits Programs: The restructuring act establishes three public benefits funds which are slated to expire at the end of 2006. Table 5 contains information about the public benefits program in Illinois.

Table 5. Illinois Public Benefits Programs*

	Research & Development	Energy Efficiency	Low Income	Renewable Energy	Total
Million $		3.0	75.0	5.0	83.0
Mills/kWh		0.03	0.60	0.04	0.67
% revenue		0.03%	0.87%	0.06%	0.96%
Admin.		DCEO	DCEO	DCEO	

Note: Trust Funds are administered by the Illinois Department of Commerce and Economic Opportunity (DCEO).
Source: American Council for an Energy-Efficient Economy, Summary Table of Public Benefit Programs and Electric Utility Restructuring (December 2005) available at http://www.aceee.org/briefs/mktabl.htm.

* In December 1997, PA 9D-551 was signed. It provided funding for EE, RE, LI (although EE and RE are at low levels) using non-bypassable, flat monthly charges on customer bills. (mills/kWh) equiv. includes $ from gas & elect. Also one-time ComEd $250 million Clean Energy Trust Fund approved by legislature in May, 1999 (not in table).

Separation of Generation and Transmission: Illinois did not require divestiture or functional separation. Thus, utilities may engage in both competitive and non-competitive services without forming a separate affiliate. All of the major utilities in Illinois chose to transfer generation assets to affiliates with the exception of Commonwealth Edison, which divested its fossil fuel generation plants.

State RTO Involvement: The restructuring legislation required Illinois utilities with transmission assets to join an RTO or ISO. Illinois utilities have joined either the Mid-West ISO or PJM West. Commonwealth Edison, for example, joined PJM West. The Ameren utilities joined the Mid-West ISO. MidAmerican has not joined an ISO, although it has received FERC authorization to engage an independent transmission operator.

Generation Capability:[347] Prior to the restructuring legislation (1997), utilities operated 97 percent of the generation capability in Illinois. By 2002, that figure dropped to 9.1 percent. The difference reflected the transfers and sales of generation assets to utility-affiliated entities and entry or expansion by independent power producers. Between 1997 and 2002, generation output in the state increased from 135 million MWhs to 188 million MWhs, a nearly 40 percent increase. During the 1993 to 1997 period, output in the state had shrunk by more than 5 percent .

Use of Customer Information: No customer-specific information can be given to a supplier without customer authorization.[348]

Standardized Labeling:[349] "The 1997 Illinois restructuring law includes provisions for disclosing

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[347] U.S. Department of Energy, Energy Information Administration, Illinois State Profile, Table 4, *available at* http://www.eia.doe.gov/cneaf/electricity/st_profiles/illinois.pdf.

[348] 220 ILL. COMP. STAT. at 5/16-122.

[349] Department of Energy, Energy Information Administration, *Disclosure Policies*, *available at* http://www.eere.energy.gov/greenpower/markets/disclosure.shtml?print.

fuel mix and emissions by retail electricity suppliers. Final rules issued by the Illinois Commerce Commission (ICC) require retail suppliers to provide a bill insert to customers each quarter with a table and pie chart representing the sources of electricity used in the previous year, beginning in January 1999. Suppliers must also provide a table showing total emissions of carbon dioxide, nitrogen oxides, and sulfur dioxide, as well as the amount of high- and low-level nuclear waste attributable to the sources of electricity."

Renewable Energy Portfolio Standard: On July 19, 2005, the ICC adopted a voluntary renewable portfolio standard target for bundled retail load starting at 3 percent in 2007 and rising by one percent each year until it reaches 8 percent in 2013.[350] The ICC's resolution also includes targeted reductions in future load growth.

Maryland: Overview of Retail Competition Plan and Market Response

Administrator and Start Date: The Maryland General Assembly enacted the Maryland Electric Customer Choice and Competition Act (SB 300) on April 8, 1999. The Act allowed for a three-year phase-in approach to electric competition, but the Maryland Public Services Commission (PSC) allowed the utilities to start electric competition all at once for all customers on July 1, 2000. The PSC oversees the customer choice program.[351]

Services Open to Competition: Generation, billing, and metering.

Consumer Options: Customers may choose to remain with the distribution utility at PSC regulated prices until the end of the transition period; they may choose a competitive supplier; or they may choose to be aggregated with other customers. The transition period ended for most consumers in Maryland as of July 2006. In other areas, the period ends in 2008.

Alternative Suppliers Licensed to Provide Service: All alternative suppliers must be licensed by the PSC, and must show proof of technical and managerial competence, compliance with FERC requirements, and compliance with state and federal environmental laws.[352] A supplier must also give proof of financial integrity,[353] and the PSC assesses each competitive supplier's application for a license on a case-by-case basis to determine whether a letter of guarantee, bond, or letter of credit is needed, and in what amount.[354] Registered suppliers and registered suppliers seeking additional customers are available on the Maryland PSC's website. There are numerous registered and active suppliers for C&I customers. For residential customers, there are numerous registered suppliers but only two suppliers in three of the four major utility territories and none in the Allegheny Power territory before the end of the transition period.

Pricing Trends: As Table 6 shows, prices rose throughout the early 1990s for all sectors, then

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[350] Illinois Commerce Commission Resolution, *Response to Governor's Sustainable Energy Plan for the State of Illinois*, Case No. 05-0437 (July 19, 2005), *available at* http://eweb.icc.state.il.us/e-docket/reports/view_file.asp?intIdFile=148072&strC=bd.

[351] MD. CODE ANN., PUB. UTIL. COS., §§7-509 (2000).

[352] *Id.* at § 7-507(b).

[353] *Id.* at § 7-507(c).

[354] Maryland Public Service Commission, *Supplier Authorization Procedures* (Mar. 17, 2000), *available at* http://www.psc.state.md.us/psc/electric/supplierauthorization.htm.

declined until 2002. Prices rose in 2003 and 2004. With the end of the transition period for most residential and small C&I customers in the state, POLR service is scheduled to be priced at market rates. Procurement contracts for POLR service starting in July 2006 are scheduled to result in price increases above existing POLR rates. For example, the scheduled price increase for customers in the BG&E distribution territory is reported to be 72 percent.[355] Because of concerns about the size of the expected price increase, a number of alternative proposals were developed to break the increase into smaller steps. Legislation just prior to the end of the transition period included deferrals of revenues and dismissal of the members of the PSC. At the time of this writing, litigation regarding the latter provision is taking place.[356]

Table 6. Maryland Average Annual Price per KWh by Sector
(nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Residential	6.7	6.9	7.2	7.9	8.0	8.2	8.4	8.4	8.3	8.3	8.4	8.4	8.0	7.7	7.7	7.7	7.8
Commercial	6.5	6.6	6.7	7.0	7.1	7.2	7.2	6.9	6.8	6.9	6.8	6.8	6.6	6.4	6.3	7.0	7.6
Industrial	4.4	4.7	5.1	5.5	5.4	5.5	5.3	4.2	4.2	4.2	4.1	4.3	4.1	4.4	4.0	4.9	6.0
All Sectors	5.8	6.0	6.3	6.8	6.8	7.0	7.0	7.1	7.0	7.0	7.0	7.0	6.8	6.6	6.2	6.5	7.2

S*ource*: Energy Information Administration

Price Changes for POLR (or Regulated) Service: Individual distribution utility plans vary, but a cap for all distribution utilities was put into effect through 2004 and then extended for two to four years. During the initial four years, distribution utilities were required to decrease prices 3-7.5 percent.[357] During this period, if the distribution utility's POLR price increased, transition charges decreased by a corresponding amount, so that standard offer customers did not have an overall price increase.[358]

POLR Service Provider: The distribution utilities provide POLR service in their respective territories until the end of the transition period (or longer if the PSC extends the period). A distribution utility can procure the electricity for its POLR customers from any supplier, including an affiliate. Individual utility settlements require the utility to be the POLR service provider for the entire rate cap/freeze period (which varies in length per utility) unless the Commission orders otherwise. POLR service rates and the respective terms were set in the individual utility settlements and have been in effect for the entire rate cap/freeze period.

Recovery of Stranded Costs/Transition Costs: Distribution utilities were given an opportunity to recover all prudently incurred and verifiable net transition costs, subject to full mitigation.[359] Transition costs eligible for recovery include those that would be recoverable under rate-of-return regulation, but are not recoverable in a restructured electric market and costs that result

[355] Andrew Green, *Legislators Not Close on Rates*, BALT. SUN (Apr. 4, 2006).

[356] Patrice Hill, *Maryland Utilities Designated Near Junk*, WASH. TIMES (July 12, 2006), *available at* http://www.washingtontimes.com/functions/print.php?StoryID=20060711-103048-5690r.

[357] MD. CODE ANN., PUB. UTIL. COS., § 7-505(d) (2000).

[358] Maryland Public Service Commission, *Maryland Electric Choice FAQ*, *available at* www.psc.state.md.us/psc/electric/FAQ/overall.htm.

[359] MD. CODE ANN., PUB. UTIL. COS., § 7-513 (2000).

from the creation of customer choice.[360] Stranded costs have been recovered through a competitive transition charge, and may be recovered over different lengths of time for each distribution utility. The PSC determines the amount of recoverable transition costs, as well as the amount of the charge to be levied on customers.

Switching Activity: Table 7 shows the proportion of customers and load taking service from alternative suppliers in each major utility distribution territory.

Table 7. Retail Customers and Load Supplier by Alternative Providers in February 2006
% of Customers and (% of Load)

Firm	Residential	Small C&I	Medium C&I	Large C&I
Allegheny Power	0.0% (0.0%)	0.1% (0.9%)	18.0% (19.3%)	58.1% (29.5%)
Baltimore G&E	0.0% (0.0%)	0.9% (1.7%)	17.2% (19.8%)	87.1% (93.4%)
Delmarva P&L	0.0% (0.0%)	1.9% (4.1%)	22.5% (28.6%)	91.0% (95.7%)
Potomac El.	5.8% (7.1%)	10.8% (14.0%)	14.2% (13.2%)	75.8% (83.3%)

Source: Maryland PSC

Table 8 shows the state aggregate level of switching as of December for each year from 2000 to 2005.

Table 8. Maryland Retail Aggregate Customer Migration Statistics, 2001-2005.
% of Customers and (% of Load) Served by Alternative Suppliers

	Dec. 2000	Dec. 2001	Dec. 2002	Dec. 2003	Dec. 2004	Dec. 2005
Residential	0.6% (0.7%)	2.6% (3.4%)	3.3% (4.1%)	3.1% (3.8%)	2.2% (2.9%)	1.5% (1.9%)
Small C&I	1.2% (3.2%)	4.1% (9.8%)	6.2% (30.4%)	5.7% (27.8%)	3.6% (4.2%)	2.8% (3.4%)
Medium C&I					21.7% (24.6%)	17.7% (21.0%)
Large C&I					58.0% (75.1%)	78.6% (87.4%)

Note: Prior to 2004, Non-residential data were combined into a single category.
Source: Maryland PSC

Public Benefits Programs: Funds for a Universal Service Program have been collected from all customers, and may not be assessed on a per kilowatt-hour basis.[361]

Table 9. Maryland Public Benefits Programs

MD's restructuring law was signed in		Research & Develop.	Energy Efficiency	Low Income	Renewable Energy	Total
	Million $		Up to 1.0	34.0		34.0+

[360] *Id.* at § 7-501(p).

[361] *Id.* at § 7-512.1 (2000).

April 1999 including a $34 M/yr. tax funded Universal Service Fund. Additional funds from individual utility settlements.	Mills/kWh			0.51		0.51+
	% revenue			0.82		0.82+
	Admin.		Utility	State		
	Source: American Council for an Energy-Efficient Economy, *Summary Table of Public Benefit Programs and Electric Utility Restructuring* (December 2005), *available at* http://www.aceee.org/briefs/mktabl.htm.					

<u>Separation of Generation and Transmission</u>: Divestiture of generation assets was not required, but functional, operational, structural or legal separation of regulated and non-regulated businesses or non-regulated affiliates was required by July 1, 2000.[362] Distribution utilities must provide a code of conduct to prevent their regulated service customers from subsidizing services of unregulated businesses.[363] A distribution utility can transfer any of its generation facilities or assets to an affiliate, if it desires.[364] Power generation affiliates can only sell power on the wholesale market, except for standard offer service suppliers. Retail sales affiliates may only buy power from the wholesale market.

<u>State RTO Involvement</u>: Maryland belongs to the multi-state PJM RTO.

<u>Generation Capability</u>: Prior to the restructuring legislation, utilities operated 95.4 percent of generating capability in Maryland. By 2002, that figure dropped to 0.1 percent. Between 1997 and 2002, generation capability increased from 11,713 to 11,859 MW accompanied by growth in the proportion of dual fired capacity.

<u>Usage of Customer Information</u>: Customer information cannot be released without a customer's consent, except for bill collection and credit rating purposes.[365] Customer lists containing names, addresses, and telephone numbers of customers may be sold to competitive suppliers. If a distribution utility intends to release such a list, it must inform its customers, and advise customers of their opportunity to prevent disclosure of their identifying information.[366]

362 *Id.* at § 7-505.b(10).

363 *Id.* at § 7-505(b)(13).

364 *Id.* at § 7-508.

365 *Id.* at 7-505(b).

366 Maryland Public Service Commission, *In the Matter of the Commission's Inquiry into the Provision and Regulation of Electric Service*, Order No. 76110 (Apr. 25, 2000).

Standardized Labeling:

- **Content:** Distribution utilities and competitive suppliers must provide customers with a uniform set of information on fuel mix and emissions. When actual data is unavailable, a regional average may be used. Labels have to include comparison of emissions and fuel mix to the regional average when information is available.[367]

- **Timing:** Labels must be provided to customers every six months.[368]

Renewable Energy Portfolio Standard: Maryland enacted a renewable energy portfolio standard in 2004. The standard gradually increases to 7.5 percent in 2019. A separate standard of 2.5 percent including hydroelectric and waste-to-heat generation applies throughout the period.

Massachusetts: Overview of Retail Competition Plan and Market Response

Administrator and Start Date: Electricity Restructuring in Massachusetts was initiated and is administered by the Department of Telecommunications and Energy (DTE). Retail competition began March 1, 1998, in accordance with the restructuring legislation enacted November 25, 1997.

Services Open to Competition: Generation only. Metering and billing are provided by the distribution utility.

Consumer Options: During the transition to competition, consumers had three types of choices to obtain their electricity supply: a) standard offer service, b) service through an aggregator, or c) service from a competitive supplier. If a supplier was unable to provide services, consumers then received a "default" service. Unlike most states that provided POLR service, Massachusetts named its POLR service as standard offer service, and developed another regulated price for those customers for which their supplier no longer provided service (default service). The transition ended in February 2005, at which time standard offer service was discontinued for all customers. Currently, customers who have not chosen a competitive supplier receive default service from the distribution utility that procures generation services from wholesale suppliers. All retail customers are eligible for default service at any time, and may remain on default service indefinitely. Customers can also select an alternative supplier or be part of a group of customers served by an aggregator. For purposes of this summary, default service will be referred to as a type of POLR service.

Alternative Suppliers Licensed to Provide Service: All alternative suppliers must be licensed to provide service to customers in Massachusetts.[369] Licensing regulations require a supplier to show technical and financial capability.[370] Massachusetts maintains a roster of registered competitive electricity suppliers including brokers and direct competitive suppliers. The roster

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[367] Maryland Public Service Commission, *In the Matter of the Commission's Inquiry into the Provision and Regulation of Electric Service,* Order No. 76241 (June 15, 2000). See section below on advertising restrictions for supplier requirements to disclose pricing information to customers.

[368] MD. CODE ANN., PUB. UTIL. COS., § 7-505(b) (2000).

[369] MASS. GEN. LAWS ch. 164, § 1F(1) (2001).

[370] 220 MASS. CODE REGS. 11.05(2) (2001).

in February 2006 included 30 direct suppliers and twice as many brokers.[371] Ten of the suppliers offered service to residential customers as did a comparable number of brokers.

Pricing Trends: As Table 10 shows, prices for the residential and commercial sectors for the 1988 to 2004 period rose intermittently before peaking in 1997 and then declined before peaking again in 2001. Prices for the industrial sector rose intermittently in the 1990s and also peaked in 2001.

Table 10. Massachusetts Average Annual Price per KWh by Sector
(nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Residential	8.5	9.1	9.7	10.4	10.6	11.0	11.1	11.3	11.3	11.6	10.6	10.1	10.8	12.5	10.9	11.7	11.75
Commercial	7.7	8.1	8.6	9.2	9.3	9.7	9.8	9.9	9.9	10.3	9.4	8.9	9.0	11.6	10.0	10.5	11.0
Industrial	6.8	7.3	7.9	8.5	8.6	8.7	8.5	8.4	8.4	8.8	8.2	7.7	8.1	9.4	8.3	9.1	8.5
All Sectors	7.8	8.3	8.8	9.5	9.7	10.0	10.0	10.1	10.1	10.5	9.6	9.1	9.5	11.6	10.1	10.6	10.8

Source: Energy Information Administration

Price Changes for Standard Offer Service: Massachusetts set a minimum 10 percent reduction of the entire bill for all customers receiving standard offer service during the transition period. On September 1, 1999, the reduction increased to at least 15 percent, in order to adjust for inflation. These rate reductions applied to all distribution utilities.[372] Distribution utilities were authorized to use securitization to meet the second rate reduction effective September 1, 1999.[373]

Standard Offer Service Provider: Standard offer service was provided until February 2005 for customers who had not chosen a competitive supplier during the transition period. It was offered by the distribution utility, at rates which were set in advance, but subject to some adjustments.[374]

POLR (default service) is offered currently to customers who are not receiving service from a competitive supplier or aggregator. Former standard offer customers were offered POLR service at the end of the transition. The price for POLR service is based on the price of procuring it in the wholesale markets through fixed price short-term (three or six months) supply contracts. Distribution companies must procure electricity for default generation service through competitive bidding, although the DTE also may authorize a competitive supplier to provide POLR service.[375]

POLR service prices cover the energy portion of the total bill. Distribution rates, taxes, and fees are additional. POLR service prices follow wholesale prices. The default prices applicable to

[371] Massachusetts Department of Telecommunications and Energy, *Massachusetts Competitive Electricity Suppliers* (February 14, 2006). The current listing of active suppliers for each distribution territory is accessible at http://www.mass.gov/dte/restruct/competition/index.htm#licensed%20competitive%20Suppliers%20and%20electricity%20brokers (under "Generation Service Information.")

[372] MASS. GEN. LAWS ch. 164, § 1B(b) (2001).

[373] *Id.* at § 1G(c)(2).

[374] *Id.* at § 1B(b).

[375] *Id.* at § 1B(d).

January of each year for the northern portion of the Boston Edison distribution area (Table 11) illustrate the pattern.

Table 11. Default Prices Applicable in January by Year, Boston Edison (north)								
	1999	2000	2001	2002	2003	2004	2005	2006
Residential	3.7	4.5	7.0	6.4	5.0	6.5	7.5	12.7
Commercial	3.7	4.5	7.0	6.6	5.2	6.6	7.3	12.3
Industrial	3.7	4.5	7.0	6.5	5.1	6.6	9.0	18.1
DTE, Fixed Default Service Prices in cents/kWh								

Recovery of Stranded Costs/Transition Costs: The restructuring legislation provided for the recovery of stranded costs through a non-bypassable charge to all customers.[376] This charge was capped by the DTE, and the DTE determined, on a case-by-case basis, the time period for recovery.[377]

Switching Restrictions and Minimum Stay Requirements: Customers can switch to or from POLR (default/basic) service.[378]

Switching Activity: Table 12 shows the proportion of customers and load taking service from alternative suppliers in each utility distribution territory. In the Commonwealth territory, switching by residential customers is much higher than in any other area of the state. Much of this residential switching is attributable to community aggregations, principally the Cape Light Compact.[379]

Table 12. Retail Customers and Load Supplied by Alternative Providers in January 2006 % of Customers and (% of Load)				
Firm and load in MWh	Residential	Small C&I	Medium C&I	Large C&I
Boston Edison 1,498,476	0.3% (0.6%)	2.0% (3.5%)	7.9% (13.6%)	34.0% (50.0%)
Cambridge 154,540	0.2% (0.3%)	6.7% (13.5%)	8.4% (12.4%)	33.6% (52.6%)
Commonwealth 403,108	54.2% (51.8%)	55.0% (57.5%)	44.3% (46.2%)	65.6% (70.5%)
Fitchburg 47,256	0.0% (0.0%)	3.8% (2.9%)	4.8% 15.5%	72.7% (86.6%)
Mass. Electric 1,995,096	2.1% (2.4%)	7.4% (12.2%)	31.1% (29.3%)	58.1% (66.2%)
Nantucket 12,547	0.2% (1.3%)	4.4% (6.6%)	23.6% (29.3%)	50.0% (53.2%)
Western Mass.	0.5% (0.7%)	6.6% (11.9%)	32.4% (36.8%)	60.2% (76.3%)
Source: Mass. Department of Telecommunications and Energy				

376 *Id.* at § 1G(a).

377 *Id.* at § 1G(e).

378 David L. O'Connor (Commissioner, Mass. Division of Energy Resources), *Retail Competition: Managing a Difficult Transition* (Apr. 6, 2001), at 6, *available at* http://www.nga.org/Files/ppt/ElecOconnor.ppt.

379 Cape Light Compact comments.

Table 13 shows the state aggregate levels of switching from January 2001 to January 2006. Although all customers of Massachusetts distribution utilities were eligible for retail access as of March 1, 1998, switching remained at minimum levels for residential and small C&I customers. Larger commercial and industrial customers were more likely to switch, but sometimes switched back to default service if default prices fell below prices from alternative suppliers. Subsequent to February 2005, the proportion of load served by alternative suppliers increased for all classes of customers.

Former standard offer customers either switched to competitive generation suppliers or started receiving POLR service at the end of February 2005. In December 2004, standard offer service applied to approximately 1.5 million customers with load of 1,959,705 MWh. The share of load served by competitive generators increased from 23.7 percent to 30.4 percent between December 2004 and December 2005 following the end of the standard offer service.

Table 13. Massachusetts Retail Aggregate Customer Migration Statistics, 2001-2006
% of Customers and (% of Load) Served by Alternative Suppliers

Date	Jan. 2001	Jan. 2002	Jan. 2003	Jan. 2004	Jan. 2005	Jan. 2006
Residential	0.1% (0.2%)	0.4% (0.4%)	2.8% (2.5%)	2.9% (2.6%)	2.7% (2.3%)	9.1% (7.6%)
Small C&I	0.6% (0.6%)	2.6% (4.4%)	8.8% (10.7%)	7.2% (11.3%)	6.8% (10.2%)	13.9% (21.2%)
Medium C&I	1.5% (2.1%)	7.4% (11.0%)	10.8% (17.2%)	11.3% (17.8%)	10.1% (16.5%)	14.9% (24.3%)
Large C&I	7.2% (13.3%)	20.1% (31.9%)	28.6% (43.1%)	32.4% (50.7%)	32.6% (48.9%)	45.7% (59.4%)

Source: Massachusetts Department of Telecommunications and Energy

Public Benefits Programs: The Massachusetts Public Benefits Programs are summarized in Table 14.

Table 14. Massachusetts Public Benefits Programs

		Research & Development	Energy Efficiency	Low Income	Renewable Energy	Total
In Nov. 1997, comprehensive legislation was signed bringing retail access to all customers in 1996, included a non-bypassable wires charge for EE, RE and LI. LI must get at least .25 mills of the EE. In Feb. 2002, legislation was signed extending the SBC for five years, through Dec. 2007.	Million $		130.0	Incl.	26.0	156.0
	Mills/kWh		2.50	In	0.50	3.00
	% revenue		2.81%	EE	0.58%	3.38%
	Admin.		Utility	Utility	MTPC	

Note: MTPC is part of the Massachusetts Technology Collaborative.
Source: American Council for an Energy-Efficient Economy, *Summary Table of Public Benefit Programs and Electric Utility Restructuring* (December 2005), *available at* http://www.aceee.org/briefs/mktabl.htm.

Separation of Generation and Transmission: The Massachusetts restructuring law required distribution utilities to divest their generation facilities (either by sale or by transfer to an affiliated company), if they sought to recover stranded costs.[380] If a distribution utility opted to transfer its generation assets to an affiliate, the two companies had to be strictly separated,[381] and distribution utilities were not be permitted to sell electricity at retail except to provide their customers with standard offer service (which has now ended).[382] Almost all of the distribution companies divested their assets to only one company.

State RTO Involvement: Massachusetts distribution utilities are within the footprint of the Independent System Operator of New England. Established in 1997, ISO-NE is responsible for managing energy markets and operating the transmission system in New England.

Generation Capability:[383] Prior to the restructuring legislation, utilities operated 86.6 percent of generating capability in Massachusetts. By 2002, that figure dropped to 9.0 percent with 91 percent of generation belonging to independent power producers. Between 1997 and 2002, generation capability increased from 11,328 MWs to 12,159 MWs. Most of the new capacity uses natural gas.[384]

Usage of Customer Information: The distribution utility cannot release proprietary customer information to the affiliate without written consent of the customer. Historical usage information will be provided to a supplier who has received customer authorization to initiate service.[385]

Standardized Labeling:[386] "In February 1998, the Massachusetts Department of Telecommunications and Energy (DTE) issued final rules (220 CMR 11.06) requiring electric retailers to provide customers with a standard disclosure label containing information on price, fuel mix, emissions, and labor characteristics of generating sources on a quarterly basis, beginning September 1, 1998. Suppliers must also issue notices in all advertisements stating that disclosure labels are available upon request. Supply mix information must be based on market settlement data or equivalent data provided by the ISO available for the most recent one-year period. Data on carbon dioxide, nitrogen oxides, and sulfur dioxide emissions must be presented in a format comparing them to the regional average. Electricity providers are also required to report the percentage of power generated from sources that have union contracts with their employees and the percentage generated from sources that use replacement labor during labor disputes. Suppliers must submit a report to the DTE annually containing "statements of verification by the ISO or an independent auditor." Massachusetts is working with other New England states to develop a Generation Information System that will supply data for implementing the disclosure requirement."

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[380] MASS. GEN. LAWS ch. 164, § 1A(b)(2) (2001).

[381] *Id.* at § 1A(c).

[382] *Id.* at § 1A(b)(1).

[383] U.S. Department of Energy, Energy Information Administration, Massachusetts State Profile, Table 4, *available at* http://www.eia.doe.gov/cneaf/electricity/st_profiles/massachusetts.pdf.

[384] U.S. Department of Energy, Energy Information Administration, State Electricity Profiles 2002, Massachusetts Electric Power Industry Generating Capability by Primary Energy Sources, 1993, 1997, and 2002.

[385] 220 MASS. CODE REGS. 11.04(12).

[386] U.S. Department of Energy, Energy Information Administration, *Disclosure Policies*, *available at* http://www.eere.energy.gov/greenpower/markets/disclosure.shtml?print.

Renewable Energy Portfolio Standard: Massachusetts enacted a minimum renewable energy portfolio standard on April 26, 2002. The standard started at 1 percent in 2003 and increases to 4 percent in 2009 in one half percent increments. After 2009, the standard is scheduled to increase in 1 percent increments at least through 2014.[387]

New Jersey: Overview of Retail Competition Plan and Market Response

Administrator and Start Date: The New Jersey Electric Discount and Energy Competition Act provided for retail choice to begin August 1, 1999, but the New Jersey Board of Public Utilities (BPU) delayed the start date to November 14, 1999, to give utilities more time to modify their computer systems to interact with competitive retail suppliers in order to ease customer switching.

Services Open to Competition: Generation is open to competition. Work on a policy to permit competition for other customer services, such as metering and billing, was suspended on June 23, 2004, for a minimum of two years.[388]

Consumer Options: New Jersey consumers can pick their own alternative supplier or join an aggregation of customers to contract with an alternative supplier. Customers received a “shopping credit” on their electric bill if they choose an alternative supplier. The shopping credit was also known as the “price to compare” and was the amount on a customer’s bill that was credited to the customer if he chose an alternate supplier and did not receive basic generation service from the distribution utility.[389]

Customers that are not served by an alternative supplier receive Basic Generation Service (BGS), which is procured through periodic auctions. Large industrial customers with BGS are charged hourly prices that track wholesale spot market prices. BGS for other customer classes is laddered on a three year cycle.

Alternative Suppliers Licensed to Provide Service: New Jersey licensing standards provide that before receiving a license, new suppliers must show financial integrity and maintain a surety bond of $250,000 for an initial license. For a renewed license, suppliers have to maintain a bond at a level determined by the BPU.[390] Competitive suppliers must renew their licenses annually. The BPU website provides lists of alternative suppliers serving residential, commercial and industrial retail customers. As of February 2006, active alternative suppliers for residential customers range from 3 in the JCP&L territory, to 1 each in the Conectiv and PSE&G territories. None offer service to residential customers in the Rockland territory. For C&I customers, there are 6 active suppliers in the Rockland territory and 19 or 20 in each of the other territories.

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387 225 Mass. Code Regs. 14.00.

388 New Jersey Board of Public Utilities, *In the Matter of the Electric Discount and Energy Competition Act of 1999 Customers Account Services Proceeding: Consolidated Billing, Customer Data Card, & Competitive Metering. Energy Consultant: Amendment to Customer Usage Information Process* (June 23, 2004), *available at* http://www.state.nj.us/bpu/wwwroot/energy/EX99090676_20040624.pdf.

389 N.J. STAT. ANN. § 48:3-51.3 (2001).

390 New Jersey Board of Public Utilities, *Interim Licensing and Registration Standards* § 4.e, *available at* www.state.nj.us/bpu/wwwroot/energy/licensstands.pdf.

Pricing Trends: As Table 15 shows, prices in all three sectors rose throughout the early part of the decade, reaching a peak in 1997. Prices for residential and commercial customers fell over the next several years before rising again, but not as high at the 1997 peak. For industrial customers, the same pattern is evident except that the 2004 price exceeded the 1997 peak.

Table 15. New Jersey Average Annual Price per KWh by Sector
(nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Residential	9.8	10.1	10.4	10.8	10.9	11.4	11.5	12.0	12.0	12.1	11.4	11.4	10.8	10.2	10.4	10.7	11.2
Commercial	8.4	8.8	8.9	9.3	9.3	9.7	9.8	10.2	10.3	10.4	10.1	9.7	8.6	9.1	8.9	9.3	10.0
Industrial	6.8	7.2	7.4	7.7	7.7	8.1	7.9	8.2	8.2	8.1	7.9	7.7	6.8	8.3	7.7	7.5	9.0
All Sectors	8.5	8.8	9.1	9.5	9.5	10.0	10.1	10.4	10.5	10.5	10.2	10.0	9.1	9.3	9.3	9.5	10.9

Source: Energy Information Administration

Price Changes for POLR (Basic Generation Service) Service: All customer classes were granted an initial 5 percent rate reduction with an additional reduction of at least 5 percent over the first three years of the transition period for POLR service. This entailed a reduction of at least 10 percent from April 1997 levels. The reductions were from the distribution portion of the customer's bill, so that even those customers that switched to a new supplier obtained the price reductions. Retail price caps expired in the summer of 2003.[391]

Beginning in 2002, New Jersey instituted the Basic Generation Service (BGS) Auction "to meet the electric demands of customers who have not selected an alternative supplier and to make BGS available on a competitive basis… The Internet BGS Auction, the first of its kind in the nation, was a descending clock auction…"[392] The bidding process for hourly priced electricity is separate from that for fixed price service and the latter involves three year supply contracts that supply one third of the anticipated load of fixed BGS. Table 16 shows the auction results for 2003 to 2005.

Table 16. Auction Results for Three Year Contracts Used to Ladder Fixed BGS Rates

	Feb. 2003	Feb. 2004	Feb. 2005
Conectiv	5.529 cent/kWh	5.513	6.648
JCP&L	5.587	5.478	6.570
PSE&G	5.560	5.515	6.541
Rockland	5.601	5.597	7.179

Source: BPU Press Releases of Feb. 5, 2003; Feb. 11, 2004; and Feb. 16, 2005. The Feb. 9, 2006, press release did not list the winning bid prices, but indicated that the average residential bill would increase 12% to 13.7% as a result of increases in the 2006 component of the laddered prices.

POLR Service (BGS) Provider: Generation services were provided by the distribution companies for three years following the opening of retail competition.[393] Through BGS, all

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391 Jeanne M. Fox (Chair, New Jersey Board of Public Utilities), *New Jersey's BGS Auction: A Model for the Nation*, PUB. UTILS. FORTNIGHTLY 16-19 (2005).

392 Press Release, New Jersey Board of Public Utilities, New Jersey's Basic Generation Service (BGS) Auction Locks in Electric Prices for Retail Customers (Feb. 15, 2002), *available at* http://www.state.nj.us/bpu/wwwroot/communication/04-02.pdf.

393 N.J. STAT. ANN. § 48:3-57.9.a (2001).

customer classes are eligible for generation service overseen by the BPU.[394] Non-residential customers who return to BGS are generally required to remain with that service for one year.[395] The auction system for procuring BGS has been in place since 2002, although rate caps applied until mid-2003.

Recovery of Stranded Costs/Transition Costs: The BPU determined the recoverable amount of stranded costs, and distribution utilities recovered most stranded costs over a maximum of 8 years, through a market transition charge (MTC).[396] All customers were be assessed this charge, except for off-grid customers who are exempt from exit fees.

Switching Restrictions and Minimum Stay Requirements: Customers can switch suppliers or return to their distribution company at any time, in accordance with the terms and conditions of their service agreement with their supplier or distribution company. A customer may not be charged a fee for switching suppliers.

Switching Activity: The Table 17 provides the switching statistics for large C&I customers in the major distribution territories as of December 2005.

Table 17. Customer Switching by Distribution Utility (December 2005)
% of Customers and (% of Load) Served by Alternative Suppliers

	Combined Residential and Non-Residential Fixed Rate	Residential Fixed Rate	Non-Residential Fixed Rate	Large C&I Hourly
Conectiv	0.0% (12.4%)	0.0%	0.3%	87.2% (95.7%)
JCP&L	0.1% (11.6%)	0.0%	0.4%	62.7% (87.7%)
PSE&G	0.1% (15.3%)	0.0%	0.7%	64.0% (84.0%)
Rockland	0.0% (4.4%)	0.0%	0.3%	55.0% (70.3%)

Note: New Jersey does not report separate residential and small C&I load of alternative suppliers.
Source: New Jersey BPU and *Restructuring Today* (January 27, 2006), p. 3.

The number of residential customers served by alternative suppliers is and has remained very low with the peak of less than 6 percent in the Conectiv (Atlantic) distribution area in December 2000.[397] As of December 2005, less than 1,000 residential customers had alternative suppliers in the entire state.[398] As with the residential sector, the number of small C&I customers served by alternative suppliers peaked in December 2000 with 8.6 percent of customers and 16.3 percent of load for this class of customer served by alternative suppliers.[399] As of December 2005, less

[394] *Id.* at § 48:3-51.3.

[395] *FTC Retail Competition Report* at A80 (citing comments received from the New Jersey Division of the Ratepayer Advocate).

[396] N.J. STAT. ANN. § 48:3-61.13.i.

[397] *FTC Retail Competition Report* at A78 -A80.

[398] New Jersey Board of Public Utilities, *New Jersey Electric Statistics* (Dec. 2005).

[399] *FTC Retail Competition Report* at A78-A80.

than 1 percent of small C&I customers had alternative suppliers, but they tended to be larger than average customers because the share of load exceeds the share of customer served by alternative suppliers.

The POLR service available to large C&I customers in New Jersey is priced on an hourly basis, CIEP, that tracks the wholesale spot market prices. Hence, large C&I customers wishing to hedge price volatility must do so by selecting an alternative supplier. New Jersey's experience has been that many large C&I customers prefer to buy from alternative suppliers when POLR service is priced on an hourly basis.

Table 18 provides aggregate switching data for residential and non-residential customers from 2003 to the end of 2005.

Table 18. New Jersey Retail Aggregate Customers Migration Statistics, 2003-2005
% of Customers and (% of Load) Served by Alternative Suppliers

Year	2003 pre August	November 2003	December 2004	December 2005
Residential and Small C&I	(1 to 2%)	3.3% (12.5%)	0.3% (15.4%)	0.0% (13.6%)
Residential		3.6%	0.0%	0.0%
Small C&I		0.8%	1.8%	0.6%
Large C&I	~ 10%	66%		64.7% (83.9%)

Note: Archives of New Jersey BPU switching statistics are not available.
Source: *Restructuring Today* various issues.

Public Benefits Programs: Table 19 identifies the elements and New Jersey's public benefit programs.

Table 19. New Jersey Public Benefits Programs

		Research & Development	Energy Efficiency	Low Income	Renewable Energy	Total
Restructuring law passed in Jan. 99. Requires funding for EE/RE at same level as existing DSM costs (approx. $235million/yr.) Full SBC is 3.6 mills. Half would pay for costs from prior year, half for programs. 25% of new must be RE. Numbers in table are new programs only set in BPU order Mar/01. LI separately funded at prior levels.	Million $		89.5	10.1	30.0	129+
	Mills/kWh		1.22	0.14	0.41	1.76
	% revenue		1.31%	0.15%	0.44%	1.89%
	Admin.		NJ BPU	Utility	NJ BPU	

Source: American Council for an Energy-Efficient Economy, *Summary Table of Public Benefit Programs and Electric Utility Restructuring* (December 2005), *available at* http://www.aceee.org/briefs/mktabl.htm.

Separation of Generation and Transmission: The restructuring act does not mandate divestiture, though the BPU may require a distribution utility to functionally separate its generation assets to the distribution utility's holding company or a related competitive business segment if there are market concentration concerns.[400] Electric distribution utilities had three options: divestiture, structural separation or functional separation. Of the four major distribution utilities in New Jersey, two divested nearly all of their generation, one divested most (but not all) of its generation, and the fourth transferred its generation assets to an unregulated affiliate.[401] In August 2000, PSE&G transferred approximately 10,200 MW of its electric generating facilities to PSEG Power, LLC, an unregulated power generation affiliate. The BPU approved the sale of Rockland Utility's generation assets to Southern Energy Affiliates in June 1999.[402]

State RTO Involvement: New Jersey is within the multi-state PJM region, an RTO that includes Pennsylvania, New Jersey, Maryland, Delaware, the District of Columbia, and parts of Virginia. In recent years, the PJM RTO has significantly expanded its geographic scope to the West and South of its original footprint. The PJM region is responsible for the operation of the region's wholesale electric market.

Generation Capability:[403] Prior to the restructuring legislation, utilities operated 81.2 percent of the generation capability in New Jersey. By 2002, that figure dropped to 6.8 percent after divestitures, transfers, and entry of new generators. Between 1997 and 2002, generation capability in the state increased from 16,855 MWs to 18,384 MWs, an increase of 9.1 percent . Nearly all of the increase was in dual fueled generators built by IPPs. During the 1993 to 1997 period, generating capability had increased by less than 3 percent .

Usage of Customer Information: Neither power suppliers nor distribution companies can disclose proprietary information, including historical payment and energy usage information without the written consent of the customer. Any third party who receives such information can only use it in order to provide continued electric service to the customer.[404]

Standardized Labeling:[405] "The New Jersey Board of Public Utilities (BPU) adopted an interim disclosure rule on July 26, 1999, in accordance with the state's restructuring law. The rule requires electricity suppliers to provide consumers with a uniform disclosure label containing information on fuel mix, carbon dioxide, sulfur dioxide, and nitrogen oxides emissions, as well as energy-efficiency efforts twice a year, effective August 1, 1999. Air pollutant emissions must be compared to the regional average. Suppliers should use data from the most recent 12-month period with a 3-month lag, unless such data are unavailable (as in the case of a new market

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400 N.J. STAT. ANN. at § 48:3-59.11.a.

401 *FTC Retail Competition Report* at A80 (citing comments received from the New Jersey Division of the Ratepayer Advocate).

402 New Jersey Board of Public Utilities, *Summary Order Including Protective Order in Docket No. EM99030195, Petition of Rockland Electric Company for Approval of the Sale of Orange and Rockland Utilities, Inc.'s Generating Assets and Certain related Property, a Transition Power Sales Agreement, and a Protective Order* (June 24, 1999), *available at* http://www.state.nj.us/bpu/wwwroot/energy/recodivestord.pdf.

403 U.S. Department of Energy, Energy Information Administration, New Jersey State Profile, Table 4, *available at* http://www.eia.doe.gov/cneaf/electricity/st_profiles/new_jersey.pdf.

404 N.J. STAT. ANN. § 48:3-85.36.b.

405 U.S. Department of Energy, Energy Information Administration, *Disclosure Policies*, *available at* http://www.eere.energy.gov/greenpower/markets/disclosure.shtml?print.

entrant). Information must be provided for each product offered and verified by an independent auditor."

Renewable Energy Portfolio Standard: The New Jersey Board of Public Utilities adopted renewable energy portfolio standards on February 1, 2005. The standard starts at 3.25 percent for 2005 and rises to 6.5 percent by 2009. On August 31, 2005, the BPU authorized specific standards for two classes of renewable energy sources in addition to continuation of the existing solar requirements.

New York: Overview of Retail Competition Plan and Market Response

Administrator and Start Date: Restructuring in New York State has taken place through orders of the New York State Public Service Commission (NYPSC), rather than through legislative initiatives. Because the PSC phased in restructuring through PSC-approved utility restructuring plans over a three year period, each utility had a different timetable to transition to retail competition.

In 2004, the NYPSC identified a number of "best practices" and ordered distribution utilities to submit plans to foster the development of retail competition.[406] Subsequently, the NYPSC adopted statewide guidelines, based on the program developed by Orange and Rockland (O&R).[407] Under the guidelines, the distribution utility notifies any customers who contact the utility that they may try an alternative supplier for a two-month period without any penalty for leaving or returning to POLR service after the trial period. Alternative suppliers participating in the program offer a one-time 7 percent discount for the trial period. Customers can either pick an alternative supplier or have one randomly assigned and customers are can return to POLR service or to another alternative supplier at the end of the trial period. As the table on retail switching indicates below, switching levels in the O&R distribution territory are higher than in other territories.

On September 23, 2005, the PSC determined that the pace of development of real-time pricing was insufficient to moderate the effects of rising fuel costs.[408] To speed the development of real-time pricing, the PSC ordered that existing real-time pricing programs in some distribution territories be expanded to include all territories and that POLR service for large C&I customers be tied to real-time pricing.

Services Open to Competition: Generation, metering and billing. Distribution companies were required to file unbundled metering tariffs and calculate a "backout" credit for customers who choose a different meter service provider. The PSC's competitive metering and meter reading rules allow customers who choose a competitive supplier and customers who remain with the distribution utility to choose competitive metering services. Customers who choose competitive

[406] New York Public Service Commission, *Statement of Policy on Further Steps toward Competition in Retail Energy Markets* (Aug. 25, 2004) (Case No. 00-M-0504).

[407] New York Public Service Commission, *Order Adopting ESCO Referral Program Guidelines and Approving an ESCO Referral Program Subject to Modifications* (Dec. 22, 2005) (Case No. 05-M-0858, et al.); NYPSC comments at 17.

[408] New York Public Service Commission, *Order Instituting Further Proceedings and Requiring the Filing of Draft Tariffs* (Sept. 23, 2005) (Case No. 03-E-0641).

metering services must procure both meter and meter data services competitively. Distribution utilities are the providers of last resort for metering and meter data services.[409]

Consumer Options: New York retail electricity customers can select an alternative supplier or be part of an aggregation of consumers that obtain electric power from an alternative supplier. Customers not served by an alternative supplier receive POLR service from the distribution utility. POLR service for large C&I customers is offered on an hourly price basis that tracks wholesale spot market prices.

Alternative Suppliers Deemed Eligible to Provide Service: The New York PSC website provides lists of alternative suppliers in each distribution territory. For example, in February 2006, the number of alternative suppliers serving residential customers ranged from 6 in the Central Hudson and O&R territories to 13 in the National Grid (Niagara Mohawk) distribution territory. C&I customers generally had more alternative suppliers to choose from.

Pricing Trends: As shown in Table 20, prices generally increased through 1997 and then wavered before increasing to higher levels in 2003 and 2004.

Table 20. New York Average Annual Price per KWh by Sector
(nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Residential	10.5	10.9	11.4	12.0	12.4	13.2	13.6	13.9	14.0	14.1	13.7	13.3	14.1	14.0	13.6	14.3	14.5
Commercial	9.6	9.9	10.5	10.9	11.2	11.7	11.7	11.9	12.1	12.1	11.6	11.2	12.5	12.9	12.3	12.9	13.0
Industrial	4.9	5.3	5.8	6.2	6.5	6.7	6.8	5.8	5.6	5.2	5.0	4.8	4.9	5.6	5.2	7.1	7.0
All Sectors	8.5	8.9	9.4	9.6	10.2	10.7	10.9	11.1	11.1	11.1	10.7	10.4	11.2	8.8	8.7	12.4	12.6

Source: Energy Information Administration

Price Changes for POLR Service: Each distribution utility's restructuring plan laid out different POLR rate reduction plans:

- Central Hudson basic electric rates were frozen at 1993 levels through June 30, 2001, for all customers. In addition, large industrial customers who chose to remain with Central Hudson for their generation services received 5 percent per year rate reductions until mid-2001.

- Con Edison industrial customers received a 25 percent immediate rate decrease, which remained fixed for five years. All other customers received a 10 percent rate decrease, phased in over five years.

- Orange and Rockland residential customers received a 4 percent decrease in rates during 1995 and 1996, while industrial and commercial customers received rate reductions of 4-14 percent . On December 1, 1997 and on December 1, 1998, residential rates were reduced an additional 1 percent . Large industrial customer rates were reduced by approximately 8.5 percent on December 1, 1997.

[409] New York Public Service Commission, *In the Matter of Competitive Metering* (Feb. 26, 2001) (Case No. 00-E-0165); New York Public Service Commission , *In the Matter of Competitive Opportunities Regarding Electric Service* (Feb. 26, 2001) (Case No. 94-E-0952).

- Rochester Gas and Electric residential and small commercial customers received a 7.5 percent rate decrease. Other commercial and most industrial customers received an 8 percent decrease. Large industrial customers received an 11.2 percent decrease. All decreases are being phased in over 5 years.

- New York State Electric and Gas industrial and large commercial customers (greater than 500 kW capacity) received a 5 percent per year rate decrease, for five years. Residential and small commercial and industrial customers have had their rates frozen at current levels for two years, bills reduced 1 percent in the third year of the plan, and a total decrease of 5 percent by the fifth year of the plan. Industrial and commercial customers who are not eligible for the 5 percent decrease received financial incentives for load growth to encourage business expansion.

- National Grid (Niagara Mohawk) customers received an overall rate decrease of an average of 4.3 percent . Residential and commercial customers were to have a 3.2 percent decrease phased in over three years. Industrial customers were to have decreases of approximately 13 percent . In addition, Niagara Mohawk rates for electricity and delivery were set until September 1, 2001. In 2001 and 2002, Niagara Mohawk was allowed to request limited rate increases for distribution services, and prices for some of the electricity sold to all customers will fluctuate with changes in market prices.

<u>POLR Service Provider</u>: The distribution companies provide regulated POLR service for customers who do not choose a competitive supplier or who return to POLR service.[410]

<u>Recovery of Stranded Costs/Transition Costs</u>:   Distribution utilities recover stranded costs (net of proceeds from selling generation assets) through a non-bypassable distribution charge. Distribution utilities were required to use creative means to reduce the amount of stranded costs before they are considered for recovery. Stranded cost calculations and timing of recovery were determined on a case-by-case basis for each distribution utility.[411]

<u>Switching Restrictions and Minimum Stay Requirements</u>: The NY PSC is currently implementing a number of policies designed to encourage consumers to try alternative suppliers.[412] One of these, known at "ESCO Referral Programs," places limits on the ability of alternative suppliers to levy charges against departing customers.[413]

<u>Switching Activity</u>: The switching statistics for December 2005 in each distribution territory appear in the Table 21.

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410 New York Public Service Commission, *Opinion and Order Regarding Competitive Opportunities for Electric Service* (May 20, 1996) (Opinion No. 96-12).

411 *Id.*

412 New York Public Service Commission, *Staff Report on the State of Competitive Energy Markets: Progress to Date and Future Opportunities* (Mar. 2, 2006) (Electric and Natural Gas Retail Markets sections I to III).

413 NYPSC comments at 18.

Table 21. New York Retail Customers and Load Supplied by Alternative Providers as of December, 2005
% of Customers and (% of Load)

Firm and Load in MWh	Residential	Small C&I	Large C&I	Total
NY IOUs 8,614,367	6.7% (9.0%)	18.4% (45.4%)	55.6% (75.7%)	8.3% 38.5%
Central Hudson 465,350	.8% (1.0%)	3.0% (15.6%)	49.2% (74.7%)	1.2% (26.9%)
Con Ed 3,425,765	4.6% (5.5%)	14.1% (40.2%)	77.5% (85.1%)	5.9% (37.4%)
National Grid 2,644,403	6.0% (7.7%)	22.9% (53.6%)	69.2% (69.2%)	7.8% (38.4%)
NYSE&G 1,100,064	6.8% (9.6%)	23.1% (54.6%)	51.7% (88.3%)	9.1% (40.7%)
O&R 349,282	30.4% (34.6%)	32.4% (49.5%)	19.7% (27.5%)	30.6% (37.6%)
Rochester G&E 629,504	17.5% (21.5%)	39.5% (58.8%)	62.2% (71.5%)	20.0% (49.5%)

Source: NYPSC

The aggregate switching statistics for the utility distribution territories in the state from 2000 to 2005 appear in Table 22. Load served by alternative suppliers has increased each year with the largest increases in 2004 and 2005. The percentage of customers served by alternative suppliers increased from 1999 to 2002, declined in 2003, and resumed growing in 2004 and 2005.

Table 22. New York Aggregate Customer Migration Statistics, 1999-2005
% of Customers and (% of Load) Served by Alternative Suppliers

<table>
<tr><th>Year</th><th>1999</th><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th><th>2005</th></tr>
<tr><td>Residential</td><td>~1.6%</td><td>3.4%</td><td>4.8%
(5.0%)</td><td>5.0%
(5.6%)</td><td>4.2%
(5.9%)</td><td>5.1%
(7.2%)</td><td>6.7%
(9.0%)</td></tr>
<tr><td>Small C&I</td><td rowspan="2">~4.3%</td><td rowspan="2">5.3%</td><td rowspan="2">6.2%
(26.0%)</td><td rowspan="2">7.1%
(30.0%)</td><td>8.0%
(26.0%)</td><td>13.0%
(36.2%)</td><td>18.4%
(45.4%)</td></tr>
<tr><td>Large C&I</td><td>23.7%
(45.1%)</td><td>48.1%
(66.8%)</td><td>55.6%
(75.7%)</td></tr>
</table>

Source: NYPSC, Electric Retail Access Migration Reports

<u>Public Benefits Programs</u>: New York's public benefit programs are charted in Table 23 below.

<table>
<tr><th colspan="7">Table 23. New York Public Benefits Programs</th></tr>
<tr><td rowspan="7">In May95, the PSC issued Order 96-12 requiring all IOUs to file restructuring plans. A July98 Order set $78 million/year for an SBC, administered by NYSERDA. In Jan01 the PSC raised the SBC to $150 million/yr and extended it for 5 years. (Table shows allocation minus 10% held open.) R&D incl. $14 million/yr for RE. Table does not include $100 million/yr EE by Power Authorities</td><td></td><td>Research & Development</td><td>Energy Efficiency</td><td>Low Income</td><td>Renewable Energy</td><td>Total</td></tr>
<tr><td>Million $</td><td>26.0</td><td>87.0</td><td>22.0</td><td></td><td>150.0</td></tr>
<tr><td>Mills/kWh</td><td>0.26</td><td>0.83</td><td>0.21</td><td></td><td>1.42</td></tr>
<tr><td>% revenue</td><td>0.20%</td><td>0.69%</td><td>0.17%</td><td></td><td>1.18%</td></tr>
<tr><td>Admin.</td><td>NYSERDA</td><td>NYSERDA</td><td>NYSERDA</td><td></td><td></td></tr>
<tr><td colspan="6">Notes: The administrator is the New York State Energy Research and Development Authority, supervised by the PSC. On December 14, 2005, the PSC ordered that the System Benefit Charge be increased to $175 M annually and that the program be extended for five years. NYPSC, System Benefits Charge (Mar. 2, 2006), available at http://www.dps.state.ny.us/SBCIII_Amended_Plan_3-2-06.pdf.

Source: American Council for an Energy-Efficient Economy, Summary Table of Public Benefit Programs and Electric Utility Restructuring (December 2005) available at http://www.aceee.org/briefs/mktabl.htm.</td></tr>
</table>

Separation of Generation and Transmission: The PSC encouraged total divestiture of generation, and it instructed distribution utilities to separate generation and energy service functions from transmission and distribution systems.[414] Each distribution utility company's restructuring agreement established different requirements for separation of generation and transmission.[415]

State RTO Involvement: New York distribution utilities belong to the New York ISO, formed in 1998. The New York ISO exercises operational control over most of New York's transmission systems, administers the ISO transmission tariff, and operates the New York Open Access Same Time Information System (OASIS).[416]

Generation Capability:[417] Prior to the restructuring regulations, utilities in New York operated 84.3 percent of the generation capability in the state. By 2002, that figure dropped to 32.4 percent. The difference reflected mandatory divestitures of generation to independent generation firms and entry or expansion of independent power producers. Between 1997 and 2002,

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[414] New York Public Service Commission , *Opinion and Order Regarding Competitive Opportunities for Electric Service* (May 20, 1996) (Opinion No. 96-12).

[415] New York Public Service Commission , *PSC Rate and Restructuring Plan Fact Sheets*, *available at* www.dps.state.ny.us/energyarch.htm#facts.

[416] New York Independent System Operator, Inc., *Frequently Asked Questions*, *available at* www.nyiso.com/public/services/customer_relations/faqs/index.jsp.

[417] U.S. Department of Energy, Energy Information Administration, New York State Profile, Table 4, *available at* http://www.eia.doe.gov/cneaf/electricity/st_profiles/new_york.pdf.

generation capability in the state increased from 35,576 MWs to 36,041 MWs. In the previous 5-year period, generation capability had decreased. Dual fueled generation increased as a proportion of generation from 34.1 percent to 39.5 percent.

Use of Customer Information: Historical customer data will be provided by distribution companies to customers or their authorized designees. All historical data that a competitive supplier receives from the distribution company must be kept confidential, unless authorized for release by the customer. A distribution company cannot disclose customer information to competitive suppliers if the customer has notified the distribution company in writing that he does not authorize release. Thereafter, customer information can only be released to a competitive supplier with the customer's written authorization.[418]

Standardized Labeling:[419] On December 15, 1998, the New York Public Service Commission (PSC) issued an order requiring electric suppliers to use a standardized label to provide information to customers regarding the environmental impacts of electricity products semi-annually. Suppliers must disclose fuel mix compared to a statewide average and emissions of sulfur dioxide, nitrogen oxides, and carbon dioxide. Fuel source and emissions information are calculated by the Department of Public Service (DPS) and provided to retail suppliers quarterly. Calculations are based on a rolling annual average with data supplied from the Independent System Operator and the EIA and verified by the DPS. The most recent reports of each load serving entity (2004) are available at http://www3.dps.state.ny.us/e/energylabel.nsf/ViewCat?ReadForm&View=LabelInfo&Cat=January+2004+-+December+2004&Count=80.

Renewable Energy Portfolio Standard: The New York PSC adopted a renewable energy portfolio standard on September 24, 2004. The policy calls for an increase in renewable energy used in the state from the then current level of 19 percent (mostly hydro) to 25 percent by 2013.

Pennsylvania: Overview of Retail Competition Plan and Market Response

Administrator and Start Date: The Electricity Generation Customer Choice and Competition Act was enacted on December 3, 1996. The Pennsylvania Electric Choice Pilot Program began in the fall of 1997, with 230,000 customers participating. These customers were able to begin shopping for their electric generation supplier beginning September 1, 1998. By January 2, 2000, electric choice was fully implemented in nearly all of Pennsylvania.[420] Retail competition is administered by the Pennsylvania Public Utility Commission (PUC).

Services Open to Competition: Generation. Generally the distribution company provides metering and billing services, although there are some areas in Pennsylvania in which the

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[418] New York Public Service Commission , Uniform Retail Access Business Practices, Appendix A, *Customer Information* (Apr. 14, 1999), *at* www.dps.state.ny.us/doc5743_appendix_a.pdf (Case No. 98-M-1343). For information on the acceptance of uniform retail access business practices in New York, *see* www.dps.state.ny.us/ubr.htm.

[419] U.S. Department of Energy, Energy Information Administration, *Disclosure Policies*, *available at* http://www.eere.energy.gov/greenpower/markets/disclosure.shtml?print.

[420] Pennsylvania Public Utility Commission, *Pennsylvania Electric Choice, Q&A*, *available at* http://www.puc.state.pa.us/utilitychoice.

alternative supplier may provide these services.[421] Pennsylvania's efforts to allow licensed generation suppliers to provide metering and billing services to retail customers were suspended on August 12, 2002.[422]

Consumer Options: Pennsylvania consumers can select an alternative supplier or be part of an aggregation of consumers buying power from an alternative supplier. Consumers not served by an alternative supplier receive POLR service arranged by the local distribution utility.

Alternative Suppliers Licensed to Provide Service: Competitive suppliers must be licensed by the PUC to provide service to Pennsylvania customers.[423] As of February 2006, the Duquesne Light territory had 4 alternative suppliers serving residential customers and 20 serving C&I customers. In the PECO territory, 6 alternative suppliers were available for residential customers and 28 for C&I customers. Outside of these two territories, residential customers only have available premium priced green generation products while C&I customers had several alternative suppliers offering service.

Pricing Trends: Table 24 displays average retail prices in Pennsylvania by customer class from 1988 to 2004. Residential, commercial, and industrial retail prices have fluctuated within a narrow range since 1991.

Table 24. Pennsylvania Average Annual Price per KWh by Sector
(nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2000	2003	2004
Residential	8.7	8.9	9.2	9.6	9.7	9.6	9.6	9.7	9.7	9.9	9.9	9.2	9.1	9.7	9.7	9.6	9.6
Commercial	7.5	7.8	8.1	8.3	8.5	8.3	8.3	8.3	8.3	8.4	8.3	7.9	6.3	8.6	8.5	8.1	8.5
Industrial	5.5	5.8	6.0	6.3	6.2	6.0	5.9	5.9	5.9	5.9	5.6	5.2	4.3	5.8	5.8	6.1	5.9
All Sectors	7.1	7.4	7.7	8.0	8.0	7.9	7.9	7.9	8.0	8.0	7.9	7.4	6.6	8.0	8.1	8.0	8.0

Source: Energy Information Administration

Price Changes for POLR Service: POLR rates for distribution service were capped at January 1, 1997 levels until July 1, 2001. Rates for generation, including transition charges, were capped at January 1, 1997 levels until January 1, 2006.[424] In some distribution utility service areas, generation caps are in place until 2008-2011 because these distribution utilities will be collecting stranded costs over these longer periods. Many distribution utilities also extended distribution rate caps until 2003-2005. Pennsylvania did not require rate reductions, although several distribution utilities agreed to reduce rates in the first year of retail choice. These reductions were to be lowered and phased out over a two to three year period.[425]

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421 Pennsylvania Public Utility Commission, *Pennsylvania Electric Choice, How to Shop Guide, available at* http://www.puc.state.pa.us/utilitychoice.

422 Letter from the Pennsylvania Public Utility Commission to the Energy Association of Pennsylvania approving an extension of a suspension of work of the Electronic Data Exchange Working Group as it relates to the implementation of competitive metering, Docket No. P-00021957 (Feb. 5, 2004).

423 66 PA. CONS. STAT. § 2809.A (2001).

424 *Id.* at § 2804.4.

425 Comments of the Pennsylvania Public Utility Commission to the *FTC Retail Competition Report* (Apr. 9, 2001).

Overall rate reductions, Table 25 for the first year ranged from 2.5 percent to 8 percent for the major utilities operating in Pennsylvania:[426]

Table 25. First Year Rate Reductions by Distribution Utility

Distribution Utility	First Year Rate Reductions
APS	2.5%
MetEd	2.5%
PECO	8.0%
Penelec	3.0%
PPL	4.0%

Shopping credit rates are the rates that a customer pays for generation if he receives generation service from the utility rather than from a competitive supplier. Shopping credit rates increased over time, but fuel cost increases have been greater and the base rates are not adjusted under the Pennsylvania settlements with distribution utilities. This has resulted in the declining market shares for alternative suppliers and the exit of alternative suppliers.

POLR Service Provider: The distribution company provides POLR service for customers who do not choose a competitive supplier, for those who are unable to obtain service from a competitive supplier, or for customers whose suppliers do not deliver service. Distribution utilities must offer standard offer service as long as the distribution utility is collecting transition charges or until 100 percent of its customers have electric choice.[427] In June 2000, the PUC issued a change in the provision of POLR service, in order to prevent "gaming" of the system by customers who were returning to their distribution utility. During the summer, market prices rose, while POLR rates remained stable, below market rates. This caused customers to be either returned to POLR service by their suppliers or to return themselves to POLR service. Many distribution utilities require customers to remain with the distribution utility for a 12-month period after switching back to the POLR provider.

Competitive POLR Service: Some distribution utilities have arranged for competitive bidding to supply the generation services portion of POLR service for customers who do not affirmatively choose an alternative supplier. This option is known as Competitive Default Service (CDS). The PUC approved additional consumer protections for the initial phase-in of CDS, including bidder qualifications, established creditworthiness, and bond limits. The PUC also reviewed the CDS annually to ensure that it is still benefited consumers.[428] The largest CDS effort took place in the PECO territory. PECO awarded a contract for 20 percent of its POLR service customers to The New Power Company. Additionally, 50,000 PECO customers were assigned to Green Mountain Energy, Inc. PECO customers assigned to the CDS provider received a two-percent discount on the shopping credit (the capped generation service rate). The CDS provider also provided no less than two percent of its supply from renewable resources and increased the use of renewable resources by one-half of a percent annually.[429] Due to concerns that POLR prices

[426] Ahmed Kaloko (Chief Economist, Pennsylvania Public Utility Commission), *Power 99–California & Pennsylvania Retail Market Development*.

[427] 66 PA. CONS. STAT. § 2807.E (2001).

[428] *Id.*

[429] *Id.*

were insufficient to cover procurement costs, the CDS suppliers withdrew from this service. No alternative suppliers have been willing to supply on these terms at present. On December 10, 2005, the PUC decided to reopen POLR service issues for comment in preparation for the end of the transition period in distribution areas in addition to Duquesne.[430]

Recovery of Stranded Costs/Transition Costs: Stranded costs have been administratively determined by the PUC on a case-by-case basis. Utilities were not required to establish market-based valuation by selling generation assets. Stranded costs are fully recoverable through a non-bypassable charge to all consumers, collectible for up to nine years, unless the PUC orders an alternative payment period.[431] Table 26 shows each utility's allowable stranded costs recovery and the seven to 10 year recovery periods to collect there costs from customers.

Table 26. Transition/Stranded Costs:

Company	Allowable Stranded Cost Recovery	Length of Recovery
Allegheny Power	$670 million	10 years
Duquesne Light	$1,331 million	7 years
GPU Energy (Met Ed.)	$975 million	10 years
GPU Energy (Penelec)	$858 million	8 years
PECO	$5,024 million	8 ½ years
Pennsylvania Power and Light	$2,864 million	9 years
Pennsylvania Power Company	$234 million	9 years
UGI Utilities	$32.5 million	
West Penn Power Company	$524 million	7 years

Source: Company Restructuring Orders and Tables

Switching Restrictions and Minimum Stay Requirements: Customers can switch suppliers at any time, although they are advised to check their supply agreement for any penalties which may apply for early termination of a supply contract. If a customer leaves POLR service and then returns, some POLR service providers require a minimum stay of 12 months.[432]

Switching Activity: At this point in time, retail switching activities are largely limited to the Duquesne Light distribution territory and to a lesser degree the PECO territory, as shown in Table 27.

Table 27. Pennsylvania Retail Customers and Load Supplied by Alternative Providers as of January 1, 2006
% of Customers and (% of Load)

Firm and Load in MWh	Residential	Small C&I	Large C&I	Total
Allegheny Power	0.0% (0.0%)	0.0% (0.0%)	0.0% (0.0%)	0.0% (0.0%)

[430] The order is *available at* http://www.puc.state.pa.us/PcDocs/578097.doc.

[431] 66 PA. CONS. STAT. § 2808.A, B (2001).

[432] Pennsylvania Public Utility Commission, *Electric Choice Frequently Asked Questions (Are there any penalties for changing suppliers?), available at* http://www.puc.state.pa.us/utilitychoice/faq.aspx?ut=ec#4.

Table 27. Pennsylvania Retail Customers and Load Supplied by Alternative Providers as of January 1, 2006 % of Customers and (% of Load)				
Firm and Load in MWh	Residential	Small C&I	Large C&I	Total
Duquesne Light	19.7% (18.5%)	20.3% (52.3%)	43.4% (83.6%)	19.8% (48.0%)
MetEd/Penelec	0.0% (0.0%)	0.0% (0.0%)	(0.1%) (5.6%)	0.0% (1.6%)
PECO	0.9% (1.0%)	23.8% (13.2%)	2.0% (1.2%)	3.2% (4.9%)
PennPower	0.0% (0.0%)	0.0 (0.0%)	0.0 (0.0%)	0.0 (0.0%)
PPL	0.0 (0.0%)	0.2 (0.7%)	0.3 (0.3%)	0.1 (0.3%)
UGI	0.0 (0.0%)	0.0 (0.0%)	0.0 (0.0%)	0.0 (0.0%)
Source: Pennsylvania Office of the Consumer Advocate				

The first quarter aggregate switching statistics for the utility distribution territories in Pennsylvania from 2000 to 2006 appear in Table 28. Load served by alternative suppliers has decreased since 2000 with the exception of an increase in 2004. Alternative suppliers served a declining number of customers from 2001 to the present (with the exception of 2004).

Table 28. Pennsylvania Retail Aggregate Customer Migration Statistics, 1999-2006 % of Customers and (% of Load) Served by Alternative Suppliers							
Year	2000	2001	2002	2003	2004	Oct. 2005	2006
Resident.	~7.8% (~7.6%)	~9.2% (~8.6%)	~10.3% (~9.1%)	~4.9% (~4.7%)	~8.2% (~7.9%)	2.9% (2.7%)	~2.3% (~2.1%)
C&I	~17.6% (~41.9%	~16.9% (~32.6%)	~3.7% (~7.8%)	~4.8% (~12.4%)	~13.5% (~13.9%)	9.6% (15.5%)	~8.9% (~14.5%)

Note: Keystone Connection (Autumn 2005) provides the percentage of customers and load served by alternative suppliers as well as the total number of customers and load for residential customers and C&I customers separately for October 2005. Calculations for the other years take the number of shoppers or shoppers' load reported in January of that year and divides them by the related Pennsylvania totals from Oct. 2005. The resulting calculations are approximations because the total number of customers and the total load in the state may have changed from year to year.

Source: Pennsylvania Office of the Consumer Advocate

Public Benefits Programs: Table 29 identifies the Pennsylvania public benefit programs.

Table 29. Pennsylvania Public Benefits Programs						
In Dec., 1995, a restructuring law was signed with retail access to be phased-in over		Research & Development	Energy Efficiency	Low Income	Renewable Energy	Total
	Million $	5.0		85.0	6.0	96.0
	Mills/kWh	0.04		0.68	0.05	0.77
	% revenue	0.05%		0.85%	0.06%	0.96%
	Admin.	SEF	Utility	SEF		

2 yrs starting in Jan99. The restructuring law resulted in PUC-approved restructuring settlement agreements for each electric company. Each settlement agreement created a system benefits fund for LI programs and a Sustainable Energy Fund (except for Duquesne).	*Note*: Administrators are Sustainable Energy Funds in each area of the state. *Source*: American Council for an Energy-Efficient Economy, Summary Table of Public Benefit Programs and Electric Utility Restructuring (December 2005) *available a*t http://www.aceee.org/briefs/mktabl.htm.

Separation of Generation and Transmission: Generation must be separated from transmission and distribution, but distribution utilities are not required to divest facilities or reorganize corporate structure.[433] However, several utilities voluntarily divested generation assets either to independent companies or to unregulated affiliates.

State RTO Involvement: The restructuring legislation directs the PUC to encourage interstate power pools to enhance competition and to complement restructuring. Much of Pennsylvania belongs to the PJM RTO. In order to meet electric load in the PJM region, PJM coordinates with member companies and uses bilateral contracts and the spot market to secure power.[434] In March 2001, Allegheny Power and PJM filed with FERC a request to expand PJM by forming PJM-West.[435]

Generation Capability:[436] Prior to the restructuring legislation, utilities in Pennsylvania operated 92.3 percent of generation capability in the state. By 2002, that figure dropped to 12.3 percent, despite the lack of a requirement for generation divestitures or transfers. The difference reflected voluntary divestitures to independent generators and transfers of generation to affiliates as well as expansion and entry of independent power producers. Between 1997 and 2002, generation capability in the state increase from 36,650 MWs to 39,783 MWs. Most of increase consisted of dual fueled generation.

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[433] 66 PA. CONS. STAT. § 2804.5 (2001).

[434] Pennsylvania Public Utility Commission, Bureau of Conservation, Economics, and Energy Planning, *Electric Power Outlook for Pennsylvania:1999-2004* (July 2000).

[435] Press Release, PJM Interconnection, LLC, Allegheny Power and PJM File with FERC to Create PJM West (Mar. 15, 2001), *available at* www.pjm.com/contributions/news-releases/2001/20010315-ap-pjm-file-with-ferc.pdf.

[436] U.S. Department of Energy, Energy Information Administration, Pennsylvania State Profile, Table 4, *available at* http://www.eia.doe.gov/cneaf/electricity/st_profiles/pennsylvania.pdf.

Use of Customer Information: A customer can restrict the disclosure of his telephone number and his historical billing data. A distribution utility or supplier who intends to supply a third-party with this information must provide a customer with the means of restricting the release of this information, either through a signed form, orally, or electronically.[437] Customer information cannot be given preferentially by a distribution utility to its affiliate.[438] During the initial phase -in period of electric restructuring, a customer's name, address, telephone number, rate class, account number and load data were given to competitive suppliers as a result of the customer's enrollment into the electric choice program. The customer had the option of restricting the release of his telephone number and load data to suppliers. After this initial phase-in period, to assure that customers retain the ability to restrict disclosure of certain information to suppliers, the PUC directed distribution utilities to send forms to customers to give them the opportunity to restrict the release of load data, or of all information (name, address, rate class, and account number). Telephone numbers would not be released to suppliers under any circumstances.[439]

Standardized Labeling:[440] The Pennsylvania Public Utility Commission (PUC) issued final rules in April 1998 requiring retail electricity suppliers to "respond to reasonable requests made by consumers for information concerning generation energy sources." Suppliers must respond to such requests "by informing consumers that this information is included in the annual licensing report and that this report exists at the Commission." Requests for information on energy efficiency must be handled in a similar manner. Suppliers must verify fuel mix data through an independent auditor and submit this information in an annual report to the Commission. Suppliers that market electricity as "having special characteristics" such as being environmentally friendly, must have information available to substantiate their claims.

Renewable Energy: Pennsylvania enacted a renewable portfolio standard through Act 213 in December 2004. The standard includes a gradual increase in generation from renewables to 18 percent over 15 years. Qualified renewables are divided into two groups: traditional (solar, wind, hydro, geothermal, biomass, and coal-mine methane) and other (waste coal, distributed generation, demand-side management, large-scale hydro, municipal waste, wood processing waste, and integrated combined coal gasification). Separate standards are set for the two groups–-8 percent and 10 percent respectively.

Texas: Overview of Retail Competition Plan and Market Response

Administrator and Start Date: The Texas restructuring bill was signed June 18, 1999. The Public Utility Commission of Texas (PUC) administers the transition to retail competition, which began with a pilot program on June 1, 2001. Retail competition for all customer classes within ERCOT began January 1, 2002.[441] Competition is not open as yet in areas outside of ERCOT

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437 52 PA. CONST. STAT. § 54.8 (2001).

438 *Id.* at § 54.122.2.

439 Comments of the Pennsylvania Utility Commission to the *FTC Retail Competition Report* (Apr. 9, 2001).

440 U.S. Department of Energy, Energy Information Administration, *Disclosure Policies*, *available at* http://www.eere.energy.gov/greenpower/markets/disclosure.shtml?print.

441 TEX. UTIL. CODE ANN. § 39.102 (2001).

because the PUC is not convinced that retail competition is feasible without a regional transmission organization in these areas.[442]

Services Open to Competition: Generation and billing (retail sales). Competitive metering for certain commercial and industrial customers began January 1, 2004.

Consumer Options: Customers within ERCOT have the option of choosing a competitive supplier, choosing an aggregator, and, in the case of residential and small commercial customers, choosing POLR service (termed "price to beat" default service).

Alternative Suppliers Licensed to Provide Service: In order to be licensed to provide service in Texas, competitive suppliers must meet financial creditworthiness and technical standards.[443] There are numerous suppliers marketing to all classes of customers in Texas that are open for retail customer choice. In addition to the Texas POLR default service offer, there are several alternative suppliers actively serving retail residential customers in each distribution territory. The figure below is from the "August 2005 Report Card on Retail Competition"[444] showing the number of alternative suppliers available to residential customers, the number of products offered by these suppliers, and the number of alternative "green" offers for residential customers in the major distribution territories within ERCOT.

TDSP	# of REPs Serving Residential Customers	# of Residential Products (Incl. PTB)	# of Renewable Products
TXU ED	13	20	5
Center Point	14	21	6
AEP Texas Central (CPL	13	17	5
TNMP	11	16	6
AEP Texas North (WTU)	10	12	3

Pricing Trends: Retail price averages in Texas have wavered over time with peaks occurring in 1994 and 2001, as shown in Table 30. Prices increased in 2003 and 2004 after declining in 2002.

Table 30. Texas Average Annual Price per KWh by Sector
(nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2030	2004
Residential	6.9	7.0	7.2	7.6	7.7	8.0	8.1	7.7	7.8	7.8	7.7	7.5	7.9	8.9	8.1	9.2	9.7
Commercial	6.0	6.1	6.2	6.6	6.7	6.9	7.0	6.6	6.7	6.7	6.6	6.5	6.8	7.7	7.0	7.8	7.9
Industrial	4.1	4.1	4.0	4.1	4.2	4.3	4.3	4.0	4.0	3.9	3.9	4.0	4.5	5.3	4.7	5.3	5.9
All Sectors	5.6	5.7	5.8	6.1	6.2	6.4	6.4	6.1	6.2	6.1	6.1	6.0	6.5	7.6	6.6	7.5	8.0

Source: Energy Information Administration

Price Changes for POLR (Default) Service: Distribution utility rates were frozen from

[442] Public Utility Commission of Texas, *Scope of Competition in Electric Markets in Texas* (January 2005) at 36-38, *available at* http://www.puc.state.tx.us/electric/reports/scope/2005/2005scope_elec.pdf.

[443] TEX. UTIL. CODE ANN. § 39.352-55 (2001).

[444] *Available at* http://www.puc.state.tx.us/electric/reports/RptCard/rptcrd/aug05rptcrd.pdf.

September 1, 1999, levels until January 1, 2002.[445] On January 1, 2002, rates for residential and small commercial customers were reduced approximately 6 percent from January 1, 1999, levels. The January 1, 2002, reduced rate is called the "price to beat."[446] It is subject to adjustment twice per year, to reflect changes in fuel costs. Because Texas primarily relies on natural gas fueled generation, the increases in natural gas prices have resulted in substantial increases in the "price to beat." POLR (default) service is available from the distribution utility's competitive retail affiliate until January 1, 2007. Prior to January 1, 2005, affiliates of distribution utilities could offer services other than POLR (default) service only if at least 40 percent of residential or small commercial customers chose a competitive supplier not affiliated with the local distribution utility. Since January 1, 2005, affiliates of distribution utilities have been allowed to offer any service they wish in addition to POLR (default) service.

The Texas PUC provides information on the price to beat and on alternative supplier's prices in each distribution territory. The information includes a comparison of each alternative supplier's price to the POLR (default) price for different levels of consumption. Table 31 shows the POLR (default) price and the range of offers from alternative suppliers for a consumer using 1000 kWh or 2000 kWh. The premium price is generally for a 100 percent wind generation product.

Table 31. Texas POLR Service Price Compared to Alternative Suppliers 1000 kWh Consumption (January 2006)

	POLR Price (cents/kWh) For 1000 kWh	Lowest Alternative % discount	Highest Alternative % premium	POLR Price (cents/kWh) For 2000 kWh	Lowest Alternative % discount	Highest Alternative % premium
West Texas Utilities	19.06	19%	4%	18.95		
TXU-SESCO	14.62	8%	10%	13.97	11%	8%
Texas-NM Power	14.48	8%	10%	14.77	11%	6%
Central Power	17.67	18%	6%	17.48	20%	6%
Centerpoint Energy	16.04	15%	9%	15.89	17%	8%

Source: Texas PUC, Retail Electric Service Rate Comparisons (January 2006 bill comparison)

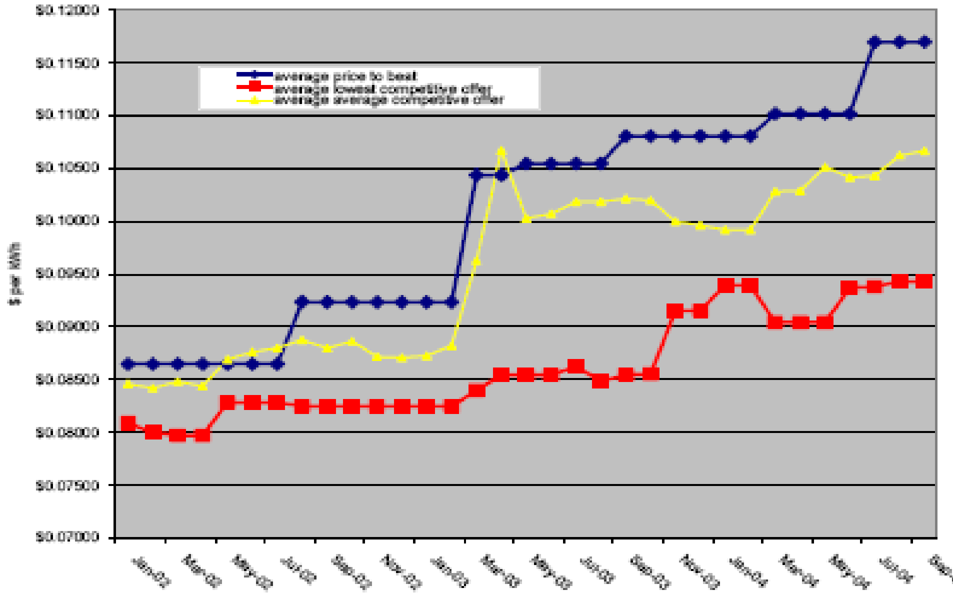
The PUC also has produced an aggregate comparison between the price to beat, the average offer of alternative suppliers, and the lowest offer of alternative suppliers. The figure below, from the PUC report to the 79th Texas Legislature, illustrates these comparisons.[447]

445 Tex. Util. Code Ann. at § 39.052.

446 *Id.* at § 39.202.

447 Public Utility Commission of Texas, *Scope of Competition in Electric Markets in Texas* (January 2005), *available at* http://www.puc.state.tx.us/electric/reports/scope/2005/2005scope_elec.pdf.

Figure 2: Average Residential Price to Beat vs. Average Competitive Offer vs. Average Lowest Competitive Offer, 2002 - 2004



Source: Average Annual Rate Comparison for Residential Electric Service, Entergy Gulf States, Inc. Tariff Rates, PUC Electric Division

<u>POLR (Default) Service Provider</u>: Until December 31, 2001, POLR (default) service was provided by the distribution utility. When competition for all customers began in 2002, POLR (default) customers were transferred to the retail affiliate of the distribution utility. The affiliates and independent retail suppliers are termed "retail electric providers" (REPs). Prices for POLR (default) service were fixed at the "price to beat" plus fuel adjustments until January 1, 2007. Affiliated retail electric providers were allowed to offer only POLR (default) service (at the "price to beat") unless alternative suppliers attained a market share of 40 percent of residential or small commercial customers. In 2004, all but one of the affiliated retail electric providers within ERCOT (the separate transmission interconnection system in Texas) were granted permission to offer additional products.[448] Starting in 2005, all affiliated retail electric suppliers were allowed to offer other products in addition to POLR (default) services to all residential and small commercial customers.

Analysis by the Texas PUC concluded that POLR (default) service pricing has been below the pricing that would have prevailed under the prior cost-of-service regulatory regime. The tables below summarize the estimated regulated rates, the average of the five lowest competitive prices, the best competitive price, and the Price to Beat for the CenterPoint and TXU Service areas.

[448] *Id.* at 24.

CenterPoint Energy Services Area	2002	2003	2004	2005
Estimated Regulated Price	11.1	12.0	12.7	13.9
Average of Lowest 5 Competetive Prices (actual)	8.2	9.0	9.8	11.4
Percentage Difference from Estimated Regulated price	26%	25%	23%	18%
Best Competetive Price	8.0	8.5	9.4	10.6
Percentage Difference from Estimated Regulated price	28%	29%	26%	24%
Reliant Energy Price to Beat	8.8	10.3	11.1	12.9

TXU Electric Delivery Service Area	2002	2003	2004	2005
Estimated Regulated Price	9.4	10.5	10.7	12.1
Average of Lowest 5 Competetive Prices (actual)	8.0	8.7	9.1	10.7
Percentage Difference from Estimated Regulated price	15%	17%	15%	12%
Best Competetive Price	7.8	8.4	8.7	10.1
Percentage Difference from Estimated Regulated price	17%	20%	19%	17%
TXU Energy Price to Beat	8.4	9.6	10.5	11.9

Source: PUC legislative report # 32198, *Electricity Pricing in Competitive Retail Markets in Texas* (March 3, 2006), *available at* http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/32198_7_504891.PDF

POLR Service Provider for other than Default Service: POLR service customers have been divided into three classes: residential, small non-residential, and large non-residential. POLR service providers supply customers in any or all of the three classes who either request POLR service or are assigned to POLR service because they are not receiving service from a REP, for any reason. The rates for this POLR service are established first through a competitive bidding process and, if no qualified bids are obtained, are then allocated to existing suppliers via a lottery process. A bidder to supply POLR service may bid for any customer class, or for more than one class. An affiliate of a distribution utility cannot bid to be the POLR service supplier in its own service territory during the period while the price to beat is in effect.[449]

The Texas PUC is currently reviewing its POLR service rules.[450]

Recovery of Stranded Costs/Transition Costs: Distribution utilities can recover all of their net non-mitigated stranded costs through a transition charge. The PUC determines the amount of

[449] Public Utility Commission of Texas, Sub. Rules § 25.43.

[450] Public Utility Commission of Texas, Project No. 31416, *Evaluation of Default Service for Residential Customers and Review of Rules Relating to the Price to Beat and Provider of Last Resort*; Reliant comments.

stranded costs eligible for recovery, which includes uneconomic generation related assets, and purchased power contracts.

Switching Restrictions and Minimum Stay Requirements Process: A customer can switch suppliers at any time subject to the terms of his contract with the competitive supplier. There are no switching fees unless a customer requests a special meter reading.[451]

Switching Activity: Retail customers have been migrating to alternative suppliers in all of the distribution territories with the highest switching rates in the AEP Central and North areas, as shown in Table 32.

Table 32: Retail Customers and Load Supplied by Alternative Providers as of January 1, 2006
% of Customers and (% of Load)

Firm and Load in MWh	Residential	Small C&I	Total
TXU	26.3% (26.2%)	30.7% (64.7%)	26.4% (50.4%)
Centerpoint	26.8% (27.3%)	34.5% (60.7%)	27.5% (47.8%)
AEP Texas Central	27.0% (31.3%)	45.8% (81.4%)	29.4% (63.8%)
AEP Texas North	33.2% (39.3%)	34.0% (78.7%)	31.9% (64.9%)
Texas NM Power	25.8% (29.9%)	35.0% (66.8%)	26.4% (56.0%)

Note: Texas does not provide separate distribution area statistics for large C&I customers.
Source: Texas Public Utility Commission

Retail customers have switched to alternative suppliers in increasing numbers and with an increasing proportion of load, as shown in Table 33.

Table 33. Texas Retail Aggregate Customer Migration Statistics, 2002-2005
% of Customers and (% of Load)

Year	2002	2003	2004	2005
Residential	7.4% (7.3%)	14.1% (15.0%)	19.9% (21.0%)	26.7% (27.5%)
Small C&I	11.5% (33.0%)	19.0% (44.1%)	26.7% (55.5%)	34.2% (65.1%)
Large C&I	19% (54%)	35% (60%)	42% (69%	53% (68%)

Note: The large C&I figures are for December 2002, December 2003, September 2004, and June 2005. The Residential and Small C&I figures are all from January except the 2005 figure which is from September.
Source: Texas Public Utility Commission

[451] Public Utility Commission of Texas, *Texas Electric Choice, Electricity Information-FAQ's, available at* http://www.powertochoose.org/yourrights/q_changing.asp.

Public Benefits Programs: The Texas public benefit programs are presented in Table 34.

<table>
<tr><th colspan="7">Table 34. Texas Public Benefits Programs</th></tr>
<tr><td rowspan="6">Restructuring Law signed in June 1999. Requires utilities to administer EE programs to achieve saving equivalent to 10% of annual load growth by 2004. PUC has established rates and procedures. Est. total annual cost is %80 million in 2003. Also a 10% LI rate discount & small SBC for customer educ. and LI assistance. Total LI is set at statutory maximum of .65 mills/kWh.[452]</td><td></td><td>Research & Development</td><td>Energy Efficiency</td><td>Low Income</td><td>Renewable Energy</td><td>Total</td></tr>
<tr><td>Million $</td><td></td><td>80.0</td><td>166.2</td><td></td><td>246.2</td></tr>
<tr><td>Mills/kWh</td><td></td><td>0.28</td><td>0.58</td><td></td><td>0.83</td></tr>
<tr><td>% revenue</td><td></td><td>0.43%</td><td>0.89%</td><td></td><td>1.28%</td></tr>
<tr><td>Admin.</td><td></td><td>Utility</td><td>PUCT</td><td></td><td></td></tr>
<tr><td colspan="6">Source: American Council for an Energy-Efficient Economy, Summary Table of Public Benefit Programs and Electric Utility Restructuring (December 2005), available at http://www.aceee.org/briefs/mktabl.htm.</td></tr>
</table>

Separation of Generation and Transmission: By January 1, 2002, utilities were required to separate their business activities into three units: a wholesale electric power generation company, a retail electricity company (REP), and a transmission and distribution company. This separation could take place either through the sale of assets to a third party, or by the creation of separate non-affiliated companies or separate affiliated companies owned by a common holding company.[453] After the beginning of retail competition, a distribution utility may not sell electricity or participate in the market for electricity except to procure electricity to serve its own needs.[454] Wholesale electric power generation companies that are affiliated with a distribution utility are required to auction off 15 percent of their installed generation capacity,[455] and no wholesale generator can own more than 20 percent of the installed capacity that can be sold in a region.[456] Before 2005, REP affiliates of transmission and distribution utilities could not offer competitive rates to residential and small commercial customers in the territory of the distribution utility, except as the POLR (default) service provider, until 40 percent of the residential or small business load in the territory is buying electricity from competitive

[452] Although the System Benefit Funds are being collected, the Legislature did not appropriate any fund for a low-income discount or for customer education in the 2005 session. Some REPs are continuing to offer low-income discounts and other benefits to these customers on a voluntary basis. Funding will be reconsidered in the 2007 legislative session; Reliant comments.

[453] Tex. Util. Code Ann. at § 39.051.

[454] *Id.* at § 39.105.

[455] *Id.* at § 39.153.

[456] *Id.* at § 39.154.

suppliers.[457] The transmission system for most of Texas is operated independently from the owners of the transmission assets by ERCOT under PUC supervision.

State RTO Involvement: Most of Texas (approximately 85 percent) is in the ERCOT interconnection.[458] ERCOT began operations as an independent system operator in 1996. It is regulated by the Texas PUC rather than by FERC.[459] Transmission operations of distribution utilities outside of ERCOT are regulated by FERC.

Generation Capability:[460] Prior to the restructuring legislation, utilities operated 88.3 percent of generation capability in Texas. By 2002, that figure dropped to 41.2 percent, as divestitures, transfers to affiliates, and entry and expansion of independent generators took place. Between 1997 and 2002, generation capability in the state increased from 73,454 MWs to 94,488 MWs, an increase of 28.6 percent . Much of the growth in generation was fueled by natural gas. The share of generation capability fueled by natural gas increased from 21.4 percent to 38.5 percent . Natural gas fueled generation more than doubled during the period.

Use of Customer Information: When the retail market opened to competition, distribution utilities were required to include customer name, address, and usage information on a list of eligible customers given to competitive suppliers.[461]

Standardized Labeling:[462] "On December 7, 2000, the Texas Public Utility Commission (PUC) issued rules requiring retail electric providers to use an Electricity Facts Label to disclose information twice a year on fuel mix and environmental impacts to their retail and small residential customers, in accordance with the state's restructuring law. The label must also be included in promotional material soliciting new customers. Fuel mix data must be compared to the state average, with energy generated from renewable resources to be listed under a single category. Emissions of carbon dioxide, sulfur dioxide, nitrogen oxides, and particulates, as well as the amount of nuclear waste generated, must be presented relative to the statewide average. According to rules adopted in August 2001, the Commission is developing a "generator scorecard" database with data on fuel mix and environmental impacts by generator to facilitate implementation of the disclosure requirements. The label is to be updated each year. Retail providers can also opt to purchase and retire "renewable energy credits" from generators to meet their disclosure requirements. Providers can project their fuel mix and emissions data for new products or products offered during the first year of competition. Any product marketed as "renewable" must include the renewable fuel mix percentage, unless it is supplied exclusively from renewable sources. Products marketed as "green" may contain some natural gas fuels along

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[457] Public Utility Commission of Texas, *Electric Competition-Fostering Competition*, *available at* www.choiceenergyservices.com/residential/pdf/Competition.pdf.

[458] ERCOT is not electrically synchronized with the Eastern or Western Interconnects.

[459] Electric Reliability Council of Texas, *The Market Guide: A Guide to How the Electric Reliability Council of Texas (ERCOT) Facilitates the Competitive Power Market* (Feb. 22, 2001).

[460] U.S. Department of Energy, Energy Information Administration, Texas State Profile, Table 4, *available at* http://www.eia.doe.gov/cneaf/electricity/st_profiles/texas.pdf.

[461] Reliant comments; Public Utility Commission of Texas, *Consumer Protections in a Competitive Electric Market*, *available at* http://www.powertochoose.org/publications/consumer_brochure.pdf.

[462] U.S. Department of Energy, Energy Information Administration, *Disclosure Policies*, *available at* http://www.eere.energy.gov/greenpower/markets/disclosure.shtml?print.

with renewable fuels if it can be shown that the natural gas was produced in Texas."[463]

Renewable Energy Portfolio Standard: Texas adopted a renewable energy portfolio standard on February 24, 2004. The standard establishes yearly new generation from renewables levels through 2019, rather than percentage requirements. The levels are 850 MW in 2004 and 2005, 1400 MW in 2006 and 2007, and 2000 MW in 2009 through 2019. In 2005, the RPS requirements were expanded to a total of 5,000 MW by 2015. Additional non-mandatory targets for renewables were established at the same time, along with a process that will allow the PUC to prioritize transmission development to facilitate delivery of energy from renewable sources.[464]

The original electric restructuring bill included many environmental protections, including that 50 percent of new generating capacity must come from natural gas, and that a percentage of electricity sold in Texas must come from renewable resources. The bill requires 50 percent reductions in nitrous oxide emissions and 25 percent reduction in sulfur dioxide emissions from power plants that were grandfathered when air permits were introduced under the Federal Clean Air Act. There reductions must be achieved by 2003 by retrofitting or shutting down the grandfathered units. In addition, distribution utilities that upgrade older generation facilities to meet emissions standards may recover the costs from retrofitting as stranded costs.[465] The PUC has adopted a renewable energy credit trading program to encourage cost-effective new renewable generation facilities.

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[463] The consumer brochure on electricity offer labeling is *available at* http://www.powertochoose.org/publications/efl_brochure.pdf.

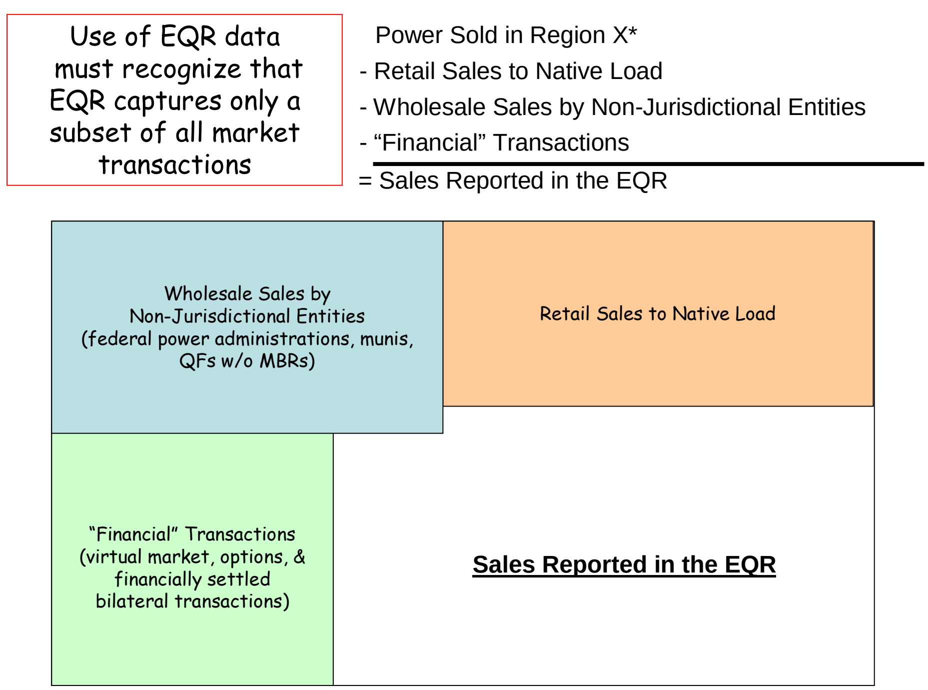
[464] Reliant comments.

[465] Public Utility Commission of Texas, *Electric Restructuring to Improve Air Quality*, *available at* www.puc.state.tx.us/nrelease/2000/082400.cfm.

APPENDIX E
ANALYSIS OF CONTRACT LENGTH AND PRICE TERMS
COMPARISON OF NYISO, MISO AND SERC MARKETS USING 2005 EQR DATA

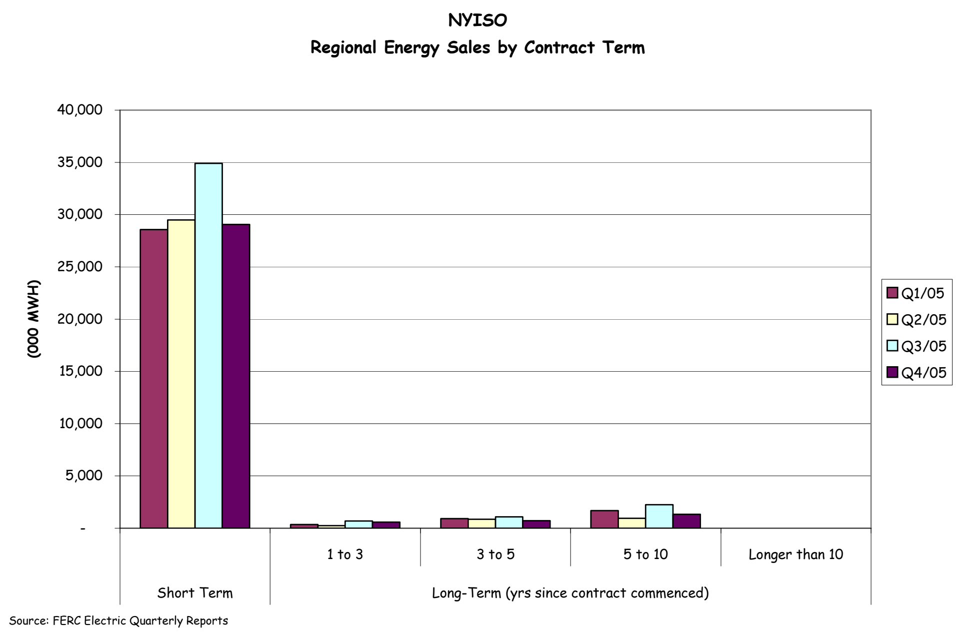
This analysis compares the short-term versus long-term sales volumes and prices in three regions using reported sales information from Electric Quarterly Reports (EQR), which are filed electronically on a quarterly basis at FERC by all holders of market-based-rate authorizations (MBRA). EQR data is available to the public on FERC's website. However, EQR data include only jurisdictional wholesale physical and booked out sales. The "physical" sales are power sales by MBRA holders physically delivered during the quarter. "Booked out" sales are power quantities that are sold, then repurchased at a later date, effectively undoing the prior sale. Depending on changes in market prices in the interim, the repurchase may produce profits or limit losses for the seller.

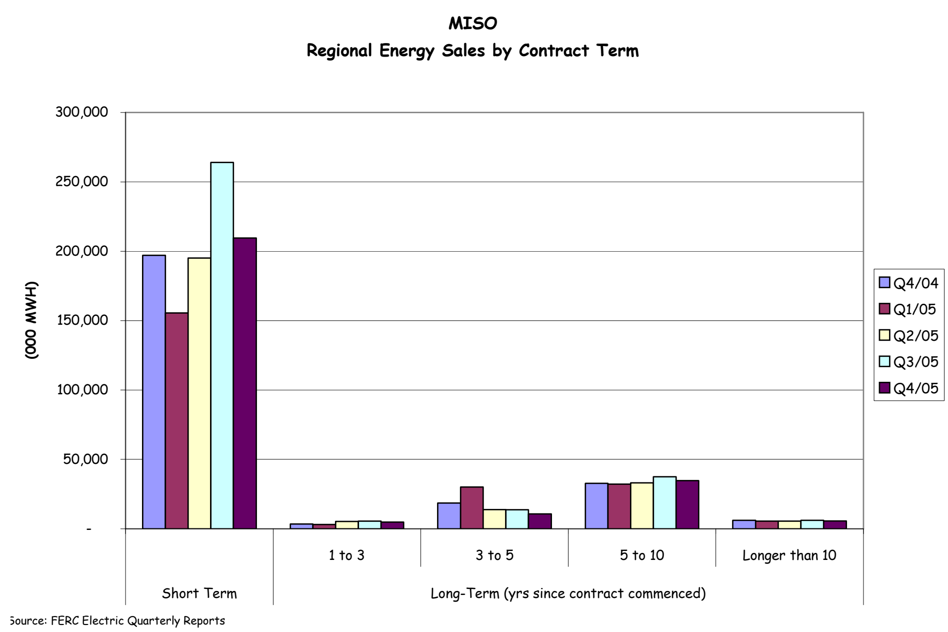
EQR limitations are best explained with the help of the diagram below, which is conceptual, not scaled, where the sales reported to EQR represent only a subset of all market transactions. Retail sales may be reportable to state commissions. Sales by non-jurisdictional entities may appear in some EIA reports. Financial transactions done on NYMEX are reportable to CFTC, but other financial transactions do not need to be reported. Sales reportable to EQR could have been transacted bilaterally, on RTO/ISO's, through ICE or through voice brokers, and credit cleared through ICE-LCH or NYMEX-ClearPort. Other transaction venues may develop. There is no complete aggregated market picture. Analysts can only try to make inferences from the partial market picture.

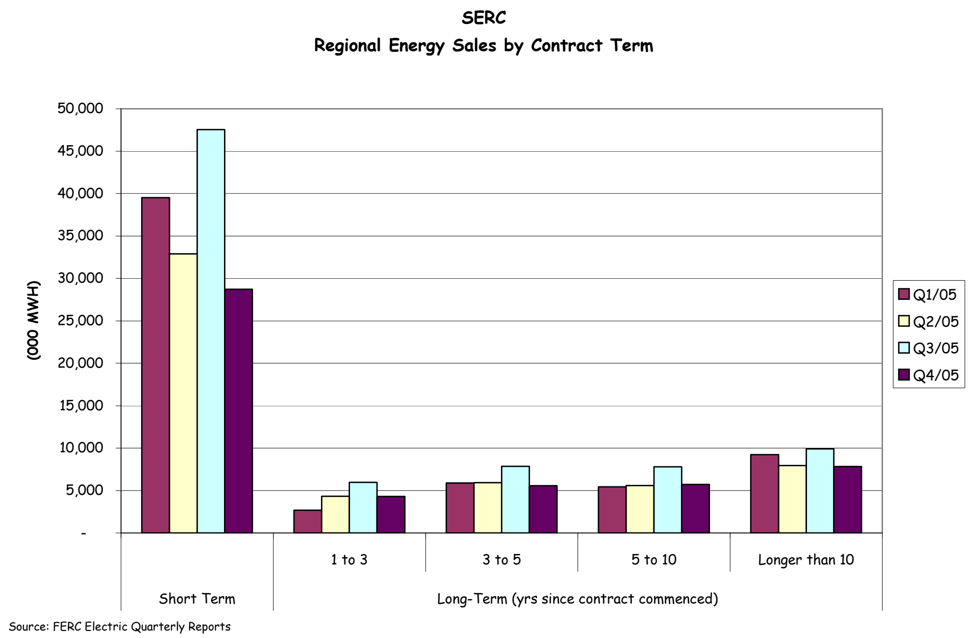


Though limited, this comparative analysis is informative. The Task Force selected NYISO, MISO and SERC as representative markets for the following reasons. NYISO provides a consistent data set for sales in its established, single-state organized market. MISO provides a consistent data set for sales in its new, multi-state organized part of the market (sales in Q1/05 occurred before the organized market started). SERC is an example of a purely bilateral wholesale market with relatively few participants (which increases the likelihood of consistent dataset).

The three graphs below show transaction volumes by vintage for each representative region.







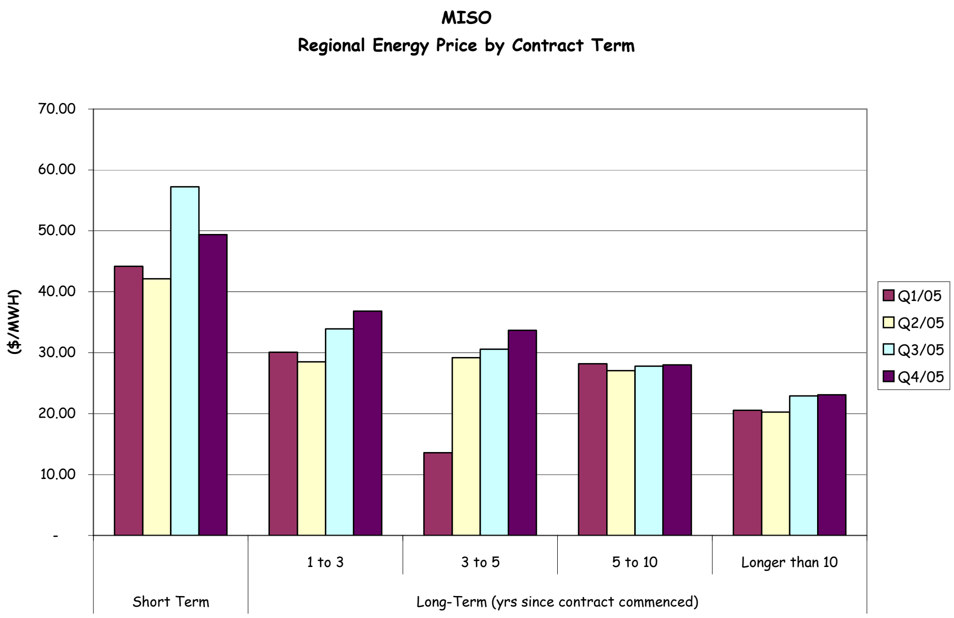
As noted earlier, EQR consists of sales transactions for power delivered during each quarter. Short term transactions are defined as transactions under contracts of one year or less or sales into organized markets, such transactions include bilateral sales as well as sales to NYISO and MISO. Long-term transactions occur under contracts lasting more than a year. For example, a contract initiated four years ago and still delivering power would be grouped under the 3 to 5 year vintage. A contract initiated 11 years ago would be grouped under the Longer than 10 years vintage. While there is a field in the EQR form for termination date, it is often not relevant in this context because many contracts are either evergreen, effective until cancelled or master agreements (with no time limits) with attachments for term-limited transactions. Major observations on the reported volumes are:

- a higher percentage of sales were short term in organized markets (91 percent in NYISO, 77 percent in MISO, 60 percent in SERC);
- relatively few contracts were older than 10 years (0 percent in NYISO, 2 percent in MISO, 16 percent in SERC);
- quarterly variation in quantities occurred primarily in sales under short term contracts.

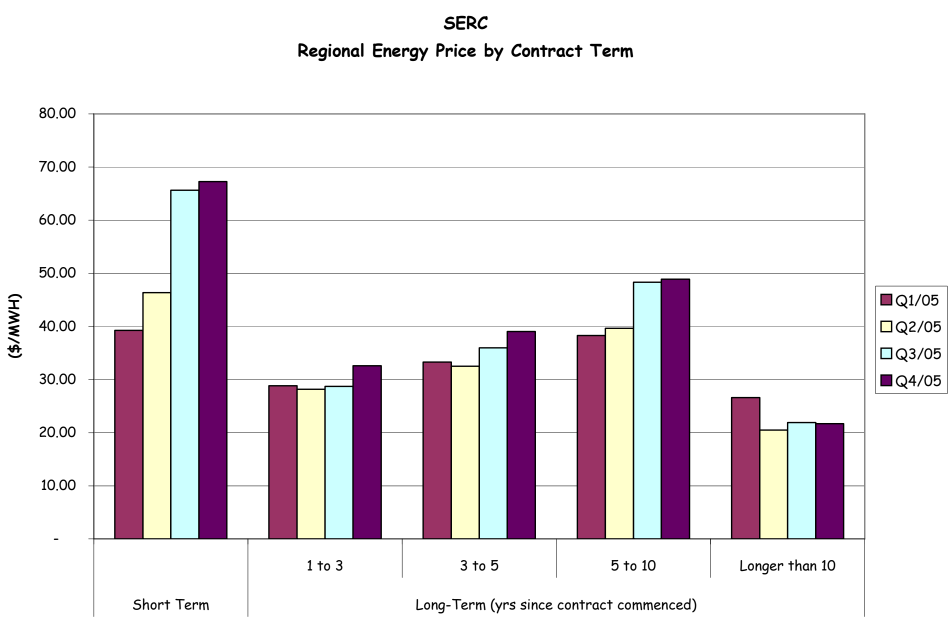
Organized exchange markets like NYISO and MISO are designed to produce efficient and reliable daily or real-time spot market prices, with heavy reliance on bilateral financial and physical transactions to fill longer term needs between parties who would then settle these bilateral transactions using organized market spot prices as “index price.” The high visibility of the spot markets, along with non-reportable financial transactions would naturally lead to a high percentage of short term transactions using EQR numbers in organized markets such as NYISO and MISO. The trend towards capacity or reliability pricing products in organized markets (e.g., RPM in PJM) also suggests that that organized markets may not rely on short term markets alone to give long-term price signal for investment.

The higher proportion of long-term contracts at SERC may suggest more effective long-term price signals than at non-organized markets. However, many of these long-term contracts are legacy contracts entered into before competitive markets were introduced. Some of these contracts are pegged to index prices that are formed with few reported transactions and therefore questionable liquidity.

The following graphs show the price patterns by contract vintage in 2005.



Source: FERC Electric Quarterly Reports



Source: FERC Electric Quarterly Reports

This analysis shows that prices under long-term contracts were somewhat lower than short-term prices in MISO and SERC, but not in NYISO. The short-term price changes are reflected in sales under long-term contracts. These changes may occur because some long-term contracts use indexed prices (i.e., short term published reference prices).

It is difficult to draw definite conclusions on prices with only a quarter's worth of data. Furthermore, organized markets are evolving and will include capacity markets that could provide stronger price signals for long-term investment.

APPENDIX F
A BIBLIOGRAPHY OF PRIMARY INFORMATION ON ELECTRIC INDUSTRY RESTRUCTURING IN THE U.S.

The process of understanding the ins and outs of restructuring markets for electricity and transmission in the U.S. has been running full bore since the early 1990s. Accordingly, a large number of documents have been published intending to explain the basic engineering, economic and regulatory theories that support restructuring ideas. The intended audience of these studies has been various – from state regulators and legislators, to academics, public power managers, and the general public.

The Task Force members have *not* attempted to generate another primer on restructuring as part of its competition study. Instead, the Task Force refers the interested reader to a variety of sources that will allow him/her to learn more about the subjects that are of the most interest.

Some of these sources are older and contain slightly outdated references – but their theoretical arguments remain applicable to current debates.

NOTE: Inclusion of articles does not indicate the Task Force's endorsement of the theories presented.

<u>General Restructuring Information Documents Available on the Web</u>:

American Public Power Association, *Restructuring at the Crossroads, FERC Electric Policy Reconsidered*, (December 2004), *available at* http://www.appanet.org/files/PDFs/APPAWhitePaperRestructuringatCrossroads1204.pdf

Matthew Brown and Richard P. Sedano, *A Comprehensive View U.S. Electric Restructuring with Policy Options for the Future*, National Council on Electricity Policy (2003), *available at* http://www.ncouncil.org/pdfs/restruc.pdf

Matthew Brown and Richard P. Sedano, *Electricity Transmission, A Primer*, National Council on Electricity Policy (June 2004), *available at* http://www.ncouncil.org/pdfs/primer.pdf

U.S. Department of Energy, Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update* (October, 2000), *available at* http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/

William W. Hogan, *Competitive Electricity Market Design: A Wholesale Primer* (December, 1998) (working paper), *available at* http://stoft.com/metaPage/lib/Hogan-1998-Primer.pdf

William W. Hogan, *Market Design and Electricity Restructuring* (November 1, 2005) (presentation at the Association of Power Exchanges 2005 Annual Conference in Orlando FL), *available at* http://ksghome.harvard.edu/~whogan/hogan_apex_110105.pdf

Paul L. Joskow, *Markets for Power in the United States: An Interim Assessment*, ENERGY J. (forthcoming 2006), *available at* http://stoft.com/metaPage/lib/Joskow-2006-power-market-assessment.pdf

Paul L. Joskow, *Restructuring, Competition, and Regulatory Reform in the U.S. Electricity Sector,* J. ECON. PERSPECTIVES 11(3), at119-38.

On-Line Libraries of Electric Industry Restructuring Documents:

Harvard Electricity Policy Group
http://www.ksg.harvard.edu/hepg/papers.htm

Center for the Study of Energy Markets (CSEM) at the University of California Energy Institute (UCEI) at UC Berkeley: http://www.ucei.berkeley.edu/pubs-csemwp.html

Stephen Stoft Website Library:
http://stoft.com/p/S2.html

Carnegie Mellon Electric Industry Center (CEIC):
http://wpweb2.tepper.cmu.edu/ceic/publications.htm

Books

RICHARD F. HIRSH, POWER LOSS: THE ORIGINS OF DEREGULATION AND RESTRUCTURING IN THE AMERICAN ELECTRIC UTILITY SYSTEM (MIT Press 1999).

SALLY HUNT, MAKING COMPETITION WORK IN ELECTRICITY (Wiley Publishing 2002).

STEVEN STOFT, POWER SYSTEM ECONOMICS: DESIGNING MARKETS FOR ELECTRICITY (IEEE Press, Wiley-Interscience 2002).

APPENDIX G
CREDIT RATINGS* OF MAJOR AMERICAN ELECTRIC GENERATION COMPANIES** AS OF JULY 24, 2006

Name	Credit Rating	Sales ($bil)	Profits ($bil)	Assets ($bil)	Market Value ($bil)
AES Corp.	B+	10.64	0.56	29.65	11.33
Allegheny Energy Inc	BB+	3.04	0.07	8.56	5.82
Alliant Energy Corp.	no rating	3.28	-0.01	7.78	3.87
Ameren Corp.	A-	6.78	0.63	18.16	10.33
American Electric Power Co., Inc.	BBB	11.9	0.81	36.17	14.36
Atmos Energy Corp.	BBB	5.89	0.15	6.62	2.13
CALPINE Corp.	D	9.23	-0.24	27.09	0.13
CenterPoint Energy, Inc.	BBB-	9.72	0.22	17.12	4.02
Cinergy Corp.	BBB	5.41	0.49	17.2	8.75
CMS Energy Corp.	B+	6.41	-0.08	16.02	3.1
Consolidated Edison	A	11.69	0.73	24.85	11.26
Constellation Energy	BBB+	17.13	0.63	21.47	10.48
Dominion Resources Inc	BBB+	18.04	1.04	52.58	25.59
DTE Energy Co.	BBB	9.02	0.54	23.36	7.7
Duke Energy Corp.	BBB	16.75	1.83	54.59	26.3
Edison International	BB	11.2	1.24	35.51	14.45
Energy East Corp.	BBB	5.3	0.26	11.45	3.7
Entergy-Koch	BBB-	10.11	0.92	29.97	15.04
Exelon Corp.	BBB+	15.36	0.97	42.39	38.06
FirstEnergy Corp.	BBB-	11.99	0.89	31.84	16.85
FPL Group, Inc.	A	11.85	0.89	33	16.56
KeySpan Corp.	A-	7.66	0.4	13.81	7.11
Kinder Morgan, Inc.	BBB	1.59	0.55	17.38	11.34
MDU Resources Group, Inc.	A-	3.46	0.28	4.42	4.23
Mirant Group	B+	3.7	NA	12.88	7.38
NiSource Inc.	BBB	7.89	0.31	17.96	5.6
Northeast Utilities	BBB	7.4	-0.25	12.57	3
NRG Energy Inc	B	2.36	0.11	7.8	3.76
NStar	A-	3.24	0.2	7.65	3.14
OGE Energy	A	6.98	0.17	5.72	2.6
Pepco Holdings, Inc.	BBB	7.73	0.32	14.22	4.5
Pacific Gas & Electric	BBB	11.7	0.92	34.07	13.02
Pinnacle West Capital Corp.	BBB-	2.99	0.18	12.07	4.05
PPL Corp.	BBB	6.22	0.69	18.04	12.09
Progress Energy Inc	BBB-	10.11	0.7	27.07	11.14
Public Service Enterprise Group, Inc.	BBB	12.43	0.68	29.82	17.43

Name	Credit Rating	Sales ($bil)	Profits ($bil)	Assets ($bil)	Market Value ($bil)
Reliant Energy	B	9.73	-0.35	13.54	3.07
SCANA Corp.	A-	4.78	0.33	9.32	4.65
Sempra Energy	A	11.74	0.92	29.21	12.29
Sierra Pacific Resources	B+	2.96	0.09	8.12	2.61
Southern Co.	A	13.55	1.59	39.88	25.24
TECO Energy, Inc.	BB+	3.01	0.27	7.17	3.55
TXU Corp.	BBB-	10.44	1.78	24.91	25.17
Williams Companies, Inc.	BB+	12.58	0.32	33.66	12.36
Wisconsin Energy Corp.	A-	3.82	0.31	10.46	4.78
Wisconsin Public Service Resources	no rating	6.96	0.16	5.45	1.99
Xcel Energy Inc.	BBB	9.63	0.51	21.65	7.49

*credit rating is the "Long Term Issuer Default Rating" from Fitch Ratings (www.fitchratings.com)

**list drawn from United States-based generation companies on Forbes list of the top 2000 global firms (http://www.forbes.com/2006/03/29/06f2k_worlds-largest-public-companies_land.html)

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Have Customers Benefited from Electricity Retail Competition?

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Abstract

Compared to traditional cost-of-service (COS) regulation, electricity retail competition may lead to lower costs but higher markups. Thus, the net policy effect on the average electricity retail price is ambiguous. This paper uses a difference-in-difference approach to estimate the policy impact for U.S. states that restructured their electricity retail markets. The results suggest that in restructured states, only residential customers have benefited from significantly lower prices but not commercial or industrial customers. Furthermore, this benefit is transitory and disappears in the long run. Overall, retail competition does not seem to deliver lower electricity prices to retail customers across the board or over time.

Keywords: Electricity; restructuring; retail choice, retail competition; difference-in-difference.

JEL codes: L52, K23, Q48, D42, D43

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1 Introduction

In the 1990s, a number of U.S. states began restructuring their electricity retail markets and pursued retail competition as an alternative to traditional cost-of-service (COS) regulation. Direct rate regulation was eschewed in favor of access regulation, thereby opening the electricity market to alternative retail service providers (RSPs). These firms procure electricity from power producers and market it to final customers, using existing electricity network infrastructure owned by local utilities. It was hoped that, by restructuring the electricity retail market to allow for competition, electricity prices determined in the marketplace would decrease, and welfare would increase.

However, there is no guarantee that retail competition will ultimately lead to lower retail prices paid by customers. Two potentially opposing effects arise from the same market restructuring process: On the one hand, competitive pressure gives all firms a strong incentive to cut costs. On the other hand, the markup rate determined through competition may exceed the markup rate charged by previously rate-regulated monopolies. In the electricity retail market, even when entry is relatively easy and RSPs possess limited market power, a higher markup rate can nonetheless arise when customers face search frictions. This is especially likely to happen for small customers, where the perceived benefits from identifying the optimal choice among many, and potentially rather complicated, alternatives may be small relative to the associated search costs and switch costs. Furthermore, search costs and switch costs may not diminish over time, even as customers become more familiar with the new regime of retail competition. Thus, unlike the hypothetical benchmark of an unregulated monopoly—where the introduction of competition would reduce both costs and markups—replacing rate regulation with competition may or may not result in lower prices.

This paper empirically investigates the policy impact of retail competition, as currently practiced in the U.S., on average electricity retail prices. Using data obtained from the Energy Information Administration (EIA) covering the period from 1990 through 2011, we examine the effects of a state's decision to implement retail competition on the average prices paid by different segments of customers: residential, commercial, and industrial.[1] To identify the policy impact, we employ a difference-in-differences (DID) approach, exploiting the fact that while some states never pursued restructuring, other states implemented retail competition in different years.

We also allow for potentially different policy effects at different stages of restructuring. Anticipating that it takes time to establish competition, states that pursue market restructuring generally stipulate additional regulatory provisions for a transitional period following the opening of their retail markets. In particular, there are two main provisions. First, during the transitional period, incumbent utilities typically are allowed to recover their "stranded costs," i.e., the difference

[1]Residential customers are mainly regular, single-family households living in houses or apartments. Commercial customers include businesses, offices, restaurants, hotels, etc., and industrial customers are large manufacturing or processing plants.

between the net book value of a generating plant used for setting cost-based regulated prices and the market value of that plant if it were required to sell its output in a competitive market. The recovery of stranded costs tends to increase the retail price than it otherwise would be. Second, during the transitional period, many restructuring states also implemented some form of "rate freeze" or "rate reduction" to ensure price stability while competition was being established. The rate freeze or rate reduction tends to decrease the retail price than it otherwise would be. The net effect on the retail price during the transitional period thus depends on the balance of these two factors. There is no *a priori* reason to believe that the policy impact of restructuring would be the same for the transitional period and the period afterwards.

Our results are illuminating. First, we find different policy impact of restructuring across customer segments. In restructured states, residential customers have benefited from significantly lower prices. The price reduction, on average, ranges from 0.87 to 1.02 ¢/kWh and is significant at the 1% level. Commercial and industrial customers, on the other hand, have not benefited from any significant price reductions associated with restructuring.

Second, the policy impact of restructuring indeed changes over time. For example, we use a five-year window for the transitional period (i.e., the short run) and the period afterwards (i.e., the long run). The price reduction experienced by residential customers is more pronounced in the short run but becomes insignificant in the long run. For residential customers, the short-run price reduction ranges from 1.14 to 1.31 ¢/kWh and is significant at the 1% level, while the long-run price reduction ranges from 0.53 to 0.72 ¢/kWh and is not significant at the 10% level. For commercial customers, the price reduction ranges from 0.46 to 0.52 ¢/kWh and is marginally significant in the short run, but insignificant in the long run. Lastly, for industrial customers, the policy impact is insignificant both in the short run and in the long run.

For electricity retail markets, the transitional period represents a hybrid regime—namely, incipient competition coupled with direct price controls (both stranded costs recovery and rate freeze or rate reduction). The period afterwards represents a relatively pure form of retail competition. The short-run policy effect is a highly significant price reduction for residential customers, suggesting that the impact from rate freeze or rate reduction outweighs the impact from stranded-costs recovery during the transitional period, at least for residential customers. On the other hand, the long-run policy impact is insignificant for all customer segments, so there is insufficient evidence that retail competition, as currently practiced in the U.S., delivers lower prices to retail customers across the board or in the long run.

The rest of the paper is organized as follows. In Section 2 we provide some background concerning electricity market restructuring in the U.S., and link this paper to the existing literature on competition and regulation of electricity markets. We then present our econometric model and discuss our identification strategy in Section 3. Data used for the empirical analysis are described in Section 4, and estimation results are reported in Section 5. We conclude with a discussion of the results in Section 6. All tables are in the Appendix.

2 Background

2.1 Restructuring of the U.S. electricity market

The U.S. electricity industry can be divided into a wholesale sector and a retail sector. The wholesale sector generates bulk power in power plants and transports it through the high-voltage, long-distance transmission grid to load centers. The retail sector purchases bulk power from the wholesale sector and distributes power through low-voltage, local distribution networks to final customers. Wholesale operations typically involve interstate commerce and are thus subject to state and federal regulations. On the other hand, retail operations do not usually involve interstate commerce and are subject to state regulations only.

A traditional electric utility is a vertically integrated local monopoly in both wholesale and retail operations, regulated by both federal and state agencies. The predominant form of regulation of utilities used to be cost-of-service (COS) regulation, i.e., price regulation. However, the mid-1990s saw a paradigm shift in electricity industry regulation in the United States. With the mandate of the 1992 Federal Energy Act, the Federal Energy Regulatory Commission (FERC) issued a series of regulatory orders to promote wholesale competition through access regulation to the transmission grid.[2] The restructuring of the wholesale market replaced traditional COS regulation of wholesale operations with wholesale competition.

Soon after the restructuring of the wholesale market, some states started to experiment with a similar restructuring of their retail markets. Traditional COS regulation of retail operations was replaced with retail competition, enabled by access regulation of distribution networks. Depending on the state, retail restructuring may be implemented through state legislation, regulatory orders, court decisions, or a combination of these actions. By the end of 2011, active retail competition exists for residential customers in 13 states, for commercial customers in 15 states, and for industrial customers in 17 states (excluding the District of Columbia). Figure 1 is a snapshot of restructured states for the year 2011. Table 1 shows the evolution of the restructuring status across states from 1990 to 2011. The policy variation across states and over time will play an important role for the identification of the restructuring policy impact (to be discussed in detail later).

When a state restructures its retail market, competition does not happen overnight: It takes time for firms to enter the newly opened market, and for customers to understand and take advantage of the newly available choices. There is hence a transitional period after restructuring has commenced, but before retail competition is fully established, during which incumbent utilities face relatively little competitive pressure. Thus, additional regulatory measures are needed to ensure a smooth transition to competition. There are two main categories of provisions. The first provision is for stranded-costs recovery. That is, in the transitional period, incumbent utilities are typically allowed to recover some or all of their stranded costs, which represents the

[2] See Federal Energy Regulatory Commission, Orders No. 888, No. 889, and No. 890.

difference between the net book value of a generating plant used for setting cost-based regulated prices and the market value of that plant if it were required to sell its output in a competitive market. In most states, stranded-cost recovery is achieved through some type of non-bypassable stranded cost charge that is assessed to *all customers* as a component of regulated monopoly distribution service (See Joskow 2000). The stranded cost charge tends to increase the retail price than it otherwise would be in the transitional period. The second provision is rate freeze or rate reduction. That is, to ensure price stability, states almost invariably stipulate a rate freeze or a rate reduction for some time after the commencement of their restructuring policies, especially so for *residential customers*.[3] The rate freeze or rate reduction tends to decrease the retail price that it otherwise would be in the transitional period, in particular for residential customers. Overall, the transitional period can be regarded as a hybrid regime of cultivating retail competition with components of direct price controls, whereas the period afterwards can be regarded as a relatively pure form of retail competition replacing traditional COS regulation.

2.2 Effects of restructuring on market outcomes

The policy changes in the electricity industry described above have spawned a growing literature that examines the impact of restructuring on market outcomes in the U.S.[4] Most of this literature focuses on the wholesale sector. It is nonetheless important in our context, as it examines the effects of restructuring on production efficiency and the exercise of market power—channels that are also relevant to the retail sector.

Kleit and Terrell (2001) estimate that gas-fired generation plants could reduce costs by up to 13% by eliminating production inefficiencies. Wholesale restructuring creates competition in the generation segment and gives plant operators an incentive to close this gap. Fabrizio *et al.* (2007) estimate that investor-owned fossil-fueled plants in states that restructured their wholesale markets reduced labor and nonfuel expenses by 3–5% relative to investor-owned plants in other states, and by 6–12% relative to government and cooperatively owned plants that were largely insulated from restructuring incentives. For nuclear-fueled plants, Zhang (2007) finds that restructuring is linked to a 5.5% increase in plant utilization, and to an 11% reduction in operating costs. Barmack *et al.* (2007) use plant level data from New England to simulate the social cost and benefit of

[3]For example, in Illinois, House Bill 362, "The Electric Service Customer Choice and Rate Relief Act of 1997," stipulated a 15 percent rate reduction for residential customers by August 1998, and another 5 percent reduction in May 2002. In Massachusetts, House Bill 5117 required retail access by March 1998, rate cuts of 10 percent by March 1998 and another 5 percent cut 18 months later. In Ohio, Senate Bill 3 was signed into law in July 1999. It allowed retail customers to choose their energy suppliers beginning January 1, 2001. It also required a 5 percent residential rate reduction and a rate freeze for 5 years. In Texas, Senate Bill 7 was enacted in June 1999. The law required retail competition to begin by January 2002, rates to be frozen for 3 years, and then a 6 percent reduction for residential and small commercial consumers.

[4]For the restructuring experiences of other countries, see Green and Newberry (1992), Pollitt (1997), Newberry and Pollitt (1997), Newberry (1999, 2002), Hogan (2002), Al-Sunaidy and Green (2006), Joskow (2006, 2008), and Zhang *et al.* (2008), among others.

restructuring. Compared to the counterfactual of continued direct regulation, restructuring led to a net social benefit of 2% of total wholesale costs.[5]

Whether such cost savings are passed on from the wholesale to the retail sector depends on each firm's market power. The literature finds less positive results on this issue. Borenstein and Bushnell (1999) use historical cost data to simulate California's electricity market after restructuring, and find potential for significant market power during high-demand hours. Using California post-restructuring data, Borenstein *et al.* (2002) find near-competitive pricing during low-demand months, but a significant departure from competitive pricing during high-demand summer months. Similarly, Wolak (2003) finds a significant increase in unilateral market power for each of the California's five large electricity suppliers, following restructuring.[6]

In contrast to what is known about wholesale markets, our understanding of the restructuring impact on electricity retail markets is still rather limited.[7] In states that restructured their electricity retail sectors, Apt (2005) compares the annual rates of change of electricity prices before and after restructuring, and argues that retail competition for industrial customers did not lead to lower industrial electricity prices. However, the before-and-after comparison may be confounded by factors whose changes coincide with the restructuring. Fagan (2006) uses historical price data for 1990–1997 to forecast 2001–2003 prices, and then compares this forecast to actual prices in 2001–2003. He finds that, relative to their predicted values, prices for industrial customers in restructured states increased less than those in non-restructured states, but the difference is not statistically significant.[8]

Our paper fills a gap in this literature. Using a long panel dataset (1990–2011), we are able to exploit differences in electricity retail market restructuring status across states *and* over time, to estimate the impact of retail competition on average prices. We further allow for different policy

[5]Similar efficiency gains have been documented in other industries that have undergone a restructuring or deregulation process (e.g., Bailey 1986, Olley and Pakes 1996, Ng and Seabright 2001). In the context of electricity markets, reductions in production costs may be partly offset by increased environmental costs associated with power generation. Fowlie (2010) finds that deregulated power generation plants in restructured electricity markets are less likely to adopt more capital-intensive environmental compliance options, compared to physically similar plants that are either rate regulated or publicly owned.

[6]A different strand of the literature examines the role of vertical arrangements between the wholesale and retail sectors for price formation in electricity markets. Joskow (1997) and Borenstein (2002) emphasizes the importance of such vertical relationships for the success of electricity market restructuring. Bushnell (2007), Mansur (2007), and Bushnell *et al.* (2008) examine a number restructured electricity markets and demonstrate that the presence of long-term vertical arrangements between the wholesale and the retail sectors are generally important not only for maintaining price stability, but also for preventing anti-competitive practices.

[7]A unique feature of the retail market, as compared to the wholesale market, is that retail customers typically do not see real-time price changes and hence cannot adjust their consumption decisions accordingly. Bushnell and Mansur (2005) find that retail consumers respond more to lagged price increases from their past bills than current price information. Borenstein and Holland (2005) and Joskow and Tirole (2006, 2007) discuss the importance of replacing traditional electric meters with real-time meters to improve efficiency in the electricity retail market.

[8]Fagan (2006) acknowledges that the result is preliminary as "the impact of restructuring on prices was still evolving in the post-restructuring period examined. Most states were (and still are) in the transition period where rates are set by a mix of competitive and regulatory forces."

impacts for residential, commercial, and industrial customers, as well as different policy impacts in the short run and long run. As we will demonstrate, the effect of retail competition on average prices depends crucially on both the customer segment and the time frame under consideration.

3 Empirical Approach

To answer the question of whether retail competition leads to lower electricity prices, compared to traditional COS regulation, we use the difference-in-difference (DID) approach. This method utilizes policy variations across both states and time periods for identification.

3.1 Econometric model

The basic, *uniform impact* model we estimate is the following:

$$y_{st} = \alpha_s + \beta_t + \gamma R_{st} + \theta X_{st} + \varepsilon_{st}. \tag{UI}$$

The dependent variable y_{st} is the average electricity retail price for state s in year t, calculated as the average revenue per unit of energy sales and services (¢/kWh).[9]

On the right hand side, α_s is the state fixed effect and β_t is the year fixed effect, allowing for a linear time trend as a special case. R_{st} is a dummy variable that takes on the value 1 if the retail market in state s has been restructured in year t, and 0 otherwise. X_{st} is a vector of control variables that capture both supply and demand side factors for state s in year t. The residual term is ε_{st}. Our parameter of interest is γ, which measures the policy impact of retail restructuring, that is, the difference between the average electricity retail price under retail competition and that under COS regulation.

In the uniform impact model (UI), the policy effect is assumed to be constant over the entire restructuring period. As outlined previously, this assumption neglects temporary regulatory measures, imposed by restructuring states, that are effective only during the transitional period. To better capture these policy differences between the short run and long run, we divide the policy impact into two parts: A transitional impact over a certain period following restructuring, and a post-transitional impact thereafter. Thus, we also estimate the following *differential impact*

[9] We focus on the average price instead of marginal price of retail electricity for several reasons. First, even if one can find the tariff schedules offered by retails service providers, the choice of the applicable tariff schedule is potentially endogenous and influenced by a customer's forecast of his own future demand, and customer-level data is not publicly available. Second, our analysis is at the state level. While it is easy to construct state-wide average price, it would be very difficult to construct state-wide marginal price even with customer-level data. Three, despite the potential efficiency reasons to install real-time meters, the majority of residential customers and small commercial customers still have conventional meters. Ito (2014) finds strong evidence that household consumers respond to average price rather than marginal price or expected marginal price in their electricity consumption.

model:

$$y_{st} \;=\; \alpha_s + \beta_t + \gamma^{SR} R_{st}^{SR} + \gamma^{LR} R_{st}^{LR} + \theta X_{st} + \varepsilon_{st}. \tag{DI}$$

In (DI), R_{st}^{SR} is a dummy variable equal to 1 if the retail market in state s has been restructured but remains in the transitional period in year t. R_{st}^{LR} is a dummy variable equal to 1 if the retail market in state s has been restructured and is in the post-transitional period in year t. (The construction of these indicators will be detailed in Section 4.2.) The coefficients γ^{SR} and γ^{LR} capture the short run and long run impacts, respectively, of switching from COS regulation to retail competition.

3.2 Identification

After controlling for observed heterogeneity through X_{st}, identification of γ (and γ^{SR}, γ^{LR}) rests on the following assumptions. First, systematic unobserved heterogeneity across states remains constant over time, so that it can be captured by the state fixed effects (α_s). Second, systematic unobserved heterogeneity over time remains constant across states, so that it can be captured by the year fixed effects (β_t). When these assumptions are satisfied, the patterns of price evolution over time are similar across states, so that γ can be identified through the following difference-in-difference method.

For state s that first implemented restructuring in year t, the observed year-over-year price difference $y(R_{st}=1)-y(R_{s,t-1}=0)$ captures the effect caused by moving from one regulatory regime to another, as well as other (policy-independent) factors that result in price changes between year $t-1$ and year t. The counterfactual benchmark is $y(R_{st}=0)-y(R_{s,t-1}=0)$, that is, the price difference that would obtain if state s had not implemented its restructuring policy. This counterfactual is not directly observable. However, it can be approximated by that of another state u that did not restructure its market in either year $t-1$ or year t. For this state, the observed price difference $y(R_{ut}=0)-y(R_{u,t-1}=0)$ captures only the policy-independent price evolution across the two years, under an unchanged regime of COS regulation. By netting out the difference across the two years, the remaining difference can be solely attributed to the policy change from COS regulation to retail competition in state s. Thus, the parameter γ is identified by the difference in differences

$$\big[\,y(R_{st}=1)-y(R_{s,t-1}=0)\big] \;-\; \big[\,y(R_{ut}=0)-y(R_{u,t-1}=0)\big].$$

One may worry about the possibility that restructuring policies are endogenous. That is, a state's decision to adopt retail competition is not random but instead depends on the prevailing electricity prices in that state.Indeed, states that implemented restructuring tend to have had (and continue to have) higher electricity prices than states that decided against restructuring. Selection based on the level of prices does not bias our estimates of the restructuring impact, as level differences are readily accounted for by the inclusion of state fixed effects.[10] On the other hand, selection based on different price trends would create a problem. For example, if state s adopted restructuring based on the observation that its retail prices had increased and were expected to continue to increase, while state u rejected restructuring based on the observation that its retail price had stayed flat and were expected to remain flat, the time-invariant state fixed effects α_s and α_u would fail to capture this trend difference. The observed price difference for state u would then underestimate the counterfactual price difference for state s, resulting in an upward bias in the estimated parameter γ.

To determine whether such trend differences played an important role in the restructuring decisions across states, we look for both document evidence and empirical evidence. First, on the document side, a careful reading of the EIA reports documenting states' restructuring decisions indeed suggests that the level of electricity retail prices, rather than the trend of price changes, was the primary concern in the decision to adopt retail competition.[11]

Second, on the empirical side, we compare the price patterns from 1990 to 1996—before any restructuring policy was implemented—between the group of states that later pursued retail competition ($g_s = 1$) and the group of states that did not ($g_s = 0$). This comparison can reveal whether systematic differences exist between the two groups of states before the policy change. In particular, we estimate the following *pre-treatment* model:

$$y_{st} \;=\; \phi g_s + \beta_t + \delta(t \cdot g_s) + \theta X_{st} + \varepsilon_{st}. \tag{PRE}$$

A significant estimate of ϕ would suggest a systematic difference in price level between the two groups, consistent with the document evidence, and this price level difference is readily accounted for in the subsequent DID analysis by the state fixed effects. On the other hand, a significant estimate of δ would indicate a systematic difference in trends between the two groups, thus raising concerns about the suitability of the DID approach.

4 Data

To empirically estimate the regression models, we compiled a state-level panel dataset for the period 1990–2011.

[10] An alternative method to our difference-in-difference approach is to use the instrumental variable approach to deal with the potential self-selection bias. That is, to find excluded variables that arguably affect states' restructuring decisions without directly influencing their retail price levels. For example, one may argue that the political composition of a state's governing bodies has a direct impact on the state's restructuring decision but not its electricity retail prices. However, when these political variables are weak instruments, the IV estimates are biased. See Bound, Jaeger, and Baker (1995), Staiger and Stock (1997), and Stock *et al.* (2002) for more detailed discussions on weak instruments.

[11] See Table 2 for the EIA report excerpts.

4.1 Dependent variable

For the dependent variable, electricity retail sales data are obtained from the EIA website.[12] These are annual, state-aggregate data on electricity sales quantity and revenue. The data are separately reported for the three main customer segments: residential, commercial, and industrial. Our focus is on the average price for all customers within the same segment, as competitive pressure induced by retail competition affects all RSPs. The average price y_{st} is thus calculated by dividing the total sales revenue by the total sales quantity.

Residential customers tend to be small, commercial customers medium-sized, and industrial customers large. Over our 22-year period, the nationwide annual electricity consumption of an average customer in each of these segments is 11, 71, and 1,576 MWh, respectively. These size differences translate into different outside options and, hence, potentially different degrees of bargaining power with RSPs.[13] While industrial and large commercial customers may resort to on-site self generation of electricity, or decide to relocate to a different area when it is economical to do so, smaller commercial and residential customers typically cannot. Outside options place an upper limit on the price a customer is willing to pay for electricity retail services. In our sample, the national average retail prices paid by residential, commercial, and industrial customers were 10.9, 9.5, and 6.9 ¢/kWh, respectively (in 2009 dollars). Given the substantial price differences across customers, we estimate the model separately for the three segments to avoid potential confounding effects due to composition changes.

4.2 Restructuring status

Data on the restructuring status of electricity retail markets by state and year are obtained from EIA state restructuring documents. We record the effective dates of states' restructuring policies as applicable to each of the three customer segments.[14] Five states—Arkansas, Montana, New Mexico, Oklahoma, and West Virginia—pursued restructuring policies but subsequently repealed these policies before they became effective. Four states—Arizona, California, Delaware, and Virginia—suspended their restructuring policies after they had been in effect for some time. In addition to the customer-segment specific restructuring status, we also construct a common status variable called "full retail choice" that indicates whether retail competition applies to all customers in all three segments.[15] As shown in Table 1, the number of states (excluding the

[12] www.eia.gov/electricity/data.cfm.

[13] Besides their relative size, the three segments differ in other characteristics as well. For example, the load profile of residential customers tends to be more variable than that for industrial customers, thus requiring more ancillary services to meet reliability standards.

[14] In the case where retail competition is phased in, the effective date is recorded as that of the first phase. On the other hand, pilot programs are not considered official restructuring policies.

[15] This is a more restrictive measure of restructuring for two reasons. First, if a state implements retail competition for industrial or commercial customers before it does so for residential customers, or introduces retail competition in

District of Columbia) with active retail competition for at least one customer segment gradually increases from zero in 1990–1996 to 20 during 2002–2004, and then decreases to 17 in 2011. The number of states with full retail choice increases from zero in 1990–1997 to 16 in 2004, and then decreases to 13 in 2011.

For each state, we also divide the entire restructuring period into a transitional period and the period afterwards. Recall from Section 2.1 that most restructuring states stipulate some forms of direct price controls—both for stranded-costs recovery and for rate freeze or rate reduction—when transitioning from COS regulation to full retail competition. The actual length of the transitional period varies from state to state (and possibly from region to region within a state), and so does the magnitude of provisional rate reductions mandated during the transition. These stipulations are determined in the legislative and regulatory process associated with restructuring, and are influenced by various parties, including regulators, incumbent utilities, potential competitors, and consumer advocacy groups. As a summary measure, we consider the first 5 years after the introduction of retail competition the transitional period, and the years afterwards the post-transitional period. Table 1 provides a breakdown of the number of observations that fall into the transitional and post-transitional period, respectively.

4.3 Supply and demand controls

Electricity prices also depend on a number of other factors that affect market supply and demand. To control for supply side factors, we consider both the generation capacity and fuel costs. More specifically, we obtain EIA state-level data on electricity generation capacity by primary fuel source (coal, natural gas, oil, nuclear, hydro, and other).[16] For fuel costs, we obtain EIA data on natural gas price at the state level (using citygate price), as well as coal and oil (WTI) prices at the national level. Interaction terms between the generation capacity and the fuel price are aslo included for each of the three fossil fuels, allowing control for a state's exposure to fuel price shocks depending on how heavily this state has invested in the given fuel type because of historic decisions. Together, these variables capture observed heterogeneity in supply conditions across states.

We also want to control for demand side heterogeneity. For residential customers, electricity is used for final consumption, and we obtain state level aggregate personal income data from the Bureau of Labor Statistics (BLS) to control for income effects. For commercial and industrial customers, electricity is an intermediate input used in production of goods and services. Ideally, we would like to obtain state level GDP data to control for derived demand. However, due

multiple phases, the effective date of full retail choice is that of the last phase for retail customers. Second, if a state suspends retail competition for residential customers while maintaining it for non-residential customers, we record this event as an end to full retail choice even though segment-specific restructuring continues.

[16]Other sources for electricity generation include wind, solar thermal, photovoltaic, geothermal, biomass, etc. Over the 22-year period, they account for 5.4% of total capacity.

to changes in GDP reporting criteria during our data period this is problematic.[17] Instead, we use the same state level aggregate personal income data from the BLS as a proxy to control for derived demand, relying on the macroeconomic identity that aggregate production equals aggregate income.

4.4 Summary statistics

Our dataset is a balanced panel of 50 states (excluding the District of Columbia) over the period 1990–2011, resulting in 1,100 observations. Summary statistics are reported in Table 3. All revenue, price, and income figures are in 2009 real dollars.

Average revenue generated from residential customers per state, per year is 2.6 billion dollars. For commercial and industrial customers, average revenue is \$2.1 and \$1.3 billion dollars, respectively. Similarly, for the three customer segments, the average sales quantity per state, per year are 24, 21, and 20 TWh (million MWh). Dividing revenue by quantity, the average prices for residential, commercial, and industrial customers are 10.9, 9.5, and 6.9 ¢/kWh, respectively.

On the supply side, the average summer generation capacity per state, per year is 17 GW (thousand MW), translating into a national average of 871 GW.[18] Out of the generation portfolio, coal, natural gas, oil, nuclear, hydropower, and all other sources account for 36%, 31%, 7%, 11%, 9%, and 5%, respectively. Over the 22-year span, the average coal price at the national level is 26 dollars per short ton, the average natural gas price at the state-level is 6 dollars per thousand cubic feet, and the average WTI oil price is 45 dollars per barrel.

On the demand side, the aggregate personal income per state, per year is 200 billion dollars, translating into a national average of 10 trillion dollars (in 2009 dollar).

5 Results

As both restructuring status (the policy variable) and average price (the outcome variable) are serially correlated, the difference-in-differences approach overestimates the significance of the policy impact unless the clustered error structure is properly corrected for (Bertrand *et al.* 2004). Here, all reported standard errors are clustered by states.

[17]The Department of Commerce (DOC) switched its GDP reporting criteria from SIC to NAISC code in 1997, and cautioned that reported GDP data under these two codes are not directly comparable. In fact, in 1997, when GDP was reported under both codes, it differs substantially across reporting codes (both in aggregate and broken down by industry). DOC has done extensive work to harmonize reported GDP under the two codes at the national level; however, state level GDP data remain incomparable before and after 1997. Since the year 1997 also corresponds to the beginning of retail competition in the states, using state level GDP data would confound the interpretation of any estimation results (i.e., any discrete jump detected in the data could be attributed either to the change in GDP reporting or to the change of retail regulation).

[18]If all generation capacity were used at 100%, 7,600 TWh of power could be produced in a year. The actual output is 3,300 TWh, implying an average capacity utilization rate of 43%.

5.1 Pre-treatment price patterns

Our first analysis compares pre-treatment price patterns in states that pursued restructuring—regardless of whether the restructuring policy was subsequently repealed, suspended, or carried through as planned—to those in states that never pursued restructuring (see regression (PRE)). This categorization captures states' intent to restructure their retail markets, despite the possibility that eventual restructuring outcomes may be different based on future market developments. Since information about future market developments during the treatment period was not available in the pre-treatment period 1990–1996, it could not have influenced the original policy deliberations.

Table 4 reports the estimation results for all three customer segments. Recall that year fixed effects allow for a linear time trend as a special case. For each customer segment, column (1) allows for different intercepts of the average retail price but requires the same trend, while column (2) allows for both different intercepts and different trends across the two groups of states. The results are revealing. As expected, the two groups of states do exhibit significant differences in their price levels. On average (column 1), residential customers in states that later pursued restructuring paid 1.7 ¢/kWh more than those in states that did not pursue restructuring, commercial customers 1.0 ¢/kWh more, and industrial customers 0.9 ¢/kWh more. The level difference is significant for all customer segments at least at the 10% level. All other control variables, when significant, are of the expected signs, as the average retail price depends positively on a state's aggregate income, negatively on its coal and hydro generation capacity, and positively on its exposure to coal price shocks. Adding a different time trend (column 2) slightly affects the estimates for the level difference —1.6 ¢/kWh for residential, 1.0 ¢/kWh for commercial, and 1.0 ¢/kWh for industrial customers—without affecting their significance levels, while the trend difference itself is insignificant. Furthermore, allowing for different time trends has no impact on the explanatory power of the model, as can be seen in the reported adjusted R^2.

Next, recall that five states—Arkansas, Montana, New Mexico, Oklahoma, and West Virginia—repealed their restructuring policies and, despite their initial intent, never actually implemented retail competition. As a robustness check, we exclude these states from the pre-treatment analysis. The estimation results are reported in column (3). After excluding the five states, the level difference estimates are even larger and more significant for all three customer segments. This is not surprising. States that repealed restructuring tend to have had lower prices than states that followed through. In fact, their low prices (and hence the lack of perceived benefits) were an important reason why these states eventually decided against restructuring. On the other hand, the trend difference estimates remain insignificant for all customer segments. These results offer us some reassurance that restructuring states did not experience a price trend that is significantly different from that of the non-restructuring states.

While our pre-treatment analysis addresses the potential endogeneity of the adoption of restructuring policies, it does not address the potential endogeneity of the suspension of restructuring policies. Recall that four states—Arizona, California, Delaware, and Virginia—suspended retail competition after having implemented it for a period of time, and the decision to suspend restructuring likely depended on the actual policy experiences in these states. For example, if restructuring was accompanied by significant price increases or other market disruptions, a state may have reacted by suspending retail competition. To ensure that our results are not sensitive to events in states that either repealed or suspended their restructuring policies, our subsequent DID regressions are performed both with and without these states.

5.2 Uniform policy impact

We now turn to our difference-in-differences analysis to estimate the policy impact of restructuring on average electricity retail prices. Table 5 reports estimation results for the uniform impact model (UI). For each of the three customer segments, we estimate the model three times by increasingly restricting our sample: Column (1) uses all 50 states; column (2) excludes the five states that repealed their restructuring policies; and column (3) further excludes the additional four states that suspended their restructuring policies after implementation. At the expense of losing observations, the control group and the treated group of states arguably become more homogeneous when moving from column (1) to column (3). State and year fixed effects are included in all estimations but are not reported.

For residential customers, retail competition leads to a price decrease ranging from 0.9 ¢/kWh (column 1) to 1.0 ¢/kWh (column 3). The estimates are highly significant at the 1% level. Given an average price of 10.9 ¢/kWh, these estimates translate into a price reduction of $8-9\%$, which is also economically significant. For commercial and industrial customers, we find no significant policy impact on price at the 10% significance level.

Note that when state and year fixed effects are included, most control variables become insignificant. One prominent exception is natural gas, where the capacity is consistently significantly negative and the price is consistently significantly positive. Thus, one is naturally concerned that natural gas, as a main driver of the electricity retail price, may affect states differently even after we control for states' exposure to natural gas price shocks. In particular, one may be concerned about the "regulatory lag," namely the time lag between when the electricity retail price changes in response to a change in the fuel price in regulated markets. The regulatory lag, and the cost under-recovery associated with it, was indeed a big concern in the 1970s, when fuel costs rose unexpectedly and sharply. To address this problem, many states have adopted "fuel adjustment clauses", which allow regulated utilities to adjust their fuel cost riders charged to customers at more frequent intervals, i.e., monthly or quarterly. However, even with fuel adjustment clauses, if retail prices still move more slowly in regulated markets than in competitive markets, our estimation results could be potentially biased with changing fuel prices. More specifically, consistently rising fuel prices would bias the estimated benefit of restructuring downward, because the impact of higher fuel costs is reflected as higher retail prices in restructured states before it is reflected in regulated states.

To check whether this is the case, we consider adding an interaction term between the restructuring variable and natural gas price. The results are reported in Table 6. It is reassuring to see that the coefficient on this interaction term is insignificant, suggesting that natural gas price shocks do not affect the electricity retail prices in restructured states differently than those in regulated states. It is also worth noting that adding this interaction term reduces (rather than increasing) the estimated benefit of restructuring, for the price reduction experienced by residential customers is now insignificant. Overall, it appears that regulatory lag does not bias our estimation of the restructuring policy benefit downward.

As a robustness check, we also estimate the uniform impact model (UI) allowing state-specific trends. This approach relies on the assumption that any policy impact of restructuring affects only the levels but not the trends of retail prices in restructured states. The results are reported in Table 7. As can be seen, when state-specific trends are included, the estimated policy impact become stronger. Residential customers now experience a price reduction ranging from 1.2 to 1.6 ¢/kWh and is significant at the 1% level. Commercial customers also benefit from restructuring with a price reduction of 0.6 ¢/kWh, significant at least at the 10% level. Industrial customers enjoy a price reduction ranging from 0.2 to 0.4 ¢/kWh, significant in one of the three model specifications. So our estimation without state-specific trends is a conservative approach, which makes it less likely to find any significant result.

5.3 Differential policy impact

As discussed in Section 2.1, many restructuring states stipulated temporary provisions when transitioning from COS regulation to retail competition. The short run impact of restructuring during the transitional period may very well be different from its long run impact in the period afterwards. The former captures the difference between COS regulation and a hybrid regime consisting of both incipient retail competition and some forms of direct price controls, while the latter represents the difference between COS regulation and a relatively pure form of retail competition.

The estimation results using a five-year window for the transitional period are reported in panel A of Table 8. For residential customers, retail competition leads to a short-run price reduction ranging from 1.1 ¢/kWh (column 1) to 1.3 ¢/kWh (column 3), significant at the 1% level. In contrast, the long run price reduction is much smaller, ranging from 0.5 ¢/kWh to 0.7 ¢/kWh and statistically insignificant after the first five years. Thus, the price benefit of restructuring found in the uniform policy impact model appears to be largely driven by the transitional period. For commercial customers, retail competition leads to a marginally significant price reduction of 0.5 ¢/kWh within the transitional period, while the long run impact is not significantly different from zero. Finally, for industrial customers, in both the short run and the long run, the policy impact of restructuring is insignificant. For all three customer segments, there is generally an upward price jump (albeit insignificant) from the transitional period to the period afterwards.

One may wonder why restructuring confers a short run benefit to residential (and in some instance, commercial) customers but not industrial customers. There are several possible explanations. One could be that there was cross-subsidization from residential to industrial customers in regulated markets, and restructuring removed such cross-subsidization so residential customers benefited. If this is the case, the benefit of removing cross-subsidization somehow diminished over time. Another possible explanation could be due to the temporary provisions in the transitional period. While stranded cost charges apply to all customers, rate freeze or rate reduction may be restricted to only residential (and small commercial) customers in some states. If this is the case, our results suggest that the impact of rate freeze or reduction outweighs the impact of stranded-costs recovery for residential customers in the short run, while both disappear in the long run with the ending of the transitional provisions.

As a sensitivity test, we consider a linear trend for the policy impact using a "year since restructuring" variable, allowing the average price to change depending on the number of years since a state began retail competition. The estimation results are reported in panel B of Table 8. With this post-restructuring trend, we find that for residential customers, retail competition leads to an immediate price decrease of 1.3–1.5 ¢/kWh, followed by an increasing price trend (albeit insignificant) of 0.07–0.08 ¢/kWh per year. The estimation results for commercial and industrial customers remain largely insignificant.

Next, instead of dividing the restructuring period into only two phases or imposing a linear trend, we consider a more flexibly, year-by-year estimation of the policy impact of restructuring. We include a set of indicator variable for $t = 1, 2, ..., T$ years since restructuring. The results are reported in Table 9. The pattern is interesting. For residential customers, retail competition lower the retail prices significantly up to the 7th year since restructuring, and becomes insignificant afterwards. Within the first seven years of significant results, the restructuring benefit (price reduction) increases in the first several years, peaks in the fifth year, and then decreases afterwards. The early increase in the policy impact is consistent with the gradual phase-in of retail competition for residential customers, and the later decrease is consistent with the ending of the transitional provisions. Commercial customers only experience significant price reductions in the second and third year of restructuring, and no significant impact afterwards. The policy impact for industrial customers is consistently insignificant.

Lastly, we further extend the flexible form of estimation to years before restructuring by including additional indicator variables $t = -1, -2, ...$ To economize on the number of parameters, we estimate the price differences at the biannual level instead of the annual level. The estimation results are reported in Table 10, where the default case is five years or more before restructuring. As expected, the biannual post-restructuring price differences are consistent with those at the annual level. More interestingly, the pre-restructuring price differences are consistently insignificant after controlling for state and year fixed effects, as well as supply and demand control variables. This offers additional reassurance that the pre-treatment price patterns for restructured states are not significantly different from those in states that never pursued restructuring.

5.4 Sensitivity tests

To check the robustness of our main results, we perform the following sensitivity tests. First, instead of using restructuring status that is specific to each customer segment, we use the status of "full retail choice" common to all three customer segments. The estimation results are reported in Table 11. Using this more restrictive measure of restructuring, we find qualitatively similar policy impacts. In the uniform impact model (panel A), both residential and commercial customers experience significant benefits from restructuring, but not industrial customers. Allowing differential policy impacts (panel B), the benefit is front-loaded but disappears for all customers in the long run.

Interestingly, using the full-retail-choice status variable, even industrial customers enjoy significant price reductions in the short run, unlike the previous findings using segment-specific status. To explain this change, recall that the primary reason for regulators to stipulate rate freeze or rate reduction during the transitional period is to protect consumer welfare, i.e., the welfare of residential customers. If retail competition is first introduced for industrial customers only, few safeguards are put in place to control the prices these large customers pay. However, when retail competition is later introduced for residential customers, temporary rate freeze or rate reduction become effective and may spill over to industrial customers.

Next, because states vary substantially by the size of their economies, we estimate the restructuring policy impact using state aggregate income as weights. The results are in Table 12. The overall pattern remains robust. In the uniform policy impact model (panel A), residential customers experience a price reduction of 0.6–0.8 ¢/kWh, significant at the 5% level. Commercial and industrial customers see no significant price changes. Allowing for differential policy impacts (panel B), we again find a more prominent, short-run benefit, while the benefit disappears in the long run.

Finally, we consider a log-linear specification of the model, so that the policy impact is estimated as a percentage change in the average retail price.[19] The results are in Table 13. The results remain robust. In the uniform impact model (panel A), residential customers experience a price reduction of 7%, consistent with the $8-9\%$ estimates we computed in the linear model. Allowing for differential policy impacts (panel B), the benefit for residential customers is front-

[19]For our supply side control variables, a $\ln 0$-problem arises due to the fact that not all states have all six categories of generation capacity installed. To circumvent this problem, we use the logarithm of state total generation capacity, together with the share of individual generation categories in total capacity, as supply side control variables.

loaded. Again we find no evidence that restructuring delivers benefits to any customer segment in the long run.

6 Discussion

It has been over a decade since some states in the U.S. implemented retail competition in their electricity markets. This paper is the first to use state-level panel data to estimate the policy impact of retail competition on electricity retail prices. The results are mixed and, generally, less favorable than what was perhaps hoped for by policy makers in restructured states. Across the three customer segments, only residential customers can be said to have benefited in a significant fashion from retail competition. Even so, the benefit appears front-loaded and mainly driven by the transitional period from COS regulation to competition. We find no evidence of a long-term benefit for either residential, commercial, or industrial customers.

These findings deserve some discussion. Given that our most favorable estimates are short-run policy impacts, one may be tempted to ask whether regulators could prolong the "transitional period" indefinitely, thus extending the short-run policy impact into the long run. In other words, could regulators maintain aggressive price controls in an otherwise open retail market? This approach, unfortunately, may not be sustainable. Regulators cannot force local utilities or RSPs to operate at or below costs. These firms can always exit retail operations if they earn less than a normal profit. They may accept price controls during the transition to open markets as an investment, exchanging lower profits in the short run for the opportunity to earn higher profits in the long run. However, unless the market-wide normal profit level decreases drastically, or technological innovations reduce operational costs significantly, it is unlikely that firms will accept permanently lower price levels and still remain in the electricity retail business.

One may also ask why restructuring and deregulation in other industries (e.g., airlines, telecommunications) have delivered significant price reductions, but not in the electricity retail sector. For residential and small commercial customers, a possible explanation is the presence of search frictions. At the U.S. income level, household expenditure on electricity is only a small fraction of total household budget. Thus, the perceived benefits from identifying the optimal choice may be small relative to the associated search costs and switch costs. It may be a daunting task for small customers to gather information from multiple RSPs, forecast their future load demand, and determine which contract delivers the best cost/risk combination. When these search frictions are sufficiently high, consumers may exhibit a preference for the status quo (i.e., their incumbent utility as the default retailer), as shown in Wilson and Price (2010) and Hortaçsu *et al.* (2012). Waterson (2003) describes this situation, "even in potentially competitive industries, reluctance by consumers to search or to switch suppliers can lead to sub-competitive outcomes."

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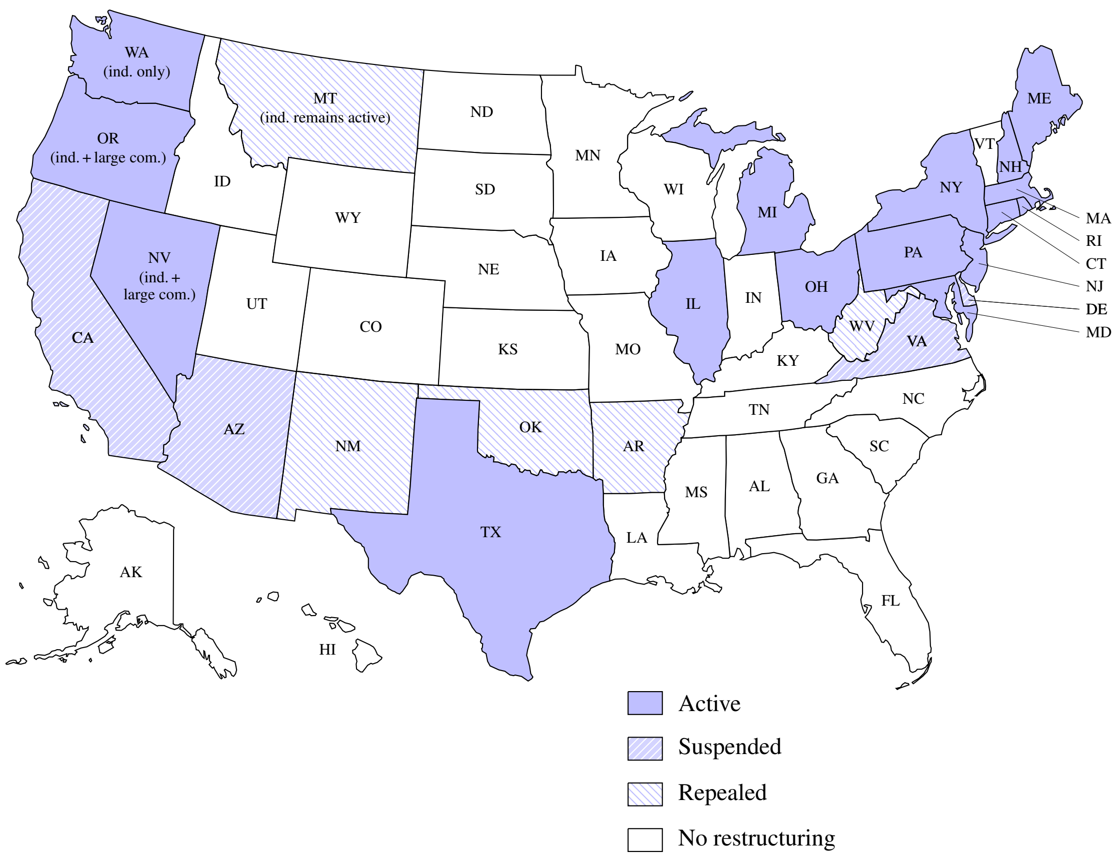
Appendix

Figure 1: State electricity retail market restructuring status, 2011



Source: Energy Information Administration

Table 1: State restructuring status

Year	Residential	Commercial	Industrial	Full retail choice
	Number of restructuring states by year			
1990–1996	0	0	0	0
1997	1	1	1	0
1998	5	5	6	3
1999	7	9	10	4
2000	11	12	13	7
2001	14	16	18	12
2002	16	18	20	15
2003	16	18	20	15
2004	16	18	20	16
2005	15	17	19	15
2006	15	17	19	15
2007	14	16	18	14
2008	13	15	17	13
2009	13	15	17	13
2010	13	15	17	13
2011	13	15	17	13
Observations in transitional/post-transitional period				
First 5 years	84	94	104	82
After first 5 years	98	113	128	86
Total observations	**182**	**207**	**232**	**168**

Table 2: State deliberations and restructuring decisions (EIA excerpts)

Retail competition adopted	Retail competition rejected
"In 1996, the average revenue per kilowatt hour (which is used as a proxy for price) of electricity sold in **California** was 9.48 cents, the tenth highest rate among the 50 States and the District of Columbia. This rate was one factor leading Governor Pete Wilson to sign Assembly Bill 1890 (AB1890) on September 23, 1996. [. . .] To implement it, **retail competition**, allowing customers to choose their electricity, began on March 31, 1998." [a]	"There is no compelling reason at this time for **Kentucky** to move quickly to restructure. [. . .] Representatives from other States that have restructured as well as experts in the field of electricity restructuring indicate that Kentucky is in a unique position because of its existing low electricity rates, which currently are the lowest east of the Rocky Mountains. Most of Kentucky's generation is coal-fired and its generators are close to coal fields which are among the cheapest fuel sources." [a]
"On November 27, 1997, HB 5117, the Electric Utility Restructuring Act, was signed by Governor Paul Cellucci to restructure the industry in **Massachusetts**. [. . .] **Retail access** was required by March 1998. [. . .] In 1996, Massachusetts had the eighth highest electricity rates in the Nation, which were most certainly a consideration in enacting the legislation the following year." [a]	"The Legislative Council Committee on Electric Utilities Restructuring issued its final report. The report recommended a slow approach to retail competition. **Idaho** was a low cost state for electricity and concerned about prices rising under a competitive market." [b]
"In both years (1996 and 1998), **Pennsylvania** had the eleventh highest average electricity price among the 50 States and the District of Columbia. Like California and Massachusetts, Pennsylvania falls into the camp of relatively high-priced States that have been somewhat aggressive in pursuing restructuring. [. . .] Governor Tom Ridge signed the Electricity Generation Customer Choice and Competition Act into law on December 3, 1996. [. . .] The law called for a phase-in of **retail choice** with one-third eligible to choose by January 1998, another third by January 1999, and the remaining third by January 2000." [a]	"In light of the low cost of electricity in **West Virginia** and the price spikes experienced this past summer in other States that have restructured retail markets, lawmakers seem to need to be convinced that restructuring will benefit West Virginia consumers. [. . .] Most concerns center on protecting small (residential) consumers from price increases." [c]

(a) www.eia.gov/cneaf/electricity/chg_stru_update/chapter8.html
(b) www.eia.gov/cneaf/electricity/page/restructuring/idaho.html
(c) www.eia.gov/cneaf/electricity/page/restructuring/west_virginia.html

Table 3: Summary statistics

Variable			**Mean**	**Std. Dev.**	**Min.**	**Max.**
Total revenue	(\$mil.)	Residential	2,586	2,834	152	17,199
		Commercial	2,085	2,646	145	16,4971
		Industrial	1,261	1,275	54	9,373
Total sales	(GWh)	Residential	23,818	23,675	1,603	145,654
		Commercial	21,146	22,380	1,450	128,214
		Industrial	20,051	18,912	459	108,300
Average price	(¢/kWh)	Residential	10.93	3.19	6.27	33.61
		Commercial	9.54	2.88	5.18	31.37
		Industrial	6.86	2.67	3.17	27.52
Summer generation capacity	(GW)	Coal	6.26	6.01	0	23.51
		Natural gas	5.42	9.89	0	73.22
		Oil	1.26	2.20	0	14.80
		Nuclear	1.99	2.50	0	12.61
		Hydro	1.56	3.41	0	21.58
		Other	0.93	1.63	0	11.57
		All sources	17.43	16.31	0.56	109.18
Fuel price	(\$/short ton)	Coal	26.49	4.87	20.49	35.77
	(\$/1000 cubic feet)	Natural gas	5.95	2.52	0.46	30.60
	(\$/barrel)	Oil	44.89	23.87	18.27	100.44
Aggregate income	(\$bil.)		200	240	12	1,623

Note: All revenue, price, and income figures are in 2009 real dollars.

Table 4: Pre-treatment price patterns

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
Pursued restructuring	1.734***	1.636***	2.361***	0.967*	0.981*	1.423**	0.863*	1.006*	1.660**
	(0.579)	(0.566)	(0.554)	(0.539)	(0.560)	(0.613)	(0.510)	(0.568)	(0.622)
Trend difference		0.033	0.043		–0.005	–0.026		–0.048	–0.084
		(0.074)	(0.090)		(0.070)	(0.081)		(0.071)	(0.081)
Aggregate income	0.013***	0.013***	0.010**	0.010**	0.010**	0.008*	0.007**	0.007**	0.005
	(0.003)	(0.003)	(0.004)	(0.004)	(0.004)	(0.004)	(0.003)	(0.003)	(0.004)
Coal capacity	–0.633***	–0.635***	–0.621***	–0.474***	–0.474***	–0.474***	–0.388***	–0.392***	–0.392***
	(0.121)	(0.119)	(0.132)	(0.111)	(0.113)	(0.128)	(0.102)	(0.106)	(0.115)
Natural gas capacity	–0.047	–0.052	0.116	0.015	0.015	0.136	–0.099	–0.092	0.061
	(0.134)	(0.140)	(0.143)	(0.144)	(0.149)	(0.148)	(0.129)	(0.135)	(0.136)
Oil capacity	0.184	0.170	0.176	0.003	0.005	0.036	0.100	0.114	0.157
	(0.293)	(0.288)	(0.266)	(0.251)	(0.255)	(0.255)	(0.121)	(0.139)	(0.140)
Nuclear capacity	0.156*	0.156*	0.100	0.104	0.104	0.078	0.073	0.073	0.032
	(0.078)	(0.078)	(0.067)	(0.095)	(0.095)	(0.088)	(0.087)	(0.088)	(0.083)
Hydro capacity	–0.326***	–0.325***	–0.281***	–0.262***	–0.262***	–0.236***	–0.290***	–0.291***	–0.296***
	(0.084)	(0.084)	(0.071)	(0.080)	(0.080)	(0.080)	(0.067)	(0.067)	(0.067)
Other capacity	–0.504**	–0.501**	–0.411	–0.232	–0.232	–0.179	–0.134	–0.138	–0.077
	(0.237)	(0.239)	(0.276)	(0.289)	(0.290)	(0.311)	(0.271)	(0.272)	(0.300)
Natural gas price	0.475	0.473	0.485	0.573	0.574	0.625*	0.465	0.469	0.458
	(0.386)	(0.389)	(0.419)	(0.348)	(0.353)	(0.372)	(0.349)	(0.355)	(0.373)
Coal cap * coal price	0.013***	0.013***	0.014***	0.009***	0.009***	0.010***	0.006*	0.006*	0.007*
	(0.003)	(0.003)	(0.004)	(0.003)	(0.003)	(0.004)	(0.003)	(0.003)	(0.003)
Natural gas cap * ng price	–0.007	–0.006	–0.042	–0.016	–0.017	–0.043	0.012	0.010	–0.024
	(0.030)	(0.031)	(0.033)	(0.032)	(0.033)	(0.034)	(0.029)	(0.030)	(0.030)
Oil cap * oil price	–0.008	–0.007	–0.006	–0.001	–0.002	–0.002	–0.004	–0.005	–0.006
	(0.007)	(0.007)	(0.007)	(0.005)	(0.005)	(0.005)	(0.004)	(0.005)	(0.005)
Adj. R-sq	0.603	0.602	0.641	0.516	0.515	0.539	0.466	0.465	0.497
States	50	50	45	50	50	45	50	50	45
Observations	350	350	315	350	350	315	350	350	315

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. Year fixed effects are used for estimation but omitted from reporting in the table.

Table 5: Uniform policy impact for the entire restructuring period

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
Restructured States	–0.872***	–0.972***	–1.020***	–0.320	–0.405	–0.364	–0.057	–0.203	–0.032
	(0.303)	(0.312)	(0.354)	(0.284)	(0.284)	(0.331)	(0.258)	(0.263)	(0.285)
Aggregate income	–0.001	–0.001	–0.000	0.001	0.001	0.003	0.001	0.001	–0.000
	(0.001)	(0.001)	(0.003)	(0.001)	(0.001)	(0.003)	(0.001)	(0.001)	(0.003)
Coal capacity	–0.293*	–0.337*	–0.259	0.004	–0.042	0.030	–0.022	–0.046	0.024
	(0.166)	(0.180)	(0.180)	(0.146)	(0.156)	(0.155)	(0.139)	(0.151)	(0.151)
Natural gas capacity	–0.079*	–0.077*	–0.080*	–0.087**	–0.081**	–0.078**	–0.096***	–0.092**	–0.074*
	(0.044)	(0.046)	(0.044)	(0.036)	(0.036)	(0.037)	(0.033)	(0.034)	(0.038)
Oil capacity	–0.010	0.007	0.047	–0.003	0.005	0.068	0.094	0.095	0.127
	(0.126)	(0.127)	(0.127)	(0.114)	(0.116)	(0.118)	(0.120)	(0.122)	(0.144)
Nuclear capacity	–0.045	–0.032	–0.017	–0.323	–0.317	–0.301	–0.335	–0.363	–0.289
	(0.451)	(0.449)	(0.469)	(0.234)	(0.233)	(0.252)	(0.234)	(0.231)	(0.254)
Hydro capacity	0.263	0.286	0.201	0.397	0.380	0.276	0.393	0.380	0.438
	(0.257)	(0.226)	(0.268)	(0.296)	(0.279)	(0.276)	(0.284)	(0.277)	(0.265)
Other capacity	0.115	0.112	0.037	0.010	0.010	–0.073	0.040	0.036	0.039
	(0.102)	(0.105)	(0.115)	(0.079)	(0.081)	(0.084)	(0.075)	(0.075)	(0.093)
Natural gas price	0.436**	0.462***	0.483***	0.410**	0.439***	0.460***	0.383**	0.417***	0.434***
	(0.179)	(0.168)	(0.161)	(0.173)	(0.159)	(0.154)	(0.164)	(0.148)	(0.143)
Coal cap * coal price	0.002	0.002	0.003	0.001	0.001	0.002	–0.001	–0.001	–0.001
	(0.002)	(0.003)	(0.003)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)
Natural gas cap * ng price	0.005	0.006	0.007*	0.004	0.004	0.004	0.006	0.006	0.006
	(0.005)	(0.005)	(0.004)	(0.004)	(0.004)	(0.003)	(0.004)	(0.004)	(0.004)
Oil cap * oil price	0.003	0.002	0.002	0.004**	0.003**	0.002	0.004**	0.003**	0.003
	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)
Adj. R-sq	0.911	0.915	0.918	0.908	0.914	0.918	0.901	0.906	0.910
States	50	45	41	50	45	41	50	45	41
Observations	1,100	990	902	1,100	990	902	1,100	990	902

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. State and year fixed effects are used for estimation but omitted from reporting in the table.

Table 6: Test the hypothesis of regulatory lag

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
Restructured States	–0.143	–0.099	0.089	–0.385	–0.345	–0.167	0.134	–0.057	0.255
	(0.658)	(0.652)	(0.828)	(0.639)	(0.636)	(0.787)	(0.573)	(0.551)	(0.650)
Restructured * Natural gas price	–0.098	–0.118	–0.143	0.009	–0.008	–0.026	–0.026	–0.020	–0.038
	(0.095)	(0.094)	(0.110)	(0.094)	(0.094)	(0.107)	(0.082)	(0.080)	(0.090)
Aggregate income	–0.001	–0.001	–0.001	0.001	0.001	0.003	0.001	0.001	–0.000
	(0.001)	(0.001)	(0.003)	(0.001)	(0.001)	(0.003)	(0.001)	(0.001)	(0.003)
Coal capacity	–0.275*	–0.316*	–0.233	0.002	–0.041	0.033	–0.019	–0.043	0.029
	(0.164)	(0.177)	(0.179)	(0.145)	(0.155)	(0.156)	(0.139)	(0.150)	(0.152)
Natural gas capacity	–0.089*	–0.089*	–0.099**	–0.086**	–0.082**	–0.081**	–0.098***	–0.093**	–0.078*
	(0.046)	(0.048)	(0.048)	(0.037)	(0.038)	(0.039)	(0.035)	(0.037)	(0.043)
Oil capacity	–0.024	–0.010	0.024	–0.002	0.004	0.065	0.090	0.093	0.121
	(0.120)	(0.122)	(0.122)	(0.111)	(0.113)	(0.116)	(0.117)	(0.120)	(0.143)
Nuclear capacity	–0.055	–0.044	–0.023	–0.323	–0.316	–0.298	–0.335	–0.362	–0.284
	(0.457)	(0.456)	(0.469)	(0.234)	(0.233)	(0.252)	(0.235)	(0.231)	(0.254)
Hydro capacity	0.259	0.284	0.206	0.398	0.379	0.276	0.386	0.376	0.434
	(0.249)	(0.215)	(0.256)	(0.297)	(0.280)	(0.276)	(0.278)	(0.274)	(0.262)
Other capacity	0.112	0.109	0.039	0.010	0.010	–0.073	0.039	0.035	0.038
	(0.100)	(0.104)	(0.114)	(0.079)	(0.080)	(0.085)	(0.074)	(0.075)	(0.095)
Natural gas price	0.446**	0.474***	0.496***	0.409**	0.440**	0.462***	0.386**	0.419***	0.437***
	(0.176)	(0.162)	(0.153)	(0.179)	(0.164)	(0.156)	(0.167)	(0.151)	(0.145)
Coal cap * coal price	0.002	0.002	0.003	0.001	0.001	0.001	–0.001	–0.001	–0.001
	(0.002)	(0.002)	(0.003)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)
Natural gas cap * ng price	0.006	0.007	0.009*	0.004	0.004	0.004	0.006	0.006	0.006
	(0.005)	(0.005)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)	(0.005)
Oil cap * oil price	0.003	0.002	0.002	0.004**	0.003**	0.003	0.004**	0.003**	0.004
	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)
Adj. R-sq	0.911	0.916	0.918	0.908	0.914	0.918	0.901	0.906	0.910
States	50	45	41	50	45	41	50	45	41
Observations	1,100	990	902	1,100	990	902	1,100	990	902

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. State and year fixed effects used for estimation but omitted from reporting in the table.

Table 7: Uniform policy impact with state-specific trends

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
Restructured states	–1.223***	–1.218***	–1.638***	–0.632***	–0.641***	–0.610*	–0.317	–0.372*	–0.167
	(0.226)	(0.224)	(0.272)	(0.186)	(0.182)	(0.327)	(0.212)	(0.207)	(0.289)
Aggregate income	–0.005	–0.005	–0.007*	–0.000	0.000	–0.002	–0.003	–0.001	–0.009*
	(0.003)	(0.003)	(0.004)	(0.003)	(0.003)	(0.004)	(0.004)	(0.004)	(0.005)
Coal capacity	–0.292*	–0.341**	–0.314*	–0.006	–0.068	–0.055	0.002	–0.026	0.009
	(0.148)	(0.149)	(0.158)	(0.164)	(0.166)	(0.185)	(0.163)	(0.166)	(0.191)
Natural gas capacity	–0.029	–0.033	–0.012	–0.032	–0.035	–0.026	–0.073*	–0.072*	–0.082
	(0.039)	(0.039)	(0.041)	(0.038)	(0.039)	(0.047)	(0.041)	(0.042)	(0.049)
Oil capacity	–0.084	–0.089	–0.059	–0.096	–0.098	–0.083	–0.176	–0.166	–0.186
	(0.092)	(0.092)	(0.091)	(0.064)	(0.064)	(0.065)	(0.113)	(0.116)	(0.116)
Nuclear capacity	0.381	0.368	0.430	–0.084	–0.096	–0.047	–0.058	–0.083	–0.120
	(0.306)	(0.306)	(0.319)	(0.279)	(0.281)	(0.288)	(0.269)	(0.267)	(0.275)
Hydro capacity	0.183	0.169	0.142	0.111	0.115	0.079	0.226	0.223	0.283
	(0.130)	(0.132)	(0.133)	(0.137)	(0.139)	(0.141)	(0.270)	(0.274)	(0.314)
Other capacity	–0.141*	–0.156*	–0.135	–0.257***	–0.263***	–0.221***	–0.247**	–0.261**	–0.208**
	(0.080)	(0.082)	(0.093)	(0.082)	(0.082)	(0.079)	(0.105)	(0.105)	(0.102)
Natural gas price	0.204*	0.220*	0.226*	0.223*	0.239**	0.243**	0.202*	0.224**	0.233**
	(0.119)	(0.114)	(0.117)	(0.120)	(0.115)	(0.116)	(0.112)	(0.101)	(0.098)
Coal cap * coal price	0.003*	0.003*	0.003*	0.002	0.002	0.001	–0.000	–0.000	–0.001
	(0.001)	(0.002)	(0.002)	(0.001)	(0.001)	(0.002)	(0.002)	(0.002)	(0.002)
Natural gas cap * ng price	0.006*	0.006*	0.007**	0.004	0.003	0.004	0.006	0.005	0.006
	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.004)	(0.004)	(0.004)
Oil cap * oil price	0.001	0.001	0.001	0.003*	0.002	0.002	0.004	0.004	0.004
	(0.001)	(0.001)	(0.001)	(0.002)	(0.002)	(0.002)	(0.003)	(0.002)	(0.003)
Adj. R-sq	0.963	0.963	0.964	0.956	0.956	0.958	0.941	0.944	0.946
States	50	45	41	50	45	41	50	45	41
Observations	1,100	990	902	1,100	990	902	1,100	990	902

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. State fixed effect, state specific trends, and year fixed effects are used for estimation but omitted from reporting in the table.

Table 8: Differential policy impact for the restructuring period

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
A. Differential policy impact using the 5-year window for the transitional period									
First 5 years of restructuring	–1.142***	–1.213***	–1.308***	–0.461	–0.521*	–0.455	–0.156	–0.284	–0.071
	(0.226)	(0.231)	(0.240)	(0.275)	(0.273)	(0.323)	(0.267)	(0.266)	(0.288)
After first 5 years	–0.530	–0.666	–0.718	–0.155	–0.270	–0.270	0.059	–0.106	0.011
	(0.489)	(0.502)	(0.562)	(0.380)	(0.385)	(0.436)	(0.327)	(0.348)	(0.387)
Difference	0.612	0.548	0.591	0.306	0.251	0.185	0.215	0.178	0.082
	(0.411)	(0.416)	(0.480)	(0.329)	(0.335)	(0.383)	(0.295)	(0.317)	(0.366)
B. Differential policy impact using linear trend for the post-restructuring period									
Restructured states	–1.274***	–1.324***	–1.482***	–0.494	–0.536*	–0.464	–0.169	–0.259	–0.061
	(0.249)	(0.251)	(0.281)	(0.308)	(0.308)	(0.380)	(0.290)	(0.299)	(0.351)
Years since restructuring	0.077	0.068	0.080	0.032	0.024	0.017	0.021	0.011	0.005
	(0.059)	(0.060)	(0.066)	(0.050)	(0.051)	(0.056)	(0.042)	(0.047)	(0.053)

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. State and year fixed effects, and additional control variables are used for estimation but omitted from reporting in the table.

Table 9: Year-by-year policy impact of the restructuring period

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
1st year of restructuring	–0.804***	–0.870***	–0.836***	–0.300	–0.349	–0.276	–0.111	–0.184	–0.066
	(0.196)	(0.194)	(0.191)	(0.298)	(0.295)	(0.322)	(0.259)	(0.279)	(0.303)
2nd year of restructuring	–1.183***	–1.259***	–1.294***	–0.598*	–0.659*	–0.568	–0.098	–0.159	0.015
	(0.231)	(0.230)	(0.240)	(0.336)	(0.330)	(0.389)	(0.286)	(0.301)	(0.339)
3rd year of restructuring	–1.455***	–1.563***	–1.541***	–0.662*	–0.747**	–0.669	–0.150	–0.311	–0.183
	(0.288)	(0.288)	(0.304)	(0.372)	(0.370)	(0.424)	(0.313)	(0.315)	(0.353)
4th year of restructuring	–1.258***	–1.379***	–1.285***	–0.267	–0.374	–0.188	0.243	–0.075	0.115
	(0.318)	(0.328)	(0.357)	(0.342)	(0.344)	(0.374)	(0.366)	(0.287)	(0.307)
5th year of restructuring	–1.531***	–1.679***	–1.850***	–0.460	–0.588	–0.668	–0.070	–0.252	–0.284
	(0.382)	(0.391)	(0.391)	(0.421)	(0.425)	(0.403)	(0.328)	(0.346)	(0.328)
6th year of restructuring	–1.334***	–1.488***	–1.515***	–0.454	–0.590	–0.597	0.040	–0.145	–0.223
	(0.400)	(0.409)	(0.450)	(0.395)	(0.398)	(0.410)	(0.341)	(0.357)	(0.367)
7th year of restructuring	–1.046**	–1.210**	–1.237**	–0.355	–0.493	–0.352	0.080	–0.100	–0.086
	(0.460)	(0.473)	(0.550)	(0.375)	(0.382)	(0.408)	(0.339)	(0.359)	(0.394)
8th year of restructuring	–0.527	–0.714	–0.748	–0.222	–0.381	–0.363	0.419	0.199	0.168
	(0.581)	(0.596)	(0.724)	(0.452)	(0.464)	(0.519)	(0.454)	(0.481)	(0.566)
9 years or more since restructuring	–0.317	–0.489	–0.337	–0.062	–0.210	–0.114	0.284	0.071	0.072
	(0.560)	(0.573)	(0.660)	(0.495)	(0.504)	(0.526)	(0.416)	(0.456)	(0.469)
Adj. R-sq	0.913	0.918	0.920	0.908	0.914	0.918	0.901	0.905	0.909
States	50	45	41	50	45	41	50	45	41
Observations	1,100	990	902	1,100	990	902	1,100	990	902

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. State and year fixed effects, and additional control variables are used for estimation but omitted from reporting in the table.

Table 10: Biannual price patterns before and after restructuring

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
3-4 years before restructuring	0.052	–0.007	0.103	0.090	0.064	0.136	–0.006	–0.037	0.015
	(0.192)	(0.191)	(0.200)	(0.169)	(0.170)	(0.165)	(0.177)	(0.185)	(0.205)
1-2 years before restructuring	–0.255	–0.336	–0.234	–0.032	–0.067	0.060	–0.047	–0.128	–0.044
	(0.251)	(0.251)	(0.249)	(0.244)	(0.247)	(0.230)	(0.241)	(0.254)	(0.251)
1-2 years since restructuring	–1.057***	–1.171***	–1.110***	–0.435	–0.508	–0.364	–0.119	–0.223	–0.035
	(0.288)	(0.287)	(0.275)	(0.398)	(0.396)	(0.425)	(0.359)	(0.383)	(0.406)
3-4 years since restructuring	–1.414***	–1.567***	–1.450***	–0.452	–0.565	–0.375	0.032	–0.241	–0.045
	(0.354)	(0.360)	(0.344)	(0.418)	(0.420)	(0.439)	(0.402)	(0.379)	(0.395)
5-6 years since restructuring	–1.486***	–1.672***	–1.722***	–0.446	–0.594	–0.587	–0.034	–0.246	–0.267
	(0.439)	(0.446)	(0.432)	(0.458)	(0.462)	(0.437)	(0.395)	(0.416)	(0.408)
7-8 years since restructuring	–0.847	–1.057*	–1.037	–0.282	–0.446	–0.314	0.225	–0.003	0.025
	(0.548)	(0.558)	(0.634)	(0.461)	(0.468)	(0.494)	(0.417)	(0.439)	(0.477)
9 years or more since restructuring	–0.378	–0.586	–0.382	–0.052	–0.216	–0.065	0.260	0.017	0.055
	(0.600)	(0.609)	(0.663)	(0.546)	(0.551)	(0.562)	(0.461)	(0.497)	(0.493)
Adj. R-sq	0.913	0.918	0.920	0.908	0.914	0.918	0.901	0.905	0.909
States	50	45	41	50	45	41	50	45	41
Observations	1,100	990	902	1,100	990	902	1,100	990	902

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. State and year fixed effects, and additional control variables are used for estimation but omitted from reporting in the table.

Table 11: Policy impact - restructuring measured as full retail choices for all three customer segments

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
A. Uniform policy impact for the entire restructuring period									
Restructured States	–0.880***	–0.983***	–1.008***	–0.506*	–0.592**	–0.592**	–0.297	–0.329	–0.229
	(0.308)	(0.317)	(0.351)	(0.256)	(0.262)	(0.287)	(0.251)	(0.256)	(0.273)
B. Differential policy impact using the 5-year window for the transitional period									
First 5 years since restructuring	–1.183***	–1.258***	–1.329***	–0.712***	–0.779***	–0.773***	–0.518**	–0.529**	–0.455*
	(0.230)	(0.234)	(0.240)	(0.207)	(0.209)	(0.225)	(0.211)	(0.215)	(0.227)
After first 5 years	–0.431	–0.575	–0.649	–0.200	–0.314	–0.389	0.030	–0.033	0.023
	(0.550)	(0.564)	(0.586)	(0.442)	(0.452)	(0.467)	(0.390)	(0.400)	(0.412)
Difference	0.752	0.682	0.680	0.512	0.465	0.384	0.548	0.496	0.478
	(0.485)	(0.492)	(0.519)	(0.398)	(0.403)	(0.428)	(0.334)	(0.340)	(0.356)

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. State and year fixed effects, and additional control variables are used for estimation but omitted from reporting in the table.

Table 12: Policy impact - using state aggregate income as regression weights

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
A. Uniform policy impact for the entire restructuring period									
Restructured states	–0.649**	–0.690**	–0.812**	–0.381	–0.425	–0.464	–0.285	–0.316	–0.075
	(0.288)	(0.291)	(0.384)	(0.256)	(0.259)	(0.319)	(0.277)	(0.282)	(0.299)
B. Differential policy impact using the 5-year window for the transitional period									
First 5 years since restructuring	–0.858***	–0.884***	–1.050***	–0.551**	–0.582**	–0.535**	–0.459*	–0.479*	–0.175
	(0.215)	(0.220)	(0.290)	(0.235)	(0.239)	(0.246)	(0.272)	(0.276)	(0.255)
After first 5 years	–0.274	–0.339	–0.494	–0.111	–0.174	–0.376	–0.005	–0.047	0.061
	(0.463)	(0.467)	(0.567)	(0.372)	(0.376)	(0.459)	(0.369)	(0.378)	(0.455)
Difference	0.584*	0.545	0.556	0.440	0.408	0.159	0.454	0.432	0.235
	(0.347)	(0.347)	(0.398)	(0.338)	(0.341)	(0.314)	(0.344)	(0.349)	(0.378)

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. State and year fixed effects, and additional control variables are used for estimation but omitted from reporting in the table.

Table 13: Policy impact - log-linear models

	Residential			Commercial			Industrial		
Average price	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)
A. Uniform policy impact for the entire restructuring period									
Restructured States	–0.066**	–0.069***	–0.069**	–0.015	–0.018	–0.002	0.022	0.009	0.044
	(0.025)	(0.025)	(0.032)	(0.028)	(0.027)	(0.030)	(0.036)	(0.036)	(0.039)
B. Differential policy impact using the 5-year window for the transitional period									
First 5 years since restructuring	–0.083***	–0.085***	–0.088***	–0.023	–0.026	–0.011	0.014	0.005	0.042
	(0.022)	(0.022)	(0.029)	(0.027)	(0.027)	(0.031)	(0.039)	(0.040)	(0.045)
After 5 years since restructuring	–0.042	–0.046	–0.042	–0.005	–0.009	0.008	0.031	0.013	0.046
	(0.033)	(0.034)	(0.040)	(0.033)	(0.033)	(0.036)	(0.038)	(0.039)	(0.042)
Difference	0.041*	0.039	0.047*	0.019	0.017	0.019	0.018	0.009	0.003
	(0.024)	(0.024)	(0.027)	(0.024)	(0.025)	(0.028)	(0.030)	(0.032)	(0.038)

Notes: 1. Standard errors are clustered by states and reported in parentheses.
2. Stars denote statistical significance: * significant at 10%; ** significant at 5%; *** significant at 1%.
3. State and year fixed effects, and additional control variables are used for estimation but omitted from reporting in the table.

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Measuring and Explaining Electricity Price Changes in Restructured States

An effort to determine the effect of restructuring on prices finds that, on average, prices for industrial customers in restructured states were lower, relative to predicted prices, than prices for industrial customers in non-restructured states. This preliminary analysis also finds that these price changes are explained primarily by high pre-restructuring prices, not whether or not a state restructured.

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Jason Salony contributed to this article.

I. Introduction

A decade ago, Rhode Island, Massachusetts, and California began the process of restructuring their electricity industries to introduce competition into the generation portion of the retail electricity supply chain. Since then, a total of 23 states and the District of Columbia actively pursued more competitive electricity industries through restructuring. A variety of factors spurred states to restructure, ranging from the success of deregulation in other network industries to concerns about utility investment decisions – especially in the wake of nuclear power plant cost overruns.[1] While the factors were wide-ranging, a key impetus for change was the desire of industrial customers in high-priced states to reduce their electric bills.[2] The promise of lower prices provided the political justification as well. **Figure 1** shows that the states with higher prices were generally those that restructured, independent of their size. More rigorous analyses by

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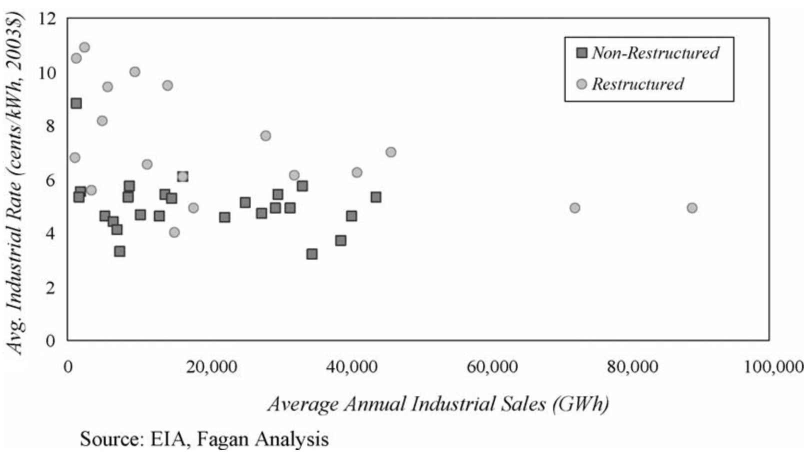

Figure 1: Distribution of Industrial Electricity Prices and Sales, Restructured and Non-Restructured States, 1993-1995

Andrews[3] and Teske[4] confirm this finding.

The California energy crisis, the collapse of Enron, the August 2003 blackout, and the high cost of natural gas led some to question the wisdom of these restructuring efforts.[5] Six states that had decided to restructure subsequently delayed or repealed their restructuring efforts. Notwithstanding these challenges, 18 restructured jurisdictions pushed forward toward a competitive marketplace.

How have prices in the restructured states changed? Has the retail price reduction objective been achieved? Several studies have examined wholesale price changes in recent years, but their results do not provide a consistent answer to the price change question.[6] In an article entitled ''Competition Has Not Lowered U.S. Industrial Electricity Prices,''[7] Apt examines the rate of change of industrial electricity prices in restructured and non-restructured states in the pre- and post-restructuring periods. Apt finds that restructured states as a group have a 1.4 percent average annual price increase, compared with a 1.0 percent increase for non-restructured states.

A recent Cambridge Energy Research Associates (CERA) study compares real electricity prices with counterfactual prices – prices that would have been expected had restructuring not occurred.[8] It finds that actual prices were lower (in real terms) than counterfactual prices and in all regions except the West. In total, CERA estimates that power deregulation has saved U.S. consumers $34 billion.

In light of these conflicting findings, this study's first objective is to determine if industrial prices in two groups of states (restructured and non-restructured) were higher or lower than prices predicted by a counterfactual model.[9] The second objective is to explain the observed relationships between actual prices and predicted prices by looking at state-level characteristics, including initial price levels, restructuring status and participation in a well-functioning regional transmission organization (RTO).

II. Research Methodology

This study used distinct methodologies for its two objectives: a counterfactual model to measure the difference between actual and predicted prices, and a two-stage least squares model to explain causality.

Objective 1: Counterfactual Assessment of Price Changes

The counterfactual portion of the study compares average retail industrial electricity prices from 2001-03 with predicted prices for the same period. Predicted prices are determined by the following equation for year t and state i:

$$P^{E}_{it} = \alpha_i + \beta_i t + \theta_i P^{G}_{it} + \varepsilon_{it}$$

where P^{E} is the real (2003$) price of electricity paid by industrial customers, t is the year from 1990-97, and P^{G} is the real (2003$) average city gate price of natural gas in the state's region.[10] The regression constant (α) and coefficients (β) and (θ) are determined for each state i using real (2003$) industrial electricity prices and real (2003$) average city gate price of natural gas for all years (1990–97).

Gas is explicitly incorporated into the predictive regression because gas prices were highly volatile during the study period,

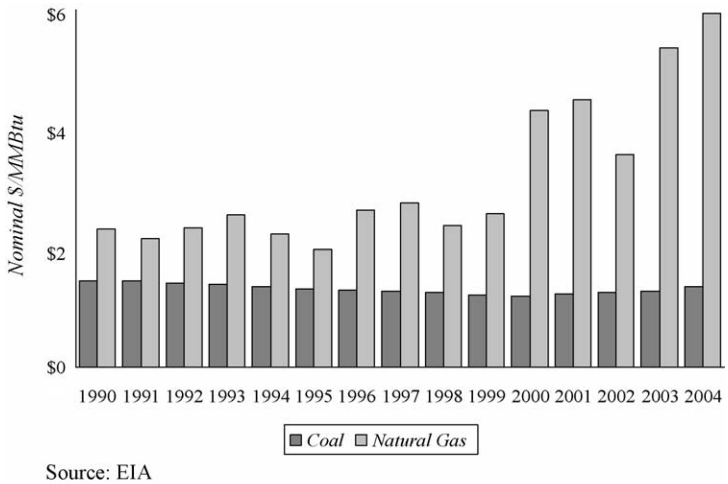

Figure 2: Delivered Coal and Natural Gas Prices, 1990-2004

while other fuels used in electricity generation (such as coal) remained relatively flat (**Figure 2**). The gas variable explicitly accounts for the impact of fuel price changes on electricity prices. Since gas prices vary by region, this study uses regional gas prices, which are regional averages of state-level city gate prices.

For each year t (2001-03) and state i, given the state-specific values of α, β, and θ described above, the predicted real (2003$) industrial price of electricity is as a function of the regional gas price. These state-level predicted prices are used to create consumption-weighted average prices for restructured and non-restructured states.[11] The group average predicted prices are compared to group average actual prices, and the absolute and percentage difference is reported.

The consumption-weighted group averages are calculated as follows: for actual prices, the average restructured (non-restructured) industrial price is the total industrial revenue divided by total industrial sales for all restructured (non-restructured) states; for predicted prices, the average restructured (non-restructured) industrial price is the total predicted industrial revenue divided by the total industrial sales for all restructured (non-restructured) states. A state's predicted industrial revenue in year t is the state's predicted industrial price (from the counterfactual regression, above) in year t multiplied by its actual industrial sales in year t. For both actual and predicted average prices, revenues and sales for three years (2001-2003) are used to limit the impact of anomalous years.

The source of the electricity price data is the U.S. Department of Energy's Energy Information Administration (EIA) Form 861. EIA data have been used in prior electricity price examinations.[12] The EIA's nominal prices are converted to real (2003) prices using the U.S. GDP (chained) price index. The post-restructuring period (2001-03) and includes three years of data to minimize the effect of outliers.

In one version of the analysis, 2001-03 prices in restructured states are adjusted to remove revenues paid as stranded asset recovery fees (also called competitive transition charges, or CTCs), before being compared with predicted prices. Since this research seeks to understand the long-term impact of restructuring on electricity prices, removing CTCs is appropriate. CTCs are short-term additions to electricity prices that typically recover stranded investments made under regulation in five to seven years, rather than the 20-plus years under regulation. For each state with CTC data (available from the Edison Electric Institute's *Typical Bills and Average Rates Report* and supplemented with public utility commission data), the CTC's share of the total electricity price is removed from the post-restructuring average price. In another version of the analysis, prices are not adjusted for CTCs; findings from both are reported.

Objective 2: Causality of Observed Price Changes

The second part of this study seeks significant determinants of the difference between predicted prices and actual prices at the state level. Five potential explanatory variables are examined: the state's restructuring status; the state's participation in a

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well-functioning RTO[13]; the state's initial pre-restructuring (i.e., 1993-95) electricity price; the state's difference between the actual 1993-95 electricity price and the counterfactual 1993-95 price; and the change in 2001-03 predicted price from 1993-95 predicted price (based on the counterfactual model). Inclusion of the change in predicted price as an independent variable accounts for the state-specific impact of gas prices and various regulatory forces on electricity prices.

The primary explanations of the price changes could be:

1. *Restructuring impacted the difference between actual and predicted prices;*
2. *Prices regressed toward the mean for all states, independent of whether the state restructured.*
3. *Effective wholesale market design and the associated well-functioning regional transmission organizations (RTOs) impacted the difference between actual and predicted prices.*

Two regression models are specified to test the potential explanations. The first model measures the impact of restructuring on the difference between a state's predicted (counterfactual) price and its actual price. The second model measures the impact of several factors (restructuring, counterfactual price change, RTO participation, pre-restructuring price, and pre-restructuring actual vs. counterfactual differential) on the observed change in prices between 1993-95 and 2001-03.

The formulations are provided below:

Model 1:

$$\mathrm{Diff}_{i,2001-2003} = \beta_0 + \beta_1 \mathrm{Rest}_i + \varepsilon_i$$

where Diff_i is the differential between state i's 2001-03 real industrial electricity price and its 2001-03 counterfactual-predicted price (actual price − predicted price), and Rest_i is the restructuring status in state i.

One possible explanation: prices regressed toward the mean for all states, independent of whether the state restructured.

Model 2:

$$\begin{aligned}\Delta P_{i,01/03\text{-}93/95} &= \beta_0 + \beta_1 \mathrm{Rest}_i \\ &\quad + \beta_2 \Delta \mathrm{Predicted}_{i,01/03\text{-}93/95} \\ &\quad + \beta_3 \mathrm{RTO}_i \\ &\quad + \beta_4 \mathrm{Initial\_Diff}_{i,1993\text{-}1995} \\ &\quad + \beta_5 P_{1993\text{-}1995} + \varepsilon_i\end{aligned}$$

where ΔP_i^{E} is the actual change in average real industrial electricity prices in state i between 1993-95 and 2001-03; Rest_i is the restructuring status in state i; $\Delta\mathrm{Predicted}_i$ is the change in the counterfactual model prediction for state i between 1993-95 and 2001-03; RTO_i is a dummy variable indicating whether state i participated in a well-functioning RTO; $\mathrm{Initial\_Diff}_i$ is the difference between the actual 1993-95 real industrial electricity price in state i and the 1993-95 price predicted by the counterfactual model; and $P_{1993\text{-}1995}$ is the pre-restructuring (1993-95) electricity price.

In both models, Rest_i is instrumented with an additional variable (as indicated in the results tables) to limit the effects of endogeneity between electricity prices and restructuring.

III. Findings

A. Counterfactual regressions

The state-by-state counterfactual regressions, where each state's electricity price is a function of time and gas price, appear to have strong statistical results. As illustrated in **Figure 3**, most of the state regressions have an adjusted R^2 greater than 0.9.

It should be noted that the vast majority of explanatory power lies with the time variable. The gas variable is rarely statistically significant in the state models.

The counterfactual prices estimated from the regressions are sometimes higher and sometimes lower than the actual prices in both the restructured and non-restructured states, as shown in **Figure 4**.

The actual prices were lower than predicted prices in 12 of 18 restructured states. Only 7 of 25 non-restructured states had actual prices that were lower than those predicted by the counterfactual.

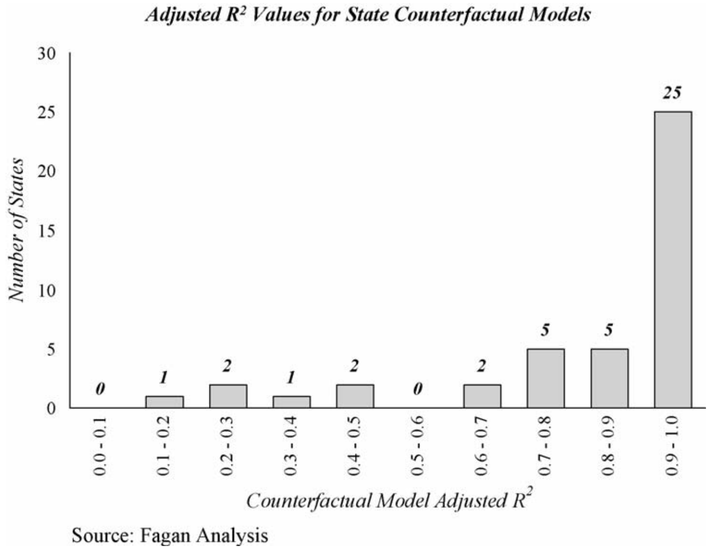

Figure 3: Adjusted R^2 Values for State Counterfactual Models

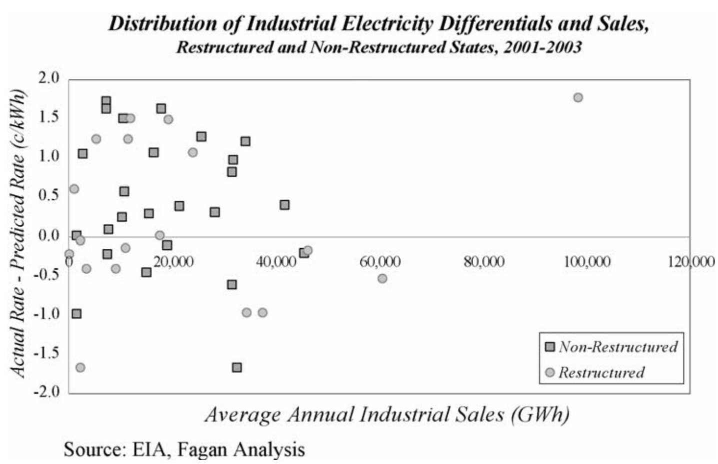

Figure 4: Distribution of Industrial Electricity Differentials and Sales, Restructured and Non-Restructured States, 2001-2003

The distribution of price differentials is shown in **Figure 5**.

A difference of means test shows that there is a statistically significant difference between differentials in restructured and non-restructured states. (The *t* statistic is 2.07, compared to a two-tailed critical *t* value of 2.05.)

B. Aggregate price changes

The individual state price changes were aggregated into group averages, following the consumption-weighting methodology described above. The results show that actual prices were 1.3 percent higher than the counterfactual predicted prices in the restructured states and 9.2 percent higher in non-restructured states, adjusting for the impact of gas price volatility and the effect of accelerated stranded cost payments (**Table 1**).

Even if revenues paid as competitive transition charges are not removed from actual prices, restructured states still appear to have performed more favorably than non-restructured states relative to their predicted prices (**Table 2**).

C. Explaining the price changes

What accounts for the difference in price changes between restructured and non-restructured states? Restructuring status, pre-restructuring price, 1993-95 differential (actual price minus predicted price) price, change in predicted price, and participation in a strong RTO are tested as explanatory variables. The simple correlations below show that restructuring has a weak relationship with the differential between actual and counterfactual price. In contrast, there is a stronger correlation between initial price and the price differential. High initial prices are negatively correlated with the difference between the actual price and the price predicted by the counterfactual (**Figure 6**).

Table 1: CTC-Adjusted Industrial Rates vs. Predicted Industrial Rates (2003 Cents per kWh)

	2001-2003 Predicted	2001-2003 Actual (CTC-Adjusted)	Difference (Actual-Predicted)	Percent Difference
Restructured States	4.95	5.02	0.07	1.3
Non-Restructured States	3.92	4.28	0.36	9.2

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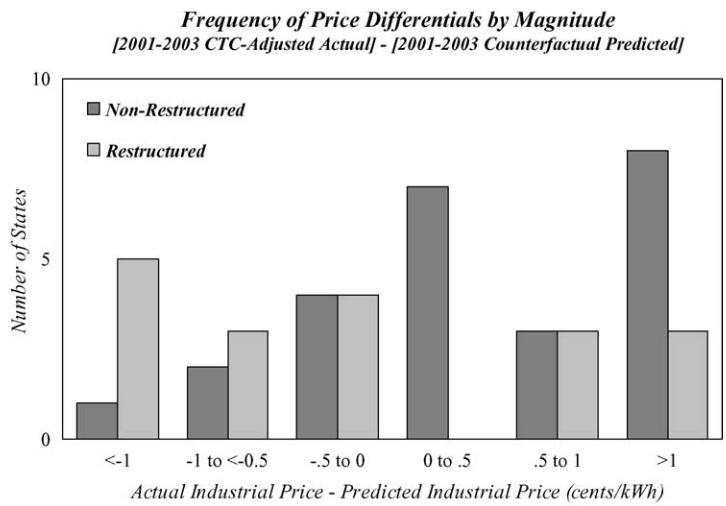

Source: Fagan Analysis

Figure 5: Frequency of Price Differentials by Magnitude [2001-2003 Unadjusted Actual] – [2001-2003 Counterfactual Predicted]

Table 2: Unadjusted Industrial Rates vs. Predicted Industrial Rates (2003 Cents per kWh)

	2001-2003 Predicted	2001-2003 Actual (Unadjusted)	Difference (Actual-Predicted)	Percent Difference
Restructured States	4.95	5.32	0.37	7.5
Non-Restructured States	3.92	4.28	0.36	9.2

The results of the two-stage least squares regressions indicate that, of the explanatory variables, only initial (pre-restructuring) price and the change in predicted price between 1993-95 and 2001-03 are significant. In Model 1, restructuring is not a significant driver of the differential between actual and predicted prices (**Table 3**). In Model 2, neither the RTO variable nor the restructuring variable is a statistically significant driver of real price change, and restructuring status lacks the anticipated sign (**Table 4**).

These results suggest that restructuring cannot be attributed as a driving factor in the observed price changes.

IV. Conclusion and Further Research

This research indicates that, on a consumption-weighted basis, average prices adjusted for CTC in restructured states were only marginally above predicted levels (1.3 percent), while prices in non-restructured states were significantly above predicted levels (9.2 percent). These aggregate trends are not uniform for all states, however – there is significant state-by-state variation. The actual prices in two-thirds of restructured states were lower than predicted, and one-quarter of non-restructured states had prices that were lower than predicted.

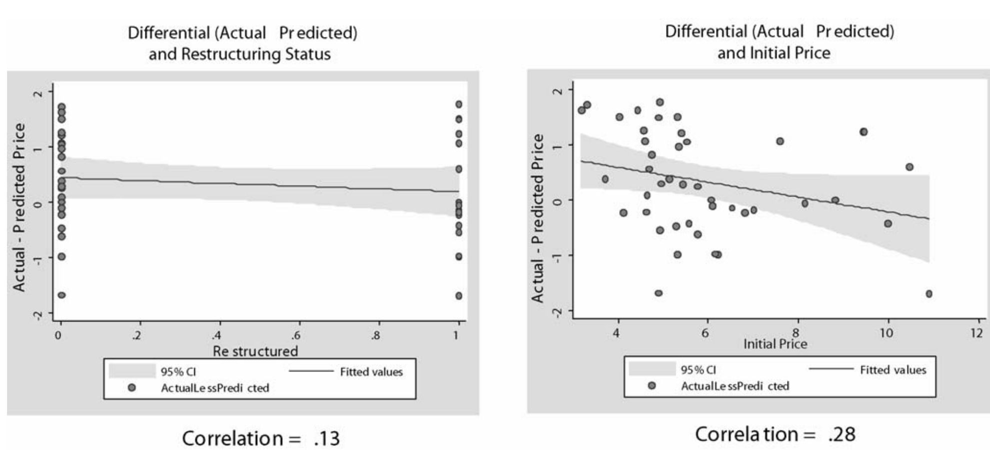

Figure 6: Correlations

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Table 3: Model 1 Two-Stage Least Squares Results

Independent Variable	Coefficient	Std. Error	*t*-Statistic	$P > \|t\|$	Adjusted R^2	*F*-Statistic
Restructuring Yes = 1; No = 0	−0.46	0.46	−1.01	0.32	−0.02	1.01
Constant	0.52	0.24	2.19	0.03		

Dependent variable: (Actual 2001-2003 Price) − (Predicted 2001-2003 Price).
Restructuring is instrumented with a dummy variable indicating participation in a well-functioning RTO.

Table 4: Model 2 Two-Stage Least Squares Results

Independent Variable	Coefficient	Std. Error	*t*-Statistic	$P > \|t\|$	Adjusted R^2	*F*-Statistic
Restructuring Yes = 1; No = 0	0.14	0.69	0.20	0.84	0.58	12.49
93/95 Actual Price	−0.19	0.07	−2.78	0.01		
93/95 Actual Price − Predicted 93/95 Price	−0.06	0.09	−0.67	0.51		
RTO Participation Yes = 1; No = 0	−0.11	0.46	−0.25	0.81		
Change in Predicted Price (01/03 − 93/95)	0.53	0.11	4.93	0.00		
Constant	1.04	0.35	3.01	0.01		

Dependent variable: (Actual 2001-2003 Price) − (Actual 1993-1995 Price).
Restructuring is instrumented with a George W. Bush's share of 2004 major party presidential votes.

The models above suggest that neither regulatory reform at the retail level (restructuring status) nor at the wholesale level (RTO participation) is a significant driver of the restructured states' superior price performance. Only the 1993-95 electricity price and the change in counterfactual-predicted prices between 1993-95 and 2001-03 are significant.[14]

The significance of pre-restructuring price as a determinant of price change may be evidence for a national pressure between 1993 and 2003 to reduce prices in all high-priced states, regardless of their restructuring status. In restructured states, the pressure may have come from price competition; in non-restructured states, it may have come from the desire of integrated utilities to appease consumers and regulators with lower prices, to keep them from choosing to restructure.[15]

The findings should be viewed as preliminary because the impact of restructuring on prices was still evolving in the post-restructuring period (2001-03) examined in the study. Most states were (and still are) in the transition period where rates are set by a mix of competitive and regulatory forces. Because industrial customers are further down the path to a competitive market, this article focuses on the industrial segment. However, it should be noted that the market is still developing even in the industrial segment. Consequently, the study should be replicated in the future once the transition period is over and the conversion to a competitive market for retail power is complete. Furthermore, a more exhaustive specification of the counterfactual regression could yield greater insights.■

Endnotes:

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7. J. Apt, *Competition Has Not Lowered U.S. Industrial Electricity Prices*, Elec. J., March 2005, at 52-61.

8. Cambridge Energy Research Associates Beyond the Crossroads: The Future Direction of Power Industry Restructuring (Washington, DC.: Cambridge Energy Research Associates, 2005).

9. Standard offer prices in most restructured states continue to be set by a mix of competitive and regulated forces. Industrial prices tend to more closely reflect the competitive marketplace than residential prices, both because of different regulatory approaches and because of higher rates of industrial switching.

10. Gas price regions roughly correspond to NERC reliability regions.

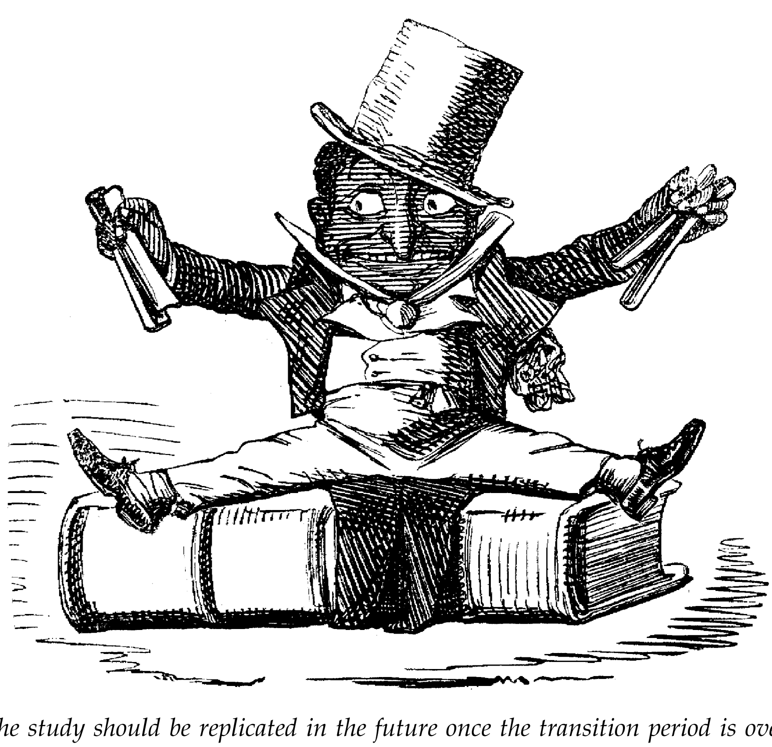
11. Six states that delayed or repealed restructuring (AR, CA, MT, OK, NM, and NV) are excluded from the analysis, as well as AK and HI. States that delayed or repealed are excluded because this study looks for the long-term impacts of regulatory policy on electricity prices. While the list of states that delayed restructuring is somewhat subjective, this study uses the definition from the U.S. Department of Energy's Federal Energy Management Program, at http://www.eere.energy.gov/femp/program/utility/utilityman_staterestruc.cfm.

12. L. Lave, J. Apt and S. Blumsack, *Rethinking Electricity Deregulation*, Elec. J., Oct. 2004, at 11–26; Andrews, *supra* note 5; Apt, *supra* note 1.

13. ''Well functioning'' is defined as having an LMP-based energy market in place during the post-restructuring period (2001-03). Thus, members of ISO New England and New York ISO, as well as states in northeastern PJM have a value of 1 and the other states are coded 0. Southern and western PJM, including parts of Illinois, Ohio, Virginia, and West Virginia, did not participate in PJM markets until after 2003. (Northeastern PJM includes Delaware, Maryland, New Jersey, Pennsylvania, and the District of Columbia.)

14. The fact that a state's 1993–95 average price is significant, while the 1993–95 differential between actual and predicted prices is not, suggests that price change between 1993 and 2003 may result from something other than ''regression to the mean.'' The ''mean'' in this case is a state-specific expected electricity price, rather than a single national price. If prices were regressing to the mean between the 1993–95 period and the 2001-03 period, we would expect the difference between 1993-95 actual price and 1993-95 counterfactual price (i.e., the state's deviation from the predicted price) to be significant, rather than the absolute magnitude of the 1993-95 price.

15. Further research, examining the relative rates of change among high-priced and low-priced non-restructured states, is needed to test this hypothesis.



The study should be replicated in the future once the transition period is over.

Competition Has Not Lowered U.S. Industrial Electricity Prices

Previous studies have shown that significant price reductions resulted from deregulation in airlines, trucking, railroads, and natural gas. Retail electricity price data from 1990 through 2003 show no such benefit to industrial customers.

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I. Introduction

Restructuring of the electric power industry followed deregulation of natural gas (1978), airlines (1978), railroads (1980), and the trucking industry (1980). Industrial customers were permitted to select their electricity generation company in the first states during 1998. Some 19 states and the District of Columbia have now implemented competition for industrial customers,[1] with rules taking effect through the ensuing six years. Roughly 40 percent of all electricity in the United States is now sold in restructured states.

Before restructuring got underway, microeconomic studies indicated that efficiency gains of 3–13 percent were feasible through competitive pressures.[2,3] The actual record on overall operations costs and thermal efficiencies is mixed.[4] One study of generators in restructured states[5] indicates that employment dropped 29 percent in restructured states and 19 percent in other states since the peak in 1991; however that 10 percent difference would have lowered cost by only roughly 0.7 percent, since labor costs represent about 7 percent of electricity cost.

The Federal Reserve Bank of New York predicted in 2000 that ''. . . the market forces introduced to the industry by deregulation

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should cause electricity rates to drop below the levels that would have prevailed under a monopoly system.''[6] This article examines the effect of restructuring on prices paid by U.S. industrial customers for electricity.

II. Data Source

The U.S. Energy Information Administration began collecting annual survey data on power sales in 1985 (EIA form 861). The annual data are collected from about 3,300 electric utilities and about 1,600 independent power producers, unregulated generation units of regulated utilities, and power marketers. Operating revenue data include ''energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric power industry participant operating revenues also include State and Federal income taxes and taxes other than income taxes paid by the utility.'' [7] Data are collected on energy (kilowatt-hours) sold.

EIA also performs a monthly survey of 450 large utilities and energy service providers accounting for approximately 70 percent of sales (form 826). Data have been collected since 1947; the survey instrument was last revised in January 1990 and data are available in a consistent format from that date through the present, with a lag of approximately eight months.[8]

The annual survey data submitted on form 861 by April 30 each year are used by EIA to correct the monthly data, and to scale the monthly data to account for all sales. Schedule A of form 861 is completed by vertically integrated utilities, schedule B by power marketers (without transmission or distribution facilities), and schedule C by distribution companies. No statutory requirement compels power marketers (or some other firms) to return the form, and the sum of schedule B is in some states less than the schedule C reported total. Although schedules B and C match well for most states, there are important errors. For example, one power marketer with large sales in Maine and Texas does not report. Adjustments to the schedule B data are made by EIA specialists, often after additional contacts with the involved parties, using their best judgment and knowledge of the particular state.

The benefits of retail competition are best studied by examining prices for large industrial customers, who have the incentive and resources to shop for the best price.

Reporting firms segment the data into industrial, commercial, residential, transportation, and ''other'' sectors.[9] Although changes implemented during 2003 in the segmentation introduce relatively small shifts, inconsistent definitions of what constitutes industrial and commercial customers exist: some distribution companies report large retailer stores as industrial, while power marketers may report the same load as commercial.

Occasional units errors appear in the EIA data. For example, the Alaska data for January 2003 was contaminated by one firm reporting in kWh and dollars, instead of the requested MWh and $k. EIA corrected this error when shown a discontinuity in the time series for Alaska.

Despite these sources of inaccuracy, the EIA data is the best national data source for electricity sales and revenue covering the period before and after the inception of restructuring.
EIA staff are quick to correct inconsistencies in the data, and have applied corrections for underreporting in a thoughtful manner. The necessity for EIA staff to adjust the raw electricity data would be lessened greatly if all firms were compelled to report, and clear guidance for segmentation of sales were applied.

III. Price History

The benefits of retail competition in the electric power industry are best studied by examining

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prices for large industrial customers, who have both the incentive and resources to shop for the best price. Because small customers were not expected to switch suppliers readily, 14 of the states that introduced retail competition mandated rate reductions for residential customers,[1] generally of approximately 5 percent. The commercial sector consists of a mix: large retailers, small shops, universities, hospitals, high-rise office buildings, and small strip malls. The heterogeneity of the commercial sector makes analysis of the effects of restructuring more difficult than for the industrial sector. Data from the industrial sector are used here. See the appendix for a discussion of how the seasonal periodicity was removed from the raw EIA data. Those wishing to examine the full set of results for all three sectors are directed to Carnegie Mellon Electricity Industry Center Working Paper CEIC-05-01, available at www.cmu.edu/electricity.

Results for the industrial sector prices for five western states are shown in **Figure 1**. The strong collateral influence of the market failure in California is seen in Washington, Oregon, and Nevada as well (the latter two are regulated states).

Much less price volatility is seen in the regulated southern states, the price history for five of which are in **Figure 2**.

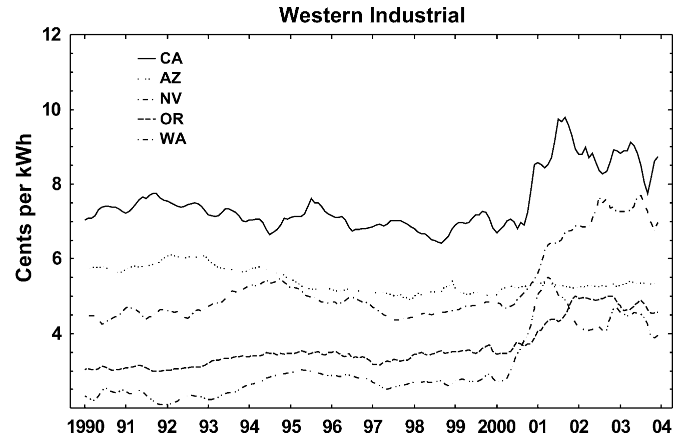

Figure 1: Industrial Prices in Five Western States, 1990–2003

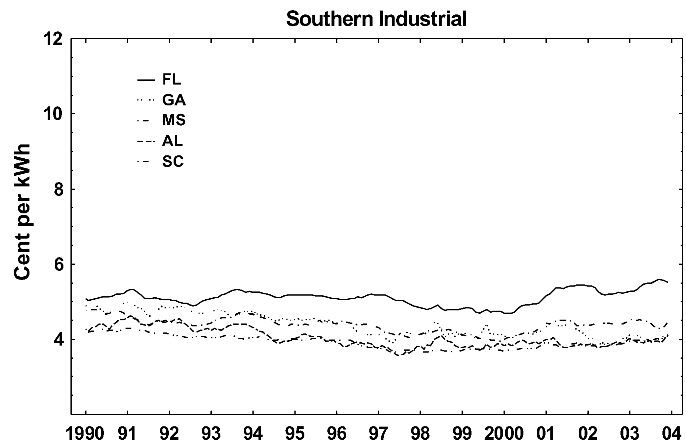

Figure 2: Industrial Prices in Five Regulated Southern States, 1990–2003

The New England states quickly followed California and Pennsylvania in implementing electric restructuring. **Figure 3** shows the industrial price history for five New England states.

Two aspects of the price history in New England deserve further comment. The price increases in Rhode Island and Massachusetts in 2000 and again in 2003 are most likely due to natural gas fuel cost

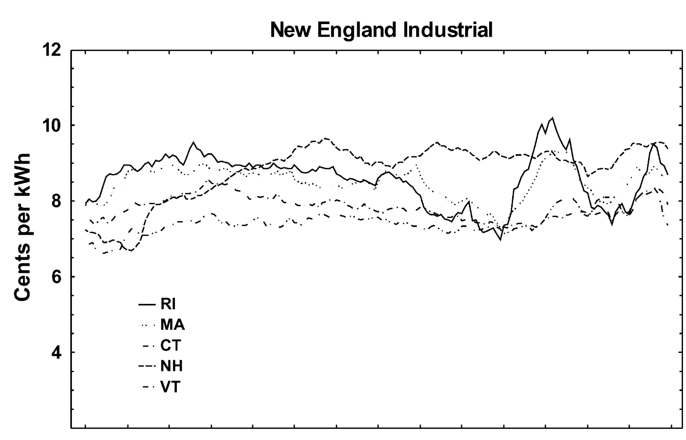

Figure 3: Industrial Prices in Five New England States, 1990–2003

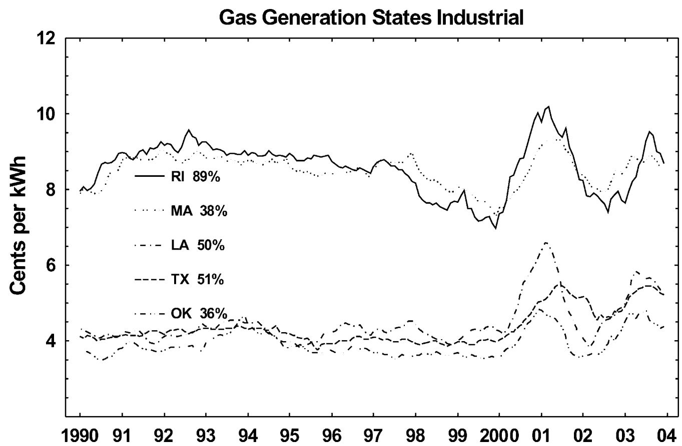

Figure 4: Industrial Prices in States With Large Percentage of Net Generation From Natural Gas[11] (2002 Percentage Shown in Parentheses), 1990–2003

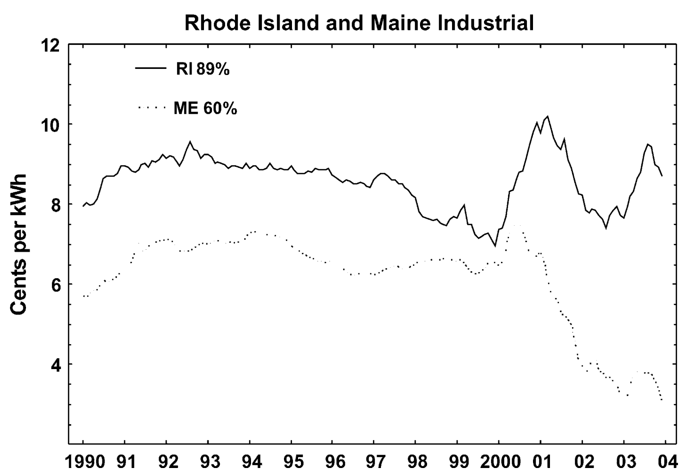

Figure 5: Industrial Prices in Rhode Island and Maine (2002 Percentage of Generation From Natural Gas Shown in Parentheses), 1990–2003

increases. This hypothesis is supported by an examination of a number of states which generate large percentages of their electricity from natural gas, shown in **Figure 4**. The 2000 and 2003 peaks are a good match to natural gas prices.[10]

Second, the state of Maine is heavily dependent on electric generation fueled by natural gas. Prices in that state began to rise in 2000, but have fallen significantly since (**Figure 5**). However, the price decrease appears to be correlated with completion of two natural gas pipelines from the Sable Island field off Nova Scotia. Prices subsequently have fallen to levels characteristic of other states close to large natural gas resources.

IV. Discussion

New England provides a laboratory for examining the effects of restructuring, since Vermont is the only regulated state in the region. As Figure 3 shows, there is little difference between the price history of Vermont and that of the other four states in the figure, with the exceptions of natural gas price changes.

A broader view can be obtained by using the data to calculate the annual rate of industrial price change in the period before and after the phase-in of restructuring for the restructured states, given in **Tables 1 and 2**. We can compare these to the price changes in nearby regulated states, shown in Table 2. The regional data in Table 2 were calculated as the average of the rates of the individual listed states. These data are shown graphically in **Figures 6 and 7**.

Using New England as an example, the average annual rate of industrial price change for Connecticut, Massachusetts, Maine, New Hampshire, New York, and Rhode Island from January 1990 to one month prior to the beginning of the phase-in period for industrial competition (shown in Table 1) was 0.9 percent per year increase. The corresponding annual rate after phase-in of competition was −1.7 percent per year (a decrease). Before proclaiming that restructuring has been a boon for industrial customers in New England we should recall that the 20 percent decrease in Maine's prices was due to other reasons. When Maine is removed, the ''before'' rate for the remaining five states was 0.8 percent, but industrial prices rose 2.0 percent after restructuring in those states. For comparison,

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Table 1: State Industrial Price Change Before and After Restructuring

State	Phase-In Period for Industrial Sector Competition[1]	Annual Percentage Change of Industrial Price: 1990 to One Month Prior to Beginning of Phase-In Period	Annual Percentage Change of Industrial Price: One Month After End of Phase-In Period Through 2003
Arizona	January 1999–December 2002	−0.6	0.6
California	April 1998	−0.6	5.0
Connecticut	January–July 2000	−0.2	2.2
Delaware	October 1999–April 2000	0.9	3.5
D.C.	January 2001	0.1	3.3
Illinois	October 1999–December 2000	−0.8	3.0
Maine	March 2000	1.3	−20.1
Maryland	July 2000–July 2002	−1.9	1.2
Massachusetts	March 1998	0.9	0.6
Michigan	June 1999–December 2001	−1.4	−3.9
Montana	July 1998	−1.1	5.9
New Hampshire	July 1998–May 2001	3.3	1.3
New Jersey	November 1999	0.2	1.3
New York	May 1998–July 2001	−1.0	4.3
Ohio	January 2001	1.0	0.5
Oregon	March 2002	4.0	−4.2
Pennsylvania	January 1999–December 1999	−0.3	2.7
Rhode Island	July 1997–January 1998	1.1	1.8
Texas	January 2002**	1.9	0.9
Virginia	January 2002–January 2004	−0.2	N/A

*Michigan industrial rates were capped through December 2003.**Except municipals, co-ops, and rural southeast Texas.

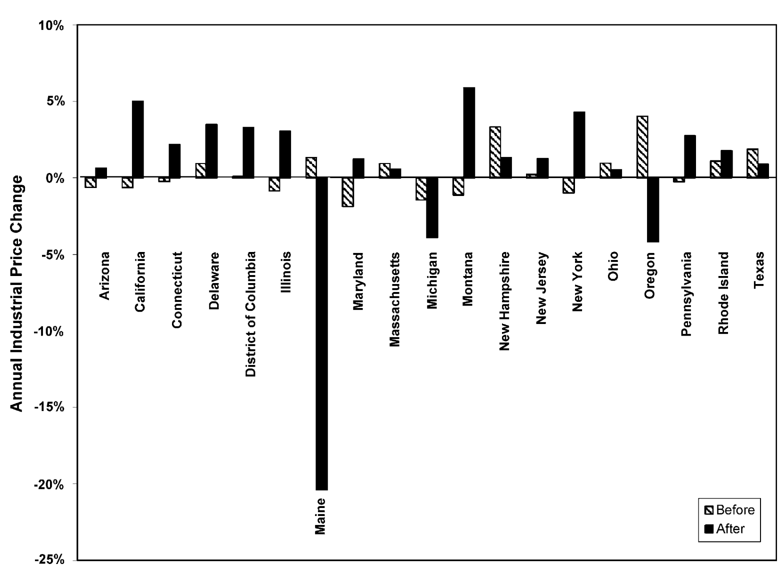

Figure 6: Annual Rate of Industrial Price Change in Restructured States Before and After Restructuring Phase-In (Data From Table 1)

Vermont's regulated prices rose 0.8 percent annually from 1990 through March 1998, and fell 0.8 percent from 2001 to 2003. (Those time periods are used as comparison periods for all regulated states to encompass the periods before and after phase-in of restructuring in other states.)

We can characterize the same data by noting that the annual rate after phase-in of competition minus that before for the New England states (without Maine) was 2.0 percent – 0.8 percent = 1.2 percent (the difference between the annual rate of

Table 2: Regional Industrial Price Change Before and After Restructuring

Region	Annual Percentage Change of Industrial Price: 1990 to One Month Prior to Beginning of Phase-In Period	One Month After End of Phase-In Period Through 2003
Western Restructured (AZ, CA, MT, OR)	0.4	1.8
Ohio Valley Restructured (IL, OH, PA)	0.0	2.1
New England Restructured (CT, MA, ME, NH, NY, RI)	0.9	−1.7
New England Restructured without Maine	0.8	2.0
All Restructured	0.4	0.5
All Restructured without Maine	0.3	1.7
Regulated States Comparison	1990–March 1998	2001–2003
Western Regulated (CO, ID, NM, NV, UT, WA, WY)	0.0	1.0
Upper Midwest Regulated (IA, MN, ND, NE, SD, WI)	−0.6	1.3
Lower Midwest Regulated (KS, MO, OK)	−1.3	−1.8
Ohio Valley Regulated (IN, KY, WV)	−0.7	2.5
Vermont	0.8	−0.8
South Regulated (AL, AR, FL, GA, LA, MS, NC, SC, TN)	−1.3	−0.8
All Continental U.S. Regulated	−0.7	0.3
All U.S. Regulated	−0.7	0.1

change after and before). The same figure for Vermont was −1.6 percent. This annual rate difference is the difference between the black bar and cross-hatched bar in Figures 6 and 7. Considering all 50 states and the District of Columbia, industrial prices decreased by an average of 0.4 percent annually before the beginning of the period of restructuring, and have increased by 0.4 percent after. The restructured jurisdictions had annual increases of 0.4 percent prior to restructuring, and increases of 0.5 percent annually after (removing Maine the corresponding figures are 0.3 percent prior to and 1.7 percent after restructuring).

Using this difference between the annual price change after phase-in of industrial sector competition and before it began as the dependent variable, we can perform a regression analysis for all 50 states (with the exception of Virginia, where phase-in is in progress) and the District of Columbia. The analysis shows that the variable of restructuring fails to explain the

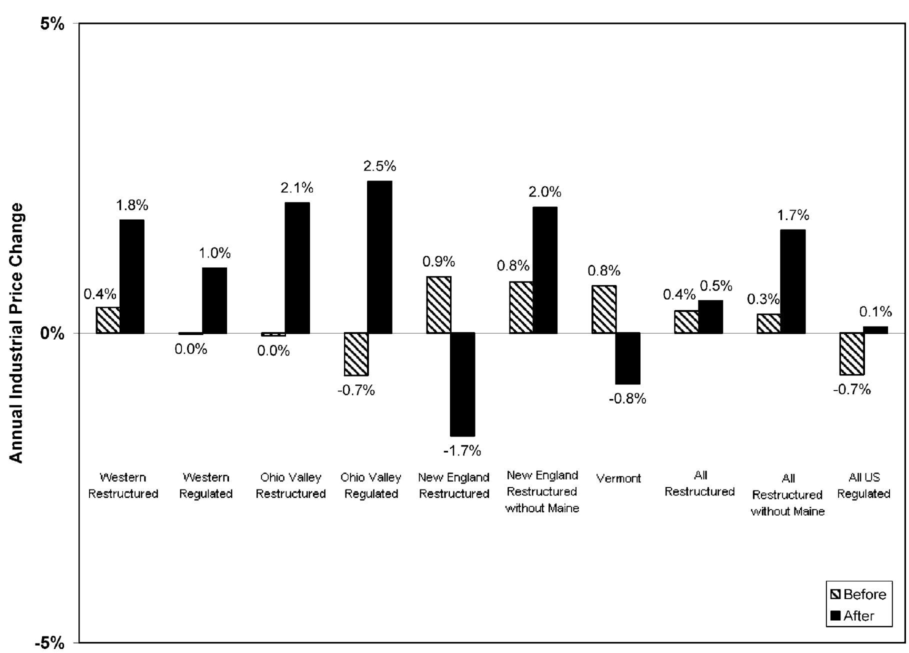

Figure 7: Regional Average Annual Rate of Industrial Price Change Before and After Restructuring Phase-In (Data From Table 2)

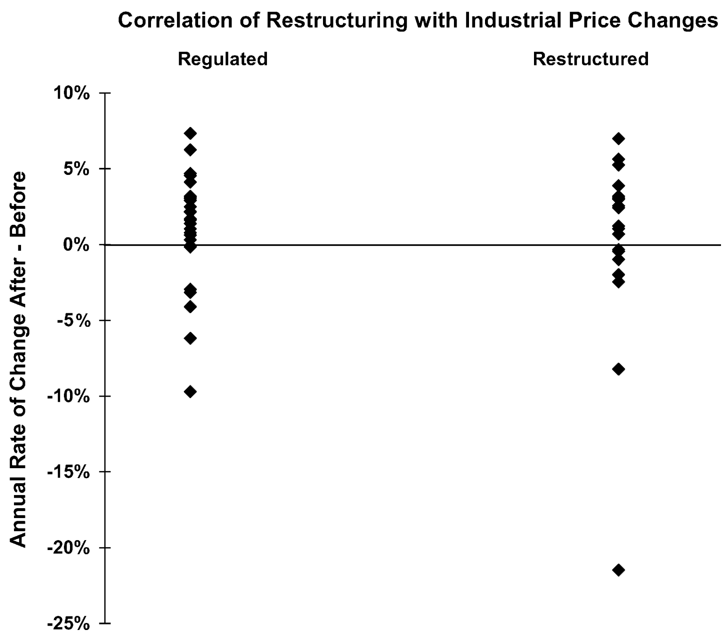

Figure 8: Correlation of Restructuring with Industrial Price Changes. Each Point Represents the Difference Between the Annual Percentage Change of Industrial Price After the Phase-In of Competition and the Annual Change Before the Phase-In for One State. The ''Before'' Period for the Regulated States is 1990–March 1998; the ''After'' Period is 2001–2003. There is No Statistically Significant Correlation Between Restructuring and Improved Industrial Prices

price changes. Figure 8 is a plot of the annual price change difference for all regulated and all restructured states. The plot includes the District of Columbia but not Virginia, whose phase-in period overlaps the end of the data. The lowest point, showing the greatest difference since restructuring, is Maine.

Inspection of Figure 8 shows there is no correlation between restructuring or regulation and improvement in the annual rate of price change. The formal regression analysis leads to the same conclusion, with an r^2 of 0.01 (r^2 would be close to one if restructuring was correlated closely with the difference in the annual price change after and before restructuring). Restructuring in the electricity industry has not led to lower industrial prices, nor to decreased rates of annual price increases.

V. Conclusion

A review of improvements in consumer welfare in other deregulated industries[12] concluded that substantial price reductions resulted from deregulation in airlines, trucking (both less-than-truckload and full truckload), railroads, and natural gas. The review notes that reductions in real terms ranged from 30 to 75 percent in these industries.

The industrial sector price data for electricity shows no similar improvement. Lave *et al.*[13] discuss a number of factors which tend to increase costs. These include free markets which are not competitive, incomplete markets for essential services, paying market clearing prices for all generation, the cost of new institutions such as regional transmission organizations (RTOs), and the increase in the cost of capital due to increased uncertainty. The first and last of these apply to some industries with successful restructuring records. It may be that appropriate regulatory involvement can lead to conditions which foster lower prices in the electricity industry as well, but issues such as shared transmission infrastructure must be resolved.

Consumer welfare has not been improved by restructuring in the electricity industry, and considerable thought should be given to whether it is wise to extend restructuring to other states before the full range of issues has been resolved and reduced prices or reduced rate of price increase have been demonstrated.

Appendix I. Data Processing

Data for many states exhibit cyclical trends in revenue, sales, or their quotient. As an example, Figure 9 shows the quotient of the EIA revenue data divided by the EIA sales data for the industrial sector in Maryland from January 1990 through December 2003.

Various techniques exist for reducing the seasonal periodicity in such data so that underlying

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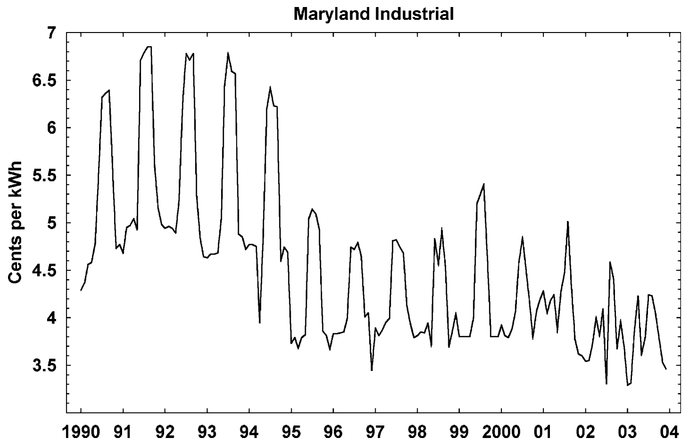

Figure 9: Monthly Industrial Sector Price Data (Revenue/Sales) for Maryland

trends can be examined quantitatively. Here we discuss three such techniques for data sets of length M months. A 12-month trailing moving average of the form

$$\text{Average}_n = \frac{1}{12}\sum_{k=n-11}^{n} \text{Data}_k \qquad (1)$$

can be constructed for each month n starting with the 12th month of data running through the end of the data at month M. This is the form of the moving average trendline used by Microsoft Excel. The disadvantage of this technique is that it lags actual changes in the data by several months.

A better form of a moving average for examining price data is centered around month n:

$$\text{Average}_n = \frac{1}{12}\sum_{k=n-5}^{n+6} \text{Data}_k \qquad (2)$$

This average is constructed from the 6th month of the data set to the $M-6$th month. As shown in **Figure 10**, the centered average does an acceptable job of showing annual trends in the data.

In the electricity data, several states have had price spikes due to market forces which coincide with summer or winter peaks. These are not well represented by the centered average technique. There is a third technique, which allows some of the abrupt changes to be displayed without obscuring the underlying trends. In this approach, the time series of data points is examined for frequencies corresponding to yearly periodicities and their harmonics (six and three months, for example). These frequencies are removed, and the resulting data show general trends, while allowing sharp changes to be displayed without the 12-month smoothing inherent in Eq. (2) above.

This technique is most easily applied by taking the discrete Fourier transform[14] of the 168-month-long data set (after padding each end with the first and last 12 months of data, respectively). The discrete Fourier transform F_n is at frequency n is constructed for N data points as:

$$F_n = \frac{1}{\sqrt{N}}\sum_{k=0}^{N-1} \text{Data}_k\, e^{-k2\pi\sqrt{-1}/N} \qquad (3)$$

For data sampled at one-month intervals, the maximum frequency in the transformed data is two months. This restriction, known as the Nyquist sampling theorem, states that a time series must be sampled at twice the frequency at which accurate data is desired. This restriction is not a serious limitation for the monthly electricity data series, as semi-monthly information is sufficient to

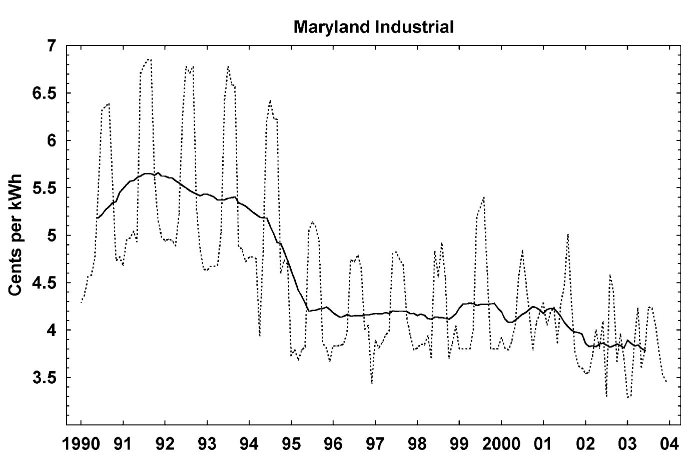

Figure 10: Centered 12-Month Average Applied to Maryland Industrial Monthly Price Data

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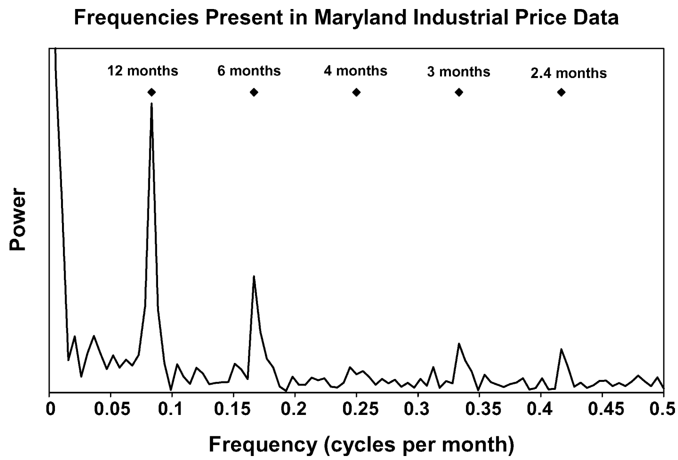

Figure 11: Frequency Spectrum of Maryland Industrial Price Data. Diamonds Mark the Frequencies Corresponding to the Annual Periodicity and its First Four Harmonics. The Power at Zero Frequency Arises From the Average Price for the 14 Years of Data

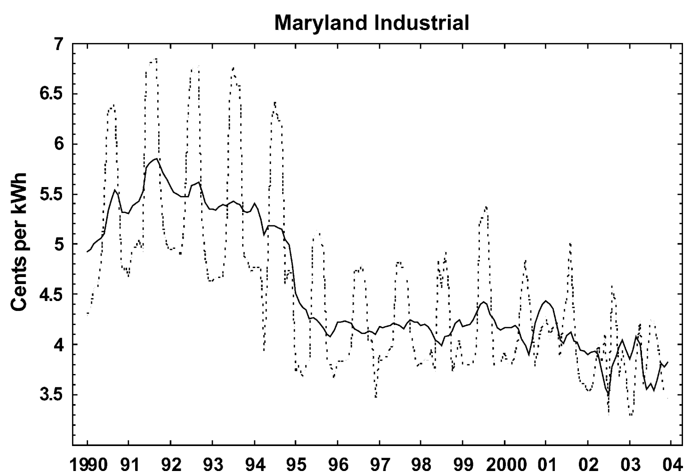

Figure 12: Fourier Transform Applied to Monthly Price Data

analyze behavior. **Figure 11** is the frequency spectrum of the Maryland industrial price data of Figure 9.

The spikes arising from the five frequencies corresponding to periods of 12, 6, 4, 3, and 2.4 months

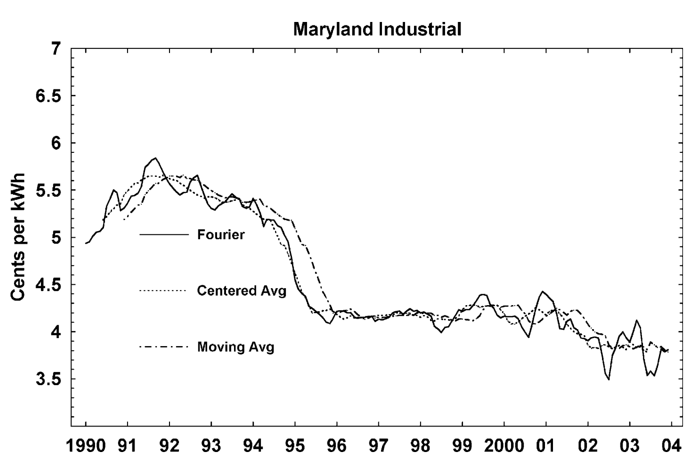

Figure 13: Comparison of Three Techniques for Reducing Seasonal Periodicities

(the annual periodicity and its first four harmonics) were removed by first setting the power at that frequency equal to the average of that at the frequency immediately below and above, then smoothed by a 7-point Gaussian filter of the form

$$\frac{e^{-k^2/2\sigma^2}}{\sigma\sqrt{2\pi}} \tag{4}$$

where frequency k runs from 3 points below the center of the spike to 3 points above, and σ is set to 1.2 so that the center frequency of the filter contains ~1/3 of the area. The data are then re-transformed to the time domain; **Figure 12** shows the result.

The results of the three techniques are compared in **Figure 13**. It is apparent that the 12-month trailing moving average displays a lag of several months in responding to the price changes in 1995, 2000, and 2001. The centered average and Fourier transform techniques give similar results. We have used the latter in this work to capture short-term behavior of the data, but our conclusions are identical when we use the centered average technique.

Other techniques are feasible, such as asymmetric averages. However, the essential features of the data are well characterized by either the Fourier or centered average technique.

Endnotes:

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  doi:/10.1016/j.tej.2005.02.006

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8. U.S. Energy Information Administration (EIA) (2004), *Historical 1990 through Current Month Retail Sales, Revenues, and Average Retail Price of Electricity by State and by Sector*, accessed via http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls and *Form EIA-826 Database Monthly Electric Utility Sales and Revenue Data*, accessed through http://www.eia.doe.gov/cneaf/electricity/page/eia826.html.

9. As noted by EIA, ''For the 2003 period forward, the Transportation consumer sector replaces the Other sector which included public street lighting, public buildings, electrified rail and transit systems and some agricultural sector data such as irrigation load. The Transportation sector consists entirely of electrified rail and urban transit systems. Data previously reported under the Other consumer sector have been relocated to the Commercial sector for 2003. Agriculture-related data (i.e., irrigation load) previously reported in the Other sector have been relocated to the Industrial sector where identified.'' See http://www.eia.doe.gov/cneaf/electricity/page/eia861.html.

10. For example, U.S. Energy Information Administration (EIA) (2004), *Natural Gas City Gate Price 1983–2004*, accessed via http://tonto.eia.doe.gov/dnav/ng/hist/n3050us3m.htm.

11. U.S. Energy Information Administration (EIA) (2004), *State Electricity Profiles 2002, Table 5*, accessed via http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html.

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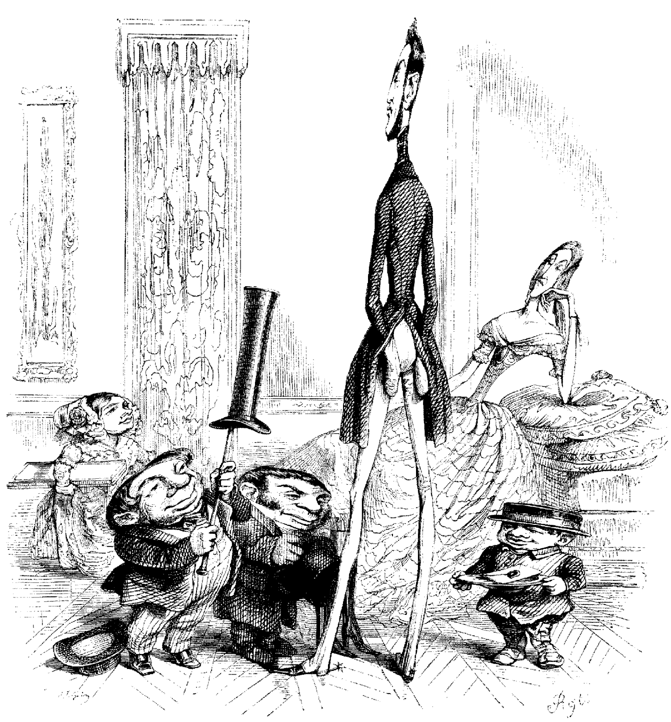

Other techniques are feasible, such as asymmetric averages.

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Electric utility deregulation: Stranded costs vs. stranded benefits

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Abstract

This study re-examines the electric utility market value-book value relation in light of the changing regulatory climate. The change in the market value-book value relation is examined by comparing the market-to-book ratio in the post-regulatory period to the regulatory period. Additionally, this paper compares the stock market's valuation of electric utility stranded costs (above market costs) to stranded benefits (below market costs). This paper demonstrates that electric utility market value and book value are no longer aligned. Additionally, this paper extends the research on deregulatory effects by documenting a differential market response to estimated stranded costs versus stranded benefits.

Keywords: Electric utilities; Deregulation; Stranded costs; Market valuation

1. Introduction

This paper considers the stock market's valuation of electric utility stranded costs and stranded benefits. Stranded costs are above-market costs,

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i.e., assets with a book value that exceeds their estimated market value. Stranded benefits are items with an estimated market value that exceeds their book value. Net stranded costs measure total stranded costs minus total stranded benefits. After federal and state deregulation in the 1990's, estimates of net stranded costs ranged from $150 to $300 billion, (Moody's, 1995, pp. 1–18). Resource Data International[1] estimates net stranded costs at $143 billion for investor-owned electric utilities, which includes total stranded costs of $202 billion less total stranded benefits of $59 billion. The market's perception of the recoverability of stranded costs and stranded benefits may affect the relation between market value and book value. There is very little history of stranded costs, and prior research does not address stranded benefits. This study re-examines the relation between electric utility market value of equity and book value of equity, examines the market's response to stranded costs versus stranded benefits, and investigates whether investors value stranded benefits.

Traditionally, under rate-of-return regulation[2] regulators set electric utility prices to cover operating costs plus an allowed return on investment. Nwaeze (1998, pp. 547–573), demonstrates an average electric utility market-to-book ratio of 1.0 prior to deregulation. He suggests the alignment is a natural result of rate regulation; utilities are expected to recover operating costs plus a normal return on invested capital. However, the Energy Policy Act of 1992 (EPA) substantially altered the regulatory climate for electric utilities. This paper extends Nwaeze and demonstrates that electric utility market value and book value are no longer aligned, in fact, the market-to-book ratio of electric utilities increased during the post-regulatory period. Furthermore, the increase in the market-to-book ratio was greater for firms with stranded benefits.

D'Souza and Jacob (2001, pp. 495–512), consider the stock market's valuation of stranded costs and find a significant negative association between electric utility stock prices and estimates of utility-specific stranded costs. This paper extends D'Souza and Jacob by considering stranded benefits, and documents a differential market response to estimated stranded costs versus stranded benefits. The results suggest that the market responds differentially to stranded costs and stranded benefits associated with generating assets. This

[1] Resource Data International, Inc. is recognized as an independent industry leader in electric power market information in the United States.

[2] In practice, some regulatory commissions also use incentive-based regulation (Schmalensee and Joskow, 1986). "Regulatory Lag" functions as an implicit incentive scheme, whereby utilities experience excess profits/losses from positive shocks, until rates are revised. Explicit incentive schemes allow utilities to earn higher rates of return if they achieve certain efficiencies, and lower rates of return for inefficiencies.

suggests that the market positively values stranded benefits viewed as being more sustainable under competition.

This study provides further evidence of the effects of deregulation by examining the market value – book value relation and stranded benefits. Consistent with prior research, regulatory effects, stranded costs and stranded benefits are important to investors in electric utilities, and may have important financial consequences.

The remainder of this paper is organized as follows. Section 2 contains background information on the electric utility industry. Section 3 describes the research methodology. Results are presented in Section 4 and Section 5 contains concluding remarks.

2. Background

2.1. Industry overview

Technological advances and increased desire for customer choice spurred the demand for deregulation of the electric utility industry. The 1978 Public Utilities Regulatory Policies Act (PURPA) allowed certain non-utilities to enter the wholesale market and was the first move toward creating more competitive markets. PURPA was designed to promote fossil fuel conservation by requiring utilities to purchase power from non-utility generators that produced electricity using renewable energy resources and cogeneration. The Energy Policy Act of 1992 (EPA) promoted competition in wholesale electricity markets by opening access to transmission networks, which resulted in fundamental changes in the electric utility industry and substantially altered the regulatory climate for electric utilities. While the intent of PURPA was to promote development of independent power from non-utility generators, the intent of the EPA was to promote competition. Besanko et al. (2001, pp. 65–88), cite two broad effects of the EPA: it opened up the wholesale market to competition and it increased the momentum toward deregulation in the retail market. The increased momentum toward deregulation was expected to ultimately provide access to market-priced power, which would drive retail power rates down to a level that creates stranded costs.

The EPA eliminated the power-generation monopoly at the electric plant level and encouraged state legislatures and regulatory commissions across the country to begin exploring direct retail access (referred to as retail wheeling[3]) for electricity consumers. More than 20 states have already

[3] Retail wheeling – a transmission or distribution service by which utilities deliver electric power sold by a third party directly to retail customers. This would allow an individual retail customer to choose his or her electricity supplier, but still receive delivery using the power lines of the local utility (Edison Electric Institute February, 2000).

introduced some form of retail wheeling.[4] As the power-generation monopoly was eliminated, some utilities were faced with excess capacity and the immediate prospect of competition that was expected to drive down prices for generated power and ultimately lower the market value of expensive, inefficient power plants. Accordingly, during the transition to a more competitive market, some capitalized costs are being rendered obsolete or uncompetitive and therefore unrecoverable. The net effect is that certain assets or portions of assets are left ‘‘stranded’’ relative to the market. However, some utilities are in very competitive positions with largely depreciated, efficient, high-market value power plants. These assets represent stranded benefits.

2.2. Stranded costs and stranded benefits

There are three major categories of stranded costs: regulatory assets[5], generating plants, and long-term contracts. Regulatory assets are expenses that are deferred by state regulatory commissions to minimize the level and volatility of electricity rates. Regulatory assets include large ‘‘one-time’’ expenses, however, the bulk of the value is in deferred federal taxes and pensions (Loxley, 1999, pp. 95–104). The large difference between book and tax depreciation on generating assets results in a deferred tax liability. The related tax expense, normally expensed under GAAP, is deferred and reported as a regulatory asset. Similarly, the accrual of pension benefits, normally expensed under GAAP, are deferred and reported as a regulatory asset.

Under rate-of-return regulation, regulators try to minimize price increases by allowing for cost recovery of generating plants slowly over long depreciable lives (30–40 years), (Loxley, 1999, pp. 95–104). As a result, these assets may have excessive book values. In a deregulated environment, some utilities may be unable to recover a large portion of their investment in generating plants, particularly nuclear power plants.

[4] As of February 2003, 24 states (including Washington, D.C.) have either enacted legislation or issued a regulatory order to implement retail access. However, five of those states have delayed implementation of retail access and one of those states has suspended retail access. Furthermore, 27 states are not actively pursuing restructuring.

[5] Regulatory assets are deferred expenses capitalized in accordance with SFAS No. 71 (FASB, 1982). They are costs that have been incurred with the expectation that the regulator will allow for future recovery. In a non-regulated enterprise such costs are ordinarily charged against current income. Typical regulatory assets include: extraordinary property losses from storm or other damage, and environment cleanup costs; unrecovered and abandoned plant and regulatory study costs; deferred income taxes; deferred fuel costs; pension and other benefits; and demand side management programs.

Nuclear power plants[6] represent a significant portion of stranded costs from generating plants. Most of these plants suffer from poor operating performance resulting in high production costs. Studness (1995, pp. 38–40) suggests that most of the stranded nuclear power plants stem from the 34 nuclear power plants that were placed in service after 1984. These 34 units account for approximately 70% of the electric utility industry's investment in generating assets.

Long-term contracts to purchase and sell electricity from utility and nonutility generators were frequently encouraged or even mandated by state regulatory commissions to ensure supply and eliminate price risk.[7] Most long-term contracts were written prior to 1990 and are based on energy prices[8] that were in effect prior to deregulation of the wholesale market (Loxley, 1999, pp. 95–104). After deregulation of the wholesale market in the early 1990's, fuel and power prices declined. As a result, some utilities were legally bound to purchase/sell power at "above/below-market" rates. Under rate-of-return regulation, the cost of purchased power is considered a reasonable operating cost, and therefore a regulated utility can pass on any above-market costs to its captive customers. In a competitive market, any excess of the contract price over the market price may not be recoverable in electricity rates. As a result, some long-term purchase contracts may have a stranded cost component. Moreover, in a competitive market, any excess of the market price over the sales price may not be recoverable in electricity rates. As a result, some long-term sales contracts may have a stranded cost component.

There are three categories of stranded benefits: generating plants, regulatory liabilities, and long-term contracts. Generating plants includes largely depreciated coal-fired and hydro generation assets. These low-cost facilities have high market values that exceed their depreciated book values (Resource Data International, Inc., (RDI), 1997). Regulatory liabilities include unearned revenue[9],

[6] Nuclear power plants have long been considered the white elephants of the electricity generation industry, and a nuclear power plant has not been built in the U. S. in over 22 years. However, some utilities are updating their nuclear power plants with the latest technology and safety systems. Also, the current political administration has streamlined the building process and encouraged increased production at nuclear power plants. Additionally, the recent combination of higher prices for natural gas and petroleum, and the energy shortage in California have created new interest in nuclear power. This sudden interest might increase the market value of nuclear power plants. However, estimates of stranded nuclear power plants used in this study predate the recent renewed interest in nuclear power.

[7] The electric utility industry relies on various fuel sources to generate electricity including coal, nuclear power, natural gas, petroleum and renewable sources.

[8] Recently, natural gas and petroleum supplies have fallen and prices have surged, while coal supplies remain abundant with generally favorable pricing. As a result, some long-term purchase contracts may no longer be above market. However, estimates of above-market long-term purchase contracts used in this study are based on energy prices after deregulation of the wholesale market and prior to the recent increases in petroleum and natural gas prices.

[9] Revenues are recorded when billed, however, any excess amounts collected (over-recovery) are recorded as unearned revenue and returned to customers in subsequent periods.

Table 1
Summary of stranded costs and stranded benefits

	Total stranded costs	Total stranded benefits	Net stranded costs
Panel A (initial sample)[a]			
$N = 114$ (*in billions*)			
Generating assets	$ 58	$31	$27
Regulatory	56	1	55
Long-term contracts	54	14	40
Total	$168	$46	$122
Panel B (final sample)[b]			
$N = 82$ (*in billions*)			
Generating assets	$44.666	$24.920	$19.746
Regulatory	41.522	0.281	41.241
Long-term contracts	45.146	5.193	39.953
Total	131.334	30.394	100.940

[a] 114 Investor-owned utilities.
[b] Thirty-two firms were eliminated because of missing Compustat and Value Line data.

deferred gains and deferred taxes. Deferred gains and taxes normally would be recognized as income under GAAP, however, state regulatory commissions defer recognition until the revenue can be matched with the related cost, or to minimize the level and volatility of electricity rates. Unearned revenue is deferred until the related utility operating cost is incurred, or until any excess amounts (over-recovery) are returned to customers in subsequent periods. Under rate-of-return regulation, regulators specify the means of recovery or refund of regulatory liabilities to customers through the ratemaking process. However, in a competitive market, regulatory liabilities may exceed the related utility operating expense, and utilities may not be required to refund these amounts or adjust rates. As a result, regulatory liabilities may have a stranded benefit component. Additionally, stranded benefits include low-cost, long-term contracts to sell electricity at "above-market" rates, and long-term contracts to purchase electricity at "below-market" rates.

In a study completed by RDI (1997)[10], total stranded costs and total stranded benefits are estimated at $202 billion and $59 billion, respectively, resulting in net stranded costs of $143 billion as of 1997. Investor-owned utilities account for $122 billion; public utilities for $10 billion; and cooperatives for $11 billion. RDI's study includes a detailed, plant-by-plant analysis of stranded costs and stranded benefits for every utility in the country. The components of the estimated $122 billion of net stranded costs for the 114 investor-owned utilities are summarized in Table 1 Panel A.

[10] I am grateful to Don Pagach and Bob Peace for making available their Resource Data International Inc. data for this study.

Estimates of stranded costs and stranded benefits are based on predictions of post-regulation prices, application of supply and demand, and cost–volume–profit analysis (Freemont et al., 1995, pp. 1–18).

3. Research methodology

3.1. Market values

Under traditional rate-based regulation, state regulatory commissions set rates to cover both operating and capital costs. Operating cost changes and additional capital investment are considered when the commission reviews the existing rates in what is called a "rate case." Some rate cases may lead to entirely new rate structures with higher or lower rates of return, or future cash flows may remain at the same levels based on the target rate-of-return allowed by the regulatory commission. If rates were revised continuously, then revenues would equal operating costs plus a return on the investment base, and the market value of the utility would equal its book value. In practice, rates are only revised periodically leading to a 'regulatory lag' during which changes in earnings may persist for a short time.

Teets (1992, pp. 274–285), examines the earnings–return relationship of non-regulated firms vs. regulated firms and finds a smaller earnings-return relationship for regulated firms. Teets concludes that regulation 'buffers' or shelters utilities from changes in the operating environment.

Nwaeze (1998, pp. 547–573), extends Teets (1992, pp. 274–285), and assesses the effectiveness of rate-of-return regulation by examining the alignment between the market value of equity and the book value of equity. He finds that over a period of relatively stable rate regulation, the difference between market values and book values for electric utilities is not statistically significant. However, the difference between market values and book values for a sample of non-regulated manufacturing firms is statistically significant. He concludes that rate-of-return regulation is reasonably effective in aligning market value with book value.

However, the changing regulatory climate and increasing competition in generation and transmission of wholesale power has changed investors' perceptions of the relative role of book value in firm valuation. Blacconiere et al. (2000, pp. 231–260) find a decrease in the relative importance of book value in explaining price. Other studies use event study methodology to test abnormal returns surrounding key legislative events leading up to and including the enactment of the EPA. Johnson et al. (1998, pp. 285–309) and Nwaeze (2000, 49–67), find significantly negative effects on stock values, but, Besanko et al. (2001, pp. 65–88) find neutral stock price reactions.

The prior research demonstrates deregulation effects on stock values by capturing the uncertainty held by investors over a few days, and relative to the general market. However, event studies cannot address whether the level of market value has changed such that market value is above or below book value in the post-regulatory period. In a deregulated, competitive market, electric utilities are free to pursue operating strategies that could generate returns in excess of regulated returns. Moreover, firms operating in competitive markets are not required to refund abnormal profits to customers. As market prices impound the expected effects of future earnings, the market value should increase relative to book value, resulting in less alignment of market value with book value. Consistent with Nwaeze's findings, we should expect the market value-book value relation of electric utilities to change. Hence, electric utilities in the post-regulatory period should have a market value-book value relation that is greater than one. This predicted change in the market value-book value relation is tested using a T-test to compare means.

After the passage of PURPA, the electric utility industry remained regulated and firms continued to be protected against cost and demand shocks under rate-of-return regulation. However, the EPA precipitated significant regulatory changes[11]. Therefore, this study defines the period subsequent to the enactment of the EPA as the post-regulatory period (1993–1997). The key legislative events leading up to and including the enactment of the EPA make-up the legislative period (1991–1992). The years prior to the legislative period (1970–1990) are considered to be the regulatory period, consistent with Nwaeze (1998, pp. 547–573).

3.2. Stranded costs vs. stranded benefits

The prior research focuses on the stock market's valuation of net stranded costs: total stranded costs minus total stranded benefits, and does not consider the structural differences between stranded costs and stranded benefits, and possible differential market expectations about recovery. Many analysts believe that not all utilities will be affected by deregulation to the same extent (Feiler and Seiple, 1994, pp. 14–15). It is generally recognized that the level of stranded costs is primarily related to the firm's ability to be cost-competitive in a deregulated environment. Production costs differ significantly across utilities. Some

[11] The Energy Policy Act of 1992 was enacted into law on October 24, 1992; however, it was preceded by the introduction of deregulation legislation into the federal legislature in early 1991, and several other key legislative events in 1991 and 1992. Johnson et al. (1998, pp. 285–309) find a significant negative market reaction during this legislative period. This study defines the post-regulatory period as the years following the legislative period, 1993–1997 and the regulatory period as the years preceding the legislative period, 1970–1990, consistent with (Nwaeze, 1998, pp. 547–573).

utilities enjoy fixed production costs[12] advantages, which are mainly driven by differences in the degree to which utilities invested in nuclear power facilities. It is unlikely that these utilities would realize significant competitive advantages in a deregulated environment, because changes in technology have probably undermined the sustainability of fixed production costs advantages. Variable production costs[13] advantages may be more sustainable because they are usually utility-specific, and more difficult to replicate. As a result, recovery of generating assets stranded benefits should be driven by the sustainability of the underlying costs, and there should be cross-sectional differences.

It is likely that investors have different expectations about recovery of stranded costs and stranded benefits. As demonstrated by D'Souza and Jacob (2001, pp. 495–512) recovery of stranded costs depends on whether the stranded items have arisen from voluntary firm business decisions or regulatory mandates. However, recovery of stranded benefits depends on sustainability of cost advantages. Besanko et al. (2001, pp. 65–88) find that investors expect low-marginal cost utilities to enjoy valuable and sustainable cost advantages in deregulated markets, while low fixed costs utilities are not expected to benefit from deregulation.

This study extends the prior research by investigating whether stranded costs and stranded benefits are valued differently. In this regard, the study extends D'Souza and Jacob (2001, pp. 495–512) by providing further evidence of the effects of deregulation on the association between market values and book values.

This study predicts a differential response to stranded costs versus stranded benefits. To test this prediction, a generic equation consistent with D'Souza and Jacob (2001, pp. 495–512) is used:

$$\mathrm{MVE}_i = a_0 + a_1\mathrm{BVE}_i + a_2\mathrm{NI}_i + a_3\mathrm{TOTSC}_i + a_4\mathrm{TOTSB}_i + \boldsymbol{\varepsilon}_i \tag{1}$$

where the variables are defined as: MVE_i is the market value of equity, firm i, 1997; BVE_i is the book value of equity, firm i, 1997; NI_i is the net income, firm i, 1997; TOTSC_i is the total stranded costs, firm i, 1997; TOTSB_i is the total stranded benefits, firm i, 1997; $\boldsymbol{\varepsilon}_i$ is a random error term.

Total stranded costs and total stranded benefits are estimated using the most recent estimates available: RDI (1997) plant-by-plant estimates. Market value of equity, book value of equity, net income, total stranded costs, and total stranded benefits are scaled by outstanding common shares to mitigate spurious correlation related to size.

Furthermore, firms with net stranded benefits (total stranded benefits exceed total stranded costs) that have a sustainable competitive advantage should

[12] Fixed costs include nonvariable operations and maintenance costs, and depreciation charges.

[13] Variable costs include the cost of fuel, plus the variable component of nonfuel operations and maintenance costs.

have a market-to-book ratio that is greater than firms with net stranded costs (total stranded costs exceed total stranded benefits). This predicted market-to-book relationship between firms with net stranded costs versus firms with net stranded benefits is tested using a *T*-test to compare means.

3.3. Sample and data sources

The initial sample consists of investor-owned utilities included in Standard Industrial Classifications [SICs] 4911 and 4931, that are included in both Compustat and The Value Line Investment Survey. Market values and financial statement data were obtained from Compustat. To be consistent with Nwaeze (1998, pp. 547–573), book value data was obtained from the Value Line Investment Survey. Value Line's book value data includes regulatory assets recognized under SFAS No. 71. Resource Data International, Inc. (RDI)'s most recent (1997) stranded cost and stranded benefit estimates were used. The final sample consists of 82 investor-owned electric utilities due to missing Compustat and Value Line data. RDI (1997) estimates $101 billion of net stranded costs for the 82 firms included in this sample. The net stranded costs estimate includes $131 billion of total stranded costs minus $30 billion of total stranded benefits. The components of RDI's (1997) estimate for the 82 firms included in this study are summarized in Table 1, Panel B.

4. Results

4.1. Market values

Table 2 reports descriptive statistics for electric utility market-to-book ratios and addresses the predictions in Section 3.1. Panel A reports results for the full sample. Panels B and C report results for firms with net stranded costs (firms with total stranded costs that exceed total stranded benefits), and firms with net stranded benefits (firms with total stranded benefits that exceed total stranded costs), respectively. As indicated in Table 2, Panel A, average net stranded costs are $1,231 billion. Net stranded cost firms (firms with total stranded costs that exceed total stranded benefits) have on average $2,246 billion of net stranded costs (Panel B), which represents 115% of their equity book value. Net stranded benefit firms (firms with total stranded benefits that exceed total stranded costs) have on average $439 million of net stranded benefits (Panel C), which represents 54% of their equity book value.

Table 2 also reports market-to-book ratios for the regulatory period (1970–1990), the post-regulatory period (1993–1997), and end-of-year 1997. The results in Panel A (all firms) confirm that the market-to-book ratio during the regulatory period (1970–1990), 0.962, was not significantly different from

Table 2
Descriptive statistics of firms

Item	Mean	Std dev	Max	Median
Panel A (all firms) N = 82				
M/B ’70–’90	0.962	0.402	3.986	0.886
M/B ’93–’97	1.591[a]	0.469	3.578	1.485
M/B ’97	1.816[a]	0.584	4.486	1.733
BK VAL ’97	2,128.20	2,147.78	9,763.39	1,401.59
NET SC (BEN)	1,230.99	2,437.99	9,647.85	440.79
TOTSC	1,601.65	2,310.78	9,944.68	716.56
TOTSB	370.66	597.27	3,589.48	154.33
GENSC	544.71	1,330.08	8,075.17	34.03
GENSB	303.90	557.14	3,250.32	0
REGSC	506.37	639.77	2,914.41	250.46
REGSB	3.43	13.20	88.24	0
PCSC	550.57	1,178.44	7,865.74	48.39
PCSB	63.33	161.95	1,143.48	0
Panel B (firms with net stranded costs) N = 51				
M/B ’70–’90	0.951	0.462	3.986	0.885
M/B ’93–’97	1.475[a]	0.400	3.331	1.423
M/B ’97	1.647[a]	0.425	2.685	1.628
BK VAL ’97	2,573.37	2,281.50	9,763.39	2,013.97
NET SC (BEN)	2,246.00	2,593.52	9,647.85	1,144.37
TOTSC	2,406.43	2,611.40	9,944.68	1,473.36
TOTSB	160.42	284.98	1,164.14	0
GENSC	870.70	1,605.64	8,075.17	298.70
GENSB	109.09	265.25	1,164.14	0
REGSC	703.51	693.90	2,914.41	475.32
REGSB	0.61	3.80	26.83	0
PCSC	832.22	1,419.85	7,865.74	203.13
PCSB	50.72	115.93	567.22	0
Panel C (firms with net stranded benefits) N = 31				
M/B ’70–’90	0.980	0.285	2.100	0.886
M/B ’93–’97	1.781[a]	0.515	3.578	1.693
M/B ’97	2.095[a]	0.700	4.486	1.880
BK VAL ’97	1,395.82	1,699.54	7,541.40	748.74
NET SC (BEN)	−438.88	452.59	−1,882.65	−234.04
TOTSC	277.66	372.85	1,706.83	132.22
TOTSB	716.54	793.13	3,589.48	380.61
GENSC	8.41	43.95	244.74	0
GENSB	624.40	741.73	3,250.32	341.77
REGSC	182.04	357.57	1,706.83	39.64
REGSB	8.05	20.27	88.24	0
PCSC	87.21	181.38	796.97	9.00
PCSB	84.09	218.41	1,143.48	0

(*continued on next page*)

Table 2 (*continued*)

M/B (Market-to-book) is defined as market value of equity divided by book value of equity.
BK VAL is defined as book value of equity (in millions).
NET SC (BENE) is defined as total stranded costs minus total stranded benefits as estimated by Research Data Inc., 1997 (in millions).
TOTSC is defined as total stranded costs as estimated by Research Data Inc., 1997 (in millions).
TOTSB is defined as total stranded benefits as estimated by Research Data Inc., 1997 (in millions).
GENSC is defined as generating assets stranded costs, as estimated by Research Data Inc., 1997 (in millions).
GENSB is defined as generating assets stranded benefits, as estimated by Research Data Inc., 1997 (in millions).
REGSC is defined as regulatory assets stranded costs, as estimated by Research Data Inc., 1997 (in millions).
REGSB is defined as regulatory stranded benefits, as estimated by Research Data Inc., 1997 (in millions).
PCSC is defined as long-term purchase contracts stranded costs, as estimated by Research Data Inc., 1997 (in millions).
PCSB is defined as long-term sales contracts stranded benefits, as estimated by Research Data Inc., 1997 (in millions).
[a] Significantly different from 1.0 at $p < 0.05$.

one. However, the post-regulatory period (1993–1997) market-to-book ratio, 1.59, indicates that electric utility market-to-book ratios have increased and are significantly different from one. The end-of-year, 1997 ratio, 1.82, is also significantly different from one. Panels B and C indicate the results are consistent when the sample is partitioned into firms with net stranded costs and firms with net stranded benefits. These results suggest market value and book value are no longer aligned and demonstrate that electric utilities have a market value-book value relation that is greater than one in the post-regulatory period, consistent with the prediction in Section 3.1. Also, these results are consistent with prior research, (Nwaeze, 1998, pp. 547–573) which demonstrates nonregulated firms have a market value-book value relation that is greater than one. These changes are also consistent with investors recognizing that electric utilities are now faced with less regulatory oversight and more growth opportunities.

Alternatively, general market movements could be suggested as an explanation for the increase in electric utility market-to-book ratios. However, in a supplemental analysis not reported here, electric utilities (versus other industries) experienced a significant differential effect on market-to-book ratios during the post-regulatory period.

Pearson correlation coefficients are reported in Table 3. Table 3 indicates a significantly negative correlation between total stranded costs and the 1997 market-to-book ratio, and a significant positive correlation between total stranded benefits and the 1997 market-to-book ratio. Also, there is an insignificant negative correlation between total stranded costs and total stranded benefits.

Table 3
Pearson product-moment correlations for 1997 between stranded cost/benefit estimates and other firm characteristics (significance levels in parentheses) $N = 82$

	NI	NETSC	TOTSC	TOTSB	GENSC	GENSB	REGSC	REGSB	PCSC	PCSB
MV/BV	0.11	−0.41	−0.35	0.34	−0.30	0.38	−0.30	0.09	−0.18	−0.08
	(0.33)	(0.00)	(0.00)	(0.00)	(0.01)	(0.00)	(0.01)	(0.43)	(0.10)	(0.48)
NI		0.13	0.21	0.29	−0.09	0.29	0.36	−0.09	0.32	0.08
		(0.26)	(0.06)	(0.01)	(0.42)	(0.01)	(0.00)	(0.42)	(0.00)	(0.48)
NETSC			0.97	0.33	0.75	0.32	0.78	−0.16	0.63	−0.11
			(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.15)	(0.00)	(0.34)
TOTSC				−0.09	0.75	−0.09	0.84	−0.17	0.66	−0.02
				(0.42)	(0.00)	(0.43)	(0.00)	(0.14)	(0.00)	(0.89)
TOTSB					−0.19	0.96	0.10	0.02	−0.01	0.37
					(0.09)	(0.00)	(0.38)	(0.89)	(0.90)	(0.00)
GENSC						−0.23	0.55	−0.10	0.03	0.09
						(0.04)	(0.00)	(0.37)	(0.78)	(0.45)
GENSB							−0.08	−0.02	−0.04	0.11
							(0.48)	(0.84)	(0.72)	(0.32)
REGSC								−0.21	0.48	0.11
								(0.06)	(0.00)	(0.34)
REGSB									0.10	−0.10
									(0.37)	(0.36)
PCSC										−0.18
										(0.10)

M/B (Market-to-book) is defined as market value of equity divided by book value of equity, 1997.
NI is defined as net income, 1997.
BK VAL is defined as book value of equity, 1997.
NET SC (BENE) is defined as total stranded costs minus total stranded benefits as estimated by Research Data Inc., 1997.
TOTSC is defined as total stranded costs as estimated by Research Data Inc., 1997.
TOTSB is defined as total stranded benefits as estimated by Research Data Inc., 1997.
GENSC is defined as generating assets stranded costs, as estimated by Research Data Inc., 1997.
GENSB is defined as generating assets stranded benefits, as estimated by Research Data Inc., 1997.
REGSC is defined as regulatory assets stranded costs, as estimated by Research Data Inc., 1997.
REGSB is defined as regulatory stranded benefits, as estimated by Research Data Inc., 1997.
PCSC is defined as long-term purchase contracts stranded costs, as estimated by Research Data Inc., 1997.
PCSB is defined as long-term sales contracts stranded benefits, as estimated by Research Data Inc., 1997.

4.2. Stranded costs vs. stranded benefits

To test for a differential market response to stranded costs versus stranded benefits, Eq. (1) is estimated. The results are presented in Table 4. Consistent with prior research on stranded costs, the results for all firms (Panel A) indicate the coefficient on total stranded costs is significantly negative (−0.160), which suggests the stock market expects investors to bear a portion of stranded costs. The coefficient on total stranded benefits is insignificant. More importantly, the difference between the coefficient on total stranded costs (a_3) and the coefficient on total stranded benefits (a_4) is marginally significant ($p = 0.10$). Hence, market valuations of stranded costs and stranded benefits differ systematically across firms.

The negative coefficient on total stranded costs captures on average the extent to which the stock market discounts the excess of book value over market value. The positive coefficient on total stranded benefits captures on average the extent to which the stock market values the excess of market value over book value. Although the coefficient on total stranded benefits is positive, it is insignificant, which likely reflects market uncertainty surrounding the ability of firms to use their competitive advantages to realize excess rates. These expectations are consistent with a post-regulatory market

Table 4
Estimates of the regression of the market value of common equity on the book value of equity, net income and total stranded costs/benefits estimates

	a_0	a_1	a_2	a_3	a_4	Adj R^2	N
Panel A[a]							
Coefficient	9.680	1.149	2.270	−0.160	0.023	47.03	82
(t-Statistic)	(2.79)*	(5.84)*	(2.80)*	(−3.88)*	(0.33)		
Panel B[b]							
Coefficient	8.281	1.236	0.869	−0.142	0.822	61.23	51
(t-Statistic)	(2.34)*	(6.44)*	(1.27)	(−3.98)*	(2.29)*		
Panel C[c]							
Coefficient	−3.773	0.978	10.882	0.562	0.257	68.82	31
(t-Statistic)	(−0.68)	(3.12)*	(5.06)*	(1.22)	(1.78)**		

$$\mathrm{MVE}_i = a_0 + a_1\mathrm{BVE}_i + a_2\mathrm{NI}_i + a_3\mathrm{TOTSC}_i + a_4\mathrm{TOTSB}_i + \varepsilon_i \quad (1)$$

where the variables are defined as MVE is the market value of equity, firm i, 1997; BVE is the book value of equity, firm i, 1997; NI is the net income, firm i, 1997; TOTSC is the total stranded costs, firm i, 1997; TOTSB is the total stranded benefits, firm i, 1997; ε_i is a random error term.

[a] All firms.

[b] Firms with net stranded costs.

[c] Firms with net stranded benefits.

* Statistically significant at $p < 0.05$.

** Statistically significant at $p < 0.10$.

characterized by increased uncertainty and risk. Johnson et al. (1998, pp. 285–309), document increases in firm-specific and market risk, and Nwaeze (2000, pp. 49–67) finds an increase in systematic risk. The results for firms with net stranded costs (Panel B) indicate the coefficients on total stranded costs (−0.142) and total stranded benefits (0.822) are both significant ($p < 0.05$), and the difference between the coefficients is marginally significant ($p = 0.07$). However, the results for firms with net stranded benefits (Panel C) indicate that the coefficient on total stranded benefits is only marginally significant ($p = 0.09$) and the difference between the coefficients on total stranded costs and total stranded benefits is insignificant. These results likely reflect market expectations regarding stranded costs recoverability and stranded benefits sustainability.

D'Souza and Jacob (2001, pp. 495–512) consider market valuation of stranded cost components, i.e., generating assets, regulatory assets and purchase contracts, and find stranded costs related to generating assets and regulatory assets are valued more negatively than stranded costs related to purchase contracts. Given the differential market response to stranded costs versus stranded benefits documented in Table 4, Eq. (2) is estimated and total stranded costs and total stranded benefits are replaced by their individual components.

$$\begin{aligned}\mathrm{MVE}_i = a_0 + a_1\mathrm{BVE}_i + a_2\mathrm{NI}_i + a_3\mathrm{GENSC}_i + a_4\mathrm{GENSB}_i \\ + a_5\mathrm{REGSC}_i + a_6\mathrm{REGSB}_i + a_7\mathrm{PCSC}_i + a_8\mathrm{PCSB}_i + \varepsilon_i \end{aligned} \tag{2}$$

where the variables are defined as: MVE_i is the market value of equity, firm i, 1997; BVE_i is the Book value of equity, firm i, 1997; NI_i is the net income, firm i, 1997; GENSC_i is the generating assets stranded costs, firm i, 1997; GENSB_i is the generating assets stranded benefits, firm i, 1997; REGSC_i is the regulatory assets stranded costs, firm i, 1997; REGSB_i is the regulatory assets stranded benefits, firm i, 1997; PCSC_i is the purchase contracts stranded costs, firm i, 1997; PCSB_i is the purchase contracts stranded benefits, firm i, 1997; ε_i is a random error term.

Results are reported in Table 5. All of the coefficients are directionally consistent with the results reported in Table 4, however, only the coefficient (0.53) on generating stranded benefits is significant. More importantly, the difference between the coefficients on generating stranded costs and generating stranded benefits is marginally significant ($p = 0.06$). The results suggest that the market responds differentially to stranded costs and stranded benefits associated with generating assets. This demonstrates that the market positively values stranded benefits viewed as being more sustainable under competition. The results (not reported here) are consistent for firms with net stranded costs, however, the results (not reported here) for firms with net stranded benefits are not significant.

Table 5
Estimates of the regression of the market value of common equity on the book value of equity, net income and total stranded costs/benefits estimates broken down by individual cost components

	A_0	a_1	a_2	a_3	a_4	a_5	a_6	a_7	a_8	Adj R^2	N
Coefficient	5.50	1.35	1.49	−0.15	0.53	−0.24	0.62	−0.10	−0.11	57.11	82
(t-Statistic)	(1.66)**	(6.68)*	(1.87)**	(−1.26)	(4.01)*	(−1.55)	(0.37)	(−1.34)	(−1.49)		

$$\mathrm{MVE}_i = a_0 + a_1\mathrm{BVE}_i + a_2\mathrm{NI}_i + a_3\mathrm{GENSC}_i + a_4\mathrm{GENSB}_i + a_5\mathrm{REGSC}_i + a_6\mathrm{REGSB}_i + a_7\mathrm{PCSC}_i + a_8\mathrm{PCSB}_i + \boldsymbol{\varepsilon}_i \quad (2)$$

where the variables are defined as MVE_i is the market value of equity, firm i, 1997; BVE_i is the book value of equity, firm i, 1997; NI_i is the net income, firm i, 1997; GENSC_i is the generating assets stranded costs, firm i, 1997; GENSB_i is the generating assets stranded benefits, firm i, 1997; REGSC_i is the regulatory assets stranded costs, firm i, 1997; REGSB_i is the regulatory assets stranded benefits, firm i, 1997; PCSC_i is the purchase contracts stranded costs, firm i, 1997; PCSB_i is the purchase contracts stranded benefits, firm i, 1997; $\boldsymbol{\varepsilon}_i$ is a random error term.

* Statistically significant at $p < 0.05$.

** Statistically significant at $p < 0.10$.

Table 6
Firms with net stranded costs vs. firms with net stranded benefits market-to-book ratio

	Regulatory period (1970–1990)	Post-regulatory period (1993–1997)	Post-Regulatory period (1997)
All firms ($N = 82$)	0.962	1.591[a,b]	1.816[a,b]
Firms with net stranded costs ($N = 51$)	0.951	1.475[a,b,c]	1.647[a,b,c]
Firms with net stranded benefits (N=31)	0.980	1.781[a,b,d]	2.095[a,b,d]

[a] Indicates statistically different from 1 at $p < 0.05$.
[b] Indicates statistically different from the regulatory period, 1970–1990 at $p < 0.05$.
[c] Statistically different from firms with net stranded benefits at $p < 0.05$.
[d] Statistically different from firms with net stranded costs at $p < 0.05$.

During the regulatory period (1970–1990), the market-to-book ratio of firms with net stranded costs (0.951) was not statistically different from the market-to-book ratio of firms with net stranded benefits (0.980). See the comparison summary in Table 6. However, during the post-regulatory period (1993-1997) the market-to-book ratio of firms with net stranded costs (1.475) is statistically different from firms with net stranded benefits (1.781). This is consistent with the prediction in Section 3.2. A higher market-to-book ratio for firms with net stranded benefits is consistent with some of those firms having competitive advantages over firms with net stranded costs. The results are consistent for the 1997 year-end numbers.

5. Conclusions

Recent federal and state deregulation has increased competition in the electricity generation industry and as a result, the market's perception of the recoverability of stranded costs may affect the relation between market value and book value. This study examines the relation between electric utility market value and book value over time, and the stock market's valuation of electric utility stranded costs and stranded benefits. The evidence demonstrates that market value and book value are no longer aligned. In fact, the market value-book value relation has increased throughout the post-regulatory period. This paper shows that electric utilities are beginning to look more like nonregulated firms. Consistent with Nwaeze (1998, pp. 547–573) nonregulated firms have a market value-book value relation that is greater than one. Moreover, the market-to-book ratio of stranded benefit firms is now statistically different from the market-to-book ratio of stranded cost firms.

Consistent with prior research, this study demonstrates that the stock market negatively values stranded costs. However, when net stranded costs are decomposed into total stranded costs and total stranded benefits, the market's response to stranded costs and stranded benefits differs systematically across firms. The implication is that stranded benefits are valued by investors, particularly stranded benefits related to generating assets that are thought to be more sustainable under competition.

The electric utility industry is still in the process of deregulation, although activity has slowed in some areas. The slow process of deregulation has allowed time for recovery of stranded items in some states, while recovery remains unresolved in other states. Unlike the prior research, this study provides empirical evidence that both stranded costs and stranded benefits are valued by investors. Moreover, this study demonstrates that generating stranded benefits which are more closely associated with sustainable competitive advantages, are more significant to investors than other stranded benefits. Given the trend toward deregulation, these findings are likely to be useful to regulators, investors and other stakeholders. The analysis is particularly relevant as legislatures debate stranded cost recovery.

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Introduction to Electricity Markets

Lopa Parikh, Edison Electric Institute

National Conference of State Legislatures
Indianapolis, Indiana
June 27, 2018

Overview of the Electric Industry Regulation

State Regulation of Shareholder - Owned Utilities

- **1890s—Electric utilities began to develop primarily in urban areas because of economies of scale**
- **Industry had characteristics of a "natural monopoly"**
  - A natural monopoly is where, for technical and social reasons, it is most efficient to have only one provider of a good or service
    - Exclusive utility franchises came with an obligation to serve all customers in a defined service area
    - Provided service regarded as vital to economic and social fabric of community (i.e., a "public utility")
    - Operated through large, integrated networks
    - Highly capital-intensive, requiring significant investment
- **1907—State regulation of electric utilities began in New York and Wisconsin**
  - Regulation spreads to two-thirds of states by 1920
  - Shareholder-owned utilities are now regulated in all 50 states

Federal Regulation of Shareholder - Owned Utilities

1935:

Congress passed federal legislation regulating
interstate utility operations

Federal Power Act (FPA)

Regulates interstate sales and resale of electricity, primarily of shareholder-owned utilities

Public Utility Holding Company Act (PUHCA)

Addressed corporate structure of utilities

FERC

- FERC is an independent regulatory agency in the Executive Branch.
- Its predecessor is the Federal Power Commission (FPC).
- FPC was reorganized as FERC in 1977.

• Although officially organized as part of the Department of Energy, FERC is an independent government agency.

• Headquarters: Washington D.C.

• Regional offices: Atlanta, Chicago, New York, Portland, Carmel, Sacramento, Little Rock and San Francisco. (Primary responsibilities: monitor hydropower dam safety, environmental compliance, and RTOs.)

FERC Jurisdiction

- FERC has limited jurisdiction as provided by Congress
  - Federal Power Act
  - Natural Gas Act
  - Interstate Commerce Act
  - PURPA
  - Authority as delegated by DOE

Core Functions

- Rates and services for electric transmission and electric wholesale power sales (FPA Parts II and III)
- Certification and decertification of "Qualifying Facilities" or "QFs," and oversight of QF-utility dealings (Public Utility Regulatory Policies Act)
- Hydroelectric dam licensing and safety (FPA Part I)
- Rates and services for natural gas pipeline transportation, certification of new facilities, and abandonment of existing facilities (NGA)
- Rates and services for oil pipeline transportation (Interstate Commerce Act)

Regulators

- Public Utility Commission (PUC) or Public Service Commission (PSC)
  - State regulators: retail rates, siting of generating units and transmissions lines, safety, reliability, utility planning
- Federal Energy Regulatory Commission (FERC)
  - Interstate sales of power, electricity markets, wholesale rates for different services, reliability, mergers
- Environmental Protection Agency (EPA)
  - Air, water, waste and chemical regulations
- North American Electric Reliability Corporation (NERC)
  - Develops and enforces standards to ensure reliability of bulk power system in North America
- Commodity Futures Trading Commission
  - Dodd Frank Act imposed regulatory regime on energy market trading

Energy Policy Act of 1992

- Created new class of “exempt wholesale generators” to sell power in competitive wholesale markets
- Expanded FERC’s authority to order transmission-owning utilities to provide transmission access to other wholesale market players
- Increased energy-efficiency standards for buildings, appliances, and federal government
- Encouraged development of alternative fuels and renewable energy
- Reformed and streamlined nuclear plant licensing

Market Evolution

Market & Rate Regulation, Part I

Until 1980's, all utilities "vertically integrated"

- One company generated electricity, transmitted it from the plant to load and distributed it to final consumers in a particular "service territory"
- No competition (a.k.a. monopoly)
- States regulated retail rates which included cost of transmission, distribution and generation
  - Utilities received guaranteed rate of return on investments to serve customers (regulatory compact)
    - Investments: least cost, used and useful
    - Rates: just and reasonable
- FERC regulated sales of power between companies (interstate wholesale sales)

Energy Policy Act of 2005

- Required mandatory reliability standards for all market players
- Provided penalty authority to FERC for violations
- Promoted transmission investment and facilitated transmission siting by granting FERC limited backstop siting authority
- Repealed PUHCA and strengthened FERC's consumer protection and merger authorities
- Increased energy efficiency standards
- Gave FERC stronger anti-market manipulation authority
- Reformed PURPA to suspend utility "must-purchase" obligation in competitive wholesale markets

Energy Independence and Security Act of 2007

Establishes stricter efficiency standards for variety of appliances; includes initiatives to strengthen building codes for commercial buildings

- Includes incentives to encourage development and production of electric drive transportation technologies, including plug-in hybrid electric vehicles
- Expands federal RD&D program for carbon capture and storage technologies
- Encourages deployment of smart grid technologies with federal matching funds for investment costs

Market & Rate Regulation, Part II

States and FERC took action to promote competition in generation and transmission

- Distribution still seen as a natural monopoly
- Some states “deregulated” utilities, separating ownership of generation and transmission functions
- Often, this facilitated retail supply competition (“retail choice”)
- FERC required transmission owners to allow non-affiliated generators to “interconnect”
  - Independent power producers don’t own transmission, don’t sell to retail customers
  - Facilitates integration of renewables/smaller generators into the transmission grid
- Changes to business model = changes to regulatory structures

Market & Rate Regulation, Part III

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) created

- Manage the reliability of the transmission grid for a state/region
- Operate wholesale power markets (and some other markets)
  - Generators bid power into wholesale markets
  - Least cost generators get “dispatched” first
  - All generators dispatched get “market clearing price” – bid of last generator dispatched
- FERC has “oversight” of these markets
- Not all states that participate in an ISO/RTO are “deregulated”

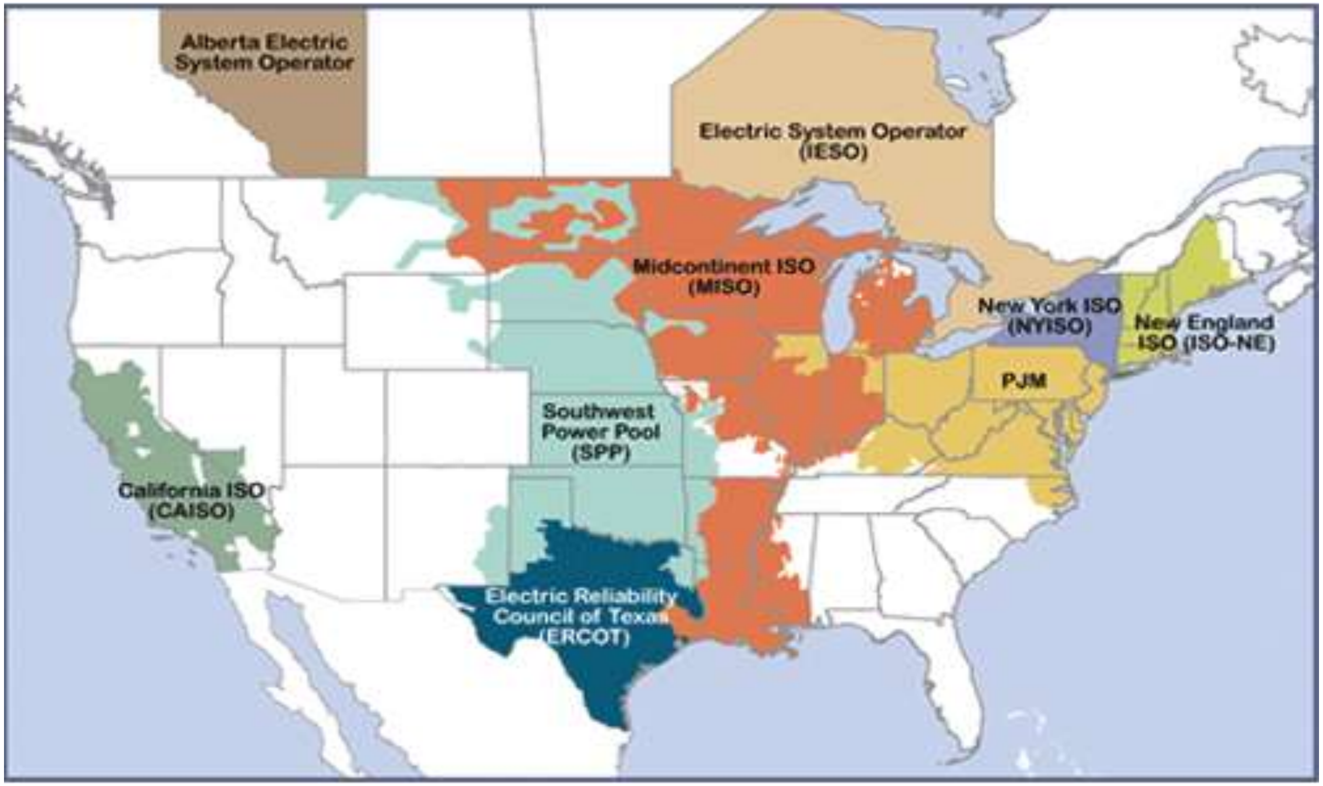
Key FERC Orders

- FERC Orders 888 and 889 (1996) opened transmission system of all shareholder-owned utilities to qualified wholesale buyers and sellers of electricity
- Order 2000 (1999) encouraged formation of Regional Transmission Organizations (RTOs)
  - Independent System Operators (ISOs) perform similar functions
- Order 1000 (2011) requires transmission planning on a regional level and allows new entrants to participate on same basis as incumbents

RTOs and ISOs

- ISO–NE: ISO New England
- New York ISO: New York only
- PJM: Pennsylvania, New Jersey, Maryland (and rest of the Mid-Atlantic states and parts of IL)
- MISO: Midwest Independent System Operator
- SPP: Southwest Power Pool
- ERCOT: Electric Reliability Council of Texas
- Cal-ISO: California Independent System Operator

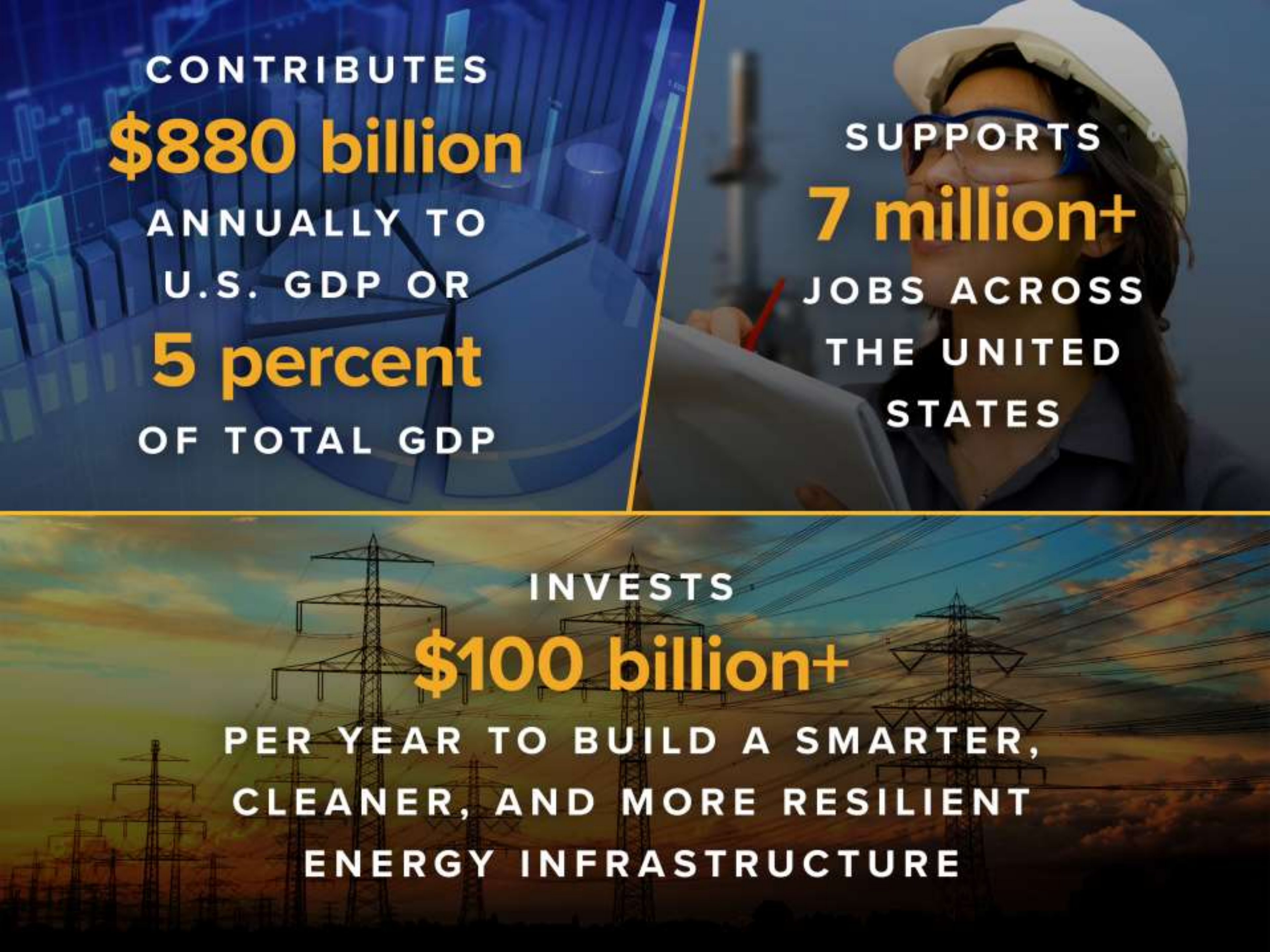
Wholesale Markets



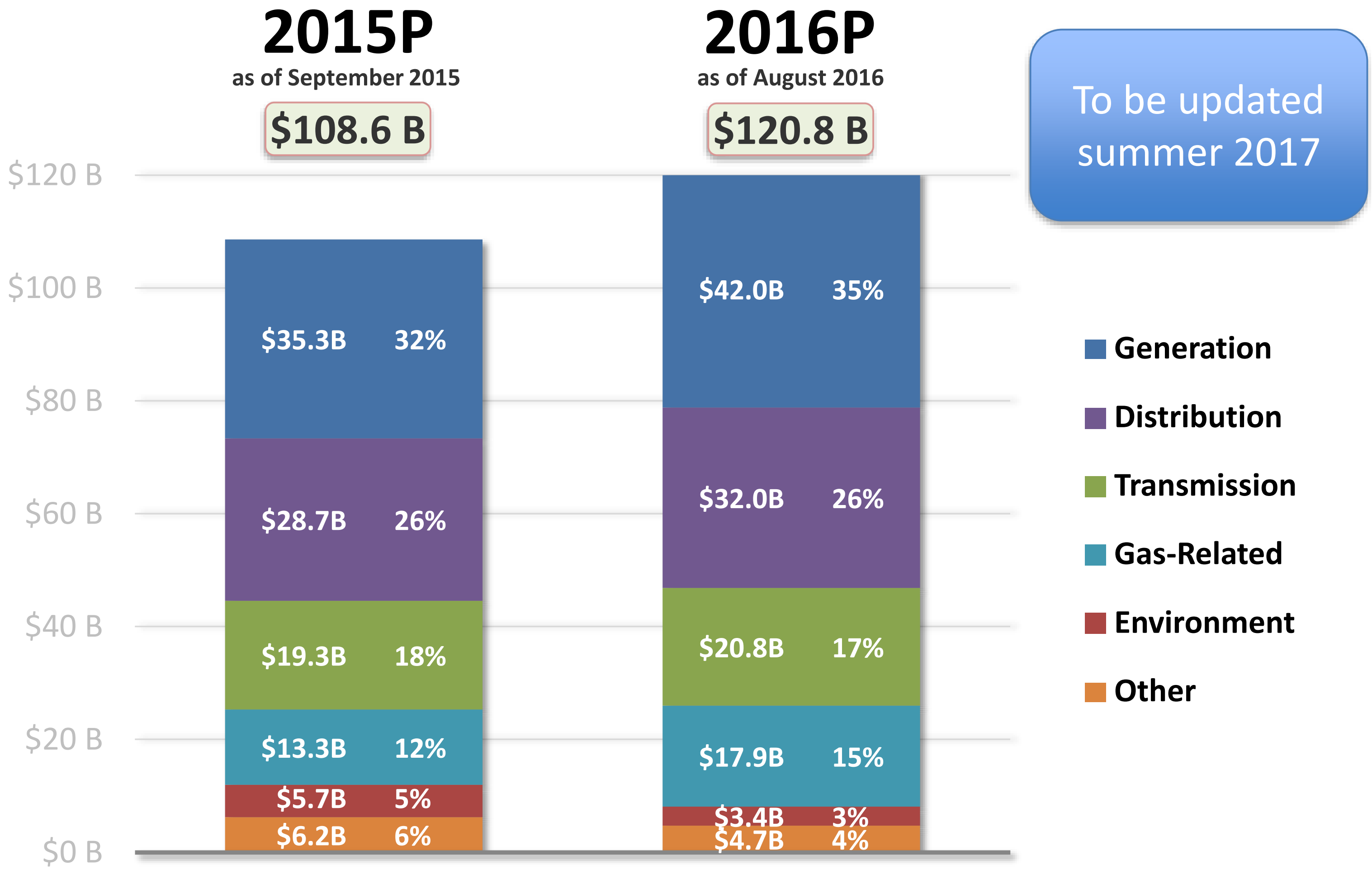
Energy Imbalance Market (EIM)

EIM Map | *CAISO*

What's Next


CONTRIBUTES
$880 billion
ANNUALLY TO
U.S. GDP OR
5 percent
OF TOTAL GDP
SUPPORTS
7 million+
JOBS ACROSS
THE UNITED
STATES
INVESTS
$100 billion+
PER YEAR TO BUILD A SMARTER,
CLEANER, AND MORE RESILIENT
ENERGY INFRASTRUCTURE

Projected Functional CapEx

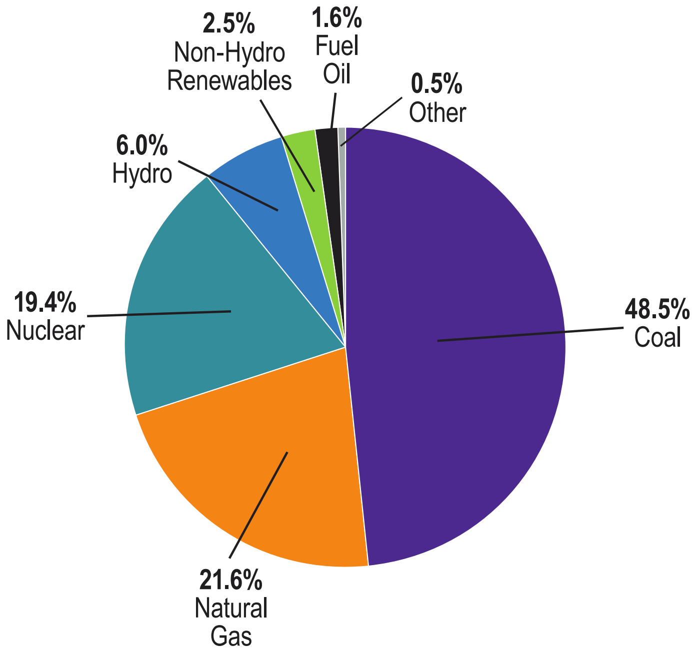


Notes: Total company functional spending of U.S. Investor-Owned Electric Utilities. 2015P total does not sum to 100% due to rounding. Projections based on publicly available information and extrapolated for companies not reporting functional detail (1.3% and 0.7% of the industry for 2015 and 2016, respectively).

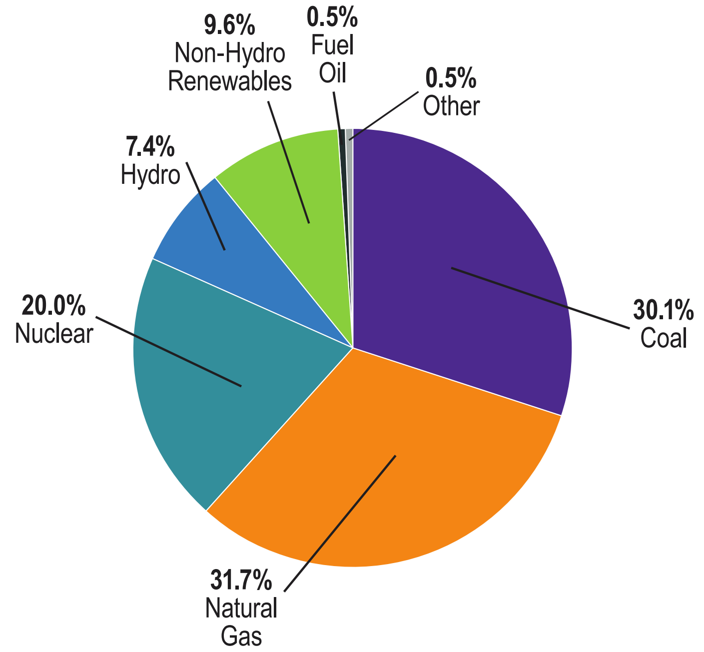
Source: EEI Finance Department, company reports , S&P Global Market Intelligence (August 2016).

Resource Mix Is Evolving

2007 National
Energy Resource Mix

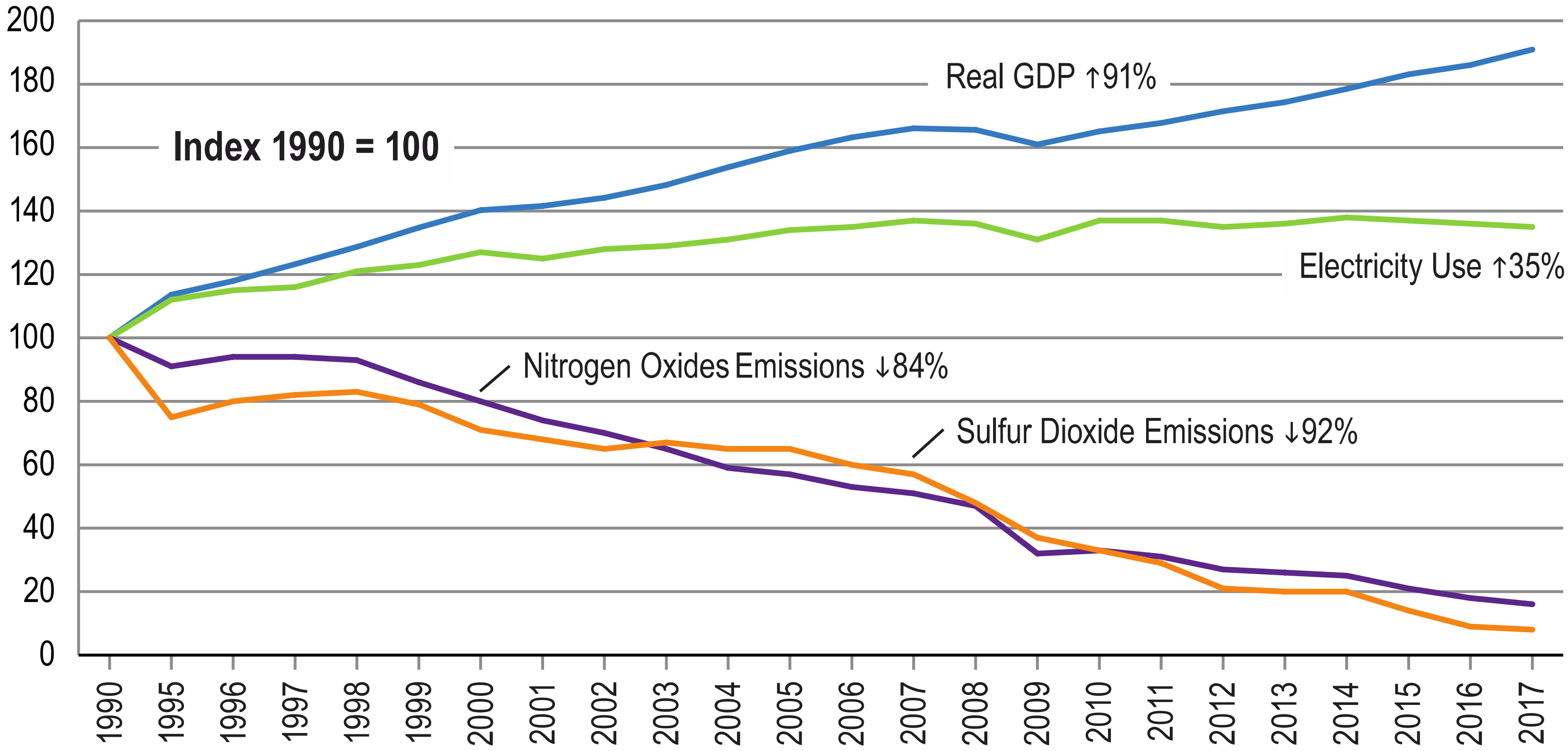


2017 National
Energy Resource Mix
(preliminary)



Source: Department of Energy, Energy Information Administration.

Power Plant Emissions Decrease Significantly (1990-2017)

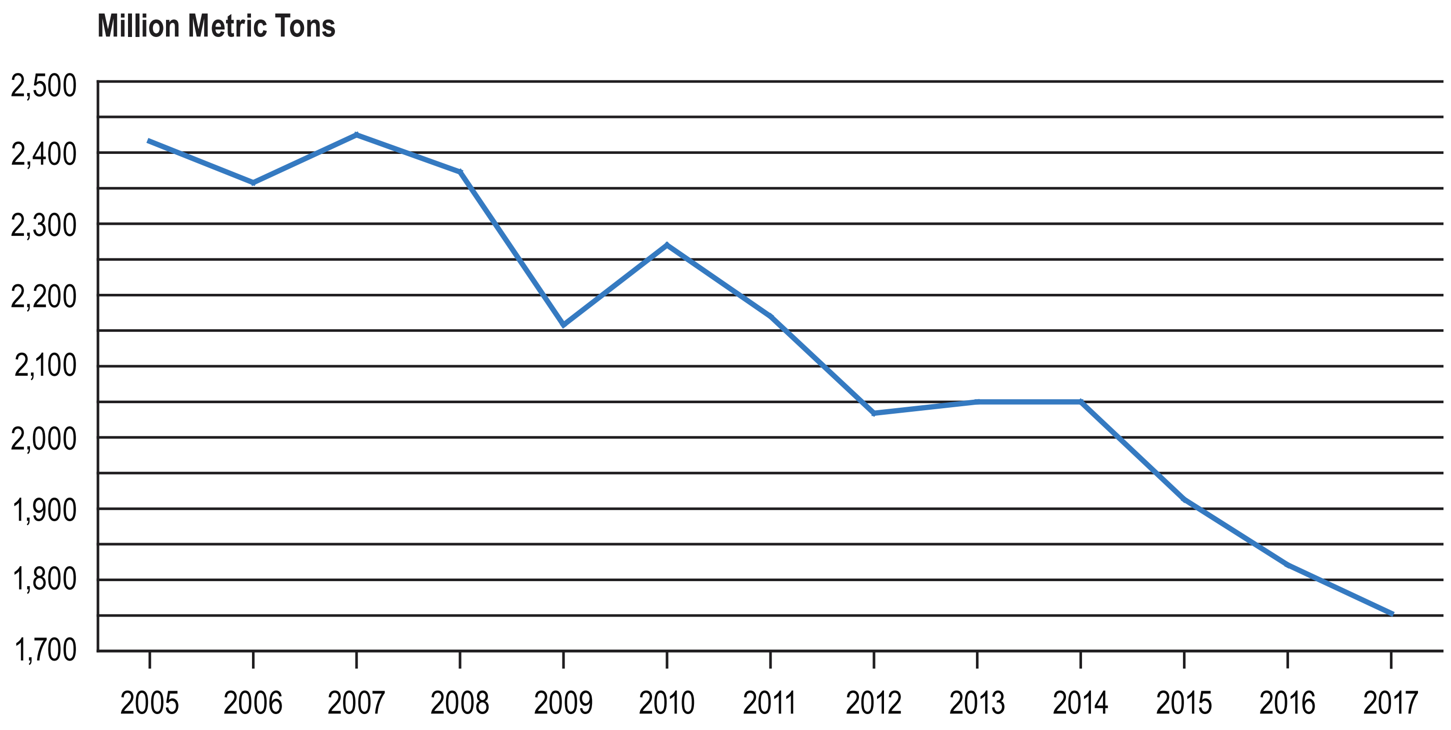


1990 represents the base year. Graph depicts increases or decreases from the base year.

Sources: U.S. Department of Energy, Energy Information Administration (EIA), U.S. Environmental Protection Agency (EPA), and U.S. Bureau of Economic Analysis.

U.S. Power Sector Carbon Dioxide Emissions Declining (2005-2017)

- 1/3 of U.S. power generation comes from zero-emissions sources
- As of 2017, industry CO_2 emissions were 27 percent below 2005 levels
- Trajectory is expected to continue based on current trends



Source: Developed from U.S. Energy Information Administration, *Monthly Energy Review*, March 2018.

Emerging FERC Issues

- Transmission rate policy
- Role of Storage and Distributed Energy Resources
- Resilience
- Natural Gas Pipeline
- PURPA
- Reliability
- State Activity and Wholesale Markets

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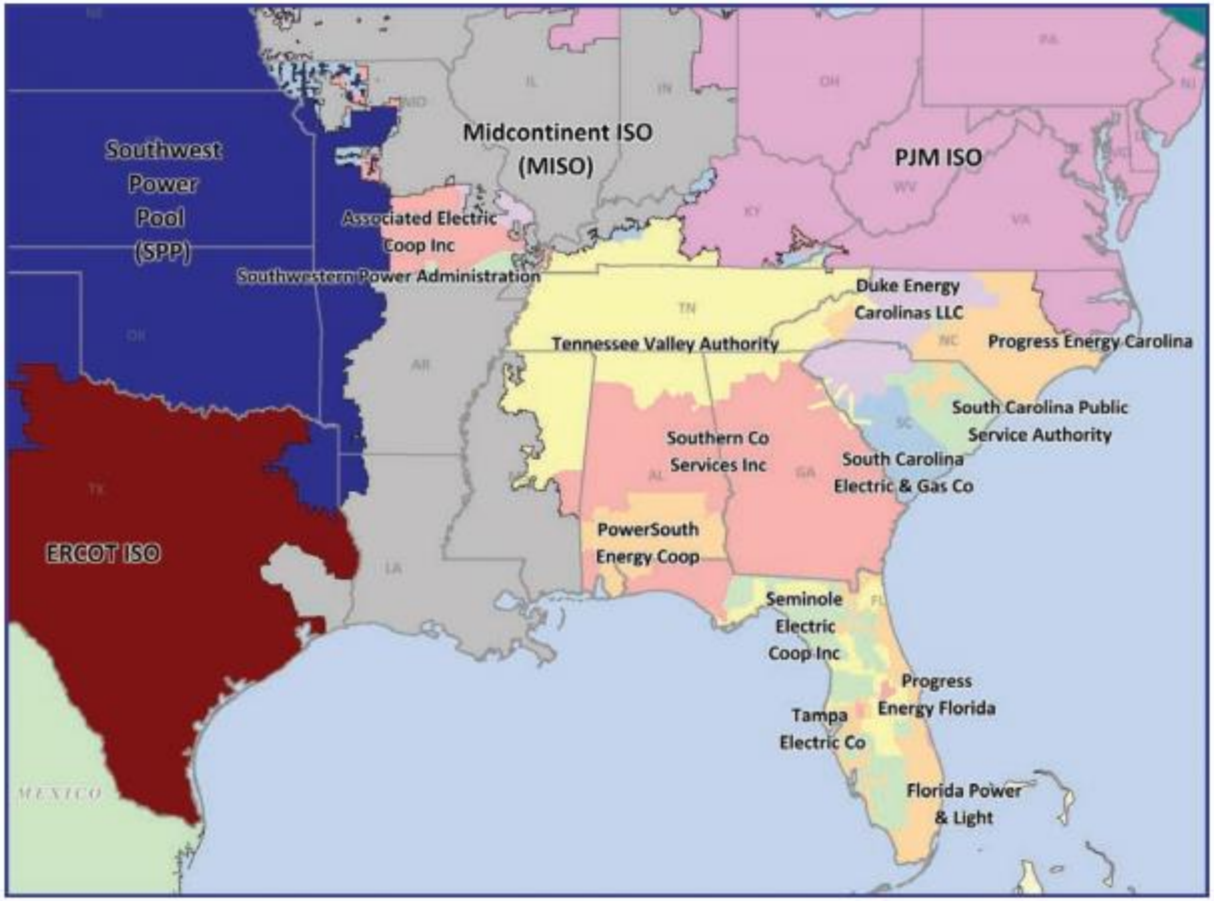
Southeast Market



Source: Federal Energy Regulatory Commission, Market Oversight, Electric Power Markets: Southeast, https://www.ferc.gov/market-oversight/mkt-electric/southeast/elec-se-market.pdf?csrt=10740772481526980426, accessed on 2/14/2019.

NEW: U.S. Crude Oil and Petroleum Products Markets

ENERGY PRIMER

A Handbook of Energy Market Basics

A staff report of The Division of Energy Market Oversight
Office of Enforcement | Federal Energy Regulatory Commission

ENERGY PRIMER

A Handbook of Energy Market Basics

November 2015

The Energy Primer is a staff product and does not necessarily reflect the views of the Commission or any Commissioner.

Energy Primer

A Handbook of Energy Market Basics

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1. Introduction

Natural gas, electricity, and oil are forms of energy that are of particular interest to the Federal Energy Regulatory Commission pursuant to its authority under the Natural Gas Act, the Federal Power Act, and the Interstate Commerce Act. This primer explores the workings of the wholesale markets for these forms of energy, as well as energy-related financial markets.

Natural gas is the second largest primary source of energy consumed in the United States, exceeded only by petroleum. A primary energy source is an energy source that can be consumed directly or converted into something else, like electricity. Roughly a third of the natural gas consumed in the United States goes into power plants for the production of electricity.

Electricity, a secondary energy source, results from the conversion of primary fuels such as fossil fuels, uranium, wind, or solar into a flow of electrons used to power modern life.

Crude oil and petroleum products are of interest to the Commission because it regulates the transport of oil by pipelines in interstate commerce.

Energy markets involve both physical and financial elements. The physical markets contain the natural resources, infrastructure, institutions and market participants involved in producing energy and delivering it to consumers. They also include the trading of and payment for the physical commodity - e.g., natural gas. The financial markets include the buying and selling of financial products derived from the physical energy. These financial markets also include market structures and institutions, market participants, products and trading, and have their own drivers of supply and demand. In general, physical and financial markets can be distinguished by the products and by the intentions of the market participants involved. Physical products are those whose contracts involve the physical delivery of the energy. Physical market participants are those who are in the market to make or take delivery of the commodity. Financial products usually do not involve the delivery of natural gas, electricity, or oil; instead, they involve the exchange of money.

Physical markets can be further differentiated by:

- Location: regions, nodes, zones or hubs
- Time frames: hourly, daily, monthly, quarterly or yearly
- Types of products: natural gas molecules or electrons, pipeline or transmission capacity and storage
- Nature of sales: retail sales involve most sales to end use customers; wholesale sales involve everything else

Physical Fundamentals

Much of the wholesale natural gas and electric power industry in the United States trades competitively; some markets are established through administrative processes based on the cost of providing service. In competitive markets, prices are largely driven by the economic concepts of supply and demand. Underlying the supply and demand for energy are physical fundamentals - the physical realities of how markets produce and deliver energy to consumers and how they form prices. These physical fundamentals will be covered in Chapter 2 (Wholesale Natural Gas Markets), Chapter 3 (Wholesale Electricity Markets), and Chapter 4 (U.S. Crude Oil and Petroleum Products Markets).

Wholesale natural gas and electricity markets differ from other competitive markets, however, in critical ways. While this primer focuses on wholesale markets, demand is ultimately determined at the retail level. Retail use is relatively inelastic in the short-term, although this may be less so with some larger customers. Retail use of natural gas or electricity exhibits some unique characteristics:

Limited customer storage options: Retail consumers have few options for storing natural gas and electricity. For natural gas, large consumers and entities that sell to retail consumers may be able to store gas, but smaller consumers do not have this option. For electricity, smaller consumers may have batteries, but nothing adequate to ensure refrigeration, for example. Without storage, consumers cannot buy when prices are low and use their stored product when prices rise. This limits consumers' response to changes in prices.

Substitutes: Retail consumers have few substitutes for natural gas or electricity, certainly in the short-term. If natural gas or electricity prices go up, consumers cannot quickly switch to a different product. Longer term, they may be able to switch to gas from electricity for heating, or they may be able to insulate or install new windows or take other steps to reduce their consumption of energy. In addition, demand-response programs can provide benefits to those who would reduce their energy needs at certain times; this might include turning off air conditioning during the hottest part of a day in order to help reduce electric load.

Necessity: Unlike most other products, natural gas and electric service are necessities today, and a lack of service can mean customers without heat, the ability to cook or refrigerate food or the ability to run their businesses. Blackouts and other service disruptions create operating problems and hazards as well. Consumers cannot postpone the purchase of electricity or natural gas. They may be able to turn down their thermostats, but cannot eliminate consumption altogether for an extended period of time.

Because consumers have limited ability to reduce demand, supply must match demand instantaneously, in all locations.

For natural gas, this means production, pipelines and storage need to be sized to meet the greatest potential demand, and deliveries need to move up and down to match changes in consumption. Natural gas has underground and above-ground storage options and linepack, which involves raising the pressure in a pipeline to pack more molecules into the same space. Natural gas flows through a pipeline at velocities averaging 25 mph, depending on the pipeline and the configuration of related facilities, so new supply can take hours or days to reach its destination. That increases the value of market-area storage, which vastly reduces the distance and time needed for gas to reach consumers.

For electricity, storage is more limited, although technologies such as batteries and flywheels are being developed. Hydroelectric pumped storage is available in a few locations; this involves pumping water to high reservoirs during times of slack electricity demand, then letting the water flow downhill through electricity-generating turbines when demand for power rises. Generating plants, transmission and distribution lines, substations and other equipment must be sized to meet the maximum amount needed by consumers at any time, in all locations. For all practical purposes, electricity use is contemporaneous with electricity generation; the power to run a light bulb is produced at the moment of illumination.

Financial Markets and Trading

The energy industries are capital intensive, requiring access to financial markets to support daily operations, trading and investment programs. Access to financial markets requires maintaining an investment grade credit rating to support activities ranging from daily transactions to long-term development of infrastructure.

Financial markets are where companies and individuals go if they need to raise or invest money. They are important to energy markets in two key ways. First, they provide access to the capital needed for operations. Second, some natural gas- or electricity-related products may trade in commodity markets or, as derivative products (see below), in financial markets.

Natural gas and electricity are traded like commodities, just like metals, corn, wheat or oil. They may not be visible, but you can turn them on and off, and measure them. Commodity markets began as ways for farmers to sell their products, or even a portion of their production before it was harvested, providing them with capital to continue operations.

Commodity markets evolved to provide other tools for farmers (and other commodity producers) to manage their risk, notably the risk of adverse changes in price. These financial products were derived from the physical products and are known as derivatives. Since their inception, trading in physical commodities and derivatives has attracted others to the market, such as speculators hoping to make a profit from changes in price.

The market for natural gas and electricity derivatives has grown enormously within the past decade, as competitive natural gas and electricity markets matured and investors came to see energy commodities as investments. This trading affects the physical markets in a number of ways, and is discussed in Chapter 5, Financial Markets and Trading.

Market Manipulation

Where there are markets, there will be those who attempt to manipulate the markets for their own benefit. These practices undermine the market's ability to operate efficiently, reduce other market participants' confidence in the markets and distort market outcomes, including prices. Some of these practices are discussed in Chapter 6, Market Manipulation.

Additional Information

This primer is written to be used either as a traditional text – read front to back – or as a reference guide. Consequently, some material is repeated in different sections and references are provided to other parts of the primer where a concept is addressed in greater detail.

Further information about various aspects of energy markets and FERC regulation can be found at www.ferc.gov; then click on Market Oversight. If you are reading this Energy Primer electronically, you can find the market oversight pages here: http://www.ferc.gov/market-oversight/market-oversight.asp

Google search also provides a quick path to information on specific FERC orders or to more general subjects (e.g., FERC regulation of natural gas pipelines).

2. Wholesale Natural Gas Markets

Natural gas markets have a significant effect on the economy and on the individuals who rely on the fuel for electric generation, manufacturing, heating, cooking and other purposes. The Department of Energy's Energy Information Administration (EIA) estimates that natural gas supplies 27 percent of the energy used in the United States, or about 26.1 trillion cubic feet (Tcf) of gas a year.

Under the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) has jurisdiction over the transportation and sale of natural gas and the companies engaged in those activities.

The natural gas market is an amalgamation of a number of subsidiary markets. There is a physical market, in which natural gas is produced, transported, stored and consumed. There is also a financial market in which physical natural gas is bought and sold as a financial product derived from physical natural gas. Natural gas markets are also regional, with prices for natural gas varying with the demand characteristics of the market, the region's access to different supply basins, pipelines and storage facilities.

Natural Gas

Natural gas is primarily methane, which is made of one carbon atom and four hydrogen atoms (CH_4), and is among the materials known as hydrocarbons. Natural gas is colorless and odorless in its natural condition. It is also highly combustible, giving off a great deal of energy and fewer emissions than fuels such as coal and oil. Natural gas occurs in geological formations in different ways: as a gas phase associated with crude oil, dissolved in the crude oil, or as a gas phase not associated with any significant crude oil. Natural gas is rich or wet if it contains significant natural gas liquids (NGL) – e.g., ethane, propane and pentane – mixed in with the methane. In contrast, natural gas is lean or dry if it does not contain these liquids. Processors remove water, liquefiable hydrocarbons and other impurities from the natural gas stream to make the natural gas suitable for sale. Natural gas liquids may be processed out and sold separately.

While natural gas is typically a gas, it can be cooled to a liquid and transported in trucks or ships. In this form, it is referred to as liquefied natural gas, or LNG.

Natural Gas Industry

As noted, the markets of the natural gas industry are both physical and financial. This chapter focuses on the physical natural gas markets, but it should be noted that financial markets can have significant impacts on the physical natural gas market.

For this discussion, the natural gas industry has three segments. The first is the supply segment, which includes exploration and development of natural gas resources and reserves, and production, which includes drilling, extraction and gas gathering. The second segment is the midstream sector, in which small-diameter gathering pipeline systems transport the gas from the wellhead to natural gas processing facilities, where impurities and other hydrocarbons are removed from the gas to create pipeline-quality dry natural gas. The third segment is transportation, which includes intrastate and interstate pipeline systems that move natural gas through large-diameter pipelines to storage facilities and a variety of consumers, including power plants, industrial facilities and local distribution companies (LDCs), which deliver the natural gas to retail consumers.

Each component of the supply chain is critical in serving customers. The quantity of reserves and production can affect market participants' expectations about current and future supply, and thus can affect prices. Similarly, the availability of pipeline and storage capacity determines which supply basins are used and the amount of gas that can be transported from producers to consumers. All of these factors affect the supply chain, but they also affect the supply-demand balance, both nationally and regionally.

A natural gas hub can occur at the interconnection of two or more pipelines where natural gas is bought and sold. The benchmark hub used to reflect the U.S. natural gas market as a whole is the Henry Hub in Louisiana. Prices at other locations are frequently shown not as the actual price, but as the differential, or basis, to Henry Hub.

Regional differences in supply and demand result in different prices for natural gas at various locations. Prices tend to be lowest in areas with low-cost production, ample infrastructure and limited demand – the Opal Hub in Wyoming, for example – and highest where production or transportation is limited and demand is high – Algonquin Citygate, in Massachusetts, for example. Transportation cost from supply to demand areas is also a factor in the regional price differentials.

The natural gas industry in the United States is undergoing a period of transition. Within the last decade, various factors have shifted the dynamics of supply and demand. These include, but are not limited to, the following:

1. Development of technology, like hydraulic fracturing and horizontal drilling, enables producers to access unconventional resources such as those in shale formations. This has vastly expanded supply and is increasing the amount of natural gas produced, which has reached levels not seen in 40 years. It also has moderated prices across the country. Notably, some of these resources are located close to eastern population centers, providing access to low-cost gas supplies with lower transportation costs.

2. Natural gas has become an investment opportunity as it is a traded commodity. As noted above, there are physical and financial investment markets. There are two distinct markets for physical natural gas: (1) a cash market, which is a daily market where natural gas is bought and sold for immediate delivery; and (2) a forward market, where natural gas is bought and sold under contract for one month or more in the future. The financial natural gas prices are often derived from the physical natural gas prices.

3. Natural gas demand for power generation is rising and is expected to increase significantly in the coming years. Power plant demand for natural gas reflects the environmental benefits of the fuel, the operating flexibility of natural gas-fired generators, and lower natural gas prices. Natural gas-fired power plants emit less air pollution than generators using coal or oil. These plants are also relatively easier to site, can be built in a range of sizes and

can increase or decrease output more flexibly than large baseload generators, such as nuclear or coal. This ability to change output quickly aids electric system operators in matching generation to customer loads, and enables operators to offset rapid changes in output from wind and other intermittent generators.

4. Pipeline expansions linking the new supply regions to markets are changing the relationships between prices in various regions. New interstate pipelines have enabled regions such as the Northeast and Mid-Atlantic to access new supply sources, expanded the amount of natural gas that can flow from traditional supply sources, and enhanced the amount that can flow overall. This has reduced prices and tempered extreme price movements during periods of peak demand.

Natural Gas Demand

Natural gas is already the fuel of choice for many sectors of the U.S. economy and, in 2014 it met about 27 percent of U.S. primary energy needs. Natural gas demand, however, can fluctuate substantially.

Over the long term, natural gas use is driven by overall economic and population growth, environmental policy, energy efficiency, technological changes and prices for natural gas and substitute energy sources such as oil, coal and electricity. In the short-term, demand stems from weather, economic activity, and competition from other fuel sources such as coal and oil.

Weather

Weather is the most significant factor affecting seasonal natural gas demand. Natural gas demand can also swing considerably within a given day, especially during periods of extreme temperatures. Short-term changes in weather, such as heat waves and winter storms, can send demand and prices soaring – or dropping – within the course of a day, sometimes unexpectedly. This unpredictability challenges suppliers and pipelines, especially when pipelines are full.

Economic Activity and Growth

Economic growth can increase the amount of natural gas used by industry, power plants and commercial entities as consumers want more of their products and services. During a recession, gas use usually declines. On the other hand, economic growth may raise personal incomes and consumption of electric-powered consumer goods.

Structural changes in the economy can also affect natural gas demand. Declining manufacturing and growing service sectors result in changes in natural gas use, as does increased global competition. New markets for products and services may require additional natural gas; movement of manufacturing overseas may reduce it.

Daily and weekly economic activity creates cyclical demand patterns. During the work day, demand rises as people get up and go to work or school. Similarly, it declines as they go to sleep. On the weekend, demand tends to vary less over the course of the day.

Prices of Natural Gas and Coal

Just as a home-owner may decide to invest in a furnace and associated piping to use natural gas for heat, so, too, a power producer may decide to make long-term investments in natural gas-fired generators. These decisions requiring long-term capital investments are cheapest and easiest to make at the time a home or power plant is built, and are more complicated to change later. Thus, over the long term, demand for natural gas can be affected by the expected costs of alternative energy sources: the cost of a natural gas furnace versus an electric one; the cost of a coal-fired generating plant versus one fueled by natural gas.

In the short-term, the opportunity for fuel switching has been significant in power generation. Electric grid operators have a choice as to which power plant to dispatch to meet increased electric demand. Dispatch is often based on the marginal cost of generation at each available plant in the generation fleet. Plants with lower marginal costs, such as nuclear, typically dispatch before plants with higher marginal costs, such as natural gas. As natural gas prices drop relative to coal prices, natural gas-fired generation can get dispatched sooner than coal-fired generation, increasing natural gas demand from the power sector.

Demographics and Social Trends

Long-term demand can also be affected by shifting demographics and social trends. Population growth in warmer climates and declines in the older industrial areas of the North have affected natural gas use. So has the trend toward larger houses.

Today, most households have a proliferation of appliances and devices that consume electricity, and continue to add more as they become more energy efficient. As the trend in generation of electricity is for a greater share to be fueled by natural gas, natural gas demand can increase from rises in electricity demand.

Environmental Concerns and Energy Efficiency

Natural gas has relatively fewer environmental problems compared with other fossil fuels, and, consequently, it is increasingly used for power generation. In addition to helping urban areas meet air quality goals, natural gas generation has not experienced as much negative public sentiment as have nuclear and coal-fired generators, making it feasible to site gas-fired generators closer to load centers. Growth in wind and other intermittent generation technologies benefit when coupled with natural gas generation, which is able to ramp up and down quickly to complement variable output.

The natural gas emissions profile has also encouraged some urban mass transit bus systems, West Coast port operations and other vehicle fleets to shift to natural gas from gasoline or diesel fuel.

Customer Sectors and Demand

In 2007, natural gas used for electric generation overtook gas-for-industrial load to become the largest customer class for natural gas. In 2014, according to the EIA, power generation used 8.2 Tcf of the 24.6 Tcf of natural gas delivered to consumers. Industrial, residential, and commercial consumers used 7.8 Tcf, 5.1 Tcf, and 3.5 Tcf, respectively.

Each customer sector contributes differently to overall demand, both in terms of the amount that demand varies over a cycle and whether its peak demand coincides with the overall system peak. Residential demand, for example, can be highly variable in colder climates, and its peak coincides with the overall system peak. Power generation's peak does not coincide with the winter gas-demand peak, but in fact its growing use of natural gas to produce electricity for air conditioning has created robust summer demand, which competes with gas supply that traditionally would flow into underground storage for later use in the winter. Industrial demand stays relatively constant year-round.

In the short term, residential and commercial natural gas use tends to be inelastic – consumers use what they need regardless of the price. Power plant demand, on the other hand, is more price-responsive as natural gas competes with other fuels, especially coal, in the production of electricity. Price inelasticity implies that a potential for price spikes exists during periods of supply constraint.

Consequently, the mix of customers in a region can affect system operations and costs. Pipelines and other equipment need to be sized to account for peak demand. Demand that stays fairly constant presents fewer operational challenges and usually enjoys lower prices. Highly variable demand will result in pipelines and equipment being used at less than full capacity for much of the year, and prices for service may be more expensive, both because the pipelines may become constrained during peak times and because the capacity is not fully used throughout the year.

Power Generation

Generation demand can soar at any time; gas-fired generators can change their output quickly, and are frequently called on to change their output due to changes in demand or when problems occur elsewhere in the power grid. Generating plants tend to consume more natural gas in the summer to meet air conditioning loads, but power demand can also climb in the winter to provide electric heating and lighting. Generation demand can also be influenced by the relative prices for natural gas and other fuels, especially coal. Since late 2008, natural gas-fired generators generally have been dispatched before some coal plants because of the decrease in natural gas prices.

Industrial

Natural gas as a fuel is used to produce items such as steel, glass, paper, clothing and brick. It also is an essential raw material for paints, fertilizer, plastics, antifreeze, dyes, photographic film, medicines and explosives. Industrial load tends to show the least seasonal variation of natural gas use, but industry is sensitive to economic pressures.

Residential

Despite population growth, natural gas used in the residential sector for home furnaces, water heaters, clothes dryers and stoves has remained fairly flat over the past decade as appliances and homes have become more energy efficient. Much of the year-to-year demand variation in this sector can be attributed to the weather during a particular year. A year with a long, cold winter will see higher gas demand than a year with a mild winter, especially in cold-winter regions where demand soars during winter months as consumers turn on their furnaces. Slightly more than half of the homes in the United States use natural gas as their main heating fuel.

Commercial

Like the residential sector, commercial consumption experiences year-to-year variation based on weather. Commercial consumers include hotels, restaurants, wholesale and retail stores and government agencies, which use natural gas primarily for heat. Consequently, its demand varies over the seasons, weeks and days.

Natural Gas Supply

Natural Gas Resources, Reserves and Production

The amount of natural gas in the ground is estimated by a variety of techniques, taking into account the technology available to extract the gas. Estimating the technically recoverable oil and natural gas resource base in the United States is an evolving process. Analysts use different methods and systems to make natural gas estimates. Natural gas supplies are characterized as resources, proved reserves and production (See Quick Facts box).

Quick Facts: Resources and Proved Reserves

- **Resources** - Total natural gas estimated to exist in a particular geological area. The estimated size of resources is different from the amount of natural gas that can or will be produced from that area.

- **Proved reserves** - Estimated amount of natural gas that, based on analysis of geologic and engineering data gathered though drilling and testing, can be reasonably projected to be recoverable under existing economic and operating conditions. Since economic and operating conditions change constantly, the estimates for proven reserves also changes often.

Resources is the largest category, which describes the total potential of natural gas supply. Proved reserves consider the feasibility and economics of extracting the natural gas. Lastly, production describes the amount of natural gas removed from the ground.

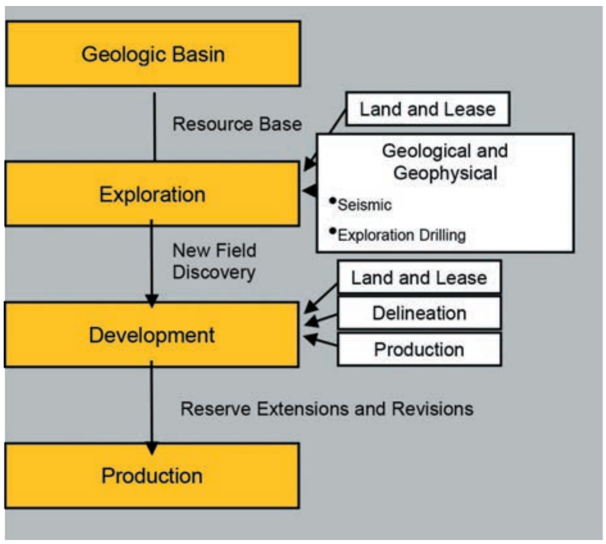
Natural gas is located underneath the surface of the earth. Natural gas is characterized by the type of basin or rock formation in which it lies. Conventional natural gas is found in porous rock formations, and in the United States is the traditional source of natural gas.

Unconventional natural gas, on the other hand, is found in shale, coal seams and tight, low-permeability rock formations. In 2007, the National Petroleum Council (NPC) defined unconventional gas as "natural gas that cannot be produced at economic flow rates or in economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment, a horizontal wellbore or by using multilateral wellbores or some other technique to expose more of the reservoir to the wellbore."

In the past few years, improvements in drilling technology have enabled producers to access unconventional supplies, notably shale, yielding significant increases in production and raising the estimate of proved reserves. Estimates of resources in 2014 amounted to approximately 2,853 Tcf (which included reserves).

This domestic growth in resources and reserves has translated into greater natural gas production, which has grown more than 35 percent since 2005, to more than 70 billion cubic feet per day (Bcfd) in 2014. Most of the growth came from shale gas, which now accounts for 50 percent of natural gas resources.

Gas Exploration and Development Process



Source: FERC staff

Worldwide, the United States accounts for one-tenth of global natural gas technically recoverable resources. Most of the natural gas resources are in the Middle East – Iran, Qatar and Saudi Arabia – followed by the United States and Russia.

Rig Count and Rig Productivity

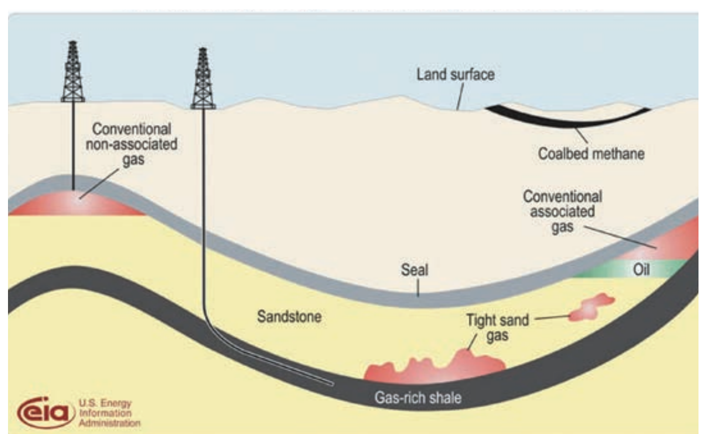
A measure of exploration, the rig count measures the number of rotary drilling rigs actually drilling for oil and gas. These measures are compiled by several companies active in drilling operations. Historically, rig counts were used as a rough predictor of future production. However, improvements in drilling technology and practices have caused a decoupling between rig count and production. The oil and gas rig count peaked at 4,530 on Dec. 28, 1981. Since then, rig count has decreased by over 80 percent while rig productivity has increased substantially, according to Baker Hughes Inc. Within the total rig count, the use of horizontal drilling rigs, used in the production of natural gas and oil in shale formations, has been growing for years, while the traditional vertical rig count has steadily declined.

The adoption of horizontal drilling has significantly increased production per rig, making comparison of rig counts over time problematic because horizontal rigs are considerably more productive than vertical rigs.

Conventional and Unconventional Natural Gas

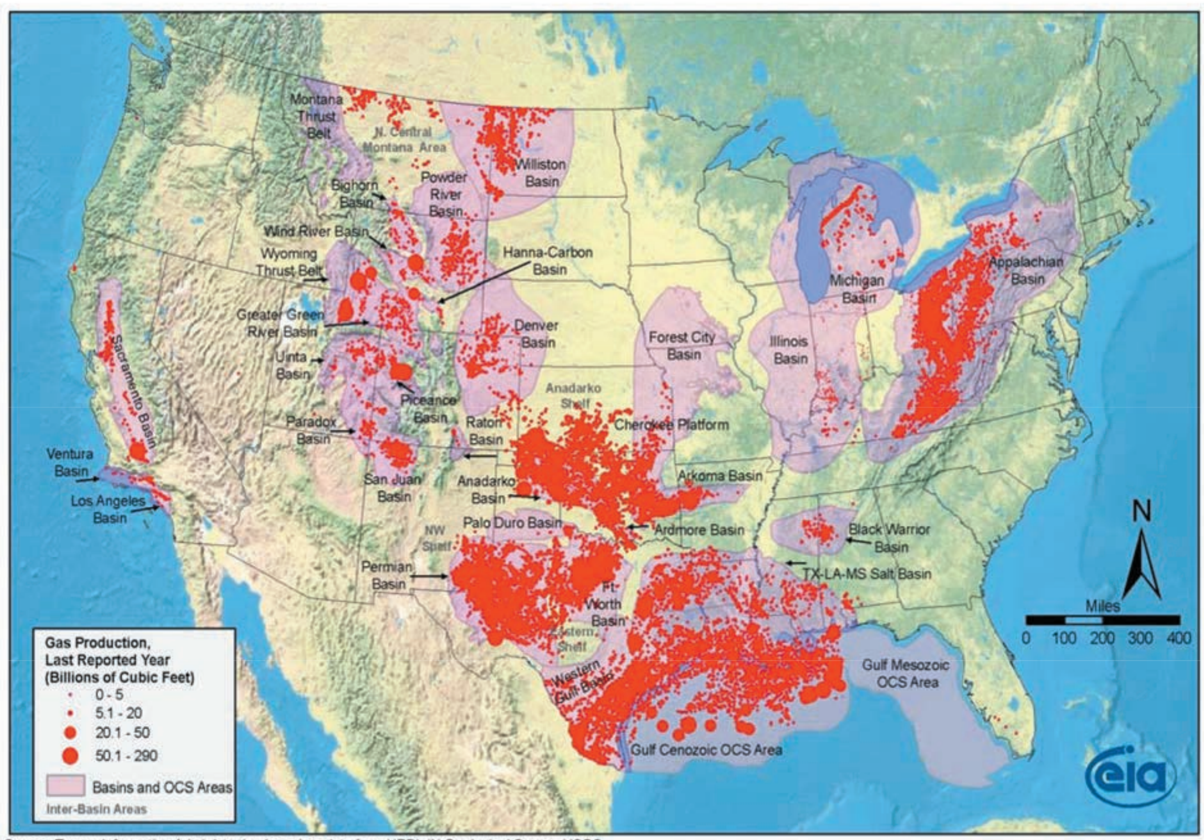
Natural gas is a fossil fuel. Natural gas historically has been found in underground reservoirs made when organic material was buried and pressurized. The remains of that organic material were trapped in the surrounding rock as oil or natural gas. Natural gas and oil are often found together. The depth of the organic materials and the temperatures at which they are buried often determine whether the organic matter turns into oil or natural gas. Generally, oil is found at depths of 3,000 to 9,000 feet; organic materials at greater depths and higher temperatures result in natural gas.

Schematic Geology of Natural Gas Resources



Source: EIA

Gas Production in Conventional Fields, Lower 48 States



Source: EIA

Natural gas basins are frequently referred to as conventional or unconventional basins or plays. These basins differ in the geology of the basin and the depth at which gas can be found. The schematic illustrates differing geologic formations in which natural gas can be found.

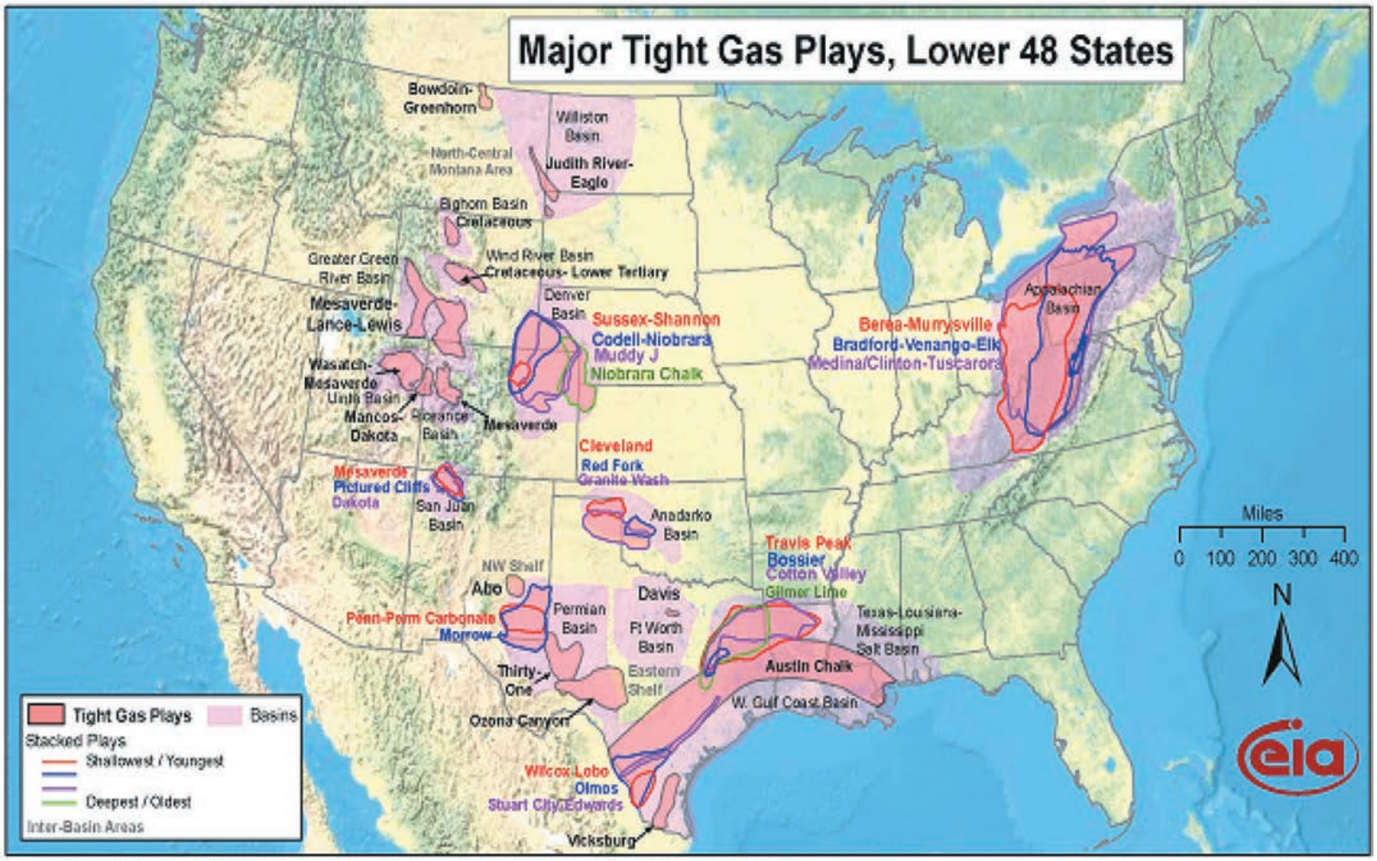
Conventional Natural Gas

Natural gas historically has been produced from what is traditionally known as conventional natural gas resources, which provided most of the country's supply needs for more than a century. Conventional gas is found in geological basins or reservoirs made of porous and permeable rocks, holding significant amounts of natural gas in the spaces in the rocks.

Conventional resources have been found both on land and offshore (see map), with the major fields in an arc from the Rocky Mountains to the Gulf of Mexico to Appalachia. The largest conventional fields reside in Texas, Wyoming, Oklahoma, New Mexico and the federal offshore area of the Gulf of Mexico. In 2000, offshore natural gas production represented 24 percent of total U.S. production; by 2013 that amount had fallen to less than 5 percent.

Federal offshore natural gas wells are drilled in the ocean floor off the coast of the United States in waters that are jurisdictional to the federal government. Most states have jurisdiction over natural resources within three nautical miles of their coastlines; Florida and Texas claim nine nautical miles of jurisdiction.

Roughly 4,000 oil and gas platforms are producing in federal waters at water depths approaching 7,500 feet (at total well depths of 25,000-30,000 feet) and at distances as far as 200



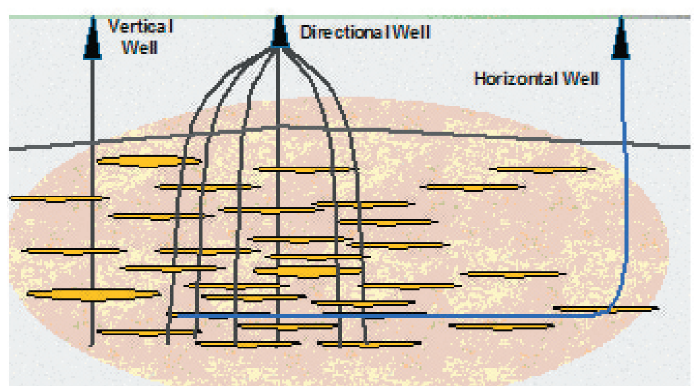
Source: EIA

miles from shore, the EIA reports. Most of these offshore wells are in the Gulf of Mexico.

Offshore production has been going on for decades. As close-in, shallow-water wells became less economic to produce, companies looked to reserves at greater water depth. Technological improvements contributed to continuing production from deep offshore wells.

Unconventional Natural Gas

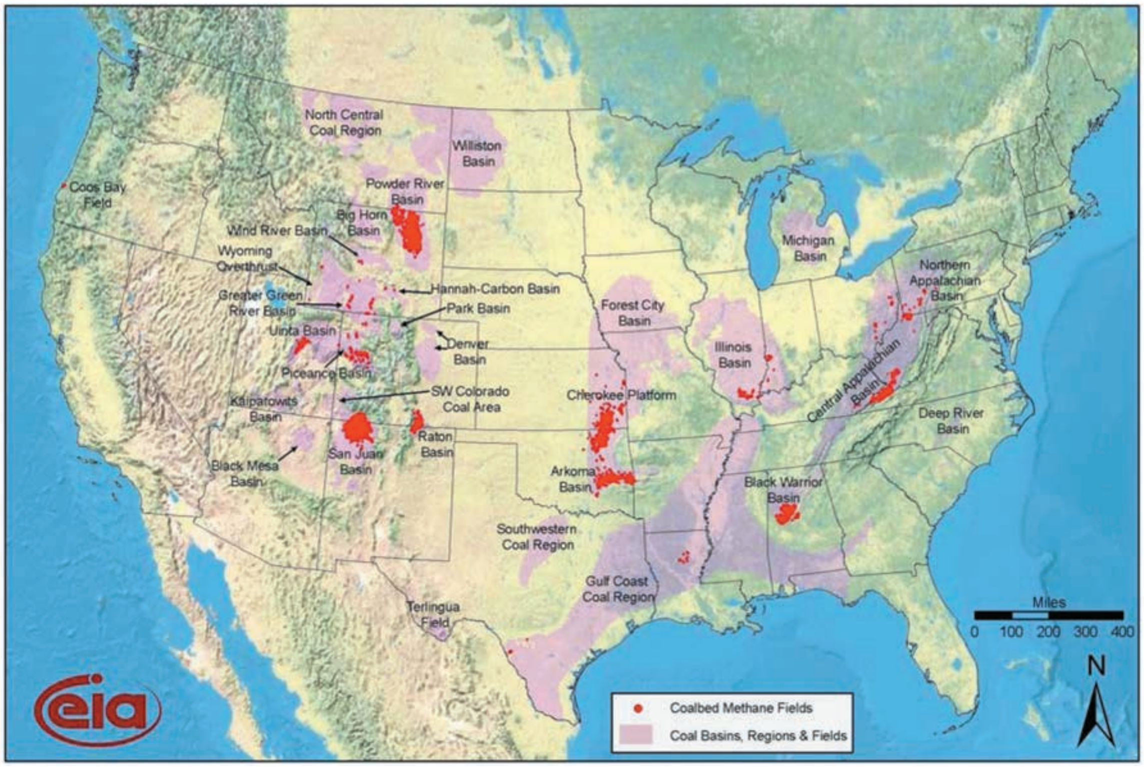
In recent years, innovations in exploration and drilling technology have led to rapid growth in the production of unconventional natural gas. This term refers to three major types of formations where gas is not found in distinct basins, but is trapped in shale, tight sands or coal seam formations over large areas.



Source: EIA

The presence of natural gas in these unconventional plays has been common knowledge for decades, but it was not until the early 1990s, when after years of experimenting in the Barnett

Coalbed Methane Fields, Lower 48 States



Source: EIA

Shale in Texas, George Mitchell and Mitchell Energy Co. developed a new drilling technique that made production in these types of formations economically feasible. The new technology included horizontal and directional wells, which allow a producer to penetrate diverse targets and increase the productivity of a well. Directional wells allow the producer to tap these resources through multiple bores. The horizontal wells have a vertical bore, but then move horizontally through the rock to access more supply. These new drilling technologies greatly improved the likelihood of a successful well and the productivity of that well.

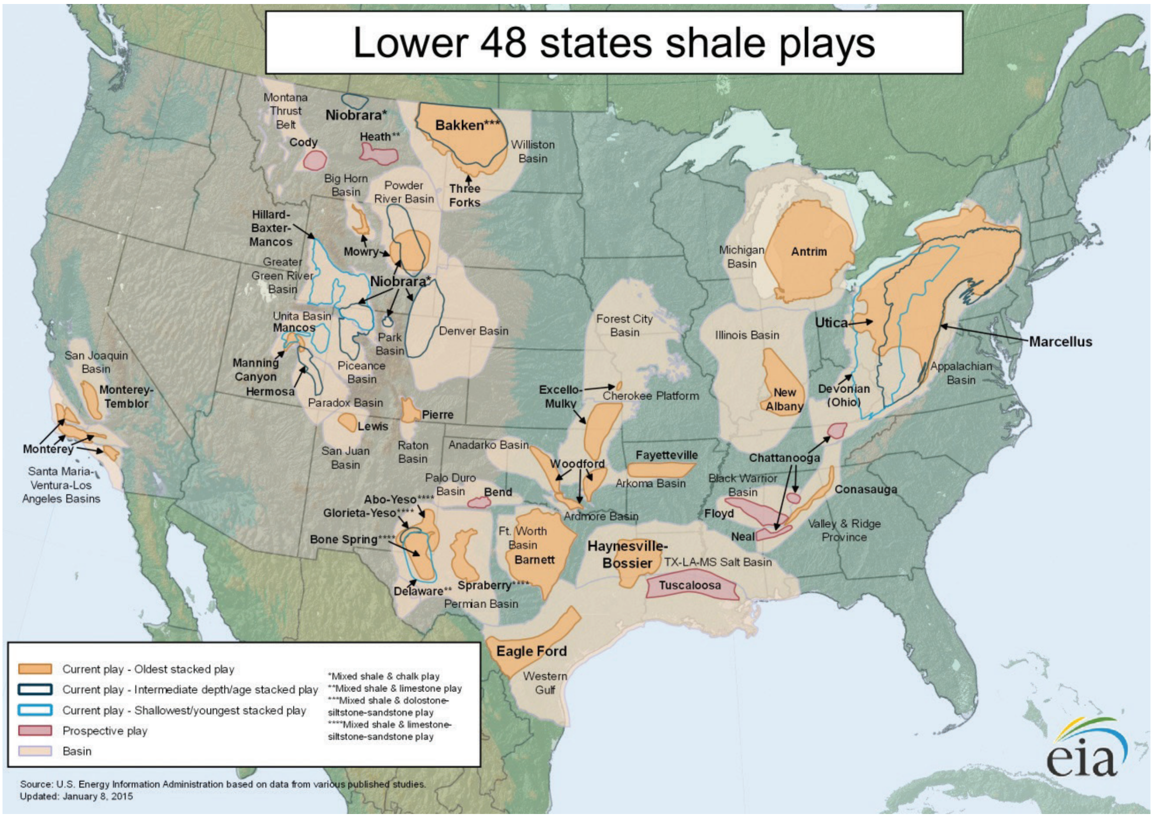
As of 2014, production from unconventional reserves supplied nearly two-thirds of U.S. gas needs.

Tight sands gas is natural gas contained in sandstone, siltstone and carbonate reservoirs of such low permeability that it will not naturally flow when a well is drilled. To extract tight sands gas, the rock has to be fractured to stimulate production. There are about 20 tight sands basins in the United States (see map); as of 2012, annual production was about 5 Tcf, or about one-fifth of U.S. domestic production.

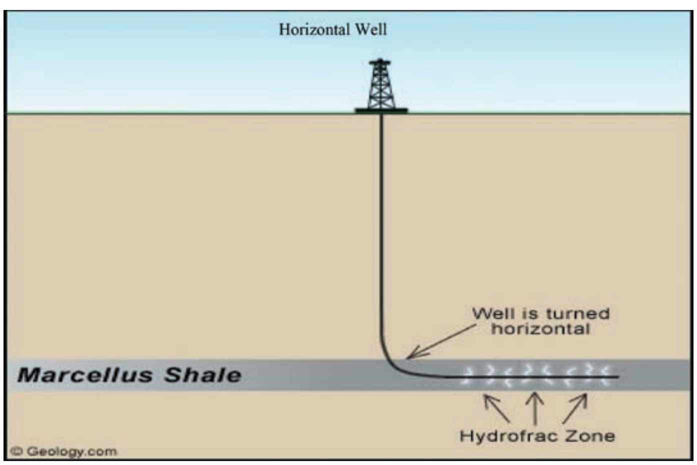
Coalbed methane (CBM) is natural gas trapped in coal seams. Fractures, or cleats, that permeate coalbeds are usually filled with water; the deeper the coalbed, the less water is present. To release the gas from the coal, pressure in the fractures is created by removing water from the coalbed.

The coalbed methane resource of the United States is estimated to be more than 700 Tcf, but less than 100 Tcf of that may be economically recoverable, according to the U.S. Geological Survey. Most CBM production in the United States is concentrated in the Rocky Mountain area, although there is significant activity in the Midcontinent and the Appalachian area.

Shale gas is found in fine-grained sedimentary rock with low permeability and porosity, including mudstone, clay stone and



Source: EIA



Source: Geology.com

what is commonly known as shale. These rock conditions require a special technique known as hydraulic fracturing (fracking) to release the natural gas. This technique involves fracturing the rock in the horizontal shaft using a series of radial explosions and water pressure (see graphic).

In the past decade the processes for finding geological formations rich in shale gas, or shale plays, have improved to the point that new wells almost always result in natural gas production. Improved exploration techniques coupled with improved drilling and production methods have lowered the cost of finding and producing shale gas, and have resulted in a significant increase in production. In 2014, shale gas accounted for about 45 percent of total gas production, with expectations of significant increases in the future.

As of 2014, the six major shale plays in the United States are Barnett, Fayetteville, Woodford, Haynesville, Eagle Ford, and Marcellus (see map on next page). Other shale formations are seeing heavy exploration activity and are expected to become major contributors of natural gas supply in the near future. The shale plays are widely distributed through the country, which has the added advantage of putting production closer to demand centers, thus reducing transportation bottlenecks and costs.

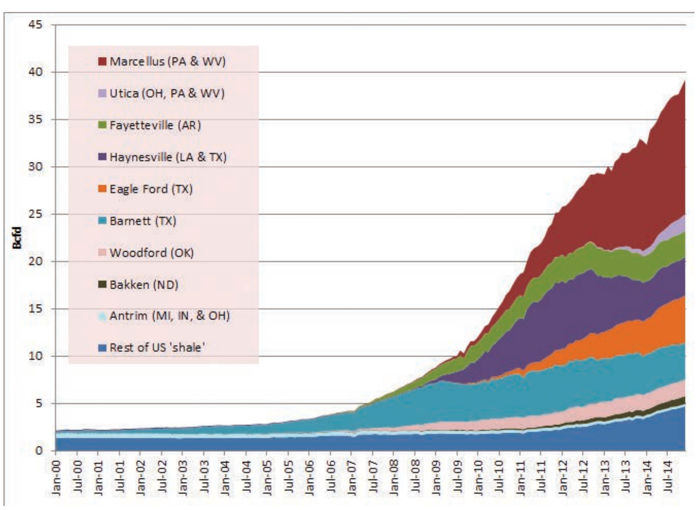
Many shale reservoirs contain natural gas liquids, which can be sold separately, and which augment the economics of producing natural gas.

The Shale Revolution

The estimated resources, proven reserves and production of shale gas have risen rapidly since 2005, and shale is transforming gas production in the United States. In 2013, according to EIA, shale gas made up 40 percent of gross production of natural gas, and has become the dominant source of domestically produced gas. By comparison, coalbed methane accounted for 5 percent of production, while 18 percent of the natural gas came from oil wells and 38 percent was produced from natural gas wells.

New shale plays have increased dry shale gas production from 1 Tcf in 2006 to over 12 Tcf in 2014. Wet shale gas reserves, those rich in oil and/or natural gas liquids account for about 20 percent of the overall United States natural gas reserves. According to the EIA, shale gas will account for about 53 percent of United States natural gas production in 2040.

Shale Gas Production by Region



Source: Derived from EIA data

Shale gas well productivity has improved considerably over the past 10 years, with technological advances in drilling and fracking technology reducing exploration, drilling, and producing costs. Rising well productivity and falling costs have resulted in larger amounts of shale gas production at lower natural gas prices.

The presence of NGL in many shale gas plays adds to shale gas well profitability. NGL prices are more closely linked to oil prices than natural gas prices and natural gas wells with high liquids content are therefore more profitable than wells producing natural gas alone. A typical barrel of NGL might contain 40-45 percent ethane, 25-30 percent propane, 5-10 percent butane and 10-15 percent natural gasoline. This can make shale gas wells less sensitive to natural gas prices than wells producing just natural gas.

The Marcellus Shale formation in Appalachia is of particular note because of its location, size and resource potential, according to the Potential Gas Committee at the Colorado School of Mines. Marcellus Shale has estimated gas resources reaching 549 Tcf, and it extends from West Virginia to New York, near the high population centers of the Northeast and Mid-Atlantic. Although Marcellus Shale has been producing significant amounts of gas only since 2008, production has been prolific with high initial well pressures and high production rates.

Growing gas production in Marcellus has already made an impact on U.S. gas transportation. As more gas has flowed out of Marcellus, less gas has been needed from the Rockies or the Gulf Coast to serve the eastern United States. This new production has contributed to a reduction in natural gas prices and the long-standing price differentials between the Northeast and other parts of the United States. It has also caused imports from Canada to decrease.

Environmental concerns present the greatest potential challenge to continued shale development. One issue involves the amount of water used for hydraulic fracturing and the disposal of the effluent used – chemicals and sand are combined with water to create a fracturing solution, which is then pumped into deep formations. Some companies recycle the returned water, which allows them to reuse such water. Concerns have also been raised regarding the potential risks and health hazards associated with wastewater (especially when stored at ground level in holding ponds) seeping into drinking water.

FERC Jurisdiction

Section 1(b) of the Natural Gas Act (NGA) exempts production and gathering facilities from FERC jurisdiction. Moreover, the Wellhead Decontrol Act of 1989, Pub. L. No. 101-60 (1989); 15 U.S.C. § 3431(b)(1)(A), completely removed federal controls on new natural gas, except sales for resale of domestic natural gas by interstate pipelines, LDCs or their affiliates. In Order No. 636, FERC required interstate pipelines to separate, or unbundle, their sales of gas from their transportation service, and to provide comparable transportation service to all shippers whether they purchase natural gas from the pipeline or another gas seller.

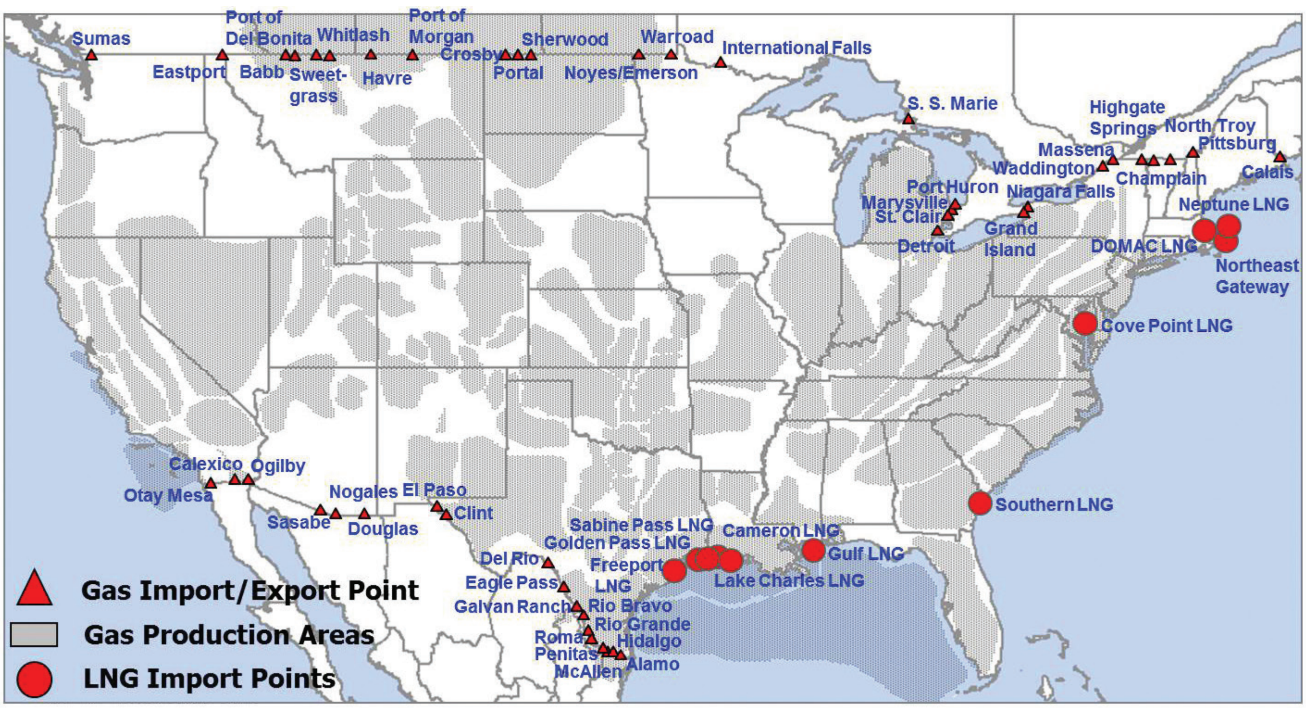
Imports and Exports

Net natural gas imports play an important role in regional U.S. markets, accounting for about 1,181 Bcf, or 4 percent, of the natural gas used in the United States in 2012. The natural gas pipeline systems of the United States and Canada are integrated, and about 98 percent of imports came from Canada, according to the EIA, while 2 percent was imported as liquefied natural gas (LNG).

Imported natural gas flows into the United States via pipelines at numerous points along the U.S. border with Canada. Imports from Canada have been of strategic importance in the Northeast and the West, which were traditionally far from the major domestic production centers. However, imports from Canada have been declining as U.S. shale production has increased. Net U.S. gas imports fell from a high of 3,785 Bcf in 2007 to 1,181 Bcf in 2014. EIA estimates that imports will continue to decrease as shale-gas production increases.

The United States also exports natural gas to Canada and Mexico, and it still occasionally exports LNG to Japan.

Natural Gas Import Entry Points



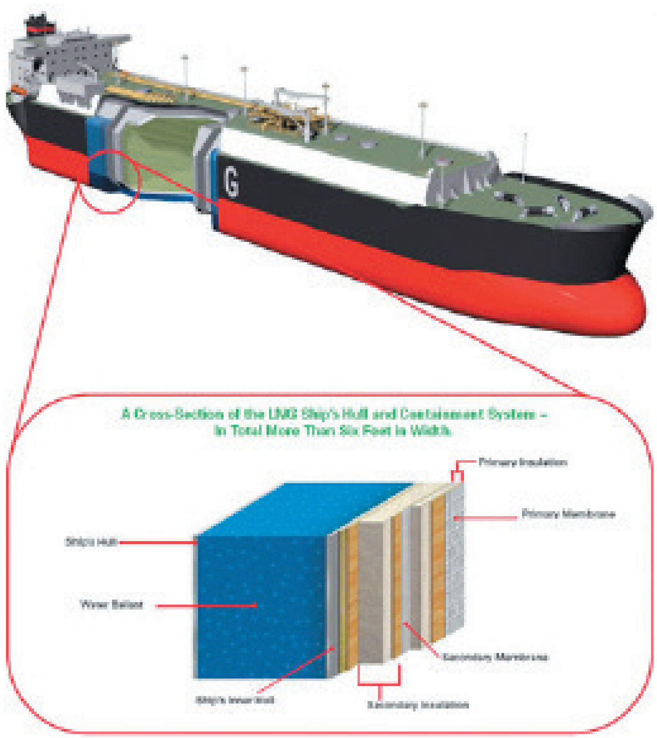
Source: Derived from Velocity Suite, ABB

Liquefied Natural Gas

Liquefied natural gas (LNG) is natural gas cooled to minus 260 degrees Fahrenheit to liquefy it, which reduces its volume by 600 times. LNG may be transported in ships and trucks to locations not connected by a pipeline network.

FERC Jurisdiction

The FERC has exclusive authority under the NGA to authorize the siting of facilities for imports or exports of LNG. This authorization, however, is conditioned on the applicant's satisfaction of other statutory requirements not administered by FERC for various aspects of the project. In addition, the Department of Energy has authority over permits to import and export.



Source: BP

The LNG Supply Chain

Natural gas is sent to liquefaction facilities for conversion to LNG. These facilities are major industrial complexes, typically costing $2 billion, with some costing as much as $50 billion.

Once liquefied, the LNG is typically transported by specialized ships with cryogenic, or insulated, tanks.

When LNG reaches an import (regasification) terminal, it is unloaded and stored as a liquid until ready for sendout. To send out gas, the regasification terminal warms the LNG to return it to a gaseous state and then sends it into the pipeline transportation network for delivery to consumers. Currently, over 95 Bcfd of regasification capacity exists globally, more than 2.5 times the amount of liquefaction capacity. Excess regasification capacity provides greater flexibility to LNG suppliers, enabling them to land cargoes in the highest-priced markets.

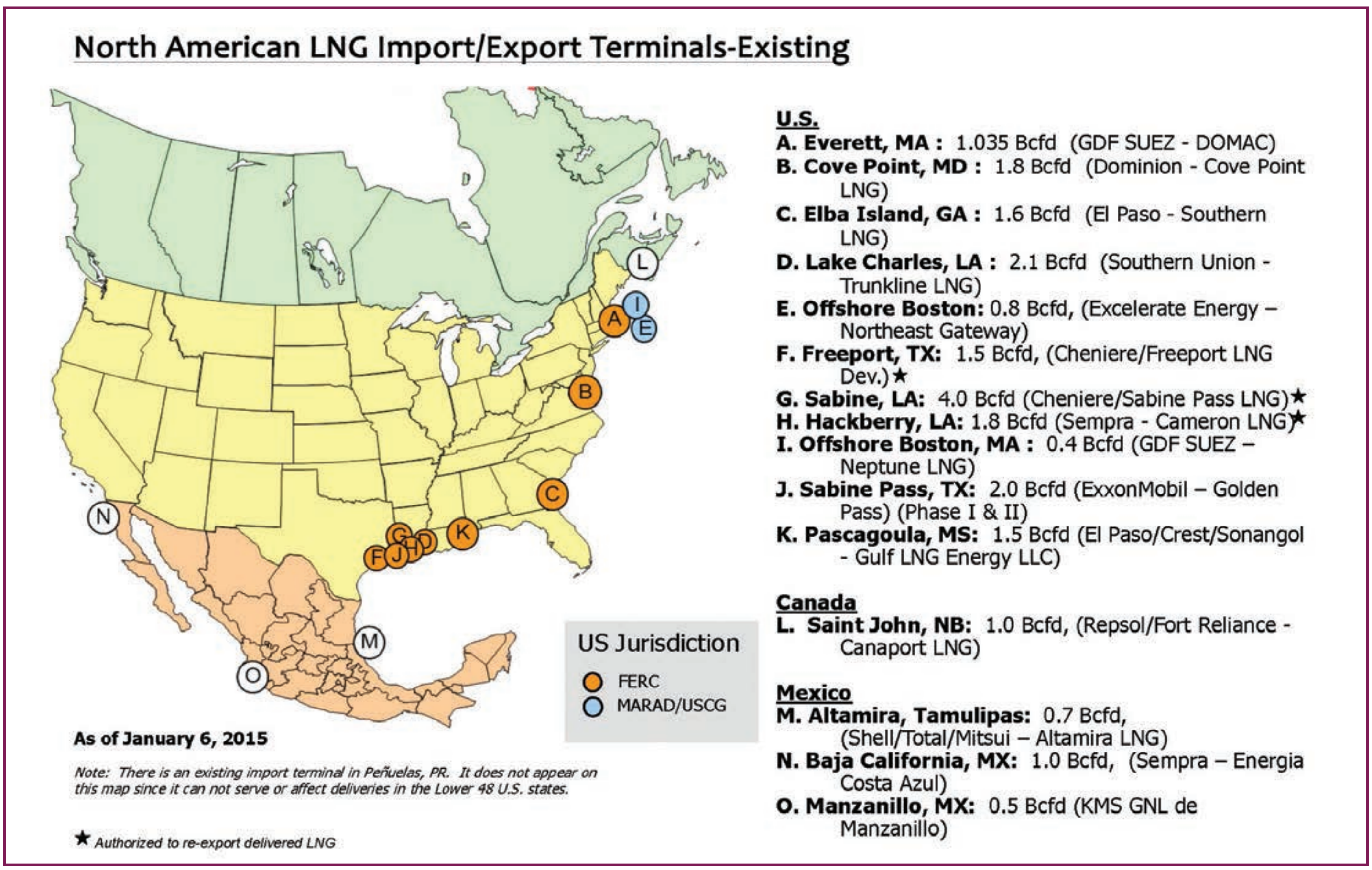
The cost of the LNG process is $2-$5 per million British thermal units (MMBtu), depending on the costs of natural gas production and liquefaction and the distance over which the LNG is shipped. Liquefaction and shipping form the largest portion of the costs. Regasification contributes the least cost of any component in the LNG supply chain. The cost of a regasification facility varies considerably; however, the majority of these costs arise from the development of the port facilities and the storage tanks. A 700-MMcfd regasification terminal may cost in the range of $500 million to $800 million.

The various components of the LNG process are broken out on the following page.

Source: CEE based on industry and government reports

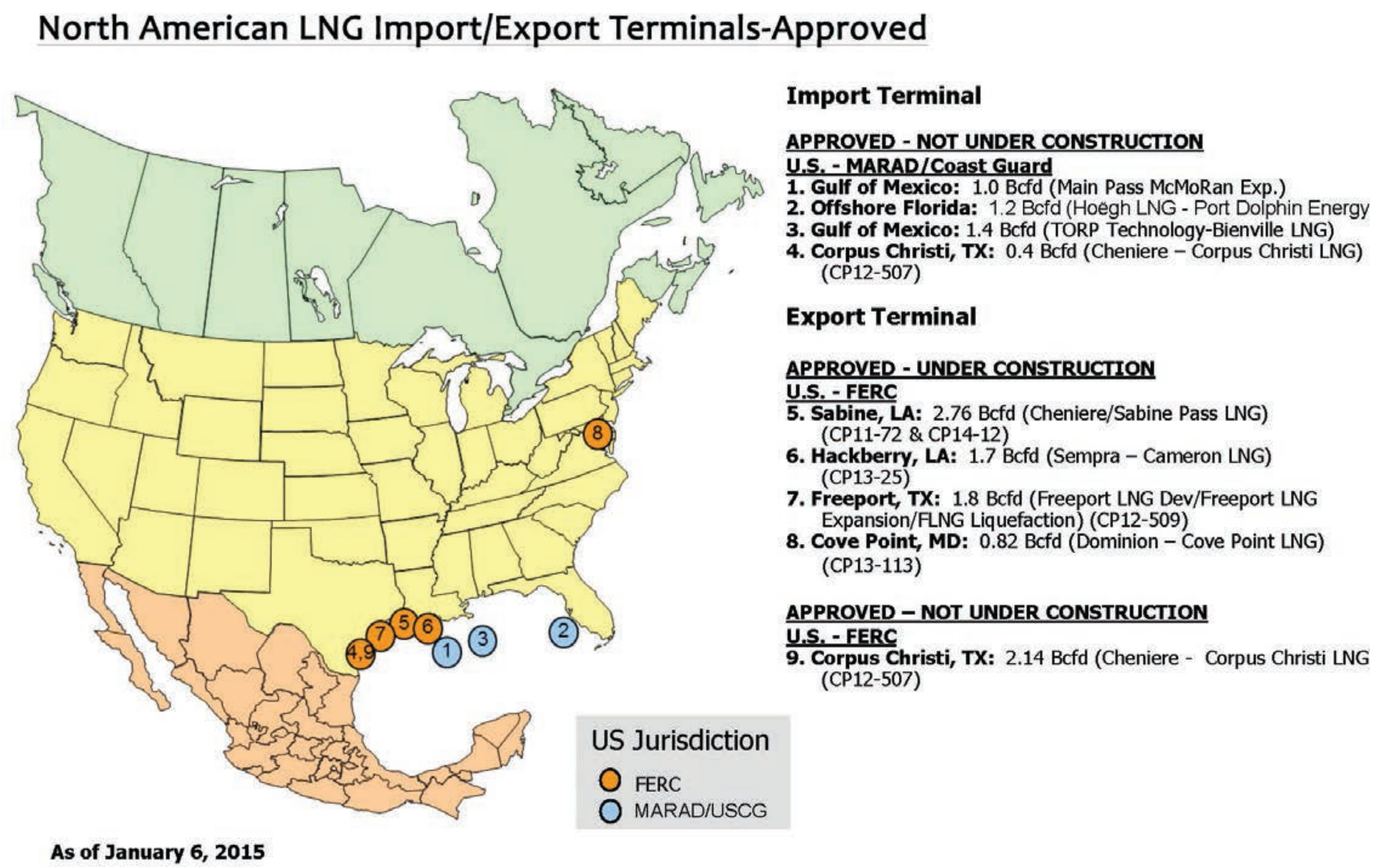
LNG in the United States

The United States is second to Japan in LNG regasification capacity. As of 2014, there were 11 LNG receiving or regasification terminals in the continental United States, with approximately 19 Bcfd of import capacity and 100 Bcf of storage capacity. All of these facilities are on the Gulf or East coasts, or just offshore. In addition, the United States can import regasified LNG into New England from the Canaport LNG terminal in New Brunswick, Canada, and into Southern California from the Costa Azul LNG terminal in Mexico's Baja California.



Source: FERC staff

Between 2003 and 2008, the United States met 1-3 percent of its natural gas demand through LNG imports, according to the EIA. LNG imports peaked at about 100 Bcf/month in the summer of 2007. Growth in relatively low-cost U.S. shale gas production has trimmed U.S. LNG imports, affecting Gulf Coast terminals the most. Today, most LNG enters the United States under long-term contracts (about half of the total) coming through the Everett (Boston) and Elba Island (Georgia) LNG terminals. The remainder of the LNG enters the United States under short-term contracts or as spot cargoes. LNG prices in the United States generally link to the prevailing price at the closest trading point to the import terminal. During 2011-14, the growth in shale gas production led to proposals to export significant volumes of domestically produced LNG. As of January 2015, several LNG export facilities have been approved, but none have yet begun operations. Since 1969, small quantities of LNG have been shipped from Alaska to Pacific Rim countries.



Source: FERC staff

Natural Gas Processing and Transportation

Most domestic natural gas production in the United States occurs in regions well away from major population centers. To get gas from the wellhead to consumers requires a vast network of processing facilities and 2.5 million miles of pipelines. In 2014, this network delivered more than 26 Tcf of natural gas to millions of customers. The U.S. natural gas system can get natural gas to and from almost any location in the Lower 48 states.

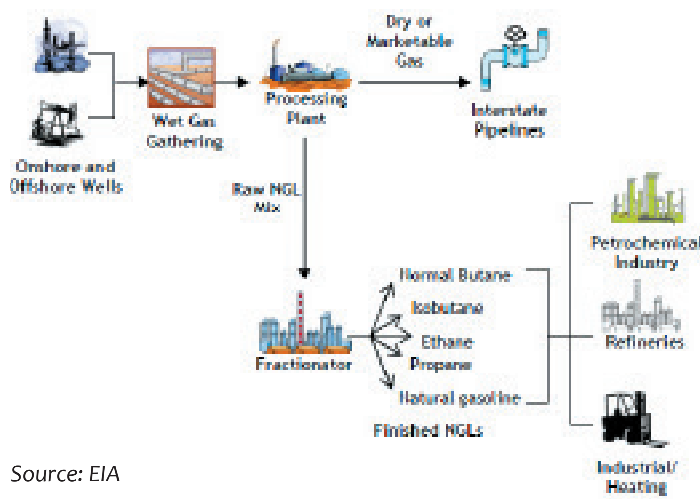
Efficient markets require that this network be robust and allow consumers access to gas from more than one production center. Supply diversity tends to improve reliability and moderate prices, while constraints increase prices.

Processing

The midstream segment of the natural gas industry between the wellhead and pipelines is shown in the graphic. This segment involves gathering the gas from the wellhead, processing the gas to remove liquids and impurities and moving the processed (dry) natural gas to pipelines and the extracted liquids to a fractionator that separates the liquids into individual components. The liquids are used by the petrochemical industry, refineries and other industrial consumers. There were about 500 gas processing plants operating in the United States in 2010.

The composition of raw, or wellhead, natural gas differs by region. Consequently, processing will differ depending on the quality of the natural gas. Natural gas may be dissolved in oil underground but separated out from the oil as it comes to the surface due to reduced pressure. In these instances, the oil and gas are sent to separate processing facilities. Where it does not separate naturally, processing is required.

Midstream Overview



Source: EIA

Once a well is completed and production starts, the natural gas moves into gathering pipelines, typically small-diameter lines that move the gas from the wellhead to either a processing plant or a larger pipeline.

Processing is required when the natural gas and oil do not separate naturally. At the processing plant, wet natural gas is dehydrated, and additional products and contaminants (such as sulfur and carbon dioxide) are extracted. The hydrocarbon liquids, extracted as natural gas liquids, are high-value products used in petrochemical applications. Once processing extracts the NGL, the stream is separated into individual components by fractionation, which uses the different boiling points of the various hydrocarbons to separate them. Once processing is complete, the gas is of pipeline quality and is ready to be moved by intrastate and interstate pipelines.

FERC Jurisdiction

The NGA gives the FERC comprehensive regulatory authority over companies that engage in either the sale of natural gas for resale or its interstate transportation. The Commission regulates market entry through Section 7 of the NGA, 15 U.S.C. § 717f, by issuing certificates of public convenience and necessity, subject to such conditions as the Commission deems appropriate, authorizing natural gas companies to transport or sell natural gas. To this end, the FERC reviews applications for the construction and operation of interstate natural gas pipelines. In its application review, the FERC ensures that the applicant has certified that it will comply with Department of Transportation safety standards. The FERC has no jurisdiction over pipeline safety or security, but actively works with other agencies with safety and security responsibilities. The Commission regulates market exit through its authority to abandon certificated service, 15 U.S.C. § 717f(b).

Natural Gas Transportation

Interstate pipelines account for 63 percent of the natural gas pipeline miles in the United States and carry natural gas across state boundaries. Intrastate pipelines account for the remaining 37 percent, and have similar operating and market characteristics.

The interstate network moves dry natural gas from producing areas to LDCs, large industrial customers, electric power plants and natural gas storage facilities. The pipelines, which range in diameter from 16 inches to as large as 48 inches, move gas between major hubs to lateral lines. Laterals, which range in diameter from 6 inches to 16 inches, distribute gas to retail customers.

The large pipelines are known as mainline transmission pipelines. The pipe used for major pipelines typically consists of strong carbon steel sufficient to meet standards set by the American Petroleum Institute. The pipe is coated to reduce corrosion. Smaller distribution lines, which operate under much lower pressures, may be made of plastic materials, which provide flexibility and ease of replacement.

Nearly one-sixth of all natural gas transmission pipelines, by mileage, are located in Texas. More than half are located in nine states: Texas, Louisiana, Kansas, Oklahoma, California, Illinois, Michigan, Mississippi and Pennsylvania.

Compressor stations, located every 50-100 miles along the pipe, add to or maintain the pressure of the natural gas, propelling it down the pipeline. Natural gas travels through pipelines at high pressures, from 200 pounds per square inch (psi) to 1,500 psi.

The natural gas is compressed by turbines, motors or engines. Turbines and reciprocating natural gas engines use some of the gas from the line to fuel their operations; electric motors rely on electricity.

Natural Gas Infrastructure

The United States natural gas market is accommodated by extensive infrastructure:

- Roughly 303,000 miles of wide-diameter, high pressure inter- and intrastate pipelines make up the mainline pipeline transportation network, run by more than 210 companies.
- More than 1,400 compressor stations maintain pressure on the natural gas pipeline network.
- More than 5,000 receipt points, 11,000 delivery points and 1,400 interconnection points implement the flow of gas across the United States.
- Nearly three dozen hubs or market centers provide addition interconnections.
- Over 400 underground natural gas storage facilities increase the flexibility of the system.
- 49 locations enable natural gas to be imported or exported via pipelines.
- There are 9 LNG import facilities and 100 LNG peaking facilities (stored gas held for peak demand periods).
- More than 1,300 local distribution companies deliver natural gas to retail customers.

Source: EIA

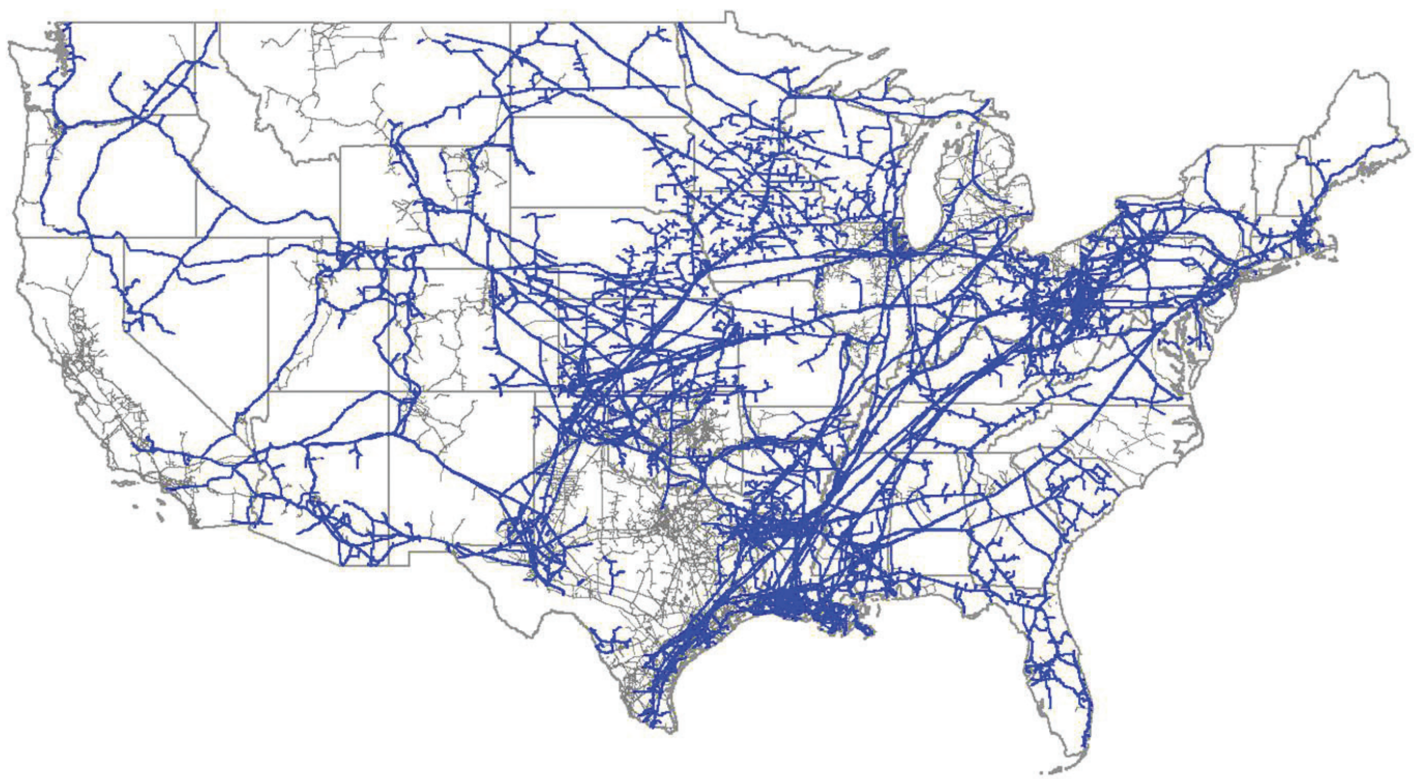
Metering stations are placed along the pipelines to measure the flow of natural gas as it moves through the system.

Movement of natural gas along a pipeline is controlled in part by a series of valves, which can be opened to allow the gas to move freely or closed to stop gas flow along a section of pipe. Large valves may be placed every 5 to 20 miles along the pipeline.

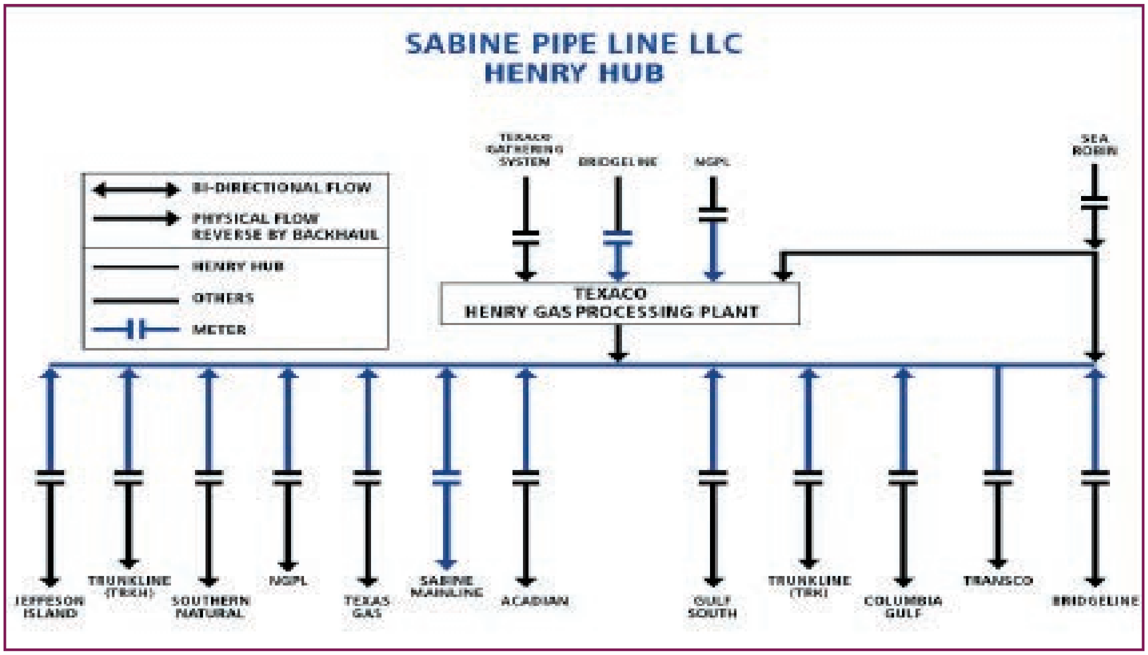
Pipeline operators use supervisory control and data acquisition (SCADA) systems, to track the natural gas as it travels through their systems. SCADA is a centralized communication system that collects, assimilates and manages the meter and compressor station data. SCADA also conveys this information to the centralized control station, allowing pipeline engineers to know what is happening on the system at all times.

As the product moves closer to the consumption areas, it may be stored in underground facilities. Plentiful storage capacity adds flexibility to the pipeline and distribution systems and helps moderate prices by providing an outlet for excess gas during periods of low demand, and readily accessible supply in periods of high demand. Some natural gas can also be stored in the pipelines as linepack, in which more molecules of gas are held in a segment of pipeline under greater-than-normal pressure.

Natural Gas Transportation System



Source: Derived from Velocity Suite, ABB



Source: Sabine Pipeline, LLC

Hubs

A key part of the pipeline distribution network is the natural gas hub. Typically, a hub is a specific point where pipeline interconnections allow the transfer of gas from one pipeline to another.

There are dozens of natural gas hubs in the country, with over 20 major hubs. The Henry Hub is the dominant benchmark point in the physical natural gas market because of its strategic location in the Gulf Coast's producing area and the number of pipeline connections to the East Coast and Midwest consumption centers. It is located in south central Louisiana, in the town of Erath, where more than a dozen major natural gas pipelines converge and exchange gas. The Henry Hub has 12 delivery points and 4 major receipt points.

Gas as a physical product can be bought and sold at the Henry Hub or other hubs around the country in daily and monthly markets. In addition, the New York Mercantile Exchange (Nymex) established a natural gas futures contract centered at the Henry Hub in 1990 that gained widespread acceptance and is generally used as the reference price for natural gas in the United States.

Distribution lines typically take natural gas from the large transportation pipelines and deliver the gas to retail customers. While some large consumers – industrial and electric generation, for example – may take service directly off a transmission pipeline, most receive their gas through their local gas utility, or LDC. These companies typically purchase natural gas and ship it on behalf of their customers, taking possession of the gas from the pipelines at local citygates and delivering it to customers at their meters. This distribution involves a network of smaller pipelines – more than two million miles, according to the U.S. Department of Transportation.

FERC Jurisdiction

The NGA requires that interstate natural gas pipelines charge just and reasonable rates for the transportation and sale of natural gas. To promote compliance with this mandate, the NGA requires gas pipelines to file rate schedules with the FERC and to notify the FERC of any subsequent changes in rates and charges. On submission of a tariff revision, the FERC may hold a hearing to determine whether the pipeline has met its burden to show that the amended rates and charges are just and reasonable.

Under Sections 4 and 5 of the NGA, 15 U.S.C. §§ 717c and 717d, the Commission regulates the rates and other terms of jurisdictional transportation and sales, ensuring that rates and charges for such services, as well as all rules, regulations, practices, and contracts affecting those rates and charges, are just and reasonable and not the product of undue discrimination (15 U.S.C. §§ 717c(a) and (b)).

Pipeline Services

Customers or shippers may choose among a variety of services on interstate pipelines. One is firm transportation capacity, or primary market service, in which an agreement is executed directly between the pipeline and a customer for a year or more, relying on primary receipt and delivery points. Shippers with firm transportation service generally receive priority to ship for the contracted quantity.

A second type of transportation service a shipper can contract for is interruptible transportation service. Interruptible transportation service is offered to customers under schedules or contracts on an as-available basis. This service can be interrupted on a short notice for a specified number of days or hours during times of peak demand or in the event of system emergencies. In exchange for interruptible service, customers pay lower prices.

A secondary market for firm transportation rights enables shippers to sell their pipeline capacity to a third party through the FERC's capacity release program. Services offered in the primary market can be offered in the secondary market by the holder of the primary service. Released capacity offers market participants the opportunity to buy and sell from each other as well as from the pipeline. Holders of primary capacity can release segments rather than their full holdings, provided segmentation is operationally feasible on the interstate pipeline's system.

Interstate pipelines also provide "no-notice service" under which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty. If a shipper has firm storage and transportation service, that shipper can schedule in the day-ahead market and yet have the ability and the right to physically take a different quantity than what was scheduled without incurring imbalance penalties. No-notice service is particularly valuable during periods of high demand when transportation capacity may be completely used. This service is especially helpful to LDCs that must serve their load without knowing their exact load level each day. No-notice service is generally priced at a premium to firm transportation service. Shippers may temporarily release this service to other parties, using FERC-approved capacity release guidelines.

Interstate Transportation Rates

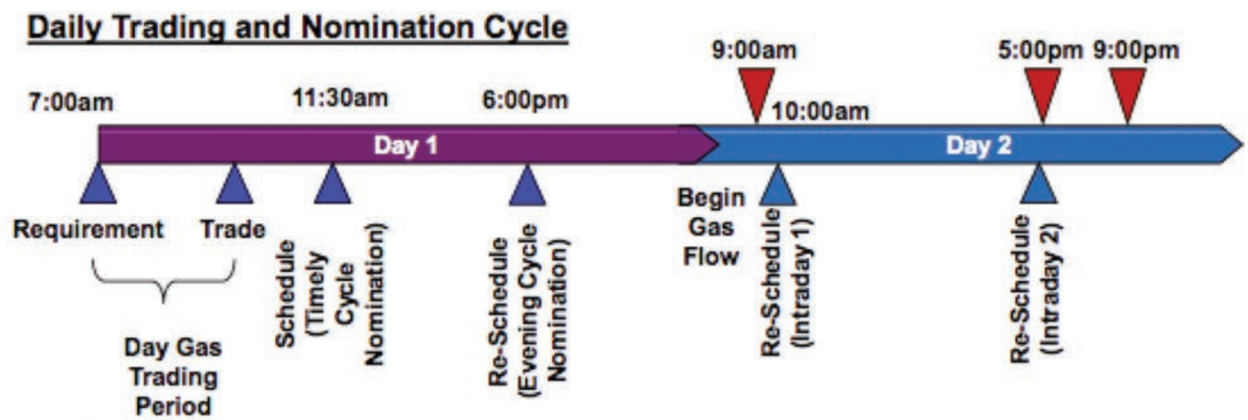
Pipeline transportation rates can be priced on zones or miles, or be a fixed postage stamp rate. In zonal pricing, the price of transportation varies by the location of the receipt and delivery points, across a series of zones.

Under postage stamp rates, shippers pay the same rate for transportation regardless of how far the gas is moved, similar to the way a postage stamp costs the same amount regardless of whether a letter is sent to New York or California. Pipelines using postage stamp rates include Northwest Pipeline, Colorado Interstate Gas and Columbia Gas Transmission.

With mileage-based rates, shippers pay based on the distance between where the gas enters the pipeline and where it is taken out of the pipeline. The rate is designed to reflect the distance involved in transporting the gas. Gas Transmission Northwest (GTN) uses mileage-based rates.

Other pipelines use hybrid or mixed-rate systems. Northern Natural Gas, for example, uses a combination zonal rate for upstream receipts and a postage stamp rate for market area deliveries.

Pipeline Capacity Scheduling



Cycle	Cycle Description
T	Timely Nominations sent by 11:30 AM and to the Pipeline by 11:45 AM to be effective at 9 AM next gas day
E	Evening Nominations sent by 6 PM and to the Pipeline by 6:15 PM to be effective 9 AM the next day. This is the cycle used for reporting on today's flow before the I2 cycle data is available.
I1	Intraday 1 nominations sent by 10 AM and to the Pipeline by 10:15 AM to be effective at 5PM the same day
I2	Intraday 2 nominations sent by 5 PM and to the Pipeline by 5:15 PM to be effective at 9 PM the same day. This is the cycle used for most Pipe2Pipe reporting purposes.

Source: *Bentek Energy LLC*

Scheduling

Pipelines have rigorous schedules that shippers must follow. Typically, shippers nominate gas in the day-ahead market, and may update their nominations at various points during the day in which the natural gas flows. The Pipeline Capacity Scheduling graphic illustrates a particular schedule.

Pipeline Usage or Load Factor

Load factor measures the use of a pipeline network. It is the average capacity used at a given point or segment relative to a measurement of maximum or peak available capacity. Customers with a 100 percent load factor use their maximum capacity every day; one with a 50 percent load factor uses its capacity only half the time. Different types of customers use pipeline capacity differently. Historically, industrial customers have exhibited high load factors and residential customers that primarily rely upon seasonal gas to heat homes have had lower load factors.

Pipelines are accustomed to serving different demands, which can affect how much of their capacity is used at various times. For example, Kern River Gas Transmission has operated at around 93 percent of capacity since 2005, while Algonquin Gas Transmission's capacity factor is considerably less. Algonquin's pipeline is used more seasonally than Kern River's, reflecting the seasonal demand in the Northeast.

Park and Loan Service

Park and loan service (PAL) is a way for shippers to balance their takes of gas with their supply, by providing a short-term load-balancing service to help shippers meet their load. Using the PAL service, shippers can take less gas than scheduled, thus parking their excess supply in the pipeline at times when the demand is lower than anticipated. If demand is higher than expected, shippers can adjust their take upward, in effect borrowing gas from the pipeline.

PAL characteristics include:

- Park and loan services typically generate low revenue and are offered with the lowest service level priority among all pipeline services.
- Rates are based on costs associated with providing the services, such as plant costs if the services are offered.
- Market centers, or hubs, routinely offer these services.
- Charges are usually commensurate with interruptible service rates.
- Pipelines earn minimal revenue from park and loan.

Pipeline Constraints and Capacity Growth

Pipeline capacity limits the supply that can be delivered to a specific region and is, therefore, a key factor in regional prices.

In recent years, the natural gas pipeline network has expanded significantly, removing bottlenecks and providing access to previously unreached supply areas.

A considerable amount of new pipeline capacity has been added in recent years to the Northeast. As Northeast production ramped up in 2008 and 2009, annual pipeline capacity additions in the region rose to 2.6 Bcfd in 2009 along with the production increases. Pipeline capacity additions moderated in 2010 and 2011 until surging again to reach annual additions of 2.9 Bcfd in 2012 and 2.6 Bcfd in 2013. Much of this new capacity was targeted at improving access to shale gas.

Building a pipeline project requires careful planning, as the projects typically entail significant costs that must be recovered over years of operations. However, unanticipated changes in supply and demand patterns can have unexpected effects on even the best-planned projects. For example, one of the largest additions to the natural gas infrastructure came when the 1.8-Bcfd Rockies Express Pipeline (REX) was completed in 2009. REX was designed to move natural gas from Wyoming to eastern Ohio in order to relieve pipeline constraints that bottled up production and depressed prices in the Rockies, while at the same time providing needed supplies into the East. When REX first went into service, Rockies producers saw a rise in prices. The Rockies gas flowing eastward displaced gas from the Permian Basin. Permian natural gas, in turn, began moving to the Southern California market. Consequently, regional price differences moderated. However, the rapid increase in Marcellus Shale production pushed Rockies supplies away from the Northeast and caused flows on REX to decrease sharply, putting the pipeline at financial risk. In 2014, REX began the process of reversing flows on parts of the pipeline to move natural gas from the east to the Midwest. This development is making more Rockies natural gas available to Western Markets, and more midcontinent production available for the Gulf Coast and Southeast states.

Other projects are operating as designed. New pipelines to increase the flow of Barnett Shale gas into the interstate network have reduced congestion across the Texas-Louisiana border.

The Florida Panhandle and Northern California used to be some of the most frequently constrained regions of the country, but each has received significant new pipeline capacity. Expansion of Florida Gas Transmission in 2011 added about 800 MMcfd, a boost of 33 percent, of gas transmission capacity to peninsular Florida. The 680-mile, 42-inch-diameter Ruby Pipeline, which began operations in 2011, now flows Rockies gas from Opal, Wyo., to Malin, Ore.

Local Distribution

Distribution lines typically take natural gas from the large interstate pipelines and deliver the gas to retail customers. While some large consumers – industrial and electric generators, for example – may take service directly off an interstate pipeline, most receive their natural gas through their LDC. LDCs typically purchase natural gas and ship it on behalf of their customers. They take possession of the natural gas from interstate pipelines at local citygates and deliver the natural gas to their customers at the customer's meter. According to the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration, this distribution involves a network of smaller pipelines totaling more than two million miles, as well as smaller scale compressors and meters.

Some states allow competition in natural gas service at the local level. In these circumstances, natural gas marketers purchase the natural gas and arrange for it to be shipped over both the interstate pipeline network and the LDC system.

Natural Gas Storage

Although natural gas production rose steadily from 2005 through 2014 because of the increase in shale gas production, day-to-day production remains relatively steady throughout the year. Demand, however, changes considerably with the seasons. Natural gas storage enables producers and purchasers to store gas during periods of relatively low demand – and low prices – then withdraw the gas during periods of relatively higher demand and prices.

Working gas storage capacity, as tracked by EIA, was more than 4,100 Bcf in 2014. The amount injected or withdrawn is the difference between demand and production. Storage capacity adds flexibility to pipeline and distribution systems and helps moderate prices by providing an outlet for excess gas during periods of low demand. Storage facilities also provide a readily accessible supply in periods of high demand. Some natural gas can also be stored in the pipelines as linepack, in which more molecules of gas are held in a segment of pipeline under greater-than-normal pressure.

EIA's weekly storage report provides a high-level snapshot of the natural gas supply and demand balance. EIA releases its storage report at 10:30 a.m. on Thursdays. The price for natural gas futures can change dramatically within seconds of the report's release. If the reported injection or withdrawal significantly differs from market expectations, the price for natural gas futures may rise or fall.

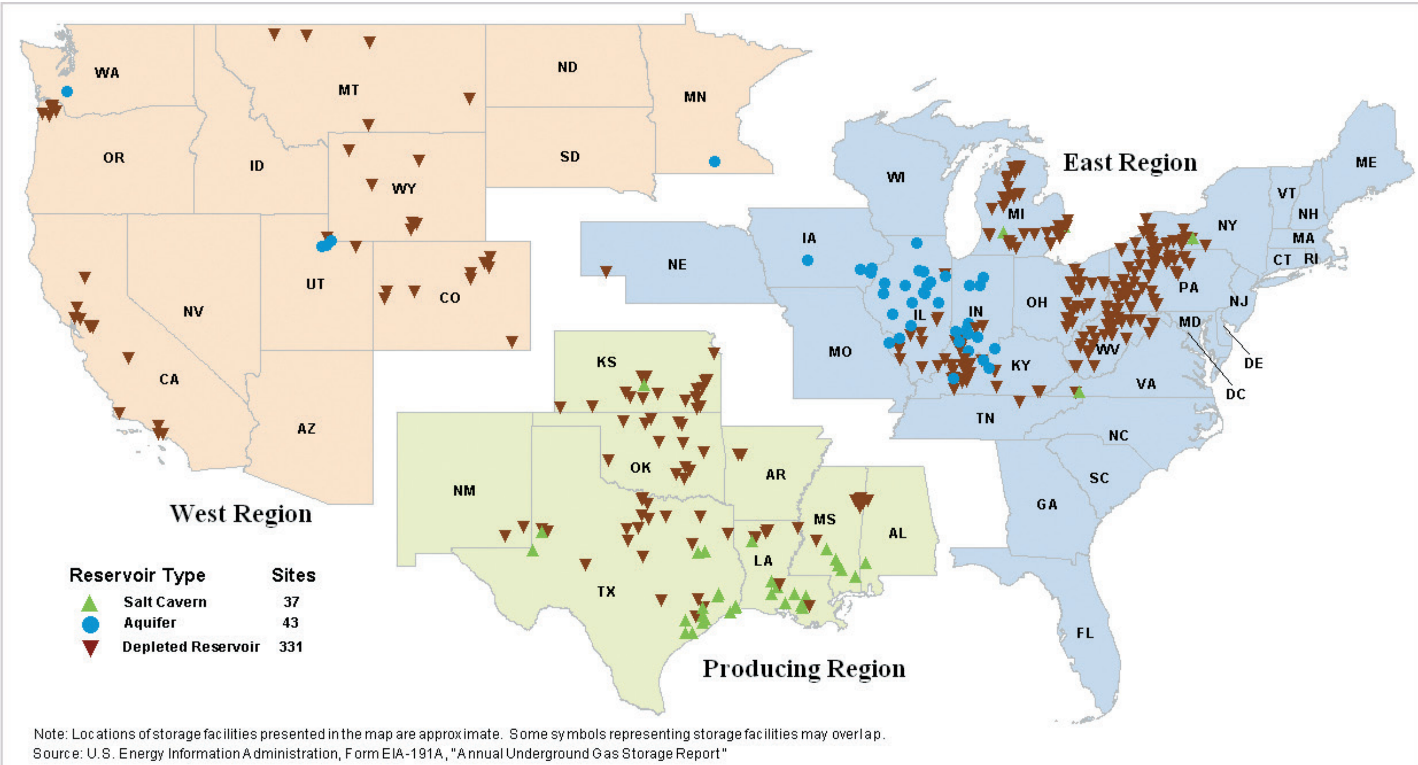
Storage Facilities

The bulk of the storage capacity in the United States is below ground. Differing cost and operational characteristics affect how each facility is used:

- Deliverability rate is the rate at which inventory can be withdrawn. The faster the natural gas can be removed from storage, the more suitable the storage facility is to helping serve rapidly changing demand.

- Cycling capability is the ability of the resource to quickly allow injections and withdrawals, which is useful for balancing supply and demand. Salt caverns tend to have high withdrawal and injection rates, enabling them to handle as many as a dozen withdrawal and injection cycles each year. LNG storage also demonstrates these capabilities.

Underground Natural Gas Storage Facilities in the Lower 48 States

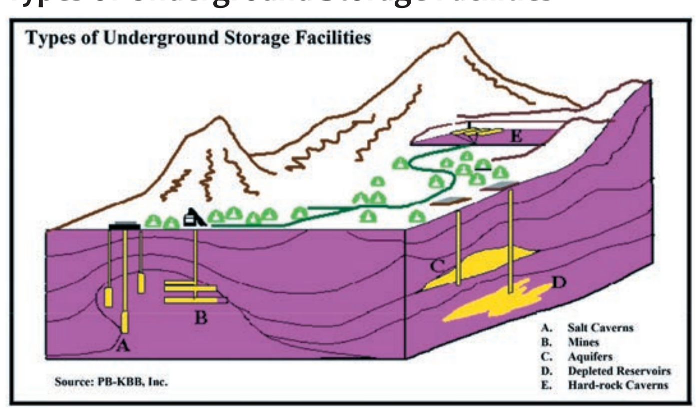


Natural gas in an underground storage facility is divided into two general categories, working gas and base gas. Base gas is the volume of natural gas, including native gas, needed as a permanent inventory in a storage reservoir to maintain adequate reservoir pressure and deliverability rates throughout the withdrawal season. Working gas is the volume of gas in the reservoir above the designed level of base gas and that can be extracted during the normal operation of the storage facility.

Most of the nation's gas storage is in depleted reservoirs (former oil and gas fields). These facilities reuse the infrastructure – wells, gathering systems and pipeline connections – originally created to support the field when it was producing. About 50 percent of total capacity goes to base gas used to maintain operating pressure at the facility, and inventory usually turns over once or twice a year.

Other storage facilities reside in aquifers that have been transformed into gas storage facilities. These are mostly in the Midwest. These aquifers consist of water-bearing sedimentary rock overlaid by an impermeable cap rock. Aquifers are the most expensive type of natural gas facility because they do not have the same retention capability as depleted reservoirs. Therefore, base gas can be well over 50 percent of the total gas volume. This makes the facility more sensitive to withdrawal and injection patterns, so inventory usually turns over just once a year.

Types of Underground Storage Facilities



Salt cavern formations exist primarily in the Gulf Coast region. These air- and water-tight caverns are created by removing salt through solution-mining, leaving a cavern that acts as a pressurized vessel. Little base gas is required, which allows inventory to turn over as many as a dozen times during the year, and results in high injection and withdrawal rates. This flexibility attracted new development, resulting in the growth of salt cavern storage through 2008. Salt caverns generally hold smaller volumes than do depleted-reservoir or aquifer gas storage facilities.

Natural gas may also be stored in above-ground tanks as LNG. There is LNG storage at all of the onshore LNG-receiving terminals, and there are about a hundred standalone LNG storage facilities in the United States, as well. LNG ships can also serve as storage, depending on timing and economics. LNG storage is highly flexible, allowing multiple inventory turns per year with high injection and withdrawal rates.

Regional Storage

The EIA divides the United States into three storage regions: producing, East and West. Just over half of the underground storage in the United States, 2,200 Bcf, sits in the East near population centers. Much of this is in aquifers and depleted fields. Almost 1,500 Bcf sits in the producing region, which has not only depleted fields but also the greatest concentration of more-flexible salt cavern storage. The remaining 600 Bcf is in the West, primarily in depleted fields, for total working gas capacity of almost 4,300 Bcf. Depending on storage levels at the end of the previous winter, and the temperatures over the injection season, U.S. working gas in storage will generally be between 80 and 90 percent full when the official winter season begins on November 1.

Storage Service and Uses

Approximately 120 entities – including interstate and intrastate pipeline companies, LDCs and independent storage service providers – operate the nearly 400 underground storage facilities active in the continental United States, according to the EIA. Facilities operated by interstate pipelines and many others are operated on an open-access basis, with much of the working gas capacity available for lease on a nondiscriminatory basis.

The ability to store large quantities of natural gas improves reliability and usually has a moderating influence on natural gas prices. Storage inventory augments natural gas supply during the winter, and acts as an additional demand component during the summer injection season. The storage injection season typically starts April 1 and continues through Oct. 31, when demand for gas heating is lowest. Storage withdrawals generally start in November and last throughout the winter.

The ability to use storage to provide for winter peaks creates an intrinsic storage value. This is the value from buying during cheaper periods of the year for use during higher-cost seasons. Depleted reservoirs or aquifers – with limited ability to turn over inventory – support this type of use. Local distribution companies or pipelines store their gas in these facilities to ensure adequate supplies for peak seasons, balance load and diversify their resources.

Storage may be priced at cost-based or market-based rates. Pricing mechanisms for low-cycling depleted fields and aquifers may use a traditional cost-of-service structure, including:

- Capacity charges for firm contract rights to physical storage capacity
- Deliverability charges for transportation to and from the storage facility
- Withdrawal charges for the removal of gas from storage
- Injection charges for the injection of gas into storage

A salt cavern, with its ability to turn over inventory frequently and quickly, allows for additional uses, enabling users to capture extrinsic value. Many salt dome facilities can cycle between injection and withdrawal at almost a moment's notice, giving users greater flexibility. Entities leasing storage capacity may move gas in and out of storage as prices change in attempts to maximize profits or minimize costs. Storage may be a component in producer or consumer hedging strategies, helping them to manage the risk of price movements.

Further, storage helps shippers avoid system imbalances and associated penalties, and supports swing gas supply services, which are short-term contracts that provide flexibility when either the supply of gas from the seller, or the demand for gas from the buyer, are unpredictable. Storage also facilitates title transfers and parking and lending services. This helps shippers balance daily receipts and deliveries, manage their overall supply portfolio or take advantage of price movements. Consequently, storage operators have begun offering a more varied menu of services, and users have begun using storage as a commercial tool and as part of a comprehensive supply portfolio strategy.

Merchant storage, frequently using salt caverns, uses market-based prices, recognizing the dynamics affecting value at any given point in time. Prices often take into account the prices at which the Nymex futures contracts are trading. They may also reflect the storage volume, the number of times the gas will be cycled, the length of the contract and the timeframe it covers and the maximum daily quantity that may be injected or withdrawn. Energy marketers have increasingly used these facilities as they try to profit from price volatility. It is also attractive to shippers, industrial consumers with uncertain loads and gas-fired generators whose needs change rapidly.

Pipelines also offer storage service, both firm and interruptible, as part of their open access transportation service under FERC rules. Rates are rarely market-based. Instead, prices are based on cost of service, with rates containing reservation and usage components for firm service and a usage component for interruptible.

Market Effects

Storage can mitigate large seasonal price swings by absorbing natural gas during low demand periods and making it available when demand rises.

Further, storage levels can affect the market's expectations about prices during the coming winter high-demand season. The amount of gas in storage in November is a key benchmark of the gas industry's ability to respond to changes in winter weather. Higher storage levels tend to reduce forward prices; lower storage levels tend to increase them, all other market conditions being equal.

FERC Jurisdiction

The underground storage of natural gas has historically been critical in assuring that the needs of natural gas customers are met. The Energy Policy Act of 2005 added a new section to the Natural Gas Act stating that the Commission may authorize natural gas companies to provide storage and storage-related services at market-based rates for new storage capacity, even though the company cannot demonstrate it lacks market power (15 U.S.C. § 717c(f)). To make this authorization, the FERC must determine that market-based rates are in the public interest and are needed to encourage the construction of new capacity, and that customers are adequately protected.

Natural Gas Markets and Trading

The natural gas industry in the United States is highly competitive, with thousands of producers, consumers and intermediate marketers. Some producers have the ability to market their natural gas and may sell it directly to LDCs, to large industrial buyers and to power plants. Other producers sell their gas to marketers who aggregate natural gas into quantities that fit the needs of different types of buyers and then transport the gas to their buyers.

Most residential and commercial customers purchase natural gas from a LDC. In contrast, many industrial customers and most power plants have the option to purchase natural gas from a marketer or producer instead of from the LDC, thereby avoiding any LDC charges.

Interstate pipelines do not buy and sell natural gas and are limited to providing transportation and storage services only. As noted, interstate pipelines transport natural gas at rates approved by the FERC.

Natural Gas Marketers

Most gas trading in the United States is performed by natural gas marketers. Any party engaging in the sale of natural gas can be termed a marketer; however, marketers are usually specialized business entities dedicated solely to transacting in the physical and financial energy markets. It is commonplace for natural gas marketers to be active in a number of energy markets, taking advantage of their knowledge of these markets to diversify their business.

Marketers can be producers of natural gas, pipeline marketing affiliates, LDC marketing affiliates, independent marketers, financial institutions, or large-volume users of natural gas. Some marketing companies may offer a full range of services, marketing numerous forms of energy and financial products, while others may be more limited in their scope. For instance, most marketing firms affiliated with producers do not sell natural gas from third parties; they are more concerned with selling their own production and hedging to protect their profit margin from these sales.

Generally speaking, there are five categories of marketing companies: major nationally integrated marketers, producer marketers, small geographically focused marketers, aggregators and brokers.

The major nationally integrated marketers offer a full range of services, and market numerous different products. They operate on a nationwide basis and have large amounts of capital to support their trading and marketing operations. Producer marketers are those entities generally concerned with selling their own natural gas production or the production of their affiliated natural gas production company. Smaller marketers target particular geographic areas and specific natural gas markets. Many marketing entities affiliated with LDCs are of this type, focusing on marketing gas for the geographic area in which their affiliated distributor operates. Aggregators generally gather small volumes from various sources, combine them, and sell the larger volumes for more favorable prices and terms than would be possible selling the smaller volumes separately. Brokers are a unique class of marketers because they never take ownership of natural gas themselves. They simply act as facilitators, bringing buyers and sellers of natural gas together.

All marketing companies must have significant backroom operations in addition to the core trading group. These support staff are responsible for coordinating everything related to the sale and purchase of physical and financial natural gas, including arranging transportation and storage, posting completed transactions, billing, accounting and any other activity that is required to complete the purchases and sales arranged by the traders.

In addition to the traders and backroom staff, marketing companies typically have extensive risk-management operations. The risk-management team is responsible for ensuring that the traders do not expose the marketing company to excessive risk.

Market Hubs

Natural gas is priced and traded at different locations throughout the country. These locations, referred to as market hubs, exist across the country and are located at the intersections of major pipeline systems. The price at which natural gas trades differs across the major hubs, depending on the supply and demand for natural gas at the particular points. The difference between the Henry Hub price and another hub is called the location differential, or basis. In addition to market hubs, other major pricing locations include citygates. Citygates are the locations at which distribution companies receive gas from a pipeline. Citygates at major metropolitan centers can offer another point at which natural gas is priced.

In addition to being the country's benchmark hub, the Henry Hub is also the delivery point for the Nymex natural gas futures contract. Changes in price at the Henry Hub provide a good indicator of how prices are generally changing across the country.

Basis usually reflects the variable cost to transport gas between the Henry Hub and another hub. Basis can change, sometimes dramatically, depending on local market conditions, and can widen considerably when pipelines between two points are congested. Basis in excess of transportation costs results from pipeline constraints and lack of pipeline competition. The gas price at a hub in Florida, for example, would be the price at the Henry Hub and the basis to the Florida hub.

Physical Trading of Natural Gas

Natural gas contracts are negotiated between buyers and sellers. There are many types of natural gas contracts, but most share some standard specifications, including specifying the buyer and seller, the price, the amount of natural gas to be sold (usually expressed in a volume per day), the receipt and delivery point, the tenure of the contract (usually expressed in number of days beginning on a specified day) and other terms and conditions. The special terms and conditions usually outline such things as the payment dates, quality of the natural gas to be sold, and any other specifications agreed to by both parties.

Natural gas contracts are negotiated between buyers and sellers over the phone or executed on electronic bulletin boards and e-commerce trading sites.

There are three main types of natural gas contracts: swing contracts, baseload contracts, and firm contracts:

- Swing (or interruptible) contracts are usually short-term contracts between one day and a month in length. These contracts are the most flexible, and are usually put in place when either the supply of gas from the seller, or the demand for gas from the buyer, are unreliable.
- Baseload contracts are similar to swing contracts. Neither the buyer nor seller is obligated to deliver or receive the exact volume specified. However, it is agreed that both parties will attempt to deliver or receive the specified volume, on a best-efforts basis.
- Firm contracts are different from swing and baseload contracts in that both parties are legally obligated to either receive or deliver the amount of gas specified in the contract. These contracts are used primarily when both the supply and demand for the specified amount of natural gas are unlikely to change.

Price Discovery

Spot (Cash) Market

The U.S. natural gas marketplace has a highly competitive spot, or cash, market where brokers and others buy and sell natural gas daily. The daily spot market for natural gas is active, and trading can occur 24 hours a day, seven days a week. The map on the next page shows some of the points where natural gas for next-day physical delivery is actively traded on the IntercontinentalExchange (ICE). Some of these points are market centers, where brokers actively trade and prices are established. In addition to these market centers, natural gas is actively traded at many other locations, including segments of individual pipelines and locations where pipelines interconnect with LDCs.

Spot market transactions are normally conducted on electronic exchanges or by telephone, with the buyer agreeing to pay a negotiated price for the natural gas to be delivered by the seller at a specified delivery point on the next day. Natural gas spot prices reflect daily supply and demand balances and can be volatile.

Bidweek

Bidweek is the name given to the last five business days of a month. This is the week when producers sell their core production and consumers buy natural gas for their core needs for the upcoming month.

Index Prices

Several publications, such as Platts Gas Daily, Natural Gas Intelligence and Natural Gas Week, survey the market for daily transaction prices that are used to form and publish a daily index that is made available the night before or the morning of the next business day. Many market participants also report their bidweek prices to publications, which convert these prices into monthly locational price indexes that are available on the first business day following the last day of bidweek. These daily and monthly indexes, in turn, are used as the basis for pricing for those firms that do not choose to enter into fixed-price contracts (or are prohibited from using them by state or local regulators).

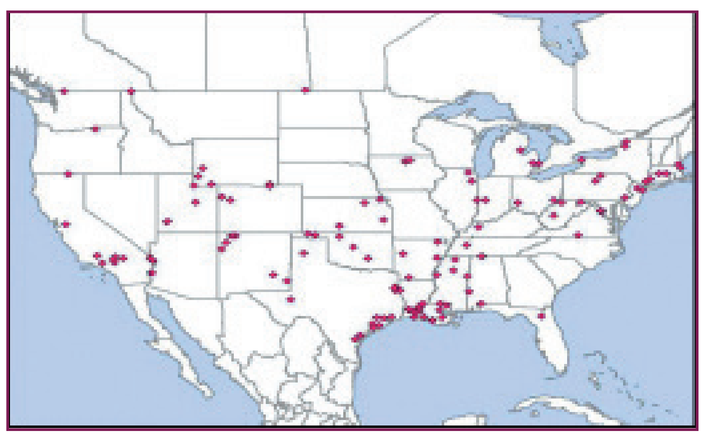
The Financial Market

In addition to trading physical natural gas, there is a significant market for natural gas derivatives and financial instruments in the United States. In the financial market, market participants are interested in profiting from the movement of the price of natural gas rather than delivering or receiving natural gas. The pricing and settlement of these financial products are tied to physical natural gas. It is estimated that the value of trading that occurs on the financial market is at least a dozen times greater than the value of physical natural gas trading.

Derivatives are financial instruments that derive their value from an underlying fundamental – in this case, the price of natural gas. Derivatives can range from being quite simple to being exceedingly complex. Traditionally, most derivatives are traded on the over-the-counter (OTC) market, which is essentially a group of market players interested in exchanging certain derivatives among themselves.

More information on financial markets appears in Chapter 5.

Hubs for Physical Trading on ICE



Source: Derived from Intercontinental Exchange data

3. Wholesale Electricity Markets

Electricity is a physical product – the flow of electrons. It is a secondary energy source in that it results from the conversion of other energy forms such as natural gas, coal or uranium, or the energy inherent in wind, sunshine or the flow of water in a river. It may not be visible, but it can be turned on and off and measured.

Quick Facts: Measuring Electricity

Electricity is measured in terms of watts, typically in kilowatts (1,000 watts) or megawatts (1,000 kilowatts).

A kilowatt (or watt or megawatt) is the amount of energy used, generated or transmitted at a point in time. The aggregation of kilowatts possible at a point in time for a power plant, for example, is its capacity. The aggregation of kilowatts used at a point of time is the demand at that point.

The number of kilowatts used in an hour (kilowatt-hour or kWh and, in larger quantities, megawatt-hour or MWh) is the amount of electricity a customer uses or a power plant generates over a period of time.

Electricity markets have retail and wholesale components. Retail markets involve the sales of electricity to consumers; wholesale markets typically involve the sales of electricity among electric utilities and electricity traders before it is eventually sold to consumers. Because FERC has jurisdiction over the wholesale markets, and not the retail markets, this paper focuses on wholesale electricity markets, although it addresses retail demand and other instances where retail markets strongly influence wholesale markets.

Much of the wholesale market and certain retail markets are competitive, with prices set competitively. Other prices are set based on the service provider's cost of service. For wholesale markets, FERC either authorizes jurisdictional entities to sell at market-based rates or reviews and authorizes cost-based rates.

In competitive markets, prices reflect the factors driving supply and demand – the physical fundamentals. Where rates are set based on costs, market fundamentals matter as well because changes in supply and demand will affect consumers by influencing the cost and reliability of electricity. Supply incorporates generation and transmission, which must be adequate to meet all customers demand simultaneously, instantaneously and reliably.

Consequently, key supply factors that affect prices include fuel prices, capital costs, transmission capacity and constraints and the operating characteristics of power plants. Sharp changes in demand, as well as extremely high levels of demand, affect prices as well, especially if less-efficient, more-expensive power plants must be turned on to serve load.

Electric Power Industry

Electricity on Demand

In the United States and other developed countries, consumers expect electricity to be available whenever they need it. Electricity use has grown enormously as consumers now consider not only refrigerators, TVs and hair dryers but also computers and other electronic devices as necessities. Consumers also expect to pay reasonable prices for the electricity they use.

Meeting these customer expectations is challenging. With few exceptions, electricity cannot be stored in any appreciable quantities, and thus must be produced as needed. Further, unlike most other markets, electricity's historical inelastic demand does not move with prices. To provide electricity on demand, electric system operations have to be planned and conducted with that goal in mind. Lacking storage and responsive demand, operators must plan and operate power plants and the transmission grid so that demand and supply exactly match, every moment of the day, every day of the year, in every location.

The Drive for Enhanced Value

The electric industry has met this growing demand with increasing efficiency. Between 1929 and 1967, the national average cost of electricity for residential customers plummeted from about 60¢/kWh to 10¢/kWh (in 2005 dollars), and remains around there today. How did the industry achieve such tremendous cost savings and then keep the real price of electricity flat over the past 40 years? Part can be explained by greater efficiency – power plants use less fuel, and new techniques make it cheaper to extract the coal and natural gas that fuels generators. Another part of the answer, though, stems from changes in the way the industry is organized and operated.

Economies of Scale

Electric power is one of the most capital intensive industries. Generation alone can account for roughly 65 percent of a customer's electric bill. Spreading these relatively fixed costs over more customers helps bring down the cost that each customer pays.

Thomas Edison's first street lighting project in the 1880s grew to electrifying whole neighborhoods, towns and cities. Providing service over larger areas allowed utilities economies of scale in generating technology. The cost per unit of production dropped as power plants grew larger and larger. The companies building these facilities were basically self-contained – they owned and operated the generation, transmission and distribution facilities. Power lines were built from their generation to their population, or load, centers. These companies were vertically integrated.

One downside of larger generating units is that they are difficult to replace if they experience unexpected shutdowns. For a single utility building a new and larger unit, the only way to ensure reliable service is to build two units – creating a capacity reserve. When coal and nuclear unit sizes grew to 500 or 1,000 MW, building two units became very expensive for any individual company.

Reserve Sharing, Interconnection and Power Pools

The solution to high reserve costs was to share reserves with adjacent utilities. Instead of building two large units, utilities could buy from their neighbors in times of need, and cut their costs significantly. To facilitate reserve sharing, utilities built major interconnecting transmission lines large enough to deliver power in case of a major generator outage. Today's bulk power grid began as a way to maintain reliable service while lowering costs.

As more utilities share reserves, the smaller the amount of reserves each must carry, and the lower the costs. The value of reserve-sharing agreements led to the formation of power

pools, the forerunners of today's regional transmission organizations.

Coordinating exchanges of energy and reserves also led to closer coordination of other utility functions, such as the process of determining which generating units to use, called unit commitment. Operators want to commit just enough capacity to ensure reliability, but no more than is needed. This began a new phase of using economies of scale in system operations encompassing whole regions of the country.

Regional coordination also was spurred by special circumstances, particularly in the West. Large federally owned dams on the Columbia and Colorado rivers generate power from the spring runoff of melting mountain snow. When the reservoirs are full and the turbines are spinning, there is not enough local demand to use the power. Since the hydropower was cheaper than any alternative, long distance transmission lines were built to deliver the excess power from the Northwest and Southwest to load centers in California.

With the transmission interconnections in place, northwestern utilities found that they could get cheaper power from southern power generation at other times of the year. These seasonal and regional disparities in availability and price provide for a lively bilateral trading market.

In the 1960s, the electric power industry created an informal, voluntary organization of operating staff to aid in coordinating the bulk power system. Then, in 1965, the largest power blackout until that time hit the northeastern United States – including New York – and southeastern Ontario, Canada, affecting 30 million people. The blackout led to the development in 1968 of the National Electric Reliability Council, shortly thereafter renamed the North American Electric Reliability Council (NERC) and nine regional reliability councils. Rather than serving as a pool or other entity for sharing resources, NERC focused on reliability. In 2006, using authority granted in the U.S. Energy Policy Act of 2005, FERC certified NERC as the electric reliability organization for the United States, and reliability standards became mandatory and enforceable.

Optimizing Unit Commitment and Economic Dispatch

The industry also reduced costs by using computers and communication technology to optimize system operations. Utilities use algorithms for optimizing the commitment of their generating units, while day-ahead market software does this for suppliers bidding into regional transmission organization markets.

In real time, demand is changing all the time. Without storage and responsive demand, the output of some generators must change to follow constantly changing demand. This is known as load following. Utilities use economic dispatch to optimize the use of these units and minimize real-time costs.

Economy Energy Trade

Since transmission interconnections were built primarily for the rare need to deliver reserves in emergencies, the industry had excess transmission capacity. This allowed utilities to use the lines to trade power. Major utilities generally owned sufficient capacity to meet their own peak power needs. However, sometimes the cost of operating their marginal generation was higher or lower than that of their neighbors. Transmission availability provided opportunities for utilities to save money by buying energy when it was cheaper than generating and selling energy to utilities with higher costs. This is called economy energy trading.

Evolving Public Policies

Different public policy theories have shaped the electric power industry over its history. All of these public policies are still in play to some extent today. Five concepts that helped shape the electricity industry and markets are outlined next.

Not-for-Profit Utilities

One of the first approaches to ensuring customer value was to depend on nonprofit electric providers. In the early days of the industry, electrification started in towns and cities. In many places, this utility service was provided by the municipal government. The federal government stepped in to develop and market the nation's significant hydroelectric resources. The Depression-era rural electrification program relied on customer-owned rural electric cooperatives and low-interest government loans. There are currently more than 1,700 municipal and almost 900 cooperative utilities in the United States.

Regulated Monopolies

A second model for operating power systems was investor-owned regulated monopolies. In the early days of the industry, while many cities went the municipal route, many investor-owned utilities were also starting up. These private utilities are regulated, typically by a state agency. Initially, they agreed to be regulated to overcome a lack of retail competition, and were granted exclusive service territories (franchise). Today, regulation focuses on mitigating market power, among other things, because many utility functions are seen as natural monopolies.

State regulators approve a utility's investments in generation and distribution facilities, either in advance of construction or afterwards when the utility seeks to include a facility's costs in retail rates. Some states eventually developed elaborate integrated resource planning (IRP) processes to determine what facilities should be built.

Power Pools

Power pools are multilateral arrangements with members ceding operational control over their generating units and transmission facilities to a common operator. Members provided incremental cost data about their units and system status data to the operator. The operator ran an energy management system that used the unit cost data to optimize on a multilateral basis unit commitment and economic dispatch.

PJM began in 1927 for utilities to share their generating resources, forming the world's first power pool. The New York Power Pool was formed in 1966 and the New England Power Pool in 1971 in response to the 1965 Northeast blackout. The Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) formed in 1941 to pool resources for the war effort.

Competition, Part 1: Competitive Generation and Open Access

The environmental movement and initiatives to open the airline and trucking industries to competition helped shape the energy industry in the 1970s. A provision in President Carter's energy plan led to passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), which ushered in the next era.

PURPA established a program implemented by states and overseen by the FERC to encourage the use of efficient cogeneration (using the heat from industrial or other processes to generate electricity) and small scale renewable generation. FERC's role was to issue regulations for the program and certify that qualifying facilities (QFs) met statutory requirements. States administratively set the price to be paid to these generators at the cost the utilities would avoid by purchasing the power rather than generating it themselves.

Most states set their avoided cost rate so low that they got little QF capacity. However, California, Texas and Massachusetts set very generous avoided cost rates and were overwhelmed with QF capacity, much of which received prices that turned out to be higher than the actual costs avoided by the purchasing utility. The rapid growth and size of the QF industry surprised many policymakers and entrepreneurs, and got them thinking about the viability of generation independent of regulated monopolies.

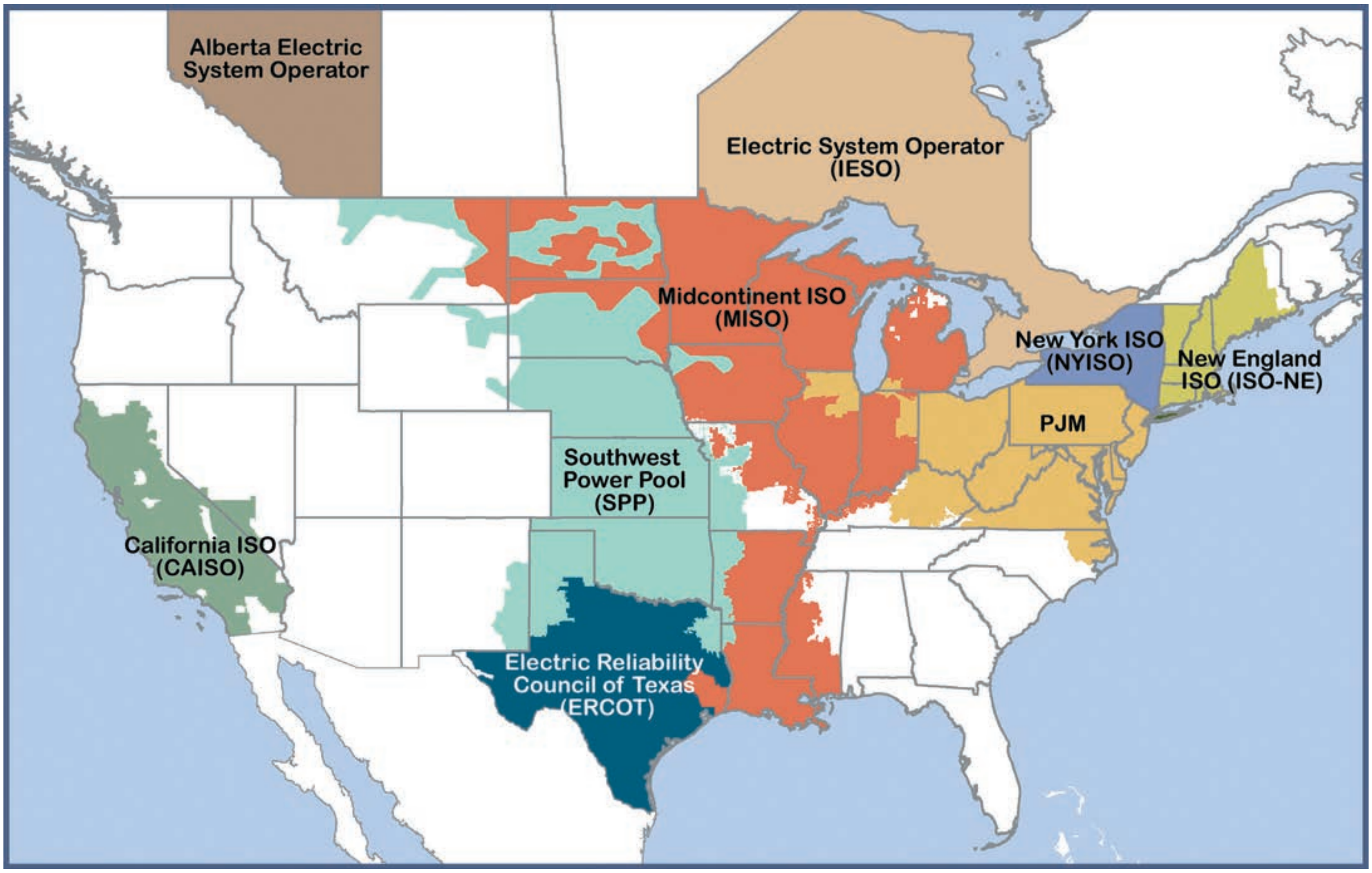
In 1988, FERC proposed rules to allow states to set their avoided-cost rate based on an auction. Instead of taking all capacity at a set rate, states could set the rate based on bids to supply a certain amount of needed capacity. The Commission also proposed to open the avoided-cost auction up to independent power producers (IPPs) that did not qualify as QFs. In this way, a regulatory program was transformed into a competitive initiative.

Under the regulated monopoly model, utilities owning and operating transmission lines had no obligation to allow others to use them. This posed a significant barrier to the development of an independent power industry. The Commission started conditioning approval in merger cases with the voluntary provision of open transmission access. The Energy Policy Act of 1992 gave the Commission authority to grant transmission access on request. These approaches to open access resulted in patchwork transmission access.

By the mid-1990s, support for opening the transmission grid to all users encouraged the Commission to pursue a generic solution. Order No. 888 required mandatory open transmission access by all transmitting utilities and a reciprocity provision successfully extended open access to non-jurisdictional entities (municipal, cooperative and federal utilities).

Order No. 889 addressed matters needed to implement open access. The rule established the Internet-based Open Access Same-Time Information System (OASIS) for posting available transmission capacity and reserving transmission capacity. These rules required significant changes to utility control room operations and limited the ability of companies to share transmission-related information with their own power marketing operating units.

North American Independent System Operators and Regional Transmission Organizations



Source: Velocity Suite, ABB

Competition, Part 2: Integrating Markets and Operations – RTOs

While the industry had historically traded electricity through bilateral transactions and power pool agreements, Order No. 888 promoted the concept of independent system operators (ISO). Along with facilitating open-access to transmission, an ISO would operate the transmission system independently of, and foster competition for electricity generation among, wholesale market participants. Several groups of transmission owners formed ISOs, some from existing power pools.

Close on the heels of Order No. 888, the Commission, in Order No. 2000, encouraged utilities to join regional transmission organizations (RTO) which, like an ISO, would operate the transmission systems and develop innovative procedures to manage transmission equitably. The Commission's proceedings in Orders Nos. 888 and 2000, along with the efforts of the states and the industry, led to the voluntary organization of ISOs and RTOs. Each of the ISOs and RTOs subsequently developed a full scale energy and ancillary service market in which buyers and sellers could bid for or offer generation. The ISOs and RTOs used the bid-based markets to determine economic dispatch. Throughout the subsequent sections of the primer, the term RTO is used to stand for both ISOs and RTOs.

Major parts of the country operate under more traditional market structures, notably the West (excluding California) and the Southeast. Notably, two-thirds of the nation's electricity load is served in RTO regions.

Electricity Demand

Americans use electricity for heat and light, to run machinery and to power a growing number of products such as televisions, radios, computers, hair dryers, and cell phones. This use has been increasing, reaching over 3,860 gigawatt-hours (GWh) of electricity in 2014. Demand dropped in 2009 with the recession, but has since recovered. Subsequent to the recession, the trend in use has been flatter.

The bulk of the electricity generated is sold to consumers, known as end-users or retail customers. Some consumers generate some or all of the power they consume. Some of the electricity sold to retail consumers is generated by integrated investor-owned utilities, federal entities, municipally owned and co-operatively owned utilities that sell the power directly to consumers. The rest of the electricity ultimately consumed by retail customers is bought and sold through wholesale electricity markets.

Demand Characteristics

Demand is often characterized as baseload or peak. Baseload is demand that occurs throughout the day or throughout the year. Refrigerators, for example, may create baseload demand. Peak load is demand that shows up during part of the day or year, all at the same time – heating or air conditioning, for example.

The amount of electricity consumed (demand) is continuously varying and follows cycles throughout the day and year. Regionally, electric demand may peak in either the summer or the winter. Spring and fall are typically shoulder months, with lower peak demand. Seasonal peaks vary regionally, although the highest levels of power load in almost all regions of the United States occur during heat waves, which are most acute during the daily peak load hours that occur during the late afternoon. However, a minority of regions reach their peak load when the weather is extremely cold. These are primarily areas with significant space-heating requirements and little summer air conditioning load. A majority of these systems are in the far northern areas of the United States, where air conditioning load is not significant. South Florida's seasonal peak also occurs during the winter, when the population and tourism surges.

Daily demand typically peaks in the late afternoon, as commercial and domestic activities peak, and, in the winter, when lighting needs grow.

Electricity use also varies between weekdays and weekends. Commercial and industrial activities are lower on weekends and peoples' noncommercial activities change with their personal schedules. The load on different weekdays also can behave differently. For example, Mondays and Fridays, being adjacent to weekends, may have different loads than Tuesday through Thursday. This is particularly true in the summer.

Because demand historically has not varied with price and because storage options are limited, generation must rise and fall to provide exactly the amount of electricity customers need. The cost of providing power typically rises as demand grows, and falls as demand declines, because higher levels of demand require activation of increasingly more expensive sources of power generation, and reductions as demand declines. As a result, power prices are typically highest during periods of peak demand. This causes system planners, power marketers and traders to all carefully track weather trends, economic growth and other factors to forecast power demand.

Demand Drivers

In general, the amount of electricity demanded is relatively insensitive to the price of electricity in the short-term (inelastic). One reason for this is that many customers – especially smaller customers – do not get price signals to which they can respond. Most residential customers are billed monthly on a preset rate structure. Large industrial customers, on the other hand, may receive real-time price signals.

Further, electricity is a necessity to most people and businesses. While they may be able to reduce their demand in the short-term – by turning down the thermostat or turning off lights, for example – electricity consumers find it difficult to do without electricity altogether. There is little storage for electricity now and few realistic substitutes. Consequently, demand tends to drive price, especially when the system is stressed.

In the longer-term, options for reducing electricity use include switching to natural gas, installing insulation and implementing other energy efficiency measures. Larger consumers may consider building their own generation facilities.

Governments and businesses are also developing demand-response programs, which may provide reduced rates or other compensation to customers who agree to reduce load in periods of electric system stress.

Factors driving demand include demographics, climate and weather, economic activity and policies and regulations.

Demographics

Population levels affect demand, with greater population levels tending to increase electricity consumption. Shifts in population also affect regional demand. Population flight in the 1980s from northern industrial regions – the Rust Belt – to warmer climates in the South affected residential consumption patterns. In the 1990s, consumption in the South surpassed that in the Midwest, making it the region with the greatest electricity use.

Climate and Weather

Weather is one of the primary factors driving demand. General climatic trends drive consumption patterns and therefore the infrastructure needed to ensure reliable service. Cold weather and short days drive winter demand in northern regions. Southern regions rely more on electric space heating, and, thus, see demand rise in the winter, although demand typically peaks in the summer with air conditioning load. In the winter, lighting contributes to the occurrence of peaks during the seasonally dark early morning and early evening hours.

Weather also can have extreme short-term effects on electricity usage. A sudden cold snap can drive heating use up quickly and a heat wave can push air conditioning loads. Other, less obvious weather patterns affect demand – rain and wind, for example, may result in sudden cooling, affecting heating or air conditioning.

Economic Activity

The pattern of socioeconomic life affects the cycle of electricity use, with weekends and holidays showing a different pattern than weekdays. Demand typically rises as people wake up and go to work, peaking in the afternoon.

The overall level of economic activity also affects power demand. During periods of robust activity, loads increase. Similarly, loads drop during recessions. These changes are most evident in the industrial sector, where business and plants may close, downsize or eliminate factory shifts. In addition to reducing overall demand, these changes may affect the pattern of demand; for example, a factory may eliminate a night shift, cutting baseload use but continuing its use during peak hours. In some cases these effects can be significant.

Quick Facts: Heating and Cooling Degree Days

In the United States, engineers developed the concept of heating and cooling degree days to measure the effects of temperature on demand. Average daily temperatures are compared to a 65°F standard - those in excess of 65° yield cooling degree days; those below 65° yield heating degree days. A day with an average temperature of 66° would yield one cooling degree day.

Energy Policies and Regulations

State regulatory agencies set prices and policies affecting retail customer service. Some states are considering changes that would enable customers to receive more accurate price signals. They include, among other things, changing rate structures so that the rate varies with the time of day, or is even linked to the cost of providing electricity.

Efforts to reduce overall demand by improving energy efficiency are underway through several governmental and utility venues.

Retail Customer Mix

Most electric utilities serve different types of customers: residential, commercial and industrial. Each class uses electricity differently, resulting in a differing load profile, or the amount that each customer class uses and the daily shape of the load. If a consumer uses electricity consistently throughout the day and seasons, the load shape is flat, and the load will be baseload. Another consumer may use more at some times than others, resulting in baseload and peaks. Greater variability in demand is typically more expensive to serve, especially if the peak occurs at the same time other customers' use peaks. Consequently, the mix of customer types affects a region's overall demand.

Residential consumers form the largest customer segment in the United States at approximately 37 percent of electricity demand. Residential consumers use electricity for air conditioning, refrigerators, space and water heating, lighting, washers and dryers, computers, televisions and other appliances. Prices for residential service are typically highest, reflecting both their variable load shape and their service from lower-voltage distribution facilities, meaning that more power lines are needed to provide service to them.

Commercial use is the next largest customer segment at approximately 36 percent, and includes office buildings, hotels and motels, restaurants, street lighting, retail stores and wholesale businesses and medical, religious, educational and social facilities.

More than half of commercial consumers' electricity use is for heating and lighting.

Industrial consumers use about 27 percent of the nation's electricity. This sector includes, for example, manufacturing, construction, mining, agriculture and forestry operations. Industrial customers often see the lowest rates, reflecting their relatively flat load structure and their ability to take service at higher voltage levels.

Transportation demand for electricity stems primarily from trains and urban transportation systems. This is less than 1 percent of electricity demand.

Load Forecasting

Demand is constantly changing, challenging grid operators and suppliers responsible for ensuring that supply will meet demand. Consequently, they expend considerable resources to forecast demand. Missed forecasts, where actual demand differs significantly from the forecast, can cause wholesale prices to be higher than they otherwise might have been.

Forecasts are necessary as well for the variety of actions that must occur if sufficient supply is to be available in the immediate or long term: planning the long-term infrastructure needs of the system, purchasing fuel and other supplies and staffing, for example. Load forecasts are also extremely important for suppliers, financial institutions and other participants in electric energy generation, transmission, distribution and trading.

Load forecasting uses mathematical models to predict demand across a region, such as a utility service territory or RTO footprint. Forecasts can be divided into three categories: short-term forecasts, which range from one hour to one week ahead; medium forecasts, usually a week to a year ahead; and long-term forecasts, which are longer than a year. It is possible to predict the next-day load with an accuracy of approximately 1 to 3 percent of what actually happens. The accuracy of these forecasts is limited by the accuracy of the weather forecasts used in their preparation and the uncertainties of human behavior. Similarly, it is impossible to predict the next year peak load with the similar accuracy because accurate long-term weather forecasts are not available.

The forecasts for different time horizons are important for different operations within a utility company. Short-term load forecasting can help to estimate transmission system power flows and to make decisions that can prevent overloading of transmission systems. Timely implementation of such decisions leads to the improvement of network reliability and to the reduced occurrences of equipment failures and blackouts. Forecasted weather parameters are the most important factors in short-term load forecasts; temperature and humidity are the most commonly used load predictors.

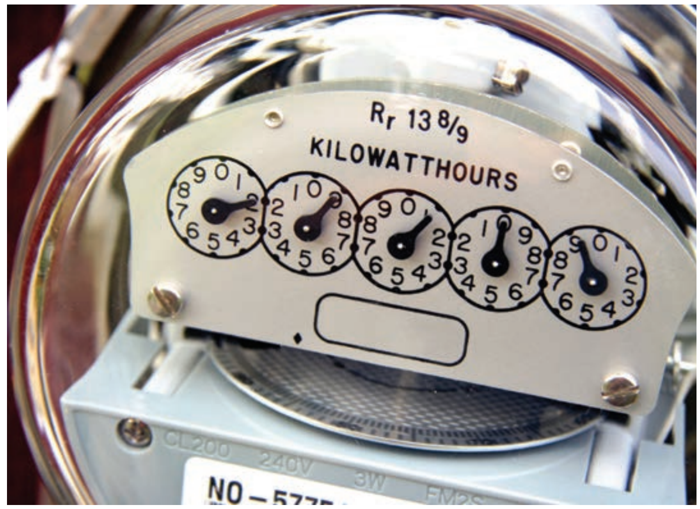
The medium- and long-term forecasts, while not precise, take into account historical load and weather data, the number of customers in different customer classes, appliances used in the area and their characteristics, economic and demographic data, and other factors. For the next-year peak forecast, it is possible to provide an estimated load based on historical weather observations. Long-term forecasts are used for system infrastructure planning and are meant to ensure that there are sufficient resources available to meet the needs of the expected future peak demand. These forecasts are made for periods extending 10 to 20 years into the future.

Demand Response

Electricity demand is generally insensitive to price, meaning that demand does not typically fall when wholesale prices rise. This occurs for several reasons, including that most end use consumers of electricity are not exposed to real-time electricity prices. However, some utilities and grid operators are developing ways to stimulate a response from consumers through demand-response programs.

Demand response (DR) is the reduction in consumption of electricity by customers from their expected consumption in response to either reliability or price triggers where the customer forgoes power use for short periods, shifts some high energy use activities to other times, or uses onsite generation.

The programs may use price signals or incentives to prompt customers to reduce their loads. The signals to respond to electric power system needs or high market prices may come from a utility or other load-serving entity, an RTO or an independent DR provider. These programs are administered by both retail and wholesale entities.



DR has the potential to lower systemwide power costs and assist in maintaining reliability. It can be used instead of running power plants or to relieve transmission congestion. There can also be environmental benefits because peaking units tend to be costly - and dirty - to run.

Demand response rewards consumers for reducing load during certain market conditions and at specific times. However, it is difficult to measure and quantify this reduction. Measuring and verifying the reduction requires development of consumers' baseline usage, against which their actual use is measured to determine the reduction in the event they are called to lessen their load. An accurate measure of their typical usage is important to prevent (or detect) gaming by participants.

Demand-Response Programs

Programs generally fall into three categories: curtailing, shifting or on-site generation.

Curtailing, or forgoing, involves reducing power use (load) during times of high prices or threats to reliability without making up the use later. For example, residential customers might turn off lights or raise thermostats during hot weather. Commercial facilities may turn off office equipment, lower building lighting or change thermostat settings by a few degrees.

Shifting involves moving or rescheduling high energy-use activities in response to high prices or DR program events to off-peak periods – evenings, nights or weekends. Industrial customers might reschedule batch production processes to evening hours or the next day. Commercial establishments may delay high-energy operations. Residential customers may wait until evening or night to use high-energy consuming appliances, such as clothes dryers or dishwashers. In shifting, the lost amenity or service is made up at a subsequent time.

On-site generation is when some customers may respond by turning on an on-site or backup emergency generator to supply some or all of their electricity needs. Although customers may have little or no interruption to their electrical usage, their net load and requirements from the power system are reduced. The ability to use on-site generation is most common for institutional customers, such as hospitals, large schools or data centers.

DR programs can be further distinguished by whether they are controlled by the system operator (dispatchable) or the customer (nondispatchable). Dispatchable demand response refers to programs that reduce customer energy use, such as direct load control of residential appliances or directed reductions to industrial customers. Dispatchable DR is used for reliability or economic reasons. Nondispatchable demand response lets the retail customer decide whether and when to reduce consumption in response to the price of power. It includes time-sensitive pricing programs based on rates that charge higher prices during high-demand hours and lower prices at other times.

As a result of technology innovations and policy directions, new types and applications of DR are emerging that encompass the use of smart appliances that respond in near real-time to price or other signals. These models may allow customers to respond more easily as they require little customer monitoring or interaction.

Demand Response in Retail Markets

Many states require utilities to use energy efficiency, DR or renewable resources. Energy Efficiency Resource Standards (EERS) in more than half of the states require utilities to achieve electric energy savings; many of these standards include peak load reduction targets. These mandates provide incentives for utilities to reduce customers' energy consumption, such as mechanisms that decouple profits from the amount of electricity sold, or performance bonuses for utilities that meet or exceed reduction targets.

Some states are implementing dynamic pricing, in which retail rates change frequently to better reflect system costs. Time-based rates depend on advanced meters at customer premises that can record usage. In time-of-use programs, customers are charged different prices at different times, with hours of peak demand costing more than off-peak hours.

In real-time pricing (RTP) programs, customers are charged prices reflecting the immediate cost of power. Industrial or very large commercial customers are often on RTP tariffs.

Critical peak pricing (CPP) uses real-time prices at times of extreme system peak, and is restricted to a small number of hours annually but features prices higher than time-of-use prices during the critical peak. Consumers do not know in advance when a critical peak might be called. A CPP program for residential customers uses a carrot without the stick: critical-peak rebates. Participating customers get rebates on their bills for responding to utility price-signals, but are not penalized if they do not lower use in those hours.

Wholesale Market Programs

Retail programs may aid RTOs, although the RTO may not be able to invoke them or even see specifically the amount of response that occurs. Wholesale-level DR occurs in the

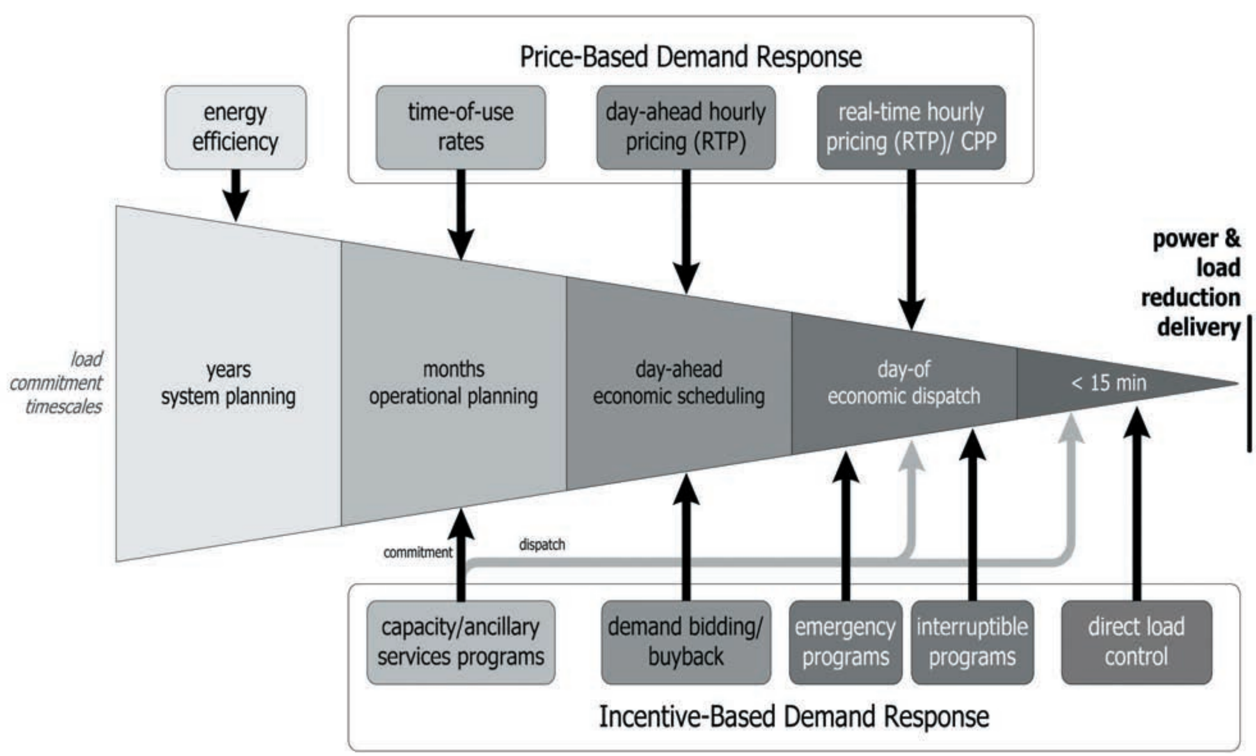
RTOs, which differ in how demand-response resources (DRR) may participate in their markets. Some RTOs permit DRR to participate in their markets as voluntary reliability resources. DRR also can participate in wholesale electricity markets as capacity resources and receive advance reservation payments in return for their commitment to participate when called. Resources that fail to perform when called are penalized. Additionally, some DRR bids into RTO day-ahead (DA) markets as energy resources, specifying the hours, number of megawatts and price at which they are willing to curtail. RTOs set minimum bid values.

Some of the RTO DR comes from individual entities; the rest is accumulated through third-party aggregators, or curtailment service providers (CSPs), who recruit customers too small to participate on their own, such as schools, commercial chains or groups of residential customers. In aggregating small customers, CSPs have increased customer participation in many wholesale reliability and emergency programs.

Demand-Response Use in Planning and Operations

Different DR programs can be used at various times to support planning and operations (see graphic). Energy efficiency programs that reduce baseload or peak demand over the long-term are incorporated into system planning. Dispatchable programs that are quickly implemented and targeted for short-term peak reductions – such as direct load control – lie on the other end of the spectrum, and are used in the moment of operation.

Demand-Response Program Use in Electric System Planning and Operations



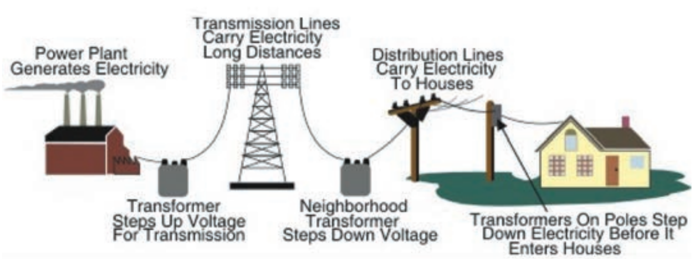
Source: U.S. Department of Energy

Electricity Supply and Delivery

Unlike many other products, electricity cannot be stored in any appreciable quantities. Further, electricity is a necessity for most consumers, whose use responds little to price changes. Finally, electric equipment and appliances are tuned to a very specific standard of power, measured as voltage. Deviations in voltage can cause devices to operate poorly or may even damage them. Consequently, the supply side of the electricity market must provide and deliver exactly the amount of power customers want at all times, at all locations. This requires constant monitoring of the grid and close coordination among industry participants.

Electricity service relies on a complex system of infrastructure that falls into two general categories: generation and the delivery services of transmission and distribution. Together, the power generation and high-voltage transmission lines that deliver power to distribution facilities constitute the bulk power system. Transmission and distribution facilities are also referred to as the power grid. These are coordinated and at times operated by a grid coordinator.

Electricity Supply and Delivery



Source: National Energy Education Development Project

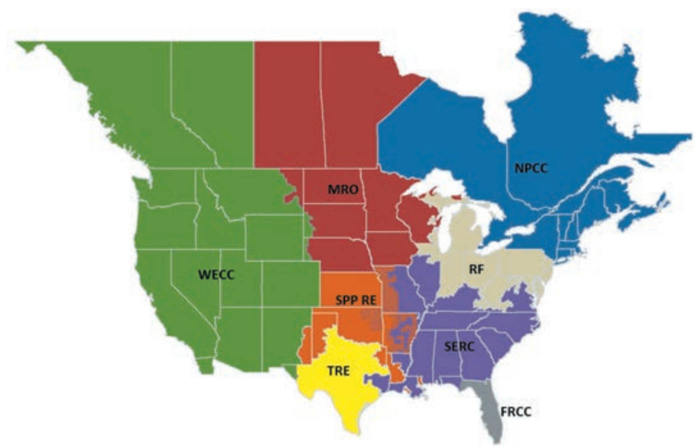
Nationally, the grid is split into three main sections – the Western, Eastern and Texas Interconnections. These sections operate independently and have limited interconnections between them.

The nation, along with Canada and a small part of Mexico, is also divided into regional entities. The regional reliability entities fall under the purview of NERC, which was designated by FERC as the nation's energy reliability organization and which develops standards, among other things, to ensure the grid's reliability. The standards, once approved by FERC, must be met by all industry participants – the standards are mandatory and enforceable. Consequently, the grid is designed and operated to meet these standards.

NERC's regions include:

- Florida Reliability Coordinating Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First Corporation (RFC)
- SERC Reliability Corp. (SERC)
- Southwest Power Pool (SPP)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

NERC Regions



Source: North American Electric Reliability Corporation

Generation

Power generators are typically categorized by the fuel they use and subcategorized by their specific operating technology. The United States has more than 1,000 gigawatts (GW) of total generating capacity. Coal, natural gas and nuclear dominate the power generation market.

Power plants each have differing costs and operational characteristics, both of which determine when, where and how plants will be built and operated.

Plant costs fall into two general categories: capital investment costs, which are amounts spent to build the plant, and operational costs, the amounts spent to maintain and run the plant. In general, there is a trade-off between these expenses: the most capital intensive plants are the cheapest to run – they have the lowest variable costs – and, conversely, the least capital intensive are more expensive to run – they have the highest variable cost. For example, nuclear plants produce vast amounts of power at low variable costs, but are quite expensive to build. Natural gas-fired combustion turbines are far less expensive to build, but are more expensive to run.

Grid operators dispatch plants – or, call them into service – with the simultaneous goals of providing reliable power at the lowest reasonable cost. Because various generation technologies have differing variable costs, plants are dispatched only when they are part of the most economic combination of plants needed to supply the customers on the grid. For plants operating in RTOs, this cost is determined by the price that generators offer. In other areas, it is determined by the marginal cost of the available generating plants.

Construction of different generating technologies is subject to a number of issues, including community concerns, regional emission restrictions and the availability of fuels or other necessary resources:

- Wind plants are generally built in areas with the appropriate meteorological conditions. In most cases, these sites are located in rural areas with limited transmission access. For example, in West Texas, the transmission lines connecting wind farms with consumer centers in Dallas and Houston can become overloaded, requiring generators to curtail production.
- Coal plants have environmental characteristics that limit both their siting and operations. Specifically, they emit NO_x, SO_x, particulates, mercury and substantially higher levels of CO_2 than gas-fired plants. This has made financing these plants and siting them near urban centers difficult.
- There have been virtually no new nuclear plants built in the United States in the past 30 years. The technology of older plant designs became a source of concern following the accident at the Three Mile Island plant in the United States in 1977, the Chernobyl plant meltdown in Ukraine in 1986 and the Japanese earthquake, tsunami and nuclear plant destruction in 2011. New plant designs have been put forward and a few are under construction. The disposition of high-level radioactive waste remains an unresolved problem, and the waste remains at plant locations.

Conventional Generation

Natural gas power plants feature three major technologies, each with its distinct set of market advantages and limitations. They are steam boilers, gas turbines and combined cycle generators. Natural gas fuels nearly a third of electricity generation.

Steam boiler technology is an older design that burns gas in a large boiler furnace to generate steam at both high pressure and a high temperature. The steam is then run through a turbine that is attached to a generator, which spins and produces electricity. Typical plant size ranges from 300 MW to 1,000 MW. Because of their size and the limited flexibility that is inherent in the centralized boiler design, these plants require fairly long start-up times to become operational and are limited in their flexibility to produce power output beyond a certain range. Furthermore, these plants are generally not as economical or easy to site as some newer technologies – which explains why few have been built in recent years.

Gas turbines (GT) are small, quick-start units similar to an aircraft jet engine. These plants are also called simple cycle turbines or combustion turbines (CT). GTs are relatively inexpensive to build, but are expensive to operate because they are relatively inefficient, providing low power output for the amount of gas burned, and have high maintenance costs. They are not designed to run on a continuous basis and are used to serve the highest demand during peak periods, such as hot summer afternoons. GTs also run when there are system-wide shortages, such as when a power line or generator trips offline. GTs typically have a short operational life due to the wear-and-tear caused by cycling. The typical capacity of a

GT is 10-50 MW and they are usually installed in banks of multiple units.

Combined cycle power plants (CCPPs) are a hybrid of the GT and steam boiler technologies. Specifically, this design incorporates a gas-combustion turbine unit along with an associated generator, and a heat recovery steam generator along with its own steam turbine. The result is a highly efficient power plant. They produce negligible amounts of SO_2 and particulate emissions and their NO_x and CO_2 emissions are significantly lower than a conventional coal plant. CCPPs, on average, require 80 percent less land than a coal-fired plant, typically 100 acres for a CCPP versus 500 acres for comparable coal plant, and CCPPs also use modest amounts of water, compared to other technologies.

Coal plants generate more than one-third of the electricity in the United States. These facilities tend to be large, baseload units that run continuously. They have high initial capital costs and are also somewhat complex in their design and operations. However, coal plants have low marginal costs and can produce substantial amounts of power. Most of the coal-fired plants in the United States are located in the Southeast and Midwest.

Oil-fired plants generally produce only a small amount of the total electricity generated in the U.S. power markets. These facilities are expensive to run and also emit more pollutants than gas plants. These plants are frequently uneconomic and typically run at low capacity factors. Like gas-fired generators, there are several types of units that burn oil; primarily, these are steam boilers and combustion turbines.

Generally, two types of oil are used for power generation: number 2 and number 6 (bunker) fuel oil. Number 2 is a lighter and cleaner fuel. It is more expensive, but because it produces fewer pollutants when burned, it is better for locations with stringent environmental regulations such as major metropolitan areas. Conversely, number 6 fuel oil is cheaper, but considered dirty because of its higher emissions. It is highly viscous (thick and heavy) and it comes from the bottom of the barrel in the refining process.

Nuclear plants provide roughly 20 percent of the nation's electricity; there are close to 100 operating units with a total capacity of approximately 100 GW. These plants are used as baseload units, meaning that they run continuously and are not especially flexible in raising or lowering their power output. Nuclear plants have high capital and fixed costs, but low variable costs, which includes fuel cost. They typically run at full power for 18 or 24 months, which is the duration of a unit's fuel cycle. At that point, they are taken off-line for refueling and maintenance. Outages typically last from 20 days to significantly longer, depending on the work needed.

Renewable Generation

Renewable resources use fuels that are not reduced or used up in the process of making electricity. They generally include biomass, geothermal, hydropower, solar, onshore and offshore wind, hydrokinetic projects, fuel cells using renewables and biogas.

Renewable generation, an important part of total U.S. capacity and generation, accounted for 13 percent of 2014 electricity generation. As total generation from all fuels has remained relatively constant in the recent years, renewable generation's share has risen, spurred by state regulations and federal tax credits. As renewable generation becomes a larger percentage of generation resources, integrating them into the operating power grid has presented challenges.

Wind and solar capacity have grown faster than other renewable resources in recent years. Wind capacity grew ten-fold (from approximately 6 GW to 65 GW) between 2003 and 2014. Utility-scale solar capacity more than tripled (from approximately 3.1 GW to 10 GW) between 2012 and 2014.

Additions are usually reported in megawatts of nameplate capacity. Actual capability varies from the nameplate for any unit type due to age, wear, maintenance or ambient conditions. But as renewable resources are often weather-dependent, their capacity factors – the ratio of average generation to the nameplate capacity for a specific period – have been lower (for example, approximately 30 percent), depending on the technology type, than for fossil-fuel-fired generation. Markets care about the difference between nameplate and capacity factor values when they evaluate capacity available to cover expected load. Capacity factors have risen with technological innovation and improved manufacturing processes.

Wind generation is among the fastest-growing renewable resources, in part due to cost declines and technology improvements as well as earlier receipt of federal tax credits. Increases in average hub heights and rotor diameters have increased average wind turbine capacity.

Because the best wind resources are often far from load centers, obtaining sufficient transmission presents a challenge to delivering its output. Other market challenges for future wind development include its variable output, which is often inversely correlated to demand (seasonally and daily); system operators' inability to dispatch wind resources to meet load increases; difficulties related to accurately forecasting its ramping; and the need for companion generation (usually fossil-fueled) to be available to balance wind generation when the wind is not blowing.

Geothermal generation taps into reservoirs of steam and hot water deep beneath the earth's surface to produce power. The best resources are in the intermountain West. Geothermal potential is determined by thermal conductivity, thickness of sedimentary rock, geothermal gradient, heat flow and surface temperature. Geothermal generation increased 14 percent from 2006 to 2014, but it decreased from 15 to 6 percent of non-hydro renewable output, due to the growth of other renewables. California hosts more than 80 percent of U.S. operating capacity.

Solar generation transforms sunlight into electricity using one of two technologies: photovoltaic (PV) or concentrating solar power (CSP). PV modules, or panels, transform sunlight directly into power using silicon wafers or nonsilicon thin-film technologies. They can be installed on roofs of buildings or at ground-level PV farms. CSP plants use a two-step process to transform the sun's energy. First, mirrors direct sunlight towards a receiver that captures the heat. CSP then employs a thermal process to create steam, driving an engine or turbine to produce electricity. CSP plants, which are dispatchable, can include low-cost energy storage that extends their availability later in peak hours.

PV growth has increased greatly as a result of policy incentives and cost declines. Annual PV installations increased nearly tenfold from 2009 to 2013 as PV system costs decreased. PV growth has been relatively concentrated; 10 states had 90 percent of PV capacity in 2014, while California alone had over half.

By the end of 2014, 1,760 MW of CSP was operational. Seven western and southwestern states have extensive CSP potential: Utah, New Mexico, Arizona, Nevada, Texas, California and Colorado. Developing that potential will require overcoming challenges of siting, transmission and the need for extensive water supplies to clean mirrors.

Hydroelectric generation is powered by the kinetic energy of falling water that drives turbine generators, which convert the energy into electricity. There are two types of hydroelectric projects: conventional and pumped storage. Conventional projects, which use a dam in a waterway, can operate in a run-of-river mode, in which water outflow from the project approximates inflow, or in a peaking mode, in which the reservoir is mostly drained to generate power during peak periods when energy is more valuable. Pumped storage projects use bodies of water at two different elevations. Water is pumped into elevated storage reservoirs during off-peak periods when pumping energy is cheaper; the water is then used to generate power during peak periods as it flows back to the lower elevation reservoir. Pumped storage is the only significant commercially deployed electricity storage technology available today.

Biomass generation includes production from many waste byproducts, such as agricultural residues, landfill gas, municipal solid waste and wood resources. The largest biomass category is wood waste, burned for heat and power in the lumber, pulp and paper industries. Challenges to biomass production include impacts on food supplies (for example, converting corn into ethanol), conserving natural resources and minimizing water pollution. State policies on renewable generation differ on eligibility of biomass technologies.

Biogas energy is created through the anaerobic (without oxygen) bacterial decomposition of manure, which is turned into a gas containing 60-70 percent methane. Biogas recovery can be installed at farms anywhere, used to run farm operations and reduce methane emissions from natural manure decomposition.

Renewable Energy Policies

Renewable development is frequently tied to policies promoting their use because of their higher cost relative to other technologies. Financial incentives include tax credits, low-cost loans, rebates or production incentives. Federal funding of research and development (R&D) has played an important role in lowering costs or reducing the time it takes for renewable technologies to become commercially viable.

Congress has provided tax incentives to spur renewable resource investments. Originally enacted in 1992, wind, biomass, geothermal, and other forms of renewable generation have been able to receive federal production tax credits (PTC) based on a facility's production. An inflation-adjusted credit, the PTC generally has a duration of 10 years from the date the facility goes online. The credit was initially set at 1.5¢/kilowatt hour (kWh) and its value in 2013 was 2.3¢/kWh or 1.1¢/kWh, depending on the type of qualifying resource. The PTC has been renewed and expanded numerous times, most recently at the end of 2014.

Another form of tax credit for renewables, including solar and other select renewable energy projects, has been a federal investment tax credit (ITC). The ITC has generally been for 30 percent of a project's equipment and construction costs.

Following the financial crisis of 2008, the American Reinvestment and Recovery Act (ARRA) provided developers with another option for projects that began construction by the end of 2010 – they could apply for Treasury-administered cash grants, which monetized the ITC's value up front. ARRA funds helped support renewable energy research and development and aided capacity growth in 2009, despite the economic downturn.

State renewable portfolio standards (RPS) and renewable energy standards (RES) have been significant drivers in the growth of investment in renewable generation. An RPS requires a certain percentage of energy sales (MWh) to come from renewable resources. Percentages usually increase incrementally from a base year to an ultimate target. Currently, 29 states plus Washington, D.C., have an RPS and eight states have renewable goals without financial penalties for nonachievement. As utilities build more renewable-powered generation, the markets in which they participate continue to address the integration of renewable output into their day-ahead and real-time operations and model expected growth as part of their long-term transmission-planning processes.

To encourage the development of distributed generation (DG), or the production of electricity at the site of consumption, and solar power, 16 states plus Washington, D.C., created RPS carve-outs or set-asides to give an extra boost to these resources, which are not yet cost-competitive with other renewables.

Renewable energy certificates (RECs) allow state regulators to track compliance with mandatory RPS targets or verify progress in voluntary state renewable programs. They also allow compliance entities to purchase credits – subject to state imposed limits on amount and price - if they have not generated or bought enough renewable energy to meet their annual requirements. Each reported megawatt-hour (MWh) of eligible generation results in a system-issued REC with a unique identification number to prevent double-counting. Each REC includes attributes such as generator location, capacity, fuel-type and source, owner and the date when operations began.

States and local utilities offer a variety of financial incentives for renewable energy to complement policy mandates. These include tax credits for in-state manufacture of renewable energy equipment, consumer rebates for purchase and installation of renewable generation or production incentives. Production incentives include extra credits for solar output based on RPS solar set-asides and feed-in tariffs.

Seven states mandate feed-in-tariffs (FITs) to support their energy and environmental goals. Also called feed-in rates or advanced renewable incentives, these programs typically are designed to encourage development of new small- and medium-sized renewable generation projects by residential and independent commercial developers.

FITs require utilities to buy the renewable generation at a fixed rate that is higher than that provided to other generators, under multiyear contracts. This enables smaller distributed renewable generators to avoid having to participate in renewable portfolio standard (RPS) auctions or other competitive procurements and compensates them for more expensive technologies. The utility passes the costs of the program to its customers.

Transmission

The alternating current (AC) power grid operates like an interconnected web, where, with a few exceptions, the flow of power is not specifically controlled by the operators on a line-by-line basis. Instead, power flows from sources of generation to consumers across any number of lines simultaneously, following the path of least resistance. There are a limited number of direct current (DC) lines, which are set up as specific paths with definite beginning and end points for scheduling and moving power. These lines are controllable by operators and have other characteristics that make them attractive to grid planners and operators, such as providing greater grid stability and lower line losses. However, DC lines cost significantly more than AC lines to construct. Consequently, DC lines are typically built for certain specialized applications involving moving large amounts of power over long distances, such as the Pacific Intertie, which extends between the Northwest and California.

Transmission lines provide a certain amount of resistance to the flow of power as electricity travels through them. This resistance is not unlike the wind resistance that a car must overcome as it travels along a highway. The resistance in power lines creates losses: the amount of power injected into a power line diminishes as it travels through the line. The amount of these losses is contingent on many factors, but typically equals several percent of the amount put into the system.

Transmission Service

FERC requires that public utilities that own transmission lines used in interstate commerce offer transmission service on a nondiscriminatory basis to all eligible customers. The rates and terms of service are published in each utility's Open Access Transmission Tariff (OATT). One type of service is point-to-point service. This service involves paying for and reserving a fixed quantity of transmission capacity and moving power up to the reservation amount from one location, the point of receipt (POR), to another location, the point of delivery (POD). Depending on availability, customers may purchase point-to-point service for durations of one hour to multiple years. The price for the service is cost-based and published in the OATT. In cases where there are multiple parties desiring transmission, it is allocated to the party willing to purchase it for the longest period of time. Capacity reassignment is the term for the resale of point-to-point transmission capacity in the secondary market.

Transmission holders may want to sell capacity in the secondary market because it is unneeded, or to make a profit. Capacity reassignment has been permitted since 1996. Beginning in 2007, resellers have been permitted to charge market-based prices for capacity reassignments, as opposed to the original cost-based price at which they purchased the capacity. The number of capacity reassignments increased from around 350 in 2007 to 30,000 in 2012. Most of the transactions were hourly, although capacity can also be reassigned on a daily, monthly or yearly basis.

If the market price of energy is greater at the POD than at the POR, the transmission has value. The transmission holder can capture this value by using the transmission – buying energy at the POR, moving it to the POD and selling it. Alternatively, the transmission holder can sell the transmission through a capacity reassignment. Thus, the price of a capacity reassignment should be equal to the expected price differential between the POD and the POR.

Grid Operations

Grid operators dispatch their systems using the least costly generation consistent with the constraints of the transmission system and reliability requirements. The dispatch process occurs in two stages: day-ahead unit commitment, or planning for the next day's dispatch, and economic dispatch, or dispatching the system in real time.

Day-Ahead Unit Commitment

In the unit commitment stage, operators decide which generating units should be committed to be online for each hour, typically for the next 24-hour period. This is done in advance of real-time operations because some generating units require several hours lead time before they are brought online. In selecting the most economic generators to commit, operators take into account forecast load requirements and each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels and the minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and nonfuel operating costs and the cost of environmental compliance.

Also, forecast conditions that can affect the transmission grid must be taken into account to ensure that the optimal dispatch can meet load reliably. This is the security aspect of commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction and weather conditions. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to replace less-expensive units.

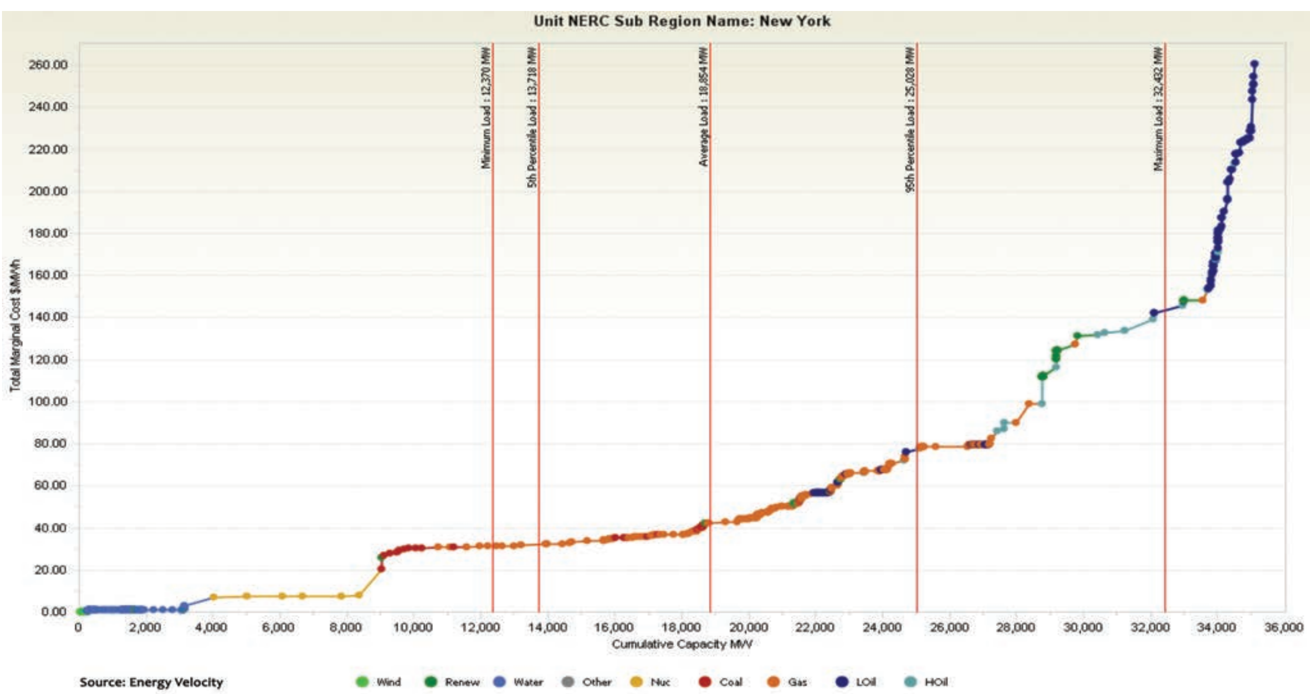
System and Unit Dispatch

In the system dispatch stage, operators must decide in real time the level at which each available resource from the unit commitment stage should be operated, given the actual load and grid conditions, so that overall production costs are minimized. Actual conditions will vary from those forecast in the day-ahead commitment, and operators must adjust the dispatch accordingly. As part of real-time operations, demand, generation and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 hertz. This is typically done by automatic generation control (AGC) to change the generation dispatch as needed.

The chart below is a depiction of the market supply curve of the power plants for the New York Independent System Operator (NYISO). This is also commonly called the supply stack. In it, all of the plants in the New York market are shown sorted according to their marginal cost of production. Their cost of production is shown on the vertical axis. The cheapest ones to run are to the left and the most expensive to the right.

Dispatch in New York, for example, first calls on wind plants, followed successively by hydro, nuclear and coal-, gas- and oil-fired generators. This assumes that the plants have sufficient resources – enough wind for the wind powered generators or enough river flow for the hydroelectric plants, for example – and that sufficient transmission capability exists to deliver plant output and meet reliability needs.

Market Supply Curve for NYISO (Illustrative)



In addition, transmission flows must be monitored to ensure that flows stay within voltage and reliability limits. If transmission flows exceed accepted limits, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch or shedding load. Operators may check conditions and issue adjusted dispatch instructions as often as every five minutes.

Ancillary Services

Ancillary services maintain electric reliability and support the transmission of electricity. These services are produced and consumed in real-time, or in the very near term. NERC and regional entities establish the minimum amount of each ancillary service that is required for maintaining grid reliability.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal, typically every few seconds. The changes are designed to maintain system frequency at 60 hertz. Failure to maintain a 60-hertz frequency can result in collapse of an electric grid.

Operating reserves are needed to restore load and generation balance when a generating unit trips off line. Operating reserves are provided by generating units and demand resources that can act quickly, by increasing output or reducing demand, to make up a generation deficiency. There are three types:

- **Spinning reserves** are primary. To provide spinning reserve a generator must be on line (synchronized to the system frequency) with some unloaded (spare) capacity and be capable of increasing its electricity output within 10 minutes. During normal operation these reserves are provided by increasing output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. Synchronized reserve can also be provided by demand-side resources.

- **Nonspinning reserves** come from generating units that can be brought online in 10 minutes. Nonspinning reserve can also be provided by demand-side resources.

- **Supplemental reserves** come from generating units that can be made available in 30 minutes and are not necessarily synchronized with the system frequency. Supplemental reserves are usually scheduled in the day-ahead market, allowing generators to offer their reserve energy at a price, thus compensating cleared supply at a single market clearing price. This only applies to ISO/RTOs, and not all reliability regions have a supplemental reserve requirement.

Black start generating units have the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators have this capability. These are the first facilities to be started up in the event of a system collapse or blackout to restore the rest of the grid.

Reactive power: Electricity consists of current, the flow of electrons, and voltage, the force that pushes the current through the wire. Reactive power is the portion of power that establishes and maintains electric and magnetic fields in AC equipment. It is necessary for transporting AC power over transmission lines, and for operating magnetic equipment, including rotating machinery and transformers. It is consumed by current as it flows. As the amount of electricity flowing on a line increases, so does the amount of reactive power needed to maintain voltage and move current. Power plants can produce both real and reactive power, and can be adjusted to change the output of both. Special equipment installed on the transmission grid is also capable of injecting reactive power to maintain voltage.

Weather

Weather is the single greatest driver of electricity demand and, thus, is a major factor in grid operations. System operators therefore rely heavily on weather forecasts to ensure they have the right generation in the right locations to run the grid reliably.

Weather affects grid operations in other ways, as well. Primary among these is on the productivity of certain types of power generators: wind and hydroelectric. Wind turbines' power output changes with wind availability and speed, which affects cost of wholesale power.

Hydroelectric plants rely on rain and snowfall to provide the river flow needed for their output. Geographically, this is most important in the Pacific Northwest, where seasonal hydro plant output is a critical source of power. Rain and the melting of winter snowpack feed the Columbia and Snake river systems. Surplus power from these generators is typically exported to California to help meet summer peak demand and provide a combination of increased reliability and lower prices.

Temperature can also affect the output of other power plants and capacity of transmission lines. Specifically, thermal plants that use a turbine – coal, gas, oil and nuclear plants – become less efficient at higher temperatures. Additionally, the capacity of transmission lines is limited by heat because the conductive material used in fabrication becomes more electrically resistant as they heat up, limiting their throughput.

Wholesale Electricity Markets and Trading

Overview

Markets for delivering power to consumers in the United States are split into two systems: traditional regulated markets and market-regulated markets run by RTOs.

In general, RTOs use their markets to make operational decisions, such as generator dispatch. Traditional systems rely on management to make those decisions, usually based on the cost of using the various generation options.

Trading for power is also split into over-the-counter (OTC) or bilateral transactions, and RTO transactions. Bilateral transactions occur in both traditional systems and in RTO regions, but in different ways.

Pricing in both RTO and traditional regions incorporate both cost-of-service and market-based rates.

Bilateral Transactions

Bilateral or OTC transactions between two parties do not occur through an RTO. In bilateral transactions, buyers and sellers know the identity of the party with whom they are doing business.

Bilateral deals can occur through direct contact and negotiation, through a voice broker or through an electronic brokerage platform, such as the IntercontinentalExchange (ICE). The deals can range from standardized contract packages, such as those traded on ICE, to customized, complex contracts known as structured transactions.

Whether the trade is done on ICE, directly between parties or through another type of broker, the trading of standard physical and financial products, such as next-day on-peak firm or swaps, allows index providers to survey traders and publish price indexes. These indexes provide price transparency.

Physical bilateral trades involving the movement of the energy from one point to another require that the parties reserve transmission capacity to move the power over the transmission grid. Transmitting utilities are required to post the availability of transmission capacity and offer service on an Open Access Same-Time Information System (OASIS) website. Traders usually reserve transmission capacity on OASIS at the same time they arrange the power contract.

When it comes time to use the reservation to transfer power between balancing authorities, one of the parties to the transaction submits an eTag electronically to Open Access Technology International (OATI), NERC's eTag contractor. OATI will process the tag and send it to all parties named on the eTag. This ensures the orderly transfer of energy and provides transmission system operators the information they need to institute curtailments as needed. Curtailments may be needed when a change in system conditions reduces the capability of the transmission system to move power and requires some transactions to be cut or reduced.

Bilateral physical transactions conducted in RTOs are settled financially. Generators offer their power into the RTO markets, and load is served through the power dispatched by the RTO. The RTO then settles bilateral transactions based on the prices in the contracts and the prices that occurred in the RTO markets.

Cost-Based Rates

Cost-based rates are used to price most transmission services and some electricity when the Commission determines that market-based rates are not appropriate, or when an entity does not seek market-based rate authority. Cost-based rates are set to recover costs associated with providing service and give a fair return on capital. Cost-based rates are typically listed in a published tariff.

The following are major inputs to setting cost-based electricity rates:

- Determining used-and-useful electricity plants. This may include generation facilities, transmission facilities, distribution plants and office and related administration facilities.
- Determining expenses from the production, transmission and distribution of electricity, including fuel and purchased power, taxes and administrative expenses.
- Establishing a fair return on capital, known as the cost of capital. This includes determining the cost of debt, common equity, preferred stock and commercial paper and other forms of short-term borrowing such as lines of credit used to finance projects and provide cash for day-to-day operations.
- Allocating electric plant and other expenses among various customer classes and setting the rate structure and rate levels.

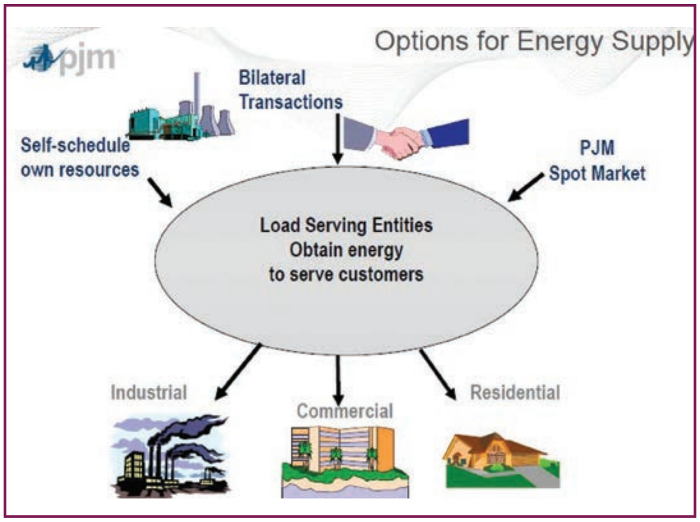
Market-Based Rates

Under market-based rates, the terms of an electric transaction are negotiated by the sellers and buyers in bilateral markets or through RTO market operations. The Commission grants market-based rate authority to electricity sellers that demonstrate that they and their affiliates lack or have adequately mitigated horizontal market power (percent of generation owned relative to total generation available in a market), and vertical market power (the ability to erect barriers to entry or influence the cost of production for competitive electricity suppliers). Wholesale sellers who have market-based rate authority and who sell into day-ahead or real-time markets administered by a RTO do so subject to the specific RTO market rules approved by the Commission and applicable to all market participants. Thus, a seller in such markets not only must have an authorization based on analysis of that individual seller's market power, but it must abide by additional rules contained in the RTO tariff.

Supplying Load

Suppliers serve customer load through a combination of self-supply, bilateral market purchases and spot purchases. In addition to serving load themselves, load-serving entities (LSEs) can contract with others to do so. The choices are:

- Self-supply means that the supplying company generates power from plants it owns to meet demand.
- Supply from bilateral purchases means that the load-serving entity buys power from a supplier.
- Supply from spot RTO market purchases means the supplying company purchases power from the RTO.



Source: PJM Interconnection

LSEs' sources of energy vary considerably. In ISO-NE, NYISO and CAISO, the load-serving entities divested much or all of their generation. In these circumstances, LSEs supply their customers' requirements through bilateral and RTO market purchases. In PJM, MISO and SPP, load-serving entities may own significant amounts of generation either directly or through affiliates and therefore use self-supply as well as bilateral and RTO market purchases.

Traditional Wholesale Electricity Markets

Traditional wholesale electricity markets exist primarily in the Southeast, Southwest and Northwest where utilities are responsible for system operations and management, and, typically, for providing power to retail consumers. Utilities in these markets are frequently vertically integrated – they own the generation, transmission and distribution systems used to serve electricity consumers. They may also include federal systems, such as the Bonneville Power Administration, the Tennessee Valley Authority and the Western Area Power Administration. Wholesale physical power trading typically occurs through bilateral transactions. Utilities in traditional regions have the following responsibilities:

- Generating or obtaining the power needed to serve customers (this varies by state)
- Ensuring the reliability of its transmission grid
- Balancing supply and demand instantaneously
- Dispatching its system resources as economically as possible
- Coordinating system dispatch with neighboring balancing authorities
- Planning for transmission requirements within the utility's footprint
- Coordinating its system development with neighboring systems

Regional Electricity Markets

Two-thirds of the population of the United States is served by electricity markets run by regional transmission organizations or independent system operators (this primer uses RTO to stand for both RTOs and ISOs). The main distinction between RTO markets and their predecessors (such as vertically integrated utilities, municipal utilities and co-ops) is that RTO markets deliver reliable electricity through competitive market mechanisms.

The basic functions of an RTO include the following:

- Ensure the reliability of the transmission grid
- Operate the grid in a defined geographic footprint
- Balance supply and demand instantaneously
- Operate competitive nondiscriminatory electricity markets
- Provide nondiscriminatory interconnection service to generators
- Plan for transmission expansion on a regional basis

In performing these functions, RTOs have operational control of the transmission system, are independent of their members, transparently manage transmission congestion, coordinate the maintenance of generation and transmission system, and oversee a transmission planning process to identify needed upgrades in both the near- and long-term.

RTOs do not own transmission or generation assets perform the actual maintenance on generation or transmission equipment, or directly serve end use customers.

Currently, seven RTOs operate in the United States, listed below in order of the size of their peak load:

- PJM Interconnection (PJM), 165 GW (summer of 2011)
- Midcontinent ISO (MISO), 126 GW (summer of 2011)
- Electric Reliability Council of Texas (ERCOT), 68 GW (summer of 2011)
- California ISO (CAISO), 50 GW (summer of 2006)
- Southwest Power Pool (SPP), 48 GW (summer of 2011)
- New York ISO (NYISO), 34 GW (summer of 2013)
- New England ISO (ISO-NE), 28 GW (summer of 2006)

RTO Markets and Features

RTO market operations encompass multiple services that are needed to provide reliable and economically efficient electric service to customers. Each of these services has its own parameters and pricing. The RTOs use markets to determine the provider(s) and prices for many of these services. These markets include the day-ahead energy market (sometimes called a Day 2 market), real-time energy market (sometimes called a Day 1 or balancing market), capacity markets (designed to ensure enough generation is available to reliably meet peak power demands), ancillary services markets, financial transmission rights (contracts for hedging the cost of limited transmission capability) and virtual trading (financial instruments to create price convergence in the day-ahead and real-time markets).

RTO Energy Markets

All RTO electricity markets have day-ahead and real-time markets. The day-ahead market schedules electricity production and consumption before the operating day, whereas the real-time market (also called the balancing market) reconciles any differences between the schedule in the day-ahead market and the real-time load while observing reliability criteria, forced or unplanned outages and the electricity flow limits on transmission lines.

The day-ahead energy market produces financially binding schedules for the production and consumption of electricity one day before its production and use (the operating day). The purpose of the day-ahead market is to give generators and load-serving entities a means for scheduling their activities sufficiently prior to their operations, based on a forecast of their needs and consistent with their business strategies.

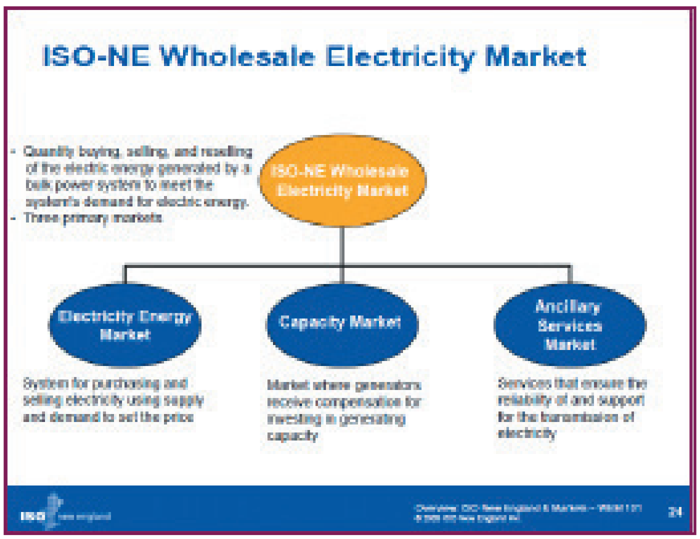
In day-ahead markets, the schedules for supply and usage of energy are compiled hours ahead of the beginning of the operating day. The RTO then runs a computerized market model that matches buyers and sellers throughout the geographic market footprint for each hour throughout the day. The model then evaluates the bids and offers of the participants, based on the power flows needed to move the electricity throughout the grid from generators to consumers. Additionally, the model must account for changing system capabilities that occur based on weather and equipment outages, plus rules and procedures that are used to ensure system reliability. The market rules dictate that generators submit supply offers and loads submit demand bids to the RTO by a deadline that is typically in the morning of the day-ahead scheduling. Typically, 95 percent of all energy transactions are scheduled in the day-ahead market, and the rest scheduled in real-time.

Generation and demand bids that are scheduled by the day-ahead market are settled at the day-ahead market prices. Inputs into setting a day-ahead market schedule include:

- Generator offers to sell electricity each hour
- Bids to buy electricity for each hour submitted by load-serving utilities
- Demand-response offers by customers to curtail usage of electricity
- Virtual demand bids and supply offers
- Operational information about the transmission grid and generating resources, including planned or known transmission and generator outage, the physical characteristics

of generating resources including minimum and maximum output levels and minimum run time and the status of interconnections to external markets

The real-time market is used to balance the differences between the day-ahead scheduled amounts of electricity based on day-ahead forecast and the actual real-time load. The real-time market is run hourly and in 5-minute intervals and clears a much smaller volume of energy and ancillary services than the day-ahead market, typically accounting for only 5 percent of scheduled energy. For generators, the real-time market provides additional opportunities for offering energy into the market. Megawatts over- or under- produced relative to the day-ahead commitments are settled at real-time prices.

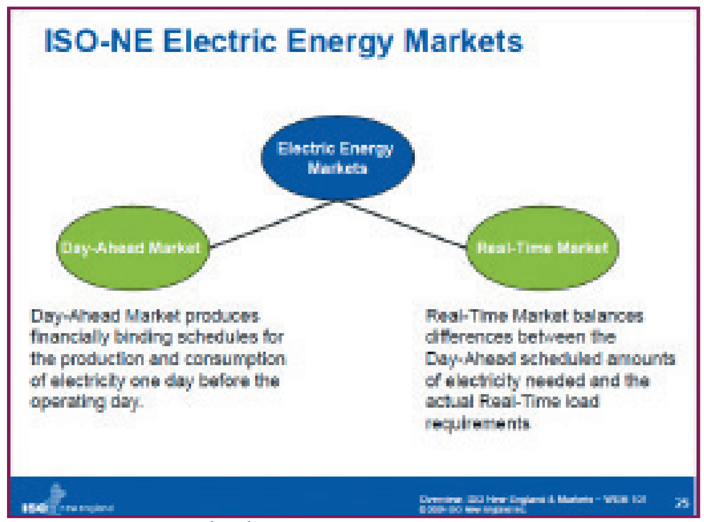


Source: ISO New England

Real-time market prices are significantly more volatile than the day-ahead market prices. This stems from demand uncertainty, transmission and generator forced outages and other unforeseen events. Because the day-ahead market generally is not presented with these events, it produces more stable prices than in real-time. Also, because the volumes in the real-time market are much smaller, there is an increased likelihood of supply and demand imbalances, which lead to both positive and negative price movements.

RTOs use markets to deal with transmission constraints through locational marginal pricing (LMP). The RTO markets calculate a LMP at each location on the power grid. The LMP reflects the marginal cost of serving load at the specific location, given the set of generators that are dispatched and the limitations of the transmission system. LMP has three elements: an energy charge, a congestion charge and a charge for transmission system energy losses.

If there are no transmission constraints, or congestion, LMPs will not vary significantly across the RTO footprint. Transmission congestion occurs when there is not enough transmission capacity for all of the least-cost generators to be selected. The result is that some more expensive generation must be dispatched to meet demand, units that might not otherwise run if more transmission capacity were available.

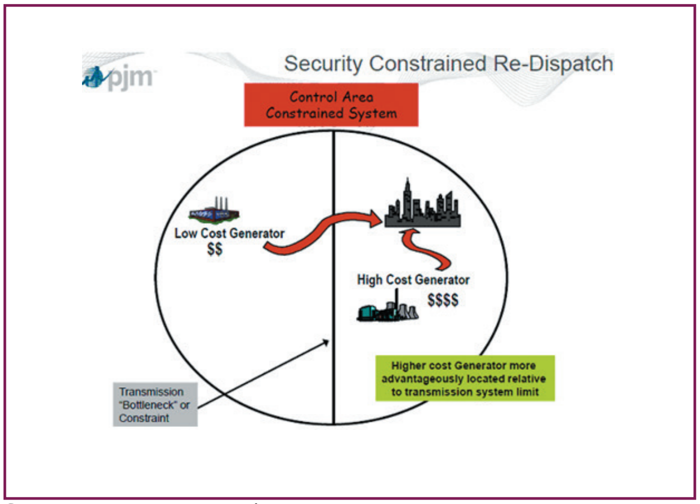


Source: ISO New England

When there are transmission constraints, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will set the LMP in that area. All sellers receive the LMP for their location and all buyers pay the market clearing price for their location.

The primary means used for relieving transmission congestion constraints is by changing the output of generation at different locations on the grid. The market-based LMP sends price signals that reflect congestion costs to market participants. That is, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (redispatch) the generation output to serve load. This change in dispatch is known as security constrained redispatch.

This redispatch could be implemented by using nonmarket procedures such as transmission loading relief (TLR). NERC established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded and power flows must be reduced to protect the network. A TLR is used to ration transmission capacity when the demand for transmission is greater than the available transmission capacity (ATC). The rationing is a priority system that cuts power flows based on size, contractual terms and scheduling.



Source: PJM Interconnection

Scarcity pricing is a mechanism used by RTOs to send price signals in the real-time market when there is a systemwide shortage of power reserves. These events occur when there is a shortage of power to meet system requirements to meet load and provide sufficient backup reserves. This can be caused by unexpectedly high power loads, supply disruptions or both.

RTOs follow one of four approaches to ensure that the market price for energy accurately reflects the value of energy during shortage periods:

- Increase the allowed bidding price of energy supply above normal levels during an emergency
- Increase bid caps above the current level during an emergency for demand bids, while keeping generation offer caps in place
- Establish a pricing structure for operating reserves that would raise prices as operating reserves grow short (demand curve)
- Set the market-clearing price during an emergency for all supply and demand response resources dispatched equal to the payment made to participants in an emergency demand-response program

Reliability must-run (RMR) units are generating plants that would otherwise retire but the RTO has determined they are needed to ensure reliability. They could also be units that have market power due to their location on the grid. RTOs enter into cost-based contracts with these generating units and allocate the cost of the contract to transmission customers. In return for payment, the RTO may call on the owner of an RMR generating unit to run the unit for grid reliability. The payment must be sufficient to pay for the cost of owning and maintaining the unit even if it does not operate.

Transmission upgrades can also reduce the need for RMR units by increasing generation deliverability throughout the RTO.

RTO Capacity Markets

RTOs, like other electric systems, are required to maintain adequate generation reserves to ensure that sufficient generation and demand-resource capacity are available to meet load and reliability requirements. LSEs have typically satisfied their reserve obligations with owned generation or bilateral contracts with other suppliers. Some RTOs have mechanisms to obtain capacity commitments, such as capacity auctions and capacity payments.

Most RTOs run a capacity market to allow LSEs a way to satisfy their reserve obligation. These markets cover short-term capacity, such as a month, season or year. PJM and ISO-NE run capacity auctions up to three years prior to when the capacity is needed. The near-term focus is consistent with providing payments to existing generation, or generation such as combustion turbines that can be sited and built within three years.

Financial Transmission Rights

Financial transmission rights (FTRs) are contracts that give market participants an offset, or hedge, against transmission congestion costs in the day-ahead market. They protect the holder from costs arising from transmission congestion over a specific path on the grid.

FTRs were originally developed in part to give native load-serving entities in the nascent RTOs price certainty similar to that available to traditional vertically integrated utilities operating in non-RTO markets. This practice continues, as FTRs are allocated to load-serving entities, transmission owners or firm transmission right holders in RTOs based on historical usage, and to entities that fund the construction of specific new transmission facilities. The details of the programs vary by RTO.

FTRs allow customers to protect against the risk of congestion-driven price increases in the day-ahead market in the RTOs. Congestion costs occur as the demand for scheduled power over a transmission path exceeds that path's flow capabilities. For example, if the transmission capacity going from Point A (the source) to Point B (the sink) is 500 MW, but the RTO seeks to send 600 MW of power from Point A to Point B when calling on the least-cost generators to serve load, the path will be congested. This will cause the price at the source to decline or the price at sink to increase, or both, causing the congestion cost of serving point B from Point A to increase. By buying an FTR over the path from Point A to Point B, the FTR holder is paid the difference of the congestion prices at the sink and source, thus allowing it to hedge against the congestion costs incurred in the day-ahead market.

FTRs are acquired through allocations and purchases. FTRs can be purchased in the RTO-administered auctions or in the secondary market.

Allocations may stem from a related product, the auction revenue right (ARR). ARRs provide the firm transmission capacity holders, transmission owners or LSEs with a portion of the money raised in the FTR auctions. In general, they are allocated based on historic load served and, in some RTOs, can be converted to FTRs. As with FTRs, ARRs, too, give eligible members an offset or hedge against transmission congestion costs in the day-ahead market. If converted to FTRs, the holder gets revenue from congestion. If kept as ARRs, the holder gets revenue from the FTR auction.

The main method for procuring FTRs is through an auction, which typically includes an annual (or multiyear) auction of one-year FTRs and monthly (or semiannually) auctions of shorter-term FTRs provided by existing FTR holders or made available by the RTO. The auctions are scheduled and run by the RTO, which requires bidding parties to post credit to cover the positions taken. FTR auction revenues are used to pay the holders of ARRs and assist the funding of future congestion payments to FTR holders. There is also a secondary market for FTRs (such as PJM's eFTR), but only a small number of transactions have been reported.

The quantity of FTRs made available by the RTO is bounded by the physical limits of the grid, as determined by a simultaneous feasibility test across all potential flowgates. This test is performed by the RTO prior to making FTRs available at auction, and takes into account existing FTR positions and system constraints. The resulting portfolio of FTRs allocated or offered at auction represents an absolute constraint on the size of the net positions that can be held by the market. Participants in FTR auctions can procure counterflow FTRs, which directly offset prevailing flow FTR capacity, thereby allowing the value at risk on a given path to exceed the physical limits of the line. However, such bids are physically constrained, as the net position held on the path must always conform to the simultaneous feasibility test.

Although FTRs are used by transmission providers and load-serving entities as a hedge, they can be purchased by any creditworthy entity seeking their financial attributes either as a hedge or as a speculative investment. In this regard, FTRs are similar to financial swaps that are executed as a contract for differences between two day-ahead LMPs (swaps are explained in the chapter on financial markets). However, FTRs are substantially different from swaps in that the quantity of FTRs is linked to physical constraints in the transmission grid, while the quantity of swaps is not. Further, FTRs are procured by allocation or FTR auction, while swaps are procured through financial over-the-counter markets or exchanges.

Variation in RTO FTRs

All six FERC-jurisdictional RTOs trade FTRs or FTR equivalent products. However, the types and qualities of the rights traded across the organized markets vary, as do differences in the methods used to allocate, auction and transfer these rights. These attributes of the FTR markets are discussed below.

Flow Type: Prevailing Flow and Counterflow. A prevailing flow FTR generally has a source in an historic generation-rich location and a sink that is in a historic load-heavy location. Alternatively, the source of a prevailing flow FTR is on the unconstrained side of a transmission interface and the sink on the constrained side. Auction clearing prices for prevailing flow FTRs are positive. Conversely, a counterflow FTR often has a source in an historic load-heavy location and a sink in an historic generation-rich location. As a result, auction clearing prices for counterflow FTRs are negative.

Peak Type: On-peak, Off-peak, 24-hour. FTRs can be purchased for either 16-hour on-peak blocks, 8-hour off-peak blocks or around-the-clock. Only PJM offers all three peak type products. NYISO offers only the 24-hour product. The other RTOs offer on-peak and off-peak products.

Allocated Rights: The RTOs allocate transmission rights to transmission owners or load-serving entities within their markets. In PJM, MISO, SPP, and ISO-NE, these are allocated as auction revenue rights (ARRs), which give their holders the right to receive a share of the funds raised during the FTR auctions. The CAISO allocates congestion revenue rights (CRR), which provide their holders a stream of payments based on the actual congestion occurring on associated paths. Finally, NYISO allocates both auction-based and congestion-based rights through multiple instruments. PJM and MISO allow ARR holders to convert all of these rights to FTRs; NYISO allows only a portion of ARR-equivalent instruments to be converted to its version of FTRs, called Transmission Congestion Credits (TCCs). ISO-NE does not allow such conversions, while the CAISO's allocation is already in a form equivalent to an FTR. Converted ARRs are fully fungible in PJM, the MISO and NYISO; CAISO only allows the sale of allocated CRRs in its secondary market, and ISO-NE has no converted instruments to sell.

Auctioned Rights: All RTOs provide FTRs (or equivalent CRRs, or TCCs) for sale to the public through two or more auctions held at various times of the year. The products sold vary by market and by auction, with some products made available only at specific auctions.

Secondary Markets: With the exception of the NYISO, each of the markets that auction FTRs also operates a bulletin board or similar venue designed to enable a secondary trading platform for FTRs. However, none of these platforms has had significant volume. NYISO offered to create a bulletin board for its participants if requested, but received no requests. The CAISO is the only market that requires the reporting of secondary FTR transactions; such transactions have not occurred despite the inability of CRR holders to resell their positions through the auction process.

Virtual Transactions

Virtual bids and offers (collectively, virtuals) are used by traders participating in the RTO markets to profit from differences between day-ahead and real-time prices. The quantity of megawatts (MW) purchased or sold by the trader in the day-ahead market is exactly offset by a sale or purchase of an identical quantity of MW in the real-time, so that the net effect on the market quantity traded is zero.

Although a trader does not have to deliver power, the transaction is not strictly financial. Virtual transactions can physically set the LMPs, the basis for payments to generators or from load.

For each hour, net virtual trades are added to the demand forecast for load if virtual demand is greater than virtual supply. This has the effect of raising the price in the day-ahead market and, more importantly, increasing the amount of generation resources procured by the RTO. Since these resources will be available to the real-time market, the fact that virtual load does not carry forward into the real-time market will decrease the real-time demand below forecast, thus placing downward pressure on real-time prices. The placement of virtuals affects the dispatch of physical capacity.

The primary benefits of virtual transactions are achieved through their financial impact on the markets. Virtuals sometimes are referred to as convergence bidding, as a competitive virtual market should theoretically cause the day-ahead and real time prices to converge in each hour.

The convergence of day-ahead and real-time prices within the RTOs is intended to mitigate market power and improve the efficiency of serving load. Thus, virtuals have a physical impact upon the operations of the RTO, as well as on market participants that physically transact at the LMPs set in the day-ahead and real-time markets.

Transmission Operations

Each RTO's Open Access Transmission Tariff (OATT) specifies the transmission services that are available to eligible customers. Customers submit requests for transmission service through the Open Access Same-Time Information System (OASIS). RTOs evaluate each transmission-service request using a model of the grid called a state estimator. Based on the model's estimation of the effects on the system, the request for transmission service is either approved or denied.

Transmission Rights by Transmission Grid

	PJM	MISO	ISO-NE	NYISO	CAISO	SPP
Name for Allocated Transmission Rights	ARR	ARR	ARR	Multiple	CRR	ARR
Convertible to Congestion Rights?	Yes	Yes	No	Some	-	Yes
Name for Auctioned Congestion Rights	FTR	FTR	FTR	TCC	CRR	TCR
Congestion Right Auction Format:						
Annual	Yes	Yes	Yes	No	Yes	Yes
Semiannual	No	No	No	Yes	No	No
Monthly	Yes	Yes	Yes	Yes	Yes	Yes
Congestion Right Auction Products:						
Multiyear	Yes	No	No	No	No	No
Annual	Yes	No	Yes	Yes	No	Yes
Semiannual	No	No	No	Yes	No	No
Quarterly	Yes	Yes	No	No	Yes	Yes
Monthly	Yes	Yes	Yes	Yes	Yes	Yes
Auction Allows Participant Resale?	Yes	Yes	Yes	Yes	No	Yes
Congestion Right Options	Yes	No	No	No	No	No
Formal Secondary FTR Market?	Yes	Yes	Yes	No	Yes	Yes

Transmission operators, including RTOs, offer two major types of transmission service: point-to-point service and network service. Network service generally has priority over point-to-point service. RTOs work with transmission owners to plan and coordinate the operation, maintenance and expansion of transmission facilities in order to provide network and point-to-point customers with transmission service.

Network transmission service is used for the transmission of energy from network generating resources to an RTO's network loads.

- Network transmission service enables network customers to use their generation resources to serve their network loads in a RTO.
- Network customers also can use the service to deliver economy energy purchases to their network loads.

Point-to-point transmission service uses an RTO's system for the transmission of energy between a point of receipt and a point of delivery, which can be into, out of, or through the RTO's Control Area. RTOs offer firm and nonfirm point-to-point transmission service for various lengths of time.

- Firm service has reservation priority over nonfirm point-to-point service.
- Nonfirm point-to-point transmission service is provided from the available transmission capability beyond network and firm point-to-point transmission service.

Transmission Planning

RTOs have systemwide or regional planning processes that identify transmission system additions and improvements needed to keep electricity flowing. Studies are conducted that test the transmission system against mandatory national reliability standards as well as regional reliability standards.

RTO transmission planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations and other reliability problems. RTOs then develop transmission plans in collaboration with transmission owners to resolve potential problems that could otherwise lead to overloads and blackouts. This process culminates in one recommended plan for the entire RTO footprint.

Financial Policies

Financial settlements is the process through which payments due from customers and to generators are calculated. Such settlements depend on day-ahead schedules, real-time metering, interchange schedules, internal energy schedules, ancillary service obligations, transmission reservations, energy prices, FTR positions and capacity positions. For each market participant a customer invoice of charges and credits includes the costs of services used to serve load.

Generally, customers receive weekly or monthly invoices stating their charges and credits. Weekly invoices must be settled within a few days of being issued, while monthly invoices must be paid within either one or two weeks depending on the policies of each RTO. All payments are made electronically. Disbursements are made within several days of the date payments are due.

Credit Policies

Credit requirements are important in organized electricity markets in which RTOs must balance the need for market liquidity against corresponding risk of default. Defaults by market participants in RTOs have generally been socialized, meaning that the cost is spread across the market. To minimize this risk, RTOs have credit policies in their tariffs, which contain provisions related to credit evaluations, credit limits, forms of collateral and the consequences of violations or defaults.

Regions

Markets vary around the United States by market type – traditional or RTO – generation types, customer use, climate, fuel costs, political and regulatory conditions, and other factors. Consequently, prices vary, driven by these market factors.

Southeast Wholesale Market Region

The Southeast electricity market is a bilateral market that includes all or parts of Florida, Georgia, Alabama, Mississippi, North Carolina, South Carolina, Missouri and Tennessee. It encompasses all or part of two NERC regions: the Florida Reliability Coordinating Council (FRCC) and the Southeastern Electric Reliability Council (SERC). Major hubs include Into Southern and TVA.

Southeastern power markets have their roots in the 1960s. In the wake of the Northeast Blackout of 1967, the Southeast began to build out its electric transmission grid; there now are several large transmission lines connecting large power plants to the grid. This was primarily to ensure reliability, but it also had economic consequences. Increased integration allowed utilities to more effectively share reserves, as well as the costs and risks of new plant construction.

If a utility were building a large nuclear or coal-fired generating facility, it would be cost-effective to have reserve sharing agreements with neighboring systems that provided the backup or capacity reserves, rather than building reserves individually. In addition, a stronger grid allowed the output of large power plants to be deliverable throughout the region, thus allowing more than one utility to share in the ownership and the costs of building large new plants. This reduced the financial risks associated with ownership of large new generating facilities to any single utility, thus making ownership of large base-load coal and nuclear units more affordable to the utilities and less risky.

A stronger transmission system also allowed for more economic transactions, including both spot transactions and long-term firm power deliveries. External sales resulted in more efficient use of grid resources and reduced costs to both buyers and sellers.

Resources

Within the Southeast, the resource mix varies between the two NERC subregions. The FRCC uses more natural gas- and oil-fired generation than the rest of the Southeast, and it is the only Southeast area where oil is significantly employed. Natural gas is the marginal fuel in almost all hours in the FRCC. Within SERC, the Southern subregion has historically generated as much as 85 percent of its electricity from baseload coal and nuclear plants. In recent years, natural gas used for generating electricity has become increasingly popular. The pattern began to change as gas supplies increased and prices fell and natural gas-fired power plants began to displace older, less-efficient coal-fired generation.

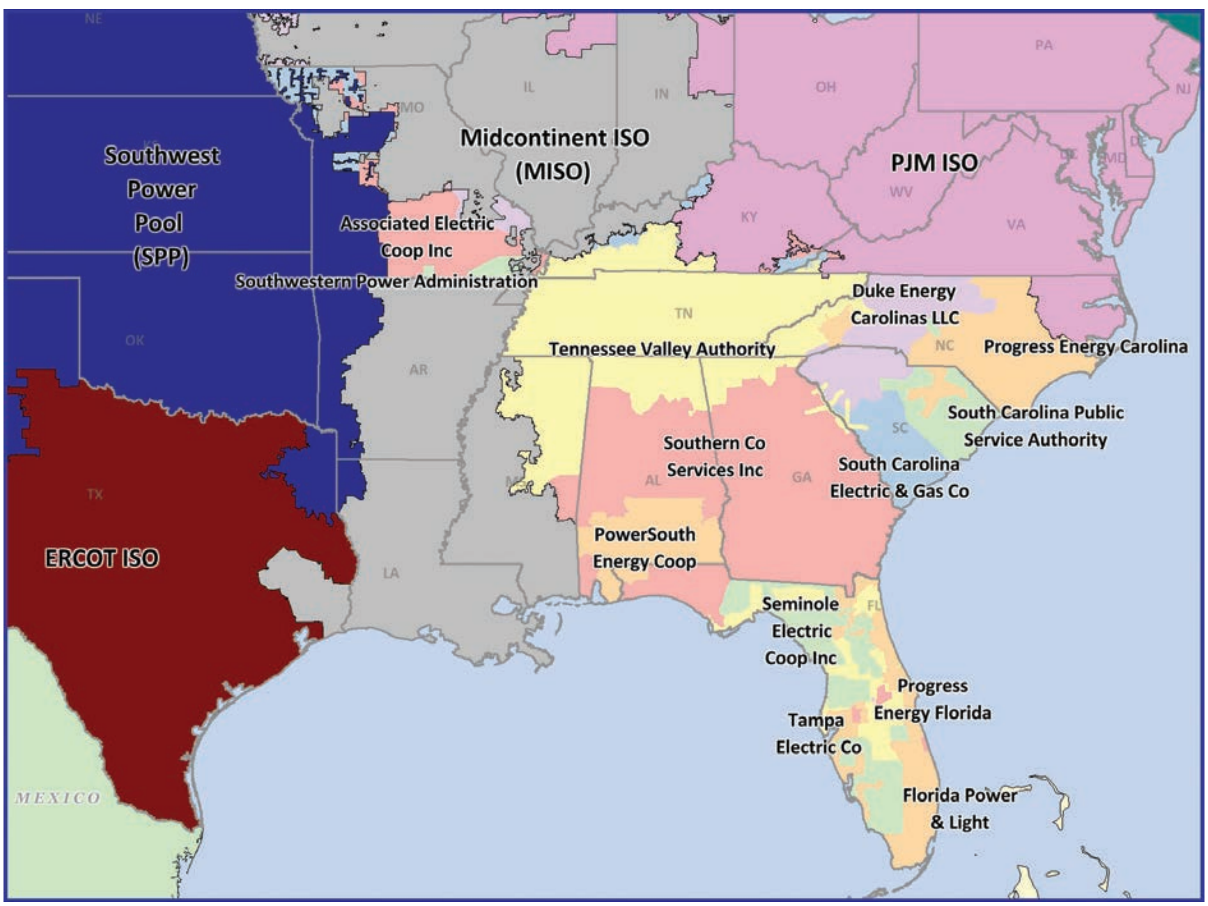
The TVA sub-region has a majority of its capacity and output in coal and nuclear, while the VACAR sub-region has the highest utilization of nuclear generation in the Southeast. Over 70 percent of this subregion's output is from baseload coal and nuclear facilities.

Trading and Market Features

Physical and financial electricity products are traded using Into Southern, TVA, VACAR and Florida price points. Volumes for these products remain low, especially in Florida, where merchant power plant development is restricted by a state statute.

Virtually all the physical sales in the Southeast are done bilaterally. Long-term energy transactions appear to be a hallmark of the Southeast; wholesale electricity transactions for a year or more outweigh spot transactions. Many long-term agreements involve full-requirements contracts or long-term

Southeast Electric Region



Source: Velocity Suite, ABB

purchase power agreements. Spot transactions accounted for less than one percent of overall supply and tend to occur during periods of system stress, usually summer heat waves or winter cold snaps. Even for a large company such as Southern Co., spot transactions occurred less than 20 percent of the time.

Wholesale spot power markets in the Southeast have relatively little spot trading and lack transparency. The relative lack of spot trades yields little data on which to base price reporting. ICE reports no electric power price for Florida. And while another publisher reports one spot electric power price for Florida, on most days, there are no reported volumes. Given the bilateral nature of wholesale power transactions in the Southeast, and the small spot market, interest in financial power products in the Southeast is weak. As a result, ICE does not provide a financial product in the Southeast.

Despite the bilateral nature of the wholesale trade and the small size of the spot market, marketers do have some presence in the Southeast. For example, marketers contribute to the trading, as they have entered into multiyear agreements with generating units.

Southern Co. Auction

Since April 23, 2009, Southern Co. has been holding daily and hourly auctions for power within its balancing area. This balancing area encompasses the service territories of Southern Co. utilities: Georgia Power, Alabama Power, Mississippi Power and Gulf Power.

According to the auction rules, Southern must offer all of its available excess generation capacity into the auction, after regulation and contingency reserves are met. The offer prices are capped because the auction is intended to mitigate any potential ability of Southern to withhold its generation resources within its balancing area.

The products auctioned are day-ahead power and real-time power (an auction takes place an hour ahead of when the energy is scheduled to flow).

Offers to sell energy and bids to purchase energy are evaluated using the simple method of sorting offers in ascending order and bids in descending order.

The auction matches parties to facilitate a bilateral transaction that is ultimately independent of the auction. Thus, there is no collateral requirement necessary to participate in the auction. However, credit screening rules dictate that matches are made only between entities willing and able to do business with one another. The selection process is based on information that each entity submits to the auction administrator.

When the auction began in 2009, Southern Co. was the only participant that could sell into it. On Jan. 3, 2010, other entities were allowed to sell into the auction, and Southern became eligible to make purchases in the auction as well as sales. However, activity in the auction has been sparse since its inception.

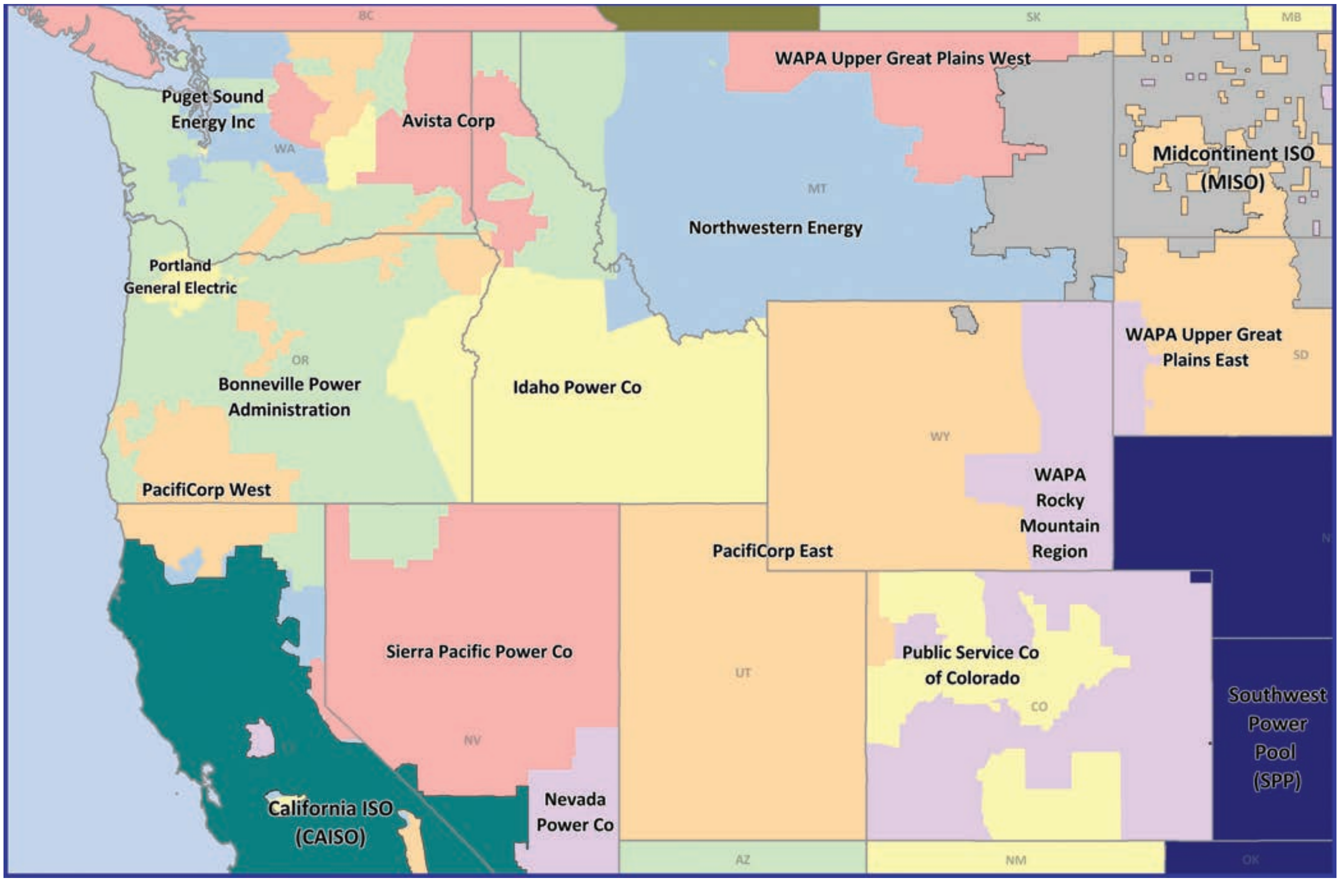
Florida IPP rule

The Florida Public Service Commission's (PSC) competitive bidding rules require investor-owned utilities (IOUs) to issue requests for proposals for any new generating project of 75 MW or greater, exclusive of single-cycle combustion-turbines. The bidding requirement can be waived by the PSC if the IOU can demonstrate that it is not in the best interests of its ratepayers.

Western Wholesale Market Regions

The power markets in the western United States are primarily bilateral markets. A key exception is most of California and portions of Nevada, which operate under CAISO. The West includes the Northwest Power Pool (NWPP), the Rocky Mountain Power Area (RMPA) and the Arizona, New Mexico, Southern Nevada Power Area (AZ/NM/SNV) within the Western Electricity Coordinating Council (WECC), a regional entity. These areas contain many balancing authorities (BAs) responsible for dispatching generation, procuring power, operating the transmission grid reliably and maintaining adequate reserves. Although the BAs operate autonomously, some have joint transmission-planning and reserve-sharing agreements.

Northwest Electric Region



Source: Velocity Suite, ABB

Trading in the western states differs from the rest of the country because financial players are active in the physical markets, as well as having a robust financial electricity market. The volume of financial sales on ICE is roughly as large as physical sales. Physical sales in WECC are dominated by financial and marketing companies.

Northwest Electric Region

The NWPP is composed of all or major portions of the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada and Utah, a small portion of Northern California and the Canadian provinces of British Columbia and Alberta. This vast area covers 1.2 million square miles. It is made up of 20 BAs. The peak demand is 54.5 GW in summer and 63 GW in winter. There are 80 GW of generation capacity, including 43 GW of hydroelectric generation.

Resources

The NWPP has a unique resource mix. Hydro generation is more than 50 percent of power supply, compared to the U.S. average of only 6 percent of power supply. The hydro generation is centered around many dams, mostly on or feeding the Columbia River. The largest dam, the Grand Coulee, can produce as much power as six nuclear plants. Due to the large amount of hydroelectric generation, the Northwest typically has less expensive power and exports power to neighboring regions, especially California, to the extent that there is transmission capacity to carry the power to more expensive markets.

The amount of hydropower produced depends on a number of factors, some natural and some controllable. On a seasonal basis, the intensity and duration of the water flow is driven by snowpack in the mountains, the fullness of the reservoirs, and rainfall. On a short-term basis, the power generation is influenced by decisions to release water locally and upstream to generate power, as well as local water-use decisions that have nothing to do with the economics of power generation, but are made for recreation, irrigation and wildlife considerations. The peak generation begins in the spring, when the snow melts, and may last into early summer.

When there is less water available, the Northwest may rely more on its coal and natural gas generation. It will occasionally import power from neighboring regions when loads are high.

Trading and Market Features

The water forecast affects the forward market for electricity in the Northwest. The daily water flow as well as weather conditions influence the prices in the daily physical market. When there is an abundance of hydro generation, the Northwest will export as much as possible on the transmission lines leading into California. Sometimes in off-peak hours there is so much generation that power prices are negative because the transmission lines are full and there is not enough local load to take all of the power.

The largest seller of wholesale power is the Bonneville Power Administration (BPA), a federal agency that markets the output from federally owned hydroelectric facilities and owns 75 percent of the region's high-voltage transmission. It meets approximately one-third of the region's firm energy supply, mostly with power sold at cost. BPA gives preference to municipal and other publicly owned electric systems in allocating its output.

Both the Alberta Electric System Operator and British Columbia Hydro are members of the NWPP. Net interchange between these two BAs and the United States tends to result in net exports from the United States into Canada. Net interchange between U.S. and Canadian balancing authorities represents about one percent of total NWPP load.

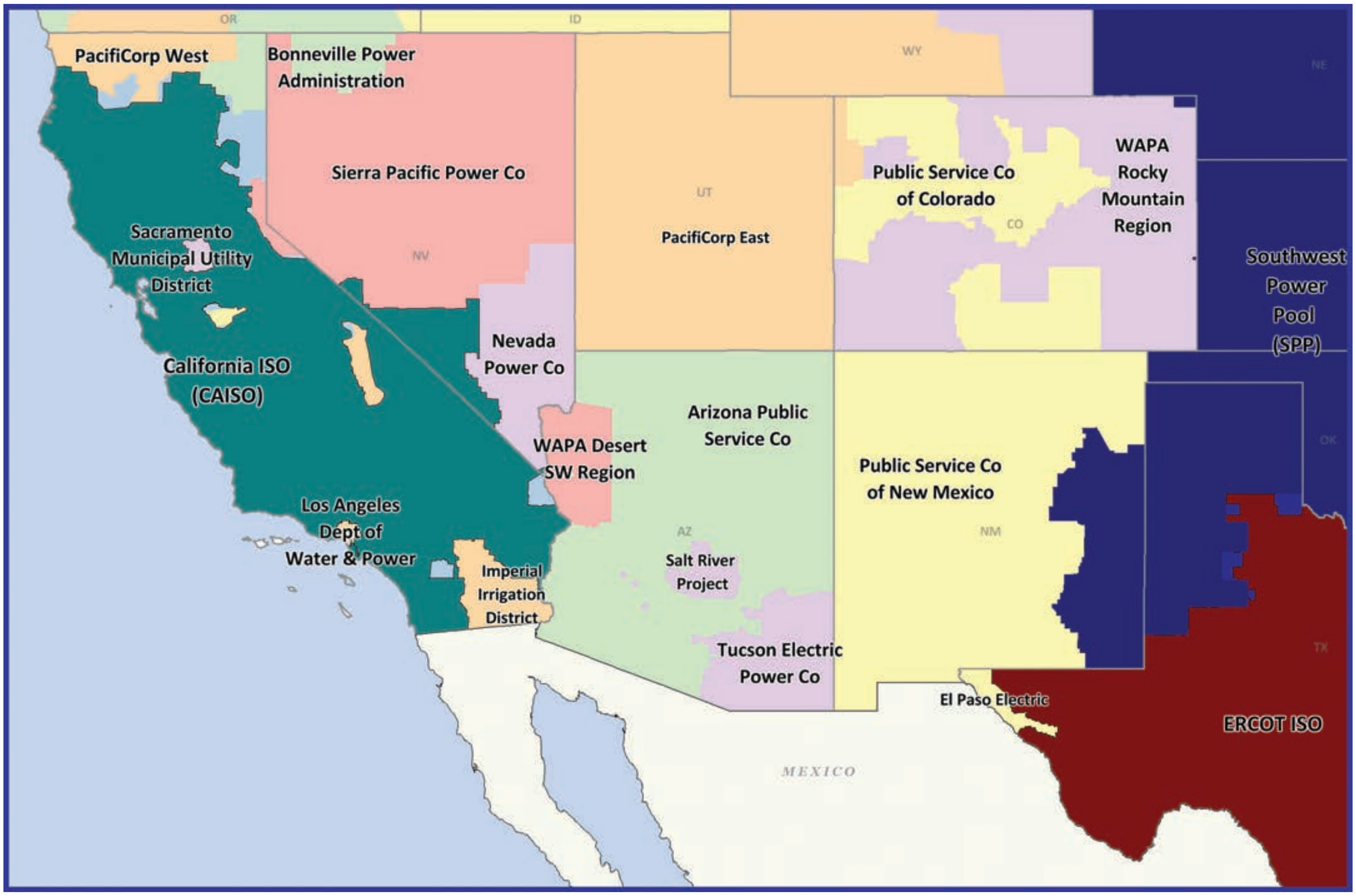
The ICE has four trading points in the Northwest: Mid-Columbia (Mid-C), California-Oregon Border (COB), Nevada-Oregon Border (NOB) and Mona (Utah). Mid-C has the most traded volume by far, averaging more than 6,200 MW of daily on-peak physical trades in 2013. COB had nearly 1,000 MW, NOB had over 800 MW and Mona had 530 MW. Mid-C also has a fairly active physical forward market.

Southwest Electric Region

The Southwest electric market encompasses the Arizona, New Mexico, southern Nevada (AZ/NM/SNV) and the Rocky Mountain Power Area (RMPA) subregions of the Western Electric Coordinating Council (WECC). Peak demand is approximately 42 GW in summer. There are approximately 50 GW of generation capacity, composed mostly of gas and coal units.

The Southwest relies on nuclear and coal generators for baseload electricity, with gas units generally used as peaking resources. The coal generators are generally located in close proximity to coal mines, resulting in low delivered fuel costs. Some generation is jointly owned among multiple nearby utilities, including the Palo Verde nuclear plant, a plant with three units totaling approximately 4,000 MW, which has owners in California and the Southwest.

Southwest Electric Region

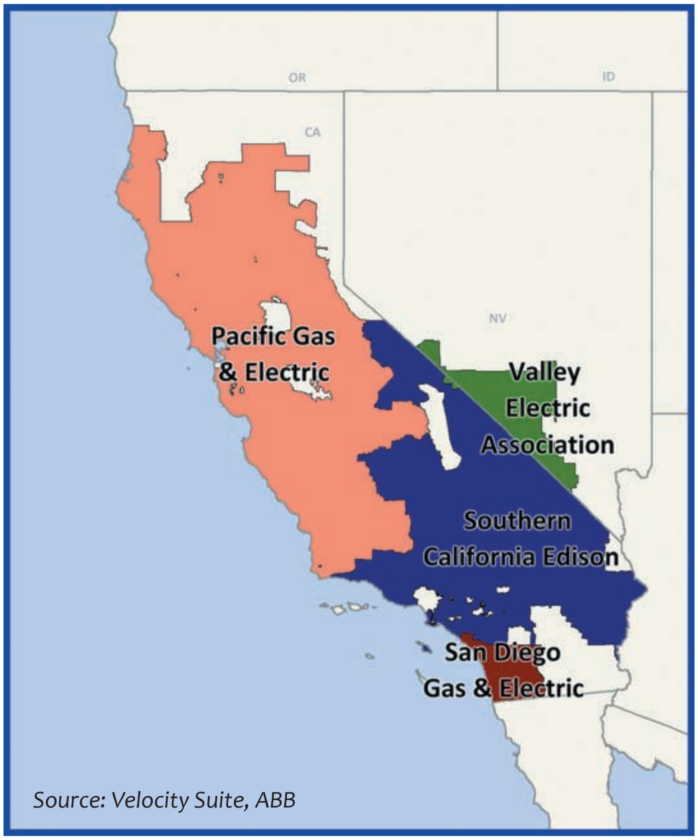


Source: Velocity Suite, ABB

The AZ/NM/SNV region is summer-peaking and experiences high loads due to air conditioning demand. The daily high temperatures average above 100 degrees in June through August in Phoenix. However, power prices tend to be the highest when there is also hot weather in Southern California, creating competition for the generation resources.

CAISO

California Independent System Operator



Source: Velocity Suite, ABB

Market Profile

Geographic Scope

CAISO is a California nonprofit public benefit corporation started in 1998 when the state restructured its electric power industry. The CAISO manages wholesale electricity markets, centrally dispatching electricity generation facilities. In managing the grid, CAISO provides open access to the transmission system and performs long-term transmission planning. It manages energy and ancillary markets in day-ahead and real-time markets and is responsible for regional reliability.

Peak Demand

CAISO's all-time peak load was 50 GW in summer 2006.

Import and Exports

Up to about one-third of CAISO's energy is supplied by imports, principally from two primary sources: the Southwest (Arizona, Nevada and New Mexico) and the Pacific Northwest (Oregon, Washington and British Columbia). Imports from the Pacific Northwest generally increase in the late spring when hydroelectric production peaks from increases in winter snowmelt and runoff.

Market Participants

CAISO's market participants include generators, retail marketers and utility customers, ranging from investor-owned utilities (IOUs), which include Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and others such as the Valley Electric Association, to some municipal utilities and financial participants.

Membership and Governance

The CAISO has a board of governors that consists of five members appointed by the governor and confirmed by the California Senate. The board's role is to provide corporate direction, review and approve management's annual strategic plans and approve CAISO's operating and capital budgets.

CAISO uses an informal stakeholder process to propose solutions to problems that may ultimately require a filing at FERC. Unlike other RTOs, which have a formal committee structure, CAISO's stakeholder process generally consists of rounds of dialogue with stakeholders on major policy issues.

Transmission Owners

The Participating Transmission Owners (PTOs) in the CAISO control area include:

- Pacific Gas and Electric Co.
- Southern California Edison

- San Diego Gas and Electric,
- Valley Electric Association
- Municipal utilities such as Vernon, Anaheim and Riverside

Chronic Constraints

Load pockets that are chronically constrained include San Diego, Los Angeles Basin, and North Coast/North Bay (San Francisco).

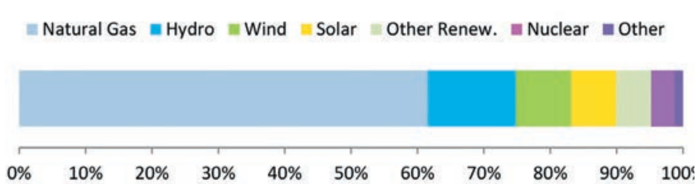
Transmission Planning

CAISO conducts an annual transmission planning process with stakeholders that includes both short-term and long-term projects.

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Demand Response

Demand response participation in the wholesale energy market is currently limited to a small amount of demand associated with water pumping loads. Other demand response in California consists of programs for managing peak summer demands operated by the state's electric utilities. In general, these demand-response programs may be triggered based on criteria that are internal to the utility or when CAISO issues a Flex Alert. Flex Alerts also inform consumers how and when to conserve electricity usage.

Market Features

Energy Markets

Day-Ahead Market

The day-ahead market allows participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

From the offers and bids, CAISO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are said to clear, meaning they are scheduled for dispatch. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the locational marginal prices (LMP) for all locations.

Generator offers scheduled in the day-ahead settlement are paid the day-ahead LMP for the megawatts accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time market to replace what was not produced.

Likewise, wholesale buyers of electricity whose bids clear in the day-ahead market settlement pay for and lock in their right to consume the cleared quantity at the day-ahead LMP. Electricity use in real time that exceeds the day-ahead purchase is paid for at the real-time LMP.

Real-Time Market

CAISO must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. While the day-ahead energy market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule. Thus, to meet energy needs within each hour of the current day the CAISO operates a spot market for energy called the real-time market.

The real-time market uses final day-ahead schedules for resources within the ISO and imports and exports as a starting point. It then operates a fifteen minute market to adjust resource schedules, and then a five minute market to balance generation and loads.

Prices resulting from the real-time market are only applicable to incremental adjustments to each resource's day-ahead schedule. Real-time bids can be submitted up to 75 minutes before the start of the operating hour.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission, and system-control equipment to support the reliability of the transmission system. RTOs procure or direct the supply of ancillary services.

CAISO procures four ancillary services in the day-ahead and real-time markets:

- Regulation up: Units providing regulation up must be able to move quickly above their scheduled operating point in response to automated signals from the ISO to maintain the frequency on the system by balancing generation and demand.
- Regulation down: Units providing regulation down must be able to move quickly below their scheduled operating point in response to automated signals from the ISO.
- Spinning reserve: Resources providing spinning reserves must be synchronized with the grid (online, or spinning) and be able to respond within 10 minutes. This is more reliable than nonspinning reserves because it is already online and synchronized.
- Nonspinning reserve: Resources providing nonspinning reserves must be able to synchronize with the grid and respond within 10 minutes.

Regulation up and regulation down are used continually to maintain system frequency by balancing generation and demand. Spinning and nonspinning resources are used to maintain system frequency and stability during emergency operating conditions (such as unplanned outage of generation or transmission facilities) and major unexpected variations in load. Spinning and nonspinning resources are often referred to collectively as operating reserves.

Capacity Markets

Capacity markets provide a means for LSEs to procure capacity needed to meet forecast load, or resource adequacy (RA) requirements, and to allow generators to recover a portion of their fixed costs. They also provide economic incentives to attract investment in new and existing supply-side and demand-side capacity resources needed to maintain bulk power system reliability requirements.

The CAISO does not operate a formal capacity market, but it does have a mandatory RA requirement. The program requires that LSEs procure 115 percent of their aggregate system load on a monthly basis, unless a different reserve margin is mandated by the LSE's local regulatory authority. The program provides deliverability criteria each LSE must meet, as well as system and local capacity requirements. Resources counted for RA purposes must make themselves available to the CAISO day-ahead and real-time markets for the capacity for which they were counted.

Market Power Mitigation

In electric power markets, mainly because of the largely nonstorable nature of electricity and the existence of transmission constraints that can limit the availability of multiple suppliers to discipline market prices, some sellers from time to time have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present.

Market power may need to be mitigated systemwide or locally when the exercise of market power may be particularly a concern for a local area. For example, when a transmission constraint creates the potential for local market power, the

RTO may apply a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – close to short-run marginal costs.

Special Provisions for Resources Needed to Ensure Grid Reliability

An RMR contract acts as an insurance policy, assuring that the CAISO has dispatch rights in order to reliably serve load in local import constrained areas. RMR contracts also help to mitigate any local market power that one or more units may have. The amount of generation capacity under RMR contracts dropped when local RA requirements were introduced. With more local resources being procured through RA contracts, the CAISO was able to significantly decrease its RMR designations in much of the system. Remaining generators with RMR contracts are located primarily near the San Francisco and Los Angeles areas.

Financial Transmission Rights

As discussed earlier in this chapter, FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead market. In California, FTRs are referred to as Congestion Revenue Rights (CRR). A CRR is an instrument that entitles the CRR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The CRR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. CRRs are monthly or quarterly products. CRRs can be bought at auction or allocated by CAISO. Allocated CRRs receive the congestion value for a specific path, similar to a converted FTR. CAISO also allocates open market CRR auction revenue to LSEs based on their physical participation in the market, similar to an ARR in other markets.

Virtual Transactions

CAISO's market includes a virtual transactions feature, termed convergence bidding, that allows more participation in the day-ahead price-setting process, allows participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time energy markets. CAISO's convergence bidding includes both virtual supply and virtual demand transactions. A virtual supply transaction is an offer to sell at the day-ahead price and a bid to buy at the real-time price. A virtual demand transaction is a bid to buy at the day-ahead price and an offer to sell at the real-time price. The virtual supply offer and the virtual demand bid may be submitted at any eligible pricing node in the CAISO system and there is no requirement for physical generation or load. The financial outcome for a particular participant is determined by the difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears.

Credit Requirements

CAISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. CAISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions

– e.g., CAISO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth, net assets, and credit rating.

Settlements

RTOs must invoice market participants for their involvement in their markets. Settlements is the process by which the RTO determines the amounts to be paid associated with buying and selling energy, capacity and ancillary services, and paying administrative charges.

The CAISO calculates, accounts for and settles all charges and payments based on received settlement quality meter data. The CAISO conducts settlements for a grid management charge, bid cost recovery, energy and ancillary services, CRR charges and payments, among other charges. The CAISO settles for both the day-ahead market and the real-time market.

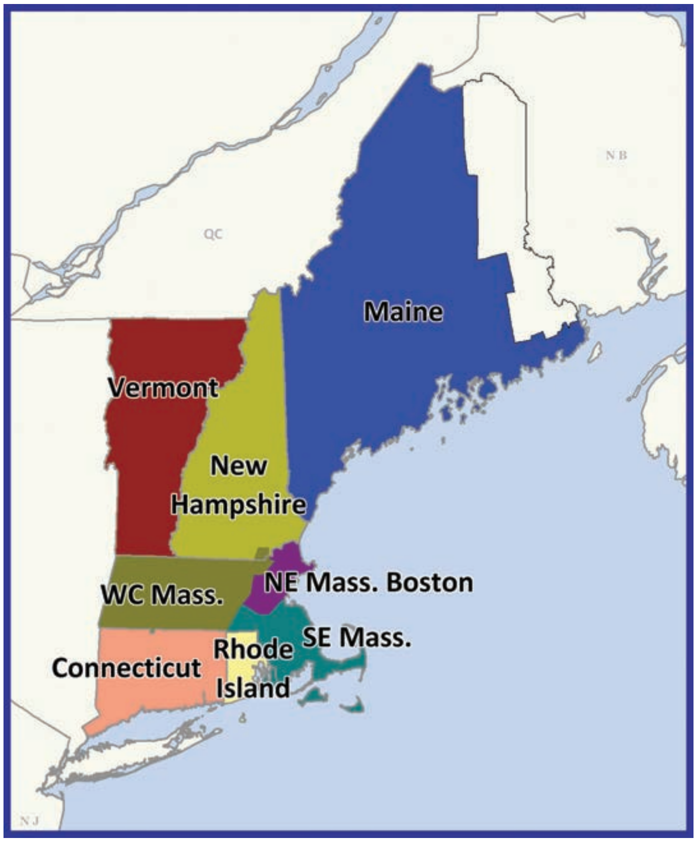
CAISO – PacifiCorp Energy Imbalance Market

On Nov. 1, 2014, CAISO began operation of an energy imbalance market (EIM) with PacifiCorp's two balancing authority areas, PacifiCorp East (PACE) and PacifiCorp West (PACW). CAISO extended its existing real-time market into the PacifiCorp to automatically dispatch resources to meet intra-hour changes in energy demand and supply. Resources participate in the EIM voluntarily and only resources that register to participate may actually bid into the EIM for the 15- and 5- minute market runs. Load buys imbalance energy directly from the EIM. For example, PacifiCorp, the largest LSE in PACE and PACW areas, buys imbalance energy through the EIM. Other entities that may purchase imbalance energy include wind generators that seek to match their generation supply with contracted demand.

The three balancing authorities – CAISO, PACE, and PACW – may transfer imbalance energy through a limited amount of transmission capability. Consequently, prices and supply are largely determined by resources within each area. CAISO's Department of Market Monitoring serves as the market monitor for the EIM. While the CAISO's operations remain under the CAISO Board of Governors, an EIM Transitional Committee advises CAISO's board of governors and is developing a proposal for long-term EIM governance. Among other benefits, the EIM may provide a broader footprint for incorporating renewable generation and an opportunity to improve the economic efficiency of generation dispatch.

ISO-NE

New England Independent System Operator



Source: Velocity Suite, ABB

Market Profile

Geographic Scope

As the RTO for New England, ISO-NE is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts and related products, in addition to administering auctions for the sale of capacity.

ISO-NE operates New England's high-voltage transmission network and performs long-term planning for the New England system. ISO-NE serves six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

Peak Demand

New England's all-time peak load was 28 GW in summer 2006.

Import and Exports

ISO-NE is interconnected with the New York Independent System Operator (NYISO), TransEnergie (Québec) and the New Brunswick System Operator. ISO-NE imports around 15 percent of its annual energy needs from Québec, NYISO, and New Brunswick. New England receives imports from Québec and New Brunswick in most hours. Between New England and New York, power flows in alternate directions depending on market conditions.

Market Participants

The New England Power Pool (NEPOOL) consists of six sectors: (1) end-user sector; (2) publicly owned entities; (3) supplier sector; (4) transmission sector; (5) generation sector; and (6) alternative resources.

Membership and Governance

ISO-NE is a not-for-profit entity governed by a 10-member, independent, non-stakeholder board of directors. The sitting members of the board elect people to fill board vacancies.

Transmission Owners

ISO-NE's transmission owners include:

- Central Maine Power Co.
- New England Power Co.
- Northeast Utilities System Cos.
- NSTAR Electric Co.
- The United Illuminating Co.
- Vermont Electric Cooperative Inc.

Chronic Constraints

Constraints in the ISO-NE are concentrated in the Northeast Massachusetts-Boston zone. However, New England completed a series of major transmission projects in 2009 to improve reliability, including projects serving Boston, southwestern Connecticut and southeastern Massachusetts. Furthermore, it continues to assess and bolster its transmission system.

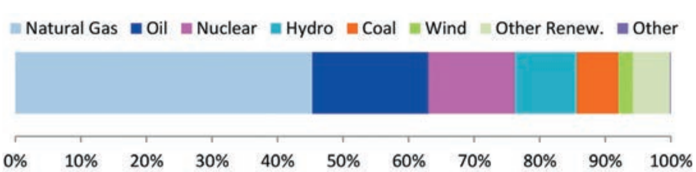
Transmission Planning

Each year, ISO-NE prepares a comprehensive 10-year regional system plan (RSP) that reports on the results of ISO system planning processes. Each plan includes forecasts of future loads (i.e., the demand for electricity measured in megawatts) and addresses how this demand may be satisfied by adding supply resources; demand resources, including demand response and energy efficiency; and new or upgraded transmission facilities. Each year's plan summarizes New England needs, as well as the needs in specific areas, and includes solutions and processes required to ensure the reliable and economic performance of the New England power system.

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Demand Response

Currently, ISO-NE administers the following demand-response programs for the New England wholesale electricity market:

- **Real-Time Demand Response Resources (RTDR)**: These resources are required to respond within 30 minutes of the ISO's instructions.
- **Real-Time Emergency Generation Resources (RTEG):** Resources that the ISO calls on to operate during a 5 percent voltage reduction that requires more than 10 minutes to implement. They must begin operating within 30 minutes of receiving a dispatch instruction.
- **Transitional Price-Response Demand**: An optional program that allows market participants with assets registered as RTDRs to offer load reductions in response to day-ahead LMP. The participant is paid the day-ahead LMP for the cleared interruptions, and real-time deviations are charged or credited at the real-time LMP.

Market Features

Energy Markets

Day-Ahead Market

The day-ahead energy market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

In the day-ahead energy market, incremental offers and decremental bids (virtual supply offers and demand bids) can also be submitted, which indicate prices at which supply or demand are willing to increase or decrease their injection or withdrawal on the system. These INCs and DECs are tools market participants can use to hedge their positions in the day-ahead energy market.

From the offers and bids, the RTO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are cleared and are scheduled. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the LMPs for all locations.

Real-Time Market

ISO-NE must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. Supply or demand for the operating day can change for a variety of reasons, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. While the day-ahead energy market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule. Thus, ISO-NE operates a spot market for energy, the real-time energy market, to meet energy needs within each hour of the current day.

ISO-NE clears the real-time energy market using supply offers, real-time load and offers and bids to sell or buy energy over the external interfaces. For generators, the market provides additional opportunities to offer supply to help meet incremental supply needs. LSEs whose actual demand comes in higher than that scheduled in the day-ahead energy market may secure additional energy from the real-time energy market.

The real-time energy market financially settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Differences from the day-ahead quantities cleared are settled at the real-time LMP.

In real time, ISO-NE will issue dispatch rates and dispatch targets. These are five-minute price and megawatt signals based on the aggregate offers of generators, which will produce the required energy production. Market participants are, throughout the day, allowed to offer imports or request exports of electricity from neighboring control areas with at least one hour's notice.

Must-Offer Requirements

Market rules in RTOs include must-offer requirements for certain categories of resources for which withholding, a form of the exercise of market power, may be a concern. Where such rules apply, sellers must commit, or offer, the generators, and schedule and operate the facilities, into the applicable market.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system. RTOs procure or direct the supply of ancillary services.

ISO-NE procures ancillary services via the forward reserve market and its regulation market. The forward reserve market compensates generators for making available their unloaded operating capacity that can be converted into electric energy within 10 or 30 minutes when needed to meet system contingencies, such as unexpected outages. The Regulation Market compensates resources that ISO-NE instructs to increase or decrease output moment by moment to balance the variations in demand and system frequency to meet industry standards. The specific ancillary services ISO-NE procures in its markets include the following:

- Ten-Minute Spinning Reserves: provided by resources already synchronized to the grid and able to generate electricity within 10 minutes.
- Ten-Minute Nonspinning Reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 10 minutes.
- Thirty-Minute Nonspinning Reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 30 minutes.
- Regulation: provided by specially equipped resources

with the capability to increase or decrease their generation output every four seconds in response to signals they receive from ISO-NE to control slight changes on the system.

Specialized ancillary services that are not bought and sold in these ancillary service markets include voltage support and black-start capability. Voltage support allows the New England control area to maintain transmission voltages. Black-start capability is the ability of a generating unit to go from a shutdown condition to an operating condition and start delivering power without assistance from a power system. ISO-NE procures these services via cost-based rates.

Capacity Markets

In ISO-NE's annual Forward Capacity Auction (FCA), both generator and demand resources offer capacity three years in advance of the period for which capacity will be supplied. The three-year lead time is intended to encourage participation by new resources and allow the market to adapt to resources leaving the market. Resources whose capacity clears the FCA acquire capacity supply obligations (CSOs). ISO-NE held its first two FCAs in 2008 for the 2010-11 and 2011-12 delivery years. The first full year of capacity market commitments began on June 1, 2010. The FCA process includes the modeling of transmission constraints to determine if load zones will be import- or export-constrained.

Market Power Mitigation

In ISO-NE, mitigation may be applied for physical withholding, economic withholding, uneconomic production, virtual transactions or other conduct if the conduct has a material effect on prices or uplift payments. The market monitor uses defined thresholds to identify physical and economic withholding and uneconomic generation, as well as defined thresholds to determine whether bids and offers would, if not mitigated, cause a material effect on LMPs or uplift charges.

Special Provisions for Resources Needed to Ensure Grid Reliability

When a resource owner requests to withdraw from the capacity market (termed a "delist bid") or to retire the resource (termed a "non-price retirement request"), the ISO evaluates whether the resource is needed for reliability, such as when a resource's withdrawal could lead to a violation of a reliability requirement – e.g., inadequate reserve margins or a loss of electric system stability.

In New England, the resource owner has the option to retire the unit or continue to operate it while the ISO works with regional stakeholders to find alternate supply or engineering solutions that could allow the resource to retire and still maintain grid reliability. Alternative solutions might include obtaining emergency sources of generation or more expensive generation from outside the region. If no other alternative is available, the ISO may compensate the unit through certain payment provisions of the capacity market or by entering into a cost of service agreement with the resource owner while other options are pursued.

Financial Transmission Rights

New England FTRs are monthly and annual products that provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead energy market. An FTR is an instrument that entitles the FTR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. The RTO holds FTR auctions to allow market participants the opportunity to acquire FTRs or to sell FTRs they currently hold. In New England, ARRs represent the right to receive revenues from the FTR auctions. ISO-NE allocates ARRs to both LSEs, in relation to historic load, and to entities who make transmission upgrades that increase the capability of the transmission system.

Virtual Transactions

New England's market includes a virtual transaction feature. Virtual transactions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. In ISO-NE's terminology, virtual transactions consist of market participants submitting increment offers and decrement bids in the day-ahead energy market. An increment offer is an offer to sell energy at a specific location in the day-ahead energy market which is not associated with a physical supply. An accepted increment offer results in scheduled generation at the specified location in the day-ahead energy market. A decrement bid is a bid to purchase energy at a specific location in the day-ahead energy market which is not associated with a physical load. An accepted decrement bid results in scheduled load at the specified location in the day-ahead energy market. The participant receives the day-ahead LMP for each megawatt of virtual supply that clears in the day-ahead energy market and is financially obligated to pay the real-time LMP at the same location. Conversely, the participant pays the day-ahead LMP for each megawatt of cleared virtual demand and receives the real-time LMP at that location.

Credit Requirements

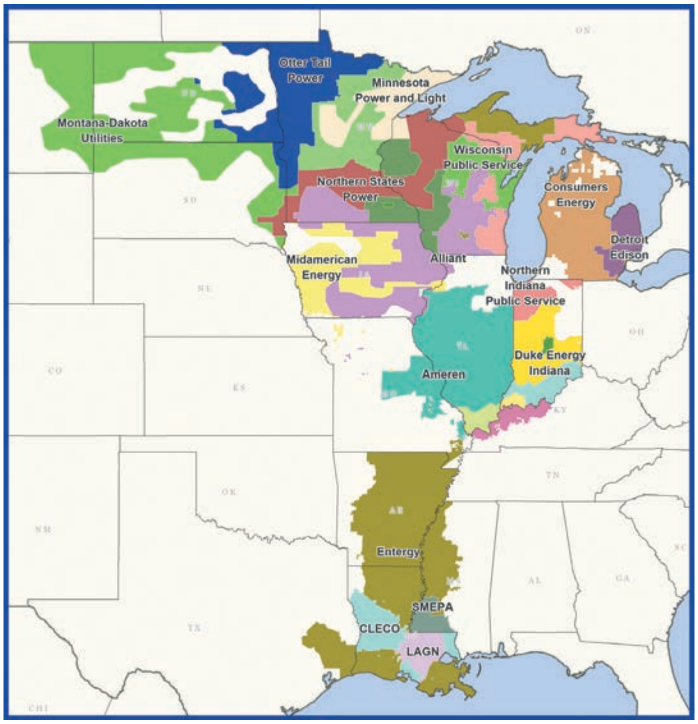
ISO-NE's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. ISO-NE assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. ISO-NE establishes a credit limit for each market participant in accordance with tariff formulas that include various creditworthiness-related specifications such as tangible net worth and total amounts due and owing to the ISO-NE market.

Settlements

RTOs must invoice market participants for their involvement in their markets. Settlements is the process by which the RTO determines the amounts to be paid associated with buying and selling energy, capacity and ancillary services, and paying administrative charges.

ISO-NE calculates, accounts for and settles all charges and payments based on received settlement quality meter data. The RTO conducts settlements for transactions related to the various wholesale electricity markets, market products, and other services including energy, capacity, ancillary services, FTR charges and payments, among other charges. The RTO settles for both the day-ahead and real-time markets.

MISO
Midcontinent Independent System Operator



Source: Velocity Suite, ABB

Market Profile

Geographic Scope

MISO operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South, extending from Michigan and Indiana to Montana and from the Canadian border to the southern extremes of Louisiana and Mississippi. The system is operated from three control centers: Carmel, Indiana; Eagan, Minnesota; and Little Rock, Arkansas. MISO also serves as the reliability coordinator for additional systems outside of its market area, primarily to the north and northwest of the market footprint.

MISO was not a power pool before organizing as an ISO in December 2001. It began market operations in April 2005. In January 2009, MISO started operating an ancillary services market and combined its 24 separate balancing areas into a single balancing area. In 2013, the RTO began operations in the MISO South region, including the utility footprints of Entergy, Cleco, and South Mississippi Electric Power Association, among others, in parts of Arkansas, Mississippi, Louisiana, and Texas.

Peak Demand

MISO's all-time peak load was 126 GW in summer 2011, prior to the MISO South integration and prior to the move of Duke Energy Ohio and Kentucky to PJM.

Import and Exports

MISO has interconnections with the PJM and Southwest Power Pool (SPP) RTOs. It is also directly connected to Southern Co., TVA, the Western Area Power Administration, the electric systems of Manitoba and Ontario, plus several smaller systems. MISO is a net importer of power overall, but the interchange with some areas can flow in either direction, depending on the relative loads and prices in the adjoining regions. Manitoba Hydro supplies a large part of MISO's load with its excess capacity, particularly in the summer.

Market Participants

MISO includes approximately 40 transmission owners, whose assets define the MISO market area. MISO's market participants include generators, power marketers, transmission-dependent utilities and load-serving entities.

Membership and Governance

An independent board of directors of eight members, including the president, governs MISO. Directors are elected by the MISO membership from candidates provided by the board.

An advisory committee of the membership provides advice to the board and information to the MISO stakeholders. Membership includes entities with an interest in MISO's operation, such as state regulators and consumer advocates, as well as transmission owners, independent power producers, power marketers and brokers, municipal and cooperative utilities and large-volume customers.

Transmission Owners

The transmission owners in MISO include:

- Alliant Energy
- American Transmission Co.
- Ameren (Missouri and Illinois)
- American Transmission Systems
- Duke
- Cleco
- Entergy
- Indianapolis Power and Light
- ITC
- Michigan Public Power Agency
- NSP Companies (Xcel)
- Northern Indiana Public Service Co.
- Otter Tail Power
- MidAmerican Energy

Chronic Constraints

MISO has certain pathways that are more likely to become congested, but the likelihood and pattern of congestion in any area is subject to weather patterns, wind production and interchange with external regions. When load is high in the eastern part of MISO and to the east in PJM, constraints occur on pathways from the Minnesota and Wisconsin areas through Chicago and across Indiana. A particular congestion point with this pattern is northern Indiana. When colder weather hits Minnesota and the Dakotas, there is often congestion in the northern direction, particularly in Iowa. Higher wind production can cause localized constraints in some areas and can cause congestion in pathways from southern Minnesota and western Iowa moving eastward. New Orleans and east Texas are also two constrained areas in MISO South. Additionally, constraints arise between Missouri and Arkansas, which connects the MISO Midwest with MISO South.

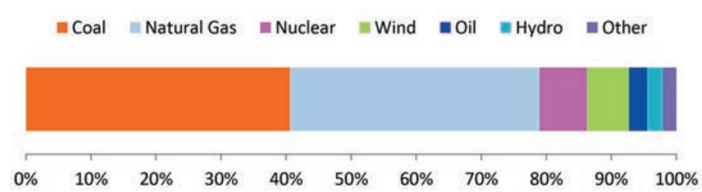
Transmission Planning

The main vehicle MISO uses for transmission planning is the MISO Transmission Expansion Plan developed by the MISO planning department in collaboration with transmission owners and other stakeholders who form the planning advisory committee. The plan is for two years. Once approved by the board, the plan becomes the responsibility of the transmission owners.

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Demand Response

Demand-side resources are able to participate in MISO's markets in providing capacity, energy in both the day-ahead and real-time markets and ancillary services.

Market Features

Energy Markets

Day-Ahead Market

The day-ahead market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

In the day-ahead market, incremental offers and decremental bids (virtual supply offers and demand bids) can also be submitted, although they are not associated with physical resources or actual load. These INCs and DECs are tools market participants can use to hedge their real time commitments or to arbitrage the day-ahead to real-time price spread.

From the offers and bids, the RTO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are scheduled. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the locational marginal prices (LMPs) for all locations.

Generators and offers scheduled in the day-ahead settlement are paid the day-ahead LMP for the megawatts accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time marketplace to replace what was not produced.

Likewise, wholesale buyers of electricity and virtual demand whose bids to buy clear in the day-ahead market settlement pay for and lock in their right to consume the cleared quantity at the day-ahead LMP. Electricity use in real-time that exceeds the day-ahead purchase is paid for at the real-time LMP.

Real-Time Market

MISO must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. Supply or demand for the operating day can change for a variety of reasons, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. While the day-ahead market produces the schedule and financial terms for the bulk of the physical transactions, a number of factors usually change the day-ahead result. Thus, MISO operates a spot market for energy, the real-time energy market, to meet actual energy needs within each hour of the operating day.

The real-time market is prepared for at the conclusion of the day-ahead market on the day before the operating day. MISO clears the real-time market using supply offers, real-time load and external offers. For generators, the market provides additional opportunities to offer supply to help meet incremental needs. LSEs whose actual demand comes in higher than what was scheduled in the day-ahead market may secure additional energy from the real-time market.

The real-time market financially settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Participants either pay or are paid the real-time LMP for the amount of load or generation in megawatt-hours that deviates from their day-ahead schedule. In real-time, MISO issues dispatch rates and dispatch targets. These are five-minute price and megawatt signals based on the aggregate offers of generators, which will produce the required energy production. Market participants are, throughout the day, allowed to offer imports or request exports of electricity from neighboring control areas by submitting transmission schedules into or out of MISO.

In real-time, generators can also deviate from the day-ahead clearing schedule by self-scheduling, which means that MISO will run a given unit without regard to the unit's economics unless running the unit presents a reliability concern. During the operating day, the real-time market acts as a balancing market for load with physical resources used to meet that load. A market price for energy and for each of the ancillary services is calculated for each five-minute dispatch interval and the resulting five-minute prices are rolled into hourly prices for billing and payment. Differences in the real-time operation from the day-ahead clearing, including all virtual transactions, are settled at the real-time price.

Must-Offer Requirements

Market rules in RTOs include must-offer requirements for certain categories of resources for which withholding, which could be an exercise of market power, may be a concern. Where such rules apply, sellers must commit, or offer, the generators, and schedule and operate the facilities, in the applicable market.

In MISO, generators who supply capacity to meet the RTO resource adequacy requirement for load are required to offer into the day-ahead and real-time markets for energy and the ancillary services for which they are qualified.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system. RTOs procure or direct the supply of ancillary services.

MISO procures ancillary services via the co-optimized energy and ancillary services market and includes the following services:

- Spinning Reserves: provided by resources already synchronized to the grid and able to provide output within 10 minutes.
- Supplemental (nonspinning) Reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 10 minutes.
- Regulation: provided by specially equipped resources with the capability to increase or decrease their generation output every four seconds in response to signals they receive to control slight changes on the system.

Capacity Markets

Capacity markets are a construct to provide assurance to government entities and to NERC a means for LSEs to prove they have procured capacity needed to meet forecast load and to allow generators to recover a portion of their fixed costs. They also provide economic incentives to attract investment in new and existing supply- side and demand-side capacity resources.

MISO maintains an annual capacity requirement on all LSEs based on the load forecast plus reserves. LSEs are required to specify to MISO what physical capacity, including demand resources, they have designated to meet their load forecast. This capacity can be acquired either through an annual capacity auction, bilateral purchase, or self-supply.

Market Power Mitigation

In electric power markets, mainly because of the largely nonstorable nature of electricity and the existence of transmission constraints that can limit the availability of multiple suppliers to discipline market prices, some sellers from time to time have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present.

Special Provisions for Resources Needed to Ensure Grid Reliability

In MISO, a power plant owner seeking to retire or suspend a generator must first obtain approval from MISO. MISO evaluates plant retirement or suspension requests for reliability need, and System Support Resource (SSR) designations are made where reliability is threatened. Once an agreement has been reached, SSRs receive compensation associated with remaining online and available.

Financial Transmission Rights

MISO FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead market. An FTR is an instrument that entitles the FTR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. Payments, or charges, are calculated relative to the difference in congestion prices in the day-ahead market across the selected FTR transmission path. MISO FTRs are monthly and annual products.

The RTO holds FTR auctions to allow market participants the opportunity to acquire FTRs, sell FTRs they currently hold, or to convert ARRs to FTRs. ARRs provide LSEs, and entities who make transmission upgrades, with a share of the revenues generated in the FTR auctions. MISO allocates ARRs to transmission customers relative to historic usage, or upgraded capability, of the transmission system.

Virtual Transactions

MISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. Cleared virtual supply (increment or virtual offers, or INCs) in the day-ahead energy market at a particular location in a certain hour creates a financial obligation for the participant to buy back the bid quantity in the real-time market at that location in that hour. Cleared virtual demand (decrement or virtual bids, or DECs) in the day-ahead market creates a financial obligation to sell the bid quantity in the real-time market. The financial outcome for a particular participant is determined by the difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears.

MISO allows virtual bids and offers into its day-ahead market where the bids and offers are included in the determination of the LMP along with physical resource offers and actual load bids. Market participants, whose virtual transactions clear in the day-ahead market, have their positions cleared in the real-time market at the real-time price. Virtual bids and offers are allowed in MISO at any pricing node or aggregate of pricing nodes.

Credit Requirements

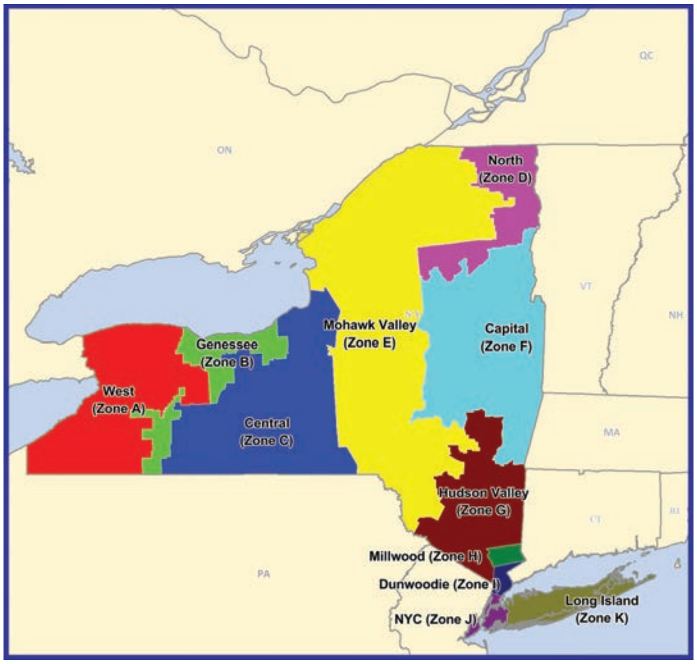
MISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions – e.g., the RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

Settlements

RTOs must invoice market participants for their involvement in their markets. The RTO determines the amount owed associated with buying and selling energy, capacity and ancillary services and paying various administrative charges. Settlements for market activity in MISO are finalized seven days after the operating day and payable after 14 days.

NYISO

New York Independent System Operator



Source: Velocity Suite, ABB

Market Profile

Geographic Scope

Prior to restructuring of the electric industry in the 1990s, New York's private utilities and public power authorities owned and operated New York's electric system. Operation of the electric grid was coordinated by a voluntary collaboration of the utilities and power authorities as the New York Power Pool (NYPP). The creation of the New York Independent System Operator (NYISO) was authorized by FERC in 1998. The formal transfer of the NYPP's responsibilities to the NYISO took place on Dec. 1, 1999.

The NYISO footprint covers the entire state of New York. NYISO is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts, and related products, in addition to administering auctions for the sale of capacity. NYISO operates New York's high-voltage transmission network and performs long-term planning.

Peak Demand

NYISO's all-time peak load was 34 GW in summer 2013.

Imports and Exports

NYISO imports and exports energy through interconnections with ISO-NE, PJM, TransEnergie (Quebec) and Ontario. Under a long-term agreement, approximately 1,000 MW of electricity regularly flows from the Consolidated Edison (Con Ed) territory in upstate New York through PSEG territory in PJM, to New York City utilizing phase angle regulator-controlled lines. This is commonly referred to as the Con Ed-PSEG Wheel and is an important source of power for NYISO.

Market Participants

NYISO's market participants include generators, transmission owners, financial institutions, traditional local utilities, electric co-ops and industrials.

Membership and Governance

NYISO is governed by an independent 10-member board of directors and management, business issues and operating committees. Each committee oversees its own set of working groups or subcommittees. These committees comprise transmission owners, generation owners and other suppliers, consumers, public power and environmental entities. Tariff revisions on market rules and operating procedures filed with the Commission are largely developed through consensus by these committees. The members of the board, as well as all employees, must not be directly associated with any market participant or stakeholder.

Transmission Owners

NYISO's transmission owners include:

- Central Hudson Gas & Electric Corp.
- Consolidated Edison Co. of New York
- Long Island Power Authority (LIPA)
- New York Power Authority (NYPA)

- New York State Electric and Gas Corp. (NYSEG)
- National Grid
- Orange & Rockland Utilities
- Rochester Gas and Electric Corp.

Chronic Constraints

The chronic transmission constraints in NYISO are in the southeastern portion of the state, leading into New York City and Long Island. As a result of their dense populations, New York City and Long Island are the largest consumers of electricity. Consequently, energy flows from the west and the north toward these two large markets, pushing transmission facilities near their operational limits. This results in transmission constraints in several key areas, often resulting in higher prices in the New York City and Long Island markets.

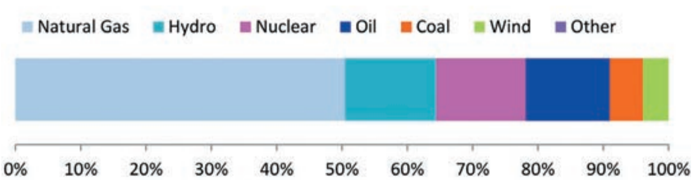
Transmission Planning

NYISO conducts a biennial transmission planning process with stakeholders that includes both short-term and long-term projects.

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Demand Response

NYISO has four demand-response (DR) programs: the emergency demand-response program (EDRP), the installed capacity (ICAP) special case resources program (SCR), the Day-Ahead Demand-Response Program (DADRP) and the Demand-Side Ancillary Services Program (DSASP).

Both the emergency and special cases programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid. Both programs are designed to reduce power usage by shutting down businesses and large power users. Companies, mostly industrial and commercial, sign up to take part in the programs. The companies are paid by NYISO for reducing energy consumption when asked to do so. Reductions are voluntary for EDRP participants. SCR participants are required to reduce power usage and as part of their agreement are paid in advance for agreeing to cut power usage on request.

NYISO's DADRP program allows energy users to bid their load reductions into the day-ahead market. Offers determined to be economic are paid at the market clearing price. Under day-ahead DR, flexible loads may effectively increase the amount of supply in the market and moderate prices.

The DSASP provides retail customers that can meet telemetry and other qualifications the ability to bid their load curtailment capability into the day-ahead market or real-time market to provide reserves and regulation service. Scheduled offers are paid the marketing clearing price for reserves or regulation.

Market Features

Energy Markets

Day-Ahead Market

The day-ahead market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

In the day-ahead market, virtual supply offers and demand bids can also be submitted. These are tools market participants can use to hedge their positions in the day-ahead market.

From the offers and bids, the RTO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below, and demand bids above, the identified price are scheduled. Offers and bids that clear are then entered into a pricing software system along with binding transmission constraints to produce the LMPs for all locations. The NYISO refers to LMPs as locational based marginal prices, or LBMPs.

Generators and offers scheduled in the day-ahead settlement are paid the day-ahead LBMP for the megawatts accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time marketplace to replace what was not produced.

Likewise, wholesale buyers of electricity and virtual demand whose bids to buy are accepted in the day-ahead market pay for and lock in their right to consume the cleared quantity at the day-ahead LBMP. Electricity used in real-time that exceeds the day-ahead purchase is paid for at the real-time LBMP.

Hour-Ahead Market

The hour-ahead market allows buyers and sellers of electricity to balance unexpected increases or decreases of electricity use after the day-ahead market closes. Bids and offers are submitted an hour ahead of time. Prices are set based on those bids and offers, generally for use in matching generation and load requirements, but those prices are advisory only. Hour-ahead scheduling is completed at least 45 minutes prior to the beginning of the dispatch hour after NYISO reviews transmission outages, the load forecast, reserve requirements and hour-ahead generation and firm transaction bids, among other things.

Real-Time Market

NYISO must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. Supply or demand for the operating day can change for a variety of reasons, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. While the day-ahead market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule. Thus, NYISO operates a spot market for energy, the real-time energy market, to meet energy needs within each hour of the current day.

Real-time market outcomes are based on supply offers, real-time load and offers and bids to sell or buy energy. LSEs whose actual demand comes in higher than that scheduled in the day-ahead market may secure additional energy from the real-time market. For generators, the market provides additional opportunities to offer supply to help meet additional needs.

The real-time market financially settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Those who were committed to produce in the day-ahead are compensated at (or pay) the real-time LBMP for the megawatts under- or over-produced in relation to the cleared amount. Those who paid for day-ahead megawatts are paid (or pay) the real-time LBMP for megawatts under- or over-consumed in real-time.

Real-time dispatch of generators occurs every five minutes, as does the setting of the real-time prices used for settlement purposes. Market participants may participate in the day-ahead, hour-ahead, and the real-time market.

Must-Offer Requirements

Under the NYISO capacity auction rules, entities that offer capacity into an auction that is subsequently purchased by load are required to offer that amount of capacity into the day-ahead energy market. This rule ensures that capacity sold through the capacity auctions is actually delivered into the market.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system. RTOs procure or direct the supply of ancillary services.

NYISO administers competitive markets for ancillary services that are required to support the power system. The two most important types of ancillary services are operating reserves and regulation. Operating reserves and regulation are typically provided by generators, but NYISO allows demand-side providers to participate in these markets as well. Operating reserve resources can either be spinning (online with additional ramping ability) or nonspinning (off-line, but able to start and synchronize quickly). NYISO relies on regulating resources that can quickly adjust their output or consumption in response to constantly changing load conditions to maintain system balance.

The NYISO relies on the following types of ancillary services:

- Ten-Minute spinning reserves: provided by resources already synchronized to the grid and able to provide output within 10 minutes.
- Ten-Minute nonspinning reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 10 minutes.
- Thirty-Minute nonspinning reserves: provided by resources not currently synchronized to the grid but capable of starting and providing output within 30 minutes.
- Regulation: provided by resources with the capability to increase or decrease their generation output within seconds in order to control changes on the system.

Capacity Markets

Capacity markets provide a means for LSEs to procure capacity needed to meet forecast load and to allow generators to recover a portion of their fixed costs. They also provide economic incentives to attract investment in new and existing supply-side and demand-side capacity resources in New York as needed to maintain bulk power system reliability requirements.

In NYISO's capacity market, LSEs procure capacity through installed-capacity (ICAP) auctions, self-supply and bilateral arrangements based on their forecasted peak load plus a margin. The NYISO conducts auctions for three different service durations: the capability period auction (covering six months), the monthly auction and the spot market auction.

New York has capacity requirements for four zones: New York City, Long Island, Lower Hudson Valley, and New York-Rest of State. The resource requirements do not change in the monthly auctions and ICAP spot market auctions relative to the capability period auction. The shorter monthly auctions are designed to account for incremental changes in LSE's load forecasts.

Market Power Mitigation

In electric power markets, mainly because of the largely nonstorable nature of electricity and the existence of transmission constraints that can limit the availability of multiple suppliers to discipline market prices, some sellers from time to time have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present.

Market power may need to be mitigated on a systemwide basis or on a local basis. When a transmission constraint creates the potential for local market power, the RTO may apply a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market.

The categories of conduct that may warrant mitigation by NYISO include physical withholding, economic withholding and uneconomic production by a generator or transmission facility to obtain benefits from a transmission constraint. Physical withholding is not offering to sell or schedule energy provided by a generator or transmission facility capable of serving a NYISO market. Physical withholding may include falsely declaring an outage, refusing to offer or schedule a generator or transmission facility; making an unjustifiable change to operating parameters of a generator that reduces its availability; or operating a generator in real-time at a lower output level than the generator would have been expected to produce had the generator followed NYISO's dispatch instructions. Economic withholding is submitting bids for a generator that are unjustifiably high so that the generator is not dispatched. NYISO will not impose mitigation unless the conduct causes or contributes to a material change in prices, or substantially increases guarantee payments to participants.

Price Caps

NYISO has an offer cap of $1,000/MWh for its day-ahead and real-time markets.

Capacity for New York City is subject to offer caps and floors. Offer caps in New York City are based on reference levels or avoided costs. Capacity from generators within New York City must be offered in each ICAP spot market auction, unless that capacity has been exported out of New York or sold to meet ICAP requirements outside New York City.

Local Market Power Mitigation

Generators in New York City are subject to automated market power mitigation procedures because New York City is geographically separated from other parts of New York; plus, generators in New York City have been deemed to have market power.

These automated procedures determine whether any day-ahead or real-time energy bids, including start-up costs bids and minimum generation bids, but excluding ancillary services bids, exceed the tariff's thresholds for economic withholding, and, if so, determine whether such bids would cause material price effects or changes in guarantee payments. If these two tests are met, mitigation is imposed automatically.

For example, the threshold for economic withholding regarding energy and minimum generation bids is a 300 percent increase or an increase of $100/MWh over the applicable reference level, whichever is lower. Energy or minimum generation bids below $25/MWh are not considered economic withholding. Regarding operating reserves and regulation bids, a 300 percent increase or an increase of $50/MW over the applicable reference level, whichever is lower, is the threshold for determining whether economic withholding has occurred. In this instance, bids below $5/MW are not considered economic withholding. If an entity's bids meet these thresholds, the applicable reference level is substituted for the entity's actual bid to determine the clearing price.

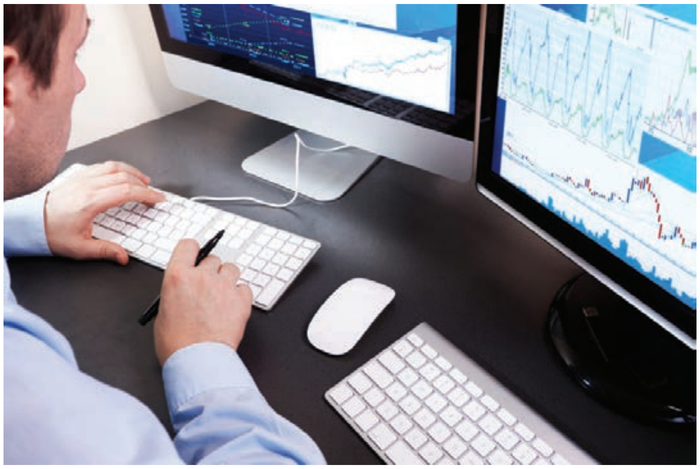
Special Provisions for Resources Needed to Ensure Reliability

Generation owners within New York seeking to retire or suspend a generator must first obtain approval from state regulators. After an assessment, if the generator is found to be necessary for reliability purposes, the local transmission owner can be compelled to reach a contract (Reliability Support Services Agreement) with the generator where compensation provisions are included to continue operation of the plant until the reliability need is resolved.

Financial Transmission Rights

FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead market. The NYISO refers to FTRs as Transmission Congestion Contracts (TCCs). A TCC is an instrument that entitles the holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations (or nodes) on the grid. The TCC also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. Payments, or charges, are calculated relative to the difference in congestion prices in the day-ahead market across the selected FTR transmission path.

A related product, ARRs, provide their holders with a share of the revenue generated in the TCC auctions. In general, ARRs are allocated based on historical load served. As with TCCs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.



Virtual Transactions

NYISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. Cleared virtual supply (virtual offers) in the day-ahead energy market at a particular location in a certain hour creates a financial obligation for the participant to buy back the bid quantity in the real-time market at that location in that hour. Cleared virtual demand (virtual bids) in the day-ahead market creates a financial obligation to sell the bid quantity in the real-time market. The financial outcome is determined by the difference between the hourly day-ahead and real-time LBMPs at the location at which the offer or bid clears. Virtual bidding in NYISO takes place on a zonal level, not a nodal level.

Credit Requirements

NYISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. NYISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions – e.g., NYISO must review the entity's request relative to various creditworthiness-related specifications such as investment grade or equivalency rating and payment history.

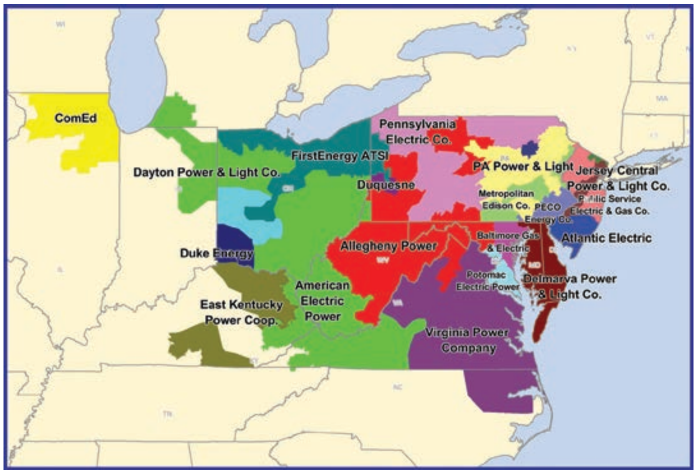
Settlements

RTOs must invoice market participants for their involvement in their markets. Settlements is the process by which the RTO determines the amounts owed and to be paid associated with buying and selling energy, capacity, ancillary services and paying various administrative charges.

NYISO uses a two-settlement process for its energy markets. The first settlement is based on day-ahead bids and offers, which clear the market and are scheduled. The second settlement is based on the real-time bids and the corresponding real-time dispatch.

PJM

The PJM Interconnection



Source: Velocity Suite, ABB

Market Profile

Geographic Scope

The PJM Interconnection operates a competitive wholesale electricity market and manages the reliability of its transmission grid. PJM provides open access to the transmission and performs long-term planning. In managing the grid, PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia. PJM's markets include energy (day-ahead and real-time), capacity and ancillary services.

PJM was founded in 1927 as a power pool of three utilities serving customers in Pennsylvania and New Jersey. In 1956, with the addition of two Maryland utilities, it became the Pennsylvania-New Jersey-Maryland Interconnection, or PJM. PJM became a fully functioning ISO in 1996 and, in 1997, it introduced markets with bid-based pricing and locational market pricing (LMP). PJM was designated an RTO in 2001.

Peak Demand

PJM's all-time peak load was 165 GW in summer 2011.

Imports and Exports

PJM has interconnections with Midcontinent ISO and New York ISO. PJM also has direct interconnections with the Tennessee Valley Authority (TVA), Progress Energy Carolinas and the Virginia and Carolinas Area (VACAR), among other systems. PJM market participants import energy from, and export energy to, external regions continuously. At times, PJM is a net importer of electricity and, at other times, PJM is a net exporter of electricity.

Market Participants

PJM's market participants include power generators, transmission owners, electric distributors, power marketers, electric distributors and large consumers.

Membership and Governance

PJM has a two-tiered governance model consisting of a board of managers and the members committee. PJM is governed by a 10-member board, nine of whom PJM members elect. The board appoints the tenth, the president and CEO, to supervise day-to-day operations. The board is generally responsible for oversight of system reliability, operating efficiency and short and long-term planning. The board ensures that no member or group of members exerts undue influence.

The members committee, which advises the board, is composed of five voting sectors representing power generators, transmission owners, electric distributors, power marketers and large consumers.

Transmission Owners

The largest transmission owners in PJM include:

- AEP
- First Energy
- PSE&G
- Dominion
- Philadelphia Electric
- Commonwealth Edison

Chronic Constraints

The largest constraints are in the Eastern Hub of PJM (New Jersey, Southeast Pennsylvania, and Delaware) and Northern Ohio. In general, transmission paths extending from generation sources in western PJM to load centers in eastern PJM tend to become constrained, particularly during peak load conditions. PJM's Mid-Atlantic markets rely on generation in the western part of PJM and thus on transmission across Pennsylvania and up from southwestern PJM to import power from sources west and southwest.

Congestion on the eastern interface also constrains power flows from the District of Columbia, Baltimore and Northern Virginia to New Jersey, Delmarva Peninsula and Philadelphia load centers. The high-voltage, bulk power transmission pathway within portions of the states of Pennsylvania, West Virginia, Virginia and Maryland serve the densely populated load centers of the metropolitan areas of Baltimore, the District of Columbia and Northern Virginia. The electricity needs of Washington-Baltimore- Northern Virginia are supplied not only by local generation but also by significant energy transfers to those areas.

In recent years, transmission congestion has not been as severe, due to upgrades to the transmission system, including construction of new transmission lines. Additionally, the availability of lower-cost natural gas has helped reduce the need for the eastern portion of PJM to import power from the west.

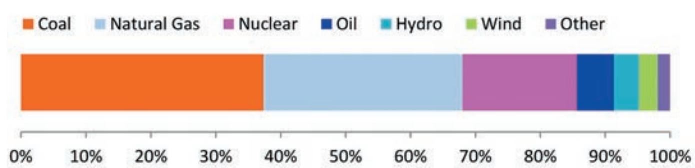
Transmission Planning

PJM's Regional Transmission Expansion Plan identifies transmission system additions and improvements needed to keep electricity flowing within PJM. Studies are conducted to test the transmission system against national and regional reliability standards. These studies look forward to identify future transmission overloads, voltage limitations and other reliability standards violations. PJM then develops transmission plans to resolve violations that could otherwise lead to overloads and blackouts.

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Demand Response

End-use customers providing demand response have the opportunity to participate in PJM's energy, capacity, synchronized reserve and regulation markets. PJM's DR programs can be grouped into emergency or economic programs. The emergency program compensates end-use customers who reduce their usage during emergency conditions on the PJM system. Participation in the emergency program may be voluntary or mandatory and payments may include energy payments, capacity payments or both. There are three options for emergency program registration and participation: energy only, capacity only and capacity-plus-energy.

The economic program allows end-use customers to reduce electricity consumption in the energy markets and receive a payment when LMPs are high. Under this program, all hours are eligible and all participation is voluntary. Participation in the program takes three forms: submitting an offer into the day-ahead market that clears; submitting an offer into the real-time market that is dispatched; and self-scheduling load reductions while providing notification to PJM. End-use customers participate in demand response in PJM through members called curtailment service providers, or CSPs, who act as agents for the customers. CSPs aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM. The payment is divided among the CSP and its retail customers based on private agreements between them.

Market Features

Energy Markets

Day-Ahead Market

The day-ahead market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real-time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

From the offers and bids, the RTO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are said to clear, meaning they are scheduled. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the LMPs for all locations.

Generators and offers scheduled in the day-ahead settlement are paid the day-ahead LMP for the megawatts accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time marketplace to replace what was not produced.

Likewise, wholesale buyers of electricity whose bids to buy clear in the day-ahead market settlement pay for and lock in their right to consume the cleared quantity at the day-ahead LMP. Electricity use in real-time that exceeds the day-ahead purchase is paid for at the real-time LMP.

Real-Time Market

PJM must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. Supply or demand for the operating day can change for a variety of reasons, including unforeseen generator or transmission outages, transmission constraints or changes from the expected demand. While the day-ahead energy market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule. Thus, PJM operates a spot market for energy, called the real-time energy market, to meet energy needs within each hour of the current day.

PJM clears the real-time market using supply offers, real-time load and offers and bids to sell or buy energy over the external interfaces. Real-time LMPs are calculated at five-minute intervals based on actual grid operating conditions as calculated in PJM's market systems. Generators that are available but not selected in the day-ahead scheduling may alter their bids for use in the real-time market during the generation rebidding period from 4 p.m. to 6 p.m.; otherwise, their original day-ahead market bids remain in effect for the real-time market.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system. RTOs procure or direct the supply of ancillary services.

PJM operates the following markets for ancillary services:

- Regulation: corrects for short-term changes in electricity use that might affect the stability of the power system.
- Synchronized reserves: supplies electricity if the grid has an unexpected need for more power on short notice.
- Day-ahead scheduling reserves (DASR): allows PJM to schedule sufficient generation to preserve reliability during unanticipated system conditions throughout the operating day.

Regulation service matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal. In addition, PJM schedules operating reserves in the day-ahead market, and resources that provide this service are credited based on their offer prices. Reserve consists of 10-minute and 30-minute products.

Synchronized reserves are the equivalent of what is commonly referred to as spinning reserves, providing 10-minute reserves from a generator that is synchronized to the grid.

The DASR is the primary market mechanism for procuring the 30-minute reserves. A resource will only be assigned an amount of DASR corresponding to that amount of energy it could provide within 30 minutes of a request. If the DASR market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Furthermore, two ancillary services are provided on a cost basis: (1) blackstart service, which helps ensure the reliable restoration of the grid following a blackout; and (2) reactive power, which supports the voltages that must be controlled for system reliability.

Capacity Markets

Capacity markets provide a means for LSEs to procure capacity needed to meet forecast load and to allow generators to recover a portion of their fixed costs. They also provide economic incentives to attract investment in new and existing supply-side and demand-side capacity resources in PJM as needed to maintain bulk power system reliability.

PJM's capacity market is called the Reliability Pricing Model (RPM). The RPM market was implemented in 2007 and is designed to ensure the future availability of capacity resources, including demand-resources and energy-efficiency resources that will be needed to keep the regional power grid operating reliably. RPM market design is based on three-year, forward-looking annual obligations for locational capacity under which supply offers are cleared against a downward sloping demand curve, called the variable resource requirement (VRR) curve. The VRR curve establishes the amount of capacity that PJM requires its LSE customers to purchase, and the price for that capacity, in each capacity zone (locational delivery area). Under RPM, when a locational delivery area is transmission-constrained in the auction (i.e., limited in the amount of generation that can be imported into those areas), capacity prices generally rise in that area relative to the overall PJM footprint.

Annual auctions are referred to as base residual auctions (BRAs). LSEs that are able to fully supply their own capacity need can choose not to participate in the auctions. Most capacity is procured through self-supply and contracted (bilateral) resources and the auctions procure any remaining needed capacity. To mitigate the exercise of market power, the RPM market rules provide a test to determine whether each capacity seller has market power. If the seller fails that test, that seller's bid is capped so as to replicate that seller's avoidable or opportunity costs.

Market Power Mitigation

In electric power markets, mainly because of the largely nonstorable nature of electricity and the existence of transmission constraints that can limit the availability of multiple suppliers to discipline markets, some sellers have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present.

Market power may need to be mitigated on a systemwide basis or on a local basis where the exercise of market power may be a concern for a local area. For example, when a transmission constraint creates the potential for local market power, the RTO may apply a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – close to short-run marginal costs.

The structural test for implementing offer capping in PJM is called the three pivotal supplier test. Generation is subject to offer caps when transmission constraints occur such that generators are run out of merit order, which means that a higher-priced generator must be run due to a transmission constraint that prevents the use of available lower-priced generation. When units are dispatched out of merit, PJM imposes offer capping for any hour in which there are three or fewer generation suppliers available for redispatch that are jointly pivotal, meaning they have the ability to increase the market price above the competitive level.

Price Caps

PJM has a $1,000/MWh offer cap in the energy markets.

Special Provisions for Resources Needed to Ensure Grid Reliability

A generator owner who wishes to retire a unit must request from PJM to deactivate the unit at least 90 days in advance of the planned date. The owner includes in the request an estimate of the amount of project investment necessary to keep the unit in operation. PJM, in turn, analyzes if the retirement would lead to a reliability issue. Additionally, the RTO estimates the period of time it would take to complete transmission upgrades necessary to alleviate the reliability issue.

If PJM requests the unit to operate past the desired deactivation date, the generator owner may file with FERC for cost recovery associated with operating the unit until it may be deactivated. Alternatively, the owner may choose to receive avoided cost compensation calculated according to PJM's tariff.

Financial Transmission Rights

FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead market. An FTR is an instrument that entitles the holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. Payments, or charges, are calculated relative to the combined difference in congestion prices in the day-ahead and real-time markets across the selected FTR transmission path.

A related product, ARRs, provide their holders with a share of the revenue generated in the FTR auctions. In general, ARRs are allocated based on historical load served and can be converted to FTRs. As with FTRs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.

Virtual Transactions

PJM's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. Cleared virtual supply (increment or virtual offers, or INCs) in the day-ahead energy market at a particular location in a certain hour creates a financial obligation for the participant to buy back the bid quantity in the real-time market at that location in that hour. Cleared virtual demand (decrement or virtual bids, or DECs) in the day-ahead market creates a financial obligation to sell the bid quantity in the real-time market. The financial outcome for a particular participant is determined by the difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears. Up-to-congestion (UTC) transactions are another type of transaction that may be submitted in the day-ahead energy market between any two buses either within PJM or between a bus within PJM and an external interface. UTC positions are liquidated in the real-time energy market.

Credit Requirements

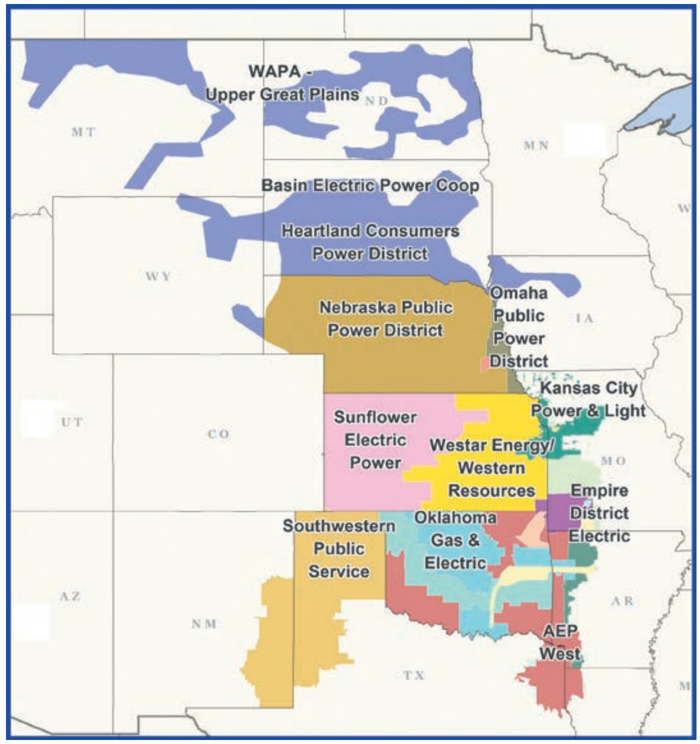
PJM's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions – e.g., the RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

Settlements

RTOs must invoice market participants for their involvement in their markets, including the amounts owed for buying and selling energy, capacity and ancillary services, and for paying administrative charges. PJM has a two-settlement system, one each for the day-ahead and real-time energy markets.

SPP

Southwest Power Pool



Source: Velocity Suite, ABB

Market Profile

Geographic Scope

Founded as an 11-member tight power pool in 1941, Southwest Power Pool (SPP) achieved RTO status in 2004, ensuring reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices for its members. Based in Little Rock, Ark., SPP manages transmission in 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Its membership is comprised of investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers and independent transmission companies.

In 2007, SPP began operating its real-time Energy Imbalance Service (EIS) market. In the same year, SPP became a FERC-approved Regional Entity. The SPP Regional Entity serves as the reliability coordinator for the NERC region, overseeing compliance with reliability standards.

In March 2014, SPP implemented its Integrated Marketplace that includes a day-ahead energy market, a real-time energy market, and an operating reserve market. SPP's Integrated Marketplace also includes a market for Transmission Congestion Rights. The SPP Integrated Marketplace co-optimizes the deployment of energy and operating reserves to dispatch resources on a least-cost basis.

In 2015, SPP expanded its footprint incorporating the Western Area Power Administration – Upper Great Plains region, the Basin Electric Power Cooperative, and the Heartlands Consumer Power District. The expansion nearly doubled SPP's service territory by square miles, adding more the 5 GW of peak demand and over 7 GW of generating capacity.

Peak Demand

SPP's all-time peak demand of 48 GW occurred in summer 2011.

Import and Exports

SPP has interties with MISO, PJM, and Tennessee Valley Authority, among other systems. Additionally, SPP has two direct-current (DC) interties with ERCOT and seven DC interties to the western interconnect through New Mexico, Colorado, Nebraska, South Dakota and Montana. At times, SPP is a net importer of electricity and, at other times, SPP is a net exporter of electricity.

Market Participants

SPP's market participants include cooperatives, independent power producers, investor-owned utilities, power marketers, municipal utilities, state agencies, transmission owners, financial participants, and a federal power marketing administration.

Membership and Governance

SPP is governed by a seven-member board of directors, with six elected by the members to serve three-year terms, plus the SPP president, who is elected by the board.

Supporting the board is the members committee, which provides input to the board through straw votes on all actions pending before the board. The members committee is composed of up to 15 people, including four representatives from investor-owned utilities; four representatives of cooperatives; two representing municipal members; three representing independent power producers and marketers; and two representing state and federal power agencies. The board is required to consider the members committee's straw vote as an indication of the level of consensus among members in advance of taking any actions.

Transmission Owners

SPP transmission owners (TOs) are investor-owned utilities, municipals, cooperatives, state agencies and independent transmission companies. Some of the larger entities by installed capacity include:

- Southwestern Electric Power Co. (AEP West)
- OG&E Electric Services
- Westar Energy Inc.
- Southwestern Public Service Co. (Xcel Energy)
- Kansas City Power & Light Co. (Great Plains Energy)
- Omaha Public Power District
- Nebraska Public Power District
- KCP&L Greater Missouri Operations (Great Plains Energy)
- Empire District Electric Co.
- Western Area Power Administration – Upper Great Plains
- Western Farmers Electric Cooperative

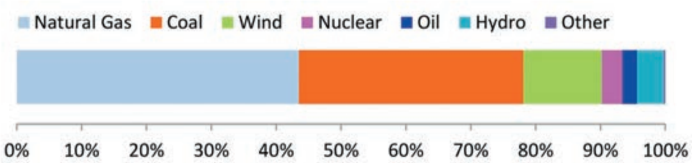
Transmission Planning

SPP conducts its transmission planning according to its Integrated Transmission Planning process, which is a three-year planning process that includes 20-year, 10-year, and near-term assessments designed to identify transmission solutions that address both near-term and long-term transmission needs. The Integrated Transmission Planning process focuses on identifying cost-effective regional transmission solutions, which are identified in an annual SPP Transmission Expansion Plan report.

Supply Resources

By plant capacity, the generating mix includes these sources:

Generation Mix



Source: Velocity Suite, ABB

Market Features

Energy Markets

Day-Ahead

The day-ahead market allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real-time. One day ahead of actual dispatch, participants submit supply offers and demand bids for energy. These bids are applied to each hour of the day and for each pricing location on the system.

From the offers and bids, the RTO constructs aggregate supply and demand curves for each location. The intersection of these curves identifies the market-clearing price at each location for every hour. Supply offers below and demand bids above the identified price are said to clear, meaning they are scheduled. Offers and bids that clear are entered into a pricing software system along with binding transmission constraints to produce the LMPs for all locations.

Generators and offers scheduled in the day-ahead settlement are paid the day-ahead LMP for the megawatts accepted. Scheduled suppliers must produce the committed quantity during real-time or buy power from the real-time marketplace to replace what was not produced.

Likewise, wholesale buyers of electricity and virtual demand whose bids to buy clear in the day-ahead market settlement pay for and lock in their right to consume the cleared quantity at the day-ahead LMP. Electricity use in real-time that exceeds the day-ahead purchase is paid for at the real-time LMP.

Real-Time

SPP must coordinate the dispatch of generation and demand resources to meet the instantaneous demand for electricity. While the day-ahead energy market produces the schedule and financial terms of energy production and use for the operating day, a number of factors can change that schedule. Thus, to meet energy needs within each hour of the current day, SPP operates a spot market for energy called the real-time market.

The real-time market uses final day-ahead schedules for resources within the RTO and imports and exports as a starting point. It then operates a five-minute market to balance generation and loads.

Must-Offer Requirements

Market rules in RTOs include must-offer requirements for certain categories of resources for which withholding, which could be an exercise of market power, may be a concern. Where such rules apply, sellers must commit, or offer, the generators, and schedule and operate the facilities, in the applicable market.

In SPP, generators who supply capacity to meet the RTO resource adequacy requirement for load are required to offer into the day-ahead and real-time markets for energy and the ancillary services for which they are qualified.

Ancillary and Other Services

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load while maintaining the reliability of the transmission system.

SPP procures ancillary services via the co-optimized energy and ancillary services market and includes the following services:

- Regulation Up reserves: Resources providing this Regulation Up must be able to move quickly above their scheduled operating point in response to automated signals from the RTO to maintain the frequency on the system by balancing generation and demand.
- Regulation Down reserves: Resources providing Regulation Down must be able to move quickly below their scheduled operating point in response to automated signals from the RTO to maintain the frequency on the system by balancing generation and demand.
- Spinning Reserves: Resources providing Spinning Reserves are already synchronized to the grid and available to serve load within a short period following a contingency event such as an unexpected failure or outage of generator, transmission line, or other electrical element.
- Supplemental Reserves: Resources that are on-line and/or off-line but capable of being synchronized to the grid and fully available to serve load following a specified period following a contingency event.

Capacity Markets

SPP does not offer a capacity market. However, it requires each market participant to have sufficient energy supply (capacity) to cover its energy obligations. SPP performs a supply adequacy analysis for each market participant based on a load forecast, resource plan, ancillary service plan and schedules received from market participants. This analysis is performed for each hour of the next operating day, with results available by 3 p.m. of the day prior to the operating day.

Market Power Mitigation

In electric power markets, mainly because of the largely non-storable nature of electricity and the existence of transmission constraints that limit the availability of multiple suppliers to discipline market prices, some sellers have the ability to raise market prices. Market power mitigation is a market design mechanism to ensure competitive offers even when competitive conditions are not present. Market power may need to be mitigated on a systemwide basis or locally.

SPP applies a set of behavioral and market outcomes tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – i.e., offer prices close to short-run marginal costs. SPP's mitigation test includes a local market power test, a pivotal supplier test, and a market impact test. Where mitigation measures are triggered by the tests, SPP generates a mitigated market solution that the RTO then uses for dispatch, commitment, and settlement purposes.

Price Caps

SPP employs an offer cap of $1,000/MWh.

Special Provisions for Resources Needed to Ensure Grid Reliability

SPP prepares annual reliability studies as part of its system planning responsibilities. In the event that studies reveal a potential constraint on SPP's ability to deliver power to a local area on the transmission system, the RTO works with regional stakeholders to find alternate transmission, operating procedure, or generation solutions for the constraint and thus maintain grid reliability. SPP parties will determine an appropriate sharing of the costs, and, if unable to reach agreement, the RTO will submit a proposed cost sharing arrangement to the Commission for approval.

Financial Transmission Rights

Financial FTRs provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead market. SPP refers to FTRs as Transmission Congestion Rights (TCRs). A TCR is an instrument that entitles the holder to receive compensation, or requires the holder to pay a charge, for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. A TCR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the selected TCR transmission path. SPP TCRs are monthly and annual products.

A related product, ARRs, provide their holders with a share of the revenue generated in the TCR auctions. In general, ARRs are allocated based on historical load served. As with TCRs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.

Virtual Transactions

SPP's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead price setting process, allow participants to manage risk, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets. Cleared virtual supply (virtual offers) in the day-ahead energy market at a particular location in a certain hour creates a financial obligation for the participant to buy back the bid quantity in the real-time market at that location in that hour. Cleared virtual demand (virtual bids) in the day-ahead market creates a financial obligation to sell the bid quantity in the real-time market. The financial outcome is determined by the difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears.

Credit Requirements

SPP's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions – e.g., the RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and various financial measures.

Settlements

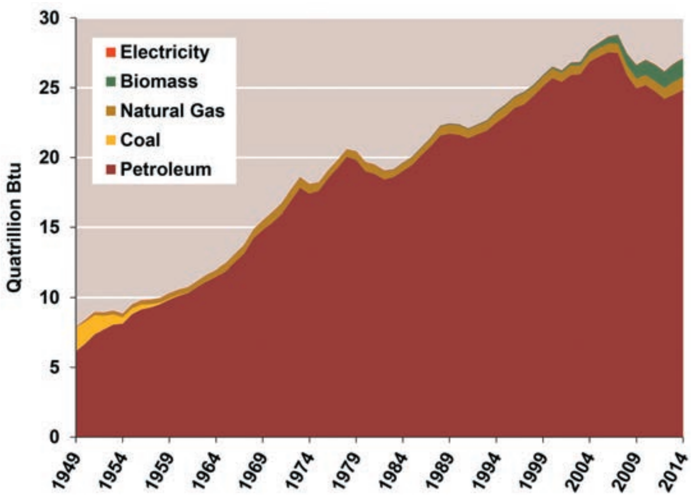
RTOs must invoice market participants for their involvement in their markets. Settlement is the process by which the RTO determines the amounts owed associated with buying and selling energy, capacity and ancillary services, and paying administrative charges.

SPP has a two-settlement system, one each for the day-ahead and real-time markets. The SPP settlement process calculates quantities of energy, ancillary services, TCRs, virtual transactions, among other market features.

4. U.S. Crude Oil & Petroleum Products Markets

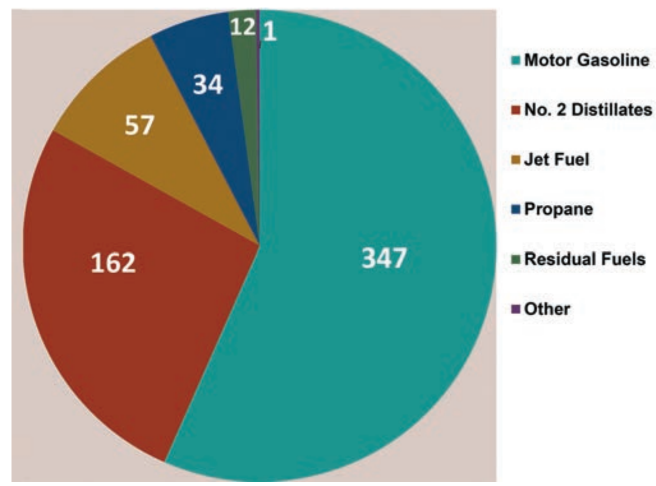
Petroleum, or crude oil, and its derived petroleum products play a key role in the U.S. economy, accounting for approximately one third of primary energy consumption in the U.S. in 2014. Its role is especially important in the transportation sector where, despite a steady increase in non-petroleum transportation fuels since 2000, petroleum products accounted for 92 percent of all transportation fuels in 2014. The remaining 8 percent consisted of biomass fuels (ethanol and biodiesel), natural gas, and electricity.

Petroleum Accounts for Most of the Energy Consumption in the Transportation Sector



Source: Derived from EIA data

U.S. Petroleum Products Supply in 2014 (Million gallons/day)



Source: Derived from EIA data

Unlike methane, the primary component of pipeline grade natural gas, petroleum is not consumed in its natural form; instead, it is refined into a number of products that can be used for numerous applications. In the U.S., the largest share of crude oil, approximately 90 percent, is consumed as transportation fuels, including gasoline, diesel, and jet fuel. Other uses include heating, power generation, and petrochemical feedstocks used to manufacture a variety of products including plastics, pharmaceuticals, fertilizers, and construction materials.

> **FERC Jurisdiction**
>
> *The Federal Energy Regulatory Commission's jurisdiction over the oil markets is limited to setting pipeline transportation rates and ensuring open access in the pipeline system.*

Petroleum is both produced domestically and imported from a number of countries. The same is true for petroleum products, especially gasoline, diesel fuel, and jet fuel. The percent of imported petroleum and petroleum products has been decreasing in recent years as U.S. crude oil production from shale has increased. Nearly 50 percent of U.S. crude oil production comes from Texas and North

Dakota, although significant amounts are produced in other states. U.S. refineries, which convert the crude oil into usable products, are found throughout the country, but are heavily concentrated on the Gulf Coast.

Petroleum

Unlike natural gas, which is a simple molecule consisting of 1 carbon atom and four hydrogen atoms (CH_4), petroleum as found in the ground is a mixture of hydrocarbons that formed from plants and animals that lived millions of years ago. Crude oil exists in a liquid form in underground pools or reservoirs, in tiny spaces within sedimentary rocks, and near the surface in tar (or oil) sands. In its natural state, crude oil ranges in density and consistency, from very thin, light-weight and volatile fluidity to extremely thick, semi-solid heavy-weight oil. Its color can vary from a light golden yellow to a deep black.

Density of an Oil (API Gravity)

The density, or "weight," of an oil is one of the largest determinants of its market value (another key characteristic is sulfur content – see text box, "Sweet or Sour?"). The density of an oil is often referred to as "light" or "heavy" and is measured using API gravity. API gravity is determined using the specific gravity of an oil, which is the ratio of its density to that of water (density of the oil/density of water) at 60 degrees Fahrenheit. Oils are generally classified as:

Light – API > 31.1	Medium – API between 22.3 and 31.1
Heavy – API < 22.3	Extra Heavy – API < 10.0

However, specific oils may be categorized differently depending on the region where they are produced and how the oil is referred to by commodity traders.

Though specific gravity is a unitless number, API gravity values in practice are often referred to as degrees. The API gravity of West Texas Intermediate is said to be 39.6 degrees. API gravity moves inversely to density, which means the denser an oil the lower its API gravity. An API of 10 is equivalent to water, which means oils with an API above 10 will float on water while oils with an API below 10 will sink.

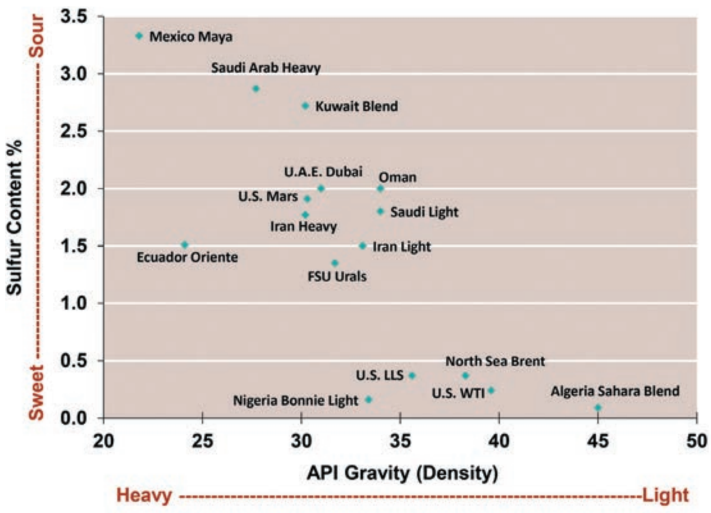
Benchmark Crude Oil

A benchmark crude oil is a specific crude oil that is widely bought and sold at well-traded locations with commonly posted prices. Other quality crude oils are traded with reference to benchmark crude oils and the pricing is typically adjusted using agreed-upon price differentials that take into account such factors as API gravity, sulfur content, and transportation costs – e.g., from production areas to refineries. WTI oil and Brent are two major benchmark crude oils with WTI used in the U.S. and Brent used in global trade. A third major benchmark, Dubai, is mostly used in Asian trade.

Different countries, regions, and geological formations produce different types of crude, which are generally described as light or heavy, depending on their viscosity, and sweet or sour, depending on their sulfur content. As a rule, heavy oils are sour as they contain more sulfur. West Texas Intermediate (WTI), the U.S. pricing benchmark, is a light, sweet oil delivered at Cushing, Oklahoma. The Brent oil benchmark, also a light, sweet oil, is a basket of North Sea oils used to set crude oil and petroleum prices around the world. By contrast, Mexico's Maya crude is both heavy and high in sulfur (sour).

Crude oils that are light and sweet usually command higher prices than heavy, sour crude oils. This is partly because gasoline and diesel fuel, which typically sell at a significant premium to heavier products produced in the refining process, are more easily and cheaply produced using light, sweet crude oil. Processing the light, sweet grades require far less sophisticated and energy-intensive refining processes.

Density and Sulfur Content of Selected Crude Oils

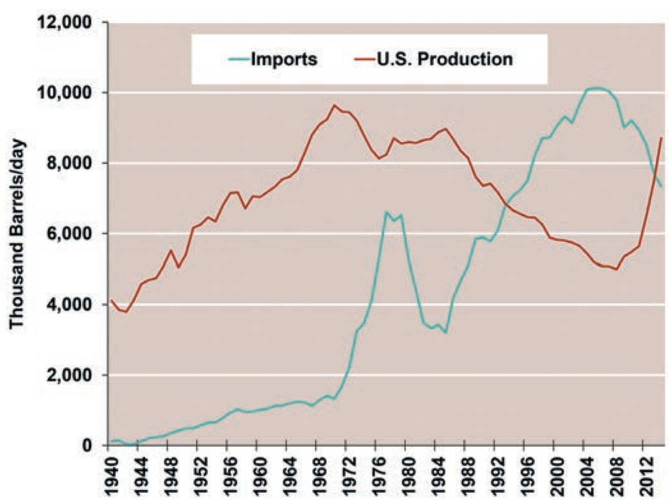


Source: Derived from EIA data

U.S. Crude Oil Supply

In 2014, the U.S. consumed approximately 16 million barrels per day (MMbd) of crude oil, of which 54 percent was produced domestically, a reversal from recent years when imports made up the majority of the supply. Between 1994 and 2013, the U.S. imported most of its crude oil. Imports peaked in 2006 at 10.1 MMbd, or 67 percent of total supply.

U.S. Crude Oil Supply – Increased Production Displaces Imports



Source: Derived from EIA data

Sweet or Sour?

The terms sweet and sour refer to the sulfur content of crude oil. Early prospectors would taste oil to determine its quality, with low sulfur oil tasting relatively sweet. Crude is considered sweet if it contains less than 0.5 percent sulfur.

Sweet crude is easier to refine and safer to extract and transport than sour crude. Because sulfur is corrosive, sweet crude also causes less equipment damage to refineries and thus results in lower maintenance costs over time. Due to these factors, sweet crude commands a price premium over sour.

Major sources of sweet crude include the Appalachian Basin in Eastern North America, Western Texas, the Bakken Formation of North Dakota and Saskatchewan, the North Sea of Europe, North Africa, Australia, and the Far East including Indonesia.

Sour crude oil has greater than 0.5 percent sulfur and some of this will be in the form of hydrogen sulfide, known for its "rotten egg" smell. Hydrogen sulfide is considered an industrial hazard and, thus, sour crude has to be stabilized via removal of hydrogen sulfide before it can be transported by oil tankers.

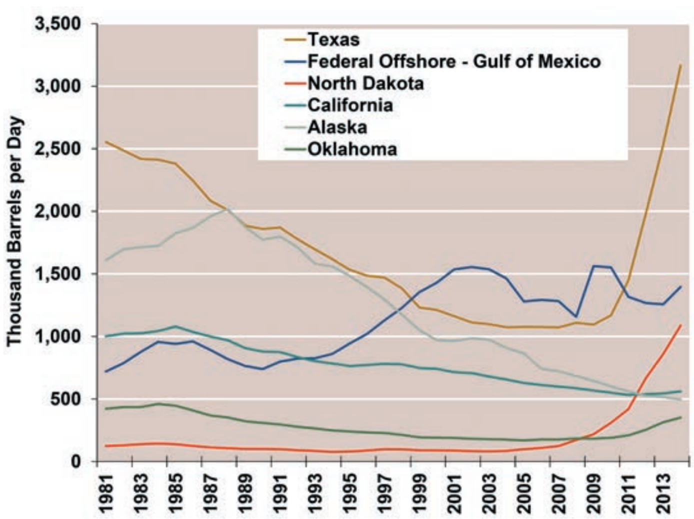
Sour crude is more common in the Gulf of Mexico, Mexico, South America, and Canada. Crude produced by OPEC Member Nations also tends to be relatively sour, with an average sulfur content of 1.77 percent.

Driving the increase in domestic oil production are the same developments that resulted in sharp increases in natural gas production, horizontal drilling and high-pressure hydraulic fracturing (fracking). To date, the most prolific example of success in this technology is in the Bakken Shale in North Dakota. Between 1990 and 2005, production in North Dakota averaged 89,000 barrels per day (Mbd). Production began to grow in 2006, as companies started to apply the horizontal drilling and fracking techniques. By 2014, production had reached 1.1 MMbd, making North Dakota the second biggest crude oil producing state in the country.

In addition to North Dakota, other major producing locations in the U.S. include Texas, offshore locations in the Gulf of Mexico, California, Oklahoma, and Alaska. Texas, the largest producing state, also experienced a substantial increase in output with the application of the new technologies. Texas onshore production fell steadily between 1980 and 2007, when it averaged 1.1 MMbd. However, production began to ramp up as companies targeted oil rich shale formations, including the Eagle Ford Shale and the Permian Basin. Production in the Permian Basin, one of the oldest oil producing formations in Texas, had been in decline prior to the implementation of the new extraction techniques. By 2014, Texas production had reached 3.2 MMbd.

One important attribute of rising crude oil production from shale is that the majority of the output consists of light, sweet oil. Approximately 90 percent of the nearly 3.0 MMbd growth in production from 2011 to 2014 consisted of light, sweet grades. This is important as it helps determine refinery investments and operations and, thus, influences the types of crude oil that are imported and processed in U.S. refineries.

Top Five U.S. Crude Oil Producing Locations

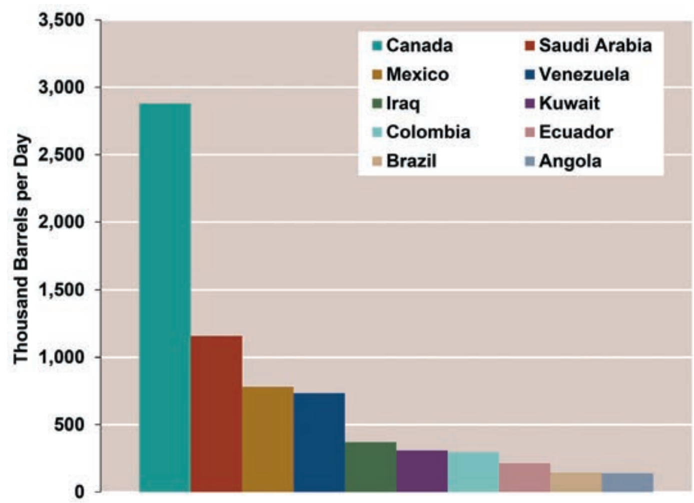


Source: Derived from EIA data

Offshore production in the Gulf of Mexico averaged 1.4 MMbd in 2014. However, it peaked in 2003 and has remained relatively flat for the past 15 years. Producing crude oil from offshore deposits is more technically challenging and costly than on-shore, and over the past few years producers have opted to shift investments to the shale formations.

Imports are also an important component to U.S. crude oil supply, accounting for 46 percent of U.S. supply, or 7.3 MMbd in 2014 (excluding petroleum products). The largest foreign supplier of crude oil (excluding petroleum products) is Canada, which in 2014 accounted for 2.9 MMbd or almost 47 percent of total imports. In Canada, unconventional oil production methods have resulted in robust production from the oil sands region in Alberta. The second largest supplier was Saudi Arabia, with 1.2 MMbd, followed by Mexico, Venezuela, and Iraq.

Top Ten Foreign Suppliers of Crude Oil to the U.S. in 2014



Source: Derived from EIA data

Petroleum Reserves

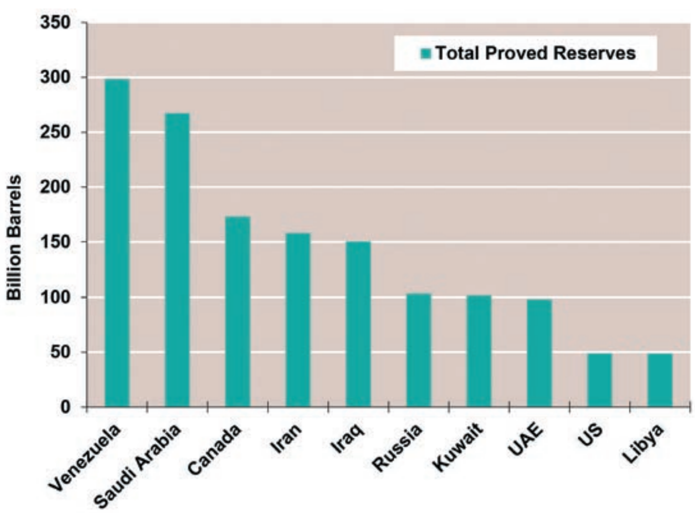
At the end of 2014, there were an estimated 1,700 billion barrels of proved reserves in the world. The U.S. accounted for 49 billion, or 2.9 percent of these reserves. That is sufficient to last approximately 53 years at current production levels, according to BP's "*Statistical Review of World Energy*" (June

2015). Proved reserves fluctuate as new geological supply sources are discovered, as the technology to produce from known sources advances, and as price fluctuations change the economics of particular resources. For example, the discovery of the pre-salt oil deposits offshore Brazil increased global proved reserves by adding a new potential source of production. The advances in horizontal drilling and slick water fracturing technology increased the size of proved reserves in the U.S. and other countries by making shale oil technically recoverable. Proven reserves also increased when crude oil consistently traded above $100/barrel between 2008 and 2014, as the high prices made drilling in high cost areas economic.

Proved Oil Reserves

Estimated quantities of oil that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

In 2014 Most of the World's Proved Oil Reserves were in the Middle East



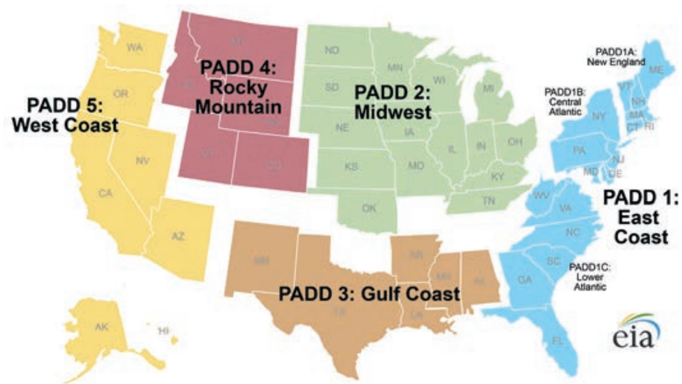
Source: Derived from BP Statistical Review of World Energy 2015 data

Although two of the top three countries by proved reserved are Venezuela and Canada, most of the world's proven reserves are in the Middle East. Five countries, Saudi Arabia, Iran, Iraq, Kuwait, and the United Arab Emirates, together hold 46 percent of all proved reserves. In addition, of the top 10 countries in proved reserves, seven are members of the Organization of Petroleum Exporting Countries (OPEC), an intergovernmental organization of oil-producing countries. This geopolitical and geographic concentration is an important factor as will be discussed later in this chapter.

Crude Oil Refining

As of January 1, 2012, the U.S. had more than 17.3 MMbd of refinery capacity. For historical reasons dating back to gasoline rationing during World War II, the U.S. is divided into five geographical regions called Petroleum Administration for Defense Districts, or PADDs. Approximately 44 percent, or 7.7 MMbd of refining capacity, is located along the Gulf Coast, in PADD 3.

Petroleum Administration for Defense Districts

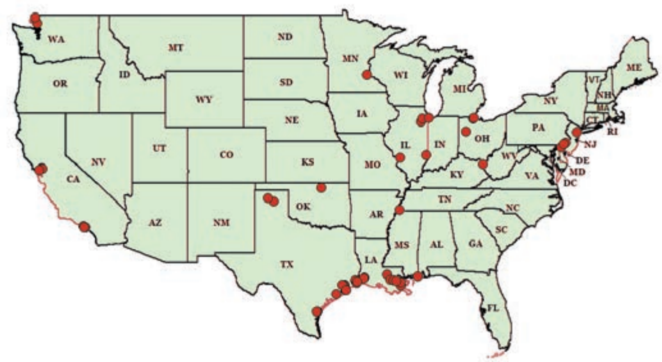


Source: EIA

Most of the largest and more modern refineries are situated along the coast of Texas, Louisiana, Mississippi, and Alabama. Many refineries are located close to the traditional crude oil production or import centers in the Gulf Coast or near major population centers where demand for refined products is greatest, including California and the areas near Philadelphia, New York City, and Chicago.

In general, crude oil refining involves processing crude oil through distillation facilities where the crude oil is heated and separated into its lighter and heavier components. The heat

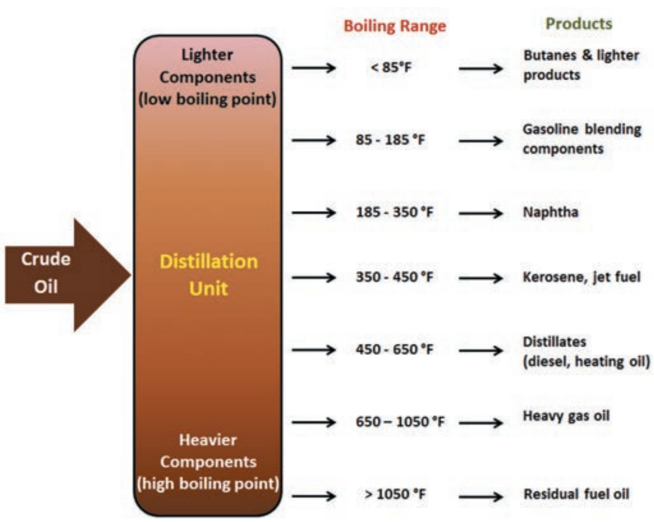
Continental U.S. Refineries – Top 50 by Capacity



Source: Derived from EIA data

causes the lighter, more volatile molecules to rise and, as they cool, the heavier components such as heavy fuels and residual fuels settle into trays and are carried out of the unit into their own processing streams. The lighter molecules rise higher in the unit and are processed into light products such as gasoline and naphtha. Depending on the refinery configuration, heavier components may be further processed to yield higher amounts of the more valuable light products. Breaking down the heavier products into lighter ones requires more specialized and expensive equipment and processes such as catalytic crackers and cokers.

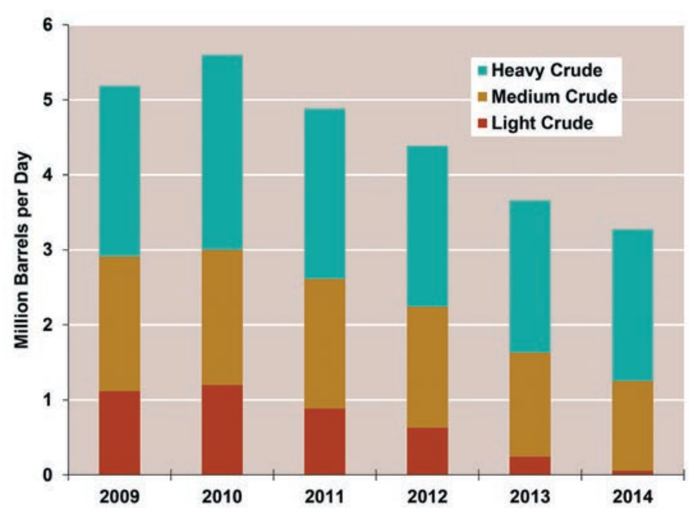
Basic Crude Oil Distillation Unit & Product Output



Source: Derived from EIA data

The growth in production of light, sweet oil from shale is changing the makeup in the types of crude processed at U.S. refineries. During the 1990s when domestic U.S. crude oil production was declining, refineries along the Gulf Coast spent billions of dollars to reconfigure their equipment and operations to handle imports of heavy, sour crude oil from Mexico and Venezuela. Despite these upgrades, refineries in the region still imported and processed as much as 1.3 MMbd of light, sweet crude oil, more than any other region of the country. Beginning in 2010, improvements to the crude oil distribution system and sustained increases in production in the region (in the Permian and Eagle Ford basins) allowed more domestic crude oil to reach the Gulf Coast refining centers, significantly reducing the need for imports of light crude. Since September 2012, imports of light, sweet crude oil to the Gulf Coast have regularly been less than 200,000 bbl/d. Similarly, Gulf Coast imports of light, sour crude also declined and have been less than 200,000 bbl/d since July 2013.

Imports of Crude Oil into the U.S. Gulf Coast



Source: Derived from EIA data

Crude Oil and Petroleum Products Transportation

There are more than 190,000 miles of petroleum pipelines in the U.S. Because of increased shale production, crude oil pipeline mileage grew 8,174 miles or 15.5 percent between 2009 and 2013. Crude pipelines move oil from the production fields and import terminals to refineries for processing into various products. Products pipelines then distribute the fuels to various parts of the country.

Colonial Pipeline Company is the largest pipeline in the U.S.; transporting 844 billion barrel-miles (one barrel transported one mile) of petroleum products in 2014. It is one of the most important products pipelines in the country as it carries supply from the refining centers in Texas and Louisiana to the major demand centers along the U.S. east coast. It transports approximately 100 million gallons per day of gasoline, diesel fuel, jet fuel, and other products from Houston, Texas to Linden, New Jersey on a 5,500-mile network, crossing 13 states. The second largest pipeline, with 583 billion barrel-miles transported in 2014 is Enbridge Energy. This pipeline begins in the oil sands producing region in Alberta, Canada, and transports 53 percent of the Canadian crude oil that comes into the U.S. Once in the U.S., it moves the crude oil from North Dakota to Chicago and south into Cushing, Oklahoma. A distant third-largest pipeline is the TransCanada Keystone Pipeline, which in 2014 transported 210 billion barrel-miles of crude oil from Canada into the U.S. mid-continent and the Gulf Coast. This is a different pipeline from the proposed TransCanada Keystone XL.

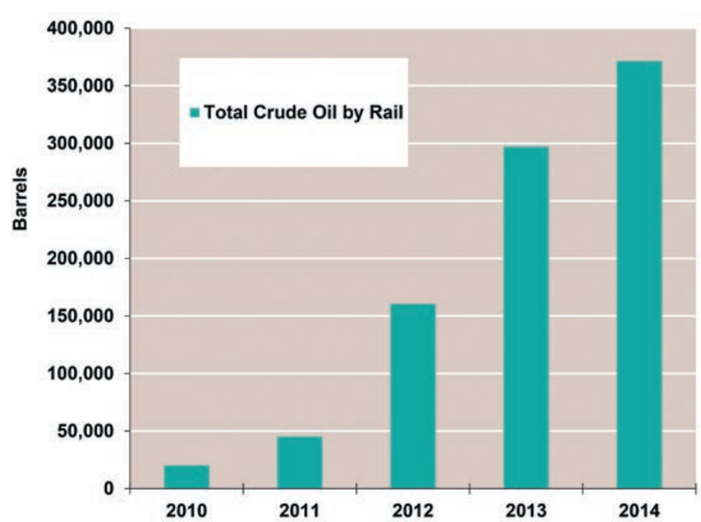
Regulation of crude oil and petroleum product pipelines falls under a number of government entities. The Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for regulating and ensuring the safe and secure movement of hazardous materials to industry and consumers by all modes of transportation, including pipelines. Its Office of Pipeline Safety ensures safety in the design, construction, operation and maintenance, and spill response of oil and natural gas pipelines and other hazardous liquid transportation pipelines.

FERC's jurisdictional responsibilities regarding crude oil and petroleum product pipelines include:

- Regulation of rates and practices of oil pipeline companies engaged in interstate transportation
- Ensuring the furnishing of pipeline transportation to shippers on a non-discriminatory and non-preferential basis
- Establishment of just and reasonable rates for transporting crude oil and petroleum products by pipeline

Changes in U.S. production dynamics in recent years, specifically the growth of crude oil production in areas not traditionally served by oil pipelines, such as the Bakken Shale formation in North Dakota, have taxed the current pipeline system. As a result, the country has experienced a sharp increase in transportation of crude oil by rail, despite the fact that pipeline transportation is more economic than rail. An advantage of rail transportation, however, is that companies can ramp-up capacity quickly and have more flexibility in origin and delivery points. The largest oil-by-rail movements have originated from PADD 2, specifically in North Dakota. In 2014, more than 262,000 barrels, or 71 percent of all inter-PADD movement came from PADD 2. The majority of those barrels were shipped to PADD 1, likely to feed refineries in the Philadelphia area. Additionally, approximately 50,000 barrels were imported or exported to Canada via rail.

Crude-by-Rail Volumes in the U.S. and Canada

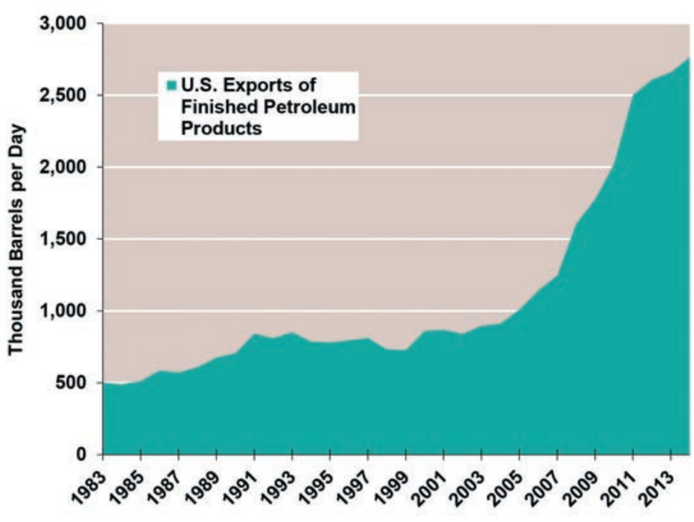


Source: Derived from EIA data

The rise of oil-by-rail shipments has raised some safety issues, as there have been a number of serious and, at times, fatal incidents involving oil-laden rail cars. The U.S. Department of Transportation has worked with the rail and oil industry on new regulations involving car design and train operations.

Two Federal statutes limit the movement of crude oil and crude oil products. First, the Jones Act of 1916, 46 U.S. Code § 55102, generally prohibits any foreign built or foreign-flagged vessel from engaging in trade that begins at any point within the United States and delivers commercial cargo to any other point within the United States. Because of the limited numbers of oil and petroleum products vessels that meet the Jones Act requirements, the ability to move crude oil and refined products between marine ports is in short supply. That means, for example, that producers are limited in their ability to move crude oil to the Gulf Coast via pipeline and then ship it to East Coast refiners. Likewise, Gulf Coast refiners are limited in their ability to move refined products up the East Coast via waterborne vessels.

U.S. Exports of Finished Petroleum Products



Source: Derived from EIA data

A second statute, § 754.2 – Crude Oil, enacted during the 1970s oil crisis, requires licensing of U.S. crude oil exports. Although this statute is widely referred to as the oil export ban, it allows for various types of exports including petroleum products, exports of slightly refined crude oil condensate, shipments of crude oil owned by a company to an affiliate refinery in Canada, and heavy-for-light crude oil swaps with Mexico. U.S. exports of petroleum products rose substantially with the increase of production of oil from shale. In 2000 the U.S. exported 868,000 barrels of finished products. This number had increased to 2.8 million barrels by 2014.

Crude Oil and Petroleum Products Demand

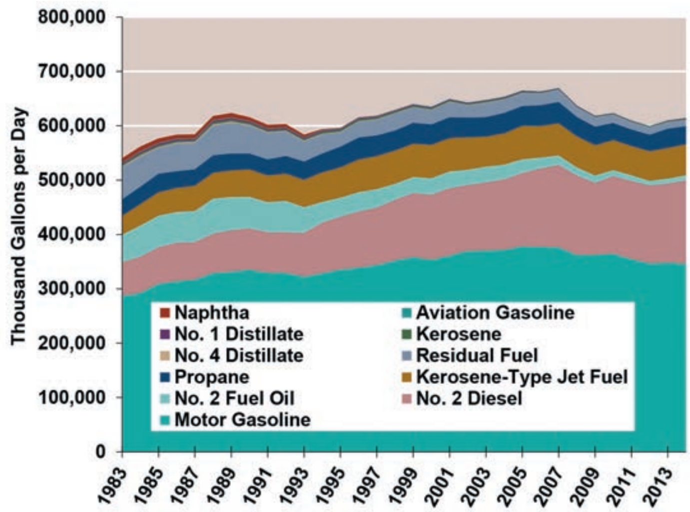
The largest demand category for petroleum products in the U.S. is the transportation sector. Motor gasoline alone made up 56 percent of petroleum products sold by prime suppliers into the U.S. market. The second largest is No. 2 distillate, which made up 26 percent of prime supplier sales in 2014, and which includes diesel fuel, also used in the transportation sector, mostly by long distance freight trucking. No. 2 distillates also include fuel oil, used for space heating and, in a lesser capacity, for electric generation. The next largest demand category is another transportation sector fuel, jet fuel, which accounted for 9 percent of sales. All told, demand from the transportation sector accounts for approximately 90 percent of all petroleum products consumed in the U.S.

Prime Suppliers

Companies that produce, import, or transport products across State boundaries, to sell to local distributors, retailers, or end users. Prime supplier sales are a good proxy for demand.

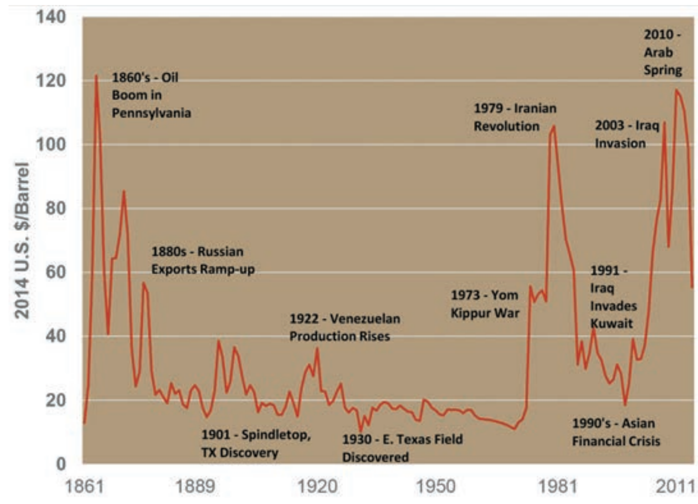
Other petroleum products include: propane used for space heating and in petrochemical processes; kerosene used in heating and lighting; No. 1 fuel oil, which can be blended into heating fuel or diesel fuel; No. 4 fuel oil used for commercial heating and power generation; residual fuels used in power generation and ship boilers; and asphalt used to build roads.

Gasoline and No. 2 Distillates Account For Most of the Petroleum Use in the U.S.



Source: Derived from EIA data

Geopolitical and Economic Events Drive Crude Oil Volatility



Source: Derived from BP Statistical Review of World Energy 2015 data

Note: Prices for 1861-1944 are U.S. average; for 1945-1983 are Arabian Light posted at Ras Tanura; for 1984-2014 are Dated Brent; and 2015 are Brent as of Q3 2015

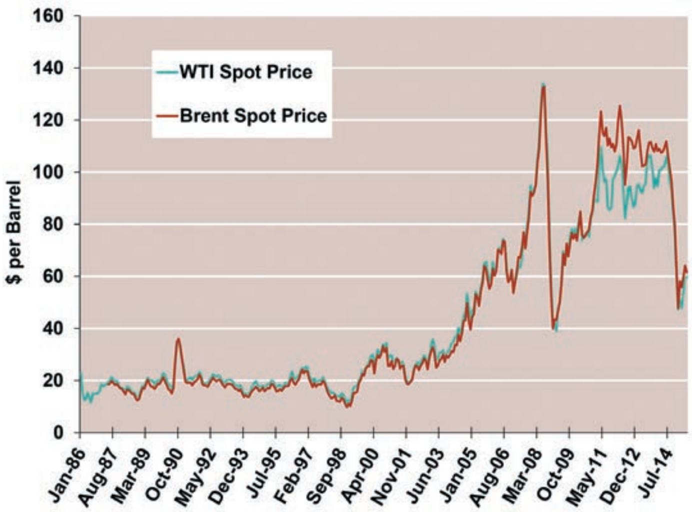
Crude Oil and Petroleum Products Markets and Trading

Because of limited oceangoing transportation options, U.S. natural gas markets have historically been shielded from international supply and demand developments. Crude oil and petroleum products are traded globally, and their prices are greatly influenced by global supply and demand, geopolitical and economic factors, and the policies of OPEC. Many of the countries in the top 10 oil suppliers to the U.S., such as Iraq, Colombia, Kuwait, Russia, and Venezuela, have a history of political unrest or governance issues. These factors can affect production, reduce supply, and cause prices to rise. As a result, world oil prices have experienced periods of great volatility, driven by supply and demand fundamentals, external shocks, and speculative trading.

As a global commodity, crude oil's price on the world markets is set by the traders who buy and sell the commodity. Although crude oil trades at various locations around the world, most trades are based on or derivative to a handful of benchmark crude prices, such as WTI, Brent, and Dubai. There are also benchmarks for petroleum products, including New York Harbor in the U.S., Amsterdam-Rotterdam-Antwerp (ARA) in Europe, and Singapore in Asia.

From 1987 through 2010, WTI and Brent traded within a few cents of each other, with WTI generally commanding a small price premium. However, the sudden and sharp increase in production of shale oil in the U.S. resulted in an oversupply at Cushing, causing WTI prices to drop below Brent. Between 2011 and 2014, Brent commanded a premium, reaching as high as $27/barrel in September 2011. The Brent premium shrank in 2015, as world prices fell significantly because of a combination of lower demand, particularly from China, and growing supply from North America and other producers around the world.

New Oil Production from Shale Drives Down Oil Prices



Source: Derived from EIA data

Despite being a widely traded commodity, the price of crude oil is not completely determined by the free market. Member countries of OPEC produce much of the oil traded around the world, and OPEC attempts to control oil prices by managing production by its member countries. Each member country has production targets that OPEC lowers to reduce world supply and drive prices up, or increases to drive prices down. The largest OPEC producer is Saudi Arabia. Other member countries include Iran, Iraq, Kuwait, Venezuela, Qatar, Libya, the United Arab Emirates, Algeria, Nigeria, Ecuador, and Angola.

As of 2015, OPEC member countries produced about 40 percent of the world's crude oil, and OPEC's oil exports accounted for about 60 percent of the total petroleum traded internationally. The actions of OPEC, particularly in member countries with substantial spare capacity, can and do affect oil prices.

5. Financial Markets and Trading

Financial markets affect physical natural gas and electricity markets in key ways. In the past decade, the commodity markets associated with natural gas and electricity expanded, both in terms of volumes traded and the types of products offered. One result from this expansion has been to alter the traditional relationship between physical and financial markets. The traditional view was that physical markets affect financial; financial products derive their value from physical products. Today, the relationship is bidirectional. Physical markets continue to affect financial markets, but now, financial markets can affect physical markets – including prices – as well.

This chapter explores natural gas and electricity commodity and capital markets.

Financial Markets and Mechanisms

Financial markets are not physical locations like grocery stores where one can go to experience the financial marketplace. Instead, they are an array of products, mechanisms, and participants that together flesh out the marketplace.

As mentioned, financial markets differ from physical markets in that no physical delivery occurs. This does not mean financial markets contain only investors and speculators; physical market participants enter the financial market to hedge. Similarly, it does not mean that financial markets involve only contracts that contain financial payout instead of physical delivery. Financial traders may use longer term physical contracts, but in a way that ensures no delivery will be required. Physical and financial markets are often closely intertwined and use the same market mechanisms.

Consequently, one good way to understand financial markets is to look at the market participants, products, market mechanisms and trading that together constitute the market.

Market Mechanisms

Transactions in both physical and financial markets are conducted through exchanges or over-the-counter (OTC). In the case of electricity, trades may also be conducted in regional transmission organizations (RTOs are addressed in Chapter 3).

Exchanges

Trading on exchanges is subject to the rules of the exchange as well as laws and regulations. Exchange-traded contracts are standardized, meaning that specifications for the product's quality, quantity, and location are established in advance by the exchange. Exchange rules typically permit bidirectional trading, or the ability to buy or sell with equal ease.

Trading in exchanges is conducted through electronic platforms, websites on which traders can buy and sell, or through trading pits where traders actively call out orders to buy and sell, known as open outcry.

Natural gas and electricity are traded on commodity exchanges such as the Nymex, the world's largest physical commodity futures exchange. In addition to other commodities, including metals and agricultural products, Nymex facilitates the sale and purchase of physical and financial natural gas products as well as financial power contracts. The ICE also offers natural gas and electricity products, as well as emissions allowances among a host of other commodities. Nodal Exchange offers locational (nodal) futures contracts to participants in the organized electricity markets. Nodal Exchange allows participants to trade electricity contracts for forward months, at RTO hubs, zones and nodes.

Margin, or equity contributed as a percentage of the current market value of a commodity contract(s), allows market participants the ability to trade without having to pay cash for the full value of the trade. Effectively, someone who trades on margin borrows much of the money used to buy or sell from the exchange or brokerage house. The trader posts collateral by putting down a certain amount of money or percentage of the trade value in cash or other items of value acceptable to the exchange.

Over-the-Counter (OTC) Markets

OTC markets are any markets that are not exchanges or RTOs. Transactions are not required to be standardized but rather can range from complicated individual negotiations for one-off structured contracts to standard products traded through an electronic brokerage platform. The ability to tailor a contract to the exact needs of the counterparties is one of the chief benefits of OTC contracts.

OTC power contracts can be traded in either traditional or RTO power markets.

OTC transactions are conducted through direct negotiations between parties or through brokers. Brokers range from voice brokers to electronic brokerage platforms. Unlike an exchange, an electronic brokerage platform matches specific buyers and sellers, and is not anonymous.

Products may be negotiated individually or may be standardized. Many negotiations start with a standardized contract, such as the natural gas contract developed by the North American Energy Standards Board (NAESB), and then modify it. Others start from scratch. Individually negotiated deals are called structured contracts. Two commonly used contracts for electricity are the Edison Electric Institute (EEI) Master Power Purchase and Sale Agreement and the WSPP Agreement (WSPP was formerly known as the Western Systems Power Pool). To be tradable, a contract must include terms and conditions that make it attractive to more than one entity. Consequently, complicated, one-off contracts negotiated to meet the need of an individual seller and buyer may have little or no resale value. Typically, the standardized contracts traded on exchanges or electronic brokerage platforms are designed to be of interest to many market participants.

In OTC markets, contracts are bilateral -- i.e., the process of negotiating the completion of a purchase or sale is between the two market participants.

Regional Transmission Organizations

Electricity is also bought and sold through RTOs. In general, RTOs operate their markets to support the physical operation of the electric grid under their control, including making decisions about what generation to dispatch to meet customer demand. RTO markets are multilateral; buyers and sellers are not matched individually against each other. RTOs allow for bilateral physical transactions, although each RTO handles these differently. RTOs provide settlement services, although this differs from the settlement offered by exchanges.

Also, RTOs use the word clearing to refer to the matching of supply and demand – to clear the market means the RTO accepts sufficient generation offers to meet demand. If a generator's offer in the day-ahead market clears, it means that generation was offered at or below the market clearing price and was chosen to generate the next day. RTOs maintain credit policies and allocate the costs of defaults or other performance failures across market participants.

RTO markets may have elements that are similar in nature to financial transactions. One of these is virtual transactions (often referred to only as virtuals). For example, a trader may offer generation in the day-ahead market, and the generation does not show up in the real time market. As a result, the trader is paid for his generation offer in the day-ahead market, based on day-ahead prices, but effectively has to pay to replace his power in the real-time market, paying the real-time price. Financial participants can participate in virtuals; they use the physical product (generation offers or demand bids) in a way that results in no physical delivery. Virtuals are financial contracts, directly integrated into the RTO's operation of its physical market; they affect physical supply and demand, and prices. Virtuals are discussed further in Chapter 3.

RTOs may also offer financial transmission rights (FTRs) programs, also discussed in Chapter 3. Typically, a transmission owner that turns over operation of its transmission to the RTO wants certainty over its ability to flow electricity and about the cost of transmission. Because the RTOs operate using markets, this certainty cannot be provided directly. FTRs and similar instruments are designed to provide some degree of financial compensation to these transmission owners and firm rights holders. FTRs are linked to the physical operation of the RTO's system in that the expected capacity of the transmission is used to determine the total capacity of FTRs offered.

FTRs compensate the transmission owners or firm rights holders in a couple of ways. First, the RTOs auction additional FTRs to others in the market, including financial participants who have no interest in buying, selling or transmitting physical power. The proceeds of the auction are returned to some of transmission owners or firm rights holders. The auction also determines a value for any FTRs held by the transmission owners or firm rights holders. FTRs can be bought and sold; the auction price gives an indication of their value for price discovery.

Other Market Mechanisms and Concepts

Leverage is the use of a small position to control or benefit a larger position. It increases the potential return, but also increases risk. Leverage can occur when a trader uses margin to trade.

Leverage can be used in other ways. As discussed in Chapter 6, some traders may try to use leverage to manipulate the market. For example, traders may use a smaller position in the physical market to benefit a larger position in the financial market. They may buy a financial product whose price is derived from a physical product. Then, they may try to buy or sell or otherwise influence the price of the physical product. If they succeed, their financial position benefits.

Liquidity refers to the trading and volumes occurring in a market. A market is said to be liquid if trading and volumes are such that any trader can liquidate his position at any time, and do so without affecting the prices. A market is thin if it has little trading or volume; in these instances, trading may affect prices. The benefits of liquidity are often used to justify practices that increase trading or volumes. However, not all trading or volumes are uniformly beneficial to markets and other market dynamics need to be taken into account.

Markets may not be uniformly liquid. For example, the market for the Nymex natural gas futures contract is generally thought to be liquid. However, when the United States Natural Gas Fund became extremely large, its monthly process of getting out of the current contract and into the next involved selling and buying an extremely large volume of contracts at one time. If these transactions affected prices, then the market was affected.

Open interest is the total number of futures contracts in a delivery month or market that has been entered into and not yet liquidated by an offsetting transaction or fulfilled by delivery. By the expiration of the settlement period, the open interest in contracts (both in terms of the total number of contracts and the number of counterparties) rapidly decreases, so that a given number of contracts will represent an increasing share of the outstanding prompt-month contracts.

Clearing is a process in which financial or physical transactions are brought to a single entity, the clearing house, which steps into the middle of the transaction and becomes the counterparty to each buyer and seller. The clearing house assumes the risk that either the buyer or seller will fail to perform its obligations. Generally, clearing is used to manage counterparty risk. Clearing houses maintain rules about the creditworthiness of traders, collateral that must be posted and, of course, fees that must be paid for the service.

Settlement occurs at the end of a trading period, when the contract expires. At this time, delivery is to be made for a physical contract (physically settled) or a financial payout made for a financial contract (financially settled). Settlement occurs both in exchanges and in OTC trades. In OTC transactions, settlement occurs under the terms agreed upon by the parties. On exchanges, settlement occurs in a documented process and timeframe established by the exchange.

For example, every day at the close of Nymex trading, the natural gas futures contracts for forward months settle. The final settlement for a given month occurs three business days prior to the start of the month of delivery (the prompt month). The contract expires and the last-day settlement (LD settlement) is calculated based upon the trading in the last half-hour. LD settlement is the final price for that particular futures contract term. The last day for trading option contracts is the day before the futures contract expires.

Most market participants avoid trading during the settlement period. As the time to termination approaches, price risk and volatility may increase, while market liquidity and the remaining open positions (open interest) are decreasing. For the Nymex natural gas futures contract, most market participants either liquidate or roll their open long or short positions well before the settlement period. Rolling is the process of liquidating the current month's contract before it expires and purchasing a comparable position in the upcoming month. The trader holds the same number of contracts, but the contract month held changes as time passes and contracts expire.

Daily settlement prices are used to revalue traders' position to the current market price, for accounting and for margin calculations. Daily and LD settlement prices are also reported in publications and indexes, and are used for price discovery.

Mark-to-market (MTM) provides that at the end of each trading day, all trading positions are revalued to current market prices. This results in financial and accounting gains and losses. Traders can remove money resulting from gains from their accounts or use them for further trading; they do not have to liquidate their positions to get the money. Losses reduce the value of a trader's position, and may reduce the amount of collateral the trader needs to be able to trade on margin. If so, this may result in a margin call from the exchange or broker.

Mark-to-market is also an accounting transaction, in that a company's or trader's accounts are revalued daily to reflect changes in asset price. Losses can reduce the book value of a company or trader, and can affect its creditworthiness.

Trading is the buying and selling of contracts. Trades and transactions are virtually synonymous. Both refer to the buying and selling of power or natural gas.

Short selling is the selling of contracts a trader does not own, on the assumption that the trader will buy offsetting contracts prior to the contracts' expiration. This can be done on an exchange or other market that allows for bidirectional trading. Short selling has been of concern for potential market manipulation – traders sell a contract to drive the price down, and then buy when the price is low. Short selling is one of the ways market participants can trade futures financially – they sell the future, then buy it before the contract expires so the contracts net out and the trader faces no delivery obligation.

A **position** is the net holdings of a participant in a market. A trader's position in a specific instrument is combined purchases and sales of that contract. A trader's overall position is the combination of all positions in all contracts the trader owns. A trader's position is often referred to as the trader's commitment in the market.

Liquidating a position is the process of getting rid of a position. A trader who owns a contract will sell it to liquidate it. A trader who has sold a contract short will buy a contract to liquidate it. After liquidation, the trader holds no contracts.

Position limits have been imposed on ICE and Nymex exchanges according to specific formulas, in accordance with regulations and proposed rules of the Commodity Futures Trading Commission. The position limits may restrict the number of shares a trader may hold in a particular investment at any point in time, during the month the contract expires, or during some period closer to settlement. For example, the CME Group (CME) imposes accountability levels for any one month and for all months, and has limits for expiration-month positions. CME's accountability for the Nymex Henry Hub natural gas futures contract are 12,000 contracts for all months, 6,000 contracts for one month and 1,000 contracts in the expiration month. Trading entities can petition to have these waived or modified.

Volumes give an indication as to the nature of the activity occurring in the market at any point in time. Volume can be expressed in a number of ways. It can be the number of transactions executed during a specified period of time or the volume of the product contained in the contracts.

Volumes give market participants information about what is going on in the market. For example, if many Nymex contracts are traded, and the number of trades is relatively few, market participants know that a relatively few traders are making high-volume trades. Conversely, if a high number of Nymex contracts are traded and the number of trades is also high, then at least some of the trading is being done in small volumes. This could result from broad interest in the market – lots of active traders – or it can result from relatively few traders making a lot of trades.

Market Participants

Financial markets are used by many types of participants. These markets present an opportunity for physical players, producers and marketers to buy or sell some physical products or to hedge physical supplies and obligations with physical or financial products. Investors, speculators and investment funds also use these physical and financial products for financial gain.

Products

Products, for purposes of trading, are contracts — also known as securities or instruments — that can be bought and sold. Contracts for physical trading in natural gas or electricity markets provide for the delivery of natural gas or electricity. The actual molecules of gas or electrons may be delivered as a result of the contract. Financial contracts do not provide for delivery of a product; instead, they provide a financial payout. Consequently, what traders buy and sell are contracts giving them a right or obligation. For physical contracts, this is the obligation to deliver or take delivery of natural gas or electricity in exchange for payment. For financial contracts, it is the right to a payout in exchange for payment, although the net value may vary over time from a net benefit to a net loss.

Other physical and financial products give traders rights to buy or sell a contract in the future at a given price – an option to buy or sell.

The word derivative is used for a category of contracts whose value is derived from some other physical or financial product or contract. Standardized derivative contracts trade on exchanges such as Nymex. Financial contracts are derivatives.

Futures contracts are derivatives of the physical contract and options on futures are derivatives of futures contracts. As futures contracts approach expiration, their price should, in theory, converge to spot prices – to derive their price from spot prices. However, at other times, futures contracts are simply the price parties are willing to pay for natural gas at some point in the future and may not derive their value from any other product or contract. Such expiring futures contracts may affect spot prices.

Instrument Basics

Each instrument is traded in its own market and is identified by the market name, such as spot or futures. Each market and instrument has characteristics such as timeframe, location, contract type, product conveyed by the contract and, for swaps, the mechanism for determining the payout.

Product conveyed: Each contract specifies what is being bought and sold. For physical contracts, this would be natural gas or electricity. For derivatives, it may be a payout derived from natural gas or electricity prices. All contracts conveying or derived from natural gas, for example, would be in natural gas markets.

Time: Each contract has a number of time elements. The trade date is the date on which the contract is written (typically the date the trade is executed).

The expiration day is the last day for a contract, after which it is no longer available to be bought and sold; it is often the same day as the settlement day. Exchanges and electronic brokerage platforms may also impose a termination date, the last date on which a contract may be traded.

Physical contracts also specify the delivery day(s) or month – the day(s) or month during which the product is to be delivered.

For physical products, begin and end dates are the dates for which a physical product (natural gas or electricity) is to be delivered. For financial products, these dates address the contracts whose prices are used to set the payout. For example, a next-day physical gas deal may have a trade date of Aug. 7, a begin date of Aug. 8 and an end date of Aug. 8. A monthly product may trade on Aug. 7, its trade date; the flow of natural gas would have a begin date of Sept. 1 and an end date of Sept. 30.

For the Nymex natural gas futures contract, the termination day and settlement day are the third-to-last business day of the month before the month in which the gas is to be delivered. The settlement period occurs from 2 p.m. to 2:30 p.m. on the termination day.

Short-term or spot contracts provide for delivery or payout during the current or next day; the price for these contracts is known as the spot price.

Daily physical contracts are for delivery on a given day or set of days.

Electricity physical and financial contracts may also specify peak or off-peak delivery, with the peak or off-peak hours defined by the contract.

Contracts for delivery a month or more into the future are forward contracts, or if they are traded on exchanges, futures contracts. The Nymex natural gas futures contract, for example, provides for the delivery of 10,000 MMBtu of natural gas in the month specified by the contract. Contracts are offered for every month over the next 12 years.

Monthly contracts are referred to by how close they are to expiring. Spot month is the current month. Prompt month is the month after the spot month or current month – it is the next trading month. For trading in January, February is the prompt month.

Another time element is the delivery or payout period, such as daily, next day or monthly. Monthly contracts generally are for delivery in equal parts over a month at a specified price for gas and for the contracted amount in each hour for power.

Location: All physical contracts specify the location where the natural gas is to be delivered, such as the Henry Hub in Louisiana. Financial contracts also have a locational element, determined by the underlier. For example, if a financial derivative uses the Nymex natural gas contract as its underlier, the derivative's locational element is the Henry Hub.

For natural gas, the locations are referred to as market hubs, which are located at the intersection of major pipeline systems. For power, contracts are often based on locations known as nodes, zones or hubs. For gas, the principal hub and pricing point is the Henry Hub, which is used for all Nymex natural gas futures contracts and is the reference point for overall prices in the United States. Prices for other locations are often references as a difference from the Henry Hub, known as basis.

Products traded on exchanges and preset products traded on OTC electronic brokerage platforms such as ICE use standardized locations or pricing points. Locations for other OTC transactions use whatever location the counterparties to the contract desire. For physical contracts, the location must be physically viable. For financial products, it can be whatever the parties desire (although complicated locations make pricing more difficult due to the lack of reference points for price discovery).

Quantity: All physical contracts specify the amount of natural gas or electricity to be delivered. For contracts traded on an exchange or for preset contracts traded on an OTC electronic brokerage platform, the quantity is predetermined and specified in the contract. For bilateral contracts traded in OTC markets, the quantity contained in the contract can be anything the parties want it to be. For standardized products traded on electronic brokerage platforms, the quantity is fixed.

Price: The price paid for a contract is usually that set by the market and is usually known at the time the contract is bought or sold.

Fixed prices are known at the time the transaction is entered into – it is the price at which the seller agrees to sell and the buyer agrees to buy. Contracts sold at fixed prices are typically paid for at the time of purchase.

Floating prices are set by formulas pegged to something whose price is not currently known but which will be known at the time the contract expires, such as an index. For example, a price may be tied to the average of the all of the daily prices at a location over the course of a month, typically as published in an index. An index contract is a commonly traded instrument based on major trading points, such as the Houston Ship Channel or the Henry Hub.

Spot price is a cash market price for a physical commodity that is available for immediate (next day) delivery, and may be reported to publishers for indexes.

Standardized forward contracts and futures contracts are traded for every month, years into the future; the Nymex natural gas futures contract is traded more than eight years into the future although only the first few years may be very liquid – i.e., actively traded. Each of those contracts for which trading has occurs has a price. Together, the prices for future contract months creates a trajectory of prices known as forward or futures curves.

The settlement price is effectively the final official reported price for certain contracts and is an average of prices for trades occurring during the settlement period. For example, the natural gas futures contract settlement price is made during the contract's 30-minute settlement period – the last 30 minutes of trading on the contract's termination day. The settlement price forms the basis for the payout for financial derivatives that use the contract as its underlier, as well as for margin calls and for reporting to index publishers.

Physical Products

Physical products involve an obligation to physically deliver. Power products include energy, transmission (firm and non-firm) and ancillary services. Electric energy products include spot transactions, full requirements sales and bundled services, among others. Natural gas products include the natural gas molecules themselves, transportation and storage.

Forward products are contracts for physical delivery in future months traded through the OTC market (including electronic brokerage platforms). If the product is traded on an exchange, it is known as a futures contract.

A futures contract is a standardized forward contract traded on a regulated exchange. Each contract represents the same quantity and quality of the underlying physical commodity, valued in the same pricing format, to be delivered and received at the same delivery location. In addition, the date of delivery and receipt is the same for all contracts traded for a particular calendar month. The only element of a futures contract that is subject to change when it is bought or sold is the price.

For the natural gas industry, the dominant futures contract is the Nymex natural gas futures contract. For this contract, the standard contract specifications are the delivery location – Sabine Pipeline Hub at the Henry Hub in Louisiana; the term – monthly; and the quantity – 10,000 MMBtu delivered equally over the course of the month. Not all forward contracts have fixed prices. Some involve trades executed now to buy or sell at some point in the future, at a price to be set in the future. One example of this is a forward physical index contract. This OTC contract obligates one party to buy the underlying commodity or security and the other party to sell it, for a delivery price to be determined when a specific index sets at some known date in the future. Many natural gas purchases are made under forward physical index contracts; among other things, it may provide state regulators with some assurance that the price paid is reasonable.

Forward and futures contracts with fixed prices can be used for price discovery, hedging or speculating. They may be traded by any of the participants listed earlier. Physical participants may use forwards or futures to obtain gas or electricity for delivery in some future month, or may use them to manage the risk of – or, hedge – their physical positions. Futures contracts that go to delivery lose their anonymity at settlement. However, only a small fraction – often, less than one percent – of futures contracts go to delivery.

Financial traders may buy or sell futures contracts for financial purposes, as exchanges have bidirectional trading – markets in which trader can buy and sell contracts with equal ease. Bidirectional trading allows the sale of contracts a trader does not own, known as short sales. A financial trade may buy a forward or future, then either sell the contract later or neutralize it by obtaining an offsetting contract. Because the two offset, the trader has no physical delivery obligation. Most Nymex natural gas futures contracts do not go to delivery.

Physical products can be combined to create different physical positions for use in physical and financial trading. A price spread can be created using forwards priced at indexes for two different hubs. The trader would buy physical natural gas at one index and sell at another. For example, the trader buys gas priced at the Houston Ship Channel index (and would have to take delivery of the gas there) and sells gas at the Texas East M-3 index (and would have to deliver it there). The trader earns the difference between the two contracts. A physical spread carries with it the obligation to make or take physical delivery of natural gas at both points, so pipeline capacity would be required to actually move gas between these points.

A financial trader could also execute this trade, but would have to unwind both positions before delivery.

Indexes are formally published for both natural gas and power using a methodology posted by the publisher. An index may be used to set the price for settlement of floating price contracts. Indexes are also used by a variety of market participants to inform their decisions in the many steps in the electricity or natural gas supply chain or in trading, known as price discovery. Data used in indexes are submitted voluntarily by firms involved in trading. Indexes are commonly formed using volume-weighted average prices.

Financial Products

Financial contracts do not provide for the delivery of a product, but instead provide a financial payout. This is often based on the value of some physical or financial product specified by the contract, called the underlier. The value of these financial contracts is derived from the value of the physical or financial instrument specified in the contract as the basis for payout; as such, they are derivatives.

A key benefit of financial products is that they have no physical delivery and they are self-liquidating. Speculators who trade futures have to undo their position to eliminate the delivery obligation. One who trades derivatives, on the other hand, does not bear the complications of unwinding positions; the individual can simply wait for expiration and receive or pay the contract's payout.

Swaps

A key financial contract structure used in natural gas and electricity markets is the swap, or contract for differences. A swap is an exchange of one asset or liability for a similar asset or liability. It may entail buying on the spot market and simultaneously selling it forward. Swaps also may involve exchanging income flows. Swaps may include calendar spreads or basis spreads which reflect expectations of time or locational price variances. Physical instruments cannot be swaps because parties to physical goods pay or receive money in exchange for delivery of the physical good. However, the exchange of money in terms of payment and payout constitutes a swap.

Options

An options contract conveys a right (but not the obligation) to buy or sell something else. It comes in two forms: the right to buy or the right to sell something at a specified price at or before a specified date. The buyer buys the right – the option – to buy or sell in the future; the seller (or writer) sells the obligation to sell or buy if the buyer exercises his right.

An option to buy is known as a call option; an option to sell is a put option. The price paid to buy or sell the option is known simply as the option's price. The price at which the option may be exercised is the strike price. Electing to buy or sell the underlying commodity or security is known as exercising the option.

Options traded on exchange or electronic trading platforms may be traded up to their expiration. Consequently, the owner of an option may sell it rather than exercise the option or let it expire.

Traders buy and sell options for a number of reasons. First, they provide a risk management tool akin to insurance. Second, traders may use options traded on exchanges or electronic trading platforms to speculate. For example, a speculator may trade an option and hope to gain from price movements, akin to how they might trade other contracts, such as futures. If a trader buys an option, the trader can sell it up to expiration and pocket the difference between the purchase price and the sales price. Further, as in futures, the seller of an option traded on an exchange can offset his obligation by purchasing the offsetting option, thereby eliminating the risk of the contract going to delivery.

Finally, traders may use options to boost their trading income or to reduce the volatility of their returns. Options require less money up-front than a futures contract or swap, which can be a benefit to traders with limited funds.

Trading and Transacting

Trading Mechanics

Market prices are the collective result of individual trades. Open interest is the aggregation of traders' positions.

Trading is the buying and selling of contracts. A trade is a single purchase or sale. A position is the accumulated unexpired contracts purchased or sold, at a point in time. Traders may have positions in each contract, as well as an overall position reflecting all their contracts.

Trading requires a buyer and a seller, each willing to transact for a price. A buyer bids a price he or she is willing to pay to purchase a contract; this is the bid price. A seller offers a product for sale; the price at which the seller offers it is the offer price.

These prices may or may not be the same. When they differ, the distance between them is the bid-offer or bid-ask spread. This spread is the difference between the highest price at which buyers are currently willing to buy (the highest bid) versus the lowest price at which sellers are currently willing to sell (the lowest offer). For example, if a buyer bids $7 and the seller offers at $10, the bid-ask spread is $3.

Trading Concepts

Traders need to know how their trades and positions will be affected by market changes. One way this is done is by considering whether a trade or position benefits or loses when prices go up or down. A position is long if it benefits from increases in price. It is short if it benefits from falling prices. If it is neutral, benefitting from neither a rise nor a fall in prices, it is said to be flat.

For example, a trader who purchases a Nymex natural gas futures contract is going long; that contract will benefit from increases in price. A trader who sells the contract is going short; the trader will benefit from falling prices.

The concept of being long or short applies to other forms of transactions. Absent anything else, a generator is long electricity; a consumer short electricity. If the generator obtains a contract to sell electricity to the consumer at its cost of generating, the generator is flat.

The task of identifying long or short is not always easy. A trader may have a variety of positions in a number of contracts, some long and some short. How the overall position benefits from swings in prices depends on each of the components and how they interact with each other.

Trading Strategies

Traders decide what products to trade, how to trade them and in which combinations. Their strategies will depend on their objectives. Broadly, market participants trade to accomplish any of three objectives: to buy or sell physical products, such as natural gas or electricity; to manage the risk of their physical positions, or hedge; or to make money.

Hedging

Market participants with physical positions are in the market to buy and sell natural gas and electricity to enhance profitability of their physical operations. These physical operations determine their individual risks and hedging needs, and each physical market participant has a risk position related to its business role in the physical delivery and consumption of natural gas and electricity. A natural gas producer has different risks and therefore different hedging objectives than an LDC that needs to purchase gas to resell to retail consumers.

An LDC, for example, is concerned with obtaining sufficient volumes to serve variable customer demand and in the price paid for those volumes. A producer may be concerned about selling all output (unless the output may be stored), and about the revenues obtained from the gas sale. Physical market participants may have other concerns as well. Producers may need a predictable cash flow to support their financing. LDCs may be concerned with state regulators determining that their gas purchasing practices were imprudent.

Such concerns drive both procurement and sales decisions as well as risk management decisions. The two are often closely interconnected. For example, an LDC needs to buy enough gas to meet extremely variable retail demand, but not too much. An LDC also wants a price that regulators and consumers will see as reasonable. Consequently, LDCs usually develop a procurement and risk management – hedging – strategy taking these factors into account.

To purchase sufficient quantities, an LDC may create a portfolio of supplies, with a block of firm supply to meet minimum daily needs. An LDC trader may also decide to buy in the spot market to meet demand peaks. An LDC may diversify the sources of gas, both to improve reliability of supply but also to diversify its price.

An LDC may also manage risk financially. In the commodities and securities markets, a hedge is a transaction entered into for the purpose of protecting the value of the commodity or security from adverse price movement by entering into an offsetting position in a related commodity or security. Hedging is used when describing the purpose of entering into a transaction with the intent of offsetting risk from another related transaction.

Speculation

Traders seeking to make money fall into a couple of categories: investors and speculators. These categories are distinguished by the strategies they use to profit from the market. Investors are relatively passive; they are in the market to benefit from long-term price movements and to diversify a broader portfolio. Speculators actively seek to gain from price movements.

Trading Analysis

In deciding whether to trade, both hedgers and speculators pay attention to what is going on in the market, and develop their own view of where the market is likely to go. They may develop complicated forecasts as the basis for decisions on a number of transactions: whether, when and where to build a merchant power plant, how to hedge natural gas production, and of course, when to buy and sell in the markets.

Two general schools influence traders' thinking when analyzing markets for trading opportunities. The first is fundamental analysis, which takes into account physical demand and supply fundamentals including production, pipeline and transmission capacity, planned and unplanned outages, weather and economic and demographic changes. Changes in information about fundamentals (or changes in perceptions of fundamentals) alter traders' views of the supply-demand balance, and therefore, of prices. Fundamental analysis is used often to determine the impacts of longer term trends in the physical market – the development of shale gas supplies, for example.

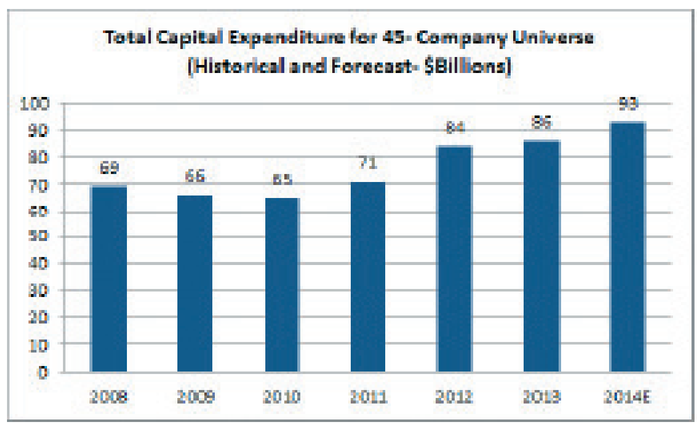
The second school of thought is technical analysis, which forecasts price movements based on patterns of price changes, rates of change, changes in trading volumes and open interest, without regard to the underlying fundamental conditions. Instead of looking at the market for a physical good, technical analysis looks at trading and price changes. These quantitative methods have become a dominant part of market analysis. Technical analysis is used most often to determine short-term movements and trends, helping traders time their buys and sells.

Capital Markets

Capital markets provide the money to make investments in infrastructure such as power plants or natural gas pipelines, to operate plants and companies and to trade or conduct transactions. Access to capital depends both on the health of capital markets and also on the perceived riskiness of the entity seeking the capital. To measure relative riskiness, many providers of capital look at different measures, including credit ratings assigned by the three major crediting rating firms: Standard and Poor's (S&P), Moody's and Fitch.

Capital Expenditures

One effect capital markets have on energy markets is in capital spending – undertaking work or investments that require capital. The 2009 recession and shake-up in capital markets took a toll on capital spending as financial commitments to infrastructure fell for the first time in years, but spending has been rising since 2011 (see bar chart).



Source: SNL Energy

The electric industry makes up the bulk of the capital expenditures expected by energy companies. The majority of the electric industry's spending has been on electric transmission & distribution and generation.

Types of Capital

Capital comes from two general sources of financing – debt and equity.

Debt financing involves borrowing money to be repaid over time, along with interest at a fixed or variable interest rate. With debt, the investor does not become an owner of the company. Some common types of debt include bonds – securities that companies issue in financial markets with maturities (when the loan has to be repaid) of more than a year; shorter term debt issued by companies through financial markets; and bank loans, such as lines of credit. A revolving line of credit is an assurance from a bank or other institution that a company may borrow and repay funds up to some limit at any time. Municipal and cooperative utilities typically use debt; they have no ownership to sell.

Characteristics of debt include:

- Capital obtained through debt must be repaid or refinanced.
- Debt may be short-term, such as lines of credit from banks or corporate paper, or it may be long-term.
- Companies must make their interest payments and repayment on schedule, or the debt holders can take action, including forcing the company into bankruptcy. A company must generate sufficient cash through its operations or through other financing to make these payments.
- Interest gets paid before equity dividends.
- Interest payments are tax deductible.
- Debt gives lenders little or no control of the company (unless it gets into financial trouble).
- Debt can leverage company profits; similarly, it can magnify losses.
- Lenders are typically conservative, wanting to minimize downside risks.
- Borrowers may be required to pay collateral to secure debt. Debt without collateral is known as unsecured debt.

Equity financing is money provided in exchange for a share in the ownership of the business. A company does not have to repay the capital received, and shareholders are entitled to benefit from the company's operations, perhaps through dividends.

- Equity capital can be kept by the company indefinitely.
- Companies can issue shares in the company – stock – through financial markets. They may also use private equity – money from venture capital firms or private investment companies that buy into a company and which may or may not take an active role in operating the company.
- The most common form of stock is common stock, which does not require regular payments, but it may receive dividends; investor-owned utilities typically pay dividends.
- Equity does not provide a tax deduction to the company; dividends and other payouts are not tax deductible.
- Stockholders and private equity investors get a say in how the company is operated and may impose restrictions.
- Equity investors may be more willing to assume higher risks in return for a higher potential returns. Utilities are typically considered fairly conservative investments. Natural gas producers attract a more risk-inclined investor.
- The return required to attract equity is higher than the interest paid to debt holders.
- Equity capital does not require collateral; it gets a share in the company.
- Additional equity capital infusions may dilute, or reduce, the value of existing shares.

Companies often try to match the type of financing with the investment they are making. Pipelines, power plants and transmission facilities are long-lived assets. They are typically financed using long-term capital, such as stock and long-term bonds, which can have 30-year maturities.

Other capital is needed to conduct day-to-day operations. Some of the cash needed to fund operations comes from a company's revenues. However, revenues do not always come in when payments are due. Consequently, companies also rely on working capital. This can include some long-term capital from stocks and medium- and long-term bonds. Short term investments and day-to-day operations also rely on commercial paper and bank loans to cover day-to-day cash needs. If a company faces significant problems, it may have to issue especially high-priced debt – junk bonds – to obtain financing. These are bonds issued by entities lacking investment grade credit ratings (see below). In the past few years, marketers and financial institutions have taken an interest in the energy industry, and have provided another source of equity financing.

Credit Ratings

Not all companies (or governments) present the same riskiness to investors. Investors, traders and others consider the risks their counterparty may present, including the risk of default. One standardized tool used to assess relative risk is the credit rating. Credit rating agencies, such as Standard and Poor's, Moody's and Fitch, assess a company's riskiness every time it wants to issue bonds. A credit rating represents the likelihood that an issuer will default on its financial obligations and the capacity and willingness of a borrower to pay principal and interest in accordance with the terms of the obligations. Many organizations, including RTOs, consider bond ratings, among other things, when setting their credit policies, which determine with whom companies may transact and whether the counterparty will need to post collateral. Each credit rating agency has its own way of assessing risk, reflected in the rating system they use.

Ratings by Industry Sector

Electric utilities largely are rated investment grade, with ratings of BBB or better.

Merchant generators include generating companies that are completely unaffiliated with integrated utilities (and are known as independent power producers, or IPPs) and those that are affiliated but which receive at least half their cash flow from competitive power sales. The affiliated companies typically have higher ratings; S&P views the integrated merchants' business profile scores as strong or satisfactory. S&P typically rates IPPs fair or weak.

The midstream sector of the natural gas industry, which contains pipelines, processing plants and storage facilities, is also typically rated investment grade. Midstream companies' ratings average BBB and are said by rating agencies to have a stable outlook.

6. Market Manipulation

Following the energy crisis in the western United States early last decade, Congress enacted the Energy Policy Act of 2005 (EPAct 2005), which added anti-manipulation provisions to the Federal Power Act, 16 U.S.C. § 824v (2012), and the Natural Gas Act, 15 U.S.C. § 717c-1 (2012). To implement these anti-manipulation provisions, the Commission issued Order No. 670, adopting the Commission's Anti-Manipulation Rule, which has been codified as 18 C.F.R. § 1c (2014). Recognizing that other regulators have long prohibited manipulation of other markets such as securities and commodities, the Commission draws from the experience of sister federal agencies in implementing the Commission's anti-manipulation authority.

The Anti-Manipulation Rule applies to any entity, which the Commission has interpreted to mean any person or form of organization, regardless of its legal status, function or activities, and prohibits (1) using a fraudulent device, scheme or artifice, or making any untrue statement of a material fact or omitting to state a material fact necessary to make a statement that was made not misleading, or engaging in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter (that is, an intentional or reckless state of mind); (3) in connection with a transaction subject to FERC jurisdiction. The Commission need not show reliance, loss causation, or damages to prove a violation.

The prohibition is intended to deter or punish fraud in wholesale energy markets. The Commission defines fraud in general terms, meaning that fraud includes any action, transaction or conspiracy for the purpose of impairing, obstructing or defeating a well-functioning market. Fraud is a question of fact that is to be determined by all the circumstances of a case. In Order No. 670, the Commission found it appropriate to model its Anti-Manipulation Rule on Securities and Exchange Commission (SEC) Rule 10b-5 in an effort to prevent (and where appropriate, remedy) fraud and manipulation affecting the markets the Commission is entrusted to protect. Like SEC Rule 10b-5, FERC's Anti-Manipulation Rule is intended to be a broad antifraud catch-all clause.

The Commission made clear in Order No. 670 that a duty to speak to avoid making untrue statements or material omissions would arise only as a result of a tariff or Commission order, rule or regulation. However, the Anti-Manipulation Rule extends to situations where an entity has either voluntarily or pursuant to a tariff or Commission directive provided information but then misrepresents or omits a material fact such that the information provided is materially misleading.

To violate the Anti-Manipulation Rule, one must also act with a sufficient state of mind, that is, level of intent. Intentional conduct or recklessness (known as scienter) is enough to satisfy the Rule.

The Commission also stated that for conduct to violate the "in connection with" element of the Rule, there must be a sufficient nexus between an entity's fraudulent conduct and a jurisdictional transaction. In committing fraud, the entity must have intended to affect, or have acted recklessly to affect, a jurisdictional transaction.

Manipulation comes in many varieties. As a federal court of appeals has stated in the context of commodities manipulation, "We think the test of manipulation must largely be a practical one.… The methods and techniques of manipulation are limited only by the ingenuity of man." *Cargill, Inc. v. Hardin*, 452 F.2d 1154, 1163 (8th Cir. 1971). The Commission recognized this reality by framing its Anti- Manipulation Rule broadly, rather than articulating specific conduct that would violate its rules. While manipulative techniques may be "limited only by the ingenuity of man," the following are broad categories of illustrative manipulations that have surfaced in the securities and commodities markets (including the energy markets) over the years. The borders of these categories are flexible and some can belong to multiple categories, such as wash trading (i.e., buying and selling identical stocks or commodities at the same time and price, or without economic risk). Traders may also combine elements of various schemes to effect a manipulation.

Manipulative Trading Techniques and Cross-Product Manipulations

A number of manipulative trading techniques that have arisen in securities and commodities trading may be subject to the Commission's Anti-Manipulation Rule. Traders may seek to inflate trading volumes or trade at off-market prices to serve purposes such as maintaining market confidence in a company's securities or to move a security's price to trigger an option. Marking the close is a manipulative practice in which a trader executes a number of transactions near the close of a day's or contract's trading to affect the closing or settlement price. This may be done to obtain mark-to-market marks for valuation, to avoid margin calls, or to benefit other positions in related instruments. Banging the open is a similar practice in which a trader buys or sells a large quantity at the opening of trading to induce others to trade at that price level and to signal information on fundamentals. Other manipulative trading techniques exist, and practices like wash and round-trip trading that are discussed in more detail below fit under this description as well.

Manipulators have grown more sophisticated with the expanded use of derivative products, whose value is set by the price of transactions in a related product. Many of the manipulative schemes that staff from FERC's Office of Enforcement (Enforcement staff) has investigated and prosecuted are cross-product schemes in which an entity engages in price-making trades in the physical market, often at a loss, with the intent to affect the settlement price of price-taking derivative instruments. Cross-product manipulation is also referred to as related-position manipulation. Such trading can violate the Anti-Manipulation Rule because the trading is not undertaken in response to supply-and-demand fundamentals but rather is undertaken to benefit another position. Such trading could be considered to undermine the functioning of jurisdictional markets.

Key to understanding cross-product manipulation is that financial and physical energy markets are interrelated: physical natural gas or electric transactions can help set energy prices on which financial products are based, so that a manipulator can use physical trades (or other energy transactions that affect physical prices) to move prices in a way that benefits his overall financial position. One useful way of looking at manipulation is that the physical transaction is a "tool" that is used to "target" a physical price. For example, the physical tool could be a physical power flow scheduled in a day ahead electricity market at a particular "node" and the target could be the day-ahead price established by the market operator for that node. Or the physical tool could be a purchase of natural gas at a trading point located near a pipeline, and the target could be a published index price corresponding to that trading point. The purpose of using the tool to target a physical price is to raise or lower that price in a way that will increase the value of a "benefiting position" (*e.g.*, Financial Transmission Right or FTR product in power markets, a swap, a futures contract, or other derivative).

Usually, increasing the value of the benefiting position is the goal or motive of the manipulative scheme. Understanding the nature and scope of a manipulator's benefiting financial positions—and how they relate to the physical positions—can be a key focus of manipulation cases. The Commission's

Anti-Manipulation Rule is an intent-based rule: a finding of manipulation requires proving that the manipulator intended (or in some cases, acted recklessly) to move prices or otherwise distort the proper functioning of the energy markets the Commission regulates. A company can put on a large physical trade that may affect market prices, but if the purpose of that trade is to hedge risk or speculate based on market fundamentals—rather than, for example, the intent to move prices to benefit a related financial position—this conduct, without more, would not violate the Commission's Anti-Manipulation Rule.

Information-Based Manipulations

Many manipulative schemes rely on spreading false information, which involves knowingly disseminating untrue information about an asset's value in order to move its price. A well-known scheme is the pump and dump, in which a participant spreads a rumor that drives the price up and then sells the shares after the price rises. In the energy markets, a common way to misrepresent a commodity's value is to misrepresent the price of the commodity or its level of trading activity. False reporting and wash-trading schemes were well-documented information-based manipulations that took place in the early 2000s and contributed to the western energy crisis. False reporting occurs when a market participant submits fictitious transactions or information to a price-index publisher to affect the index settlement price. Another form of information-based manipulation involves providing misinformation through conduct that is intended to misrepresent a market participant's characteristics, circumstances, or intentions, in order to receive a benefit, payment, or award for which it would not be eligible but for the misleading conduct. This includes engaging in trading strategies that are intended to create market results that are inconsistent with the purpose of the transactions.

Similarly, wash trading may involve actual but offsetting trades for the same (possibly nonmarket) price and volume between the same market participants such that no economic exchange takes place; however, it may falsely inflate trading volumes at a price level and give the impression of greater trading activity. False reporting and wash trading have resulted in a number of criminal prosecutions by the Department of Justice.

Withholding

Withholding is the removal of supply from the market and is one of the oldest forms of commodities manipulation. The classic manipulation of a market corner involves taking a long contract position in a deliverable commodity and stockpiling physical supply to force those who have taken a short position to buy back those positions at an inflated price.

Withholding played an important role in the western power crisis that engulfed California in 2000. Market participants, particularly Enron, exploited supply-demand imbalances and poor market design. Generation operators scheduled maintenance outages during peak demand periods, which is an example of physical withholding. In addition, transmission lines were overscheduled to create the appearance of congestion in an effort to reduce the supply of electricity. The result of these efforts in combination with economic withholding and information-based schemes discussed above was that wholesale electricity prices soared. Utilities such as Pacific Gas & Electric (PG&E) and Southern California Edison were unable to pass on these high prices to their retail customers because of state price caps. The crisis led to widespread blackouts, heavy losses to the state's economy and the bankruptcy, in April 2001, of PG&E.

Economic withholding, which also contributed to the western power crisis, is similar to physical withholding, but rather than turning off a generator or stockpiling a physical commodity, the manipulator sets an offer price for a needed resource that is so high that the resource will not be selected in the market. For example, a generator in a constrained market such as New York City could purposely set its offer price high enough that it would not be called on to run. This scheme would create a shortage of generation and, thus, would raise prices for the benefit of the rest of its generation fleet or its financial positions. As withholding is intended to benefit a market participant's overall portfolio, it is similar to cross-product manipulation, discussed above.

Representative Matters

The following representative matters involve at least one of the types of manipulative schemes described above. Each of these matters has either been resolved through settlement or is currently pending before a district court or administrative law judge.

Barclays Bank, PLC, Daniel Brin, Scott Connelly, Karen Levine, and Ryan Smith (Barclays and Traders)

On July 16, 2013, the Commission issued an order determining that Barclays and Traders violated the Commission's Anti-Manipulation Rule and assessed civil penalties of $435 million against Barclays and $18 million against the Traders.[1] The Commission also ordered Barclays to disgorge $34.9 million plus interest in unjust profits. The Commission found that Barclays and Traders engaged in loss-generating trading of next-day, fixed-price physical electricity on the ICE with the intent to benefit financial swap positions at primary electricity trading points in the western United States. In sum, Barclays undertook fixed-price, Day-Ahead physical trades at various Western trading points – tool – to intentionally change the ICE daily index – the target – for the benefit of its financial swap positions whose price was based on that index – the benefiting position.

Barclays and Traders elected to challenge the penalty in federal district court, and Enforcement staff filed an action to affirm the Commission's assessment in the United States District Court for the Eastern District of California on October 9, 2013. The matter is pending before that court.

BP America, Inc. and Affiliates

On August 5, 2013, the Commission issued an order to show cause and notice of proposed penalty to BP.[2] In that proceeding, Enforcement staff alleged that BP made uneconomic sales at Houston Ship Channel and took steps to increase its market share at Houston Ship Channel as part of a manipulative scheme to suppress the Houston Ship Channel Gas Daily index, and that this scheme was motivated by a desire to benefit certain physical and financial positions held by BP whose price was set by the same index. In sum, as cross-product manipulation, Enforcement staff alleged that BP undertook trades at Houston Ship Channel – the tool – with the intent to alter the price of the Houston Ship Channel Gas Daily index - the target – to increase the value of physical and financial positions whose prices were set by the index - the benefiting positions. On May 15, 2014, the Commission set the matter for hearing to determine whether BP's conduct violated the Anti-Manipulation Rule.[3]

Constellation Energy Commodities Group

In 2012, the Commission approved a settlement with Constellation Energy Commodities Group (CCG) in which CCG agreed to disgorge $110 million in unjust profits and pay a civil penalty of $135 million. Enforcement staff had alleged that CCG entered into significant loss-generating physical and virtual day-ahead transactions in electricity markets in and around New York State with the intent to move day-ahead price settlements to benefit financial swap positions that received their prices from those settlements.

1 *Barclays Bank PLC, Daniel Brin, Scott Connelly, Karen Levine, and Ryan Smith*, 144 FERC ¶ 61,041 (2013) (order assessing civil penalties).

2 BP A*merica Inc.,* 144 FERC ¶ 61,100 (2013).

3 *BP America Inc.,* 147 FERC ¶ 61,130 (2014).

Deutsche Bank Energy Trading (Deutsche Bank)

On January 22, 2013, the Commission approved a settlement between the Office of Enforcement and Deutsche Bank, in which Deutsche Bank agreed to disgorge $172,645 in unjust profits and pay a civil penalty of $1.5 million. In the settlement, Enforcement staff concluded that Deutsche Bank violated the Commission's Anti-Manipulation Rule, through cross-product manipulation in which it traded physical exports at Silver Peak that were not profitable with the intent to benefit its Congestion Revenue Rights (CRR) position. Deutsche Bank had a CRR position at the 17-MW Silver Peak intertie that started to lose money. To stem those losses, Deutsche Bank submitted export bids to change the price at Silver Peak, as that price affected the value of Deutsche Bank's CRR position. By changing that price, Deutsche Bank diminished its losses on the CRR position. Deutsche Bank consistently lost money on its export at Silver Peak, but those losses were offset by the avoided losses on its CRR position. In sum, as cross-product manipulation, Deutsche Bank traded physical exports – the tool – to alter the price at the Silver Peak – the target – to diminish its losses on its CRR position – the benefiting position.

ISO-NE Day-Ahead Load Response Program (DALRP)

Based on an Enforcement investigation of Rumford Paper Company (Rumford), Lincoln Paper and Tissue LLC (Lincoln), Competitive Energy Services, LLC (CES), and Richard Silkman, the Commission in July 2012 issued each subject an order to show cause alleging that their conduct related to the DALRP in the ISO New England market (ISO-NE) violated the Commission's Anti-Manipulation Rule. The Office of Enforcement and Rumford settled the allegations against the company, which the Commission approved in March 2013.[4] On August 29, 2013, the Commission issued Orders Assessing Civil Penalties to Lincoln, CES, and Silkman, finding that the subjects fraudulently inflated load baselines and repeatedly offered load reductions at the minimum offer price in order to maintain the inflated baseline.[5] Enforcement staff found that the scheme involved uneconomic energy purchases that served no legitimate purpose and were designed to increase DALRP payments that would not have otherwise been obtained. The Commission determined that this scheme misled ISO-NE, inducing payments to these entities based on the inflated baselines for load reductions that never occurred.

The Commission ordered Lincoln to pay $5 million in civil penalties and approximately $379,000 in disgorgement; CES to pay $7.5 million in civil penalties and approximately $167,000 in disgorgement; and Silkman to pay $1.25 million in civil penalties. None of the respondents paid the amounts assessed by the Commission. Enforcement staff filed two petitions in the United States District Court for the District of Massachusetts on December 2, 2013 seeking review and affirmance of the Commission's orders. These petitions are pending.

4 *Rumford Paper Co.*, 142 FERC ¶ 61,218 (2013) (order approving stipulation and consent agreement).

5 *Lincoln Paper and Tissue, LLC*, 144 FERC ¶ 61,162 (2013) (order assessing civil penalty); *Competitive Energy Services, LLC*, 144 FERC ¶ 61,163 (2013) (order assessing civil penalty); *Richard Silkman*, 144 FERC ¶ 61,164 (2013) (order assessing civil penalty).

JP Morgan Ventures Energy Corporation (JPMVEC)

On July 30, 2013, the Commission approved a settlement between the Office of Enforcement and JPMVEC resolving an investigation of JPMVEC's bidding practices.6 JPMVEC paid $285 million in civil penalties, $124 million in disgorgement to CAISO ratepayers, and $1 million in disgorgement to MISO. In addition, the company agreed to waive its claims that CAISO owed it money from two of the strategies that Enforcement staff had investigated, and to conduct a comprehensive external assessment of its policies and practices in the power business.

Enforcement staff determined that JPMVEC violated the Commission's Anti-Manipulation Rule by engaging in twelve manipulative bidding schemes in CAISO and MISO. These schemes distorted a well-functioning market in several ways, including but not limited to, misleading CAISO and MISO into paying JPMVEC at rates far above market prices; submitting bids that were expected to, and did, lose money at market rates, as they were not driven by the market forces of supply and demand; defrauding the ISOs by obtaining payments for benefits that JPMVEC did not deliver; and displacing other generation and influencing energy and congestion prices.

6 *In Re Make-Whole Payments and Related Bidding Strategies,* 144 FERC ¶ 61,068 (2013).

Louis Dreyfus Energy Services L.P. (Louis Dreyfus)

On February 7, 2014, the Commission approved a settlement between the Office of Enforcement, Louis Dreyfus, and one of its traders, Xu Cheng.7 Under the terms of the settlement, Louis Dreyfus agreed to disgorge $3,334,000 in unjust earnings, plus interest, and pay a civil penalty of $4,072,257. Cheng, who had previously crafted and described the manipulative scheme in his doctoral dissertation, agreed to pay a civil penalty of $310,000. In addition, Louis Dreyfus prohibited Cheng from virtual trading anywhere in the United States, and agreed that he would not be permitted to resume such trading for at least two years.

In the settlement, Enforcement staff concluded that Louis Dreyfus violated the Commission's Anti-Manipulation Rule when it made certain virtual trades in MISO with the intent to increase the value of its nearby FTR position. Louis Dreyfus established an FTR position near the Velva node. Louis Dreyfus earned little or no profit on that FTR position, until it started to place virtual demand bids at the Velva node to benefit the FTR position. Louis Dreyfus consistently lost money on those virtual demand bids, but that loss was offset on its gains on its FTR position. In sum, as cross-product manipulation, Louis Dreyfus submitted virtual demand bids – the tool – to alter the price at the Velva node – the target – to increase the value of its FTR position – the benefiting position.

7 *MISO Virtual and FTR Trading (Louis Dreyfus Energy Services),* 146 FERC ¶ 61,072 (2014).

Capacity Markets
Wholesale Market Regions
Market Pricing
Electric Power
Natural Gas
Weather
Transmission Organization
Market Trading
Supply & Delivery

Energy Primer

A Handbook of Energy Market Basics

Federal Energy Regulatory Commission | www.FERC.gov
888 First Street, NE Washington D.C. 20426

Status of Restructuring: Wholesale and Retail Markets

PRESENTED TO

National Conference of State Legislatures

PRESENTED BY

Sanem Sergici, Ph.D.

June 26, 2018

THE Brattle GROUP

The views expressed in this presentation are strictly those of the presenter and do not necessarily state or reflect the views of *The Brattle Group, Inc*.

Agenda

Status of Restructured Wholesale Electricity Markets

- Overview and verdict
- Are the markets functioning?

Status of Restructured Retail Electricity Markets

- Challenges Faced by Retail Choice
- Importance of Retail Choice
- What Can Be Changed?

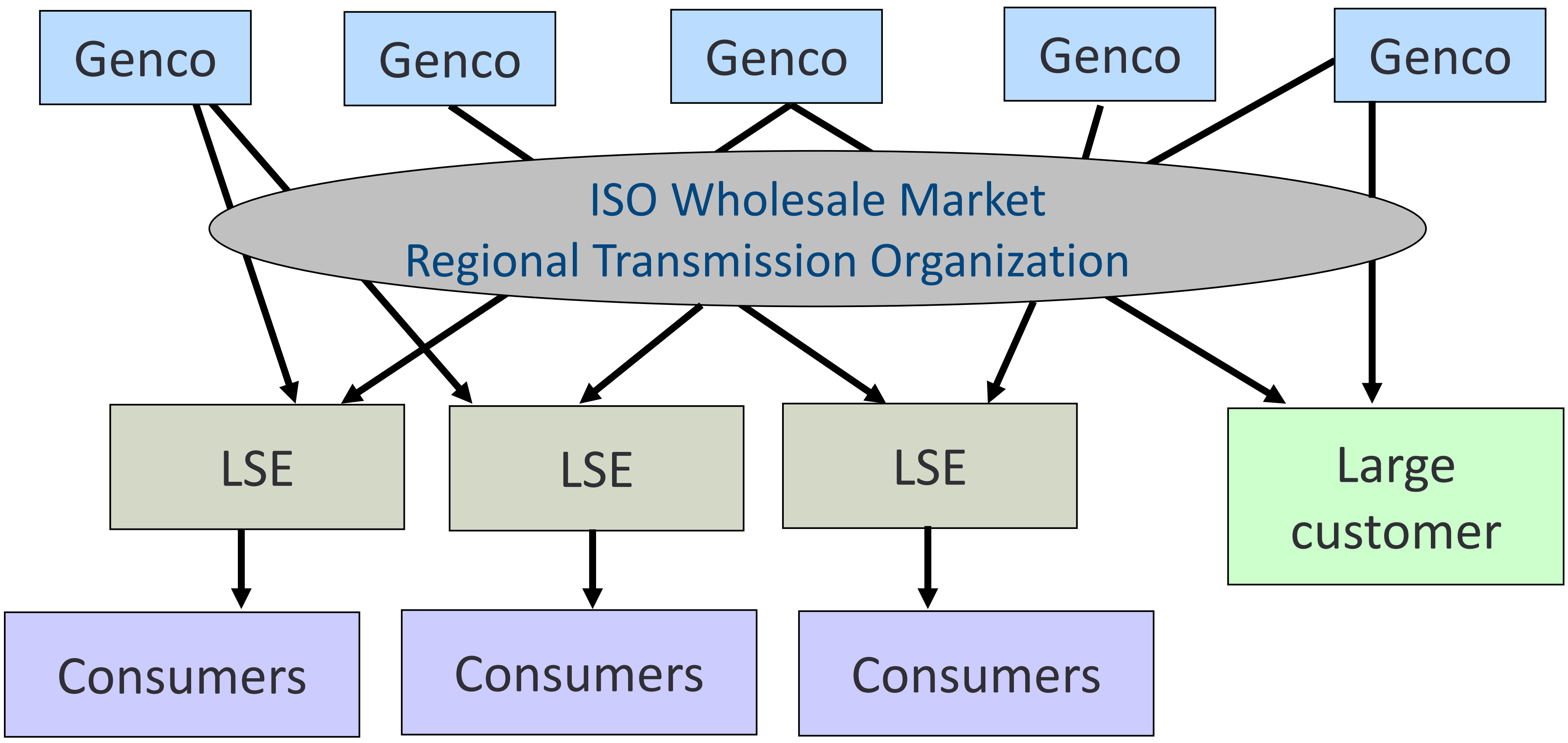
Restructured Markets - Wholesale

Restructured Markets – Regional transmission organizations (RTOs)

- Aggregated transmission system operated by independent system operator (ISO) whose primary functions are to provide open access to the transmission system and balance supply and demand
  - Utilities retain transmission ownership, obligations for maintenance, expansion
  - Federal Energy Regulatory Commission (FERC) sets RTO’s rate and regulates
- Generation competitively bid into market
  - Some utilities have retained generation ownership
  - New entrants
  - Very loosely regulated by FERC
- Residual traditional utility, now known as Local Distribution Company (LDC), operates and maintains the wires and delivery service to retail customers
  - Under wholesale competition as vertically integrated company
    - Retains supplier role, purchasing on behalf of customers
  - Under retail competition
    - Organizes procurement of residual obligations, called Provider of Last Resort (POLR), via RFPs or auctions
  - In both approaches, performance overseen by state public utility commissions

Restructured Markets - Wholesale

Wholesale Competition- Centralized Market Design



The Verdict on Wholesale Restructuring

While many details of market design remain contested, there is broad consensus on the benefits of restructured wholesale power markets from their scale (diversity), pooled dispatch, marginal cost pricing, and coordinated transmission planning. For example:

- Southwest Power Pool (SPP) and other RTO/ISO benefit studies show generation **fuel-cost savings** of 3-8%
- Midcontinent ISO (MISO): load and variable generation diversity in larger regional footprint offers $1.2-1.8 billion in annual generation-related **investment-cost savings**
- Expanding Energy Imbalance Market (EIM) in the western U.S. has shown to significantly reduce the **cost of balancing** variable renewable generation
- Regional wholesale power markets have shown to accelerate growth of **demand response** and greatly facilitate **renewable generation investment** in wind-rich states
- Improved transmission access and regional planning for a larger footprint reduces the cost of achieving **state policy objectives**

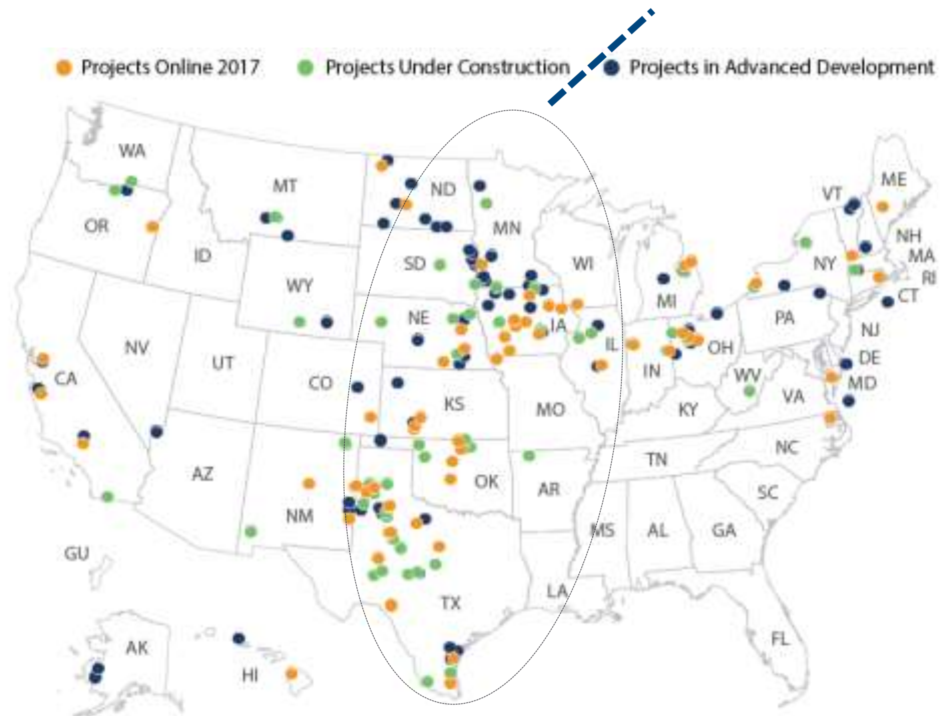
Example: Wind Investments in RTO/ISO Markets

RTO/ISO markets account for most of recent renewable generation development

- Majority of 2017 wind additions (shown on map) are in areas that offer both favorable wind conditions and RTO membership:
  - The 7 states with the most wind generation are all in RTO/ISO markets (ERCOT, SPP, MISO)
  - Less development in similarly wind-rich areas without ISO/RTO markets (e.g., WY, CO, MT, NM)
- The RTO advantages are price visibility, liquidity, and ability to hedge

Wind Generation Projects Online & Under Construction in 2017

ERCOT, SPP, MISO



Source: AWEA, “U.S. Wind Industry Fourth Quarter 2017 Market Report,” American Wind Energy Association, January 25, 2018.

What are some allegations about wholesale power markets failing?

Increasingly frequent debates over whether existing power markets should:

- Guard against early retirements of baseload coal and nuclear plants
- Provide incentives for a significant degree of fuel diversity
- Support certain States' public policy choices, e.g. re local job retention or environmental policy goals

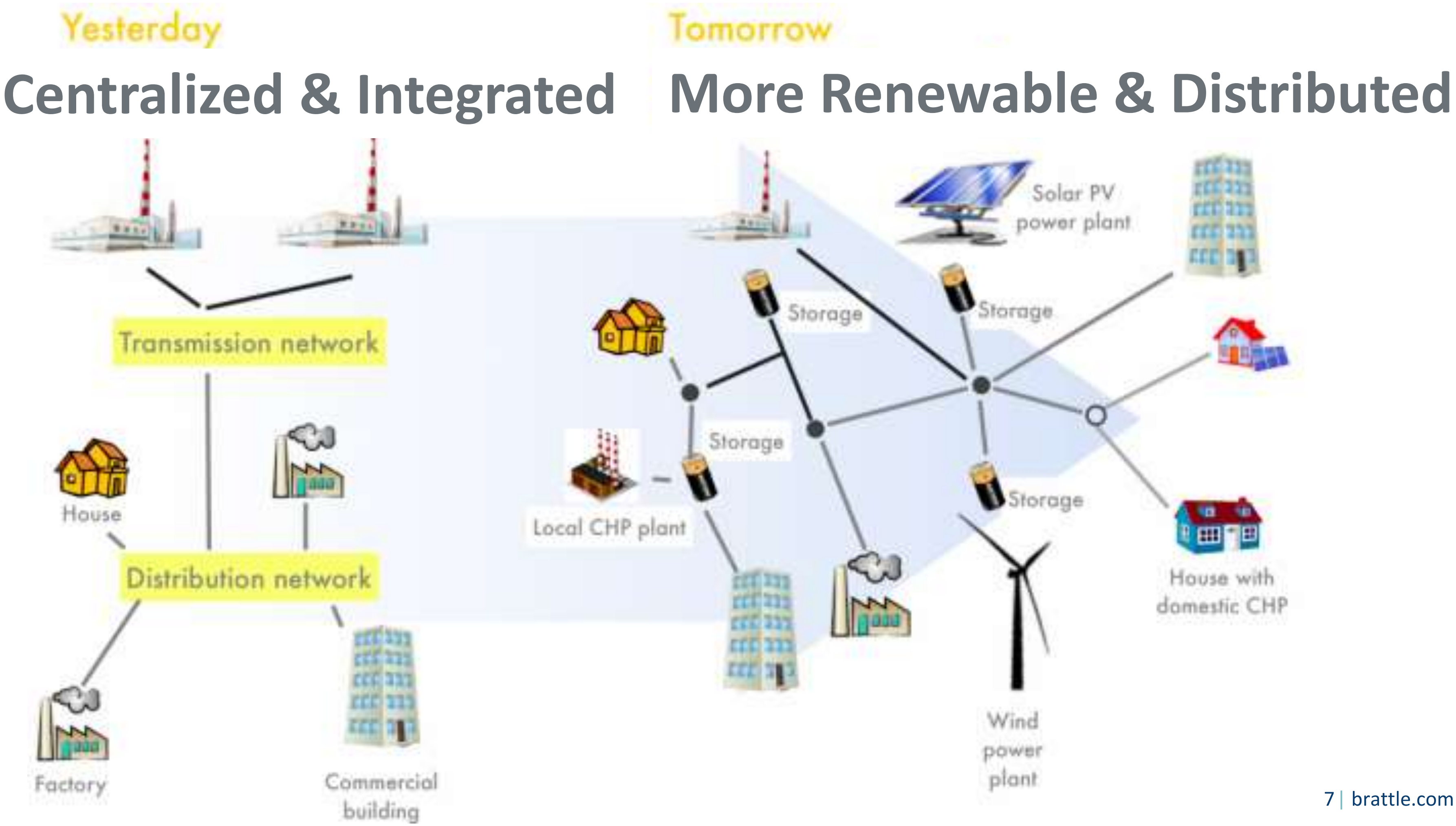
Many of these are concerns that have not been demonstrated to be economical, or that can be better achieved through other mechanisms without overriding or distorting competitive market operations.

RTO markets have mostly achieved their goals of economical and reliable power supply. However, revenue/value sources of resources will shift over time even in well-designed wholesale power markets

1. Average energy prices ↓
2. Scarcity pricing ↑
3. Flexibility and reserves ↑
4. Capacity markets/resource adequacy ?
5. Clean energy attributes (where exist) ↑
6. Trade and diversification across market seams ↑

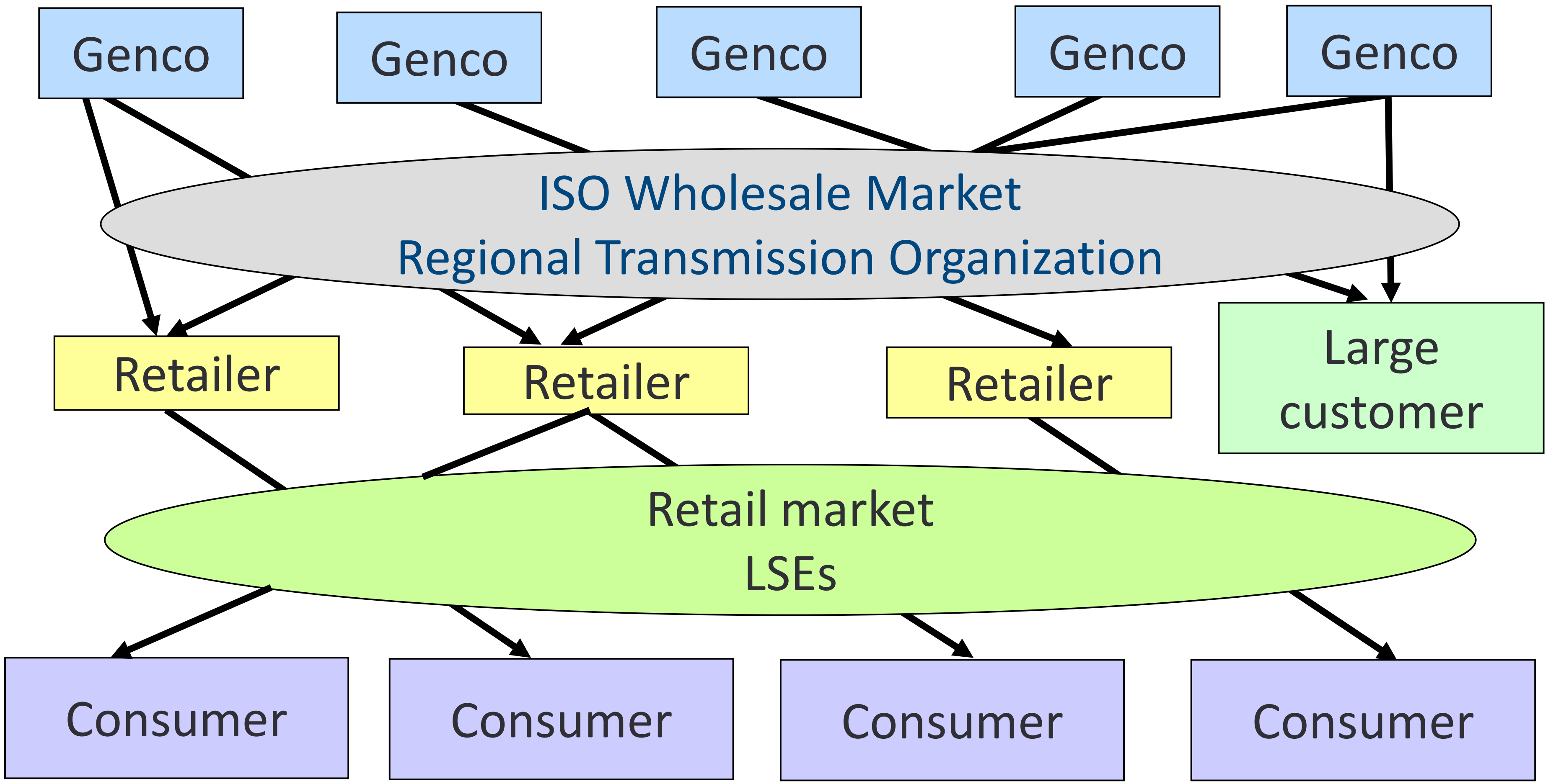
Electricity Market Restructuring: Where Are We Going?

Fundamental changes in technologies and consumer preferences will drive the need for continuous evolutions in wholesale and retail market designs



Restructured Markets with Retail Competition

Centralized Wholesale Market/ Decentralized Retail Market



Standardizing Some Terminology

Retail Electric Provider (“REP”) = ESCO, Retail Supplier, etc. who procure power from wholesale market for resale to end-use customers choosing a competitive supplier

Default Service (“Default”) = Standard Offer, Provider of Last Resort (POLR), Price to Beat, PUC Offer, etc. (any required backstop alternative for non-shopping or transitional customers)

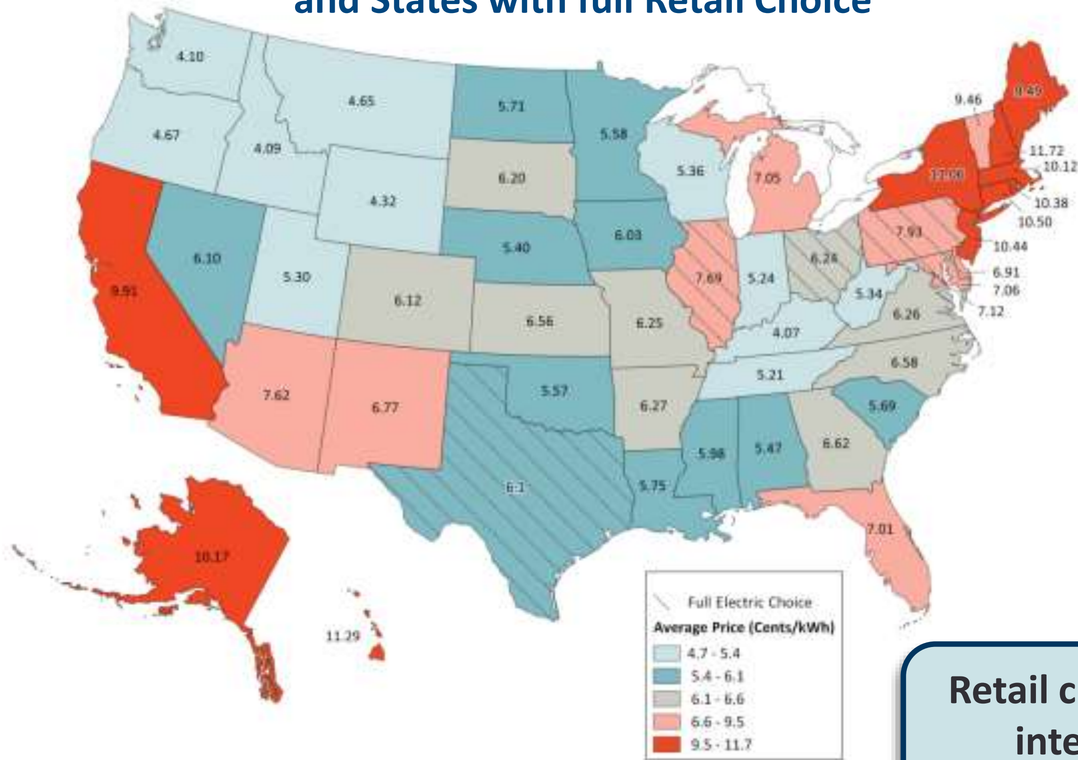
CCA = Community Choice Aggregation, or any form of opt-out municipal retail supply service

DERs = Distributed Energy Resources, i.e. customer-premise equipment to manage energy supply or use

Inception of Retail Electric Choice

From the mid-1990s through the early 2000s, several states liberalized electric markets to allow for retail electric choice

Average 1995 Retail Prices of Electricity by State (cents/kWh) and States with full Retail Choice



- The goal was to reduce consumers' electricity bills and substitute competition for regulation
- Typically states that had highest retail electricity rates in the mid-1990's were the states that implemented retail choice
- States also hoped to foster service innovations, including:
  - Billing Options
  - Hedging
  - Access to Renewable Energy

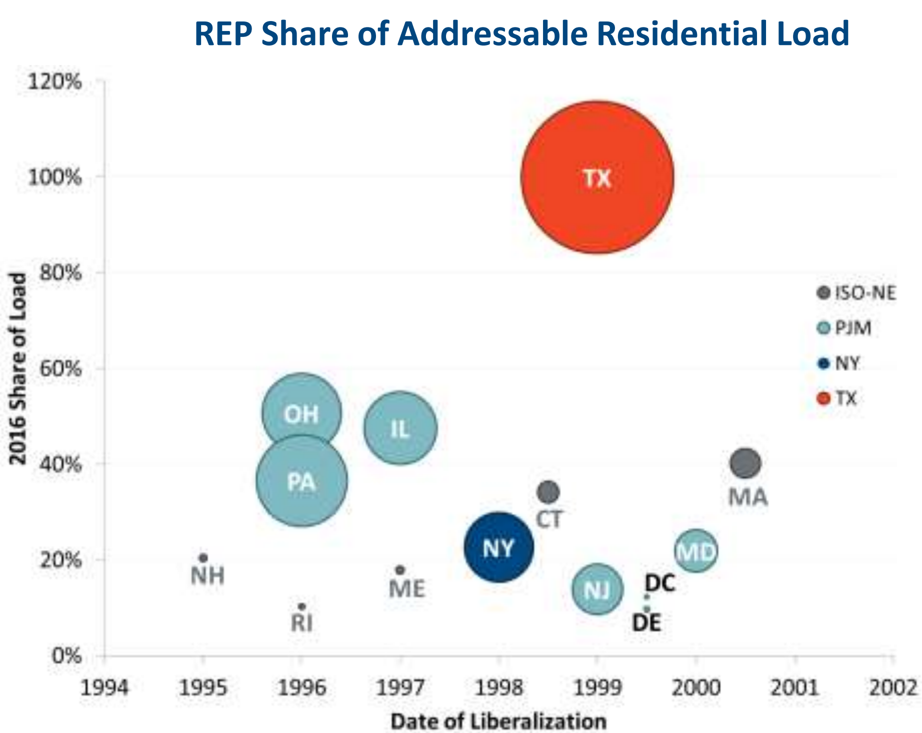
Retail choice is now facing a resurgence of interest in some states while being criticized and restricted in others.

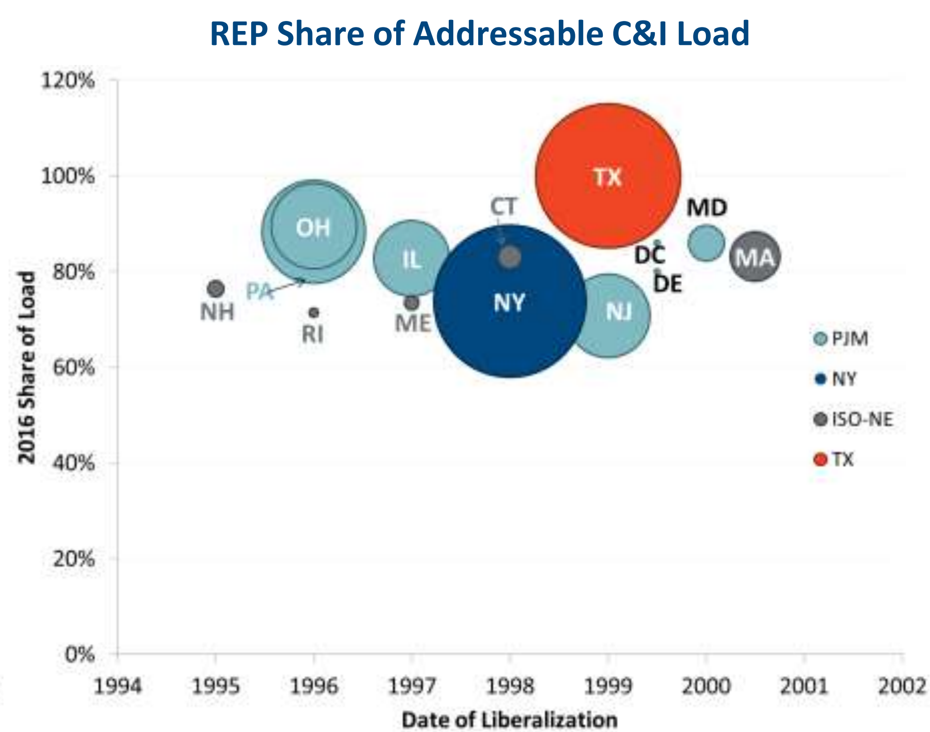
Sources:
EIA, "Detailed State Data," https://www.eia.gov/electricity/data/state/.
Brattle Analysis.

Current Participation in Retail Electric Choice

In the 13 states (and D.C.) with retail choice, 10-50% of residential and 50-75% of commercial and industrial (C&I) total eligible load are served by Retail Energy Providers (REPs)

- In Texas where there is no Default service, REPs serve 100% of both residential and C&I load





Notes:
[1]: Partial competition states are not included.
[2]: Diameter of circles reflects number of "addressable" customers in 2016.

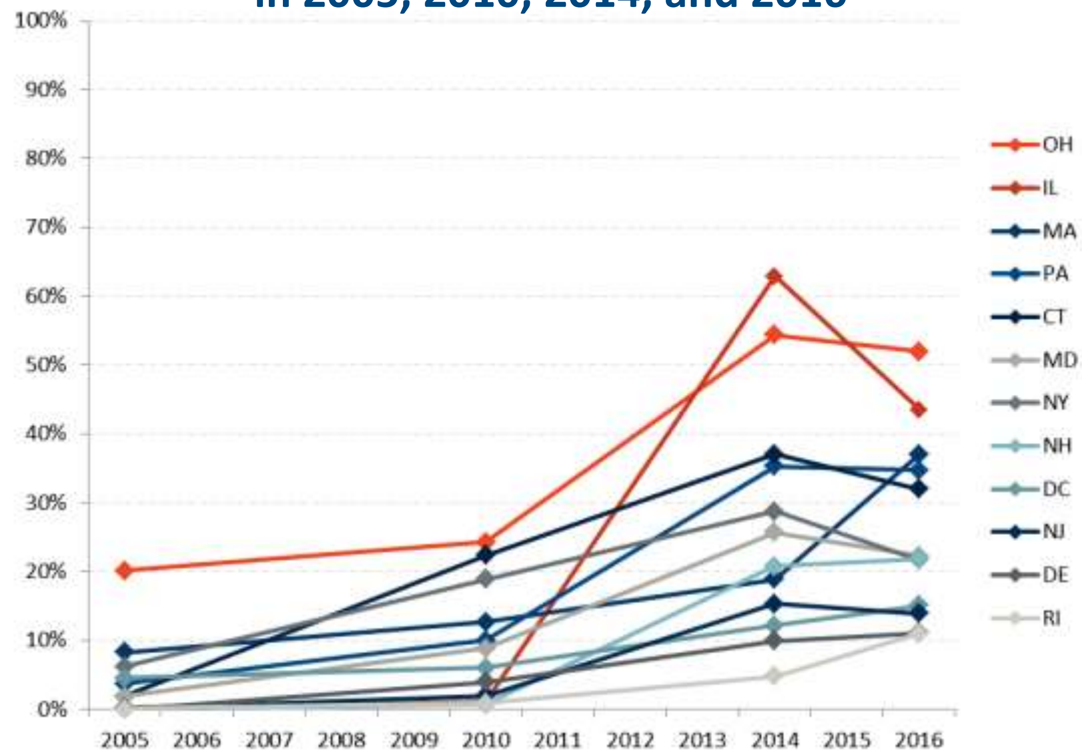
Sources: The Brattle Group and US Energy Information (EIA).

Trends in Retail Electric Choice

REPs have increased their market share in all states since 2007

- C&I customers quickly adopted retail choice as it was approved; residential adoption was slower
- Recent increases in OH, IL, and MA are attributable to Community Choice Aggregation programs*
- REP market share slightly declined in several states after the Polar Vortex in 2014

REP Share of Addressable Market in 2005, 2010, 2014, and 2016



Sources: The Brattle Group, US Energy Information Administration (EIA), Maine Public Utilities Commission

Notes:

[1] ME uses data published by the state PUC, due to anomalies in the EIA data

[2] Based on state rules addressable customers do not include customers on municipal, co-op, or state/federal agency service

[3] Texas is excluded from the figure. Texas REPs serve 100% of addressable customers

Source: *LEAN Energy, "CCA by State," http://www.leanenergyus.org/cca-by-state/.

Increased Scrutiny from State Regulators

A few state attorneys general have taken the position that retail choice is harming residential customers and have recommended ending REP service to these customers

New York

The retail choice market has been under review since 2012.

REPS were restricted from serving low income customers in December 2016. Ongoing case by NY AG looking to restrict REP service to all residential customers

Massachusetts

In March 2018, the AG published a report which criticizes retail choice and recommends eliminating REP service to all residential customers

Sources: See appendix.

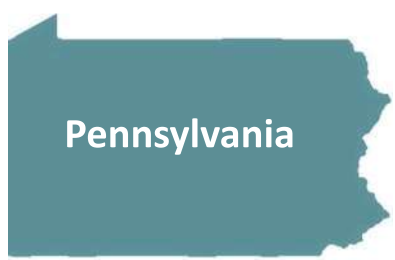
Enforcement against Deceptive Practices

Several additional state attorneys general have taken enforcement action against specific REPs for deceptive marketing practices and misleading customers

AG files lawsuits against REPs for misleading customers in 2016, 2017, and 2018

Customers file lawsuit against REPs in 2017 for colluding with each other to raise rates

REP pays $5.2 million to settle lawsuit in 2016 for deceptive marketing



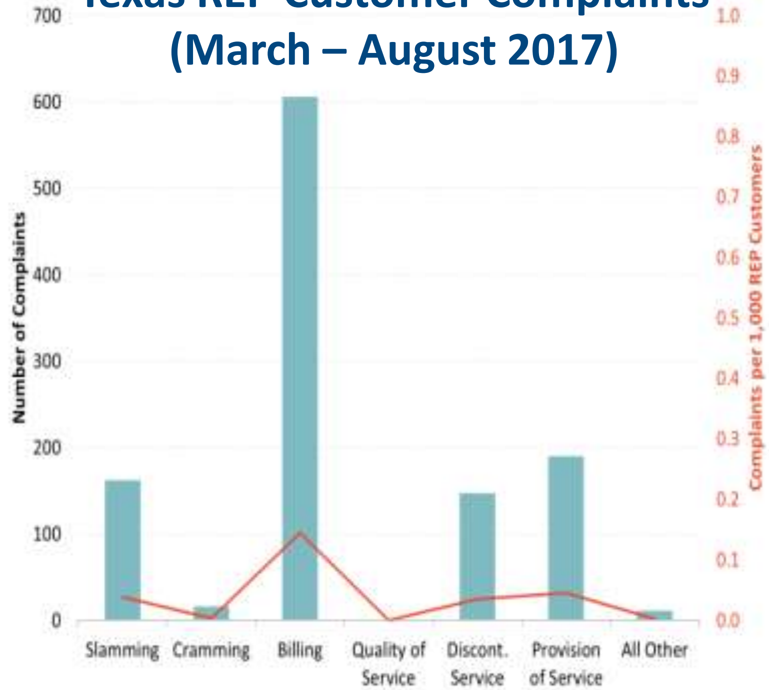
REP settles for $2.1 million for allegations made by AG in 2015 for malicious marketing practices

Sources: See appendix.

Deciphering Substance of Complaints

Based on reporting by the few states that track complaints, the majority of customer complaints center on billing issues.

Texas REP Customer Complaints (March – August 2017)



- Complexity or ambiguity in contract terms makes pricing difficult to understand

- Market complexity also makes evaluating performance and identifying the root cause of complaints difficult

Sources:
Public Utility Commission of Texas, "Customer Complaint Statistics, https://www.puc.texas.gov/consumer/electricity/CustomerComplaintStats.aspx.
Public Utility Commission of Texas, "June 2017 Report Card on Retail Competition and Summary of Market Share Data," https://www.puc.texas.gov/consumer/electricity/CustomerComplaintStats.aspx.
Notes:
Customer complaint data is from 3/1/2017 - 8/31/2017 and number of REP customers as of June 2017.

Recap of the Issues

While there is generally agreement that Retail Choice is working for C&I customers, there is controversy around the success of, and appropriate design for, mass market services

- Some of this controversy is shaped by political views of regulation rather than by empirical economic analysis – Texas model vs. Massachusetts (or NY, etc.)
  - Many market performance analyses and commentaries are either informal, anecdotal, or rely on imprecise metrics
- The wide variety of frameworks for Retail Choice across states make performance analyses very difficult. Significant differences include:
  - Definition of Default Service – fall-back or competitive alternative?
  - Procurement for Default Service -- auctions and RFPs, utility served, various horizons
  - Quality of available customer information – Power to Choose, but very different content
  - REP versus utility relationship with the customer
  - Nature of the upstream wholesale market – one-part pricing, capacity products, …
- New statistical and behavioral studies of comparative mass market Retail Choice performance could control for these differences.

It is very likely that there is room for improvements that would enhance the market for REPs and customers while also reassuring regulators and AGs that customers are protected.

Importance of Retail Choice:
Market Innovations by REPs

REPs are innovating the market for electricity in the following ways, but adoption has been slow:

Green Power:

- In 2015, 20% of green power sold to electricity customers was a result of retail choice
- REPs offer other eco-conscious products to green customers (energy audits, home protection, carbon offsets, demand response programs)

Non-Traditional Price Structures:

- Price risk management, flat monthly billing, free night usage, and various promotions and discounts are utilized by REPs
- 4Change Energy and Gexa Energy allocate a portion of profits to charitable organizations

Bundled Services:

- Several REPs offer home automation devices in conjunction with home automation devices
- In Texas, Reliant Energy sells home security along with its energy offerings
- NRG partnered with Comcast in pilot bundling energy and broadcast service in Pennsylvania

"Retail environments are encouraging energy players and other consumer-facing customers to get creative." - Katherine Tweed, Senior Writer at Green Tech Media

"Leading utilities are looking at how to make money from self-consumption service offerings, **not just the sale of more electrons**"- Green Tech Media*

"I come from the electric industry and there is a common wisdom there that people don't really care about energy, **they only care about cheap energy** and **being there when they need it**. I now understand **this assumption is wrong**."
- Scott Kessler, Director of Business Development at LO3 Energy*

* Emphasis added.
Sources: See appendix.

Importance of Retail Choice:
Future of Distributed Energy Resources

A part of the vision for the Distributed Energy Resources (DER) revolution is allowing electricity transactions between third-parties; retail choice may provide a framework.

- Existing REPs can become agents offering DER improvements, or new companies can enter the REP market with creative new offerings
- Potential offerings tied to energy pricing, include:
  - DERs that cause load flattening or peak shifting for better terms of energy prices or reducing capacity requirements
  - Facilitating customer-to-customer or customer-to-generator transactions via REP-hosted DER aggregation and use-scheduling
- The necessary customization of these offerings will require sophisticated REPs who are able to credibly describe and appropriately account for upfront costs versus long-term savings to customers
  - Additional rules and regulations for these REPs and DER packages may be required until the mass market becomes familiar and competitive with these innovations

What Could Be Changed?
Possible Redesigns to Improve Choice

Customer protection

- Better contract comparison tools/info (beyond Power to Choose websites)?
- Standardized REP contracts (c.f. , ARM mortgages with stated indices and caps on movement)?
- Requirements to guarantee benefits or demonstrate innovation?

Design of POLR/Default Service

- High-cost fallback only, or competitive alternative?
- LMP-only to allow risk management by REPs?
- *May require metrics for monitoring quality of REP competition* – none in place today

Customer Relation

- REPs hold customer relation rather than utilities (billing, receivables' risk,…)?

Community Choice Aggregation (CCA)

- How can stranded costs be assigned? Obligation to serve? Can communities return later?

Choice in non-RTO regions

- <u>Much</u> more difficult to administer because of lack of FTRs and capacity markets

Conclusions

Retail Choice has had mixed success – Attractive to C&I customers who have the sophistication to evaluate and utilize it, while sometimes vulnerable to abuse for mass market customers.

- A few "bad apples" may be spoiling the barrel via slamming, obscure contracts, unreasonable fly-up pricing, etc.
- There are few empirical studies evaluating retail choice that fully correct for design differences across areas or that capture the value or fair cost of all REP services
- POLR, though protective for customers, can also be part of the problem; its design has not been fully harmonized with fostering competitive retail markets
- REPs may be needed as key players in facilitating DER adoption and future improvements in retail energy usage.

It is likely there are new positions on POLR design, product disclosure, and consumer protection that can make retail choice better.

Presenter Information

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Dr. Sanem Sergici is a Principal in The Brattle Group's Boston, MA office specializing in program design, evaluation, and big data analytics in the areas of energy efficiency, demand response, smart grid and innovative pricing. She regularly supports electric utilities, regulators, law firms, and technology firms in their strategic and regulatory questions related to retail rate design and grid modernization investments.

Dr. Sergici has been at the forefront of the design and impact analysis of innovative retail pricing, enabling technology, and behavior-based energy efficiency pilots and programs in North America. She has led numerous studies in these areas that were instrumental in regulatory approvals of Advanced Metering Infrastructure (AMI) investments and smart rate offerings for electricity customers. She also has significant expertise in development of load forecasting models; ratemaking for electric utilities; and energy litigation. Most recently, in the context of the New York Reforming the Energy Vision (NYREV) Initiative, Dr. Sergici studied the incentives required for and the impacts of incorporating large quantities of Distributed Energy Resources (DERs) including energy efficiency, demand response, and solar PVs in New York.

Dr. Sergici is a frequent presenter on the economic analysis of DERs and regularly publishes in academic and industry journals. She received her Ph.D. in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her M.A. in Economics from Northeastern University, and B.S. in Economics from Middle East Technical University (METU), Ankara, Turkey.

About The Brattle Group

The Brattle Group provides consulting and expert testimony in economics, finance, and regulation to corporations, law firms, and governmental agencies worldwide.

We combine in-depth industry experience and rigorous analyses to help clients answer complex economic and financial questions in litigation and regulation, develop strategies for changing markets, and make critical business decisions.

Our services to the electric power industry include:

- Climate Change Policy and Planning
- Cost of Capital
- Demand Forecasting Methodology
- Demand Response and Energy Efficiency
- Electricity Market Modeling
- Energy Asset Valuation
- Energy Contract Litigation
- Environmental Compliance
- Fuel and Power Procurement
- Incentive Regulation
- Rate Design and Cost Allocation
- Regulatory Strategy and Litigation Support
- Renewables
- Resource Planning
- Retail Access and Restructuring
- Risk Management
- Market-Based Rates
- Market Design and Competitive Analysis
- Mergers and Acquisitions
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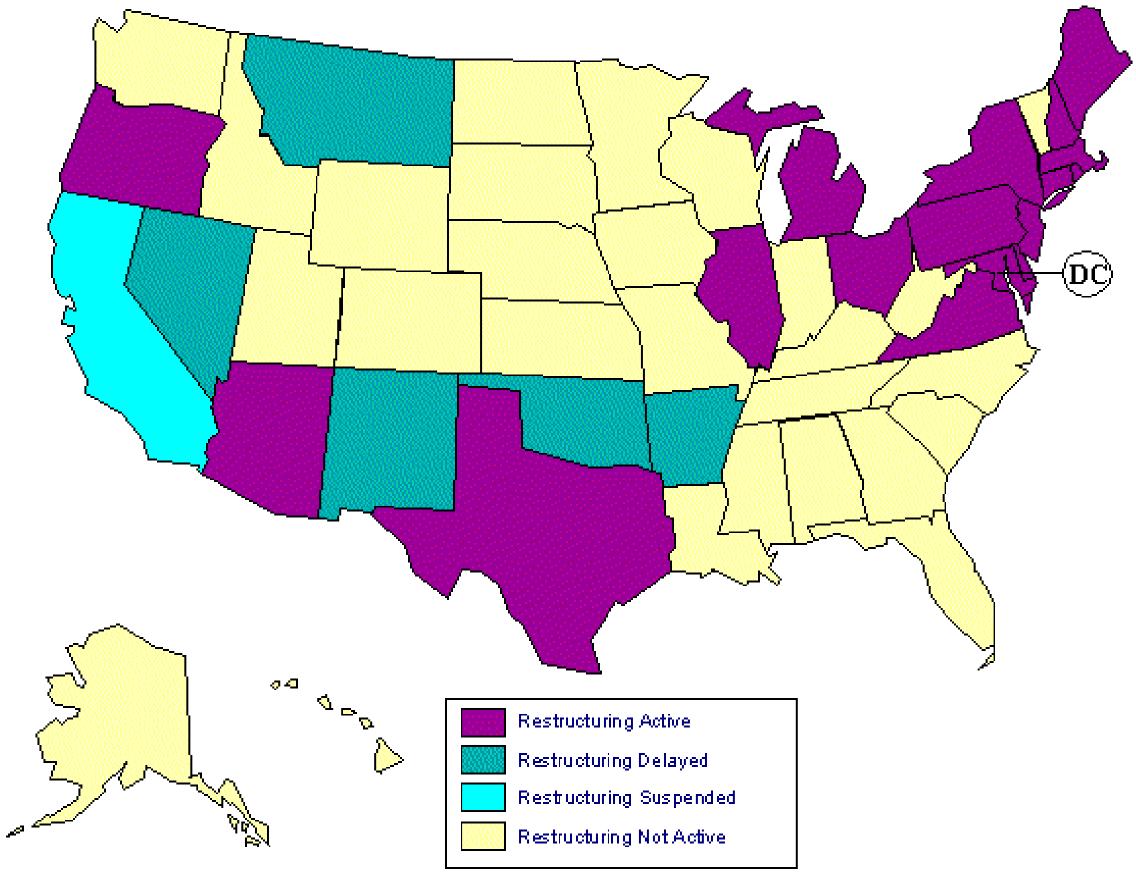
Status of State Electric Industry Restructuring Activity
-- as of February 2003 --

(February 2003 was the last update. No further updates are currently planned)

Retail Access Timeline Customer Participation in Retail Access	(Click on a State below to see Current Restructuring Status)	Status of State Restructuring Activity Table



Alabama	Alaska	Arizona	Arkansas	California	Colorado
Connecticut	Delaware	District of Columbia	Florida	Georgia	Hawaii
Idaho	Illinois	Indiana	Iowa	Kansas	Kentucky
Louisiana	Maine	Maryland	Massachusetts	Michigan	Minnesota
Mississippi	Missouri	Montana	Nebraska	Nevada	New Hampshire
New Jersey	New Mexico	New York	North Carolina	North Dakota	Ohio
Oklahoma	Oregon	Pennsylvania	Rhode Island	South Carolina	South Dakota
Tennessee	Texas	Utah	Vermont	Virginia	Washington
West Virginia	Wisconsin	Wyoming			

Source: US Energy Information Administration, http://large.stanford.edu/publications/coal/references/docs/restructure.pdf, accessed 2/14/2019.

This site provides an overview of the status of electric industry restructuring in each state. Twenty-four states and the District of Columbia have either enacted enabling legislation or issued a regulatory order to implement retail access. The local distribution company continues to provide transmission and distribution (delivery of energy) services. Retail access allows customers to choose their own supplier of generation energy services, but each state's retail access schedule varies according to the legislative mandates or regulatory orders. The information in the "Status of State Electric Industry Restructuring Activity Map" was gathered from state public utility commissions, state legislatures, and utility company web pages.

The state activity map is coded by color to indicate each state's restructuring progress. Purple colored states are active in the restructuring process, and these states have either enacted enabling legislation or issued a regulatory order to implement retail access. Retail access is either currently available to all or some customers or will soon be available. Those states are Arizona, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia. In Oregon, no customers are currently participating in the State's retail access program, but the law allows nonresidential customers access. Yellow colored states are not actively pursuing restructuring. Those states are Alabama, Alaska, Colorado, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, West Virginia, Wisconsin, and Wyoming. In West Virginia, the Legislature and Governor have not approved the Public Service Commission's restructuring plan, authorized by HB 4277. The Legislature has not passed a resolution resolving the tax issues of the PSC's plan, and no activity has occurred since early in 2001. A green colored state signifies a delay in the restructuring process or the implementation of retail access. Those states are Arkansas, Montana, Nevada, New Mexico, and Oklahoma. California is the only blue colored state because direct retail access has been suspended.

Each state has a link to several tables dedicated to summarizing regulatory orders, legislation, investigative studies, retail access, stranded costs, public benefits programs, pilot programs, and any additional information. The information is updated on a monthly basis, and gathered from a variety of sources including the state legislatures, public utility commissions, state energy commissions, Office of the Governor, and news agencies.

Source: Energy Information Administration.

CONTACT
Ms. Channele Carner
Email: channele.carner@eia.doe.gov
Phone: (202) 287-1928

Status of State Electric Industry Restructuring Activity

Timeline as of February 2003

State	Legislative Enactment/ Regulatory Order*	Access for Residential Customers	Access for Commercial and Industrial Customers	Full Retail Access for All Customers	Comments
Arizona [1]	House Bill 2663 (5/29/98) and Regulatory Settlement Orders	December 1998	December 1998	January 1, 2001	
Arkansas	Senate Bill 236 (2/20/01)	October 1, 2003	October 1, 2003	October 1, 2005	Rescheduled from original start date of October 2002
California [2]	Assembly Bill 1890 (9/23/96)	March 31, 1998	March 31, 1998	March 31, 1998	Initially, retail access was due to start on January 1, 1998, but was delayed until March 31, 1998. On September 20, 2001, the provisions of AB 1890 concerning retail access were suspended.
Connecticut [3]	House Bill 5005 (4/29/98)	January 1, 2000	January 1, 2000	July 1, 2000	
Delaware [4]	House Bill 10 (3/31/99)	October 1, 2000	October 1, 1999	April 1, 2001	
District of Columbia	PSC Order 11796 (9/18/00)	January 1, 2001	January 1, 2001	January 1, 2001	
Illinois	House Bill 362 (12/16/97) and Senate Bill 24 (6/30/99)	May 1, 2002	October 1, 1999	May 1, 2002	HB 362 provides for retail access, but SB 24 extends the effective implementation date.
Maine	Legislative Directive 1804 (5/29/97)	March 1, 2000	March 1, 2000	March 1, 2000	
Maryland	Senate Bill 300 (4/8/99)	July 1, 2000	July 1, 2000	July 1, 2002	
Massachusetts	House Bill 5117 (11/25/97)	March 1, 1998	March 1, 1998	March 1, 1998	
Michigan [5]	Senate Bills 937 and 1253 (6/3/00) and Regulatory Settlement Orders	January 1, 2002	January 1, 2002	January 1, 2002	

Montana	Senate Bill 390 (5/2/97)	July 1, 2004	July 1, 2004	July 1, 2004	Under SB 390, retail access was to be fully implemented by July 1, 2002. It has since been rescheduled until July 1, 2004.
Nevada	Assembly Bills 366 (7/16/97), 369 (4/18/01), and 661 (7/17/01)	Not Permitted Under Law	Between April 2002 and June 2002	Mid-2002 for Commercial and Industrial Customers Only	AB 369 suspended the provisions of AB 366 indefintely for residential customers, and AB 661 allowed large commercial and industrial consumer access in mid-2002.
New Hampshire [6]	House Bill 1392 (5/21/96), PUC Orders (2/28/97), Senate Bill 472 (5/17/00), PUC Orders (9/8/00)	July 1, 1998 to May 1, 2001	July 1, 1998 to May 1, 2001	May 1, 2001	There were legal impediments which delayed the process.
New Jersey	Assembly Bill 10/Senate Bill 5 (2/9/99) and BPU Order (7/7/99)	November 14, 1999	November 14, 1999	November 14, 1999	Procedural issues delayed implementation from the original start date of August 1, 1999.
New Mexico	Senate Bill 428 (4/8/99) and Senate Bill 266 (3/8/01)	January 1, 2007	July 1, 2008	July 1, 2008	SB 266 delayed the provisions of SB 428 until January 1, 2007 and July 1, 2008.
New York	PSC Order (5/20/96)	May 1, 1998 to July 1, 2001	May 1, 1998 to July 1, 2001	July 1, 2001	Implementation varies for each investor-owned utility.
Ohio	Senate Bill 3 (7/6/99)	January 1, 2001	January 1, 2001	January 1, 2001	
Oklahoma	Senate Bill 500 (4/25/97) and Senate Bill 440 (5/22/01)	Implementation Delayed Indefinitely	Implementation Delayed Indefinitely	Implementation Delayed Indefinitely	SB 440 delays the provisions of SB 500 indefinitely. Under SB 500, retail access would have begun on July 1, 2002.
Oregon	Senate Bill 1149 (7/23/99) and PUC Order (8/29/00) and House Bill 3633 (6/21/01)	Not Permitted Under Law	March 1, 2002	March 1, 2002 for Commercial and Industrial Customers Only	HB 3633 delayed the provisions of SB 1149 and the PUC order implementing retail access from October 1, 2001 until March 1, 2002. Subject to some reservations.
Pennsylvania	House Bill 1509 (12/3/96)	January 1, 1999	January 1, 1999	January 1, 2000	

Rhode Island	House Bill 8124 (8/7/96)	July 1, 1997	July 1, 1997	January 1, 1998	
Texas	Senate Bill 7 (5/27/99)	July 31, 2001	July 31, 2001	January 1, 2002	The pilot program was delayed from its original start date of June 1, 2001 to allow the Electric Reliability Council of Texas time to complete its operational procedures.
Virginia	Senate Bill 1269 (7/1/99)	January 1, 2002 - January 1, 2004	January 1, 2002 - January 1, 2004	January 1, 2004	
West Virginia [7]	House Bill 4277 (3/14/98) and PSC Plan (12/20/99)	The West Virginia Legislature has not passed necessary legislation to implement retail access	The West Virginia Legislature has not passed necessary legislation to implement retail access	The West Virginia Legislature has not passed necessary legislation to implement retail access	HB 4277 authorized the PSC to submit a plan for the legislature's approval. However, the PSC plan has not been enacted pending resolution of tax issues affecting the electric utility industry.

Date in parentheses reflects either the date of the legislative enactment or the date on which the regulatory order was issued. Refer to respective Commission websites for full details.

[1] ARIZONA: Salt River Project opened 20 percent of its service territory to retail competition in December 1998, and full retail competition by June 2000. Arizona Public Service Company opened 20 percent of its retail load to competition on October 1999. Tucson Electric Power opened 20 percent of its retail load to competition on January 1, 2000.

[2] CALIFORNIA: On September 20, 2001, the California Public Utilities Commission suspended retail access.

[3] CONNECTICUT: 35 percent of customers will be able to choose an alternate supplier by January 1, 2000 and 100 percent by July 1, 2000.

[4] DELAWARE: The PSC ordered that the start dates for Conectiv Power residential customers was October 1, 2000, for large customers October 1, 1999, and for medium customers January 15, 2000. Delaware Electric Cooperative's residential and small business customers were eligible on April 1, 2001.

[5] MICHIGAN: All customers of Detriot Edison and Consumers Energy, as well as cooperative customers with a peak load of 1 MW or more, will have retail access to alternative suppliers by January 1, 2002. According to Public Act 141, cooperatives are not required to offer retail access before January 1, 2005 or unbundle its rates before July 1, 2004.

[6] NEW HAMPSHIRE: On July 1, 1998, Granite State Electric opened its retail load to competition. PSNH did not implement customer choice until May 1, 2001.

[7] WEST VIRGINIA: Retail access under the PSC plan would have been implemented by January 2001, but the required tax reform legislation has not been enacted.

Source: Energy Information Administration.

From:	Cameron Schilling
To:	Mcleod, Alex; McAlarney, Vesselka
Subject:	RE: Florida proposed electricity market deregulation
Date:	Tuesday, February 19, 2019 9:41:11 AM

Alex and Vesselka,

I have some informal responses from our staff. These statements are not for attribution to FERC but instead we encourage you to use them as background as you research this issue.

In addition, I have a couple of experienced FERC staffers who would be willing to meet with you via phone to further discuss your questions. Some of the answers are complicated and might be better conveyed over the phone.

Another good resource that might explain wholesale markets at a high level is FERC's energy primer.

Regardless, here is a bit of information based on the questions you posed:

1. **What would revenue impacts be to state and local government budgets as a result of deregulation/RTO creation? And**
    a. FERC cannot provide an opinion on state budget impacts. However, most RTO/ISOs are funded through a transmission tariff charge. Therefore, many of the costs and benefits for implementing a regional market ultimately affect electric utility customers.
2. **What would the role of FERC be under the following scenarios;**
    a. If both retail and wholesale markets are de-regulated but no ISO is created
        i. A state can deregulate without an ISO or RTO, but the transmission operators would have to comply with Order Nos. 888 and 890 and generators would have to apply for market based rates among other things.
    b. If both retail and wholesale markets are de-regulated and FL created its own ISO?
        i. If the state sought to create a single state RTO, the Commission has to approve and find the RTO to be of sufficient scope and breadth. This is less of a problem with ISOs as we have some single state ISOs, but even then we do have to approve the governance structure and procedures and a variety of other factors.
3. **We are hoping to get information of FERC's role in the transition from a regulated to a deregulated electricity market and also how its role would be different in a deregulated market than it is currently. Further, why would it have these new roles? What about deregulation changes FERC's role and are there any Florida specific circumstances (for example, the FRCC covers most but not all of Florida, so a different NERC region covers some of Florida and some of other states (is that significant?)) that affect FERC's role.**
    a. Generally, the nature of FERC's role doesn't change, and it doesn't depend on the fact that FRCC doesn't cover the whole state. FERC already has jurisdiction over transmission and wholesale sales in the state. Deregulation will introduce more competition and more transactions. If they chose to create

an ISO, then the ISO would be directly FERC-jurisdictional.

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Office of External Affairs
Federal Energy Regulatory Commission
202-502-6717
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From: Mcleod, Alex [mailto:MCLEOD.ALEX@leg.state.fl.us]
Sent: Monday, February 18, 2019 11:25 AM
To: Cameron Schilling <Cameron.Schilling@ferc.gov>
Subject: Florida proposed electricity market deregulation

Hi Cameron,

I work for the Florida Legislature. My colleague, Vesselka McAlarney, has been in contact with you.

I just wanted to follow up on her last email.

We are hoping to get information of FERC's role in the transition from a regulated to a deregulated electricity market and also how its role would be different in a deregulated market than it is currently.
Further, why would it have these new roles? What about deregulation changes FERC's role and are there any Florida specific circumstances (for example, the FRCC covers most but not all of Florida, so a different NERC region covers some of Florida and some of other states (is that significant?)) that affect FERC's role.

Thanks for any help you could provide.

Alex McLeod

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TABLE 1

Descriptive Statistics of Firm Characteristics for 1995 (in Millions of Dollars). Our Sample Consists of 95 Electric Utilities. We First Identify All Firms Listed on Compustat Under SIC Code 4911 or 4931 (124 Firms). We Are Left with a Sample of 95 Firms After Eliminating Utilities Incorporated Outside the U.S. (11) and Those with Missing Data (18).

	Mean	Median	Std. Dev.
MVE	2718.6	1479.7	2964.3
BVE	2018.3	1187.6	2188.4
ASSET	6064.9	3448.0	6547.3
REGASS	574.7	201.2	932.4
REGASS as % of BE	33.9%	17.7%	
GENSC	280.4	15.9	1453.4
GENSC as % of BE	19.0%	2.7%	
CONSC	556.8	19.8	1566.0
CONSC as % of BE	23.3%	3.1%	
TOTALSC	1411.9	288.6	2619.1
TOTALSC as % of BVE	76.2%	40.2%	

MVE = market value of common equity at the end of fiscal 1995; BVE = book value of common equity at the end of fiscal 1995; ASSET = book value of total assets at the end of fiscal 1995; REGASS = regulatory assets at the end of 1995; GENSC = book value less estimates of market value of electric utility generating plant assets at the end of 1995; CONSC = estimates of present value of net future costs arising from long-term power purchase contracts measured at the end of 1995; TOTALSC = REGASS + GENSC + CONSC.

We obtain data on MVE, BVE and ASSET from the 1995 Compustat annual tape, and data on REGASS from utility FERC Form-1 filings at the end of fiscal 1995. Resource Data International provided us with GENSC and CONSC estimates.

involves relatively sophisticated projections of future market prices, so it is also possible that they might get reflected in prices only after the estimates are publicly released.[9]

Barth and Kallapur [1996] note two potential econometric problems associated with levels-based research designs using accounting data: heteroskedastic regression errors and biases in coefficient estimates because cross-sectional scale differences result in spurious correlations between dependent and independent variables (i.e., large (small) values of the dependent variable are generally associated with large (small) values of the independent variables). Much of past accounting research of this genre has attempted to mitigate these potential econometric problems by using a scale proxy as a deflator. The number of common shares outstanding is a frequently used deflator (e.g., Barth and McNichols [1994], Barth and Clinch [1998]). Easton [1998] points out that scale differences may persist even on a per share basis and suggests that book value of equity is a better proxy for scale.

We estimate equation (1) using book value and the number of common shares outstanding as alternative deflators. Our results are similar for both

[9] Since information about net income for a fiscal year and fiscal-year end book values might not be publicly known at year-end, we also repeat all estimations using as dependent variable the market value of equity at the end of the first quarter of the following fiscal year. Results are unaltered.

Our results indicate that there is a less negative association between stranded cost estimates and firm values for the sub-sample of utilities that choose to make more extensive stranded cost disclosures. This relation is also in evidence, however, for the two years preceding the disclosure year, suggesting that the more favorable market valuation is not prompted by stranded cost disclosure per se. We find that voluntary disclosers operate in jurisdictions that are moving faster toward deregulation and have more clearly established stranded cost recovery mechanisms. It appears that both stranded cost valuation and the decision to disclose these costs in financial statements are prompted by reduction in uncertainty about stranded cost recoverability.

APPENDIX

This Appendix describes the methodology used by Resource Data International (RDI) to compute estimates of stranded cost associated with utilities' generating assets and contractual commitments.

RDI uses an analytical model called Inter-Regional Electric Market Model (IREMM) to develop energy price forecasts for more than 200 different market areas. Using forecasts of energy price, capacity price, capacity factor and availability, RDI computes the stream of revenues associated with each generating unit belonging to each utility. If a utility reports in FORM EIA-411 that a unit will be retired within the next ten years, RDI uses this retirement date to determine the duration of projected revenues. For nuclear units, RDI assumes that the retirement date will coincide with the expiration date of its operating license. RDI assumes that all other units will continue to operate through 2035, unless they are unable to recover operating costs through revenues.

Next, RDI forecasts the expected costs of each generating asset. Cost forecasts include operation and maintenance expenses (variable as well as fixed) and ownership costs such as income and property taxes. RDI computes annual net cash flows for each generating unit as the difference between forecasted revenues and costs, and estimates the market value of each generating plant as the present value of these projected future net cash flows, using a discount rate of 12%. This discount rate is based on an assumed capital structure comprising 40% debt and 60% equity, with the cost of debt assumed to be 8% and that of equity 15%. The difference between the book value and the estimated market value of each generating unit captures the stranded cost component associated with that asset. RDI then aggregates these generating stranded cost estimates to the company level.

For power purchase contracts, RDI computes stranded costs by multiplying the actual amount of energy to be purchased under the contract by the difference between the forecast price of electricity each year and the corresponding contractual rate for the year. RDI uses actual contract expiration dates where available, and assumes an expiration date of 2005 in other instances. It uses a discount rate of 12% to arrive at present value estimates.

RDI analyzes data on a contract-by-contract basis and then aggregates data to the company level.

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Tab 8

Presentations

ASSOCIATED INDUSTRIES OF FLORIDA
The Voice of Florida Business Since 1920

Associated Industries of Florida FIEC Comments

For large commercial and industrial consumers of energy, reliability of electricity supply is not just expected, it is an absolute necessity. Without it, commercial and industrial customers shut down. Hospitals go dark, as do schools and government buildings. Workers go home. Wages are lost. And, the impact on the taxes and fees this Conference is challenged to assess are lowered through reduced operations, sales and salaries.

If there is one thing that has allowed our members to grow and flourish in the almost 100 years of AIF's existence, it is affordable, reliable electricity. Whether it is large industries, or the builders and developers of Florida's dramatic residential growth during the past century, electricity has remained critical to our state's economy, which in turn has driven the revenues of state and local governments.

Here in Florida, we have a highly reliable electric power system. A system that has been built over decades and one that our incumbent utilities continue to improve through hardening and smart technology, even in the face of hurricanes and other natural disasters.

However, this proposed constitutional amendment would force the very utilities that have built this tremendously reliable system to not only divest of their power-generating plants, but also the poles, wires and transformers that feed our daily diet of energy. [1]

So, who will own these critical components of our state's economic infrastructure? And, while the ballot initiative seems to task the incumbent utilities with "construction, operation and repair" of transmission and distribution system, why would they want to take on that responsibility and risk without having the ability to plan, and direct investment in the assets they are managing - but don't own? So, if they don't, who will operate and manage the wires coming to our businesses, industries and homes?

For example, how will storm response be managed in the future? Investor-owned utilities, municipalities and electric cooperatives all have mutual aid agreements with their affiliated organizations. There is no indication that a new structure for unregulated ownership of IOU transmission and distribution assets will have similar agreements. This is a very significant issue, not just for the health and safety of our citizens, but for our economy. Florida has a GDP or approximately $2.7bn/day[2]. Based on this, any delay in storm restoration due to reduced electric system mutual aid agreements or other issues created by deregulation presumably could cost local governments $10's if not $100's of millions of dollars.

Will these unknown entities pay the same fees and taxes paid by our incumbent utilities, and if not, what will local and state government do to make up the difference? If the answer is to increase sales, property and other taxes on business, industry and residential consumers - it's the wrong answer!

While we are on the subject of unknowns, I would like to also mention the unknown of power supply. Since our local utilities will be forced to sell their power plants to as-yet-unknown buyers, what requirements will there be for those buyers to operate these plants well into the future? As we have seen in states that deregulated electricity, power supply suffers without regulatory oversight and accurate price signals. While price signals are appropriate for industry to determine what products they should manufacture, lack of regulation and appropriate price signals for power plants causes them to simply shut down.

The reliability of our electric system is paramount both to our current businesses as well as our ability to attract new businesses to the state. But the real-life experience in states with deregulated electricity markets shows that reliability should be a real concern for us.

In the deregulated Texas electricity market, it is predicted that this summer could be a big challenge for electric supply, with electric generating reserves down to near seven percent, nearly half of their target reserve margin of 13.7 percent. Unfortunately, this is not a new issue, as they have previously experienced blackouts or brownouts in 2011, 2014, and 2015.

In 2011, rolling blackouts forced Texas to import power from Mexico, and Houston saw power cut to 300,000 customers at a time. In Dallas, blackouts knocked hospitals offline.[3] In 2014, some homes and businesses lost power for over 8 hours.[4] In 2015, customers were asked to cut back on energy use to avoid forced interruptions to power.[5] The Houston Chronicle recently reported that DeAnn Walker, chairman of the Texas Public Utility Commission, has called the shrinking power supply cushion "very scary."[6]

Members, I've asked several questions today. However, I do not believe there are answers at this point, and there may not be for years to come if this initiative moves forward. We will be providing you our own economic study based on the best available information. However, I strongly suggest that any study has many areas that may or may not turn out to be true. But, we fully anticipate any impact it shows will be negative to state and local revenues.

A portion of AIF's Mission Statement says that we will encourage and support the business and industrial enterprises of Florida in support of constructive policies relating to all matters affecting them, and for their protection against unjust action from any source.

Frankly, I do not envy your role. In the case of this ballot initiative, the unknowns are unknown. The risks are high. The possible actions that could raise prices and decrease electric reliability are unjust. And, for that reason, I believe this is <u>not</u> a <u>constructive</u> policy, but <u>rather</u> is <u>destructive,</u> and our electric system too critical for our economy, for jobs in Florida and for the revenues of the state and local government to move this ballot initiative forward.

Thank you for your time.

[1] The language of the amendment specifically "Limits investor-owned utilities to construction, operation, and repair of electrical transmission and distribution systems."
[2]Bureau of Economic Analysis Current Release: November 14, 2018
https://dos.elections.myflorida.com/initiatives/initdetail.asp?account=73832&seqnum=1
[3] See "Rolling Blackouts Force Texas To Import Power From Mexico," by Christopher Helman, *Forbes*, February 2011.
[4] See "A Guide to the 2011 Texas Blackouts," *State Impact by NPR*
[5] See [VIDEO] "Energy Alert issued for Texas: What it means for your electricity usage," by Jeff Ehling, *ABC 13*, August 2015.
[6] See "Another Texas power plant is mothballed, raising concerns over reserves and prices" by L.M. Sixel, Jan. 7, 2019

Support Material

Articles
RTO Insider
Texas PUC Responds to Shrinking Reserve Margin
https://www.rtoinsider.com/ercot-puct-reserve-margin-109500/
The indefinite mothballing of a 470-MW coal-fired plant has reduced *ERCOT*'s "pretty scary" reserve margin of 8.1% to 7.4%, prodding the Texas Public Utility Commission into ordering several market changes.

Forbes
Forbes: Rolling Blackouts Force Texas To Import Power From Mexico
https://www.forbes.com/sites/christopherhelman/2011/02/03/rolling-blackouts-force-texas-to-import-power-from-mexico/#713bb0a71101

Study
International Journal of Energy Economics and Policy
http://dergipark.gov.tr/download/article-file/361345
It is clear that electric utility deregulation is negatively affecting adding generating capacity and maintaining high U.S. electrical system reliability, in the deregulated 15 states and District of Columbia. ... Deteriorating U.S. electrical system reliability in deregulated states indicates that without a meaningful change in current U.S. electricity energy policy, no new states should deregulate their electric utilities.

MEMORANDUM

TO: Mr. Brewster Bevis, Senior Vice President of State and Federal Affairs
Associated Industries of Florida

FROM: Hank Fishkind, Ph.D., President

SUBJECT: Testimony to the Financial Impact Estimating Conference
February 11, 2018
Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice

DATE: February 12, 2019

VIA: Email only to: BBevis@aif.com

1.0 Qualifications to Provide Expert Testimony

I have a Ph.D. in economics. My resume is provided in appendix #1. I have consulted with Florida's investor owned and municipally owned electric utilities on numerous occasions over the last 40 years and have appeared as an expert witness in front of the Florida Public Service Commission on a number of occasions.

2.0 Electric Utilities are Natural Monopolies

It is well established that electric utilities are natural monopolies.[1] Technological change has the demonstrated ability to convert natural monopolies into competitive market marketplaces as illustrated in the telecommunications market. However, at this time electric utilities remain as natural monopolies.

3.0 Basic Economics of Proposed Deregulation Amendment

Since the provision of electric service (including generation and transmission) is a natural monopoly, then it follows that allowing customers choice of provider compromises the economics of the natural monopoly resulting in higher prices.

[1] Testimony of Mark Futrell, Deputy Executive Director, Florida Public Service Commission

The literature in the impact of deregulation is by and large consistent in finding that deregulation has resulted in higher, not lower, rates for consumers.[2]

4.0 Likely Impact on State and Local Revenues

While there is uncertainty surrounding how a future legislature might implement deregulation policy, there is no doubt concerning the directional impact of the proposed amendment on the values of electric generation and transmission facilities, their values would fall with deregulation for the following reasons. First, deregulation injects additional risk which by itself reduces the value of the income streams associated with electricity sales. This has the consequential impact of reducing the values of the facilities associated with the existing electric utilities. Second, utilities shed generation assets in states that deregulated.

Electric utilities are some of the largest sources of ad valorem tax revenues to local governments and school boards in Florida. Even modest declines in the value of these assets would result in significant reductions in these revenues. In 2018 the investor owned electric utilities paid over $1 billion in property taxes. So, even a 5% reduction would cost over $50 million per year with a present value in excess of $700 million. In addition, it is likely that there would also be reductions in franchise taxes, sales and use taxes, and gross receipts taxes. Altogether, even a 5% compromise results in a potential loss of over $112 million per year with a present value in excess of $1.2 billion.

[2] For example see: PSC Consultants (March 2014), Electric Industry Deregulation: a Look at Four States, Borensein, Severin (Winter 2002), "The Trouble with Electricity Markets", Journal of Economic Perspectives, Texas Coalition for Affordable Power (2018), Deregulated Electricity in Texas.

SELECT CLIENT LIST

AEGON
Barron Collier
BP
Cemex/CSR/Rinker Materials
Colonial Properties Trust
Collier Enterprises
Falcone Group
Fannie Mae
Florida Power Corporation
Forest City Enterprises
FPL
King Ranch
Kitson & Partners
Lennar
Major Central FL Attraction Co.
Mosaic
Newland Communities
Perry Capital
Rayonier
Starwood Land Ventures, LLC
State of Florida
State of Pennsylvania
St. Joe
U.S. Department of Justice
The Villages
Waste Management, Inc.

Henry H. Fishkind, Ph.D.

President

hankf@fishkind.com

PROFESSIONAL SYNOPSIS

With over 30 years of experience in economic analysis and forecasting, Dr. Henry Fishkind is widely regarded as one of Florida's premier economists and financial advisors. Dr. Fishkind's career began in the public sector where he worked as an economist and associate professor at the University of Florida. In 1980 Dr. Fishkind became the associate director for programs at the University of Florida's Bureau of Economic and Business Research. During his tenure at the university, Dr. Fishkind served from 1979-1981 on the governor's economic advisory board. He began his career as a private sector consultant when he became president of M.G. Lewis Econometrics in Winter Park, Florida. In 1988 Dr. Fishkind formed Fishkind & Associates, Inc. as a full service economic and financial consulting firm.

From 2001-2003 Dr. Fishkind was a member of Governor Bush's Council of Economic Advisors, and also served on the board of directors of Engle Homes, Summit Properties, and ABT Funds until the companies were sold.

AREAS OF EXPERTISE

Economic Analysis
Econometric Modeling
Project Finance & Feasibility
Financial Analysis & Advisory
Privacy
Intellectual Property
Fiscal Impact Analysis
Real Estate Economics

PROFESSIONAL EXPERIENCE

Chairman, FLSAFE	2008 - 2011
Managing Partner, Woodbridge Vintage Chips	1994 - 2007
President, Fishkind & Associates, Inc.	1988 - Present
President, M.G. Lewis Econometrics, Inc.	1984 - 1987
Associate Director for Programs, Bureau of Economics & Business Research, University of Florida	1980 - 1983
Economist/Associate Professor, University of Florida	1975 – 1983

EDUCATION

Indiana University, Doctor of Philosophy, Economics, 1975
Syracuse University, BA, Economics, 1971

LICENSES

Municipal Advisor MSRB License # 867-01196
U.S. Securities and Exchange Commission # K1055

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February 19, 2019

Amy Baker
Chief Economist
Office of Economic and Demographic Research
111 West Madison Street, Suite 574
Tallahassee, FL 32399-6588

Re: Florida Chamber of Commerce Financial Analysis Regarding Proposed Amendment - Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice

Dear Mrs. Baker,

The Florida Chamber of Commerce respectfully submits the attached financial impact analysis regarding the proposed ballot initiative to restructure the Florida's electricity market. As an interested party, the Florida Chamber of Commerce retained Charles River Associates to conduct an independent analysis to estimate the potential changes in revenues and costs to state and local governments that would result from the implementation of the proposed ballot initiative. **This analysis concluded electricity market restructuring would have an adverse financial impact, in terms of lower tax revenues and increased costs, of $1.2 to $1.5 Billion or more per year to the Florida state and local governments – and ultimately, to taxpayers**.

Negative Financial Impact by Major Category		**Range Estimate** ($ millions)	
		Low	High
Revenue Losses	Franchise Fees	650	650
	Gross Receipt Tax	270	320
	Municipal Public Service Tax	200	300
	Property Tax	60	140
Higher Costs	Administrative Costs	30	80
	RTO or ISO – impact of higher rates	20	25
Total Potential Impact		**1,230**	**1,515**
Incremental impact from higher electricity rates – net impact of revenue and costs for every 10% rate increase		90 *(GRT and government electricity bills)*	

We hope this financial impact report provides beneficial support and additional information to the Financial Impact Estimating Conference. If you or any of the other principals have any questions regarding the research or analysis conducted therein, please do not hesitate to contact me at 850.270.5525 or fbrown@deanmead.com.

Sincerely,

French Brown

Enclosure

Charles River Associates

Prepared for:

Florida Chamber of Commerce

136 S. Bronough Street

Tallahassee, FL 32301

Florida Electricity Markets Restructuring Ballot Initiative

Potential Financial Impact to Florida State and Local Governments

Prepared by:

Charles River Associates

200 Clarendon Street

Boston, Massachusetts 02116

Date: February 19, 2019

CRA Project No. D27183

Confidential material

Disclaimer

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Table of contents

1. Executive Summary

Citizens for Energy Choices is seeking, through a proposed ballot initiative, a constitutional amendment to restructure the electricity market in the State of Florida.

More specifically, the proposed amendment would require the Florida legislature to adopt laws by 2025 that would limit the activity of the IOUs to only the construction, operation, and repair of transmission and distribution (T&D) systems (forcing IOUs to divest all generation, and possibly T&D assets), and establish competitive wholesale and retail electricity generation and supply markets.

Florida law requires that the Financial Impact Estimating Conference (FIEC) review any proposed ballot initiative and prepare a financial impact analysis.

As one of the stakeholders, the Florida Chamber of Commerce retained Charles River Associates (CRA) to conduct an independent analysis to estimate the potential changes in revenues and costs to state and local governments that would result from the implementation of the proposed ballot initiative.

Electricity market restructuring would have an adverse financial impact, in terms of lower tax revenues and increased costs, of $1.2 to $1.5 Billion or more per year to the Florida state and local governments – and ultimately, to taxpayers.

Table 1: Summary of Potential Annual Financial Impacts from Market Restructuring

Negative Financial Impact by Major Category		**Range Estimate** ($ millions)	
		Low	High
Revenue Losses	4.3.2. Franchise Fees	650	650
	4.3.4. Gross Receipt Tax	270	320
	4.3.3. Municipal Public Service Tax	200	300
	4.3.1. Property Tax	60	140
Higher Costs	4.3.5. Administrative Costs	30	80
	2.3.2. RTO or ISO[1] – impact of higher rates	20	25
Total Potential Impact		**1,230**	**1,515**
4.3.5. Incremental impact from higher electricity rates – net impact of revenue and costs for every 10% rate increase		90 *(GRT and government electricity bills)*	

CRA reviewed the impact of a transition to a restructured electricity market across other jurisdictions over the last 20 years. Then, CRA analyzed the potential financial impact of restructuring the Florida electricity market, as prescribed by the ballot language, to state and

[1] Total RTO or ISO ongoing costs would run between $200 and $250 million annually would be recovered via higher rates – state and local governments account for 10% of demand and thus would see $20-$25M in the form of higher bills.

local governments including lower revenues (e.g., franchise fees, property taxes, MPST, and GRT) and higher costs (e.g., administrative, litigation, regulatory, etc.)

Given time constraints, CRA did not conduct an expansive bottom-up plant level production cost modeling analysis. Instead, a top-down approach was utilized to develop potential future outcomes under different scenarios – based on historical precedents of restructuring in other jurisdictions, recent industry trends, and the current status of the Florida electric system. CRA's analyses assume fundamental energy constraints are met such as resource adequacy requirements within Florida and existing infrastructure (i.e. based on current interstate electric transmission and natural gas pipeline capacities).

A literature review by CRA indicates that electricity market restructuring in other jurisdictions has not only resulted in higher electric rates for consumers overall but also significantly higher costs for states to develop new institutions to manage wholesale markets, educate consumers, ensure adequate supply and reliability, handle increased litigation, provide public assistance to low income ratepayers, and manage the overall higher regulatory complexity.

In addition, given the language of the ballot petition, Florida governments would likely experience a severe loss of tax revenues from Franchise Fees, Property Taxes, Municipal Public Service Taxes, and Gross Receipt Tax. Additionally, based on the experience from other jurisdictions, Florida would also likely incur significantly higher costs across state and local governments.

Finally, our analysis indicated negative financial implications across all scenarios and sensitivities – any potential increases in sales tax driven by higher rates are relatively insignificant compared to the other combined negative impacts of tax revenue losses and higher costs.

New state taxes would need to be implemented by the legislature (but would require a supermajority in both chambers to pass) to offset losses or result in a reduction of state government services across the state. Offsetting local government tax losses and increased costs and/or preventing service reductions would also present a major challenge – requiring regulatory and contractual changes for each affected local jurisdiction across the state.

The ranges quantified above in Table 1 are not meant to be a comprehensive evaluation and represent a conservative view of the overall potential impact of restructuring the Florida electric market. There are several other potentially adverse impacts that have not been included given the availability of information, time constraints, and degree of uncertainty. Below is a non-exhaustive list of additional challenges identified, but not quantified at this time, all of these would drive further negative financial impacts to the state and local governments in Florida.

- Public assistance for low income, elderly and fixed-income ratepayers
- Litigation, regulatory, and consumer advocacy cost for unfair practices
- Recovery of stranded costs for IOU generation assets
- Grid reliability investments and ancillary services
- Natural gas supply availability constraints and price risk
- Job loss impact of closures and lower government spend (driven by revenue losses)
- Economic impact of higher electric rates – e.g. job losses or slower economic growth
- Incentives required to attract sufficient Provider of Last Resort ('POLR') suppliers

In conclusion, the findings from our analyses indicate that restructuring the Florida electricity market would have a substantial detrimental financial impact to the state and local governments – in the range of $1.2 to $1.5 Billion annually. Furthermore, this impact could be considerably worse based on additional challenges not yet quantifiable due to the high degree of uncertainty and risk associated with the proposed petition ballot.

2. Review of Electricity Restructuring in the United States

2.1. Historical Overview of Restructuring

From the mid 1990's to 2002, the US experienced a wave of electric market restructuring as state legislators across the US attempted to transform electricity markets in the wake of deregulation precedents in other industries (e.g. airlines, telecommunications, etc.) to reverse rising electricity rates. However, this wave effectively ended in 2002 with Texas (the last state to implement restructuring and remain restructured) and with additional states (e.g. Montana, Virginia, etc.) over the subsequent years suspending or repealing previous attempts at restructuring.

There were many reasons behind the end of the wave of electric market restructuring. One of the most impactful was the 2000-2001 California energy crisis, which highlighted how market failures can arise from unforeseen circumstances related to electricity market restructuring. California became the first state to deregulate its electricity market in 1996. In 2000, prices in wholesale markets became deregulated while retail prices remained regulated. This enabled widespread market manipulation that created supply & demand shortages, rolling blackouts, and extensive financial losses (estimated to have cost CA between $40 and $45 Billion)[2].

Just as critical, however, were the significantly rising electricity prices experienced across all the recently restructured markets – the opposite of what was intended by legislators and regulators.

While the comparison between regulated and restructured markets is complex, the core difference is how pricing is determined in each construct. In general, regulated market prices are based on average generation costs (i.e. cost of service) – which at the time was driven by coal and nuclear baseload generation. In contrast, prices in restructured markets are generally set by the marginal cost of generation, which was mostly gas at that time (i.e. market prices).

Between 2001 and 2009, there was a clear disadvantage for restructured markets (with significant gas-fired generation) as the cost of natural gas increased faster than other fuels. However, since 2009, gas prices have significantly declined, driven by improvements in shale extraction technologies (see Figure 1 below). Lower gas prices have decreased the marginal generation cost of electricity – this trend has benefited restructured markets.

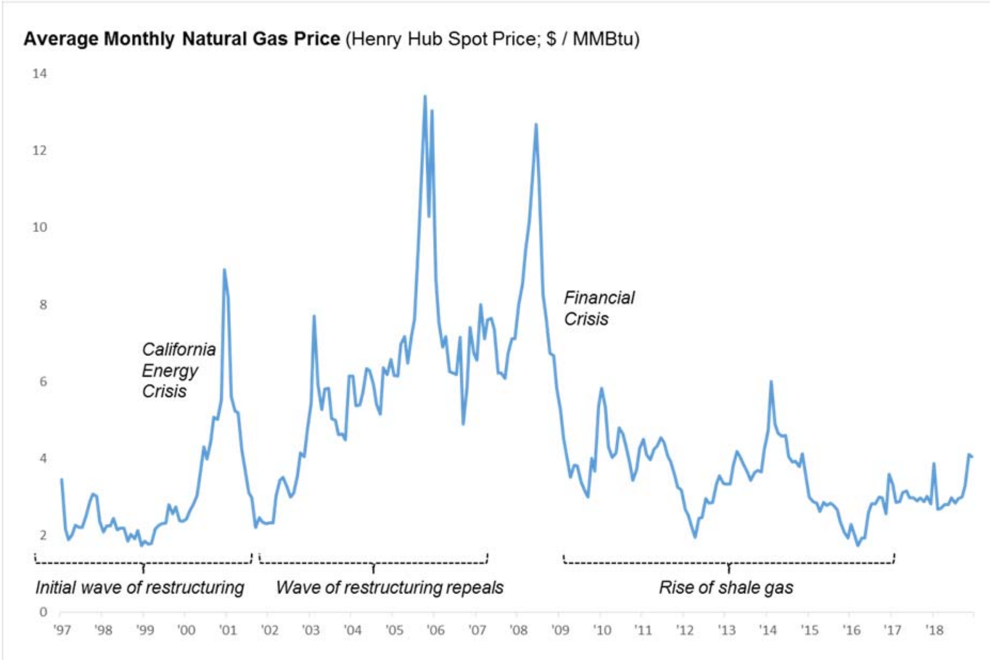
But, this has also reduced rates in regulated markets as more and more regulated utilities are displacing higher priced generation with lower cost natural gas generation. In Florida, for context, natural gas accounted for ~68% of the total generation in 2017 compared with ~44% in 2007. In the same time period, coal generation has decreased by ~50% and currently accounts for ~15% of generation – thus leaving little room for further improvement[3].

As a result, electricity rates have been consistently lower in regulated markets than in restructured markets – remaining to the current day.

[2] *The California Electricity Crisis: Causes and Policy Options*. Weare, Christopher (2003); Public Policy Institute of California.

[3] Energy Information Administration (EIA). Florida Electricity Profile. https://www.eia.gov/electricity/state/florida/

Figure 1: US Natural Gas Prices[4]



However, there is nothing to suggest that this current trend will continue indefinitely. There is considerable risk associated with natural gas pricing in the longer term, including the ability of producers to keep up with growing demand (e.g., LNG exports, Mexico pipeline exports, continued coal to gas switching, etc.) and ability of midstream players to build new transmission capacity due to environmental litigation, FERC uncertainties, local siting, etc.

This is especially true in Florida where there is no local natural gas production. Gas fueled electric generation is dependent on only three major interstate gas pipelines – any new natural gas electricity generation would require additional pipeline expansion projects. Gas pipeline developers require long-term firm contracts to finance these projects. This is an important point to note. One of the central intentions of restructuring would be to incentivize new natural gas generation capacity. However, restructured markets are not compatible with long term contracts, given that merchant generators operate on short term and real time purchases. This would severely limit the potential for natural gas capacity increase in a restructured Florida market.

Furthermore, as natural gas combined cycle plants are increasingly becoming the default baseload generation across the country and renewables such as wind and solar continue to see dramatic cost declines and greater share of generation, it is unclear that the current marginal to average cost relationship will continue along the recent trend or reverse itself in the near future. Over 68% of Florida generation is already fueled by natural gas, so the price differential between average cost and marginal cost impact would be lower than what was experienced in other jurisdictions.

Finally, there are many additional factors that have been shown to result in higher prices associated with restructured markets. We will address the most relevant to the current ballot initiative impact in later sections of this report. Some of the factors that have been shown to cause higher electricity prices include transmission congestion charges, stranded cost recovery of previously regulated generation assets, capacity and ancillary service charges,

[4] EIA – Natural Gas Prices Data

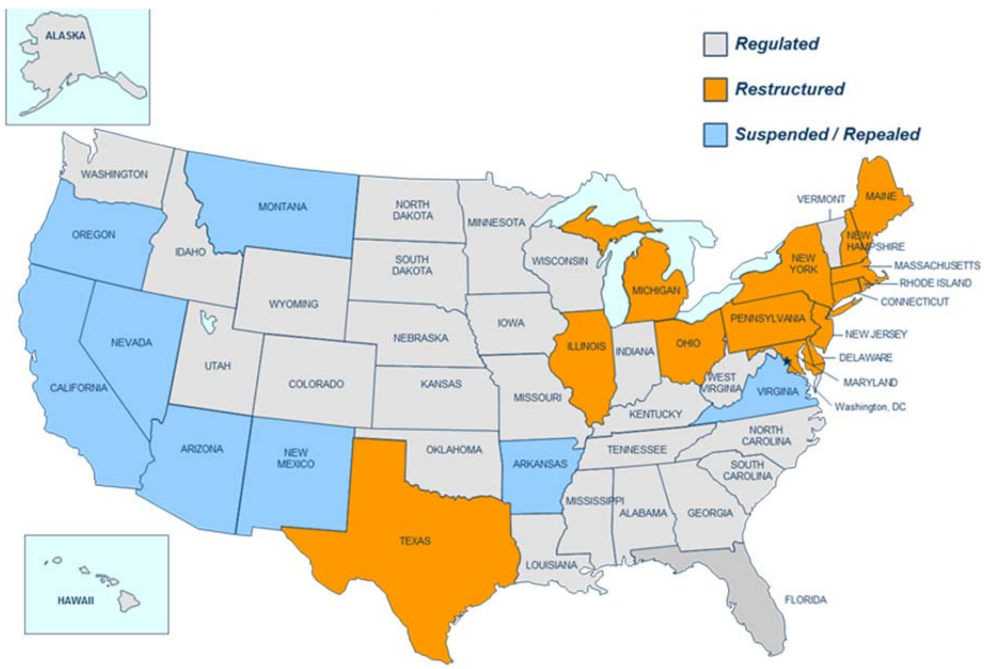
ISO or RTO fees, risk management costs, rents from additional market intermediaries, customer marketing and switching costs, regulatory, legal and administrative costs, counterparty risks, etc.

2.2. Comparison of Regulated and Restructured States

Restructuring in the US – Background

Currently, there are fifteen jurisdictions (fourteen states and Washington, D.C.) with restructured electricity markets and eight states that have suspended or repealed formerly enacted restructuring (four of these retained partial retail choice – CA, NV, OR, and VA)[5], as seen in Figure 2. Of all the states, Texas has attained the most widespread restructuring, with over 85% of consumers participating in the deregulated market. We will discuss Texas in more detail later in this report.

Figure 2: Status of Electricity Market Restructuring in the United States



Evaluating the success or failure of restructuring efforts is challenging. There are many potential outcomes (e.g. rates by customer type, generation cost savings, customer satisfaction, etc.) that can be measured and these vary significantly across markets and time. Additionally, electricity markets are large and complex systems with multiple factors affecting each of these outcomes.

Given that complexity, we have focused our analysis on a few selected outcomes. We start with a direct comparison of average rates for all consumer types between traditional regulated markets and restructured markets over time. We have chosen two points in time for

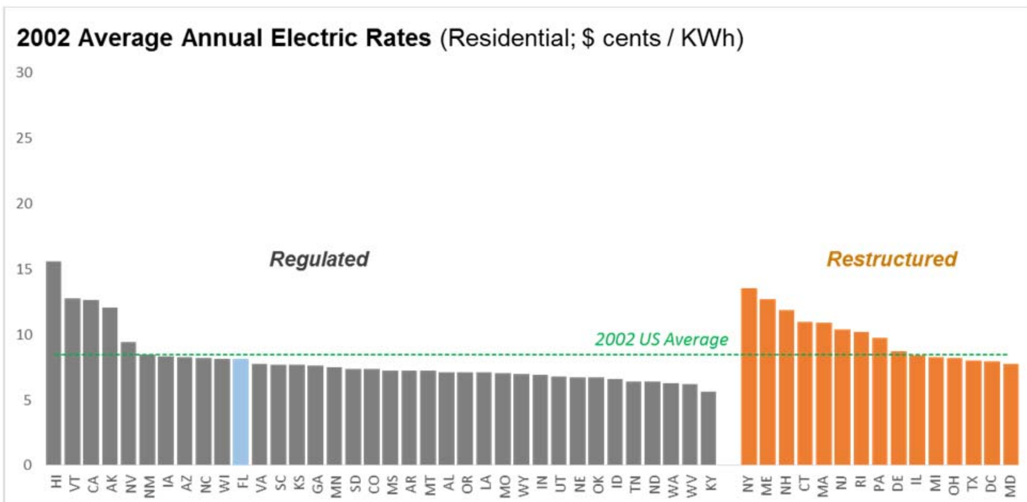
5 *Retail Choice in Electricity: What we have learned in 20 years*; Christensen Associates Energy Consulting report prepared for Electric Markets Research Foundation; 2016

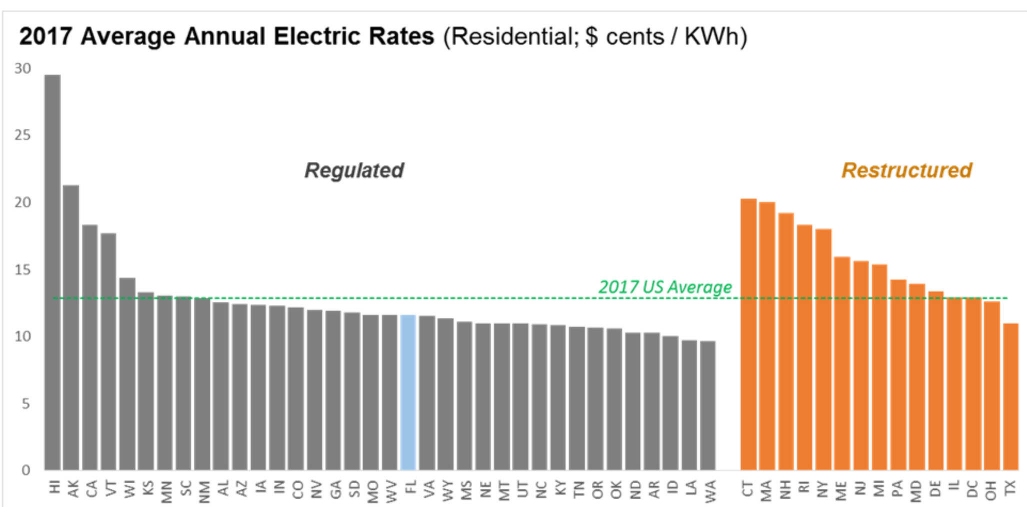
comparison: 2002, the last year of the initial wave of restructuring, and 2017, the latest year with full data available.

In 2002, just after the initial wave of restructuring, 5 out of 36 regulated states (or ~14%) and 8 out of 15 restructured states (or ~53%) had rates above the overall national average. Over the following 15 years, the average overall national rate increased from 7.2 cents/KWh to 10.48 cents/KWh (an increase of ~46%). Accordingly, rates increased in both groups.

However, by 2017, the number of regulated states with above average rates declined to 4 out of 36 (or ~11%) while the number of restructured states with above average rates increased to 11 out of 15 (or ~73%)[6]. We see similar results when examining all consumer classes. For example, in terms of residential rates, in 2002 nearly half of the restructured jurisdiction had rates below the national average. However, by 2017 nearly all restructured markets had residential rates higher than the national average. By contrast, in the same timeframe, Florida significantly improved its electricity rates position relative to the national residential average: from 29th lowest rate in 2002 to 18th in 2017(see figures below).

Figure 3: Comparison of Average Electricity Rates by State in 2002 and 2017

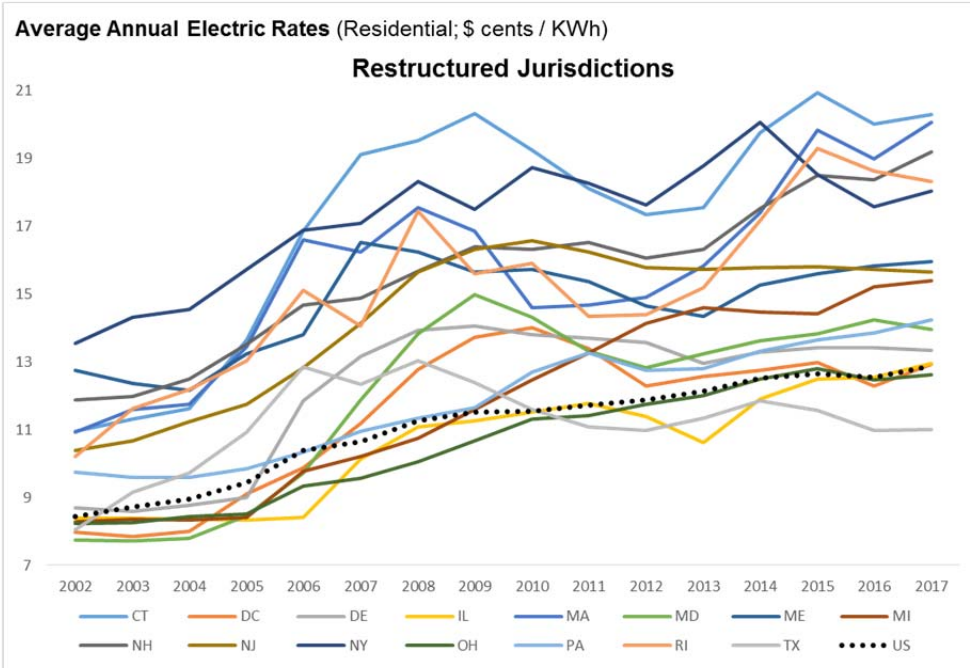




6 EIA State Electricity Profiles

Focusing closer on the restructured states over the same time period, we can see that all restructured markets experienced rate increases in the 2000's significantly faster than the national average. Since 2010, restructured state rates have tended to follow the overall national average but at new higher levels (on average 22% higher as of 2017). **No jurisdiction, including Texas, was able to reduce residential rates consistently after restructuring its electricity markets**, as seen in Figure 4.

Figure 4: Average Electric Rates for Restructured Jurisdictions between 2002 and 2017[7]



Rate changes are the most visible and commonly cited impact associated with restructuring. However, there are other important impacts resulting from a restructuring process. The focus of this report is to address the potential impact to state and local governments. To that end, we will shift the discussion to some of these other impacts.

Restructuring Impact at the State Level

Reviewing the previous restructuring events across jurisdictions, we can see that there have been a range of institutional, regulatory, and legislative challenges in the regions where restructuring has occurred. These challenges can be broadly categorized as follows.

- Establishment of overall market rules and oversight bodies for new Independent Power Producers (IPPs), incumbent Investor Owned Utilities (IOUs), utility affiliates (unregulated subsidiaries of IOU parent companies with generation assets), and other new market players (e.g. energy brokers, marketing organizations, etc.)
- Creation of new ISOs or RTOs and independent oversight and control of transmission networks
- Development and enforcement of market definitions and controls – timing of retail choice, retail rate controls, incentive pricing to foster competition, provider of last resort rules, etc.

[7] EIA State Electricity Profiles

- Oversight of generation asset divestiture and stranded asset implications (including utility recovery mechanisms and associated rate impacts)
- Protection for vulnerable (e.g., low income) customers – including education, new policies, rebates and utility bill assistance, etc.
- Increased licensing, permitting, and litigation from various market entities (e.g. consumer group, project developers, energy suppliers, environmental protection groups, etc.)

In all cases, these challenges triggered significant one-time costs for these states in the period just prior to restructuring and, in most cases there was a significant increase in ongoing regulatory related costs after restructuring, as compared with costs 1-3 years prior to restructuring. We will discuss cost increases in selected states in more detail in a later section.

In order to better illuminate the relative differences in costs that are directly related to electricity restructuring borne by each state, we examined recent Public Service Commission (PSC) expenditures across regulated and restructured markets. Note that not all states publish detailed costs at the PSC level and oversight responsibilities vary greatly across states (i.e. many have oversight of industries in addition to electricity).

For our analyses, we focused on a sample of 21 states that had a narrow set of public utility responsibilities (generally electric, gas, water and sewer) and that publish detailed budget and expense figures. An analysis of before and after restructuring was only possible for a select number of states as PSC responsibilities, cost structure, and reporting tended to change over time in many states over the last 20 years, which is the timeframe before and after most restructuring events.

Additionally, since state size was the main factor associated with level of costs, we utilized a unit cost approach to enable a comparison among states. In this case, we used overall PSC 2017 costs divided by the total population residing in each state in 2017.

The result of the analysis concluded that restructured states have a significantly higher relative PSC administration cost than regulated states**,** partially driven by the challenges highlighted above and in the previous section.

On average, state administrative costs in restructured states are more than double similar costs in regulated states ($1.5 / person vs. $3.5 / person, or 2.3x higher)[8]. **Applying the above cost differential of 2.3x to Florida's current PSC costs, would reflect a cost impact of well over $50 million per year.**

2.3. Electric Market Restructuring – State Level Impact

Electricity market restructuring paths have varied significantly across the US. We have chosen Texas as the main example to describe in further detail issues that may arise in a restructuring scenario in Florida due to similarities with Florida in terms of size and regulatory framework (single state ISO or RTO). When considering the language of the Florida ballot petition, the state that seems to mirror most closely the structure and is thus most relevant is Texas. In fact, the proponents of the ballot initiative have stated that it was authored with the intent of replicating the Texas model in Florida.

[8] Population data from US Census Bureau and PSC costs from individual state budget office reports (ME, PA, NY, AL, OH, NV, CA, MI, IL, MD, UT, AR, MS, LA, IN, TN, FL, GA, TX, SC, and NC)

As part of our research, we also considered New York, given that it also has a single state ISO. We uncovered very similar findings to our analyses of Texas. We did not include these additional findings to avoid duplication of information, but can provide this data if requested.

2.3.1. Texas

Comparison of Texas to Florida – Before and After Restructuring

Overall, historically, there have been many similarities between the Texas and Florida electricity markets. However, as we will detail in this section, some of these similarities have become points of contrast due to the diverging paths taken by the two states since 2002 (i.e. driven by the impact in Texas from the market restructuring).

- Both are large states in terms of geographic size and population (28 million in Texas and 21 million in Florida – numbers 2 and 3 in the U.S. respectively, behind CA)
- Good economic growth with positive electricity demand growth, partially driven by population growth well above the national average (1.8% and 1.5% since 2002 for Texas and Florida respectively)
- Similar climate with electricity summer demand peaks and electricity rates below the national average for all consumer classes
- Similar electricity generation mix – with a majority natural gas generation followed by coal (both also have ~10% nuclear and future growth potential for solar)
- Similar reserve margin – Texas had reserve margins well above 20% prior to 2002 (which declined over time as a result of restructuring – details in section below)
- Relatively contained grid with limited inter-connection to other states or systems and a single state ISO / RTO (likely to be the case in a Florida restructuring scenario)

However, there are also some key differences worth noting between the two markets.

- Texas is a major natural gas producer and Florida depends exclusively on interstate pipelines for its natural gas supply
- While both states generate most of their electricity from natural gas, Florida has significant gas transportation costs (Texas has much lower cost gas available)
- Texas also has a large renewable wind resource with low cost wind generation that now accounts for ~17% of the state's generation mix, while Florida does not have viable wind resources. Texas also has stronger solar resources than Florida.
- Florida interconnects with other states and therefore subject to FERC jurisdiction while ERCOT is isolated and is not regulated by FERC
- Although, as stated by the proponents, the ballot initiative's intent is to replicate the Texas market restructuring in Florida, the actual language goes far beyond the requirements in Texas (e.g., constitutional amendment approach, forced divestiture of all IOU generation assets, lack of 'ownership' of T&D system, etc.)

Given the availability of large low cost energy resources (wind and natural gas) within the state, one would expect Texas to have significantly lower electricity rates than Florida. However, from 2013 to 2017, residential rates in TX & FL have been nearly equal. Residential customers in restructured parts of Texas have actually paid higher prices as described below.

Texas Restructuring Background and Overall Impact

Starting in 1999, Texas began drafting legislation and putting in mechanisms to allow for a deregulated market – through amendments made to the state's Public Utility Code. The market started fully in 2002 with the approval of Texas Senate Bill 7.

One of the key elements of the bill was the ‘Price to Beat’ clause – which established a price floor for incumbent utilities while allowing new entrants to charge higher rates for the first five years. This mechanism was intended to improve competition and eventually lower rates.

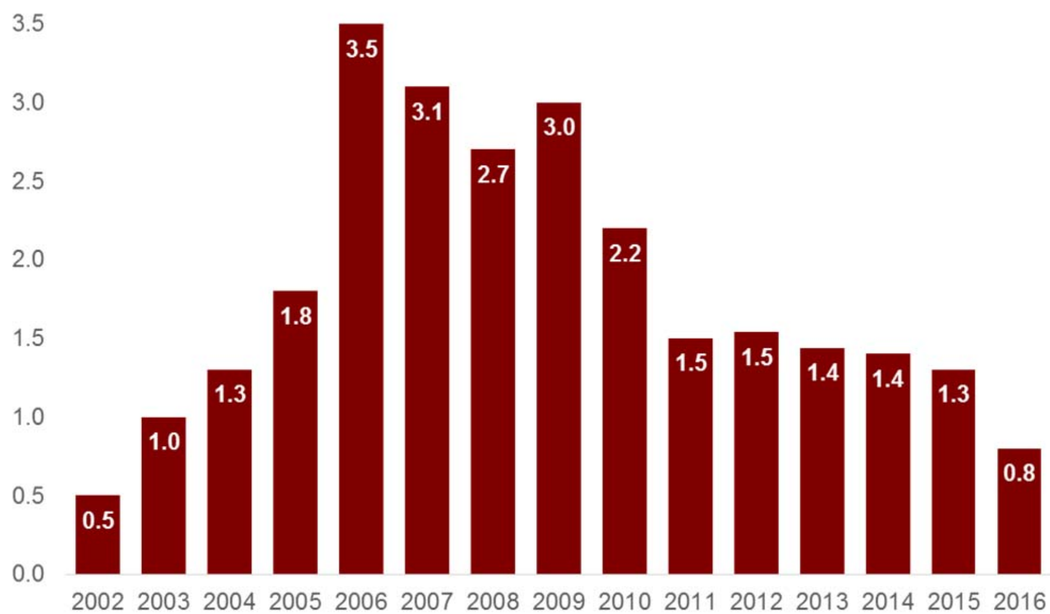
However, it actually has resulted in significantly higher overall rates in restructured areas of the state relative to areas not subject to restructuring. Several parts of Texas remain regulated which include western (e.g., El Paso), northern (e.g., Amarillo), central (e.g., Austin), and eastern (e.g., Jasper) portions of the state[9].

Texas consumers have consistently paid higher residential electric prices in restructured areas, as compared to prices in areas exempt from deregulation. This annual trend began during the very first year of deregulation, in 2002, and has continued through 2017. A similar outcome was seen in New York – a recent NYPSC report showed that consumers who signed up with competitive suppliers paid ~$820 million more for electricity and gas than they would have with their local IOU (over a 30 month period ending in June 2016)[10].

These consistently higher rates have had a major adverse impact on consumers’ bills over the period. To illustrate this point, we can examine the aggregated bill value differential between the higher deregulated rates vs. the lower regulated rates.

The overall consumer ‘lost savings’ for the state reached as high as $3.5 Billion per year (in 2006) and has cost consumers in restructured areas of Texas over $27 Billion in total between 2002 and 2017. The graph below shows the annual impact of ‘lost savings’ in Texas[11].

Figure 5: Consumer ‘Lost Savings’ Driven by Restructuring in Texas ($ Billions)



9 https://quickelectricity.com/texas-energy-deregulation-map/

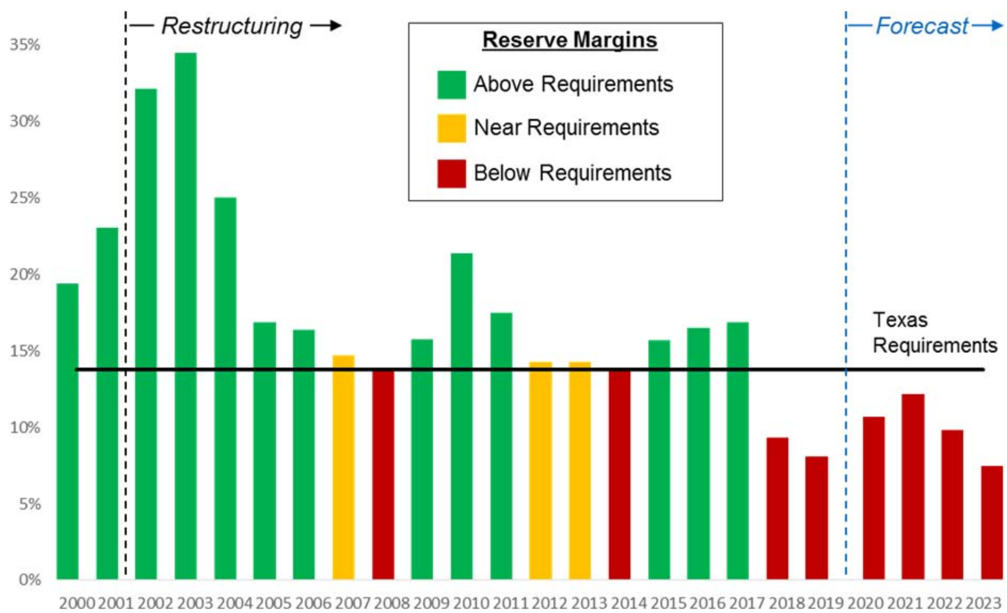
10 *AT RISK: NY reviews electric, gas free-choice program.* Jeff Platsky; Gannett; Feb 2018.

11 Electricity Prices in Texas Snapshot Report – 2018; Texas Coalition for Affordable Power

Restructuring Impact to Generation Reliability in Texas

The transition to a restructured regime has affected reliability tremendously. The resource adequacy reserve margin[12] that describes the amount – in percentage points over the estimated peak – of resources needed to maintain NERC's resource adequacy reliability standards has deteriorated significantly since the transition in Texas. The exhibit below provides the reserve margin on an annual basis since the implementation of the market reforms. The target depicts NERC's 14%.[13]

Figure 6: Impact of Restructuring on Reliability in Texas (Reserve Margin %)



Notably, the margin has been consistently low or well below the minimum level required by NERC since 2005. More troubling is that is also expected to remain at below required levels in the foreseeable future. The market based reforms (scarcity pricing model) implemented during the transition have failed to incentivize enough capital for the construction of excess generation capacity to maintain NERC's planning reserve margin standards negatively affecting reliability in the region (Texas is an energy-only market without a capacity market).

As wind and solar resources continue to grow, the reserve margin issue is only expected to worsen (since are intermittent and do not add to the reserve margin). The reserve margin for Texas has been forecasted to be 7.4% in the summer of 2019 – well below the 14% requirement. This has resulted in the PUC having the unenviable choice between significantly higher costs or increased outages and blackouts. One recent proposal to increase incentives has been assessed at an additional cost of $2 Billion per year to close the reserve gap – that will, in turn, likely increase electricity rates in Texas.[14]

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12 Per NERC "Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of adequacy."

13 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf page 27

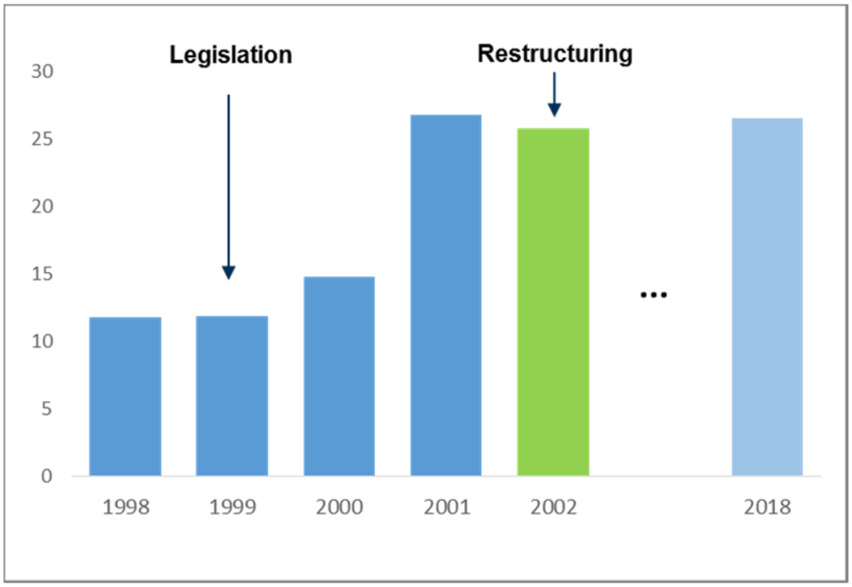
14 *Texas regulators, power industry representatives mull ERCOT resource adequacy*; S&P Global Market Intelligence; 2/7/19

Texas Public Utilities Commission Costs

In order to establish the restructured market, the Texas PUC had to significantly expand resources in order to prepare for a new market, ensure execution, and oversee the new market structure. Although there were some oversight costs shifted to the RTO (ERCOT), the new PUC responsibilities more than offset the cost reductions associated with this shift – as can be seen in Figure 7 below[15].

There was a significant ramp-up in costs in the years preceding deregulation and PUC costs have remained considerably higher ever since. There was an 81% increase in costs between 2000 and 2001 alone[16]. Some of the additional costs included professional fees to contractors and consultants to address the various challenges, as highlighted in the previous section. One program worth noting that contributed to the large increase in costs seen in 2001, was to develop, implement, and manage consumer education.

Figure 7: Texas Public Utility Commission Costs ($ millions)



Texas Public Assistance Programs

In addition to administration fees, the resulting residential rate hikes and accompanying higher bills had an especially severe negative financial impact on low income families. In response, Texas put in place several support programs with costs in the hundreds of millions of dollars. The costs of these programs were generally excluded from the PUC budgets.

Our research of Texas appropriation budgets showed that the state expenses of PUC related costs for financial assistance to low income consumers increased from $29 million in 2002[17] to $326 million in 2016[18]. We also did not find any PUC cost line items related to low income assistance published prior to 2002.

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15 *Legislative Appropriations Request for Fiscal Years 2018 and 2019*; Governor's Office of Budget, Planning and Policy

16 *Legislative Summary Document Regarding PUC Texas – January 2003*; State Auditor's Office (SAO 03-377)

17 *Legislative Summary Document Regarding PUC of Texas*. January 2003. State Auditor's Office (SAO 03-377). Page 3

18 *Legislative Appropriation Request submitted to the Governor's Office of Budget*. Texas PUC, August 12, 2016. Page 11

There were also other assistance programs in place over the period with various funding sources. One such program, 'Lite Up Texas', which was funded by a combination of state general funds, fuel surcharges, and federal subsidies, reached a peak total fund value of $800 million in 2013 before being depleted by 2017.[19]

2.3.2. Impact of Formation and Upkeep of ISO or RTO

A transition to a restructured will require the formation of an Independent System Operator (ISO) or Regional Transmission Organization (RTO) which would manage the transmission system and the newly implemented competitive electricity markets. FERC Order 2000 and 888[20] specify detailed functions that need to be in place before and shortly after the new entity is formed. The figure below depicts the minimum functions of an ISO or RTO for two different timeframes. Per the FERC's guidance, the Implementation functions should be in place shortly after the formation of the system operator while Ongoing includes the functions that should be performed over the long term.

Table 2: Description of the Minimum Functions of an ISO/RTO

	Implementation	Ongoing
Tariff Administration and Design	X	X
Congestion Management	X	X
Parallel Path Flow	X	X
Ancillary Services	X	X
OASIS – software costs	X	X
Market Monitoring	X	X
Transmission Planning	X	X
Interregional Coordination	X	X
Day-Ahead Energy Market		X
Same - Day Energy Market		X
Ancillary Services Market		X
Capacity Market		X

Since Florida has currently no ISO or RTO, the state would incur both Implementation and Ongoing costs associated with the new entity. The Implementation costs include new software, communications, buildings etc. while the Ongoing or administrative costs are related to staffing, software upgrades due to new market designs, operations and maintenance etc.

Since there have not been any new ISO or RTOs formed in the past 20 years, it is difficult to accurately estimate the start-up costs for Implementation functions. A FERC staff report produced in 2004 provides indicates these costs to be between $38 million and $117 million – depending on market size and RTO or ISO mandate. In today's terms, that would amount to a range **between $50 and $155 million for Implementation**[21].

Based on a 2016 FERC Staff report, the administrative costs vary widely across the RTOs and ISOs, with the five-year average administrative costs ranging from $0.27 per megawatt-

[19] *Texas stops helping poor families pay their electric bills*; Texas Tribune / Star-Telegram September 03 2016

[20] Federal Energy Regulatory Commission

[21] https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf?csrt=10019579922585194549

hour for SPP to $1.10 per megawatt-hour for ISO-NE. The variance is due to many drivers such as maturity of the market, location and others.

Single state RTOs like CAISO and NYISO have an average of ~$1 per MWh. If this rate is applied to the annual Florida retail sales of 233 TWh, the estimated annual administrative cost would be close to $230 million. In conclusion it is expected that a new ISO or RTO in Florida would cost **over $150 million for implementation** and **between $200 and $250 million per year for ongoing costs**. These costs would be recovered through higher rates and since government make up approximately 10% of state demand, **state and local governments would see an impact of $20 to $25 million annually in the form of higher electric bills.**

3. Overview of the Florida Electricity Market

This section provides background on the Florida electricity market including current market structure, a snapshot of transmission and generation infrastructure, some high-level commentary of the evolution of electric sales and rates, and a summary of the state's most recent integrated resource planning outcomes.

3.1. Current Electricity Market

Overall Structure

Florida's electricity market is one of the largest markets in the U.S., second to Texas on a net generation basis and third behind Texas and California on a total retail sales basis. In 2017, Florida's net generation and total retail sales were 238 TWh and 233 TWh, respectively, accounting for approximately 6% of generation and sales in the country.[22] Investor-owned utilities (IOUs) make up 75% of generation in the state, with the remainder owned by cooperatives and municipal utilities.

Florida operates under a regulatory authority from the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (FPSC). Under the Federal Power Act (FPA), FERC has regulatory authority of wholesale transmission and power (i.e. transmission and sales for resale in interstate commerce). In addition, FERC oversees corporate activities and transactions of public utilities (e.g. mergers and acquisitions), enforces prohibition of energy market manipulation, and ensures the reliability of the bulk-power system through the development of mandatory standards and compliance mechanisms. FERC delegates authority over system reliability to the North American Electric Reliability Corporation (NERC). A majority of the state of Florida, the peninsular area east of the Apalachicola River, is part of the Florida Reliability Coordinating Council (FRCC) NERC region, and the remainder of the State is a part of the Southeast Reliability Corporation (SERC). Over 95% of electricity sales in Florida take place in the FRCC region.

The FPSC oversees, to varying degrees the operations of IOUs, municipally-owned electric utilities, and rural electric cooperatives.[23] It regulates all aspects of the state's IOUs operations, and has jurisdiction over rate structure, territorial boundaries, bulk power supply operations and planning for municipals and cooperatives. In addition, the FPSC requires preparation and conducts an annual review of utility TYSP to ensure that the plans are suitable to the state's expected electricity needs. Through its regulatory oversight, the FPSC

[22] TWh = 1,000 GWh. "State Electricity Profiles," EIA, January 8, 2019. Available at: https://www.eia.gov/electricity/state/

[23] "Facts and Figures of the Florida Utility Industry," FPSC, May 2018. Available at : http://www.psc.state.fl.us/Files/PDF/Publications/Reports/General/Factsandfigures/May%202018.pdf

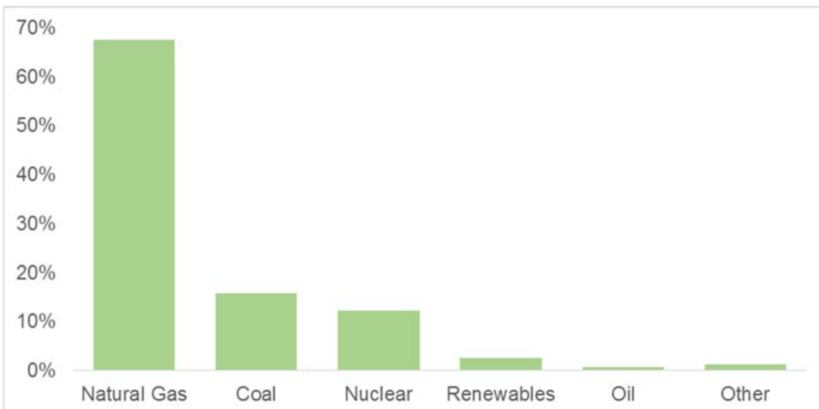
ensures that generation investments made by the Florida IOUs are prudent and cost-effective for all customers.

3.2. Generation and Transmission Infrastructure

Generation, Load, and Rates

Nearly all sales of electricity in Florida take place in the FRCC region. This section focuses on the overall Florida market, its load and generation profile, and its transmission system. Overall, retail sales of electricity in Florida have grown 1.1% annually from 2012 (220 TWh) to 2017 (233 TWh).[24] Florida grew capacity grew to meet increasing demand – mostly driven by additions of low-cost natural gas generation, which now comprises 68% of the total generation in Florida (see Figure 8).

Figure 8: State of Florida Electricity Generation by Primary Energy Source - 2017 [25]



Investments made by Florida's IOUs in generation have supported a stable electricity market with enough reserve capacity to meet the standards required by the FPSC (20%) and producing flat to declining electricity rates over the last 10 years (see Figure 9) – contrasting to the decline in reserve margins experienced in Texas as described in section 2.3.1. above.

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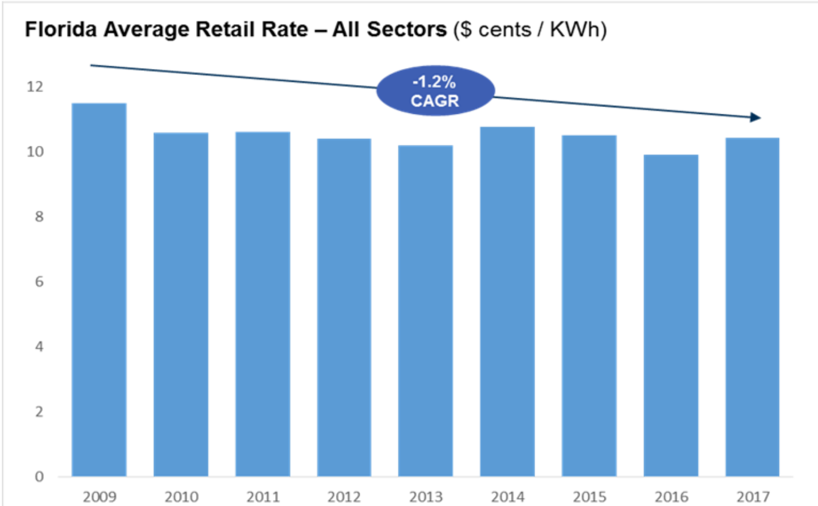
24 EIA – Florida State Energy Profile

25 EIA – Florida State Electricity Profile

Figure 9: Florida Average Retail Rates – 2009 to 2017



Electric Transmission

Florida has a high voltage network of transmission lines up to 500kV AC. In 2012, NERC reported[26] that the FRCC region had 12,031 circuit miles of transmission lines rated 100kV and above. The FPSC review of Ten-Year Site Plans (TYSP) also noted that 220 miles of additional mileage has been approved and are expected to enter service between 2018 and 2019[27]. The Florida peninsula maintains 3,400 MW of summer import capacity and 800 MW of summer export capacity[28].

The FRCC has not identified any specific short-term reliability-related need for additional major transmission capacity for the next ten years. Planned transmission projects by the utilities are primarily purposed towards system expansion for demand growth, resource integration and long-term reliability. There have been no identified transmission constrained areas within FRCC. FRCC is expected to meet all NERC requirements for transmission planning in both the near and long term[29].

Natural Gas Transmission Infrastructure

Florida is supplied with natural gas through three major interstate pipelines: Florida Gas Transmission (FGT), Gulfstream, and Sabal Trail. Additional gas is also supplied by two minor pipelines: Gulf South Pipeline (western panhandle) and Southern Natural Gas (portions of north Florida).

FGT pipeline is a 5,325 mile pipeline that originates in Texas and follows the Gulf Coast delivering natural gas to both the panhandle and the peninsula of Florida (where it

26 2012 Long-Term Reliability Assessment, North American Electric Reliability Corporation. November 2012

27 REVIEW OF THE 2018 TEN-YEAR SITE PLANS OF FLORIDA'S ELECTRIC UTILITIES, Florida Public Service Commission. November 2018

28 The winter import capacity is 3,400 MW and the winter import capacity is 400 MW; 2018 Facts & Figures of the Florida Utility Industry, Florida Public Service Commission.

29 2018 Long-Term Reliability Assessment, North American Electric Reliability Corporation. December 2018

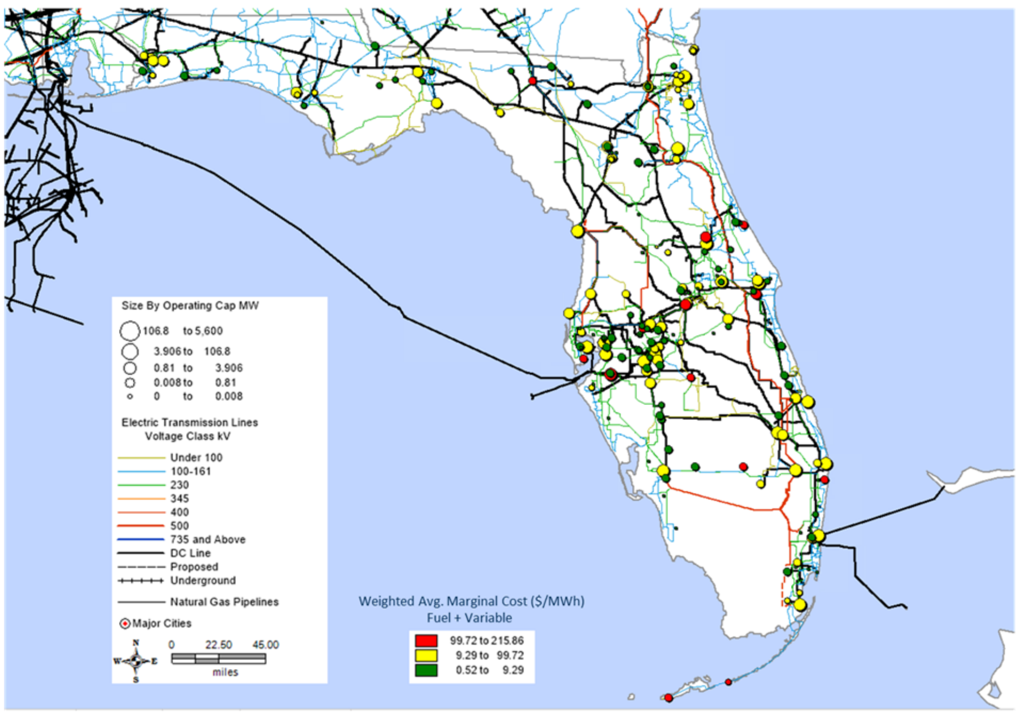
terminates). It has a capacity of 3.1 Bcf/d. It transports 66% of the natural gas consumed in Florida[30].

Gulfstream is a 745 mile under-water pipeline transporting gas from Louisiana via the Gulf of Mexico to the Tampa Bay region with a capacity of 1.3Bcf/d[31].

Sabal Trail Transmission is a 517 mile pipeline that originates from Alabama and cuts through Georgia. It serves the northern peninsula and terminates at the Central Florida Hub. It has a capacity of 0.83Bcf/d. Since any additional expansions of FGT and Gulfstream would likely be cost prohibitive, further capacity expansions would likely have to be based on Sabal Trail.

However, any pipeline expansion under a restructured market scenario would be significantly more challenging. Pipeline owner and developers require long term ‘take or pay’ contracts on firm demand – which is not typically feasible in restructured markets as wholesale markets are driven by short term sales. Moreover, transitioning to a restructured markets will likely have a major impact on current natural gas supply contracts with potential for large litigation costs and/or additional stranded cost impacts.

Figure 10: Summary of Florida Energy Infrastructure - Gas and Electric



3.3. Summary of FPSC Ten-Year Site Plans

Ten-Year Site Plans (TYSP) are the ultimate product of the Integrated Resource Plan (IRP) process where utilities illustrate how they will serve their customers over the long-term. They offer a window into a utility’s estimates for future growth and their investment plans to meet

30 Florida Gas Transmission. https://fgttransfer.energytransfer.com/ipost/FGT/turnpike-palmetto/company-profile?active=companyProfile

31 http://gulfstreamgas.com/

load for the next ten years. These plans are made with risk and cost minimization in mind with the best possible information available at the time. They include scheduled retirements and planned additions in generation that will affect the generation mix.

The most recent TYSP does not reflect any electricity market restructuring. But, uncertainty created by the proposed ballot initiative would impact future utility investment in new generation. If restructuring takes place, the new TYSP would require significant changes.

Overall, the filed TYSP of 11 reporting utilities in Florida project consistent load growth, both in terms of number of customers and retail energy sales, over the study horizon. To meet this growth, utilities expect to expand renewable generation resources by an estimated 7 GW with solar photovoltaics being the primary expanded resource. Furthermore, non-renewable resources are expected to add 8.2 GW of capacity, primarily made up of natural gas-fired generation. 5.7 GW of natural gas fired generation has already been approved and will be in service by 2022. As a result, the electrical grid is expected to rely on natural gas plants for around 65% of generation consistently for the planning period. About 6 GW of existing generation is currently expected to be retired over the study horizon, primarily consisting of coal plants and natural gas combustion units.[32]

Table 3: Expected Net Capacity Additions 2018-2027 per Filed 2018 Ten Year Site Plans

Company	Solar PV*	Natural Gas Com-bined Cycle	Coal	Natural Gas Steam	Natural Gas Com-bustion Turbine	Oil / Gas Turbine	Total
FPL	3,803	2,941	(254)	(884)	(1,626)	-	**3,980**
DEF	2,300	2,318	(766)	-	(131)	(24)	**3,697**
TECO	598	1,118	(385)	-	-	-	**1,331**
GPC	-	595	(150)	-	(12)	-	**433**
FMPA	149	-	-	-	-	-	**149**
GRU	-	-	-	(75)	(35)	-	**(110)**
JEA	84	-	(1,002)	-	-	-	**(918)**
LAK	-	-	-	-	-	-	**-**
OUC	56	-	-	-	-	-	**56**
SEC	40	1,108	(630)	-	-	-	**518**
TAL	40	-	-	(76)	100	-	**64**
RCI**	50	-	-	-	-	-	**50**
FRCC	**7,120**	**8,080**	**(3,187)**	**(1,035)**	**(1,704)**	**(24)**	**9,250**

*Solar PV additions include planned PPAs in addition to utility-owned capacity. Solar PV capacity represented in this table is net capacity, not firm capacity.
**Reedy Creek Improvement District did not submit a Ten-Year-Site Plan (nor is it required to).

32 REVIEW OF THE 2018 TEN-YEAR SITE PLANS OF FLORIDA'S ELECTRIC UTILITIES, *Florida Public Service Commission*. November 2018

3.4. State and Local Government Revenues and Costs

In Florida, a large portion of state and local government revenues are collected from electric utility taxes and fees. Utilities pay taxes to state and local governments based on the gross receipts accumulated through electricity sales, taxes based on the value of their physical property, and, in many cases, franchise fees for using the public right-of-way occupied by their facilities and exclusivity rights.

Restructuring would significantly alter both tax structures and utility business revenues, which will, in turn, would result in tax revenue losses for state and local governments. Although the overall impact to tax revenues will depend on how much retail electric rates change,

Florida state and local revenues are primarily expected to decrease regardless of rate changes due to the elimination of franchise fees, reductions in public service taxes, and reduced property taxes from lower valuations of IOU generation assets (current combined net taxable book value of ~$20 Billion).

Restructuring will also require policymakers to rethink fundamental tax system issues, including how to provide fairness among different types of electricity suppliers, how to educate consumers on tax system changes, how to minimize unanticipated losses in tax revenue, and how to prevent concentrated property tax losses in municipalities that host IOU generating facilities. The potential impacts of restructuring on franchise fees and property tax revenues are discussed in more detail in Section 4.3.

<u>Summary of taxes paid by IOUs impacting state and local revenues – 2017</u>

- Property Tax: ~$1,000 million
- Municipal Public Service Tax: ~$880 million
- Franchise Fees: ~$650 million
- Gross Receipt Tax: ~$450 million

4. Potential Impact of Electricity Restructuring in Florida

In the previous sections, we provided context and background about electricity market restructuring across the U.S. and the current situation in the Florida electric market. For the remainder of the report, we will focus specifically on the potential impact of restructuring the Florida electricity market on the state and local governments according to the language in the ballot petition.

4.1. Proposed Ballot Initiative

Unlike market restructuring in other states, the Florida Ballot Petition proposes a constitutional amendment. This would require a more stringent process than required by ordinary legislation.

If subsequent changes need to be made to the energy market design, it would need to go through the same stringent process. For example, if the restructured market fails to attract robust competition or to achieve the desired outcomes on issues such as reliability and environmental concerns, it would take a change to the constitution to remedy the situation.

As stated in the Ballot Summary below, the proposal would limit IOUs to construction, operation and repair of T&D systems only. There is no mention of ‘owning’ the T&D assets in the current language.

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.

As we will discuss later in this section, this amendment will likely cause a significant net decrease in tax revenues for the state. Since the state of Florida has a supermajority requirement for raising new taxes or fees, any effort to enact new tax laws to compensate for the tax revenue losses would require two-thirds approval in both chambers (House and Senate).

Our analysis does not consider the impact of also divesting the T&D systems as stated above. If that is indeed the case, the impact would be considerably more negative than the estimates described below.

4.2. Approach for Impact Quantification

The following sections analyze the potential impact to Florida's tax revenues and costs (state and local) that could arise from restructuring the electricity market. The impact to tax revenues is multi-faceted and is characterized by significant uncertainty in regards to changes in the tax structure after the restructuring. CRA's analysis is focused on the existing tax structure and assesses the impacts of the proposed new restructured regime.

We have divided the potential impact assessment into four sections to provide a more detailed review of the proposed change. The first three sections focus on potential revenue losses associated with the three main tax schemes in Florida affected by restructuring: (i) franchise fees, (ii) Municipal Service Tax and (iii) property tax, while the fourth provides a wider review of potential cost impacts to functions related to the state and local government. We will also discuss the risk to the Gross Receipt Tax revenues and the potential impact of higher electricity rates on tax revenues and government costs (i.e. impact on electricity bills).

Since the potential tax impact relies on valuation of generating plants currently owned by the utilities, it is important to understand how the value of these assets would be affected by restructuring.

Overview of Approaches to Asset Valuation

The impact of restructuring on property taxes is focused on the change in the Fair Market Value of the generation resources after the state moves to the restructured regime. An appraisal of utility assets is performed each year to estimate the Fair Market Value for the utility's tangible property. Valuations may be performed through a cost approach, an income approach, or a market-based approach (sometimes called a comparables approach, or unit approach) to valuation. CRA considered all three of these approaches to estimating the Fair Market Value for generation assets in Florida under restructuring. This section provides a brief overview of these valuation methods.

The income approach to valuation estimates the Fair Market Value of an asset based on market participant expectations of the cash flows that the asset would generate over its remaining useful life. An essential component of the income approach is the estimation of future cash flow a market participant would expect to generate from operating the asset.

The estimated cash flows for each of the years in the discrete projection period are then converted to their present value equivalent using a rate of return appropriate for the risk of achieving the projected cash flows. The present value of the estimated cash flows are then added to the present value equivalent of any residual value of the asset at the end of the projection period to arrive at a Fair Market Value estimate.

The cost approach estimates the Fair Market Value of an asset by using the economic principle that a buyer will pay no more for an asset than the cost to obtain an asset of equal utility. This approach provides an indication of value by calculating the current replacement or reproduction cost of an asset and making deductions for physical deterioration and all other relevant forms of obsolescence.

The last major valuation approach is the market based, or comparables, approach. Under the comparables approach, a Fair Market Value is estimated based on how similar assets were valued in the past through sales or other market related operations. The comparables approach includes the multiples method, which uses an applicable financial metric that can be measured for both the asset in question and the asset for which the information is known. This metric is then applied on the unknown asset to estimate its value.

Although more robust, the income and cost based approaches could not be utilized in CRA's analysis. Ideally, this analysis would be done on a plant-by-plant basis, taking into consideration locational impacts and common use facilities. Due to a lack of data and production cost modeling capability, CRA estimated the post-restructuring Fair Market Value of generation assets in Florida using the multiples comparables method.

Market Based Valuation Approach

The comparables approach to estimate the Fair Market Value of assets after restructuring is comprised of two steps. The first step is to determine an appropriate financial metric that is measurable both for the regulated generation assets in Florida and for restructured assets. Because there are currently no restructured assets in Florida, we estimate the impact of restructuring by a comparison to assets that participate in established markets.

Specifically, we use a comparison of the values of publicly traded Independent Power Producers (IPPs). IPPs are most suitable to the comparables approach and to estimating the Fair Market Value of restructured generation assets because their business and assets base is primarily generation and they do not own other tangible assets such as transmission. Therefore, the relationship between IPP tangible[33] and book values[34] can provide a reasonable estimate of the impact of restructuring on the taxable values of generation assets.

Under a restructured market, the tangible book value metric provides a Fair Market Value estimate for all tangible assets, such as generation plants. To estimate the Fair Market Value under a restructured regime, CRA used the comparables method, using the ratio between book value and tangible book value of IPP merchant generators as a metric for comparison. By looking specifically at the tangible book values of IPP merchant generator companies, which operate only in generation, we are able to isolate the market value of generation plants in restructured markets.

Assuming a constant number of shares for both book value and tangible book value per share, CRA estimated the following ratios. The average of these ratios suggests that under a restructured market regime, the Fair Market Value of generation assets will be about 60% lower than their book value. Table 4 below depicts four major IPPs and their book to tangible book ratios.

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[33] Tangible book value is what common shareholders can expect to receive if the firm is under impairment and all of its assets are liquidated at their book value. Intangible assets, such as goodwill or employee knowledge, are removed from this calculation since they cannot be sold during this process.

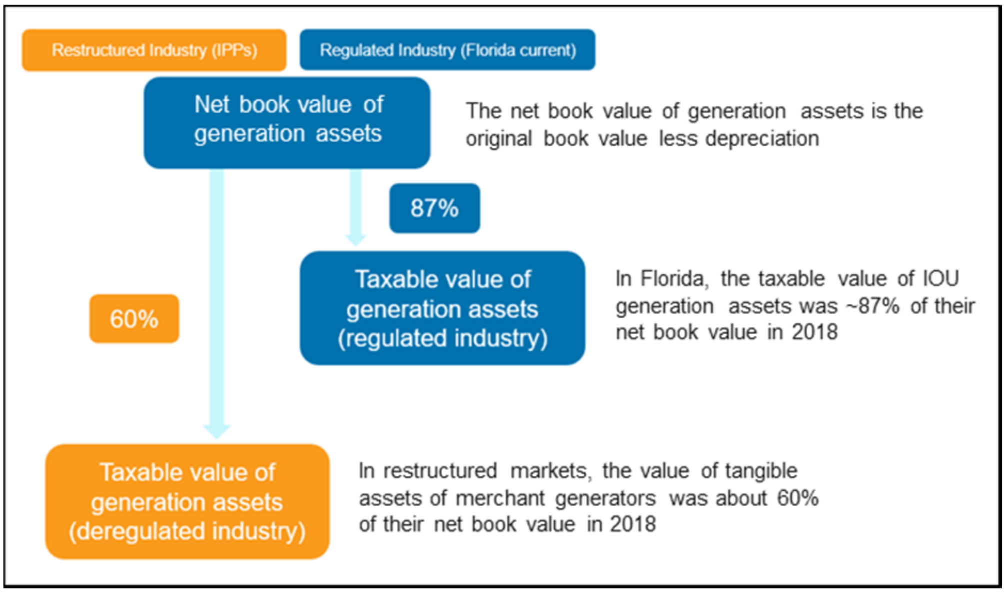
[34] The book value is a business or asset's value as recorded in the balance sheet. It reflects a business or asset's cost when it was acquired less depreciation, i.e. the value lost as the asset ages. Although depreciation as recorded on the balance sheet differs from the asset's actual depreciation, it provides a reasonable estimate.

Table 4: Tangible Book Value to Book Value Ratios of IPP Merchant Generators, 2018

Company	Ticker	Book Value per Share	Tangible Value per Share	Ratio
Vistra	VST	17.4	3.9	23%
AES	AES	5.0	1.6	31%
Calpine	CPN	8.3	9.1	109%
TransAlta	TAC	5.9	4.2	70%
Average	-	**9.2**	**4.7**	**~60%**

A review of generating assets in the current regulated market in Florida shows that in 2018, the taxable value for the IOU owned generating plants was, on average, 87 percent of the 2018 book value.[35] Using these comparables, we estimate a post-restructuring change in the Fair Market Value of generation assets in Florida of negative 27 percent. Figure 11 below summarizes these conclusions. The impact of this change in taxable values to municipal property tax revenues is further discussed in Section 4.3.

Figure 11: Book Value to Taxable Value in Regulated and Restructured Industries



4.3. Financial Impact Potential to Florida State and Local Governments

In this section of the report, CRA details the impacts to state and local governments under the most probable potential outcomes as described above after restructuring is implemented. The tax revenues will be affected when the state transitions to the new structure.

Moreover, municipalities and local jurisdictions are particularly vulnerable to restructuring due to a number of current, locally-imposed utility taxes that directly fund municipal activities. Most notably, impacts to the utility franchise fee, municipal public service tax, and property tax could result in significantly lower local tax revenues.

Decreases in these tax revenues could have a drastic negative effect on local jurisdictions because their budgets are based on projected revenues received from these taxes.

35 Publicly available financial statements for Florida IOUs

Policymakers will be forced to rethink local tax structures in order to fill any gaps created in their municipal budget, which may take years.

4.3.1. Property Tax

At present, property taxes on residential and commercial real estate provide Florida county governments with one of their largest sources of revenue, and even the single largest one in some cases. In fiscal year 2017-18, for example, property tax was the largest component of annual revenue in Hillsborough County[36] with the franchised IOU in Tampa, Tampa Electric (TECO), being the largest property taxpayer in the county.

In general IOUs, which own the most personal property utility assets in the state, tend to contribute the highest amount of property tax revenues to municipalities. In FY 2017-18, Florida IOUs jointly paid $1.03 Billion in property taxes to local governments.[37] About 31 percent of FPL's $2.3 Billion in total FY 2018-19 taxes and fees was paid through property taxes, of which over a third was paid on generation-related properties.[38]

Utilities pay a significant amount of property taxes on their generating plants to the local jurisdictions in which they are located. As a result, under industry restructuring, the amount of personal property taxes collected by local governments will be affected by:

- Changes in property values as a result of sales of utility assets;
- Retirement of a power plant that is unable to compete in the deregulated market; and
- Differences in approaches to valuing and taxing utility and non-utility property.

In assessing the changes in property values, CRA constructed three different scenarios to provide a range of potential outcomes after restructuring. The first scenario identified as "industry restructuring only" maintains the current generating and transmission resources footprint and focuses primarily on the changes in the Fair Market Value of the generating plants using the market based valuation approach described in section 4.2.

The second scenario called "limited closure of units" assumes that some high cost units of the generation fleet would be closed as the new merchant generation owners attempt to improve profitability by removing unprofitable units while seeking to increase pricing.

The supply gap would be met by increasing electricity imports up to the existing inter-connection capacity limit. Based on our assessment of the Florida electric system, we expect that only a small portion of the fleet would be at risk of closure.

Lastly, the third potential outcome called "displacement of units by new generation" assumes the partial close of this generation gap by adding new low cost generation capacity consisting of either solar PV or new natural gas combined cycle plants, without expanding interstate gas pipeline capacity.

Since CRA did not conduct an expansive bottom-up plant level production cost modeling analysis, it relies on the application of industry trends that will most likely reflect future outcomes under the new deregulated environment.

Even though the analysis is not technical, CRA's decisions ensure fundamental energy constraints are met such as resource adequacy within Florida and infrastructure constraints

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36 https://www.hillsboroughcounty.org/library/hillsborough/media-center/documents/budget/fy-18-19/fy18--fy19-adopted-budget.pdf?la=en&hash=647991EDEE434F4D378B64A575F98540DCC0BFF5,p.65

37 Florida Chamber of Commerce data

38 Florida Chamber of Commerce data

(i.e. electric transmission and natural gas pipeline capacities). Also, the generating resources chosen for closure were based on extensive analysis using the following criteria:

- Location and potential impact on transmission congestion
- Impact on overall reserve margins for the state
- Focused on large units of more than 300 MW capacity
- Marginal cost position of the generating assets
- Industry trends such as coal retirements

The following table depicts an overview of the scenarios and their impact on the current property tax.

Table 5: Description of Scenarios and Assumptions Used in Analysis

Scenarios for consideration	Generation Capacity		New Gas / Electric Transmission Capacity	**Property Tax Loss Impact** ($ millions)
	Closures	New Capacity		
Industry restructuring only	None	None	None	**110**
Limited closure of units	3,300 MW	None	None	**140**
Displacement of units by new generation	5,000 MW	1,500 MW CC 3,500 MW PV	None	**60**

4.3.2. Franchise Fee

A franchise fee is a contracted fee charged to a private company for the privilege of using the city's rights-of-way. In general, the franchise fee is assessed to entities because of three main reasons[39]: *it is fair rent for the use of the city's rights-of-way to derive a private profit; it is consideration for the city to agree not to compete with the private party during the term of the franchise agreement;* ***and it is a fee paid the city to offset the costs incurred by the city as a result of the private party's disparate or exclusive use of public property*****.**

The estimation of the franchise taxes varies among towns and cities in Florida and it is uncertain how this tax will be affected after restructuring. However, the concept of the assessed entity to be conducting business within the town or city limits is applicable and is identified throughout the franchise related documentation we reviewed.

In most Franchise Fee contracts, there is specific language that allows for utilities to exit the contract if there is a loss of exclusivity, which clearly takes place in a market restructuring. Since there is no clear guidance on the ballot initiative or in the current law on how the franchise fees will remain after the restructuring, CRA assumes that they will be completely

[39] Town of Longboat Key – Fiscal year 2015 Adopted Budget

eliminated. **The elimination of the franchise fees will result in $650 million loss in tax revenues per year.**

4.3.3. Municipal Public Service Tax

Municipal Public Service Taxes (MPST) are locally imposed on retail customers for the purchase of electricity that is consumed within the municipality. The tax is collected by the utility based on payments received, then paid to the municipality or county. In effect, the MPST is a pass-through tax imposed on the customer, where utilities act as agents or collectors on behalf of the state. Though it may differ by municipality, the tax is typically levied at a rate of 10 percent of payments received from retail customers, with total tax revenues of ~$880 million in 2018.

In a restructuring scenario as proposed by the ballot initiative, each municipality would be likely to lose the revenue earned from the MPST imposed on generation. Under the provisions of the current statute terms, the conditions typically apply to utilities and not generation providers. As such, these statutes would no longer be applicable to the situation in a restructured market.

We estimate that approximately 30 to 40 percent of total taxes were related to generation (estimate based on property tax values). Using this approximation to estimate the generation portion of the MPST revenue, we estimate that the municipalities would lose between **$250 million and $350 million in MPST revenues in total. If IOUs are also forced to divest their T&D assets, the municipalities would likely lose the full $880 million.**

4.3.4. Gross Receipt Tax

Currently, Florida levies a 2.5% tax on the gross receipts of electricity sales. In 2017, the total Gross Receipt Tax (GRT) collections in Florida amounted to over $1.16 Billion for all utilities (including gas, water, and electricity), of which an estimated $450 million was collected from Florida IOUs.

Because GRTs are paid based on a fixed percentage of a firm’s total revenue, any changes to prices or quantities sold of electricity will directly affect the GRT tax base, in turn impacting the amount of tax revenues collected from utilities. Restructuring is certain to reduce utility revenues collected from generation assets, which will be removed from utility ownership and, consequently, from the utility gross receipts tax base. For some IOUs, this effect alone could significantly reduce gross receipts tax payments. Florida Power & Light (FPL), for example, whose projections show 70% of its 2019 revenues to be generation-related, would cease to pay the corresponding proportion of GRT to the state of Florida under restructuring, representing a loss of over $173 million in annual revenue to the state government.[40]

Any reduction in GRT payments will have a direct negative impact in Florida public education funding. A 1974 constitutional amendment earmarked GRT collections for funding of capital outlay needs of public schools (PECO), community colleges, and state universities.[41] As a result, changes in utility GRTs feed directly into the funding available for PECO use.

Finally, any additional potential negative impacts to transmission, distribution, or customer-related revenues, such as possible decreases in retail electric rates, will further reduce tax revenue received by state governments, although the exact magnitude of this effect cannot be known in advance. GRT revenues are additionally threatened by the possibility that consumers will switch to out-of-state energy providers under retail choice. Because the GRT

[40] Public record of FP&L financial statements

[41] http://edr.state.fl.us/content/revenues/reports/tax-handbook/taxhandbook2018.pdf

cannot be applied to out-of-state companies, these providers can offer consumers lower rates by excluding the tax electric rates. Out-of-state suppliers' energy charges would thus escape the GRT altogether, causing an additional reduction in revenues for Florida government.

Additionally, higher electricity rates resulting from restructuring could potentially increase GRT collections. However, any increase related to higher rates would be more than offset by higher government electric bills by a factor of 4 to 1. Given that state and local governments make up approximately 10% of the state's total electricity consumption, for every $100 of increase rates, we would see a $10 increase in government bills and an increase in GRT of $2.5. We conducted a sensitivity analysis that showed that **for every 10% increase in rates, the state would incur additional electricity costs of $120 million which would be partly offset by a higher GRT of $30 million – or a net loss of $90 million.**

Given the high degree of uncertainty, we are unable to precisely quantify the impact of restructuring to GRT collections. However, based on a range of 60% to 70% of GRT associated with generation, we can say that **$270 million to $320 million of annual GRT collections will be at risk.**

4.3.5. State and Local Government Costs

Based on our research as highlighted in sections 2.2 and 2.3, we estimate that if Florida undergoes a similar process to other restructured states (especially Texas), **the potential increase in PSC related costs for electric industry oversight, external consulting fees and others would range from $30 million to $80 million**. Some examples of the key potential drivers of higher cost to the PSC included in this range are listed below.

<u>Additional resources required to oversee ISO or RTO functions and new markets</u>

The new construct will require additional oversight by the state commission in regards to new market designs, policy initiatives and consumer advocacy. Inevitably, the state regulators will act as the consumers' representatives at the ISO or RTO functions and will actively participate in all FERC cases that apply to in-state efforts. Based on the review of other PSCs similar to Florida (i.e. Texas, New York) and applying the relative increase to current FPSC costs, **we expect this increase to be up to $5 million per year.**

<u>Consulting and contractor costs associated with the ramp-up period leading up to restructuring</u>

Current FPSC staff is not well versed into the intricacies of restructured market design. Therefore, they will require the assistance of external experts to navigate through and understand the new regime. The consulting fees will be initially high due to the active participation of the PSC staff in the formation of the ISO or RTO and the transition to a restructured regime. Based on the review of other PSCs similar to Florida (i.e. Texas, New York) and applying the relative increase to current FPSC costs, **we expect this to range from $5 to $10 million initially with over $5 million annually post implementation.**[42]

<u>Development and enforcement of market definitions and controls and increased participation in litigation</u>

One of the most critical functions of the FPSC staff after the implementation of the new construct will be the initiation and deployment of safeguards around fraud and market malfeasance. As evidenced by the number of litigation cases related to the electric industry significantly increased after restructuring in Texas.

This significant increase in cases necessitated a more active role for the Texas Commission and its staff. Based on the review of other PSCs similar to Florida (i.e. Texas, New York) and

[42] These estimations were based on information on comparable costs identified in Maine during the transition.

applying the relative increase to current FPSC costs. **Active participation in litigation by the PSC may result in more $5 million per year in added cost.**

Additional siting and permitting costs for transmission

The restructured regime will not remove the sitting and permitting costs oversight by the FPSC that is currently in place. As seen in other jurisdictions, the new construct will likely increase the amount of transmission investment required for Florida in a restructuring scenario. Thus, increasing the burden for oversight in regards to transmission planning and construction prudency.

States in PJM, ISO-NE and MISO have incorporated a Certificate of Public Convenience and Necessity (CPCN) process to ensure that any new transmission and generation investments benefits exceed costs. These cases under the new market structure are more involved since market related studies have to be conducted that were not necessary before, which in effect will increase the FPSC staff workload since incremental documents will need to be reviewed.

An increase of 10% in new costs due to these incremental functions and cases, will add close to $5 million per year.

New public assistance programs to offset higher rates for low income families

Lastly, CRA's research indicated that an increased amount of public assistance programs is typically needed under restructured regimes due to increased electricity costs and fraud. A recent study conducted by the National Consumer Law Center for Massachusetts showed that:

> *For the period of June 2016 through May 2017, Connecticut residential customers who purchased electricity through competitive supply companies paid $66,736,598.41 more that they would have paid their regulated public utility companies for the same electric service. In Illinois, residential customers who purchased electricity from competitive supply companies spent an additional $152,108,081 from June 2016 through May 2017 over the prices charged by regulated public utility companies. In New York, residential and some small commercial customers overpaid by $817 million between January 2014 and June 2016, and* ***low-income customers overpaid by almost $96,000,000*** *during the same period, compared to the prices charged by regulated public utility companies. Massachusetts customers paid $176,800,000 more than what they would have paid for electricity from their utility, during the period of July 2015 through June 2017* [43]

Since a large portion of costs are incurred by low income consumers, these higher bills may also cause a portion of state and federal low income assistance funds to be absorbed by for-profit competitive supply companies. States such as Connecticut, New York, and Illinois have taken steps to protect consumers from high prices and deceptive practices. However, these efforts are still in progress and the low income assistance programs are still negatively affected. A more careful investigation and a deployment of safeguard for low-income consumers will drive even higher the cost of the state regulatory commission. Implementing programs to safeguard and educate low income consumers and provide relief to those that participate in these programs can add a significant amount of cost to the state. Given the high degree of uncertainty since it depends on the extent of increased rates and number of low-income ratepayers impacted, we are not able to quantify the potential impact. However, **based on the example of other jurisdictions, the annual negative impact would likely be $100's of millions.**

Additionally, for the electricity rate sensitivities, we have assessed the potential higher costs impact to state and local government related to increased electricity bills. Currently, state and

43 http://www.nclc.org/images/pdf/pr-reports/competitive-energy-supply-report.pdf

local governments collectively pay ~$1.2 Billion annually to the Florida IOUs for electric service. Increased electricity rates would directly impact government costs offsetting benefits from higher sales taxes. As noted above, a **10% increase in rates would have a negative impact of $120 million per year.**

Recovery of Generation Stranded Costs

A major unintended consequence of restructuring that will have a lasting impact on customers relates to stranded cost recovery. Stranded costs are based on investments and other commitments utilities have made pursuant to their obligation to serve their customer base throughout their existence. Costs associated with these commitments that may not be able to be recovered in a competitive electricity market are referred to as "stranded."

In Texas, estimates of stranded costs were considered during the transition to deregulation in order to provide for early mitigation and recovery, as applicable. The process of estimating and recovering of these costs was very convoluted and required multiple years to complete consuming significant amount of time and resources. Due to fluctuating market conditions over time and regulatory decisions, estimates of stranded costs ranged from negative $2 Billion - during periods of high natural gas prices making higher-cost plants more economical - to over $6.5 Billion. **By the time the issue was fully litigated in Texas, the total amount to be recovered from customers amounted to over $9.5 Billion.**

4.4. Impact of Restructuring – Summary of Findings

The table below provides a summary of the range of impacts to state and local governments.

Table 6: Summary of the Ranges of Annual Impacts to State and Local Governments

<table>
<tr><th colspan="2" rowspan="2">Negative Financial Impact by Major Category</th><th colspan="2">Range Estimate ($ millions)</th></tr>
<tr><th>Low</th><th>High</th></tr>
<tr><td rowspan="4">Revenue Losses</td><td>4.3.2. Franchise Fees</td><td>650</td><td>650</td></tr>
<tr><td>4.3.4. Gross Receipt Tax</td><td>270</td><td>320</td></tr>
<tr><td>4.3.3. Municipal Public Service Tax</td><td>200</td><td>300</td></tr>
<tr><td>4.3.1. Property Tax</td><td>60</td><td>140</td></tr>
<tr><td rowspan="2">Higher Costs</td><td>4.3.5. Administrative Costs</td><td>30</td><td>80</td></tr>
<tr><td>2.3.2. RTO or ISO – impact of higher rates</td><td>20</td><td>25</td></tr>
<tr><td colspan="2">Total Potential Impact</td><td>1,230</td><td>1,515</td></tr>
<tr><td colspan="2">4.3.5. Incremental impact from higher electricity rates – net impact of revenue and costs for every 10% rate increase</td><td colspan="2">90
(GRT and government electricity bills)</td></tr>
</table>

The ranges quantified above are not meant to be a comprehensive evaluation and represent a conservative view of the overall potential impact of restructuring the Florida electric market. There are several other impacts that have not been included given the availability of information, time constraints, and degree of uncertainty.

Below is a non-exhaustive list of additional challenges identified but not quantified at this time. All of which would further impact local and state governments in Florida adversely.

- Public assistance for low income, elderly and fixed-income ratepayers
- Litigation, regulatory, and consumer advocacy cost for unfair practices
- Recovery of stranded costs for IOU generation assets
- Grid reliability investments and ancillary services
- Natural gas supply availability constraints and price risk
- Job loss impact of closures and lower government spend (driven by revenue losses)
- Economic impact of higher electric rates – e.g. job losses or slower economic growth
- Incentives required to attract sufficient Provider of Last Resort (‘POLR’) suppliers

Florida electricity market would have a negative financial impact of $1.2 to $1.5 Billion annually to Florida state and local governments. Furthermore, this impact could be considerably worse based on additional challenges not yet quantifiable due to the high degree of uncertainty and risk associated with the proposed petition ballot.

FISCAL IMPACT OF A PROPOSED CONSTITUTIONAL AMENDMENT TO DEREGULATE FLORIDA'S INVESTOR-OWNED ELECTRIC UTILITIES

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Executive Summary

- There is an amendment proposed to Florida's constitution that would allow customers of Florida's investor-owned utilities the right to choose their electric provider and to generate and sell electricity. If passed, the amendment would deregulate the retail electricity market currently regulated by the Florida Public Service Commission.

- It is important to point out that the provision of electricity is widely understood to be a natural monopoly. As a result of the economies of scale in the production and distribution of electricity, consumers are expected to have the lowest costs in markets that allow providers to exploit these economies through the grant of monopoly provision under regulation. And in fact, this is what the data demonstrate.

- Residential electric rates in Florida are 10 percent below the U.S. average. Florida's average rate is 11.61 cents per KWh while the U.S. average is 12.89 cents per KWh.

- In addition, since 2010 residential electric rates in Florida have increased at just a 1.5% pace outperforming 86 percent of the other states.

- Proponents of utility deregulation promote the belief that most consumers will see significant reductions in their electric bills. To date seventeen states have deregulated their retail electric markets, and residential electric rates are higher than the national average in fifteen of the seventeen deregulated markets.

- Proponents of the Florida initiative point to Texas as the best, case-study for what they project for Florida under deregulation. Results from Texas contradict claims that deregulation will produce lower residential electric rates. To the contrary, since deregulation in Texas in 2002, those areas deregulated have experienced higher residential electric rates than those in regulated areas every single year. The total cost to Texas consumers is estimated at $22 billion.

- Deregulation in Florida would cause an enormous loss in government revenues ranging from no less than $325 million per year to as much as $1.2 billion per year. Most of this is caused by the termination of existing franchise agreements and a reduction in the taxable value of electric generation and transmission facilities.

- We cannot presume the Legislature will raise taxes or find new revenue sources for any decrease in local and state revenue shortfalls due to adoption of this proposed restructuring amendment. Therefore, our analysis will provide the lost revenues to local and state government absent any additional Legislative tax increases. Accordingly, the negative impact to local and state government will be very significant.

- Deregulation would compromise the benefits of the natural monopoly in provision of electric service. In addition, deregulation would increase the risk associated with generating and distributing electricity. As a direct result, the values of Florida's generation and transmission systems would decline. For these reasons, deregulation would cause a huge loss in local government revenues.

    - Overall tax loss estimates range from $324 million to $1.2 billion per year.

- Finally, deregulation would have the unintended consequence of reducing electric system reliability. This is in fact what has happened in Texas.

1.0 Introduction and Background

1.1 Introduction

As discussed below, a proposed amendment to Florida's constitution that would allow customers of Florida's investor-owned utilities the right to choose their electric provider and to generate and sell electricity. If passed, the amendment would deregulate the retail electricity market currently regulated by the Florida Public Service Commission.

The generation and distribution of electricity is widely understood to be a natural monopoly where increasing economies of scale are dominant. In such markets the lowest cost of service results from exploiting these economies while at the same time regulating the monopolistic providers to prevent exploitation of their monopoly position.

As a result, electrical utilities have traditionally been vertically integrated with each company responsible for electric generation, transmission and distribution to the end-user customers. In order to protect consumers and smaller utilities from monopolistic pricing, electric rates are typically regulated by state and federal governments. The regulated prices have been based upon actual costs, along with an allowance for the cost of construction of new capacity and allowance for a profit margin typically calculated as a return on rate base.

In Florida, there are five investor-owned electric utilities (IOUs) that provide the vast majority of electricity to consumers. These utilities are regulated by the Florida Public Service Commission, which regulates electricity prices based upon fuel costs, capital costs, administrative costs and a return on investment.

Regulated utilities have a duty provide for the ever-increasing demand for electricity. They are responsible for planning and constructing new capacity in time to meet the new demand. The regulated pricing structure allows the utilities to recapture their capital investment over time with fees included in each end users monthly bill.

In the 1990's, inflation, price volatility and demand for new electricity generation facilities led to ever increasing electricity prices. The higher prices charged to consumers spawned a movement toward deregulation of electric utilities. These efforts were spearheaded primarily by industrial entities in the hope that greater competition would result in lower electricity prices and the potential for favorable terms of service. Deregulation of the industry was seen as been a tool used to increase competition with the expectation of lowering consumer prices and increased innovation. In order to facilitate competition by electricity generators, unbundling of the generation from the transmission and distribution functions has to occur. Unbundling can facilitate the entrance into the market by third-party suppliers. The new competition, along with other economic factors can lead to productive innovation in both generation and transmission systems, dynamic pricing mechanisms, demand response programs, smart metering and green pricing programs. The unbundling can also result in higher costs for accounting processes, transmission sharing and capital capacity for the electrical generator as well as higher prices for the electricity consumer.

A petition was filed for the Energy Choice Amendment ballot initiative which would amend Florida's constitution to allow voters to decide whether or not to approve the deregulation of the investor owned electric utility (IOUs) markets in the state. Specifically, the Energy Choice Amendment requires the Legislature to implement language that entitles electricity customers to purchase competitively priced electricity.

The language ultimately enacted by the Legislature must: 1) limit the activity of investor owned electric utilities to construction, operation and repair of electrical transmission and distribution systems; 2) promote competition in the generation and retail sale of electricity through various means, including limitation of market power; 3) protect against unwarranted service disconnections, unauthorized changes in electric service, and deceptive or unfair practices; 4) prohibit any granting of either monopolies or exclusive franchises for the generation and sale of electricity; and 5) establish an independent market monitor to ensure competitiveness of the wholesale and retail electric markets. The Energy Choice Amendment's requirement that the Legislative implementation provide an entitlement of electricity customers to "competitively priced electricity" directs the Legislature to honor the chief purpose of the amendment.[1]

1.2 States with Deregulated Electrical Utilities

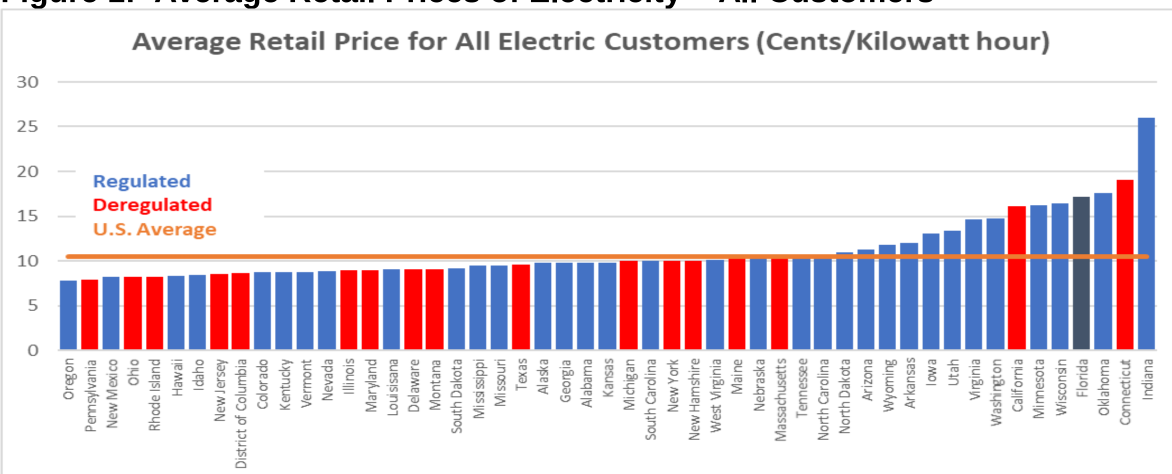
Deregulation of electrical utilities has occurred primarily in states with relatively higher electric rates. There are currently seventeen states which have either deregulated or partially deregulated their electrical utilities. These include: California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island and Texas. Utility customers in the deregulated states are able to choose their electricity provider, which may not be the same as the electricity generator. This distribution utility purchases the electricity that it sells to its retail customers from the wholesale market comprised of the electric generation companies.

[1] Memorandum to Financial Impact Estimating Conference; Citizens for Energy Choices; February 11, 2019.

1.3 Comparative Electrical Prices

Figure 1 shows the weighted-average price of electricity in each state. The states in red indicate deregulated and partially deregulated utility states. The average for the U.S. is 10.48 cents per KWh. Most of the deregulated states appear to have electric prices at or below the average for the country. This data seems to show that Florida consumers pay much higher prices for electricity than most of the rest of the country.

Figure 1: Average Retail Prices of Electricity – All Customers



Source: U.S. Energy Information Administration

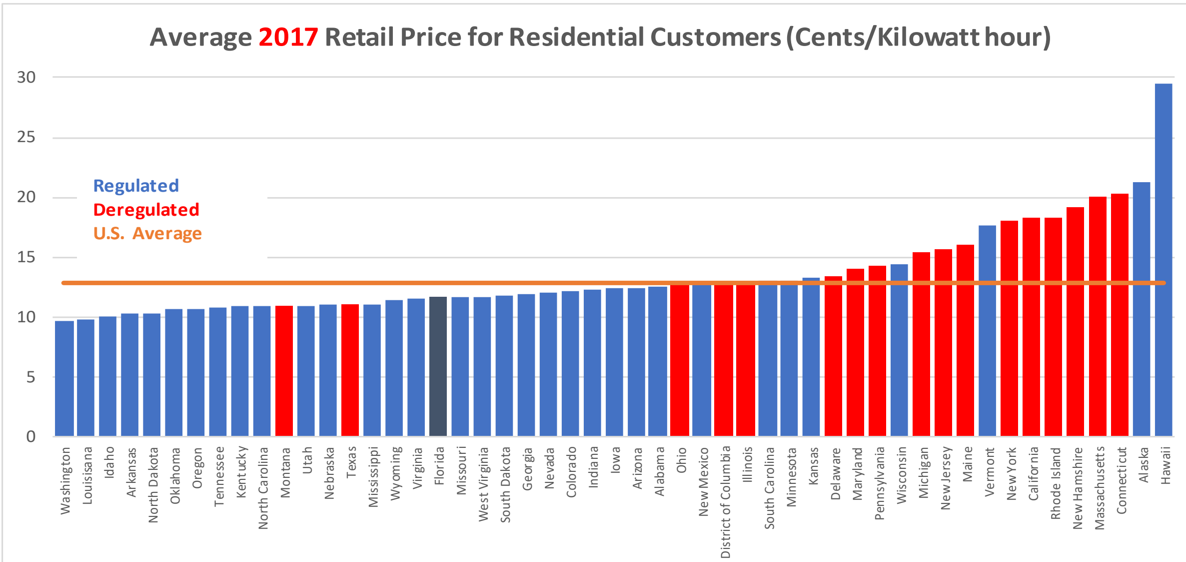
However, the data used in Figure 1 do not provide a complete picture of the impact of deregulation. Many of the deregulated states have significant numbers of high-energy consuming industrial plants. In deregulated states, the high-energy consumers are able to negotiate contract pricing which is significantly lower than the standard prices offered to most other consumers. This price differential for the high energy consumers skews the weighted average electricity price. Florida has few heavy industrial plants so its average electricity price is therefore less impacted by contract discount pricing.

Proponents of utility deregulation promote the belief that most consumers will see significant reductions in their electric bills. Figure 2 shows what the actual impact of electric prices is for residential consumers. This graph shows that most of the deregulated utilities still continue to charge residential user rates that are above the U.S. average. JBS Energy, Inc. produced a cross-sectional regression analysis of the impacts of deregulation on electricity prices. They found that "there is about a 10 percent increase in residential rates associated with deregulation."[2]

[2] Does Deregulation Raise Electric Rates? A Cross Sectional Analysis; William B. Marcus; JBS Energy, Inc.; December, 2011.

The data also show that the electric rates paid by Florida residential customers are 10 percent below the U.S. average. Florida's average rate is 11.61 cents per KWh while the U.S. average is 12.89 cents per KWh.

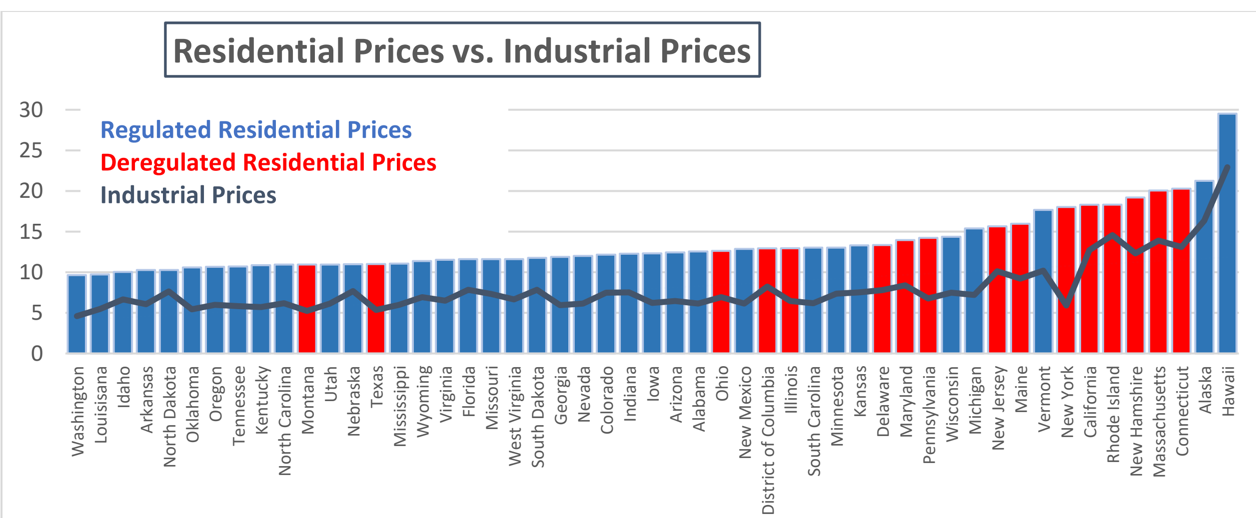
Figure 2: Average Retail Price of Electricity for Residential Customers



Source: U.S. Energy Information Administration

The price break given to major industrial power users is evident in Figure 3. In most cases, the average price that residential customers pay is over 40 percent higher than the prices paid by industrial users.

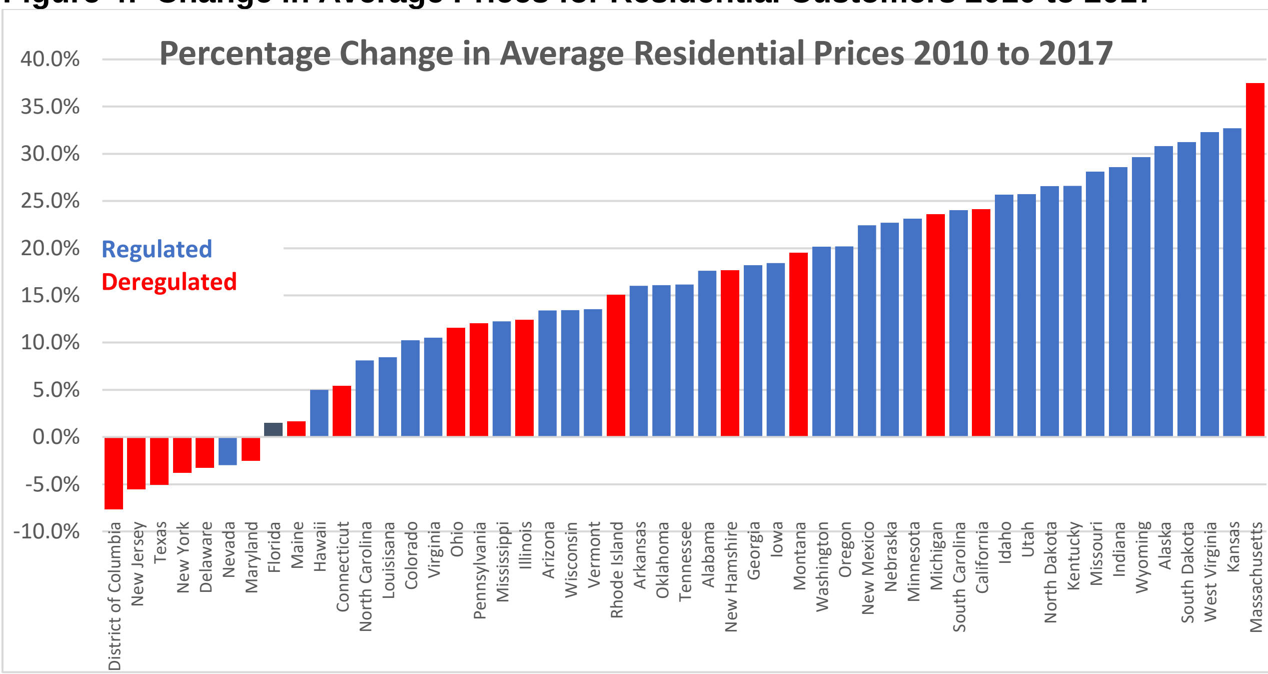
Figure 3: Residential Electricity Prices vs. Industrial Prices



Source: U.S. Energy Information Administration

Prices for electricity are heavily dependent upon fuel prices. Most generation plants in deregulated states use natural gas as fuel. As the price of natural gas increased, so has the price per KWh charged to the consumer. With recent moderations in the price of natural gas, many of the deregulated utilities have been able control their price increases and some, like New Jersey, Texas and New York have even been able to modestly reduce their retail pricing (Figure 4). Deregulation has enabled some utilities to gain control over their energy costs, but most deregulated utilities still charge residential customers more than the U.S. average price.

Figure 4: Change in Average Prices for Residential Customers 2010 to 2017



Source: U.S. Energy Information Administration, Fishkind & Associates, Inc.

Florida utilities have performed very well with only a 1.49 percent increase in rates over the 2010 to 2017 period, faring better than 86 percent of the other states.

1.4 Case Study Findings

Texas

Texas began its deregulation process in 1999 and reached full deregulation in 2002 for selected market areas of the state. Electrical utilities in some portions of Texas are still fully regulated. Initially the retail electric providers were required to charge rates that were 6 percent below the regulated rates.[3] This became known as the "price to beat", the price that new competitors tried to beat with lower rates. The price to beat mechanism included provisions to increase the price when natural gas prices increased, but did not include a mandate on lowering the price when fuel prices decreased. The result was that electricity prices escalated, but never came down.

Texas is also unique in that the state has taken jurisdiction over both the wholesale and retail electricity markets. Deregulation was theoretically supposed to lead to new generation capacity to be built where and when it is needed. This has not happened in Texas as "the state is now faced with significant reliability challenges due to generation reserve shortages."[4] An energy emergency has resulted in rotation outages to keep the system functioning.

The role of the Electric Reliability Council of Texas (ERCOT) was expanded to include overall control of the power grid for most of the state. The transmission system in Texas is not designed for the new dynamic deregulated market. Improper linkage systems, computer programming issues and management problems led to service problems. The restructuring of the system took many years longer than projected and was substantially above original cost estimates. There are persistent issues with moving power from places with extra power to places where additional power is necessary.[5]

In response to the reliability problem, the cap on wholesale power prices was increased to $9,000 per MWh, about 300 times the average wholesale electricity price.[6] Texas has the nation's highest wholesale price cap for energy.[7] This "fix" has not led to significant capacity improvements. It seems that deregulation has fostered a short-term outlook by investors rather than the long-term, consumer-oriented view taken my regulated utilities.

[3] Deregulated Electricity in Texas, A History of Retail Competition; Texas Coalition for Affordable Power; March 2014.
[4] Electric Industry Deregulation: A Look at the Experience of Four States; Public Sector Consultants, March, 2014.
[5] Deregulated Electricity in Texas, A History of Retail Competition; Texas Coalition for Affordable Power; March 2014.
[6] Electric Industry Deregulation: A Look at the Experience of Four States; Public Sector Consultants, March, 2014.
[7] Deregulated Electricity in Texas, A History of Retail Competition; Texas Coalition for Affordable Power; March 2014.

The reliability issues created a demand for additional electricity to be purchased on the spot market. Surges in demand created temporary surges in pricing. "Under the ERCOT-managed spot market, the cost of the highest acceptable bid for power dictates the price to all successful bidders."[8] In other words, even the lowest price bidders get the highest bid price for their power. This situation was fertile ground for exploitation by some energy providers and spurred regulatory investigations, lawsuits and bankruptcies.[9]

Six of these wholesale energy providers (including Enron) were found to have profited by incorrectly projecting their own energy needs. They reported shortages that created the appearance that power demand did not match power availability. This allowed them to get paid extra for relieving congestion that did not actually exist.[10]

Deregulation in Texas created additional consequences. The utilities experienced major problems with billing and IT systems which were costly to both customers and providers. The existing laws made it difficult for new providers to enter into the market. Market manipulation and other abuses forced legislative structural changes to be made to the wholesale market. Some third-party suppliers became very aggressive in signing up customers without proper authorization. Deregulation has required new legislation and resulted in major litigation in order to deal with the cost recovery of the utilities stranded costs.[11]

In Texas, most deregulated utilities have primarily natural gas generation facilities. As a result, the lack of diversity in generation type led to significant price volatility when natural gas prices increased. The regulated utilities have a greater mix of generation facilities and have experienced much less price volatility. Over the past decade, deregulated areas of Texas have consistently paid more for electricity than regulated areas of the state.[12]

Overall, electricity prices In Texas have been declining in recent years and are now below the national average. However, the first decade of deregulation led to price hikes that suggests that consumers paid $22 billion more for electricity than they would have without deregulation.[13]

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[8] Ibid
[9] Ibid
[10] Ibid
[11] Ibid
[12] Electric Industry Deregulation: A Look at the Experience of Four States; Public Sector Consultants, March, 2014.
[13] Deregulated Electricity in Texas, A History of Retail Competition; Texas Coalition for Affordable Power; March 2014.

California

California was the first state to deregulate its electric utilities. The wholesale market was deregulated, while the retail rates were regulated for most providers. Initially, rates were capped at 50 percent above the national average for up to four years. The law allowed the recapture of stranded costs from residential and small business consumers. The utilities used much of this stranded cost revenue to fund stock buy-back plans and to purchase out-of-state utilities for their investment portfolios. Utilities were encouraged to unbundle their capital facilities.

Since wholesale price increases could not be passed on to retail consumers, new providers determined early on that there was little profit to be made serving residential customers. Within months of deregulation the bid prices for reserve power jumped from $1 to as much as $9,999. Enron and other suppliers manipulated the market by withholding electricity causing artificial shortages and rolling blackouts. These shortages resulting in very high surge pricing forcing the wholesale electricity prices to be increased to record levels and consumer bills to be tripled. The wholesale energy costs rose above the fixed retail prices paid by consumers. Regulations prevented utilities from discontinuing service so utilities were forced to purchase spot market electricity at prices above which they billed their customers. As a result, many utilities lost their financial reserves and some went bankrupt. The contrived energy shortages with the resulting higher electricity prices also stymied investment in new capacity. Building new capacity would result in lower prices and lower profit.

In 2001, the State entered into a $10 billion power buying plan with electricity generation providers in an attempt to prevent further blackouts and prevent the bankruptcy of a major utility. The State was spending $40 to $50 million per day in the energy spot market securing power.

California's experience with deregulation is a case study in what can go wrong. The many causes for the crisis in the state include: a shortage of generating capacity; wholesale generator market fuel price increases; shortsighted legislation; and faulty market design. The State, the utilities and all electric consumers lost significant amounts of money as a result of the poorly legislated, mismanaged deregulation.

Illinois

The Illinois' electric utilities were deregulated in 1999 for commercial and industrial customers, eventually expanding to include residential customers. The deregulation process in Illinois was protracted taking years. The State imposed rate caps for 10 years, effectively preventing alternative suppliers from entering the market. In 2007, the rate cap expired and prices surged 26 to 56+ percent for residential customers and 60 to 70+ percent for commercial and industrial customers. State Attorney General filed complaint against the wholesale suppliers for perceived market manipulation. The State finally created a new state agency to oversee the electricity planning and procurement process.

For a period afterwards, the alternative suppliers were saving consumers money on electricity. By 2017, the alternative suppliers pricing was higher than that of the major utilities.

New Jersey

New Jersey has historically had some of the highest electricity costs in the country. It passed legislation that deregulated the electric utilities in early 1999 expecting that there would be a decrease in prices and an increase in suppliers. Prices for all customers were capped at 10 percent below 1999 prices for four years. This spawned very few alternative suppliers. After the rate caps expired, the cost of electricity jumped higher. New Jersey still has one of the highest electricity rates in the country.

During the first ten year under deregulation, the residential participation in alternative providers was also very low, about 1 percent, until about 2010 when participation rate jumped to about 10 percent. This participation rate is still low in comparison to that of other deregulated states.

New Jersey imports approximately 25 percent of its electricity from other states. The State passed legislation to help support prices as an incentive for utilities to invest in new capacity within the state. These efforts have been fraught with expensive legal challenges. The result is that the State has subsidized the construction of new electric generation plants with tax payors picking up the tab.

Maryland

Electric Utilities in Maryland became deregulated in 1999 by legislature which required utilities to sell their power generation plants. In 2010, a new regulation was implemented which allowed utilities to purchase the customer debt from other third-party suppliers. The utilities could then issue shutoff notices in order to collect unpaid bills. With the debt risk now eliminated, the third-party suppliers were able to raise their prices to whatever the market would bear. Low-income households were targeted with initial low-cost plans by these third-party providers, sometimes by door-to-door solicitations.

The new contracts also allowed for significant rate changes monthly and the implementation of termination or switching fees. An Able Foundation report determined that from 2014 to 2017, third-party customers overpaid by $255 million.[14] An analysis of low-income customers with public assistance for their electric bills found that they were paying, on average, 51 percent more than the standard rates offered by the utility.[15]

[14] Maryland's Dysfunctional Residential Third-Party Supply Market: An Assessment of Costs and Policies; Abell Foundation; Peltier and Makhijani, Ph.D.; December 2018

[15] Ibid.

Maryland utilities, under deregulation have not developed the necessary new electric generation capacity required for the future. The State has passed new legislation in support of the planning, construction and financing additional in-state electric generation facilities. Like New Jersey, these legislative issues have given rise to expensive legal challenges.

Pennsylvania

Pennsylvania was an early entrant into the realm of energy deregulation with legislation in 1996. Rate caps were initially implemented. The rate caps were removed in 2011 encouraging alternative suppliers to enter into the market. Prices for industrial customers were well below the default rates while residential rates were usually higher than the default rates. The suppliers with higher rates appeared to have targeted low-income households as the majority of these paid higher rates. Only 33 percent of residential customers were using the alternative suppliers by early 2018.

Pennsylvania implemented a third-party witness requirement for those asking to switch providers. This helped prevent customers from being switched without their knowledge, a practice known as "slamming".

Ohio

Ohio began the restructuring of electric utilities in 1999 and full deregulation occurred in 2001. The IOUs provided 91 percent of the electric services and were required to unbundle their generation facilities from the transmission and supply facilities.[16] A 5 percent rate cut and freeze was implemented. The rate freeze kept rates artificially low and stifled new competition from entering into the market. The fixed rates also gave little incentive for consumers to switch providers. After the 5-year rate freeze, jumped substantially.

Ohio utilities have placed an emphasis on updating transmission facilities. Generation facilities have not been constructed to meet the predicted demand from growth, leaving the entire system vulnerable to future reliability issues. Pricing and additional capacity issues have forced the Ohio legislature to regularly implement new legislation and assert some control to solve the problems that have occurred as a result of deregulation.

Montana

Despite relatively low electricity costs, Montana decided to deregulate its electric utilities in the late 1990's. It was deregulated for industrial customers in 1998 and for residential and small business customers in 2002. Rate caps were implemented for two years. Most of the utility's infrastructure was sold to out-of-state utilities. As rates increased, some residents attempted to force a buy-back of the sold electric generation facilities. In 2007, Montana started to re-regulate the electric utilities for residential customers.

[16] Updated Electric Industry Deregulation: Ohio Case Study; Public Sector Consultants, Inc. November 2016.

Prior to deregulation, the electric generation and transmission capital facilities were paid for in customer's monthly bills. Now that the facilities have been sold to out-of-state utilities, the monthly electric bills include some of the cost of those facilities that have already been paid for by consumers. "The legacy of deregulation in Montana includes the disintegration of a Fortune 500 Company, the loss to Montana of one of the nation's least expensive and most stable sources of electric supply, explosive rate increases that shocked residents, businesses, and the state economy during the years that deregulation took full effect."[17]

1.5 Stranded Investment Costs and Future Capital Investment

Stranded costs are the expenses associated with a utility's capital investments, in particular the electric generation facilities. These costs create problems for the major utilities that have invested heavily in generation facilities to cover anticipated future demand. Prior to deregulation, these costs were captured by assessments on every electric bill. After deregulation, it is unclear how these costs can be recovered.

The stranded cost problem can have major implications on future electric supply. These costs may cause some electric generating companies with high costs and marginal returns may have to go out of business. Any inability to recover all capital costs may make future investments in additional capacity less likely as loans and/or bonds may not be readily available for new construction.

The burden caused by stranded costs may be left to the shareholders of the utility, in which case the market value of the utility's stock would be significantly depressed. For example, New Hampshire's largest utility company, Public Service of New Hampshire experienced dramatic declined in its stock value after deregulation was announced.[18] Potential solutions may involve issuing bonds and making customers pay monthly to cover the debt service. This solution will certainly be challenged in the courts and be costly. Ultimately, these costs will continue to be borne by the end user.

Utilities not only have a problem recovering their stranded costs, but they also must be concerned about the planning, construction and financing of future capital facilities. The deregulation of utilities decreases their future revenue stream making debt financing more difficult and more expensive. A study published by the International Association for Energy Economics found that research and development declined by 78.6 percent after energy markets are deregulated.[19] The reduction in planning and construction of future capacity can lead to serious future power reliability problems.

[17] Electric Industry Deregulation: A Look at the Experience of Four States; Public Sector Consultants, March, 2014.
[18] Will Northeast Utilities Survive New Hampshire's Rate Cutting?; The New Your Times, Section D, Page 16 (October 16,1997)
[19] Powering Progress: Restructuring, Competition and R&D in the U.S. Electric Utility Industry; Paroma Sanyal, Linda Cohen; The Energy Journal; Vol. 30, No. 2. 2009; pp. 41-79.

1.6 Market Manipulation

Some unforeseen consequences have occurred with the advent of electric utility deregulation in the 1990's. Enron along with some utilities and electric providers engaged in market manipulation in order to boost their profits. Market manipulation in utility markets can occur at several levels. Some utilities restricted the amount of power offered forcing spot-market pricing for the extra electricity needed. Restricting access to transmission lines has the same effect. The manipulation of power exchanges and the spot market wholesale prices allowed higher prices to be charged during high-demand periods. Regulated electricity markets have much less ability to manipulate the market.

2.0 Fiscal Impacts on Local and State Governments

2.1 Property Taxes

Property taxes are imposed by city and county governments and local school districts. The taxes are based upon a taxable value assigned by the local property appraiser. The appraiser established values using three methodologies: 1) construction cost; 2) sales and 3) comparable properties. Most utilities are assessed at a percent of their development costs less depreciation. Deregulation has usually resulting in the separation of the generation assets from the transmission assets and the operational assets. The overall taxable value becomes more difficult to assess for the unbundled assets and can lead to significant decreases in overall system value. Also, the sales approach to valuation could be used to show that the reduced sales from the major utilities due to third-party suppliers, should result in lower taxable values.

The reduction in property taxes from the electric utilities can be substantial. Data from recent sales of power plants have shown that the resulting valuations ranged from 10 percent to 100 percent below net book value. The average discount was 49.6 percent. Nuclear, coal and older generation facilities experienced the largest decrease in net value. This decrease in value may significantly impact counties where these types of plants are located.

As an example, New Hampshire faced an approximately 30 percent decline in local property tax revenues from the electric company's capital facilities, as a result of deregulation.[20] Table 1 provides data showing the property taxes that were paid in 2018 by the Investor Owned Utilities (IOUs). A little over $1.0 Billion was paid by the four IOUs to municipal governments and local school districts. Approximately one-third was based upon the value of generation plants and equipment. The other two-thirds was based upon transmission and operating facilities.

[20] Electric Utility Week, December 22, 1997.

Table 1: Property Taxes Paid by IOUs and Potential Reduction

Provider	Change in Taxable Value	2018 Total Property Taxes Paid to County	2018 Property Tax paid for Generation Plant	Property Tax paid for non-Generation Assets	Potential Total Change in Property Tax Revenue
FPL		$716,442,767	$252,947,136	$463,495,631	
Duke		$247,178,367	$38,809,660	$208,368,707	
TECO		$107,000,000	$53,080,000	$53,920,000	
Gulf Power		$12,499,151	$4,421,372	$8,077,778	
Total		$1,083,120,285	$349,258,169	$733,862,116	
Potential Change in Revenue @	-10.0%		-$34,925,817	-$73,386,212	-$108,312,028
Potential Change in Revenue @	-20.0%		-$69,851,634	-$146,772,423	-$216,624,057
Potential Change in Revenue @	-30.0%		-$104,777,451	-$220,158,635	-$324,936,085
Potential Change in Revenue @	-40.0%		-$139,703,268	-$293,544,846	-$433,248,114

Fishkind projects that there will be at least a 10 percent change in property tax value and revenue. Other studies have shown a potential decrease of 36.9 percent to over 49 percent. This will result in a net decrease of property tax revenue of at least $108 million statewide. The table shows that a potential 40 percent change could result in a net loss of over $433 million annually to local governments statewide.

2.2 Franchise Fees

Franchise fees are provided to local governments as an exclusive right to serve a given territory. Restructuring would completely abolish the exclusivity and territory agreements with state and local governments. The proposed ballot initiative specifically states in Section (c) that the Legislature shall adopt legislation that shall “prohibit any granting of either monopolies or exclusive franchises for the generation and sale of electricity.” Accordingly, existing franchise agreements will be cancelled and voided along with any associated revenues.

Franchise fees are a significant revenue source for local governments. Utilities pay these fees per inter-local agreements. The fees are based upon electricity sales within their jurisdiction. Table 2 provides the 2018 sales from Florida’s IOUs. Total sales of electricity exceeded $12.3 billion. These sales resulted in the payment of $669.0 million in franchise fees paid to local governments.

Table 2: Franchise Fees Paid by IOUs

Provider	Change in Sales	Total Sales Revenue	Franchise Fees Paid
FPL		$9,064,697,681	$476,432,711
Duke		$1,648,531,026	$103,229,419
TECO		$776,550,000	$46,599,000
Gulf Power		$881,050,279	$42,783,514
Total		$12,370,828,986	$669,044,644
Potential Change in Revenue @	-25.0%		-$167,261,161
Potential Change in Revenue @	-50.0%		-$334,522,322
Potential Change in Revenue @	-100.0%		-$669,044,644

The loss of franchise fee from the deregulation process could be substantial. It is possible that each new third-party provider would have to negotiate an inter-local agreement with each city and county government. The losses incurred from deregulation could reach 100 percent. In addition, out of state electricity generation and delivery companies may also be able to provide service to Florida customers. Florida municipalities may lose the franchise fee revenue on retail sales of electricity from out-of-state sellers, as they may not be considered to have nexus not require inter-local agreements.

Taking these factors into consideration, Fishkind has estimated that the loss of franchise fee revenue to local governments as a result of deregulation will cost the state from $167 million to $669 million annually.

2.3 Sales Tax

Sales tax is payable on the retail price of electricity used by end consumers and is collected by the utilities for the State. With deregulation, the retail sale of electricity would be unbundled from the generation and transmission components. In Florida, most services are non-taxable. Deregulation may result in structural changes to the taxability of electricity since the transmission and delivery components may be classified as services. The sales tax regulations may need to be amended and new legislature implemented if deregulation is approved. This process has caused political and legal issues for other states that have implemented deregulation.

Out of state electricity generation and delivery companies may also be able to provide service to Florida customers. Florida may lose the sales tax revenue on retail sales of electricity from out-of-state sellers, as they may not be considered to have nexus. Out of state providers may explore legal means to avoid having to collect and pay sales taxes to the State of Florida.

Another potential consequence of deregulation is the possibility of a decrease in sales tax that may result from price reductions from the sale of electricity. Table 3 provides data showing that $222.1 million in sales taxes was paid in 2018 by the IOUs from the sale of electricity. With all of the potential roadblocks to implementing and collection, a 10 percent reduction in sales tax receipts seems a conservative projection. At this reduction in sales tax, the State and local governments would lose $22.2 million per year.

Table 3: Sales Tax and Gross Receipts Tax

	Change in Total Sales	Sales & Use Tax from Sales	Sales & Use Tax from Purchases	Gross Receipts Tax
FPL, Duke, TECO GP Total		$222,135,913	$67,159,677	$268,735,859
Potential Change in Revenue @	-10.0%	-$22,213,591		-$26,873,586
Potential Change in Revenue @	-20.0%	-$44,427,183		-$53,747,172
Potential Change in Revenue @	-30.0%	-$66,640,774		-$80,620,758

2.4 Gross Receipts Tax

The gross receipts tax, like sales tax, is also based upon utility sales. The gross receipts tax is a state tax that is earmarked for school capital outlay and debt service on capital facilities. The question of taxability of services and the out of state provider factors which could impact sales tax collection will also impact the collection of the gross receipts tax.

Table 3 shows that the IOUs paid $268.7 million in gross receipts tax in 2018. Deregulation could potentially cause a decrease of $26.8 million or more in revenue. This revenue is used to fund new school construction, major school repairs, and capital equipment. It is also used as a basis for bonding and debt repayment of school construction. A loss of $26.8 million per year may result in a loss of bonding power of over $300 million.

2.5 Combined Tax Revenue Impacts

Table 4 provides the projected change in tax revenue that the State, local governments and school districts of Florida may experience as a result of deregulation. The projected loss ranged from $324 million to over $1.5 billion per year.

Table 4: Combined Tax Revenue Impacts

Potential Total Loss of Revenue	
From	-$324,660,367
To	-$1,249,554,290

IMPACT OF DEREGULATION ON ELECTRIC UTILITIES

February 21, 2019

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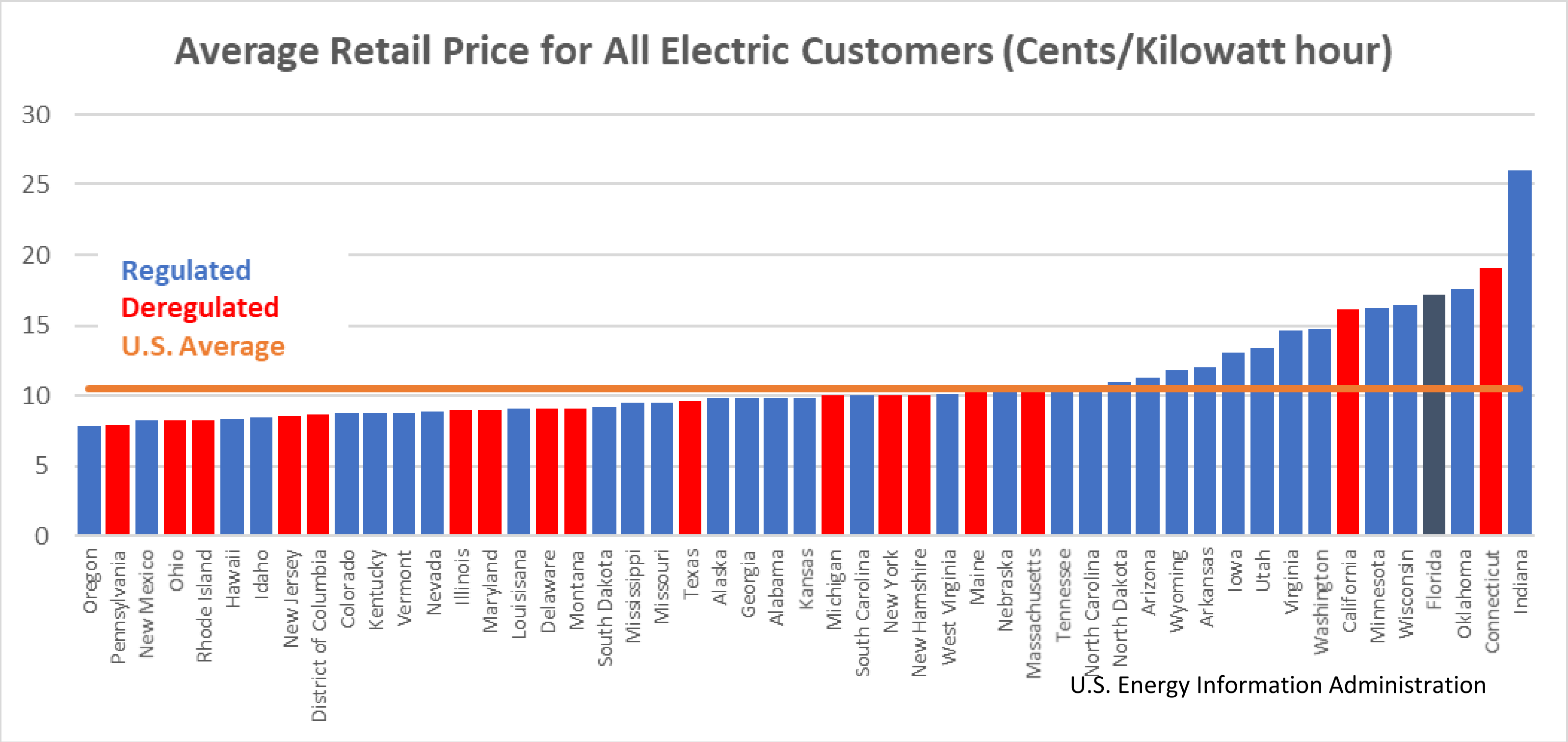
Deregulation Electric Prices 2017

Initial look at overall electric prices suggests that deregulation has been successful.



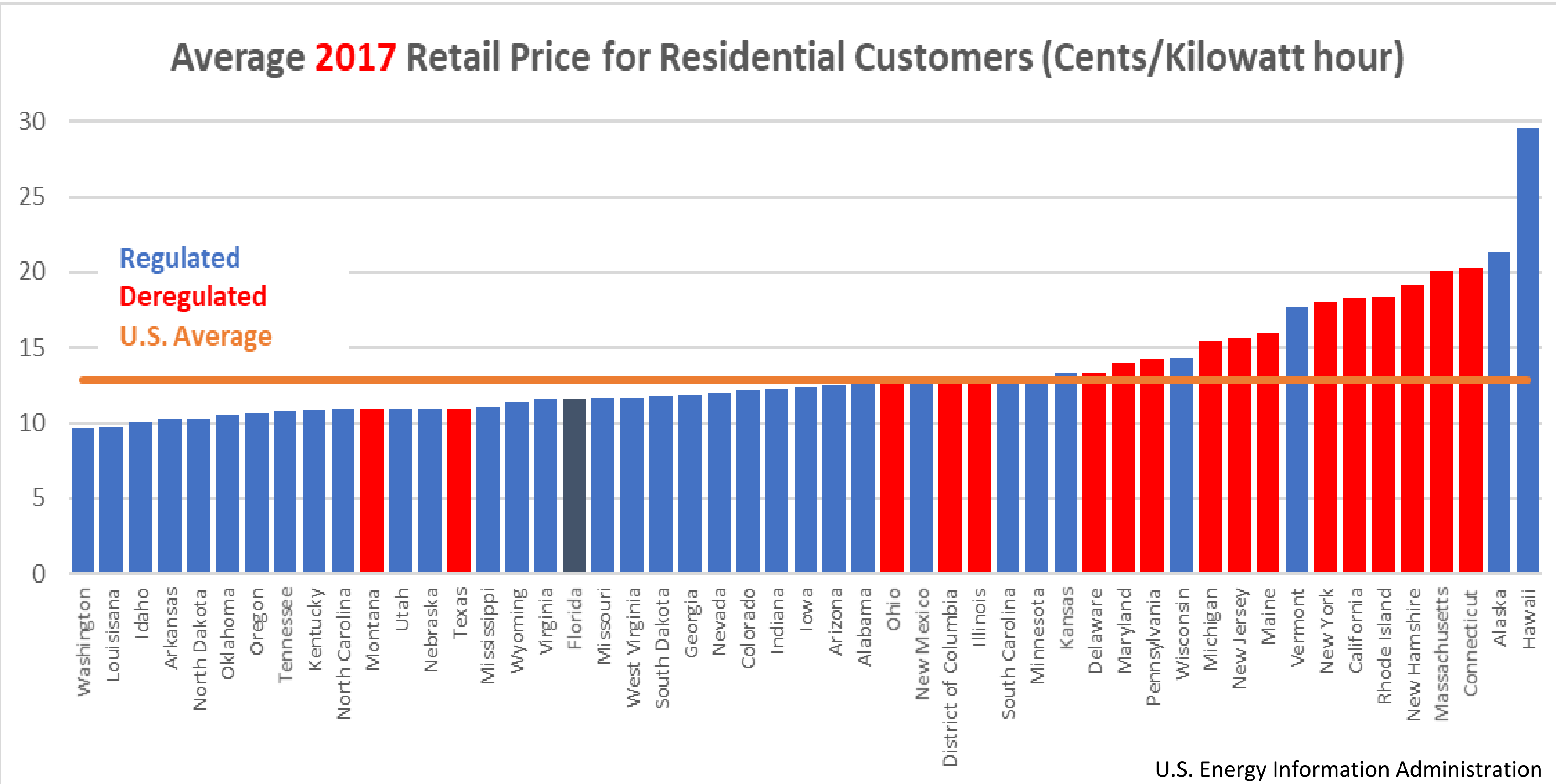
Deregulation Electric Prices 2017

The data shows that the overall average retail price of electricity for most regulated and unregulated states is at or below the U.S. average.

This summary view does not show what the residential consumer pays because the average is skewed by the large industrial consumers that pay heavily discounted prices.

Florida does not have a large industrial base of heavy electric consumers, therefore its average price is much higher that most other states.

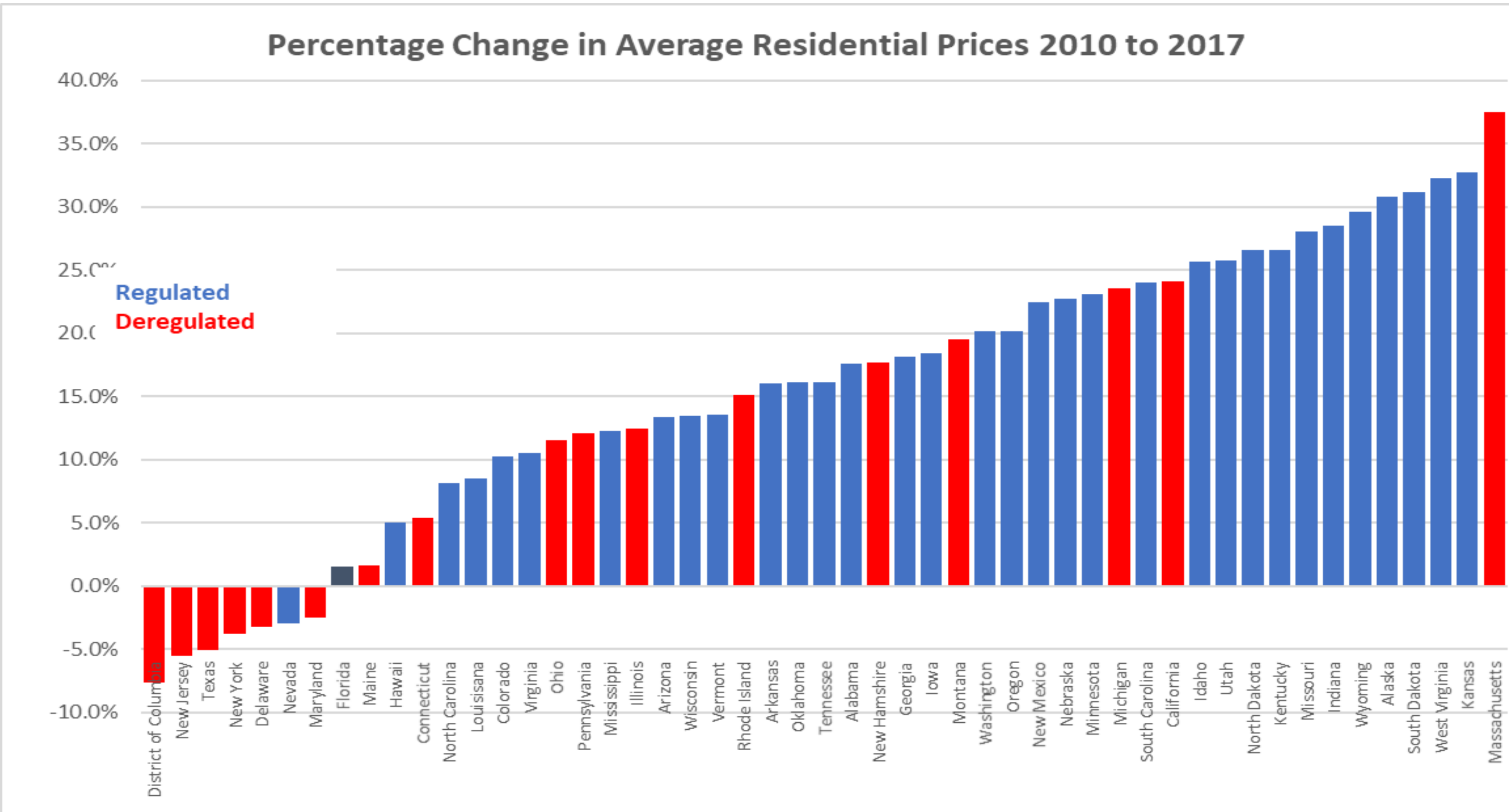
Average Electricity Price for Residential Customers - 2017



Average Electricity Price for Residential Customers - 2017

- This doesn't tell the entire story about deregulation either.
  - Most states that have deregulated their electric utilities had higher average rates than most.
  - Most states that deregulated maintained rate locks for several years, after which prices typically rose significantly.
  - The average price of electricity in Florida for residential customers is well below the U.S. average.

Average Change in Electricity Price for Residential Customers – 2010 to 2017



Average Change in Electricity Price for Residential Customers – 2010 to 2017

- The data show that several of the deregulated states have had either decreases or modest growth in electric prices.
- In recent years, the decreasing cost of fuel and other factors have allowed deregulated utilities to either reduce their high prices or reduce their rate of increases.
- Florida utilities have performed very well with only a 1.5% increase in average rates from 2010.

Deregulation Case Study Findings

- Many states implemented a rate lock for several years following deregulation.
  - This kept rates artificially low
  - Kept new suppliers from entering the market
  - Usually resulted in significant rate increases as soon as the rate locks expired.
- Rates in deregulated states tend to be more volatile.
- Fuel purchased during high demand periods is purchased on the spot market. Often, the least expensive providers are the older, fully depreciated coal plants. Deregulation helps to support this outdated and dangerous energy source.

Deregulation Case Study Findings

- Deregulation has allowed inappropriate market manipulation in certain situations.
  - Manipulation of the wholesale markets occurred and was common for spot market prices to escalate thousands of dollars above cost during high emergency demand (e.g. ENRON and others).
- Deregulation has also allowed providers to offer deceptive rate plans to residential consumers (low rate initially, but skyrockets above a fixed level, or low rate but consumer must pay for at least a fixed amount, etc.).

Deregulation Case Study Findings

- Deregulation usually resulted in or required that the vertically integrated utilities separate their electric generation facilities from their distribution system and from their supply system.
  - The sale of these capital facilities often occurred at a discount, lowering stock prices and property values.
  - The separation of the three business elements makes revenue projections more speculative and thus loans and bonding for new capital facilities are severely impacted negatively. Leading to less capital investment.
  - Short-term profit motivation reduces incentive to invest in future energy generation capacity.

Deregulation Case Study Findings

- Stranded costs are the expenses associated with a utility's capital investments, in particular the electric generation facilities.
- These costs create problems for the major utilities that have invested heavily in generation facilities to cover anticipated future demand.
- Prior to deregulation, these costs were captured by assessments on every electric bill. After deregulation, it is unclear how these costs can be recovered.
- Several states have attempted to solve this issue through legislative directives. These are usually met with costly legal challenges.

Deregulation Case Study Findings

- Deregulation can create structural problems that must be addressed through new legislation, interlocal agreements and lawsuits.
- Sales Tax and Gross Receipts Tax
  – Who pays?
  – What about out of state providers?
  – Distribution and providers are Services and many not be taxable?

Deregulation Case Study Findings

- The future collection of Franchise Fees is another potential problem. These fees are paid to cities and counties through interlocal agreements.
  - Will every new provider have to enter into an agreement with every city and county in its service area?
  - The ballot initiative appears to prohibit the granting of franchises for electricity.
  - This situation could yield a 100% loss of Franchise Fee revenue to Florida's cities and counties.

Impact on Property Taxes

- Case studies have shown that deregulation can result in lower property taxes due to lower retail sales, lower property value, etc.
- Sales data shows that the sale of generation plants are valued at an average of less than 50% of book value.
- The next table shows the property taxes paid by the Investor Owned Utilities in Florida.
- The property taxes paid in 2018 totaled $1.0 Billion.
- Fishkind projects that, at a minimum, there will be a decrease in property tax revenue for the cities and counties in Florida of $108 million per year. Losses have been predicted to be as high as $433 million.

Impact on Property Taxes

Provider	Change in Taxable Value	2018 Total Property Taxes Paid to County	2018 Property Tax paid for Generation Plant	Property Tax paid for non-Generation Assets	Potential Total Change in Property Tax Revenue
FPL		$716,442,767	$252,947,136	$463,495,631	
Duke		$247,178,367	$38,809,660	$208,368,707	
TECO		$107,000,000	$53,080,000	$53,920,000	
Gulf Power		$12,499,151	$4,421,372	$8,077,778	
Total		$1,083,120,285	$349,258,169	$733,862,116	
Potential Change in Revenue @	-10.0%		-$34,925,817	-$73,386,212	-$108,312,028
Potential Change in Revenue @	-20.0%		-$69,851,634	-$146,772,423	-$216,624,057
Potential Change in Revenue @	-30.0%		-$104,777,451	-$220,158,635	-$324,936,085
Potential Change in Revenue @	-40.0%		-$139,703,268	-$293,544,846	-$433,248,114

Impact on Franchise Fees

- The collection of Franchise Fees is dependent upon interlocal agreements between suppliers and local governments. Estimates of up to a 100% loss in revenue have been made.
- We estimate that Florida cities and counties could lose between $167 million and $669 million each year through deregulation.

Impact on Franchise Fees

Provider	Change in Sales	Total Sales Revenue	Franchise Fees Paid
FPL		$9,064,697,681	$476,432,711
Duke		$1,648,531,026	$103,229,419
TECO		$776,550,000	$46,599,000
Gulf Power		$881,050,279	$42,783,514
Total		$12,370,828,986	$669,044,644
Potential Change in Revenue @	-25.0%		-$167,261,161
Potential Change in Revenue @	-50.0%		-$334,522,322
Potential Change in Revenue @	-100.0%		-$669,044,644

Impact on Sales & Use Tax and Gross Receipts Tax

- The collection of sales taxes and gross receipts tax is dependent upon the taxability of electricity.
  - The taxability of the transmission and provision of electricity are both “services” and may result in legal challenges from in state and out of state providers.
- The Gross Receipts Tax is used by the Department of Education to fund Capital Outlay and Debt Service for new facilities.
- The potential range in impacts from decreased sales and prices is provided in the next table.

Impact on Sales & Use Tax and Gross Receipts Tax

	Change in Total Sales	Sales & Use Tax from Sales	Sales & Use Tax from Purchases	Gross Receipts Tax
FPL, Duke, TECO GP Total		$222,135,913	$67,159,677	$268,735,859
Potential Change in Revenue @	-10.0%	-$22,213,591		-$26,873,586
Potential Change in Revenue @	-20.0%	-$44,427,183		-$53,747,172
Potential Change in Revenue @	-30.0%	-$66,640,774		-$80,620,758

Total Fiscal Impact on Tax Revenue for the State, Cities, Counties and Schools

FISHKIND & ASSOCIATES

- A summary of the potential fiscal impacts shows that total revenues of $324 million to $1.2 billion could be lost as a result of deregulation.

Lee County Electric Cooperative, Inc.
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PEOPLE. POWER. POSSIBILITIES.

February 20, 2019

VIA EMAIL TRANSMISSION – edrcoordinator@leg.state.fl.us

The Florida Legislature
Office of Economic and Demographic Research
111 West Madison Street, Suite 574
Tallahassee, FL 32399-6588

Dear Financial Impact Estimating Conference Principals:

SUBJECT: Petition Initiative Entitled: *Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice*

This letter is offered in opposition to the above-referenced petition initiative to amend Florida's constitution. It is our opinion the proposal, if approved, would decrease revenues and increase costs to state and local governments.

Lee County Electric Cooperative ("LCEC") is a not-for-profit electric distribution cooperative providing reliable and cost-competitive electricity to nearly 220,000 member customers in Southwest Florida, including several governmental customers. LCEC is one of the largest electric cooperatives in the United States and began operations in 1940.

We believe the proposed amendment, if implemented, would significantly and adversely impact LCEC's ability to serve its member customers. For example, LCEC has entered into a long-term, "full requirements" wholesale power purchase agreement with Florida Power & Light Company ("FPL") under which FPL provides LCEC with all of the electrical supply it needs to serve its member customers. The proposed amendment would require FPL to divest itself of its electrical generating facilities that support the FPL/LCEC long-term power supply contract. Thus, in the event that the long-term contract is impaired or terminated, LCEC and its customers would face uncertainty and risk in attempting to replace that power in a restructured market. Many states that have restructured their energy markets have experienced generation capacity shortages. Higher wholesale rates would translate into higher retail rates for customers, including for our state and local government customers.

The current electric system has served Floridians, including state and local governments, extremely well for decades with low costs and high reliability. This proposed amendment and its implementation will undoubtedly bring much uncertainty and financial risk to Florida's electric rates and reliability.

Thank you for your consideration of our comments as you prepare your Financial Impact Statement.

Sincerely,

Dennie Hamilton
Executive Vice President
and Chief Executive Officer

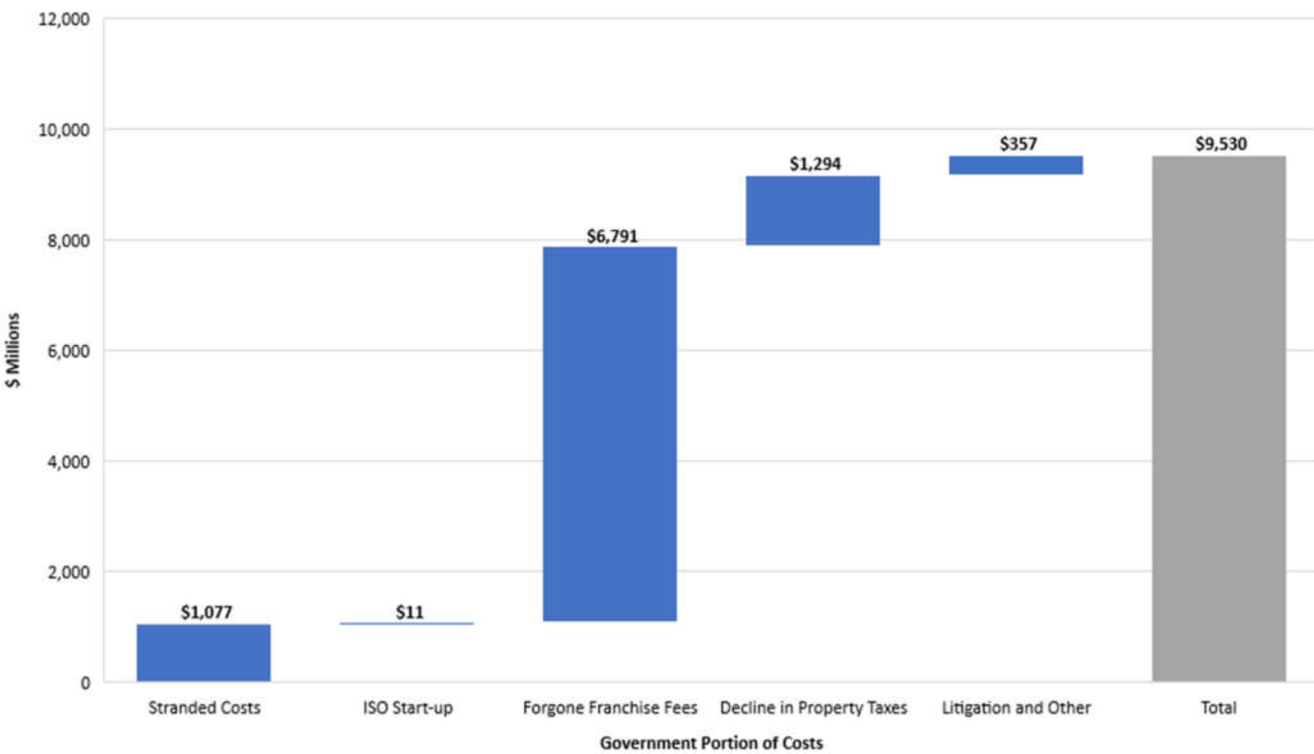
EXECUTIVE SUMMARY

FINANCIAL IMPACT

If approved, the ballot measure *"Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice"* (the "Amendment") would 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. It would dramatically increase the risk and volatility of the state's energy markets.

Over ten years, the minimum impact on state and local government alone is in excess of $9.5 billion. The eventual cost to Florida and its governmental agencies would be much larger.

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



KEY CONCLUSIONS

The plain language of the Amendment is clear: Florida's investor-owned utilities ("IOUs") would be limited to the construction, operation and repair of transmission and distribution ("T&D") systems. As a result, they would be precluded from owning generation, T&D and other electric infrastructure and from providing generation service of any kind. By forcibly expelling IOUs that currently supply electricity to approximately 75% of Floridians from Florida's electric energy market, IOUs would be required 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 unnamed "multiple providers in competitive wholesale and retail electricity markets" or by self-generation, yet there is no guarantee that such a market exists, no back-stop provisions for the adequate generation or delivery of power and none of the price oversight or other protections currently

[1] "Other" includes costs such as ongoing wholesale market operations costs and customer education costs.

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.

At a minimum, the Amendment would:

- Eliminate the state's IOUs from Florida's electric energy market and force the sale or "divestiture" of their more than 50 power plants, more than 150,000 miles of T&D, and other electric infrastructure, creating ***more than ten billion dollars*** in generation-related "stranded" costs alone, which will need to be paid for by or through government action to avoid an unconstitutional "taking";
- Require the formation of an independent system operator, costing customers, including state and local government, ***hundreds of millions of dollars*** in start-up costs and on-going administrative costs;
- ***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;
- 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*** the IOUs have committed in power purchase agreements and natural gas supply and transportation contracts, and investments in transmission and distribution;
- 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.

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 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.[2] Restructuring has not gained ground 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. In fact, numerous states that previously restructured are currently evaluating options to reregulate in some fashion in order to provide price protections and reliable energy supply for their citizens.

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2 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).

COMPETITIVE ENERGY MARKET FOR CUSTOMERS OF INVESTOR-OWNED UTILITIES

SUPPORT FOR FIEC FINANCIAL IMPACT STATEMENT

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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.

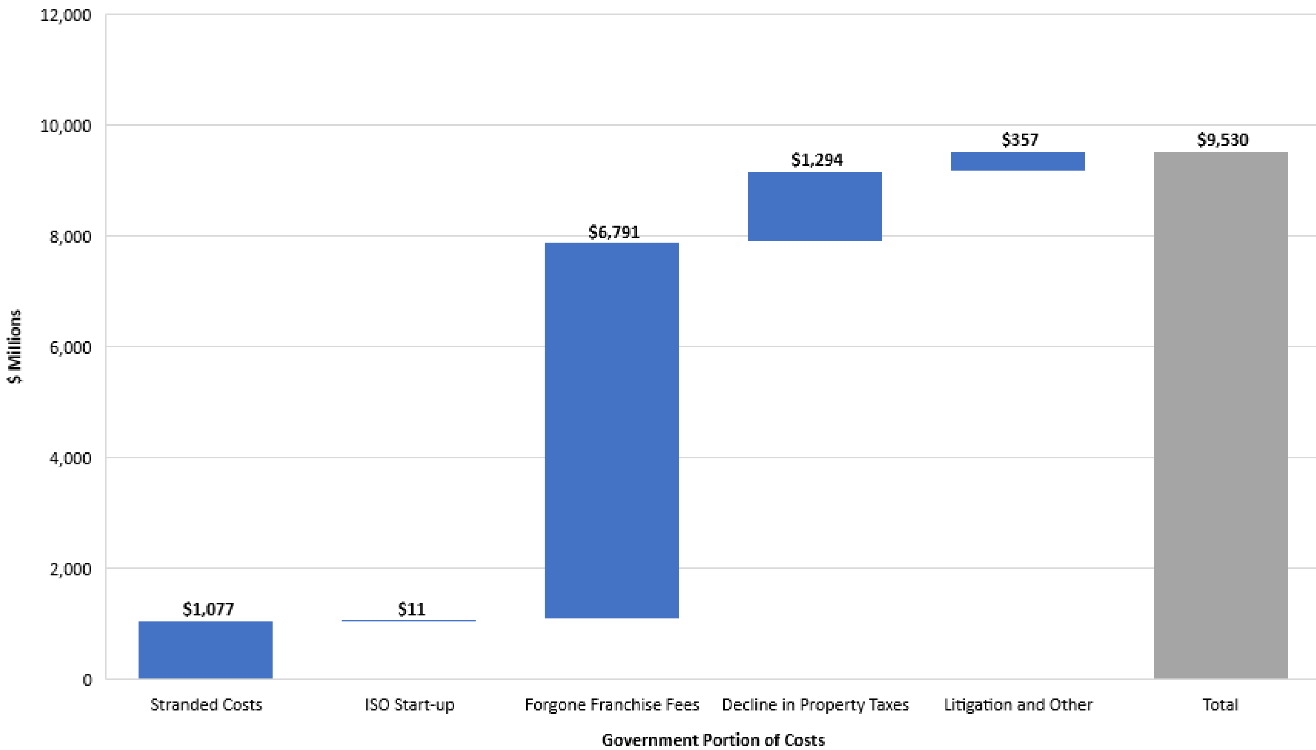
Cost Category	Quantification/Total Impact on Florida Customers	State and Local Government Portion	
		Low Estimate	High Estimate
Litigation Costs	• Litigation costs to implement the Constitutional Amendment range from $150 million to $300 million	• $150 million	• $300 million
Total Upfront or One-Time 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.

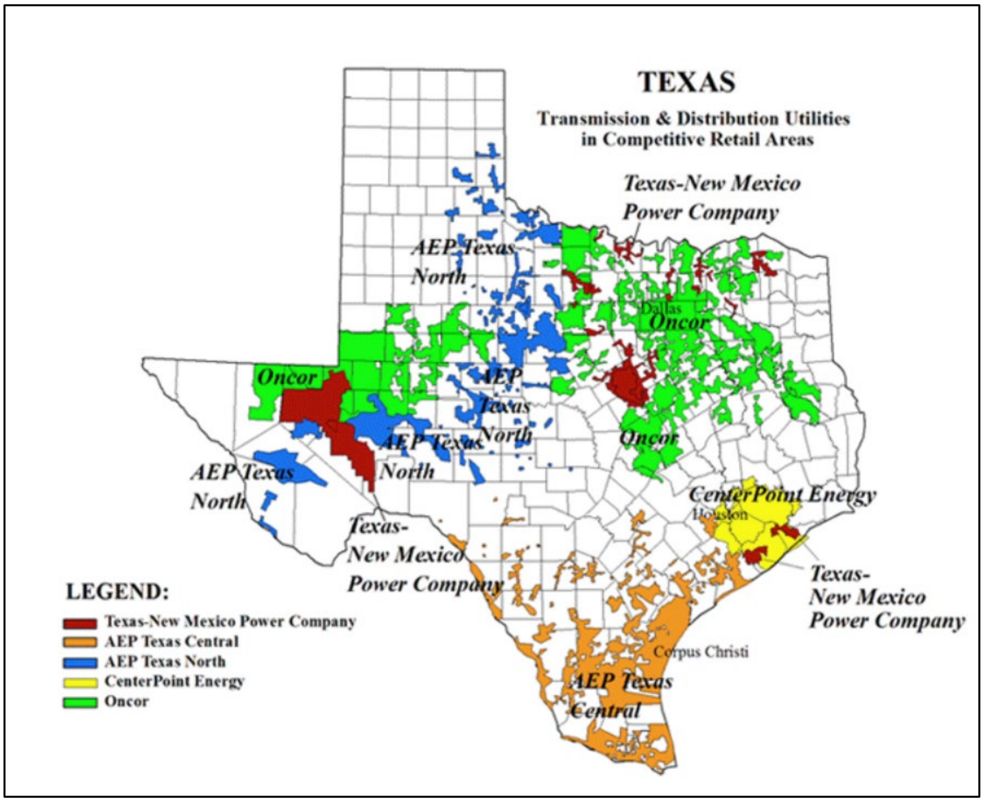
Prohibiting IOU ownership of generation and T&D leaves the state's entire electric system in the hands of yet-to-be identified entities, reducing the current IOU T&D operations to potential subcontractor status for the yet-to-be-identified T&D owner (assuming the IOUs even choose to enter this business). 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

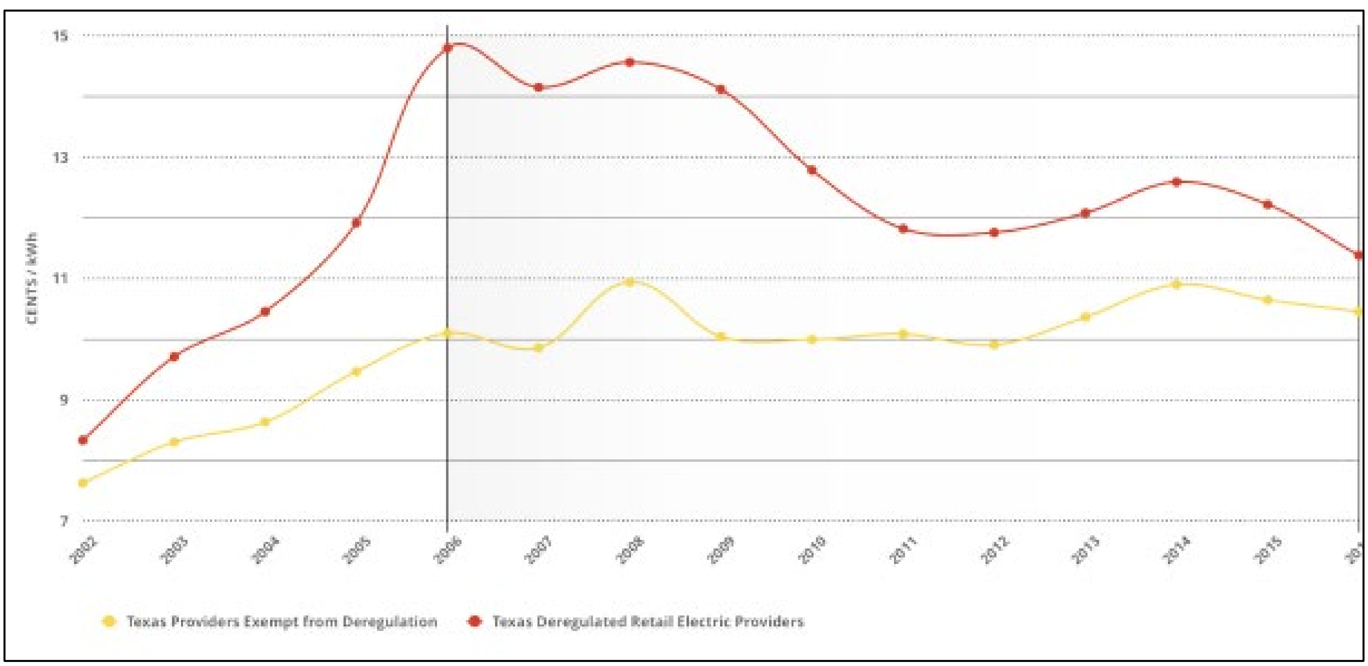
The sponsors of the Amendment point to Texas as the shining example of the success of electric restructuring.

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.

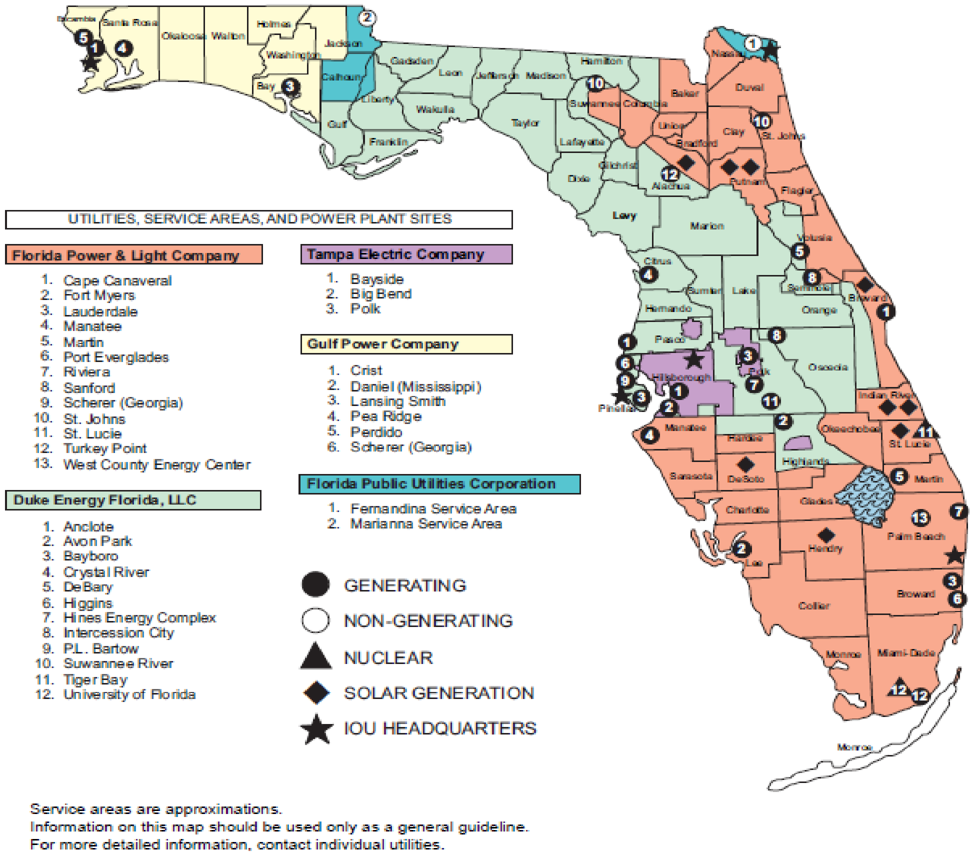
[11] TCAP History of Deregulation 2018, pg. 32.

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.

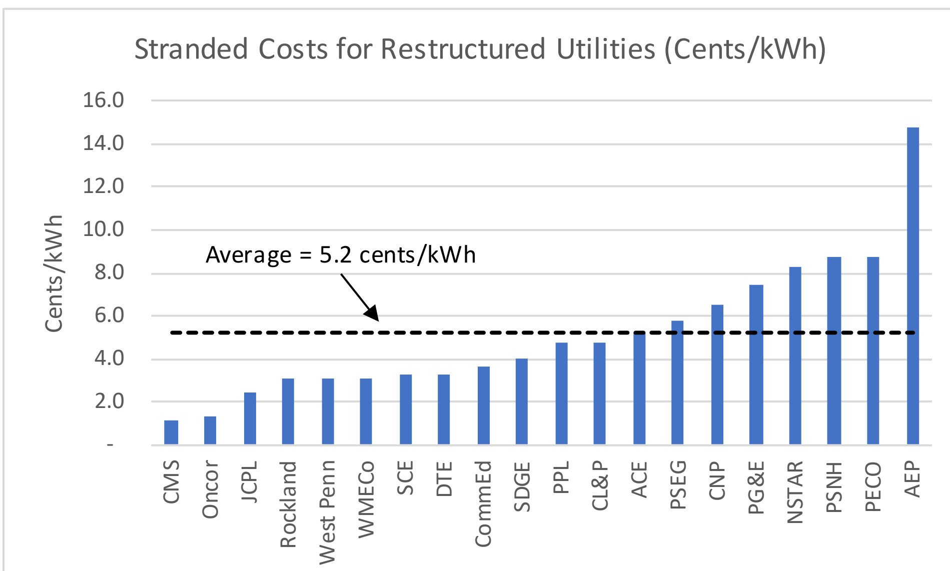
24 IOU Earnings Surveillance Reports.

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,

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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

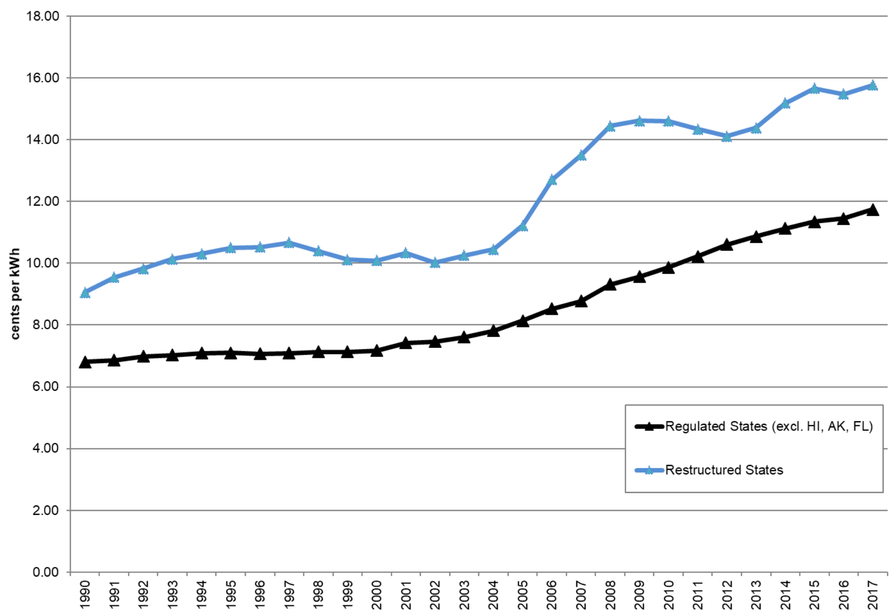
From 1990 to 2017, rates in restructured markets have been on average 42% percent higher than rates in regulated markets, as shown below.[48] Over the same period, rates in restructured markets have been approximately 26% higher than rates in Florida.

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:

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[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).

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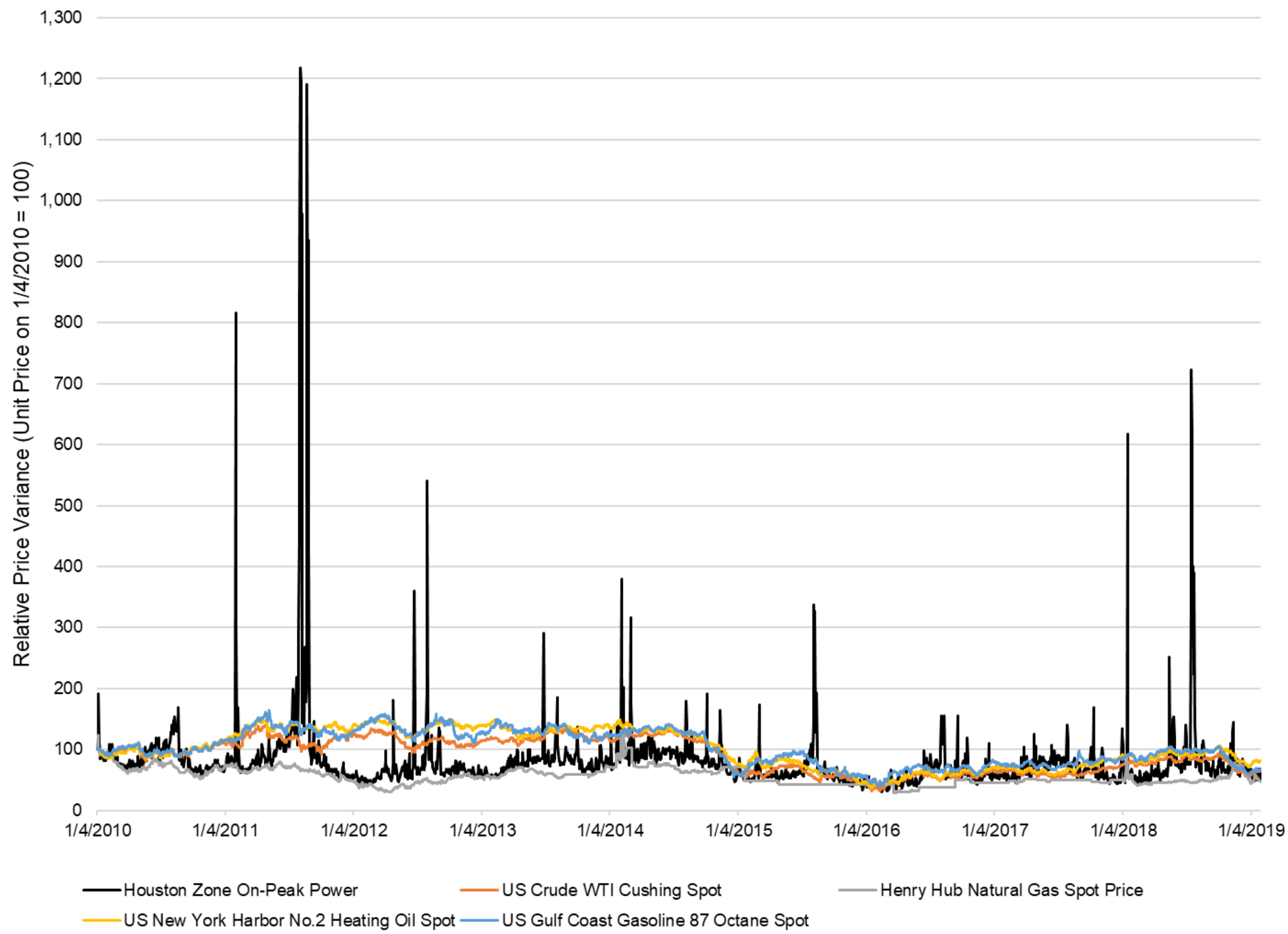
54 New York Public Service Commission Order Resetting Retail Energy Markets and Establishing Further Process, CASE 15-M-0127, (2/23/2016), p. 2. This Order was challenged in the New York court system, and subsequent process is ongoing.

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

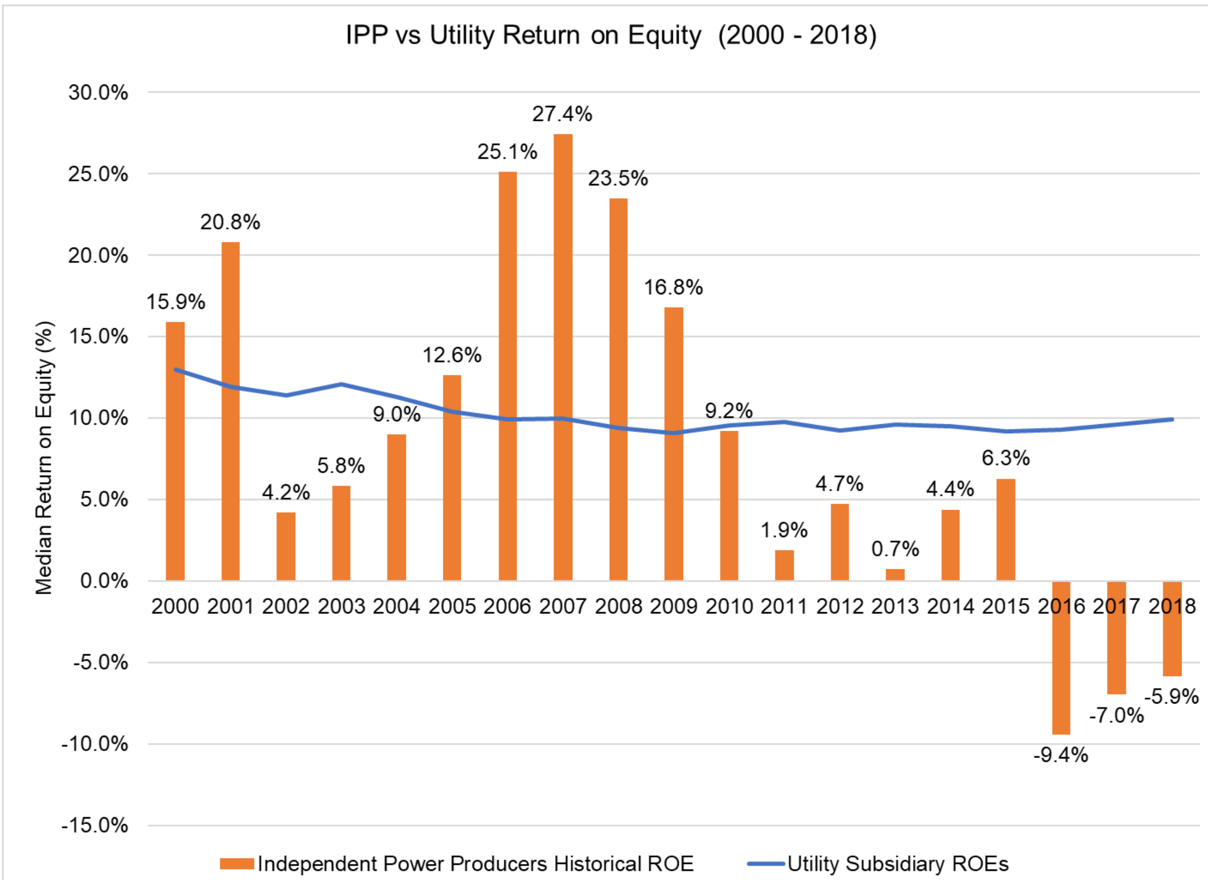
Under the Amendment, IOUs (whose rates are regulated by the Florida Public Service Commission and who currently supply more than 76%[59] of Florida's electric energy at below national average prices) would be

[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.

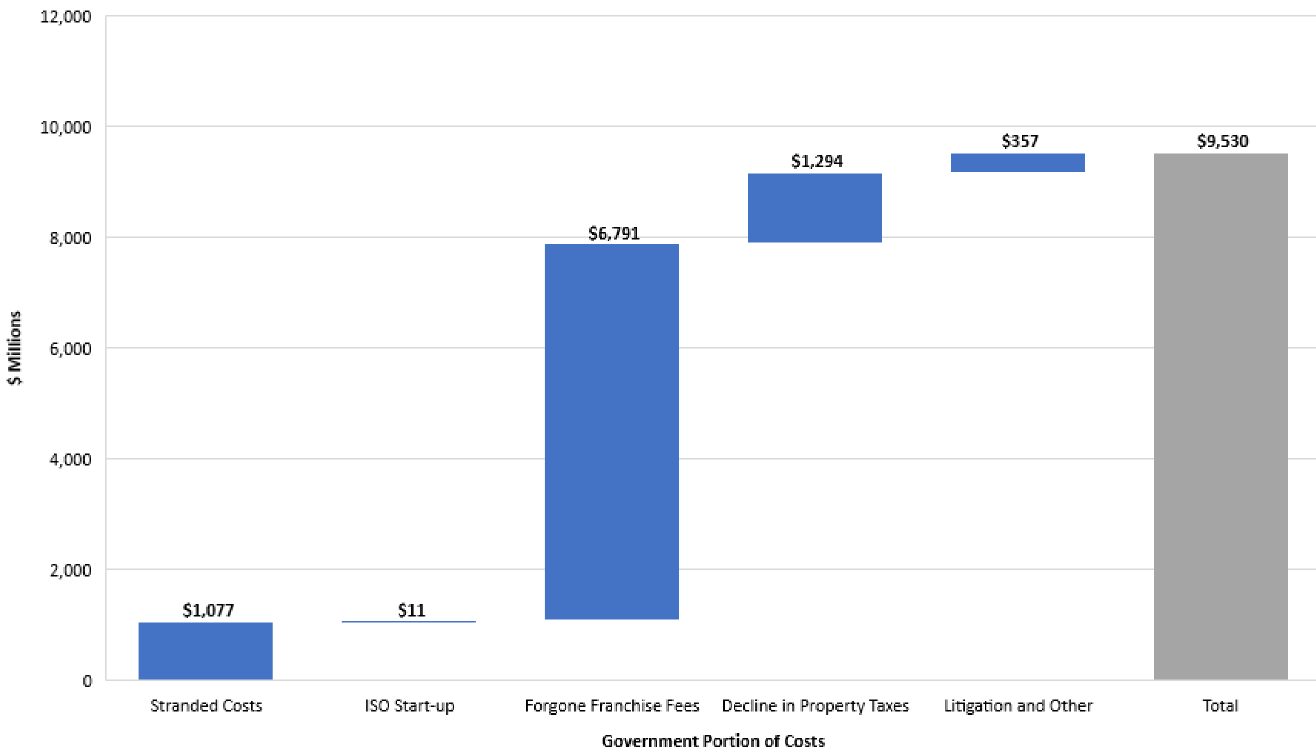
XI. CONCLUSION

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.	

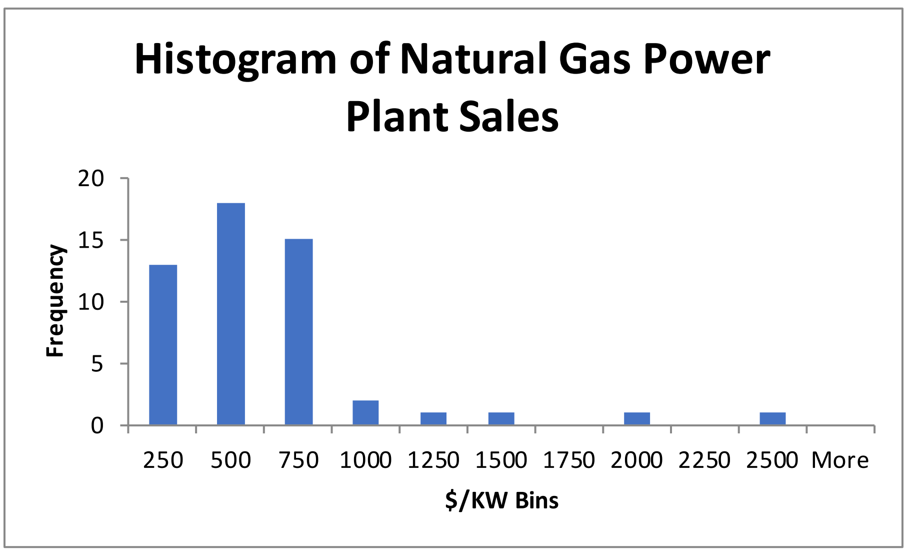
As shown in the table above, significant costs borne by state and local governments can be expected from restructuring. Those costs include both one-time costs (*e.g.*, hundreds of millions of dollars to establish an ISO/RTO) and on-going costs (*e.g.*, stranded costs recovered through electricity rates 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).

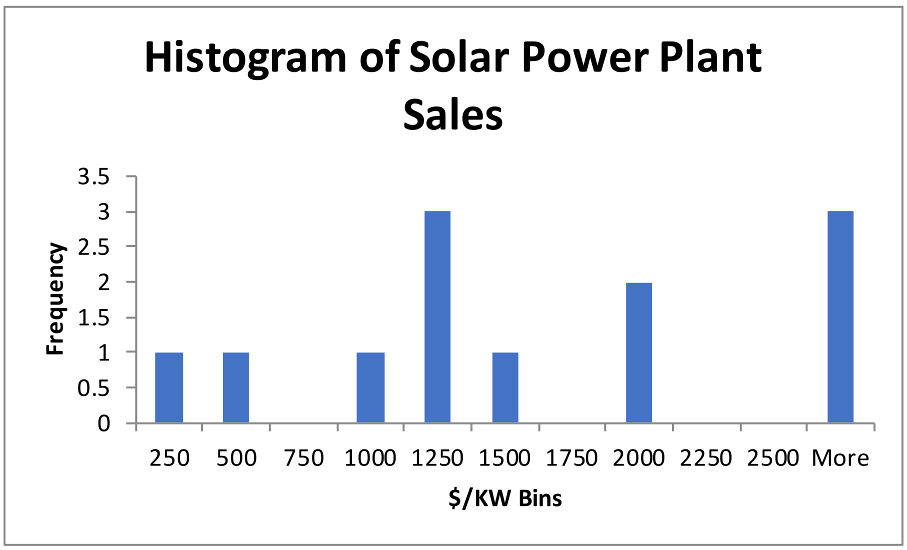
Natural Gas

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**	



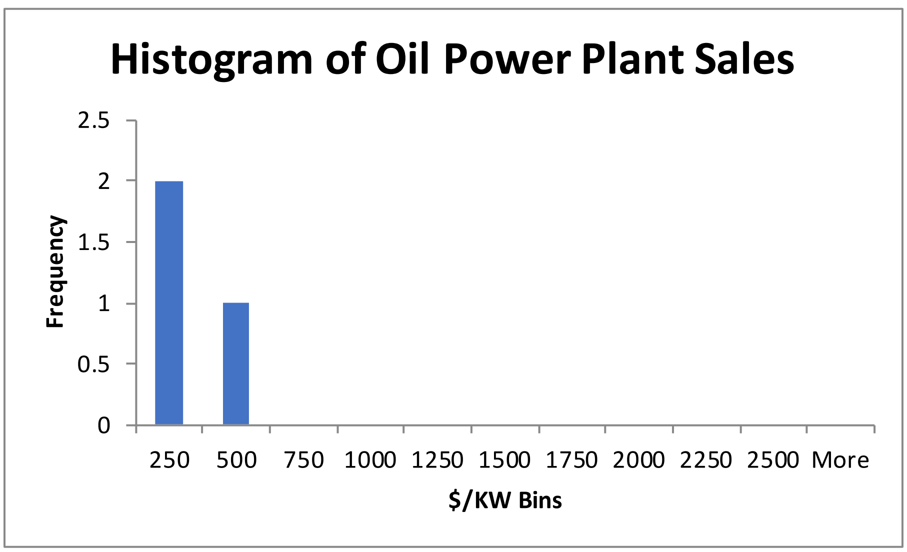
Solar

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

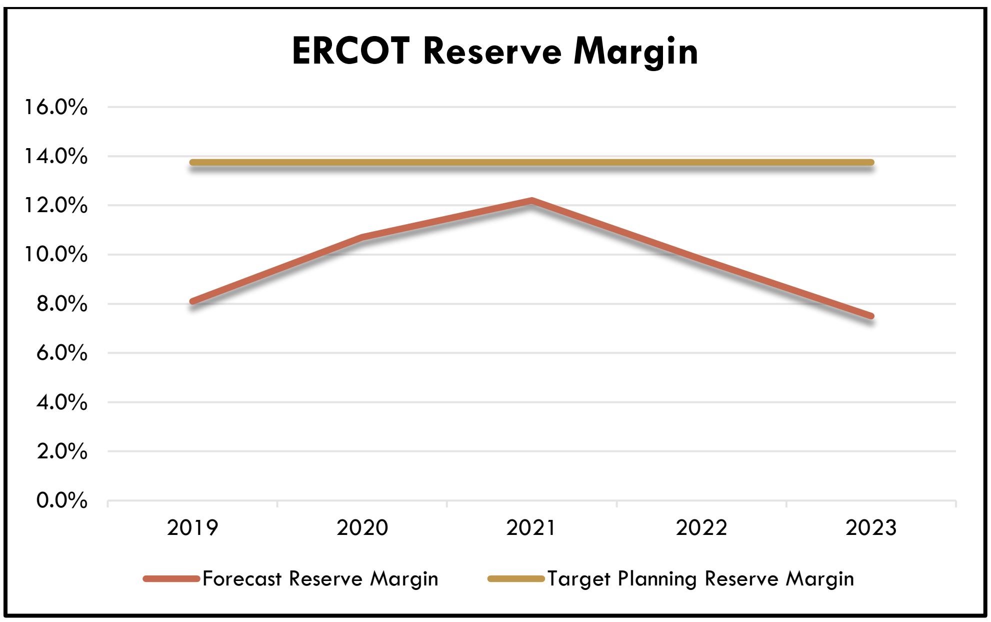
Wholesale energy markets are designed to send price signals to incent new entry and retain existing generation when needed for bulk power system reliability. New entry, as well as existing generation, has been challenged in their ability to recover their fixed and variable operating costs, including 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.

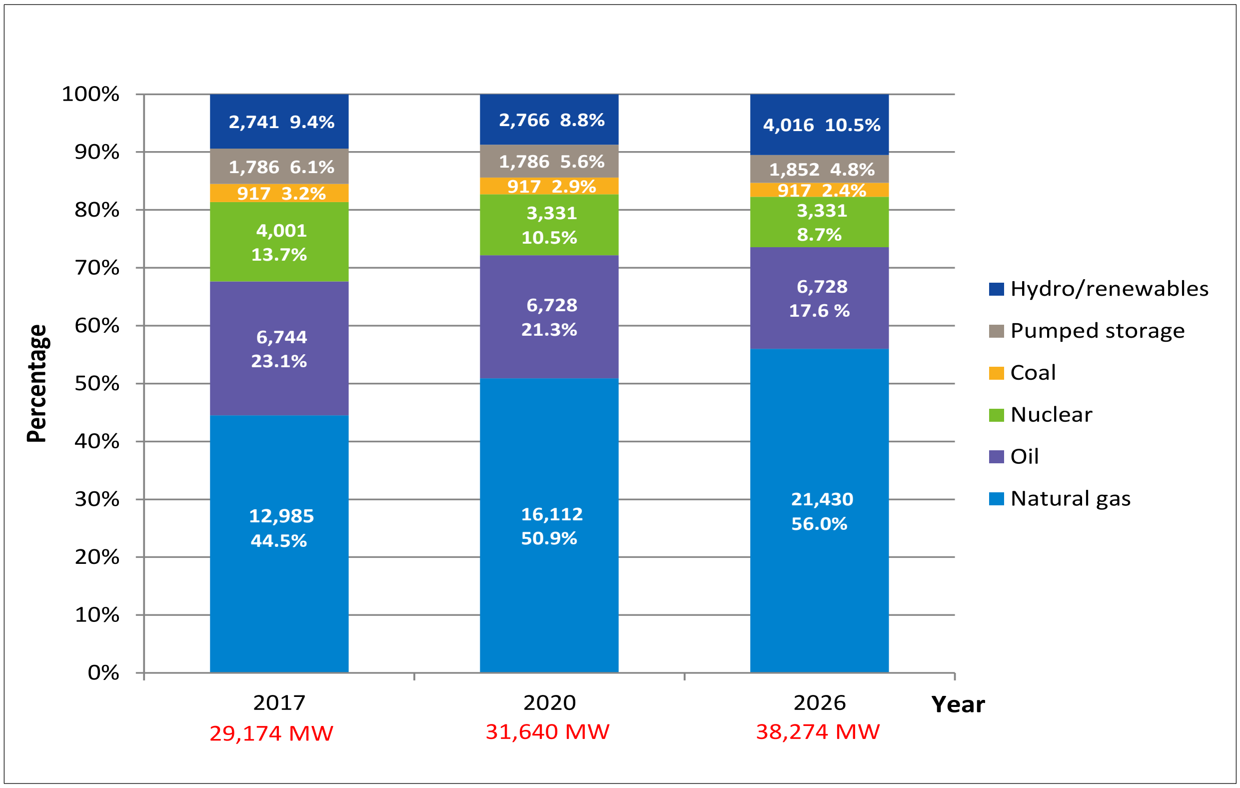
TABLE AP5- 2: EXAMPLES OF RESTRUCTURED STATE EFFORTS TO ACHIEVE RESOURCE PLANNING GOALS

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

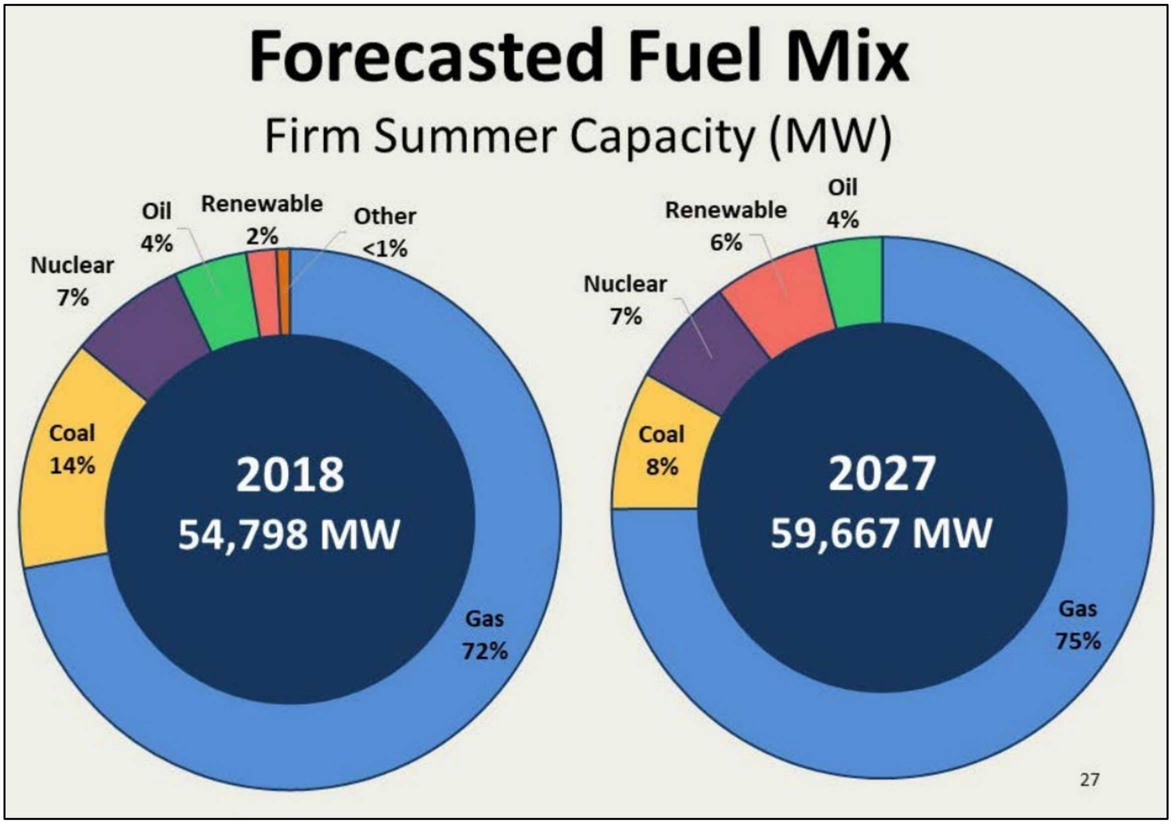
ISO-NE has outlined the challenges, citing the "fuel-security risks to system reliability." An ISO-NE report discusses the causes of this risk, including heavy reliance on natural-gas-fired capacity; reliability issues due to limited natural gas transmission infrastructure into the region, as well as 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

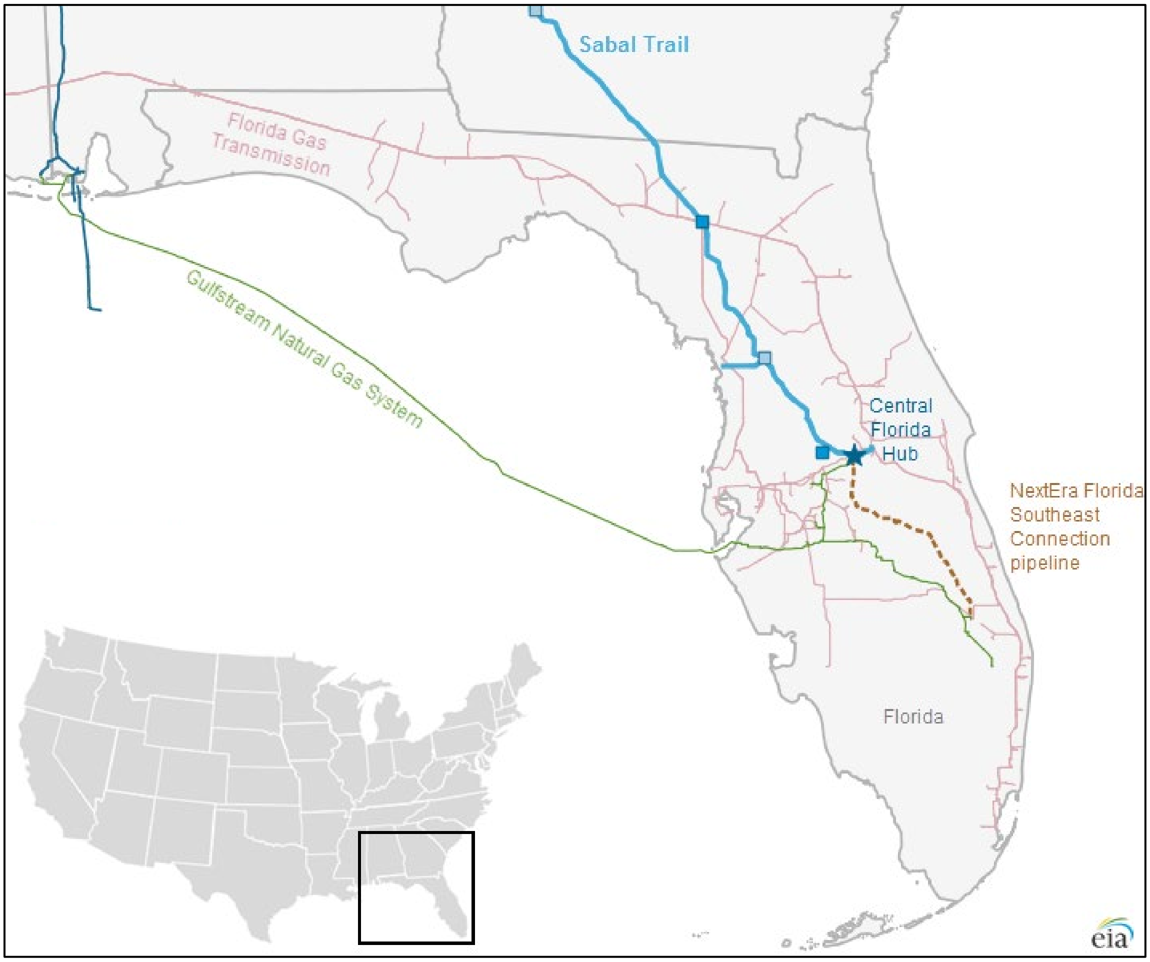


Source: FRCC[11]

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]

Nuclear Outlook is Stable in 10-yr Horizon

Existing[1/] Nuclear Capacity (Summer)

St. Lucie 1	981 MW
St. Lucie 2	986 MW
Turkey Point 3	811 MW
Turkey Point 4	821 MW
	3,599 MW

Planned Nuclear Capacity (Summer)

Turkey Point 3 Upgrade (10/2018)	20 MW
Turkey Point 4 Upgrade (12/2018)	20 MW
	40 MW

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.

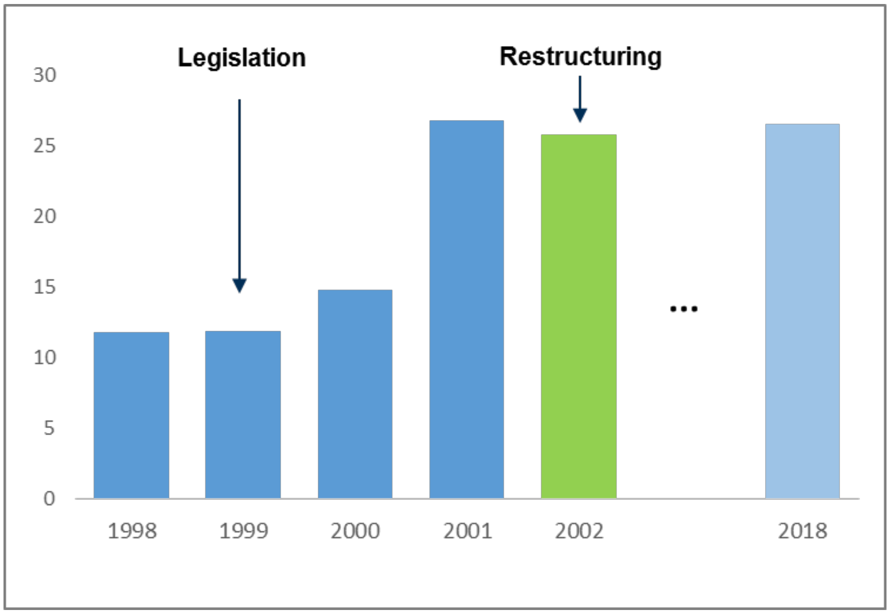
Texas Public Utility Commission Cost Increases due to Restructuring[1]

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]

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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.

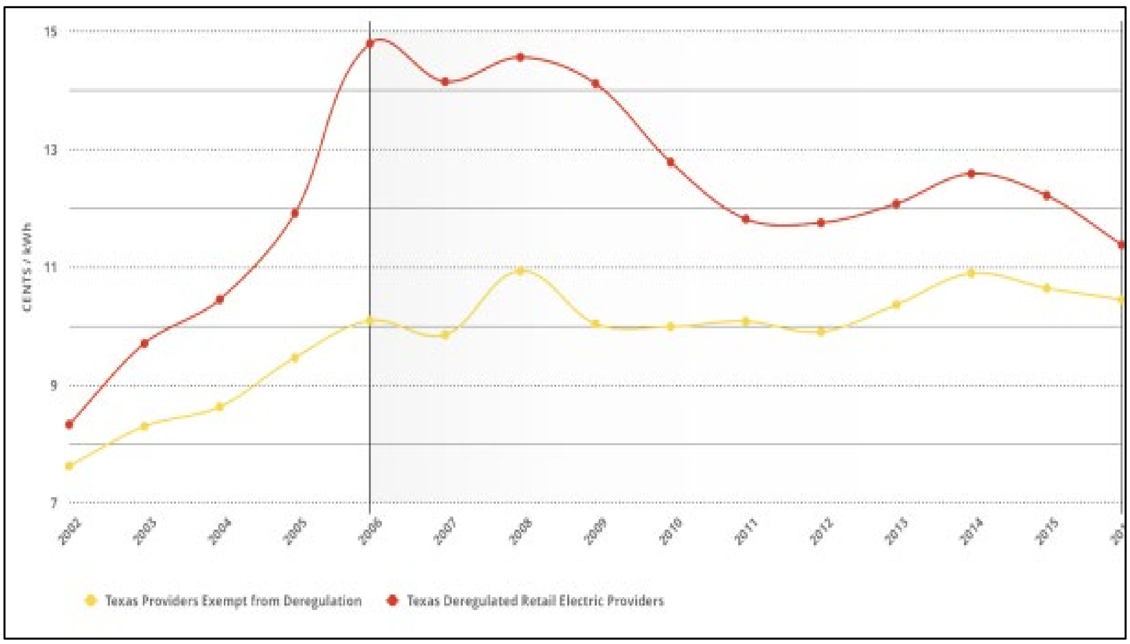
15 Ibid., pp. 12-13.

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]

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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]

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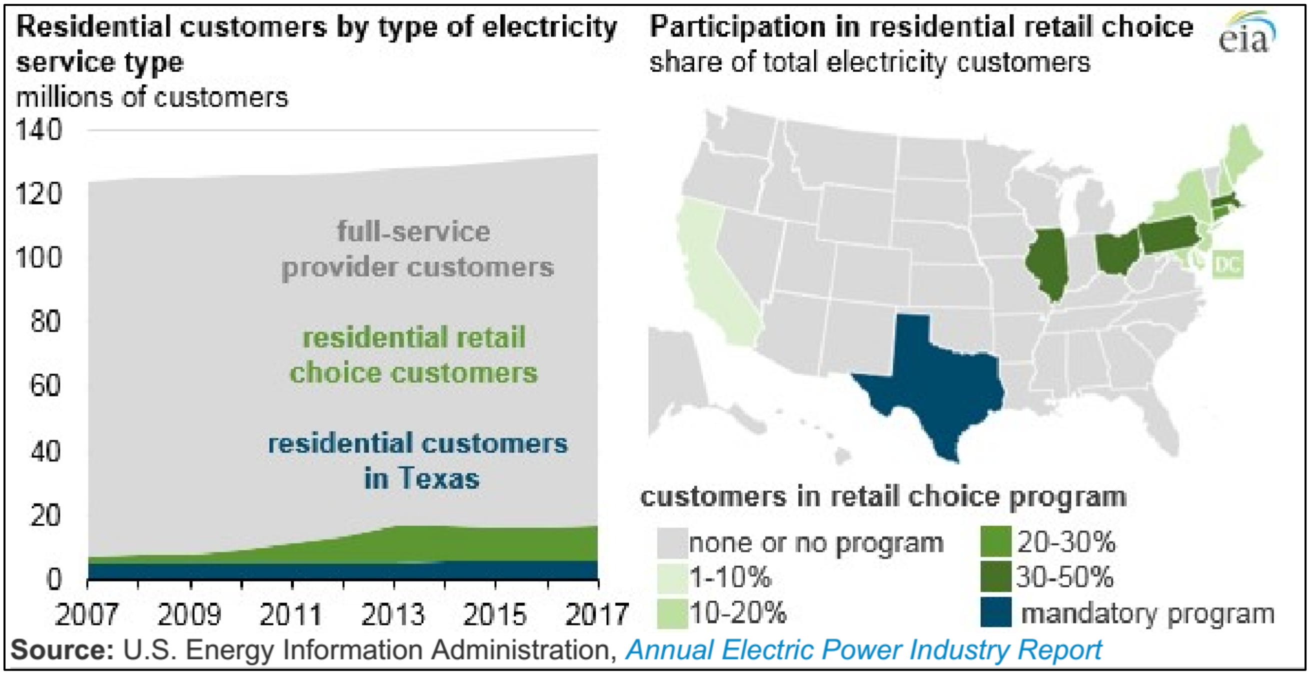
33 Sources: Crius Energy Trust, Management Discussion and Analysis ("MD&A"), March 8, 2018, pages 10 and 12; Just Energy MD&A, May 16, 2018, pages 4 and 30; Genie Energy Ltd, 2017 Form 10-K, pages 27 and 28; Spark Energy Inc., 2017 Form10-K; pages 52 and 93. Calculated as average of Crius, Just Energy, 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.

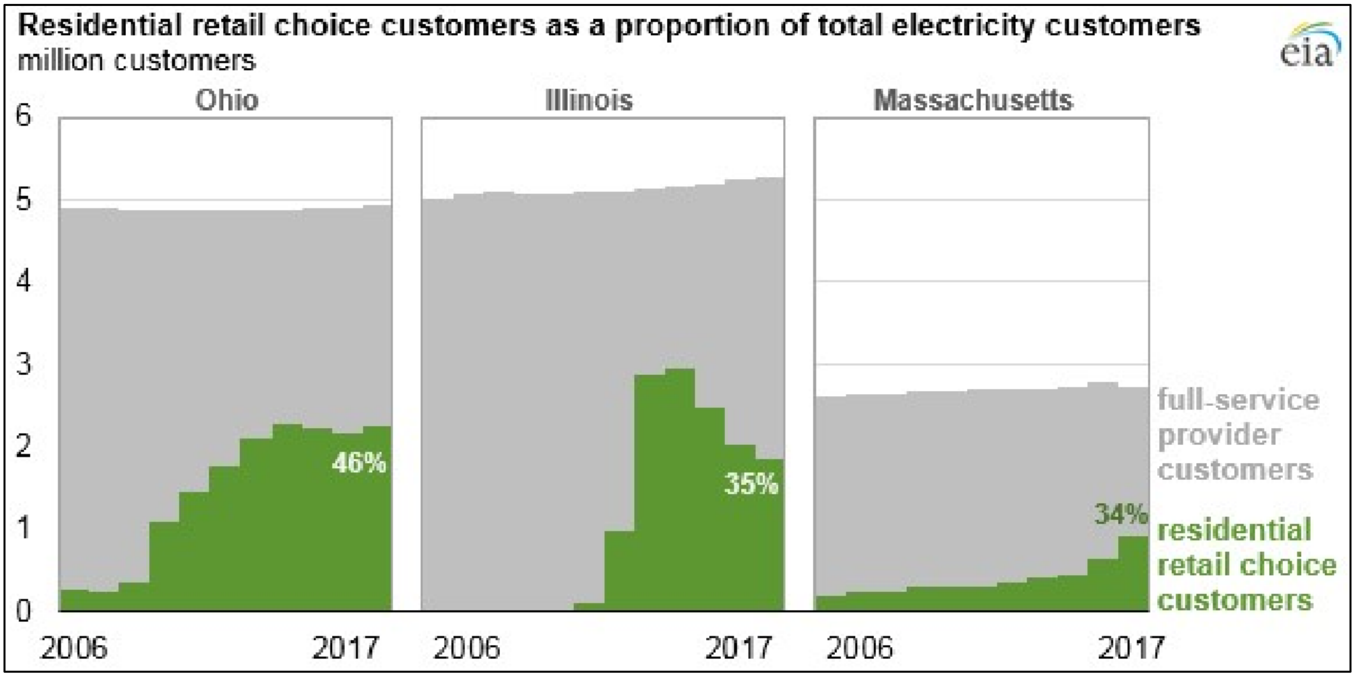
One factor impacting residential participation in competitive retail markets that also have utility provided service is "community choice aggregation" ("CCA") or "municipal aggregation." CCA legislation enables local governments to enter into contracts whereby customers participate in competitive retail 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

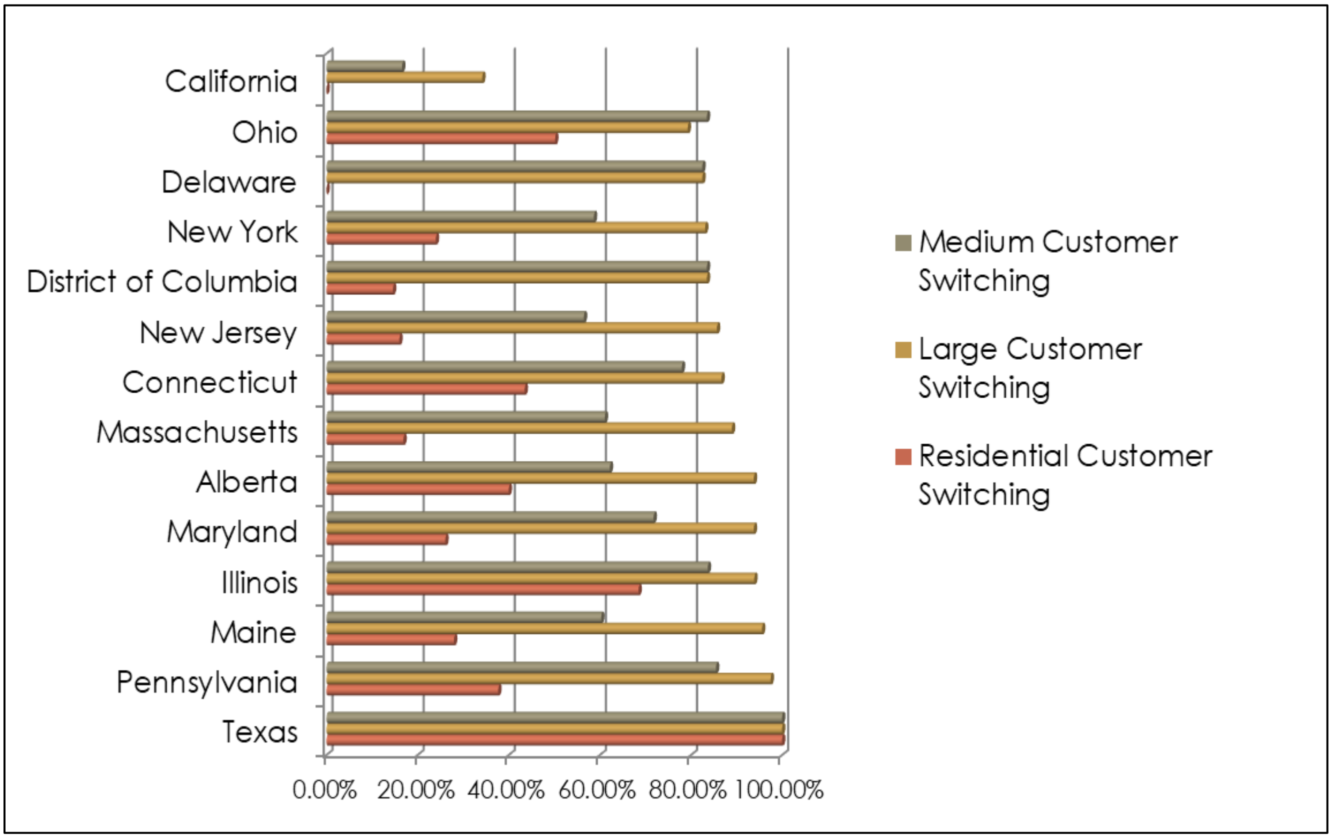


In contrast to residential customers, the migration to retail suppliers by industrial customers has been much greater. In Massachusetts in 2014, 73% of large commercial and industrial customers used retail supply and this grew to 85% in 2018.

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

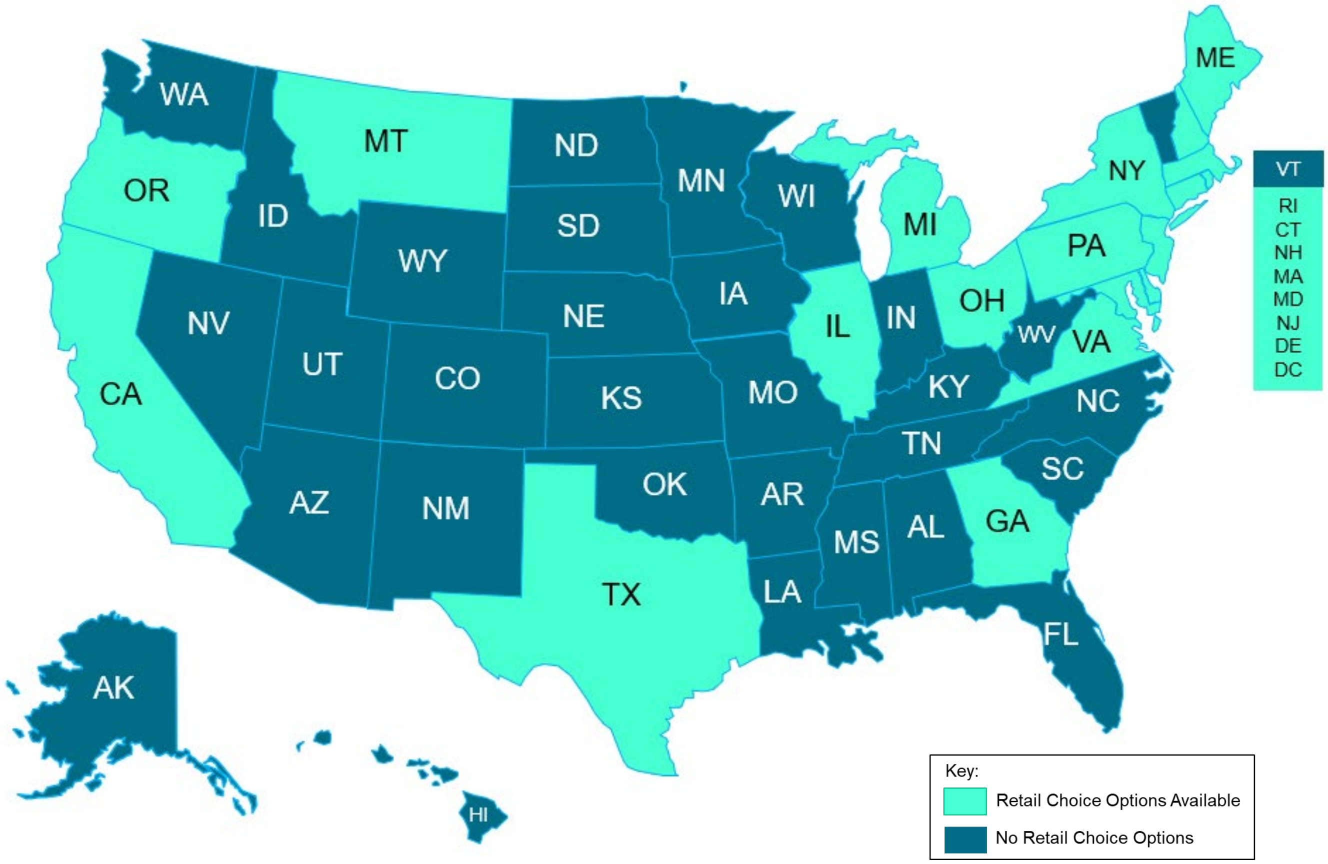
Currently, Floridians' electricity service is provided either by municipal electric companies, electric cooperatives or investor owned utilities ("IOUs"). The state's IOUs are vertically integrated and are regulated by the Florida Public Service Commission ("FPSC") and other state and federal regulatory 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.

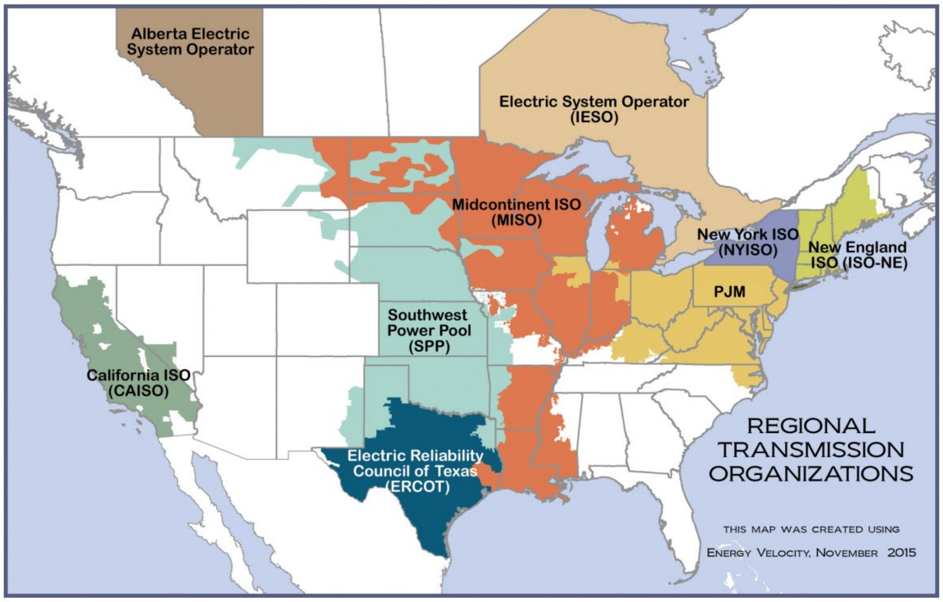
Background

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

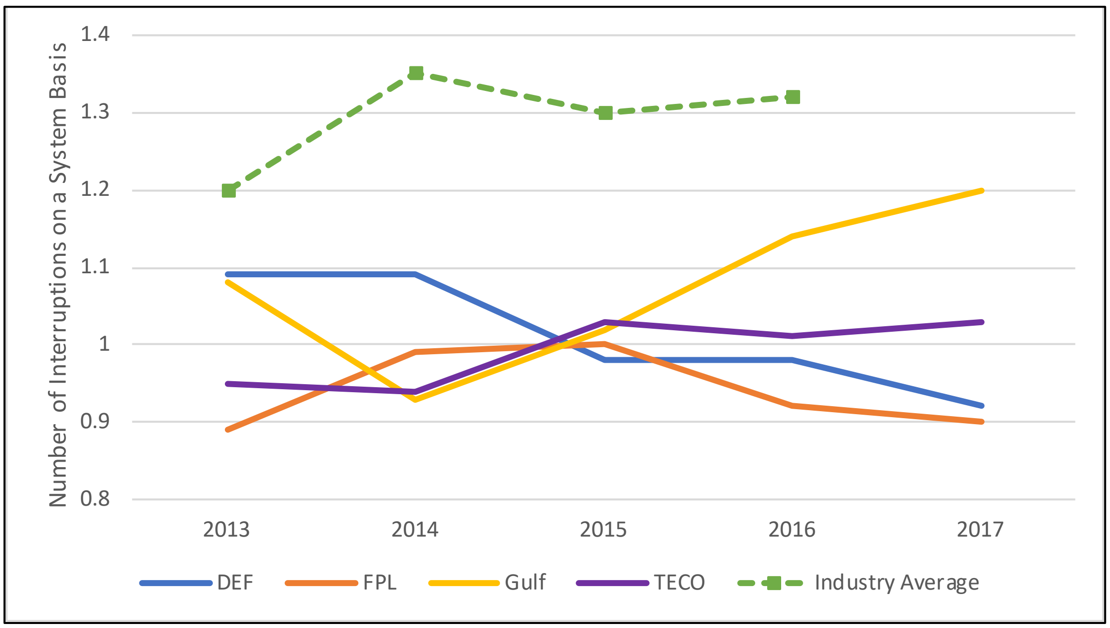
Three elements of restructuring combine to give Florida reason to be concerned about the impacts of restructuring on reliability and resource adequacy. These are: (1) the transfer of jurisdiction from the FPSC to the FERC; (2) the abandonment of integrated resource planning processes and recourse to 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]

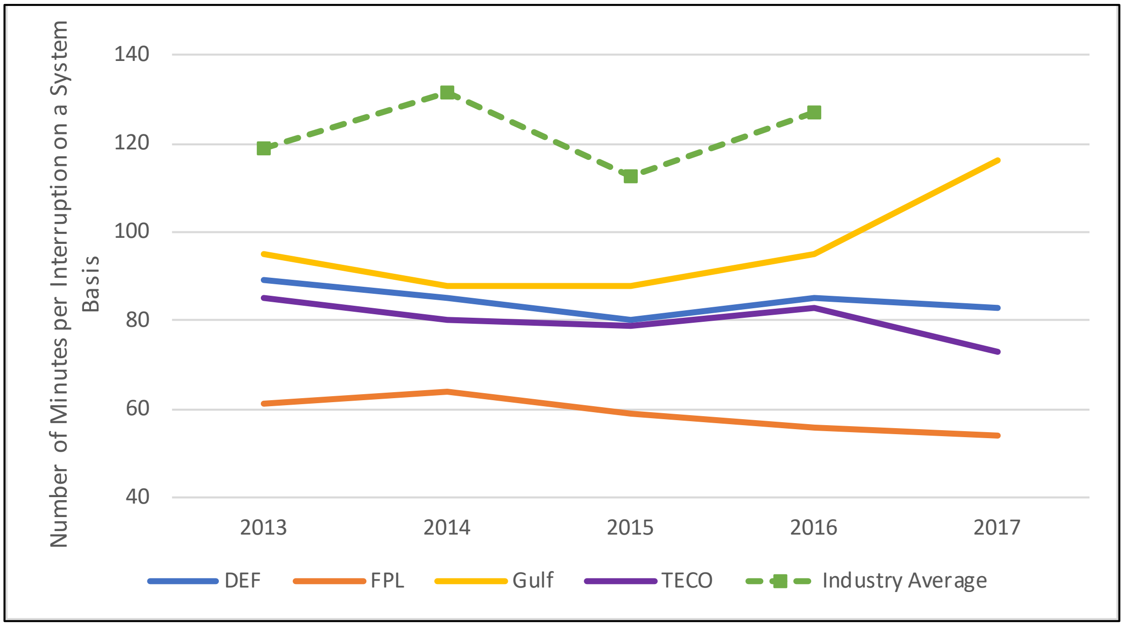
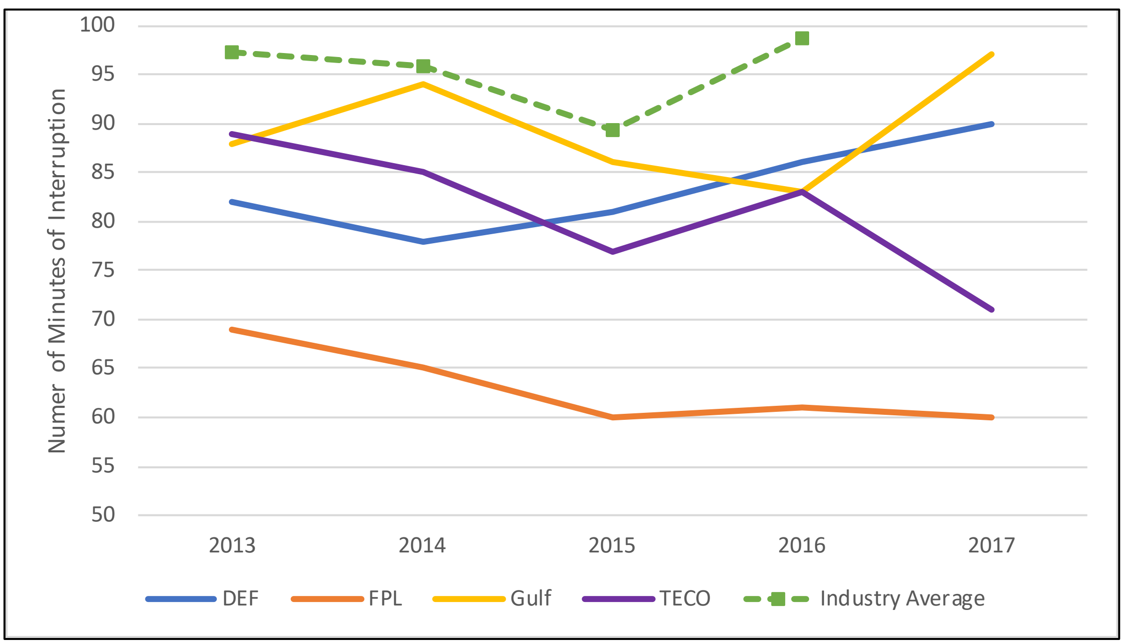


FIGURE AP8- 4: CUSTOMER AVERAGE INTERRUPTION DURATION INDEX [6]

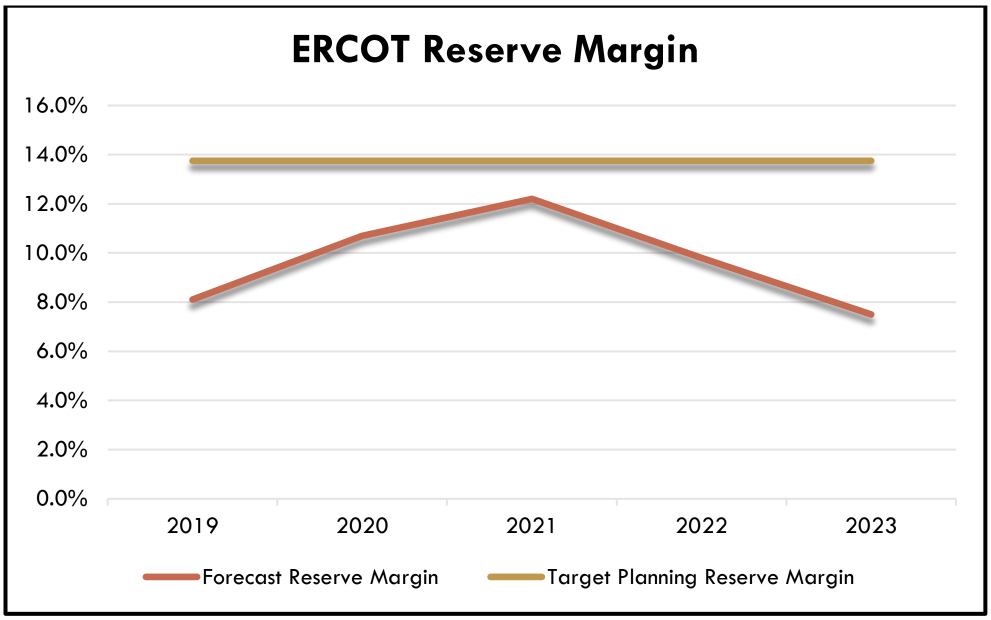


5 Ibid.
6 Ibid.

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.

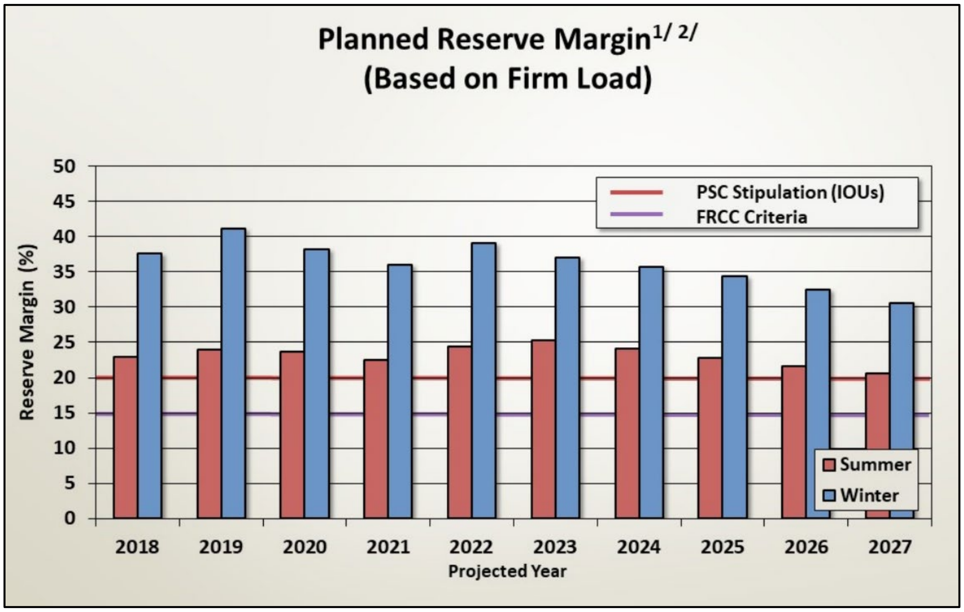
proposed gas-fired projects totaling 1.8 GW of capacity and five wind projects totaling 1.1 GW have been canceled since May, and another 2.5 GW of gas, wind and solar projects have been delayed.[10]

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



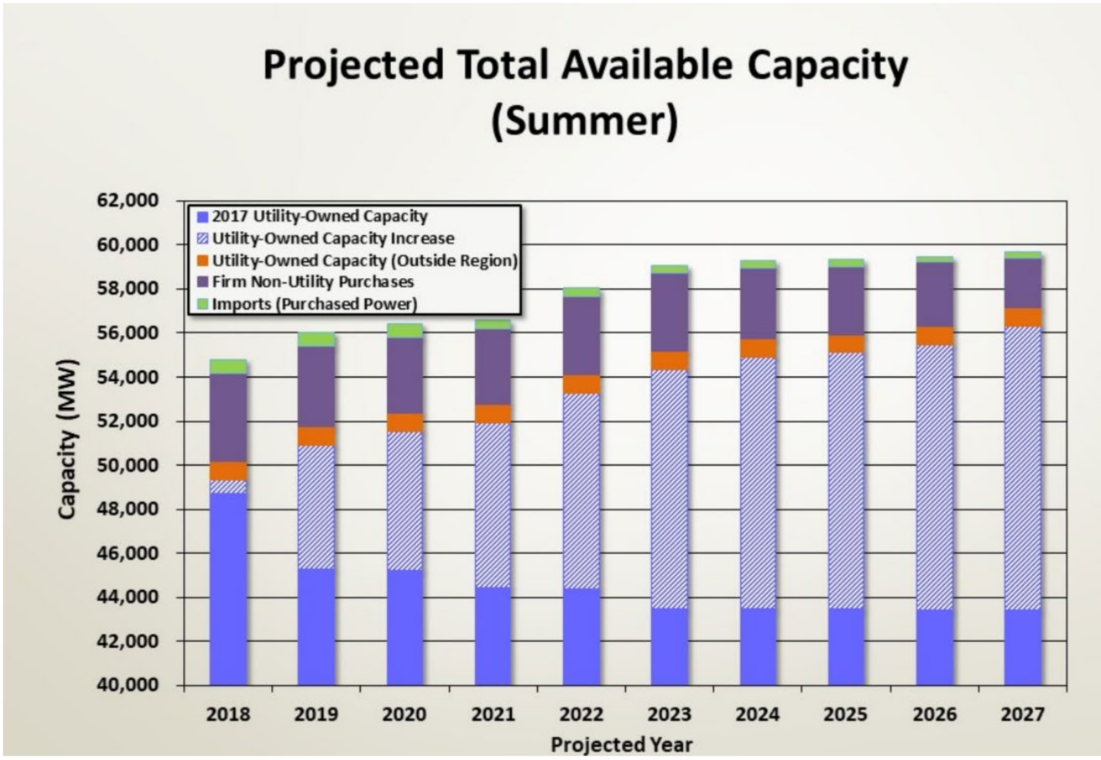
Source: Florida Reliability Coordinating Council, Inc.[15]

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.

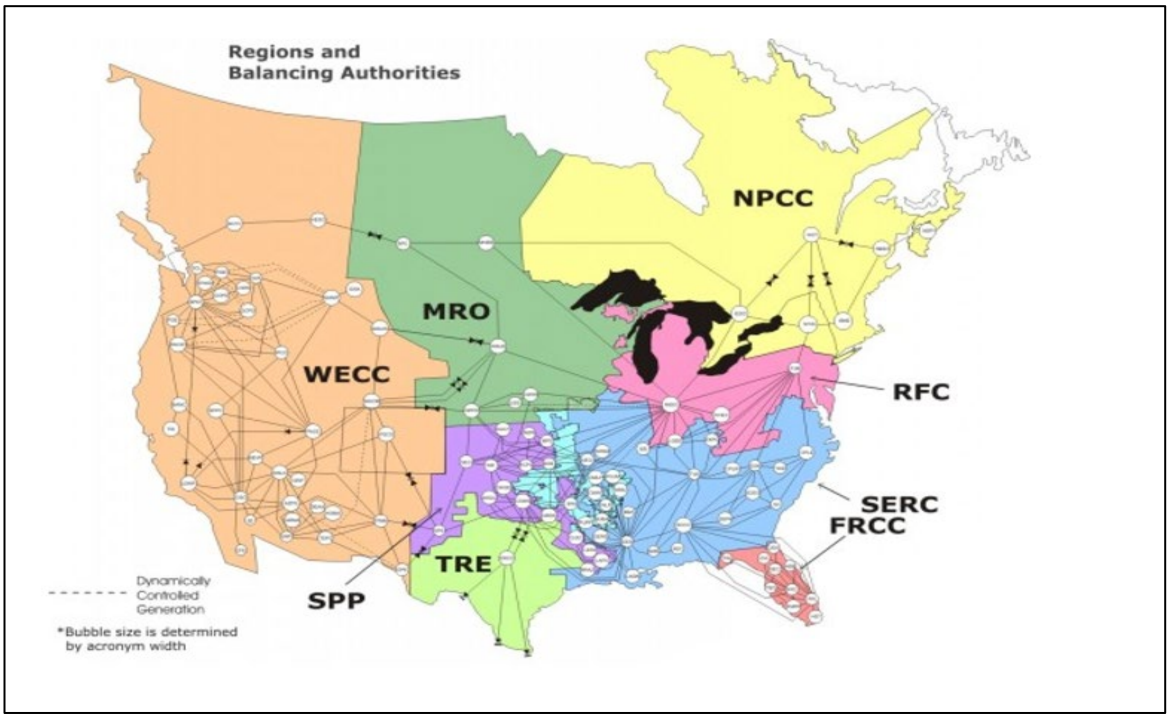
enforce standards to ensure the reliability of the nation's electric grid. In 2006, FERC certified NERC as the national electric reliability organization.

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.

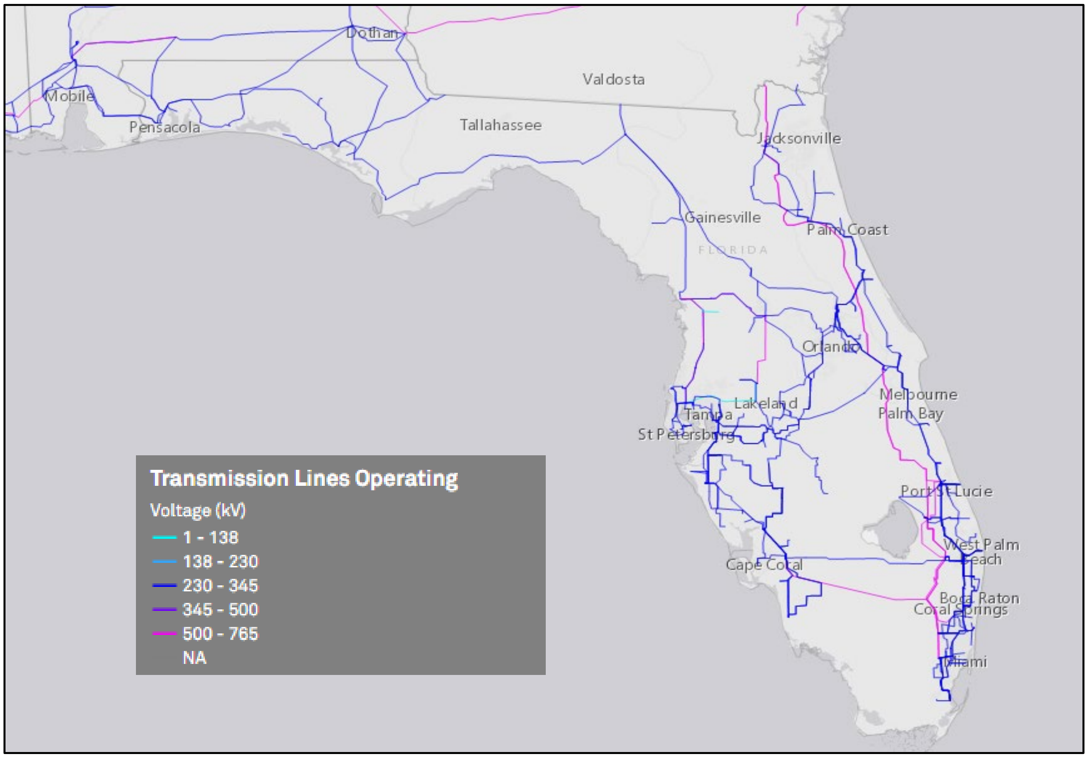
Peninsular Florida is relatively isolated in terms of its electric power interconnections. Its only link with another bulk power system is with SERC at the Florida/Georgia border and in the Florida panhandle through interconnections with Georgia Power. This makes FRCC among the regions in the US with 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

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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.

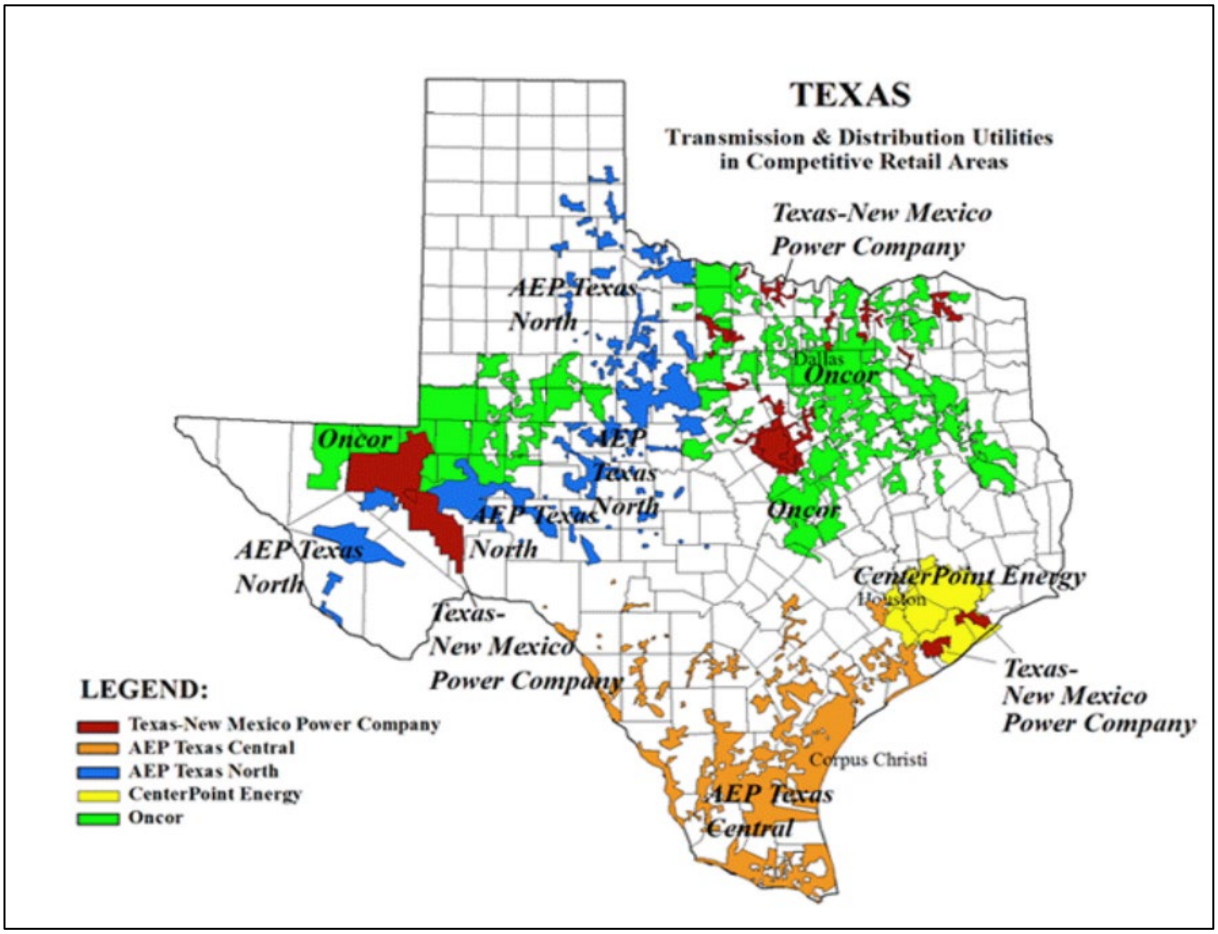
Comparison – Texas v. Florida

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.

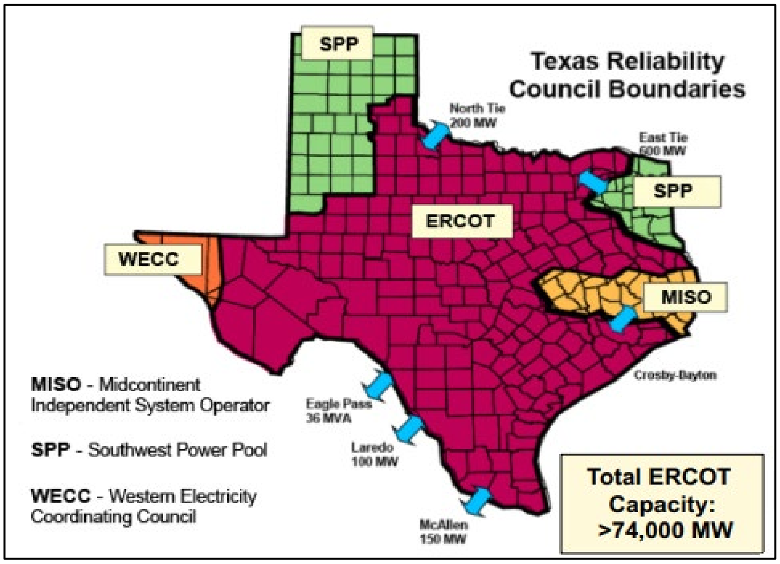
FIGURE AP9- 1: COMPETITIVE RETAIL AREAS IN TEXAS[2]



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]



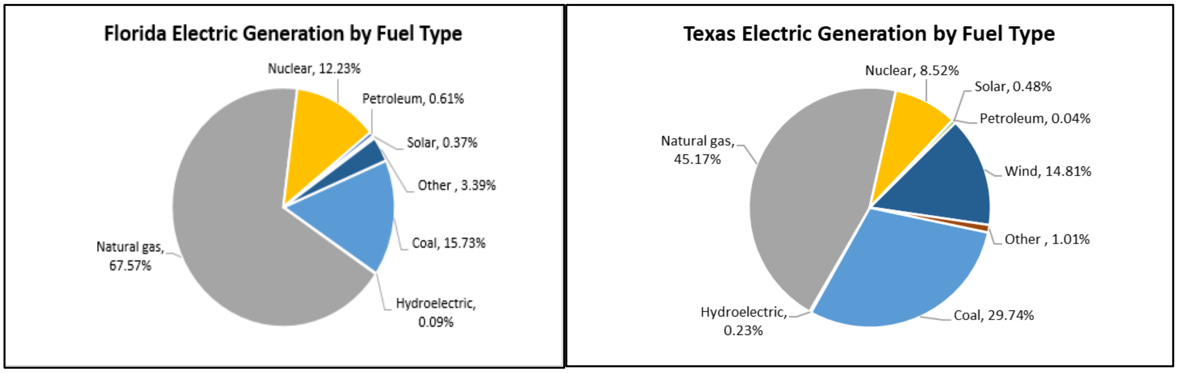
Importantly, because Texas restructured only the ERCOT region, the limited direct current interconnections with neighboring regions allowed the state to avoid FERC jurisdiction. As a result, the state regulatory commission and Texas law had final oversight over how electric service would be provided 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.

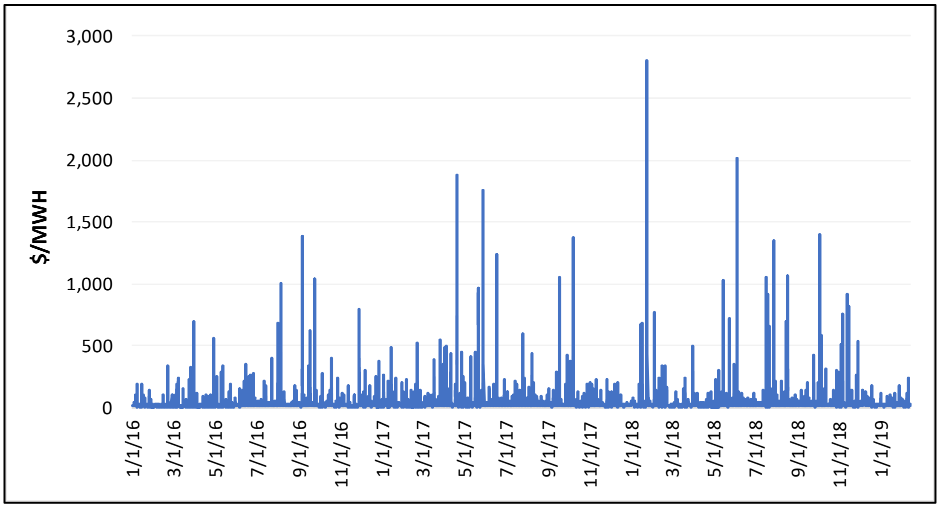
Wholesale Prices

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]

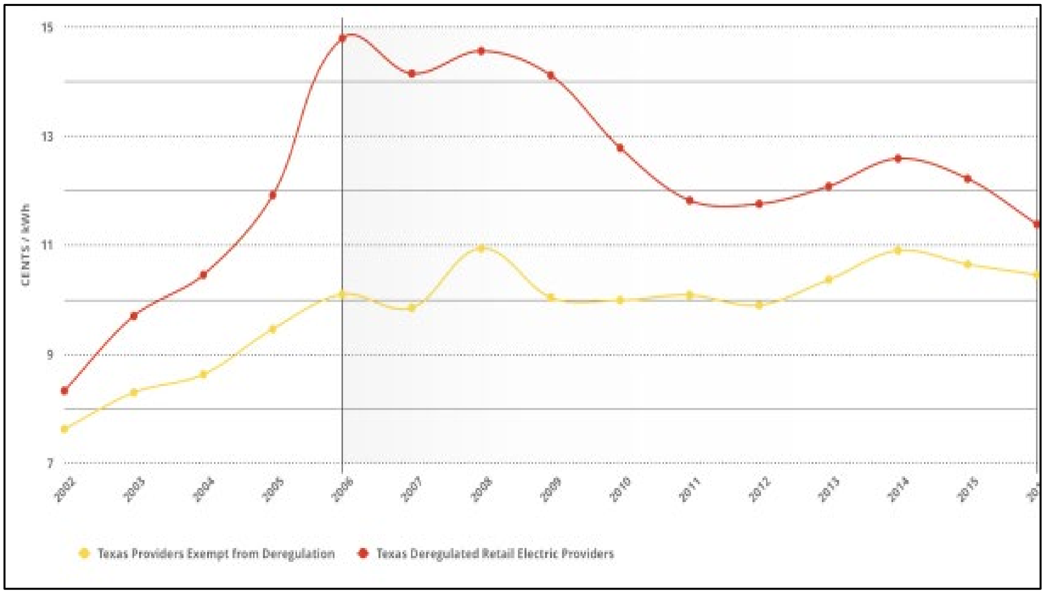


Retail Prices in Texas

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

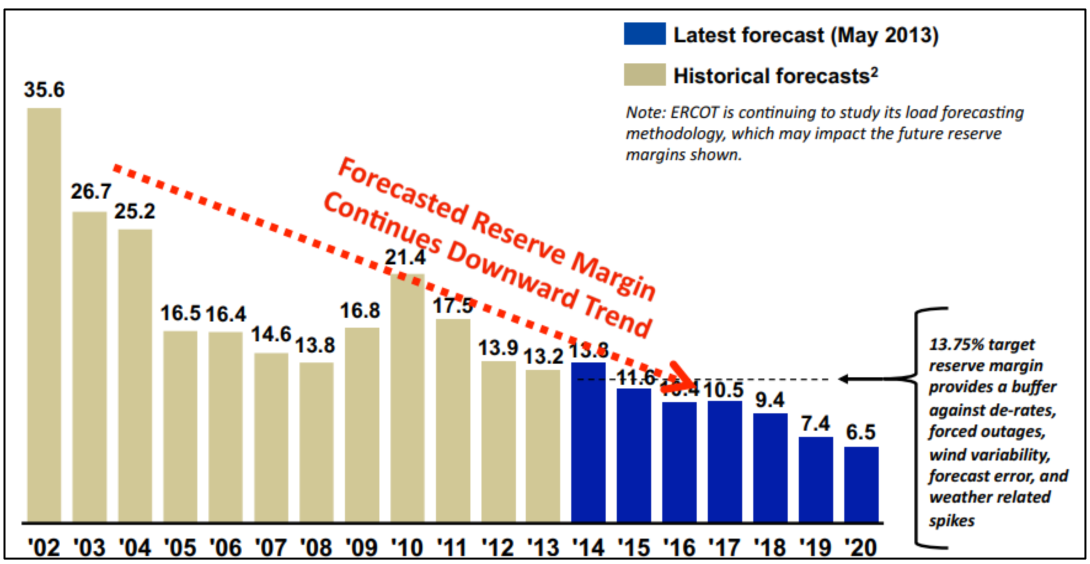
[10] TCAP Report on Electricity Prices in Texas, April 2018.
[11] NERC Long Term Reliability Assessment 2011.

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.

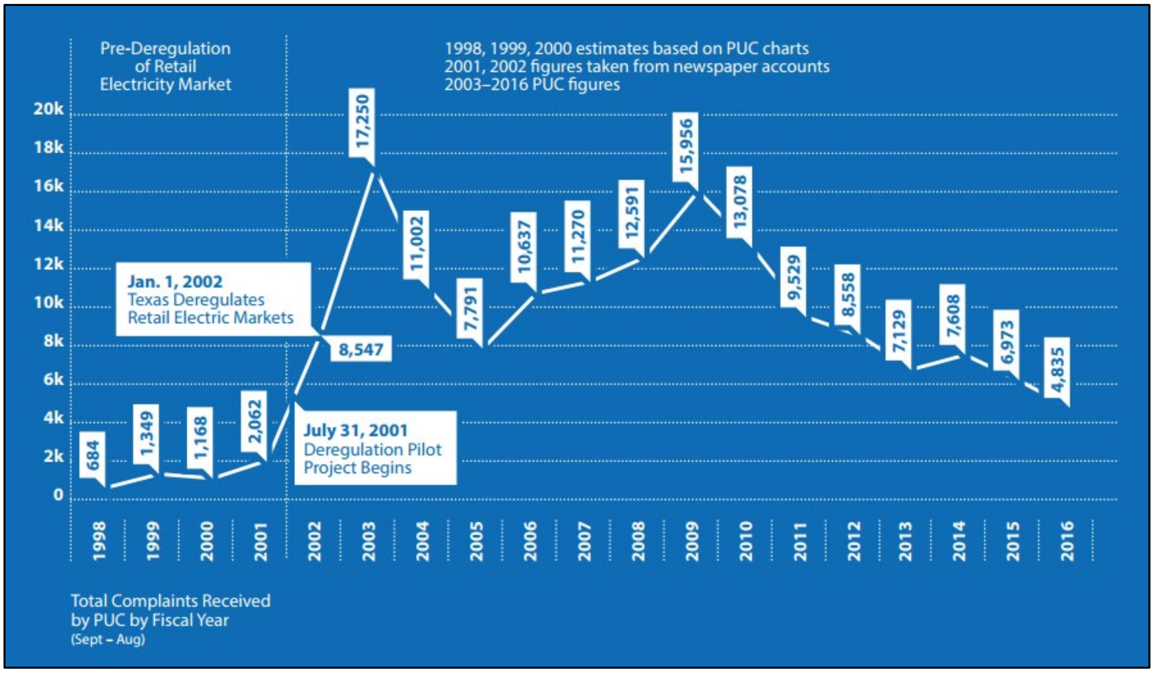
However, approximately two years later, on February 26, 2008, ERCOT officials took emergency action to avoid blackouts. A sudden loss in wind power, coupled with other factors, sent grid operators taking emergency actions once again to avoid a catastrophic system collapse. It was a serious emergency 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

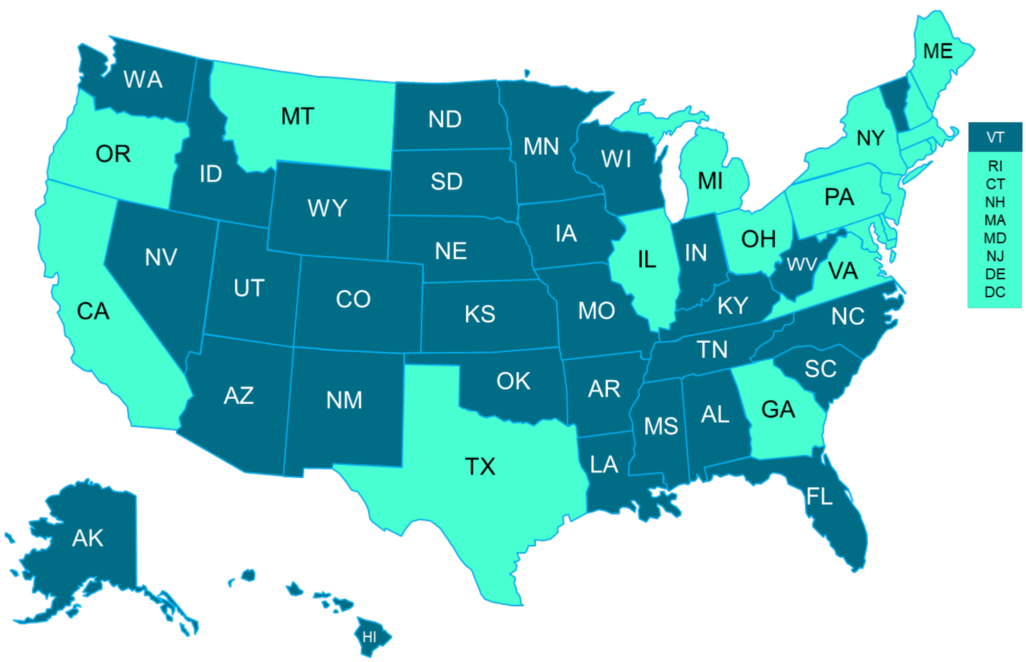
Debates concerning electric industry restructuring often center around the likely impact on electricity costs and prices, the prices paid by retail customers (including industrial, commercial, and residential customers as well as government facilities and other essential service buildings). A key driver 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.

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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).

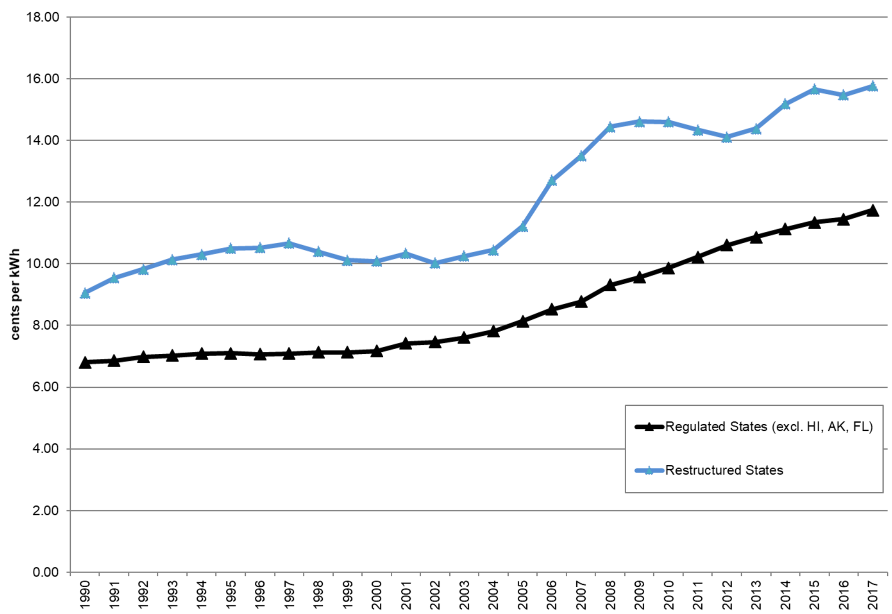
4 Dormady, N., Hoyt, M. Roa-Henriquez, A. & Welch, W. 2019. Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, at 4. See also: Restructuring the Electricity Market in Nevada, Possibilities, Prospects, and Pitfalls. Guinn Center Technical Report, 2018, 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)

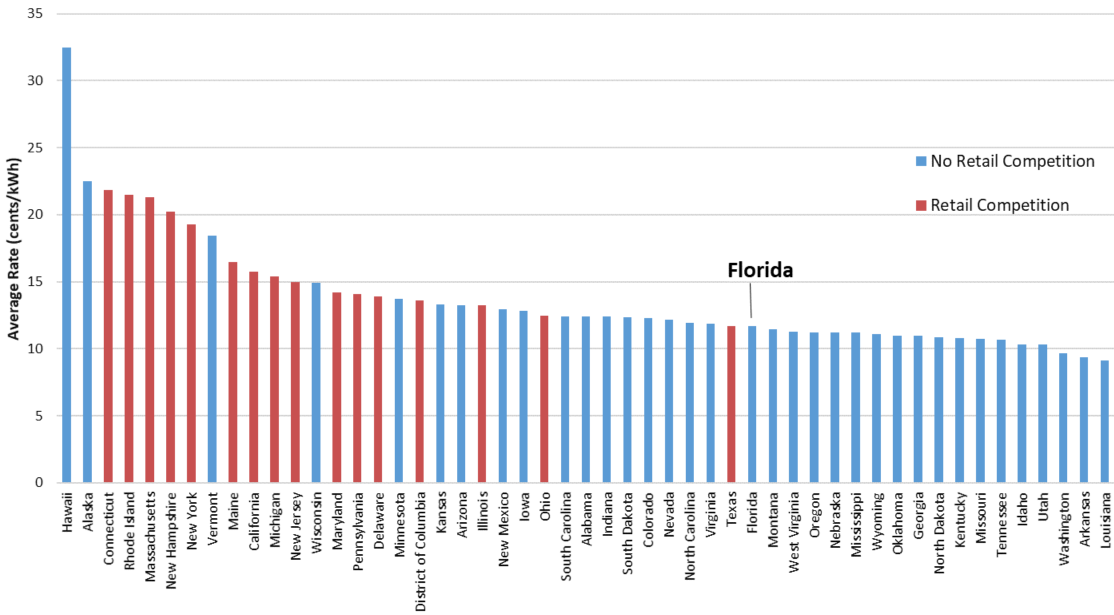


Data source: EIA Electric Power Monthly, October 12, 2018[6,7]

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.

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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

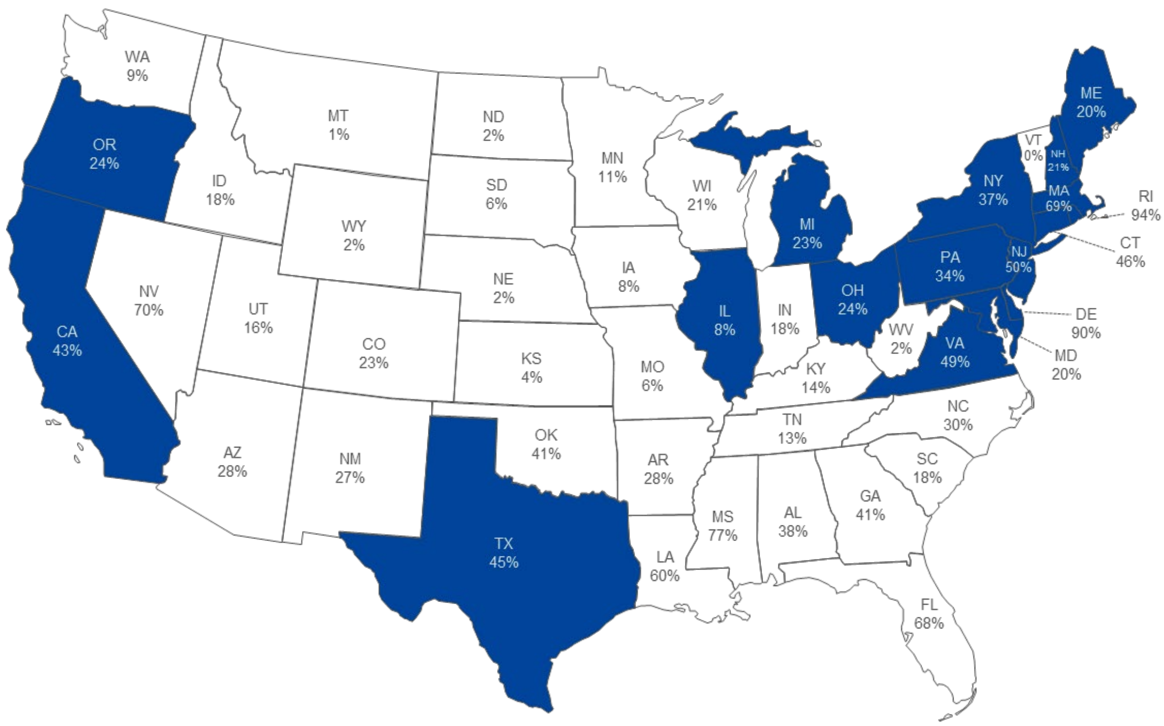
19 Who Pays for Retail Electric Deregulation? Evidence of Cross-Subsidization from Complete Bill Data, Dormady, Hoyt, Roa-Henriquez, Welch, December 2018, at 2.

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)

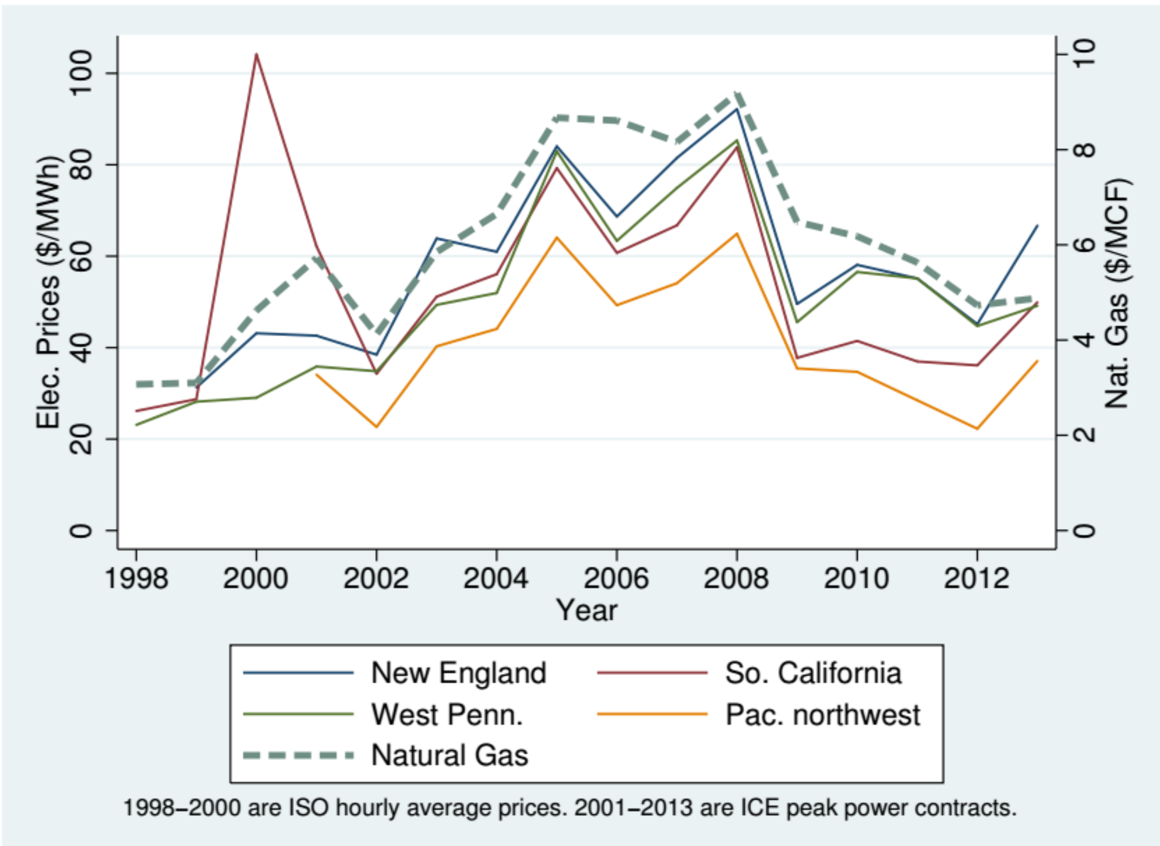


Blue denotes states with restructured electric markets

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.

Financial Impact Estimating Conference Principals' Workshop

Right to Competitive Market for Customers of Investor-Owned Utilities; Allowing Energy Choice

February 21, 2019

CONCENTRIC ENERGY ADVISORS

RADEY
ATTORNEYS & COUNSELORS at LAW

AGENDA

- Introduction
- Key Financial Impact Summary
- Implementation and Other Costs
- Stranded Costs
- Tax Revenues and Franchise Fees
- Conclusion

The financial impact of the ballot measure is clear – if approved, it will cost the state billions of dollars.

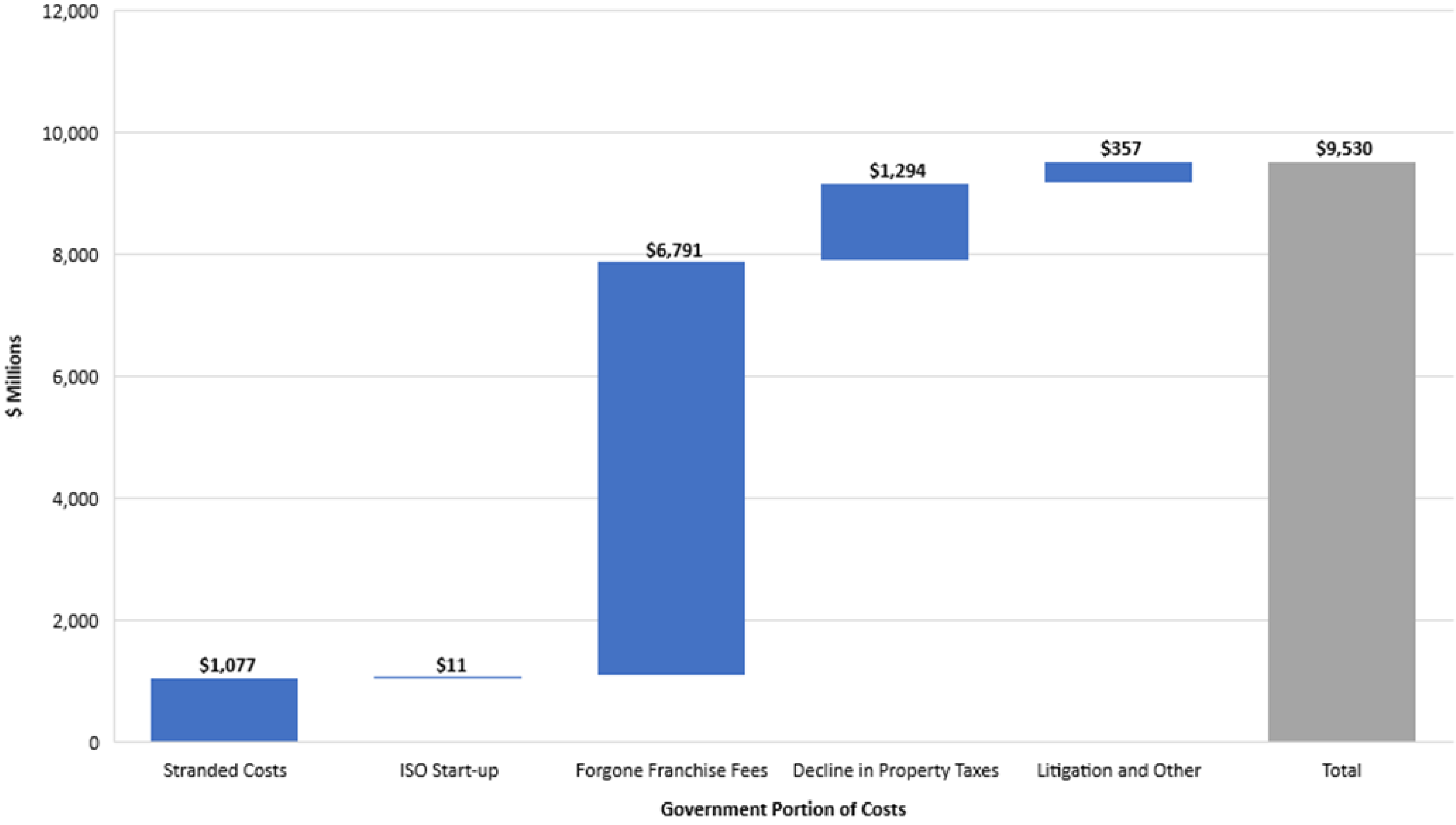
INTRODUCTION

- Florida's four major IOUs – Duke Energy Florida, Florida Power & Light Company, Gulf Power Company, and Tampa Electric Company – submitted a report (the "IOU Report") to the FIEC for its consideration in formulating it financial impact statement for the ballot measure *"Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice"* (the "Amendment")
- The IOU Report provides information and analysis based largely on publicly available information and includes independent research and analysis conducted by Concentric Energy Advisors, Inc.
- The IOU Report concludes that the Amendment would cost state and local government **between $1.3 billion and $1.7 billion** in upfront or one-time costs and **in excess of $825 million** in annual, on-going costs.

There is no credible scenario where the Amendment will not be financially negative to state and local government.

Over ten years, the minimum cost to state and local government alone will be in excess of $9.5 billion.

INTRODUCTION (CONTINUED)

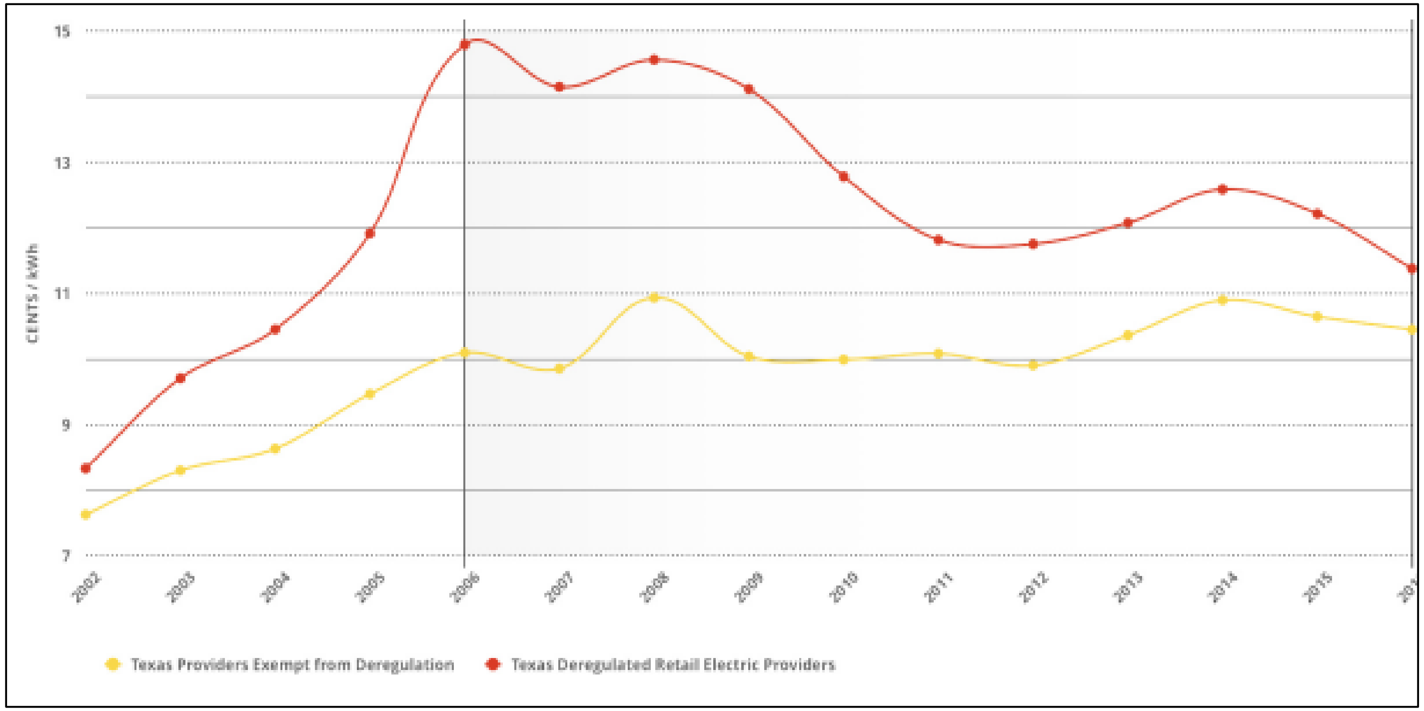


Texas is not a "shining star" in electric industry restructuring as the proponents of the Amendment have alleged.

INTRODUCTION (CONTINUED)

- The Texas Coalition for Affordable Power found that Texans have consistently paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation.
- Rolling blackouts and shrinking reserve margins threaten Texas.
- Customer complaints filed at the Texas Public Utility Commission increased dramatically following restructuring.

Average Residential Electricity Prices in Texas



Florida should not follow Texas' lead.

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The Amendment will "destructure" not "restructure" the state's energy markets and cost Floridians more than $10 billion in upfront and one-time costs.

KEY FINANCIAL IMPACT SUMMARY

State and local government will bear more than a billion dollars in upfront and one-time costs.

Cost Category	Total Impact to Florida and its Electricity Customers	Impact to State and Local Governments
Generation Stranded Costs	$10.0-$12.3 billion	$1.1-$1.4 billion
T&D Stranded Costs	IOUs have current investments of **over $24 billion** in T&D and other electric infrastructure – some portion of that investment could be stranded when IOUs divest their T&D ownership. Those costs are not included here.	
Wholesale Market and ISO Start-up/RTO Integration	• Start-up costs from $100-$500 million • Other costs (e.g., customer education) of approximately $20 million	• Start-up costs $11-$55 million • Other costs of $20 million
Litigation Costs	• Litigation costs to implement the constitutional amendment ranges from **$150-$300 million**	• The entire cost would impact State and Local Governments **$150-$300 million**
Total Upfront or One-Time Costs	**$10.1-$13.2 billion**	**$1.3-$1.7 billion**

The Amendment will create approximately $1 billion in annual, on-going costs to Floridians.

KEY FINANCIAL IMPACT SUMMARY (CONTINUED)

State and local government will bear more than $825 million in annual, on-going costs.

Cost Category	Total Impact to Florida and its Electricity Customers per year	Impact to State and Local Governments per year
Franchise Fees	$679 million	$679 million
Tax Revenues	• Property taxes *decrease* by $129.4-$173.8 million • Numerous risks to other taxes	$129.4-$173.8 million
ISO Management Costs	$170-$228 million	$18.7-$25.1 million
Total Ongoing Annual Costs	**$978.5 million to $1.1 billion per year**	**$827.2-$878.0 million per year**

- For those costs that would be borne by all Florida electricity customers, state and local government would bear a portion of the costs based on their proportionate share of electricity purchases (approximately 11%).
- The assumptions and support for this summary are provided in Appendix 1 to the IOU Report.

There are numerous other costs that would occur post-Amendment; $1.3 billion in upfront and one-time costs and more than $825 million in annual, on-going costs is the *minimum* impact on state and local government.

KEY FINANCIAL IMPACT SUMMARY (CONTINUED)

- Stranded costs beyond those quantified in the IOU Report, including for natural gas pipeline contracts, PPA, regulatory assets and other stranded costs.
- Costs to IOUs for the early retirement of debt.
- Costs for 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.
- Additional costs to state and local governments related to implementation and ongoing administrative costs under restructuring.
- 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.

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The Amendment is poorly drafted. It creates constitutional rights to things the Legislature may be unable to deliver. Litigation is inevitable.

IMPLEMENTATION AND OTHER COSTS

- The Amendment does not say what the Sponsors say it means.
- 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, including:
  - Texas specifically allowed continued ownership of T&D by IOUs (Texas Senate Bill 7, Section 31.002)
  - Texas did not restructure the entire state and did not create an entitlement to self-generate or multiple service providers
- No other U.S. state has ever implemented electric market restructuring through a constitutional Amendment. This is a very important and costly distinction.
  - For example, pursuant to the Amendment, judicial relief may be sought by citizens who do not find themselves with “meaningful choices among a wide variety of competing electricity providers”

Hundreds of millions of dollars will be spent on lawyers and consultants over many, many years with no assurance of achieving the promised results.

Forming and administering a functioning wholesale market is costly. Upfront costs to state and local government are expected to be no less than $50 million.

IMPLEMENTATION AND OTHER COSTS (CONTINUED)

- ISO implementation would cost between $100 to $500 million.
- Annual costs to administer the ISO would be in the range of $170 to $228 million based on other single state ISO/RTOs like New York ISO and ERCOT.
- In addition, other costs for education and Commission costs would be incurred.

	Low ($ millions)	High ($ millions)	State and Local Gov Portion ($ millions)
Implementation Costs	$100	$500	$11-$55
Administrative costs	$170	$228	$18.7-$25.1
Other costs	$20	$20	$20

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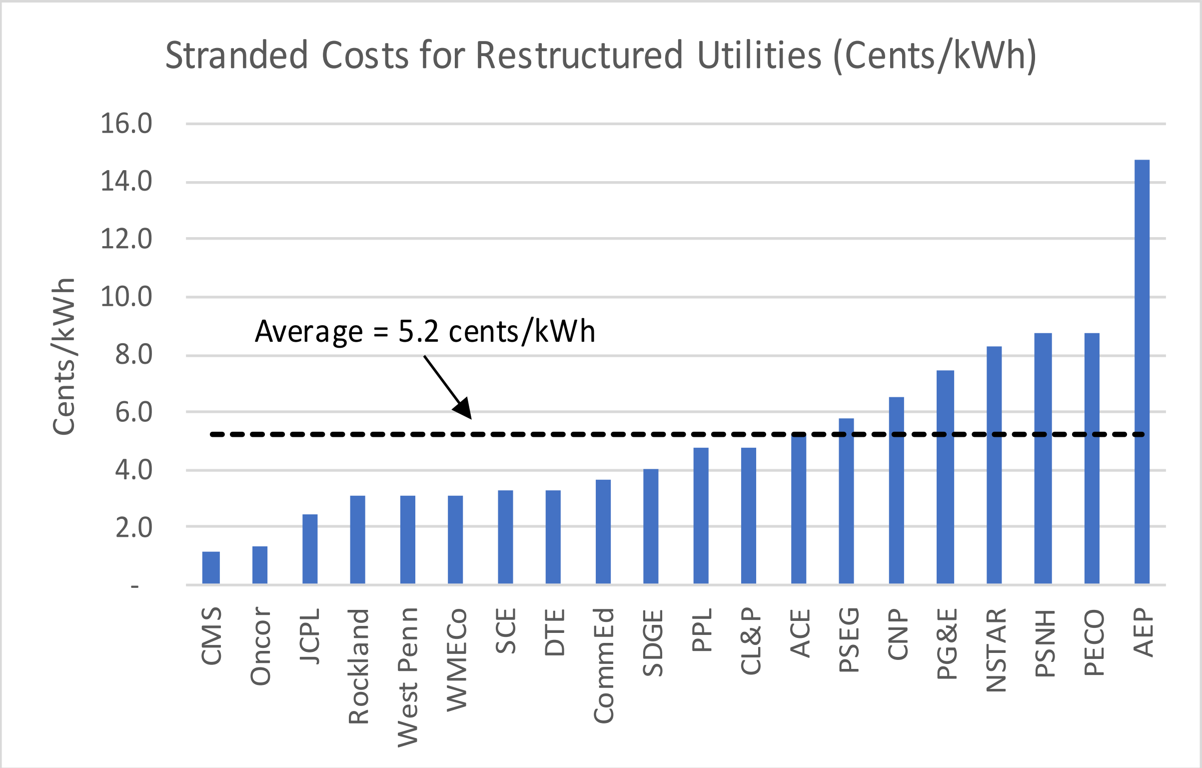
Generation stranded costs in restructured states have been significant.

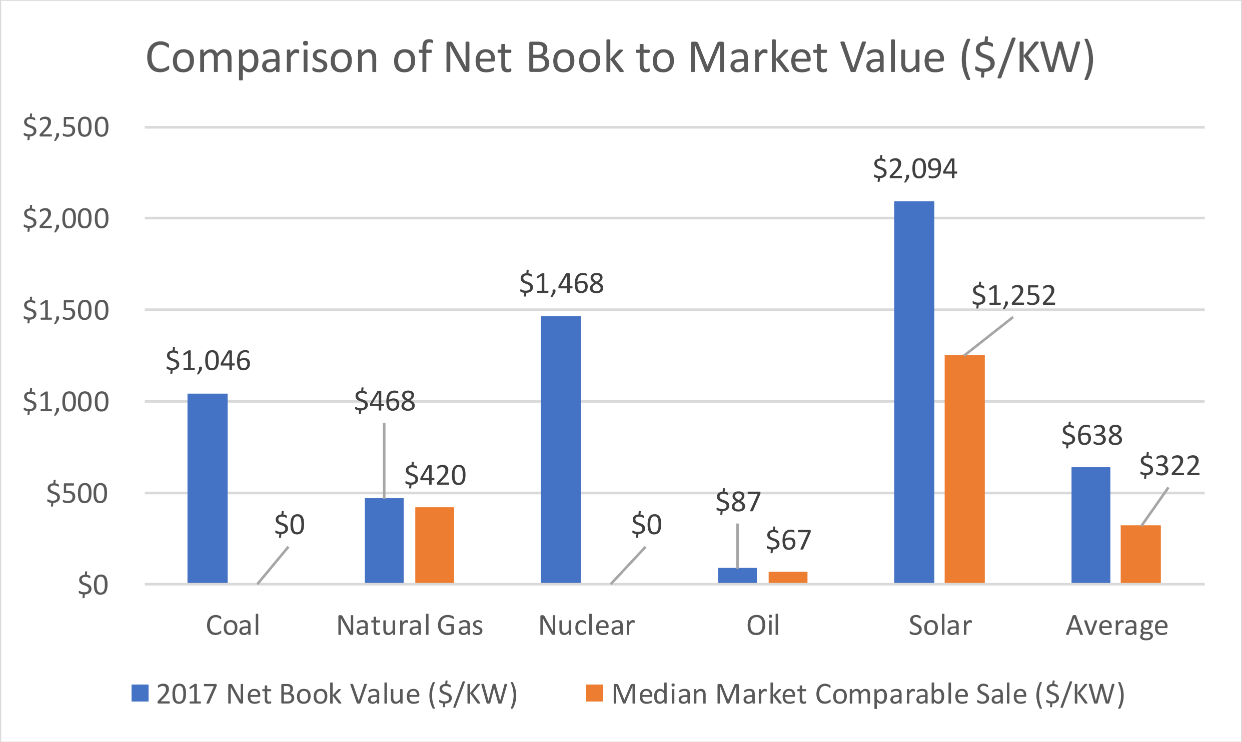
STRANDED COSTS



- Stranded costs studied in other states range from 1.2¢/kWh to 14.8¢/kWh, or $2.2-$27.9 billion when extrapolated to Florida.
- The average of 5.2¢/kWh would equate to **$9.8 billion in stranded costs** in Florida.

Recent sales of power plants have produced values, which when applied to the IOU power plants, would be well below book value.

STRANDED COSTS (CONTINUED)



- Recent sales of U.S. power plants indicate potential discounts to book value in Florida of between 10% to 100%, with an **average 49.6% discount**.
- The average discount of 49.6% would equate to **$12.3 billion of stranded costs** in Florida.

Generation stranded costs alone can reasonably be expected to exceed $10 billion. In addition, substantial incremental stranded costs would be incurred for T&D assets, PPAs, fuel contracts, and other contractual commitments.

ADDITIONAL STRANDED COSTS

- The four Florida IOUs have more than $24 billion currently invested in T&D assets – almost the same amount as is invested in generation.
- Other source of stranded costs include "out of the money" power purchase agreements ("PPAs"), fuel contracts, and other contractual commitments.
- For example, the IOUs hold billions of dollars of long-term fuel and pipeline transportation contracts that are unlikely to be attractive to merchant generators, and therefore may produce billions of dollars of stranded costs. Experience in other regions demonstrate that merchant generators are unwilling to sign firm transportation contracts on the pipelines, and prefer short-term contracts.

While not quantified in the IOU Report, the additional stranded costs will be substantial; thus the $10 billion is very conservative.

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Florida IOUs pay over $3.5 billion in taxes and fees to state and local government.

TAX REVENUES AND FRANCHISE FEES

($millions)	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	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**	**$27.6**	**$868.2**

Significant state and local government revenue sources are at risk from restructuring. Certain taxes may be eliminated entirely, while others will be diminished.

TAX REVENUES AND FRANCHISE FEES (CONTINUED)

Tax/Fee	Main Risk Factors from Restructuring
Sales Tax/Use Tax	• No tax on T&D portion of bill if sales tax does not apply to unbundled sales of electricity. • Avoidance of sales tax through out-of-state purchases.
Gross Receipts Tax	• Based on the current phrasing of statute, it is unclear whether the gross receipts tax would continue to apply at all. • Avoidance of gross receipts tax through out-of-state purchases.
Property Tax	• Sales prices of divested assets at less than book value will decrease the property base and an associated taxes.
Local Option Tax	• No tax on T&D portion of bill if sales tax does not apply to unbundled sales of electricity. • Avoidance of sales tax through out-of-state purchases.
Municipal Utility Tax	• No tax on T&D portion of bill if sales tax does not apply to unbundled sales of electricity.

Reduced property values would dramatically reduce property taxes.

TAX REVENUES AND FRANCHISE FEES (CONTINUED)

- Florida's IOUs paid more than $1 billion in property taxes in 2018.
- Our analysis indicates IOU 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.

Impaired Value %	Total Property Taxes Paid by Florida IOUs for Generation Property	Estimated Annual Property Tax Revenue Loss
36.9% - 49.6%	$350.2 million	$129.4-$173.8 million

Any impairment of T&D assets could lead to an equally large reduction in property tax revenue.

With no franchise, there will be no franchise fees.

TAX REVENUES AND FRANCHISE FEES (CONTINUED)

- Prohibiting exclusive franchises and prohibiting IOUs from owning T&D, would effectively negate municipalities' franchise agreements with the IOUs, eliminating this source of revenue.
- This same concern was voiced by the League of Cities during the FIEC public workshop on February 11, 2019.

Annual franchise fee revenue of $679 million would be eliminated under the Amendment.

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CONCLUSION

- 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.**
- 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**.

There is no credible scenario where the Amendment will not be financially negative to state and local government.

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Citizens for Energy Choices

SUBJECT: Financial Impact Statement for the Amendment: Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice ("Energy Choice Amendment")

DATE: February 21, 2019

This second memorandum from the sponsors of the Energy Choice Amendment to the FIEC is intended to provide additional information on issues raised at the FIEC Public Workshop held on February 11, 2019. This memorandum addresses various topics about which the potential for impacts to revenues or costs of the state and local governments were raised at the public workshop. Specifically, Part I of this memorandum discusses the Energy Choice Amendment's effect on revenue sources and cost drivers including: Franchise Fees; Ad Valorem Taxes; Gross Receipts Tax; Public Service Tax; Stranded Costs; ISO Implementation; and FERC v. Florida Wholesale Market Oversight. The memorandum considers these topics within the context of the FIEC's duty to issue a statement on the Energy Choice Amendment's probable financial impact on the revenues and costs to the state and local governments. In addition, Part II of the memorandum provides additional information regarding reliability and retail marketer service offerings based on questions from FIEC principals at the February 11, 2019 public workshop.

PART I

Franchise Fee Revenues

Franchise Agreements Not Prohibited by Energy Choice Amendment

The Energy Choice Amendment requires the Legislature to enact implementing law that "prohibits any granting of either monopolies or exclusive franchises for the generation and sale of electricity." The Florida League of Cities supposes that such language will prohibit cities and counties from entering into or keeping their franchise agreements with the investor-owned utilities ("IOUs") currently using public rights-of-way and easements under their control.

Under existing Florida law, an electric utility's right to generate and sell electricity exclusively within a given geographic area is established and enforced through Florida Public Service Commission ("FPSC") orders approving territorial agreements among the various electric utilities which divide among themselves exclusive service territory, and through orders of the FPSC resolving territorial conflicts between electric utilities. Monopoly or exclusive franchise rights to generate and sell electricity are bestowed upon IOUs by these orders of the FPSC, not by franchise agreements between IOUs and local governments.

Nothing in the language quoted by the League prohibits a franchise agreement between a local government and an IOU. As discussed above, a franchise agreement is not a grant of a monopoly or exclusive franchise for the generation and sale of electricity under current law, and it would not be such under the terms of the Energy Choice Amendment, as both the power generating functions and the retail merchant functions of a vertically integrated IOU are outside the subject matter of a franchise agreement, which addresses the right of the IOU to utilize at fixed rates public rights-of-way and easements for the performance of transmission and distribution functions.

Even after passage and implementation of the Energy Choice Amendment, IOUs are likely in a competitively structured market to continue to operate as rate-regulated transmission and distribution companies without competition in that role. Since the amendment prohibits these companies from directly owning generation assets and from directly competing for the retail sale of electricity, a franchise granted to one of them, even if exclusive, would not be a franchise for the generation and sale of electricity.

Moreover, nothing in the Energy Choice Amendment prevents the Legislature from structuring its implementation in a way that would protect franchise fee revenues. The City of Houston's experience following deregulation in Texas is illustrative that local governments continue to collect franchise fee revenue from IOUs following market deregulation.

After deregulation in Texas, Houston's franchise fee calculations were made based on kilowatt hours consumed within the City limits rather than gross revenue from sales to retail customers. According to the City's FY2018 Budget, before deregulation Houston's franchise fee payments fluctuated from $80 million to as much as $90 million per year. After a brief initial period following deregulation when franchise fee revenues fell to an annual average of $75 million, Houston now collects above a base franchise fee of $96 million and had projected FY2017 and FY2018 revenues of $101 million and $100.8 million respectively. An excerpt of the City's FY2018 Budget document is attached as **Appendix "A"**.

It is unknown how Florida's legislature might address this topic in implementing the Energy Choice Amendment. Any attempt to describe the *probable* effect of the Amendment on franchise fee revenues collected by local governments would therefore be speculative.

Franchise Ordinance Termination Provisions Are Not Automatic

In the Amendment Sponsor's view, the Energy Choice Amendment's passage is unlikely to result in the widespread cancellation of franchise agreements between IOUs and cities or counties. Such an outcome is clearly uncertain.

Beginning in 1996, in response to a wave of electricity market re-structuring around the country, electric utilities began including within franchise agreements offered to local governments provisions allowing termination if the introduction of retail competition harmed the IOU's ability to compete. These provisions typically state the following, or something substantially similar:

> 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 incorporated 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 incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee 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. The Grantee shall give the Grantor at least 90 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice.

This example is excerpted from a form agreement offered by FPL to the City of South Miami in 2014 during its negotiation for a franchise agreement renewal and is substantively identical to language found in numerous FPL franchise agreements entered after 1996, including the Longboat Key franchise ordinance quoted by the Florida League of Cities at the February 11, 2019, FIEC meeting.

It is important to note that under these provisions, termination of the agreement is not automatic upon the introduction of retail competition. The IOU's right to terminate is not triggered by a change in the law, rather it is triggered when the utility determines that the existence of the franchise agreement has placed it at a competitive disadvantage with respect to the new service provider, and it has notified the local government of that competitive disadvantage. Even then, most franchise agreements with this mechanism provide the local government an opportunity to avoid termination by offering a remedy.

The language in these agreements is usually silent as to the nature of the remedy a local government must offer to avoid termination of the agreement. It is therefore uncertain and speculative to guess whether any franchise agreement will be terminated following an IOU's exercise of these rights, because the local government has the opportunity to propose a remedy or negotiate revised terms, which may or may not involve the amount of revenue paid to the local government. In a review of nearly 190 franchise agreements only one was found containing this kind of termination provision that did not also provide an express opportunity to remedy prior to termination.

As discussed above, it is probable that following market restructuring required by the Energy Choice Amendment, existing Florida IOUs will continue to operate as rate-regulated monopoly transmission and distribution companies, and would be prohibited from directly competing with new retail providers or with electricity generating companies. Thus, a city's franchise agreement with an IOU would not create a competitive disadvantage for the company, because the Energy Choice Amendment and implementing legislation is unlikely to allow for competition in the provision of transmission and distribution services.

It is also important to note that franchise agreements are not uniform throughout the state and across IOUs. Each IOU offers its own form agreement, and every local government to varying degrees, negotiates its own terms which deviate from the form agreement. Several current agreements are attached as composite **Appendix "B"** for comparison purposes. Consider that agreements entered between 1985 and1996 (some of which remain in effect – the term is almost uniformly 30 years) contain no right of termination due to competitive disadvantage. Thus, an IOU would be unable to terminate such a franchise agreement by reason of competition caused by market restructuring.

Finally, a franchise agreement is more than just an agreement by the IOU to pay a fee to the local government. Franchise agreements grant significant benefits to the IOU, including the city or county's agreement, for a 30-year term, not to take over and operate the portions of the utility system located within the local government's jurisdictional boundaries. Additionally, such agreements provide a means for addressing the IOU's uses of the public rights-of-way and public easements within the jurisdiction, which may be more advantageous to the utility than terms provided in Florida Statutes. These benefits are all of a kind beneficial to the role an IOU is likely to continue to play as a rate-regulated transmission and distribution entity in Florida's restructured retail electricity market.

Since it is unknown whether widespread termination of franchise agreements might occur pursuant to termination provisions contained within them, it is unknown whether such termination, as a legal matter, could occur, and it is unknown how the Legislature might address the issue in its implementation of the Energy Choice Amendment, it is impossible to determine that any gain or loss of franchise fee revenue by local government is *probable*.

Right-of-Way Fees May Exist Without Franchise Agreements

A franchise fee is a charge imposed upon a utility for the grant of a franchise and for the privilege of using the local government's rights-of-way to conduct the utility business. A franchise fee is fair rent for the use of such rights-of-way and consideration for the local government agreeing not to provide competing utility services during the franchise term. See City of Plant City v. Mayo, 337 So. 2d 966 (Fla. 1976); Santa Rosa County v. Gulf Power Co., 635 So. 2d 96 (Fla. 1st DCA 1994), rev. denied, 645 So. 2d 452 (Fla. 1994); and City of Hialeah Gardens v. Dade County, 348 So. 2d 1174 (Fla. 3d DCA 1977).

By definition, a franchise ordinance grants a special privilege that is not available to the general public. The Florida Supreme Court explained in Leonard v. Baylen Street Wharf Co., 52 So. 718 (Fla. 1910), that "[a] franchise is a special privilege conferred upon individuals or corporations by governmental authority to do something that cannot be done of common right." Id. at 718. However, "[f]ranchises [are] not . . . the absolute property of any one, but their use may be granted or permitted by proper governmental authority, subject to supervision and regulation, and upon such terms as may be lawfully imposed." Id. Franchises are used for "the good of the public, usually for the purpose of rendering an adequate service without unjust discrimination, and for a reasonable compensation." Id. Finally, "[p]rivate rights in franchises are confined to a proper use of them for the general welfare, subject to lawful governmental regulation." Id.

In addition to compensation for the relinquishment of property rights, when counties and municipalities have the authority to own, operate, and maintain utilities themselves any permission granted to another entity to perform those services is additional justification for the fee. See Alpert v. Boise Water Corp., 795 P. 2d 298 (Idaho 1990). In Alpert, each franchise provided that the utility would pay to the cities a three percent (3%) franchise fee from all sales within the corporate limits as "consideration for the franchise contract." Id. at 300. The Idaho Supreme Court stated, "[C]ities have the right to own and operate utilities and provide those services to their residents[.] [T]he surrender of this right is valid consideration for the franchise fee charged to the utilities." Id. at 306.

The home rule authority of a county or municipality to enter into a franchise agreement with a utility and to impose a fee that is bargained for in exchange for the government property rights relinquished is settled. An evolving issue is the extent of the power of a county or municipality to unilaterally impose a fee for a privileged use of its right-of-way whether such charge is characterized as a rental fee, a regulatory fee or both.

Customarily, a franchise fee is calculated as a percentage of the gross revenues received by a utility from a defined geographic area. A franchise fee imposed by a municipality is based upon the gross revenues received by the utility from the municipal areas and a franchise fee imposed by a county is generally based upon the gross revenues received by the utility from the unincorporated areas (whether a franchise fee imposed by a county could be based on gross receipts received by the utility countywide has not been addressed.)

In Alachua County v. State, 737 So. 2d 1065 (Fla. 1999), because the electric utilities would not consent to a franchise agreement, Alachua County unilaterally imposed a fee for the privileged use of its rights-of-way. The fee imposed was three percent (3%) of the gross revenues generated by the electric utilities and the utilities were allowed to separately state the fee on the electric bill. The record in the validation proceedings did not, in the words of the Court, establish any "nexus between its alleged 'reasonable rental charge' . . . and the rental value of the rights-of-way." Id. at 1067-68. As a consequence, the Court held that the unilaterally imposed privilege fee was a tax not authorized by general law.

The Alachua County case was distinguished by the Court in Florida Power Corp. v. City of Winter Park, 887 So. 2d 1237 (Fla. 2004). There, the electric utility refused to renegotiate a franchise agreement which had previously provided for the payment of a franchise fee of six percent (6%) of the gross revenues received from the sale of electricity within the City of Winter Park. The Court likened the electric utility to a holdover tenant in the public rights-of-way and held that the electric utility would be subject to the six percent fee until the parties reached a new agreement or the City exercised its rights to acquire granted under the franchise agreement. The Court distinguished its prior holding in Alachua County as follows:

> Moreover, we reiterate that Alachua validates fees that are reasonably related to the government's cost of regulation or the rental value of the occupied land, as well as those that are the result of a bargained-for exchange. [cit. omitted] In the instant case, the trial court specifically found that the City had "offer[ed] sufficient evidence that the six percent fee was reasonably related" to the costs of regulation, and had "also

> presented strong evidence that the six percent fee is a fair 'market rate' for such use, occupation, or rental."

887 So. 2d at 1241.

In summary, a bargained for reasonable fee in a franchise agreement is not a tax. The fact that the franchise agreement has expired does not render the charge a tax and it remains a valid fee until a new agreement is reached or any contractually granted acquisition rights are exercised. Additionally, a unilaterally imposed fee reasonably related to the cost of regulation and constituting a reasonable rental charge for the use of public property is a valid fee.

A city and a county have the home rule power to impose such a fee on electric utilities for the use of the rights-of-way. The extent to which a local government might attempt to exercise such authority in the event its franchise agreement is voided or terminated is unknown. Therefore, any attempt to determine the *probable* impact of such events on state and local governments in the aggregate is impossible.

Ad Valorem Tax Revenues

Opponents of the Energy Choice Amendment speculate that, under specified circumstances that are unlikely to exist following implementation of the Amendment, electricity generating assets might decrease in value, in turn resulting in a decrease in ad valorem tax revenue collections by local governments.

Ad Valorem Taxes

From the Sarasota County tax collector's website (https://www.sarasotataxcollector.com/services/tax-services/property-tax/ad-valorem):

> Ad Valorem Tax
>
> In Florida, the real estate tax bill is a combined notice of ad valorem taxes and non-ad valorem assessments. The tangible tax bill is only for ad valorem taxes.
>
> Ad valorem taxes are paid in arrears (at the end of the year) and are based on the calendar year from January 1 – December 31. The Property Appraiser assesses the value of a property and the Board of County Commissioners, School Board, Cities, and other levying bodies set the millage rates.
>
> A millage rate is the rate of tax per thousand dollars of taxable value. To determine the ad valorem tax, multiply the taxable value (assessed value less any exemptions) by the millage rate and divide by 1,000. For example,

$100,000 in taxable value with a millage rate of 5.0000 would generate $500 in taxes.

The Property Appraiser certifies the values and exemptions on the tax roll. The Tax Collector merges the ad valorem and non-ad valorem tax rolls and mails a tax bill to the owner's last address of record.

Valuation of Assets Subject to Ad Valorem Tax

From the Sarasota County property appraiser's website (https://www.sc-pa.com/about-value/appraisal-process/):

> The Property Appraiser's office is required to determine the value of all real property (real estate) and tangible personal property (e.g. business equipment, rental furnishings) as of January 1 of each year.
>
> Three values are established for each parcel (real estate) or account (tangible personal property): Market (aka Just) Value is established through the appraisal process, as set out in Florida Law.
>
> Assessed Value and Taxable Value are derived through classified uses or the application of various exemptions, such as the familiar homestead exemption, also as set out in Florida Law.
>
> Arriving at Just (Market) Value
>
> The purpose of the appraisal is to estimate the "Just Value" of the identified property (s.4 Art. VII State Constitution) as of the appraisal date, January 1, of each year s.192.042(1) F.S.).
>
> Just (Market) Value is defined as "Just Value" - "Just Valuation", "Actual Value" and "Value" - Means the price at which a property, if offered for sale in the open market, with a reasonable time for the seller to find a purchaser, would transfer for cash or its equivalent, under prevailing market conditions between parties who have knowledge of the uses to which the property may be put, both seeking to maximize their gains and neither being in a position to take advantage of the exigencies of the other (12D-1.002 (5) F.A.C.).
>
> The Supreme Court of Florida determined that "fair market value" and "just valuation" should be declared "legally synonymous." ... in turn may be established by the classic formula that it is the amount a "purchaser willing but not obliged to buy, would pay to one willing but not obliged to sell." (Walter v. Schuler, 176 So. 2d 81 (FL 1965).
>
> The fee simple rights to the property are appraised.

The Supreme Court of the State of Florida identified these rights in Department of Revenue v. Morganwoods Greentree, Inc., 341 So. 2d 756, 758 (FL 1977):

> We reaffirm the general rule that in the levy of property tax the assessed value of the land must represent all the interests in the land. This means that despite the mortgage, lease, or sublease of the property, the landowner will still be taxed as though he possessed the property in fee simple. The general property tax ignores fragmenting of ownership and seeks payment from only one "owner".

Factors Determining Value

In arriving at just valuation as required under section 4, Article VII of the State Constitution, the property appraiser shall take into consideration the following factors:

1. The present cash value of the property, which is the amount a willing purchaser would pay a willing seller, exclusive of reasonable fees and costs of purchase, in cash or the immediate equivalent thereof in a transaction at arm's length;

2. The highest and best use to which the property can be expected to be put in the immediate future and the present use of the property, taking into consideration any applicable judicial limitation or local or state land use regulation and considering any moratorium imposed by executive order, law, ordinance, regulation, resolution, or proclamation adopted by any governmental body or agency or the Governor when the moratorium or judicial limitation prohibits or restricts the development of property as otherwise authorized by applicable law;

3. The location of said property;

4. The quantity or size of said property;

5. The cost of said property and the present replacement value of any improvements thereon;

6. The condition of said property;

7. The income from said property; and

8. The net proceeds of the sale of the property, as received by the seller, after deduction of all of the usual and reasonable fees and costs

of the sale, including the costs and expenses of financing, and allowance for unconventional or atypical terms of financing arrangements. When the net proceeds of the sale of any property are utilized, directly or indirectly, in the determination of just valuation of realty of the sold parcel or any other parcel under the provisions of this section, the property appraiser for the purposes of such determination, shall exclude any portion of such net proceeds attributable to payments for household furnishings or other items of personal property."

These eight factors are all considered in arriving at a value conclusion.

Impact on Ad Valorem Tax Revenues

As noted in the information above, "the Assessed Value of property is derived through classified uses or the application of various exemptions." Without public disclosure of the specific approach an appraiser uses to derive the Assessed Value in a specific circumstance, the Market Value is generally seen as a proxy for the Assessed Value of a property. In the case of determining the Market Value of a utility's electricity generating facility, analysis of several of the 8 factors listed above would not change at all as a result of restructuring the electricity market in Florida.

Specifically, the highest and best use (Factor No. 2) of the property would not change. Whether the price of the electricity produced by the electricity generating plant is subject to rate regulation or to the variabilities of the wholesale power markets, the highest and best use of an electricity generating plant site is to generate electricity for sale into the market in which it has access to deliver its product. No regulatory change required under the Energy Choice Amendment would limit, restrict or deny the owner of an electricity generating plant to produce electricity from said plant and sell it into the market.

Factor Nos. 3-6 relate to the location, size, quantity, condition acquisition and replacement costs of the property. Market restructuring to introduce wholesale and retail competition and to re-organize the means of owning electricity generating assets has no rational bearing on an analysis of these factors. Restructuring the electricity markets in Florida will have no impact on the location of the land, the size or quantity of the land, the acquisition price of raw land, the replacement value of electricity generating assets, or condition of the property.

Whether market re-structuring and ownership re-organization has any effect on the cash value of the property (Factor No. 1), the income the property is able to generate (Factor No. 7), and any potential proceeds from the sale of the property if the property is sold (Factor No. 8), is subject to reasonable debate.

Opponents of the Energy Choice Amendment claim market restructuring will cause wholesale prices, and as a follow-on effect retail electricity prices, to increase. If they are correct, such price increases may result in increased income potential, higher cash value, and potentially higher sale proceeds in the event of sale, for electricity generating plant owners, potentially increasing the Market Value of the plant. Following this logic, if wholesale prices decrease following restructuring resulting in lower retail prices for end-use customers, as the Energy Choice Amendment's Proponents argue, electricity market restructuring may lead to decreases in the Market Value of the electricity generating plants.

It is impossible to determine at this time the *probable* outcomes from individual Property Appraisers application of the foregoing factors to determine electricity generating plant Market Value in a restructured electricity marketplace. Any statement of the probable impact of the Energy Choice Amendment on ad valorem tax revenues to local governments would necessarily be uncertain and speculative.

Gross Receipts Tax

The Energy Choice Amendment will require changes to current law imposing and implementing the Gross Receipts Tax, however, it is unknown at this time what changes the Legislature may enact regarding the tax, and how those changes might result in increased or decreased revenues to the state and local governments.

The Gross Receipts Tax is a tax imposed on the gross receipts from utility services that are delivered to retail consumers in the state. Section 203.01(1)(a)1., Florida Statutes. The tax does not apply to sales of electricity to public utilities for resale to end users (i.e., it only applies to retail receipts, not wholesale receipts).

The tax is calculated by determining the total kilowatt hours delivered multiplied by an index price[1]. The tax is 2.5% of the result. Section 203.01(d)1., Florida Statutes. The formula is as follows:

i. [Kwh] x [Index Price] = [GRT Base Charge]

ii. [GRT Base Charge] x [0.025] = [GRT that applies to the retail invoice]

The tax is also calculated on the sales tax that is charged for electricity. Section 203.01(1)(a)3., Florida Statutes.

Any entity identified as a "distribution company" under current law, pays the tax. Section 203.01(1)(c)1., Florida Statutes, provides:

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[1] The index price is the Florida price per kilowatt hour for retail consumers in the previous calendar year, as published in the United States Energy Information Administration Electric Power Monthly and announced by the Department of Revenue on June 1 of each year to be effective for the 12-month period beginning July 1 of that year. For each residential, commercial, and industrial customer class, the applicable index posted for residential, commercial, and industrial shall be applied in calculating the gross receipts to which the tax applies. If publication of the indices is delayed or discontinued, the last posted index shall be used until a current index is posted or the department adopts a comparable index by rule.

> The tax … shall be levied against the total amount of gross receipts received by a distribution company for its sale of utility services if the utility service is delivered to the retail consumer by a distribution company and the retail consumer pays the distribution company a charge for utility service which includes a charge for both the electricity and the transportation of electricity to the retail consumer.

The law defines a "distribution company" as any person owning or operating local electric… utility distribution facilities within this state for the transmission, delivery, and sale of electricity or natural or manufactured gas." Section 203.012(1), Florida Statutes.

The Florida Constitution requires the revenue from the GRT to go to the "Public Education Capital Outlay and Debt Service Trust Fund." Fla. Const. Art XII, Subsection 9(a)(2)

Unless the Legislature revises the law in implementing the Energy Choice Amendment, the Amendment's requirements will disqualify a retail marketing company from being classified as a "distribution company" because it would not own or operate electricity distribution systems in the state. In addition, sales from competitive generators to marketers would not be taxed because those are sales for resale, which are currently exempt. Under the law as currently written, the taxable entity would no longer exist.

In the long term, lower end-sector electricity prices would push down the averages published by the EIA and used to calculate the GRT.

Nothing in the Energy Choice Amendment prevents the Legislature from enacting implementing legislation to include the new retail electricity marketers within the class of entities subject to Gross Receipts Tax. Additionally, nothing in the Energy Choice Amendment prohibits the Legislature from revising the index price formula to account for falling end-sector average prices. While the Energy Choice Amendment will impact the Gross Receipts Tax as currently implemented in Florida Statutes, it is unknow whether that will result in impacts to state and local government revenues because it is unknown how the Legislature might address the issue.

Public Service Tax

Under Section 166.231, Florida Statutes, municipalities and charter counties are authorized to charge a maximum 10 percent Public Service Tax on the purchase of utility services within their jurisdictions, including electricity. The tax is authorized at the state level by statute, but is implemented by hundreds of local ordinances.

The Public Service Tax on electricity is collected by the seller from the purchaser at the time of payment for electricity service. Based on the location of the electricity purchaser's meter, it is then remitted to the particular municipality or charter county imposing the tax, as prescribed by local ordinance.

Local, state, and federal government entities are exempt from the Public Service Tax under Section 166.231, Florida Statutes, as are recognized churches. Municipalities and charter counties have the authority to exempt certain other amounts of the Public Service Tax for residential and industrial electricity customers, as set by Section 166.231, Florida Statutes.

Under Section 166.231, Florida Statutes, the Public Service Tax "shall not be applied against any fuel adjustment charge." The term fuel adjustment charge "means all increases in the cost of utility services to the ultimate consumer resulting from an increase in the cost of fuel to the utility subsequent to October 1, 1973." This reduces the amount of public service taxes on electricity.

Municipalities and charter counties can levy the tax in any amount up to 10 percent. They also have the authority under Section 166.232, Florida Statutes, to determine whether to levy the tax on either (a) payments received for electricity, or on (b) kilowatts of electricity consumed. Beyond this, the specifics of each jurisdiction's method of calculation are set by local ordinance.

Public Service Tax proceeds are considered general revenue for the municipality or charter country that collects them, and are accordingly used for a wide variety of purposes.

The effect of electricity market restructuring on the Public Service Tax on electricity service depends upon how the Legislature chooses to implement the Energy Choice Amendment, but some outcomes can be predicted:

a. As currently written, the Public Service Tax would still apply to retail electricity providers. Unlike the Gross Receipts Tax on electricity, which is levied on distribution companies alone, the Public Service Tax is levied on the purchase of electricity itself. Therefore, municipalities and charter counties could still collect the Public Service Tax from competitive retail electricity providers.

b. The Public Service Tax will be equally applicable to in-state and out-of-state retail electricity providers. Competitive electricity markets will likely attract retail electricity providers who are located outside of the State of Florida. In the past, U.S. Supreme Court precedent barred states from compelling out-of-state retailers to collect taxes on the sale of goods made to residents of states in which those out-of-state retailers did not have a physical presence. For example, this exemption once allowed companies like Amazon to sell goods in Florida without collecting sales taxes. However, the U.S. Supreme Court overturned this precedent in 2018, in South Dakota v. Wayfair, Inc., 138 S. Ct. 2080. As a result, there is no federal barrier to the collection of taxes on the sale of goods from out-of-state retailers, including the Public Service Tax on the sale of electricity.

c. Tough it is currently unknown how many, the Public Service Tax will be collected from an increased number of taxable entities. The Public Service Tax on electricity is currently collected by Florida's existing 57 electric utilities, but each taxing jurisdiction collects these taxes from no more than a few of these utilities. In a competitive market, the number of retail electricity providers serving Floridians would increase, and they would not be limited to the boundaries of existing utility territories. As a result, in a restructured electricity market, the Public Service Tax would be collected from a larger number of taxable entities than is the case today.

Florida already has some experience in the application of the Public Service Tax in a competitive natural gas market, and the introduction of competition had little effect on the collection of the tax on natural gas sales.

The Legislature's implementation of the Energy Choice Amendment will determine its full impact on the Public Service Tax on electricity. However, as a point of comparison, the competitive natural gas market created in Florida in 2000 by Rule 25-7.0335, Florida Administrative Code, had minimal effect on the Public Service Tax on natural gas. According to data from the FPSC, the Florida Department of Revenue, and the U.S. Energy Information Administration:

- Florida's cities and counties collected $18,481,168 of Public Service Taxes on natural gas in 2002 and $27,601,397 in 2016 – a 49 percent increase during this 14-year period.[2]

- During this same period, 1.6 billion therms of natural gas were sold to Florida customers in 2002, while 2.2 billion therms were sold in 2016 – a 40 percent increase. At the same time, competitive suppliers increased their overall market share by 87 percent.[3]

- Also during this same period, regional wholesale natural gas prices fluctuated up and down from month-to-month and year-to-year, but declined by 25 percent overall from 2002 to 2016.[4]

[2] Public Service Tax Data: Municipal and County Revenues – Florida Office of Economic and Demographic Research. http://edr.state.fl.us/Content/local-government/data/data-a-to-z/m-r.cfm

[3] Facts and Figures of the Florida Utility Industry: January 2004 and May 2018 Reports – Florida Public Service Commission. http://www.psc.state.fl.us/Publications/Reports#

[4] Annual Henry Hub Natural Gas Spot Prices, 2002 to 2016 – U.S. Energy Information Administration. https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm

Therefore, the Public Service Tax on natural gas appears largely unaffected by either the introduction of competition into Florida's natural gas market or fluctuations in wholesale natural gas prices. Instead, increased natural gas consumption appears to have been the driving factor in the increased collection of the Public Service Tax on natural gas from 2002 to 2016. Depending upon how the Legislature implements the Energy Choice Amendment, restructuring electricity markets may or may not have similar effects.

Because it is impossible to know at this time what choices the Legislature might make in implementing the Energy Choice Amendment or in revising application of the Public Service Tax for electricity, the *probable* impact to revenues of state and local governments cannot be determined at this time.

Stranded Costs

According to DIA Management Consultants[5] a stranded cost "is the decline in the value of an asset as a result of regulatory change." The Congressional Budget Office defines stranded costs "as the decline in the value of electricity-generating assets due to the restructuring of the industry."

"Regulated electric rates are designed specifically to cover a utility's cost of doing business, i.e., to recover its operating costs and invested capital and to provide an opportunity to earn a reasonable return on its capital. On the other hand, market-based prices are indifferent to the costs incurred by any individual market participant. Therefore, as electric markets are opened to competition the level of revenue earned by a utility may no longer closely match the level required to cover its costs. Some may earn more than their cost of doing business, others less. The difference between costs expected to be recovered under rate regulation and those recoverable in a competitive market is termed "stranded costs." If market prices are lower than regulated rates, as many expect, utilities could be faced with investments that are unrecoverable in the competitive market.

"The issue of stranded costs has several facets. One is to clearly define what is meant by "stranded costs." The utility's cost obligations must be identified and quantified. Although a company may have "strandable" costs, future market conditions will dictate whether these costs are unrecoverable. Therefore, expected future market revenues must be quantified, as well. Other considerations are: Whether stranded costs should be recovered? If so, should 100% of the stranded costs be recovered or only a portion? Who should pay for the stranded costs and what mechanism should be used for recovery? Has the utility company made a bona-fide effort to mitigate its stranded costs? and, Were the original investments and expenditures prudent?"[6]

[5] https://ceic.tepper.cmu.edu/-/media/files/tepper/centers/ceic/seminar%20files/2004-2005/rode_ceic_stranded_cost_case%20pdf.pdf?la=en
[6] http://www.psc.state.ga.us/electricindust/5d.htm

Following implementation of the Energy Choice Amendment, an IOU that currently owns and operates transmission and distribution assets subject to rate regulation will likely continue to do so, as only the provision of retail marketing functions and power generating functions would be prohibited to them. As a result, rates charged for performance of the transmission and distribution functions by the incumbent IOUs would continue to allow for recovery of allowed "accounting" costs such as the IOUs operating costs and the costs of repaying investors over time while still providing a "reasonable" rate of return.

With respect to electricity generating assets, IOU affiliates or successors would only be able to charge prices that are supported within the market, affected by the forces of supply and demand. In a competitive market, where retail electricity prices are subject to market forces, it is possible that either windfall gains or losses might occur with respect to investor returns. For example, where generating assets are highly depreciated and the market supports higher prices, there is the possibility for windfall profits, or "negative stranded costs." Where the portfolio of electricity generating assets includes uneconomical plants previously afforded cost recovery under regulated market conditions, or if market forces drive retail prices down, or if electricity demand falls, the revenue generated may not support full recovery of previously authorized costs, resulting in losses in anticipated profits (stranded costs).

For illustration purposes, the Texas restructuring experience paints a picture of how stranded costs might result from deregulation in Florida, and the potential range of such calculations.

Texas Background

- As of 2001 (pre-Enron), the Texas PUC calculated that CenterPoint had negative stranded costs of $2.6 billion and ratepayers would receive a rate reduction.

- During the period from 2001-2004, the power market collapsed, and natural gas prices increased substantially.

- In 2002, TXU reached a $1.3 billion settlement with the Texas PUC over stranded costs (it had sought $2.8 billion).

- In early 2004, Texas-New Mexico Power sought recovery of $357 million but was awarded $137 million (determined using a sale-of-assets method).

- On March 31, 2004, CenterPoint filed for recovery of $4.4 billion (based on a partial stock valuation method), filing a 3,000+ page application for stranded cost recovery with the Texas PUC.

Impacts on State and Local Government Revenues and Costs

Higher-than-expected revenues realized from operating electricity generating assets is likely to result in the assets having a market value greater than their book value (higher revenues drive higher profits and cash flow, which in turn, would lead to a higher valuation). As most of the relevant government revenue sources are either directly or indirectly tied to revenue from the sale of electricity (Gross Receipts Tax, Public Service Tax, and Sales and Use Tax for non-exempt commercial accounts), or are tied to the value of the assets (Ad Valorem Property Tax), in such a case, and to the extent currently existing taxes remain applicable, tax revenues for state and local governments could remain the same or increase. Additionally, under such conditions it is possible that an increase in revenues to state and local governments could result indirectly from the economic benefits to customers from the "give-back" of the negative stranded costs refunded to consumers (in the case of negative stranded costs, investor owned utilities would be required to "pay back" end-use customers for the value derived from the generation assets that were built on their behalf).

In the case of positive stranded costs, where expected revenues from operating the electricity generating plants in a competitive wholesale market are lower than the revenues generated in a rate regulated non-competitive market, tax revenues tied to utility operations would likely be lower for state and local governments. However, any implementation of the Energy Choice Amendment is likely to allow an IOU to recover its stranded costs over time from consumers. These types of costs are usually recovered through some form of competitive transition charge that would be included as a rider charge on the customer's bill. The timing of the recovery period for the stranded costs is subject to a variety of uncertain factors, including litigation and negotiation. Similar factors affect any discount rate that might be used to determine the magnitude of any such rate rider or surcharge. As a matter of policy, in its implementation the Legislature may choose to subject these competitive transition charges to the same Gross Receipts Tax, Public Service Tax and Sales and Use Tax as traditional electricity charges.

In Texas, such transition charges are not subject to the public utility gross receipts assessment on electricity or the miscellaneous gross receipts tax on electricity.[7] There the competition transition charges are subject to sales tax if they are not broken out on a customer's bill. Furthermore, in Texas, the IOUs that were permitted to recover stranded costs through competitive transition charges subsequently were able to securitize those costs through the issuance of "transition bonds." These bonds were issued as asset-backed securities (backed by the utilities' right to recover the transition charges over time), rated AAA by S&P and Moody's, and had average lives ranging from 2-11 years. The proceeds of the bonds were used by the investor owned utilities to invest back into the utility although it was typically used to repurchase or retire debt or equity.[8] These investments could potentially generate future state and local government tax revenues but that is indeterminable at this point. Clearly, many options are available to the

[7] https://comptroller.texas.gov/taxes/publications/96-1309.pdf
[8] http://pages.stern.nyu.edu/~igiddy/cases/oncor3.pdf

Legislature to address the issue of stranded cost recovery or refund in its implementation of the Energy Choice Amendment.

Determining whether and how much stranded costs will result from implementation of the Energy Choice Amendment in Florida is a fact-specific inquiry subject to in-depth financial and accounting review, a type usually undertaken in adversarial administrative proceedings, and it cannot be accomplished by the FIEC within its limited role and within the procedures that constrain it. Any attempt to quantify such costs would be highly speculative given the limited facts available. Further, the Energy Choice Amendment leaves to the Legislature the task of determining the nature and structure of the wholesale electricity market that would result from passage of the Amendment, and details controlling how to address stranded costs, material factors in determining what stranded cost impacts will occur, if any. It is therefore impossible to determine the *probable* impacts that stranded costs would have on state and local government revenues and costs.

ISO Implementation/FERC Oversight

FERC Oversight

It is unlikely that Federal Energy Regulatory Commission ("FERC") jurisdiction over Florida's wholesale electricity markets will result in increased costs to Florida's state or local governments following restructuring under the Energy Choice Amendment. Further, it is unlikely that following deregulation in Florida increased costs to state or local governments will result from the two North American Electric Reliability Corporation ("NERC") Regional Reliability Councils ("RRCs") having reliability oversight in Florida.[9]

Energy Choice Amendment opponents raised the specter of increased state government costs resulting from FERC jurisdiction over wholesale markets in Florida – factor not present in Texas wholesale markets. The impact of such a difference must be considered in light of what FERC does.[10] FERC:

- Regulates the transmission and wholesale sales of electricity in interstate commerce;
    - This jurisdiction already exists and applies to any interstate transactions of electricity; nothing in the amendment language requires or suggests an increase in the volume of interstate transactions.

[9] The Florida Reliability Coordinating Council ("FRCC") oversees reliability in peninsular Florida, and the SERC Reliability Corporation ("SERC") (formerly the Southeastern Electric Reliability Council) oversees reliability in the western panhandle region of Florida.
[10] https://www.ferc.gov/about/ferc-does.asp

  - In a restructured market, the individual competitive entities engaging in interstate commerce would incur the costs of oversight (as opposed to the current paradigm, in which every cost, no matter how wasteful or avoidable, is pushed down to the ratepayers, including state and local governments who purchase electricity).

- Reviews certain mergers and acquisitions and corporate transactions by electricity companies;
  - This already applies in cases where multi-state utilities with operations in Florida merge or acquire utilities with assets outside of Florida.
- Regulates the transmission and sale of natural gas for resale in interstate commerce;
  - This already applies.
- Regulates the transportation of oil by pipeline in interstate commerce;
  - This already applies.
- Approves the siting and abandonment of interstate natural gas pipelines and storage facilities;
  - This already applies.
- Reviews the siting application for electric transmission projects under limited circumstances;
  - This already applies.
- Ensures the safe operation and reliability of proposed and operating LNG terminals;
  - This already applies.

- Licenses and inspects private, municipal, and state hydroelectric projects;
    - This already applies.
- Protects the reliability of the high voltage interstate transmission system through mandatory reliability standards;
    - This already applies.
- Monitors and investigates energy markets;
    - To the extent that this doesn't already apply, the benefits and reduced costs to consumers of ensuring robust energy markets and reducing market power far outweigh the cost such oversight might cause.
    - FERC's potential oversight will lessen, not increase, the cost born by Florida's state and local governments in performing similar functions.
- Enforces FERC regulatory requirements through imposition of civil penalties and other means;
    - This already applies.
- Oversees environmental matters related to natural gas and hydroelectricity projects and other matters;
    - This already applies.
- Administers accounting and financial reporting regulations and conduct of regulated companies.
    - This already applies.

In summary: all of FERC's responsibilities—and associated costs—already apply to Florida's electric system. Incumbent utilities that are resistant to having their monopolies disrupted are invoking the specter of federal oversight to fearmonger. In fact, FERC oversight already exists in all relevant respects, both regarding Florida's electric grid and in other wholesale (ISO/RTO) markets that currently exist in other jurisdictions. Any additional cost of federal oversight—if any materialize—would be borne by individual market participants, not by the state or local governments.

Regarding increased costs due to the existence of two regional reliability councils in the state of Florida, the answer must again be considered in light of what RRCs do:

- NERC oversees eight regional reliability entities and encompasses all the interconnected power systems of the contiguous United States, Canada and Mexico.

- SERC was formed on April 29, 2005, as the successor to the Southeast Electric Reliability Council (also known as SERC). The original SERC was formed January 14, 1970 by the functional merger of four smaller reliability entities: the CARVA Pool, Tennessee Valley Authority (TVA), Southern Company (SOCO) and the Florida Electric Power Coordinating Group (FEPCG). On September 16, 1996, the SERC member companies formerly represented by FEPCG formed the Florida Reliability Coordinating Council (FRCC) and separated from SERC.

- FRCC is currently dominated by Florida IOUs, particularly Florida Power and Light Company.

- To the extent that it is expedient to do so, the organizations can be modified as they were in 1996 and in 2005 (for example, to create a single, FL-only RRC).

- It is not clear that it is necessary to do so—in fact, market power and reliability may be better addressed by having the wholesale market overseen by both RRCs.

- The mere existence of multiple (and preexisting) RRCs in the area covered by the amendment does not suggest there will be additional costs to state or local governments—only that two already existing entities will be overseeing the market.

ISO Implementation

An Independent System Operator ("ISO") is an entity that enables a tight power pool to satisfy the requirement of providing non-discriminatory access to electricity transmission. These entities grew out of FERC's suggestion in its Orders 888 and 889 of the concept of such an entity to perform such a function.

According to the ERCOT 2018-19 Budget Summary, attached here as **Appendix "C"**, most of ERCOT's revenues come from a System Administrative Fee, which is included in wholesale power bills, and is ultimately passed through as a cost to end-use electricity consumers. The current fee for ERCOT is about 55.5 cents/MWH, which is about $7/year for the average residential consumer in Texas.

In its implementation, the Florida Legislature could provide for any ISO to be funded by market participants, not the state. As it is unknown how the Legislature might address establishment of a Florida ISO, any attempt to determine the *probable* cost to state or local governments would require speculation.

PART II

Reliability and Reserve Margins

Comments made at the February 11, 2019, FIEC Public Workshop by the energy Choice Amendment's opponents suggested that retail electric competition leads to lower reserve margins and less reliability. Evidence suggests that is not true.

The Florida Reliability Coordinating Council (FRCC) currently requires a minimum reserve margin of 15% for planning purposes and the FPSC requires Florida's existing IOUs to maintain a minimum of 20%. The statewide reserve margin for Summer is nearly 25% in Florida. ERCOT has a target planning reserve margin of 13.75%, but there are no requirements associated with it. The Brattle Group has performed a number of studies for ERCOT and has concluded that the economically optimal reserve margin is approximately 10%. There have been no reliability issues related to the system-wide reserve margin. It's impossible to determine if there could be any impact associated with a potential change in the reserve margin requirement, without knowing how the law will ultimately handle reserve margin requirements and guidelines. In Texas, a choice was made to not set any minimum reserve margin and let the market ultimately determine the appropriate reserve margin. This minimizes costs for consumers in that uneconomic excess capacity is ultimately minimized while potential shortfalls in capacity are identified and rectified by higher prices in the forward markets. This has worked as intended. Florida, however, can choose to handle this differently than Texas.

Restructuring and Reliability Go Hand-in-Hand

Because competition uses existing infrastructure, electricity choice does not have a negative impact on reliability. If anything, choice allows utilities to better focus on the safety and reliability aspects of energy service. While other events may cause occasional electric outages, the Texas Reliability Entity has found no instances of market manipulation or service interruptions attributable to the restructured market design. This organization is appointed by NERC to oversee reliability in the ERCOT region and is independent of the state and market entities.

Instead, this oversight ensures reliability. ERCOT has experienced a number of reliability events unrelated to restructuring, including a “black swan” event in February 2011, in which 225 generators failed due to an unprecedented combination of challenges (extreme low temperatures, wind, ice, and snow; an all-time high winter peak electrical demand; and fuel supply issues). In October 2014 in Lower Rio Grande Valley, where there is both limited generation and limited transmission, the area experienced a blackout due to the failure of three generators combined with pre-scheduled outages and high load due to high temperatures. In response to these events, ERCOT, PUCT, and market participants revised protocols, established new requirements and initiated investments to avoid future occurrences.

And Florida, which has never enjoyed choice, is not immune to outages. On February 26, 2008, portions of the lower two-thirds of the Bulk Electric System in peninsular Florida experienced a loss of service to electric customers. The event led to the loss of service from 22 transmission lines, 4,300 MW of generation, and 3,650 MW of customer service or load. Approximately 596,000 FPL customer accounts and 354,000 non-FPL customer accounts were out of service, representing approximately 8% of Florida electric customer accounts.

In response to the event, FERC opened a formal investigation into the cause and events surrounding the blackout.[11] NERC also opened a parallel Compliance Violation Investigation (NERC0002CVI). As a result of these investigations, FPL agreed to pay a $25 million fine and adopt several reliability enhancement measures.

The U.S. has several layers of oversight designed to ensure reliability. In addition to state public service/utilities commissions, two federal regulatory agencies (FERC/NERC) oversee the national electric grid, and each of the 10 wholesale market areas in North America is overseen by a grid operator (ISO/RTO). Of the eight Reliability Entities overseeing the entire U.S. and Canadian electric system, the FRCC is the only entity other than ERCOT to operate entirely within a single state (FRCC – Florida; ERCOT – Texas), which is another reason the Texas model applies well to Florida.

Services Provided by Retail Marketers

What do retail energy suppliers do and how do they contribute to the market?

Retail energy suppliers source energy in the wholesale market in the most efficient and cost-effective ways available. They develop products and services for sale and

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[11] Florida Blackout FERC Docket No. IN08-5-000 Order Approving Stipulation and Consent Agreement and Order of Non-Public, Formal Investigation, 122 FERC ¶ 61,244 (2008).

invoice their customers, collecting revenue on behalf of themselves as well as the utility. Finally, energy retailers must compete to earn their customers' business.

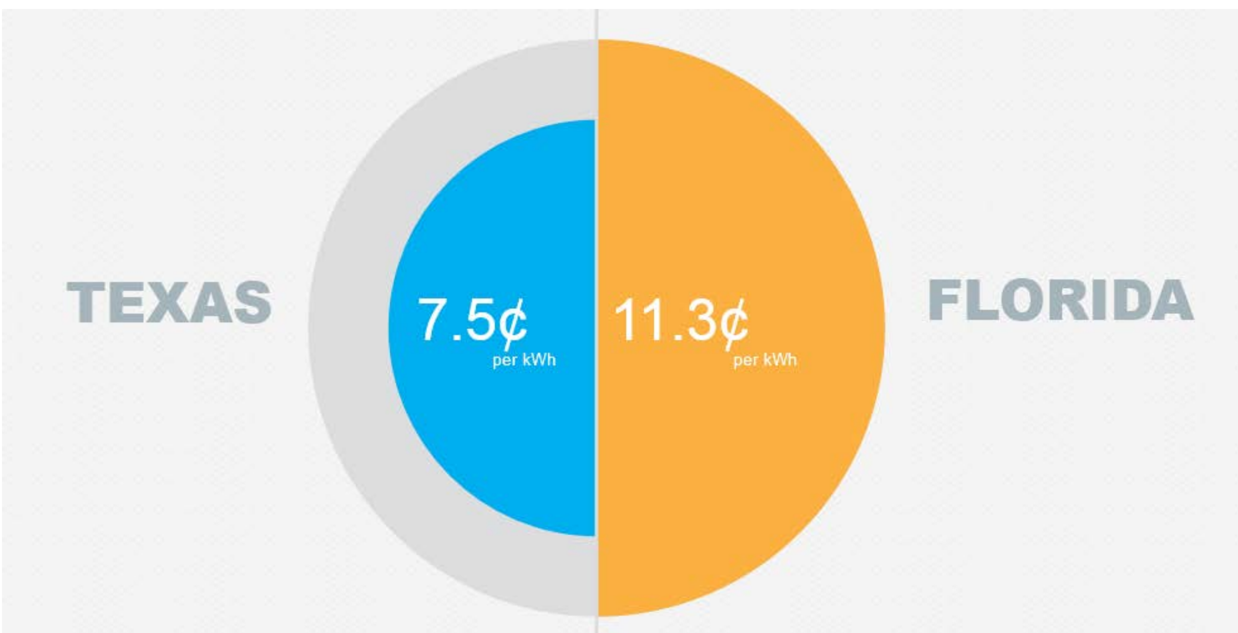
Energy retailers contribute to restructured markets and their economies in three ways:

1. **Lower prices** – At its core, energy restructuring produces a free market that drives competition for the right to supply the end-use customer.

   Competitive market prices are determined by the market and the competition within the market versus the traditional regulated model where energy is supplied by one utility. These monopoly utilities charge rates based on their costs, plus a set rate of return on their assets as set by regulatory bodies.

   This model is highly inefficient as the utilities have little incentive to secure energy at the lowest cost and frequently keep outdated generation units online to collect their guaranteed returns.

   Under a restructured market, municipalities, co-ops, and IOUs can participate in the competitive wholesale market, passing on the savings to end-use retail customers including city and state organizations.



2. **Innovation** – In restructured markets, retail energy suppliers drive innovation that benefits consumers. This can include commodity products as well as non-commodity products designed to lower costs, reduce energy consumption and manage risk. Retailers who don't innovate for the benefit of the consumer are

driven out by competitive forces within the market. Innovations within restructured electric markets include:

Rate Options

- ✓ Time-of-use rates
- ✓ Fixed rates
- ✓ Index rates
- ✓ Prepaid rates

Green Products & Analytics

- ✓ Green and renewable energy plans
- ✓ Home solar & distributed generation
- ✓ Battery storage
- ✓ Demand response programs
- ✓ Mobile power pack
- ✓ LED Lighting
- ✓ EV chargers
- ✓ Energy usage emails and graphs
- ✓ Energy usage and billing analytics

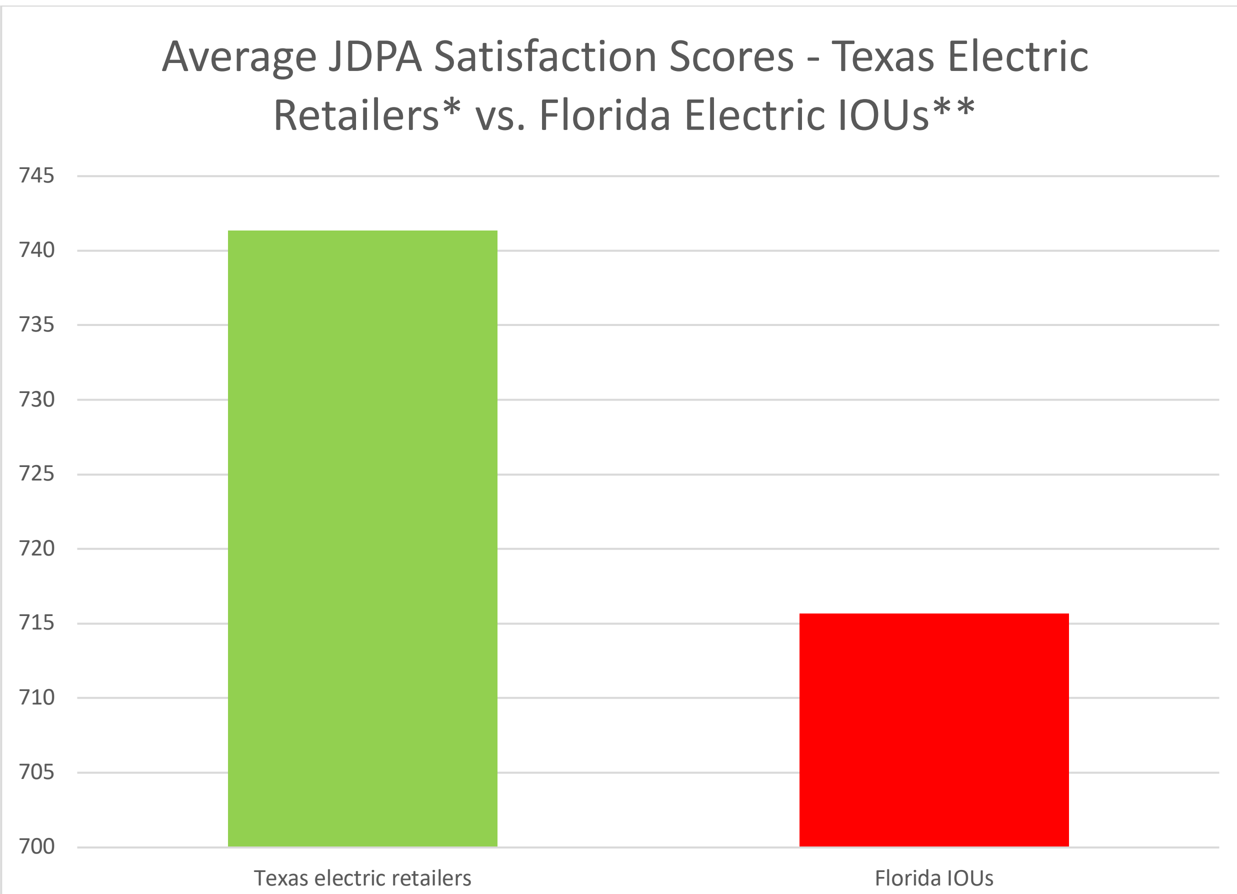
Additional Non-commodity Services

- ✓ Surge protection
- ✓ Internet service
- ✓ Cellular service
- ✓ Cable television
- ✓ Nest Protect
- ✓ Home security and automation
- ✓ Home warranty protection
- ✓ Identity protection
- ✓ Home energy checkup
- ✓ AC/Heater tune-ups
- ✓ Electric wiring warranty repair
- ✓ Home, renters, and auto insurance
- ✓ Rewards and loyalty programs
- ✓ Home generators
- ✓ Furnace air filters
- ✓ Google Home
- ✓ Google Chromecast
- ✓ Nest Thermostat
- ✓ Nest Protect
- ✓ Nest cameras
- ✓ Nest doorbell

3. **Customer experience** – In restructured markets, customers can shop around for the suppliers that can best meet their service needs. They're able to vote with their dollars and choose the companies they prefer to do business with or not do business with.

   In regulated markets, consumers must obtain their electricity from the local monopoly utility. As such, the experience offered by these monopolies lags behind the experience offered by retailers in restructured markets.

   J.D. Power & Associates ("JDPA") conducts annual consumer satisfaction surveys that measure satisfaction of electric consumers in retail and regulated markets. The results are clear: Electric retailers in restructured markets such as Texas offer significantly better customer experiences than regulated Florida utilities.



*2016 JDPA Retail Electric Satisfaction Study https://www.jdpower.com/business/press-releases/jd-power-2016-retail-electric-provider-residential-customer-satisfaction-study

**2018 JDPA Electric Utility Satisfaction Survey https://www.jdpower.com/business/press-releases/2018-electric-utility-residential-customer-satisfaction-study

LIST OF APPENDICES

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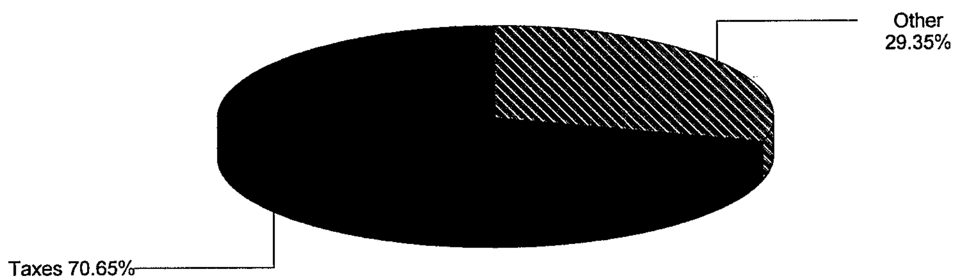
APPENDIX A

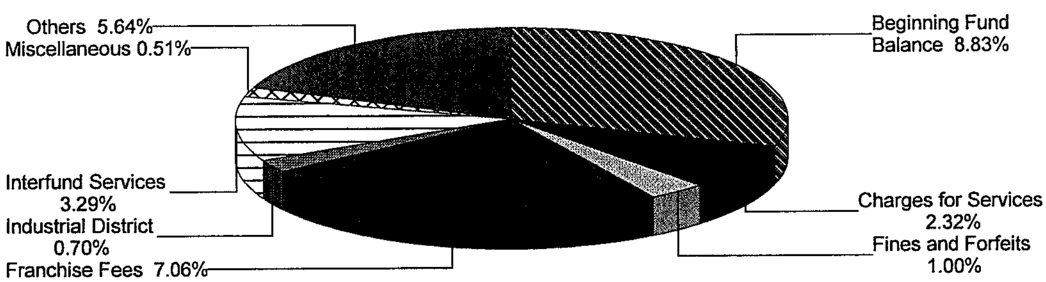
GENERAL FUND RESOURCES SUMMARY

The General Fund is the City of Houston's largest operating fund. With total resources of $2.6 billion budgeted in FY2018, this fund relies heavily on various forms of revenue to finance its operations. As illustrated below, approximately 71% percent of the total resources in the General Fund are from taxes, mainly property and sales taxes.

GENERAL FUND RESOURCES
FY2018 BUDGET



COMPOSITION OF OTHER (ABOVE)



The composition of the FY2018 General Fund resources is listed below:

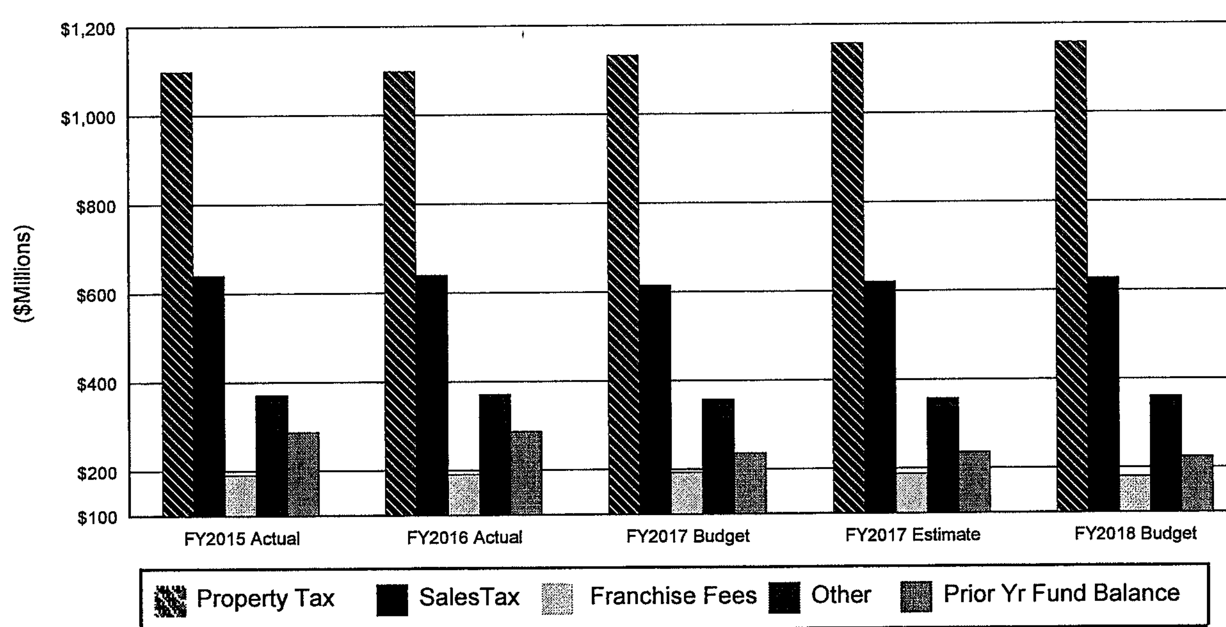
RESOURCE CATEGORIES	RESOURCE FY2018 BUDGET*	% OF TOTAL BUDGET
Taxes:		
Property Taxes	1,158,297	45.40%
Sales Taxes	627,000	24.57%
Other Tax	17,413	0.68%
Franchise Fees	180,082	7.06%
Industrial District	17,917	0.70%
Licenses and Permits	36,942	1.45%
Intergovernmental	71,062	2.79%
Charges for Services	59,230	2.32%
Interfund Services	83,859	3.29%
Fines and Forfeits	25,466	1.01%
Interest	3,000	0.12%
Miscellaneous/Other	13,138	0.51%
Total Revenue	2,293,406	89.90%
Sale of Capital Assets	14,540	0.57%
Transfers In	18,265	0.72%
Beginning FY2018 Fund Balance	225,277	8.83%
TOTAL RESOURCES	2,551,488	100.00%

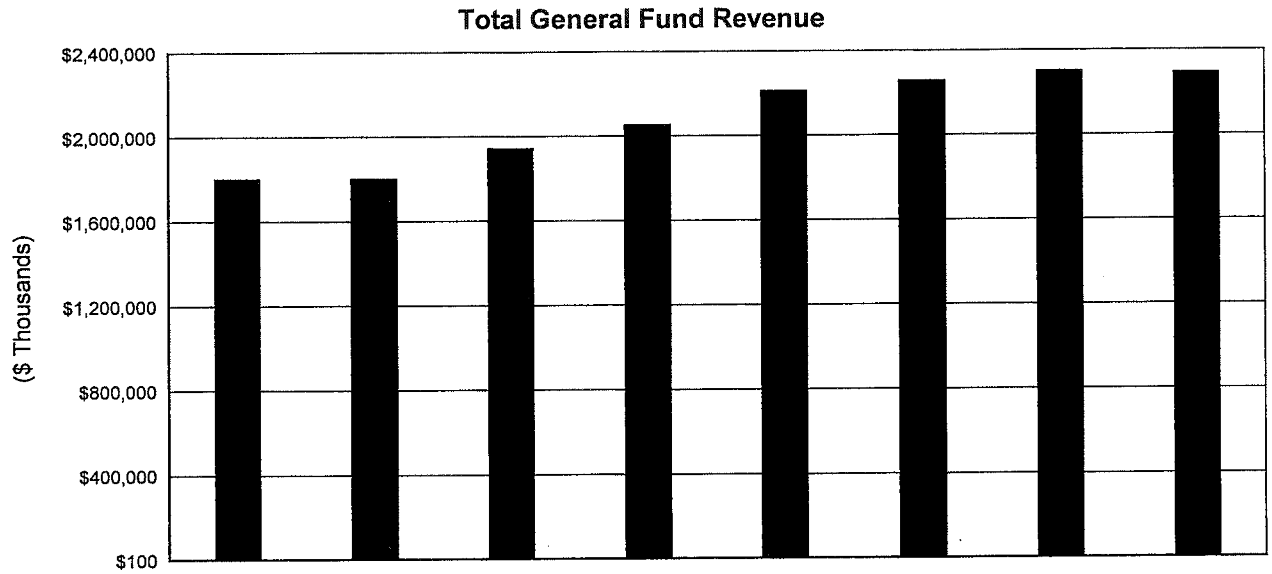
* Dollars in Thousands

Total may reflect slight variances due to rounding

The graph below provides a four-year comparsion of the City's resources in millions of dollars.

RELATIONSHIP OF GENERAL FUND RESOURCES
FY2015 THROUGH FY2018





FY2011 Actual	FY2012 Actual	FY2013 Actual	FY2014 Actual	FY2015 Actual	FY2016 Actual	FY2017 Estimate	FY2018 Budget
$1,802,727	$1,802,694	$1,944,446	$2,053,802	$2,213,132	$2,258,257	$2,302,987	$2,293,406

Table I below provides the FY2018 General Fund revenue budget by categories. As shown, the total revenue is expected to be $2.3 billion or $9.6 million lower than the projected FY2017 revenue.

Table I

FY2018 Revenue Budget
Compared with FY2017 Estimate

	Projected Revenue ($ Thousands)		
Category	**FY2017 Estimate**	**FY2018 Budget**	**Increase / (Decrease)**
General Property Taxes	1,158,377	1,158,297	(80)
Industrial Assessment	18,322	17,917	(405)
Sales Taxes	621,000	627,000	6,000
Other Tax	16,909	17,413	504
Electric Franchise	102,030	102,270	240
Telephone Franchise	40,906	37,215	(3,691)
Gas Franchise	15,016	13,791	(1,225)
Other Franchise	30,431	26,806	(3,625)
Licenses and Permits	39,219	36,942	(2,277)
Intergovernmental	71,413	71,062	(351)
Charges for Services	59,119	59,230	111
Direct Interfund Services	55,581	54,859	(722)
Indirect Interfund Services	27,172	29,001	1,829
Municipal Courts Fines and Forfeits	21,371	21,371	0
Other Fines and Forfeits	4,128	4,094	(34)
Interest	4,000	3,000	(1,000)
Miscellaneous/Other	17,994	13,138	(4,856)
Total	**2,302,988**	**2,293,406**	**(9,582)**

Table II provides the revenue estimate for each distinct revenue source that is expected to produce at least $3 million in FY2018. The remainder of this document describes the projection logic that has been used for each of these items.

Table II

Revenue Estimates for Revenue Sources Over $3 Million

Item	FY2017 Estimate	FY2018 Budget	Increase / (Decrease)
	Projected Revenue ($ Thousands)		
General Property Taxes	$1,158,377	$1,158,297	$ (80)
Sales Taxes	621,000	627,000	6,000
Industrial Assessment	18,322	17,917	(405)
Mixed Beverage Tax	16,687	17,188	501
Electric Franchise	101,018	100,836	(182)
Telephone Franchise	40,892	37,215	(3,677)
Gas Franchise	15,016	13,791	(1,225)
Cable TV Franchise Tax	22,442	19,077	(3,366)
Solid Waste Hauler Franchise Fee	7,595	7,664	69
Licenses and Permits	39,219	36,942	(2,277)
TIRZ Funding	29,096	29,174	78
Intergovernmental Revenue - 1115 Waiver	18,194	20,308	2,114
Ambulance Fees	46,500	46,200	(300)
Ambulance Fee Supplemental Reimbursement	24,033	21,500	(2,533)
Other Charges for Services	12,619	13,030	411
Interfund Police Protection	26,519	26,049	(469)
Interfund Fire Protection	20,360	20,360	-
Other Direct Interfund	8,702	8,449	(253)
Indirect Cost Recovery	27,172	29,001	1,828
Moving Violations	11,777	11,777	-
Other Municipal Courts Fines and Forfeitures	9,595	9,595	-
Miscellaneous/Other	17,994	13,138	(4,857)
All Other Revenues	9,859	8,900	(959)
Total	**$2,302,988**	**$2,293,406**	**$ (9,582)**

Taxes

Property Taxes

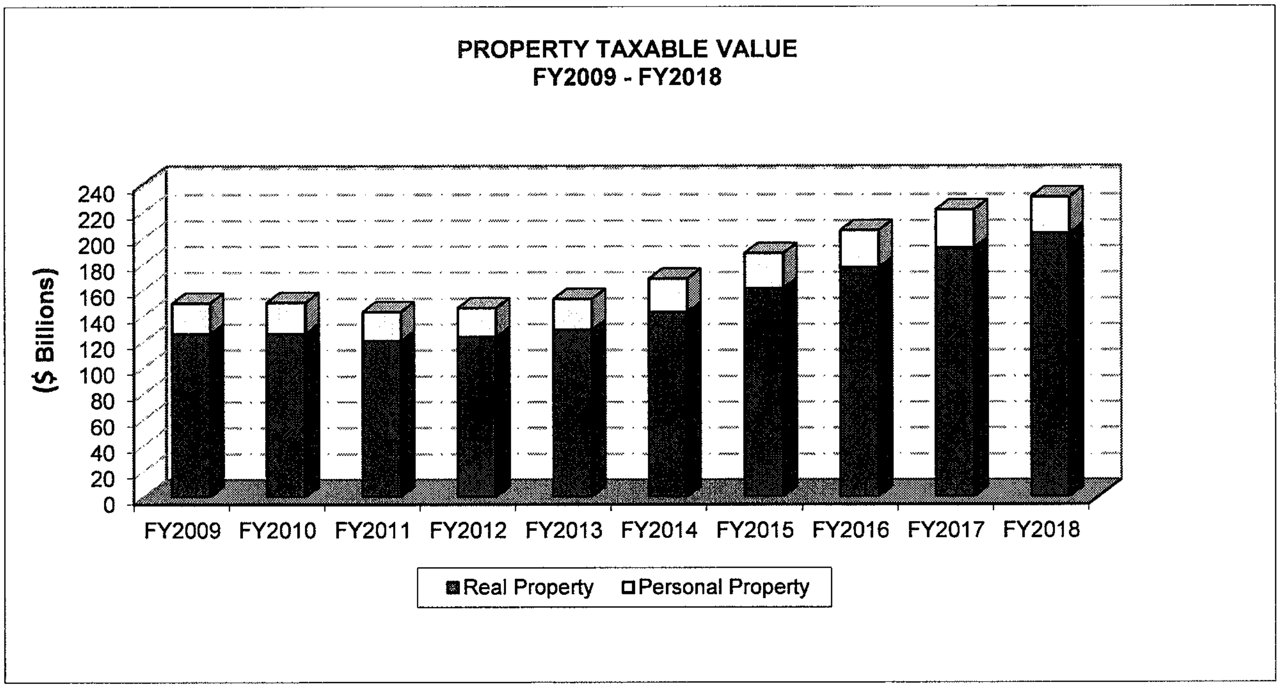
General property taxes are ad valorem taxes levied on the assessed valuation of real and personal property. Taxable values for all real and personal property within the City, depending on their locations, are established by the Harris County Appraisal District (HCAD), Montgomery County Appraisal District (MCAD) or Fort Bend County Appraisal District (FBCAD), collectively County Appraisal Districts (CAD), based upon market values as of January 1st. City Council approves exemptions such as homestead, 65 and over, disabled as well as Freeport exemptions and then sets a tax rate according to the state law. The current tax rate for the City of Houston is 58.642 cents per $100 of taxable value.

Based upon the adopted tax rate set by Council and taxable value as assessed by CAD, tax bills are generated and sent to taxpayers by Harris County Tax Office around mid-November. Payment is due by January 31st of the following year. Taxes not paid by the due date are delinquent and subject to penalties and interest charges. Taxpayers who wish to appeal values set by CAD may do so if taxes on the uncontested value are paid timely.

Occasionally, taxes are overpaid as a result of errors in appraisal or an overpayment by a taxpayer. Harris County Tax Office refunds such payments based upon the Texas Property Tax Code and documentation supplied by the taxpayers. Fluctuations in collections reflect changes in assessed property values, collection efforts, and tax rate.

The FY2018 property tax value certified estimate provided by CAD to the City in April 2017 is $231.1 billion, which is net of the current senior/disabled exemption of $160,000. The estimated taxable value is then reduced by the estimated incremental value of properties within the Tax Increment Reinvestment Zones (TIRZ). The net of TIRZ taxable value is estimated at $202.7 billion.

Below is a graph showing the ten-year history of property taxable values in Houston, with the $231.1 billion estimate shown for FY2018.



CITY OF HOUSTON APPRAISED VALUE
($ Millions)

Fiscal Year	Tax Year	Real Property	Personal Property	Total Value
2005	2004	86,433	19,467	105,900
2006	2005	91,827	19,293	111,120
2007	2006	99,483	20,858	120,341
2008	2007	112,241	23,214	135,455
2009	2008	125,982	23,645	149,627
2010	2009	125,999	24,094	150,093
2011	2010	120,546	22,360	142,906
2012	2011	123,292	22,381	145,673
2013	2012	129,096	23,692	152,788
2014	2013	142,599	25,810	168,409
2015	2014	160,919	27,031	187,950
2016	2015	177,083	28,462	205,545
2017	2016	194,948	28,266	223,214
2018	2017	203,214	27,920	231,134*

*County Appraisal District Certified Estimates, as of April 2017.

Property Tax Collections

In November 2004, Proposition No. 1 was passed amending the City Charter to limit the annual increase in total ad valorem tax revenues. The increase is capped at the lower of the increase in Consumer Price Indexes (CPI) plus the growth in population or 4.5% over the prior fiscal year. In addition, in November 2006, Proposition H was passed to further increase the applicable revenue limitations by $90 million.

The FY2018 property tax revenue estimate is derived according to Proposition 1 and Proposition H. The Finance Department applied the 2016 inflation rate of 1.5842% and population estimate as of 7/1/2016 of 0.32% to arrive at a net revenue estimate of $1.16 billion. This revenue will remain relatively flat, compared to the estimated FY2017 revenue of $1.16 billion. The property tax rate will be adjusted accordingly to levy revenues no higher than the Proposition 1 and Proposition H limitation.

The Proposition 1 and Proposition H revenue limitation is calculated with the following assumptions.

Population (1)	
July 1, 2003	2,009,669
July 1, 2004	2,012,626 + 0.1471%
July 1, 2005	2,076,189 + 3.1582%
July 1, 2006	2,144,491 + 3.2898%
July 1, 2007	2,208,180 + 2.9699%
July 1, 2008	2,244,615 + 1.6500%
July 1, 2009	2,257,926 + 0.5930%
July 1, 2010	2,099,451 + 0.0000%
July 1, 2011	2,145,146 + 2.1765%
July 1, 2012	2,160,821 + 0.7307%
July 1, 2013	2,195,914 + 1.6241%
July 1, 2014	2,239,558 + 1.9875%
July 1, 2015	2,296,224 + 2.5302%
July 1, 2016	2,303,482 + 0.3161%

CPI (2)		
2003	163.7	
2004	169.5	+ 3.5431%
2005	175.6	+ 3.5988%
2006	180.6	+ 2.8474%
2007	183.8	+ 1.7929%
2008	189.967	+ 3.3339%
2009	190.495	+ 0.2779%
2010	194.172	+ 1.9302%
2011	200.495	+ 3.2564%
2012	204.213	+ 1.8544%
2013	207.574	+ 1.6458%
2014	213.365	+ 2.7898%
2015	213.039	- 0.1528%
2016	216.414	+ 1.5842%

	($ In Thousand)
FY2005 Actual	$671,294
Population Increase 2004	0.1471%
CPI Increase 2004	3.5431%
FY2006 CAP	$696,066
Population Increase 2005	3.1582%
CPI Increase 2005	3.5988%
FY2007 CAP	$743,100
Population Increase 2006	3.2898%
CPI Increase 2006	2.8474%
FY2008 CAP	$788,705
Population Increase 2007	2.9699%
CPI Increase 2007	1.7929%
FY2009 CAP	$826,269
Population Increase 2008	1.6500%
CPI Increase 2008	3.3339%
FY2010 CAP	$867,450
Population Increase 2009	0.5930%
CPI Increase 2009	0.2779%
FY2011 CAP	$875,005
Population Decrease 2010	-7.0186%
CPI Increase 2010	1.9302%
FY2012 CAP	$875,005
Population Increase 2011	2.1765%
CPI Increase 2011	3.2564%
FY2013 CAP	$922,543
Population Increase 2012	0.7307%
CPI Increase 2012	1.8544%
FY2014 CAP	$946,392
Population Increase 2013	1.6241%
CPI Increase 2013	1.6458%
FY2015 CAP	$977,338
Population Increase 2014	1.9875%
CPI Increase 2014	2.7898%
FY2016 CAP	$1,024,029
Population Increase 2015	2.5302%
CPI Decrease 2015	-0.1528%
FY2017 CAP	$1,048,375
Population Increase 2016	0.3161%
CPI Increase 2016	1.5842%
	$1,068,297
Proposition H (3)	$90,000
FY2018 CAP	**$1,158,297**

FY2017 Estimate	$1,158,377
FY2018 CAP (Based on 4.5% Increase from FY2017 Estimate)	$1,207,457
Final FY2018 CAP (the Lower FY2018 CAP)	**$1,158,297**

(1) Population numbers based upon the US Census Bureau estimate most recently published when deciding limits of each respective year's property tax revenue budget increase.
(2) CPI increase based on the change in the CPI-U for Houston-Galveston-Brazoria, Texas as published by the Bureau of Labor Statistics, for the preceding calendar year.
(3) In accordance with Proposition H, to increase the applicable revenue limitation by $90 million.

Sales Tax

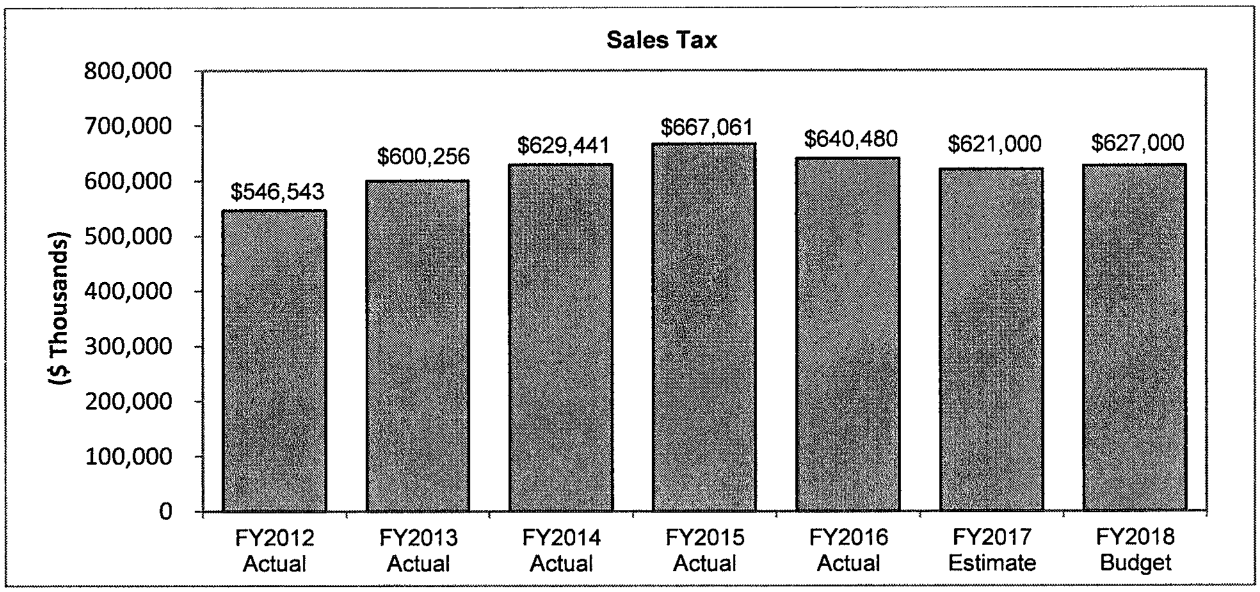
General sales and use taxes are imposed upon the sale or consumption of certain goods and services at the point of sale. In the City of Houston, a $0.0825 sales and use tax is applied for every dollar of sales. The

Metropolitan Transit Authority (METRO) receives $0.01, and the State of Texas receives $0.0625. The State Comptroller remits a $0.01 share to the City, after withholding a 2% service charge.

The sales tax projections are derived from econometric models which take into account the sectors of the Houston economy and estimates of income, prices, population, and Primary Metropolitan Statistical Area (PMSA) retail sales.

The FY2018 budget amount of $627 million is approximately $6 million, or 0.97% higher than FY2017 estimated amount of $621 million. This estimate is supported by the uncertainty regarding the path of oil prices. Employment is the key driver of sales tax revenue, including consumer sales and business to business sales. Historically, the sales tax has responded in an immediate manner to changes in our employment growth and/or decline. The energy exploration and drilling boom has slowed significantly, and while Houston's economy has diversified, it is still strongly tied to energy. The City will monitor oil and gas prices to see if low prices further impact the local economy.

The following graph provides a seven-year comparison of the City's Sales Tax revenue.



Industrial District Assessments

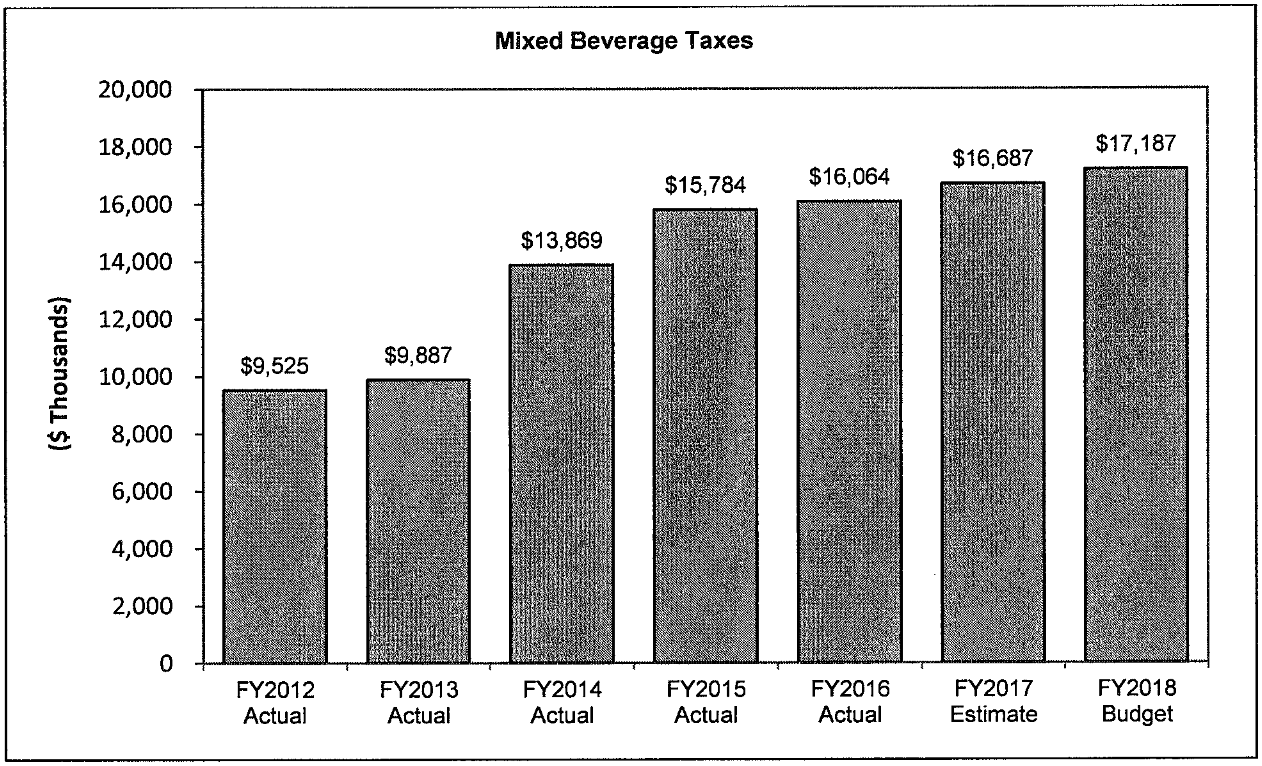
The City of Houston has Industrial District Contract Agreements having a term of fifteen years with more than 100 companies that are located within the Houston Extra-Territorial Jurisdiction (ETJ). A contractually reduced ad valorem assessed valuation fee is calculated and billed annually to each company in lieu of the property being annexed and subject to City of Houston property taxes. Industrial District Assessments are based on current year property values provided by HCAD. The City expects to collect $17.9 million in FY2018.

Mixed Beverage Tax

Following the end of each calendar quarter, the State Comptroller allocates 10.7143% of the mixed beverage tax received to the counties and cities.

Mixed beverage tax allocation amounts are dependent upon the timing and accuracy of taxpayer's returns and payments, but generally represent taxes remitted to the Comptroller's Office during the calendar quarter immediately preceding the month the allocation is distributed.

For the FY2018 projection, we are anticipating the revenue estimate of $17.2 million reflecting the trend in recent years. The following graph shows the seven-year comparison of the City's mixed beverage tax revenue.



Franchise Fees

Franchise fees are paid by companies, entities, or persons for the privilege of using public property for private purposes. Franchise agreements have been granted to numerous utilities and other enterprises, either directly by the City of Houston or by the State of Texas, including CenterPoint Energy, AT&T, several cable television firms, and others.

Changes in franchise revenue depend on many factors including economic fluctuations, rate charges, customer usage, franchise agreement changes and legislative actions.

Electric Franchise

Electric franchise fees are paid to the City for the right to conduct an electric light and power business and to use the City's rights-of-way for that business.

There are two companies in Houston that pay electric franchise fees: CenterPoint Energy Houston Electric ("CenterPoint") and Entergy. CenterPoint pays approximately 99.9% of the electric franchise fees paid to the City, which represents approximately $100.7 million per year.

Prior to electric deregulation, which became effective on January 1, 2002, electricity franchise payments were calculated as a percentage of the electric company's gross revenues from sales to customers located within the City limits. Under this payment formula, electric franchise fees to the City fluctuated from $80 million to as much as $90 million per year.

From January 2002 through June 2005, franchise payments were no longer calculated based on a percentage of gross revenues, but instead were based on kilowatt hour consumption by customers within the City limits. During this period, electric franchise revenues dropped significantly, averaging $75 million each year.

In July 2005, the City and CenterPoint entered into a new franchise agreement for a term of 30 years. The new agreement establishes a base franchise fee to the City of approximately $96 million per fiscal year, payable monthly, which is adjusted annually based on kilowatt hours delivered in the City.

The FY2017 electric franchise fee estimate is $101 million. The FY2018 electric franchise fee estimate of $100.8 million is approximately 0.18% lower than the FY2017 estimate. Kilowatt hour consumption for calendar year 2016 was down 0.26% from 2015.

The City of Houston exercises original jurisdiction over the rates, operations and services of these electric utilities for the Houston area.

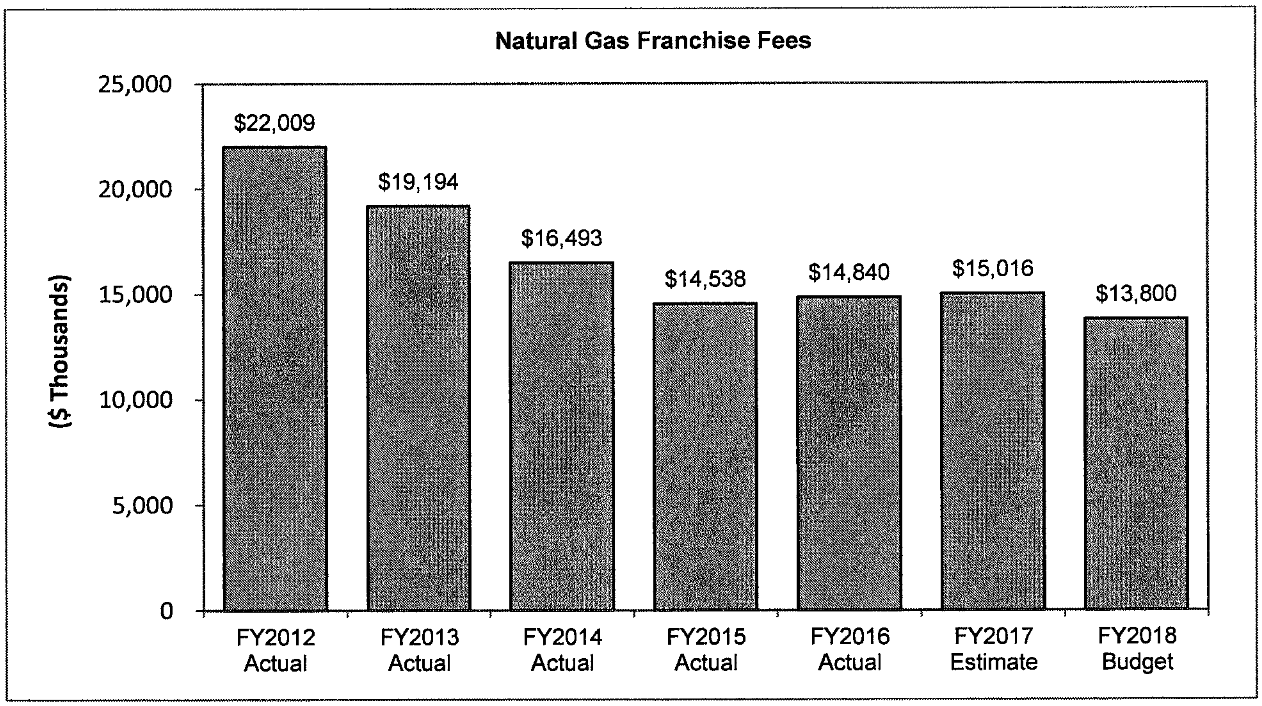
Natural Gas Franchise

Like electric franchise fees, natural gas franchise fees are paid by utilities that use the City's rights-of-way for the transportation, delivery, sale and distribution of natural gas to customers in the City.

There is one company in Houston that pays natural gas franchise fees to the City of Houston: CenterPoint Energy Resources Corporation ("CenterPoint" – formerly Entex). These fees are paid monthly and are based on 5% of gross receipts on a rolling 3-year average. For FY2018, franchise fees are based on CenterPoint's 2014, 2015 and 2016 gross revenues.

The estimate for FY2017 natural gas franchise fees from CenterPoint is approximately $15 million. The FY2018 natural gas franchise fee estimate is $13.8 million, a decrease of 8.16% from FY2017. CenterPoint's calendar year 2016 revenues were $232.4 million compared to calendar year 2013's revenues of $305.9 million, a decrease of 24.03%. Residential and commercial account revenues in 2016 were down 19.89% and 40.10%, respectively, compared to 2013's accounts, which account for the majority of the loss in overall revenues.

The graph below provides a seven-year comparison of the City's natural gas franchise fee revenue.



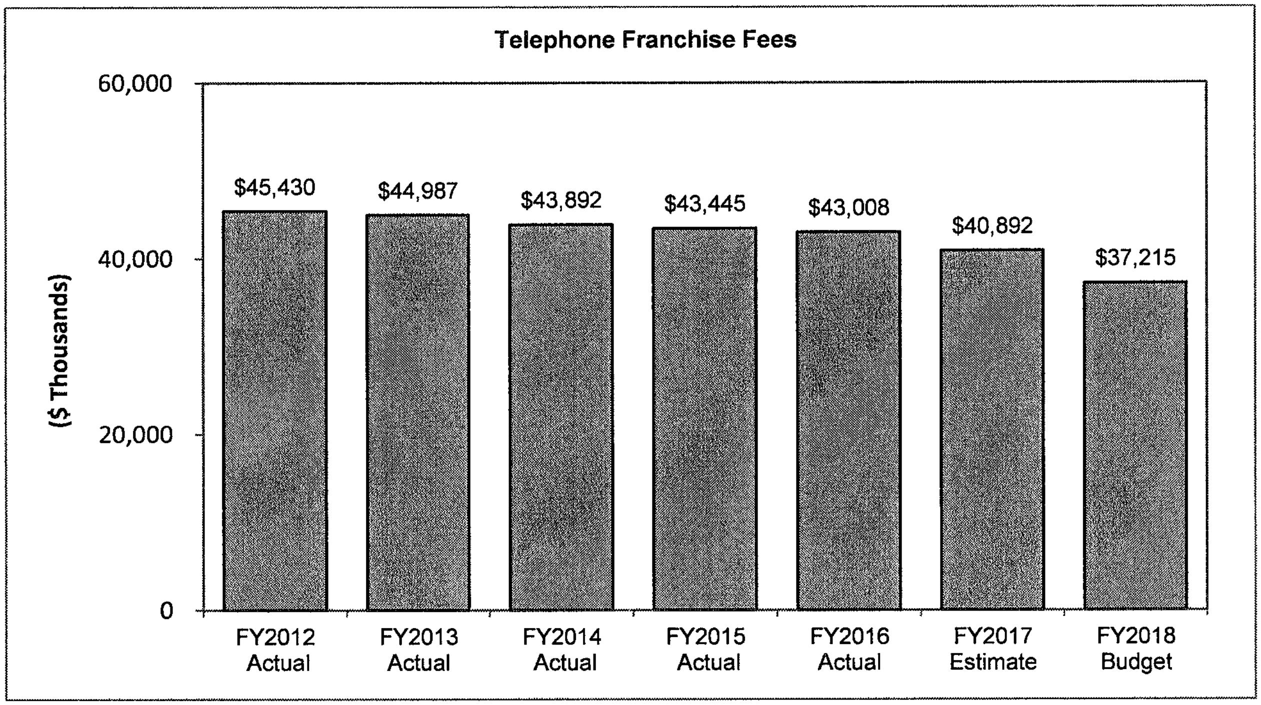
The City of Houston exercises original jurisdiction over the rates, operations and services of these natural gas utilities for the Houston area.

Telephone Franchise

Since deregulation of this industry in 2000, the telephone franchise fee paid to municipalities in Texas has been determined by applying an "access line rate," assigned by the Public Utilities Commission of Texas (PUCT) and adjusted annually for inflation, to the number of access lines in the municipality reported quarterly by each Certificated Telecommunications Provider ("CTP") doing business in that municipality. The access line rates that will be in effect during the fiscal year are as follows: residential - $1.81; non-residential - $6.13; and point-to-point - $17.35.

The FY2017 estimate for telephone franchise fee is $41 million, exclusive of audit recoveries. The FY2018 projection of $37.2 million is a 9.27% decrease from FY2017 estimate, and is reflective of the continued decrease in the number of access lines being reported by CTPs.

The following graph below provides a seven-year comparison of the City's telephone franchise fee revenue.



Cable TV Franchise Fees

The City of Houston currently has two active cable franchises with the following cable companies: SuddenLink Communications and Phonoscope. The cable franchises expire in 2017 and 2018, respectively. Pursuant to the terms of their franchise agreements, these companies pay franchise fees in the amount of 5% of their gross revenues from sales to Houston customers. In addition, there are two cable television/video service-providers operating in Houston under state-issued certificates of franchise authority: Comcast Cable and AT&T U-Verse. Under the terms of the state franchise, these operators also pay the City of Houston 5% of their gross revenues from sales to Houston customers. The largest of either type of franchise is Comcast, which accounts for approximately 65.4% of the total cable franchise revenue projection for FY2018. The projection for FY2018 is $19.1 million, which is 14.73% lower than the FY2017 estimate of $22.4 million. Continuing decreases in AT&T U-verse franchise fee payments are expected based on industry publication articles indicating AT&T is driving customers to its DirectTV platform and away from its U-verse platform.

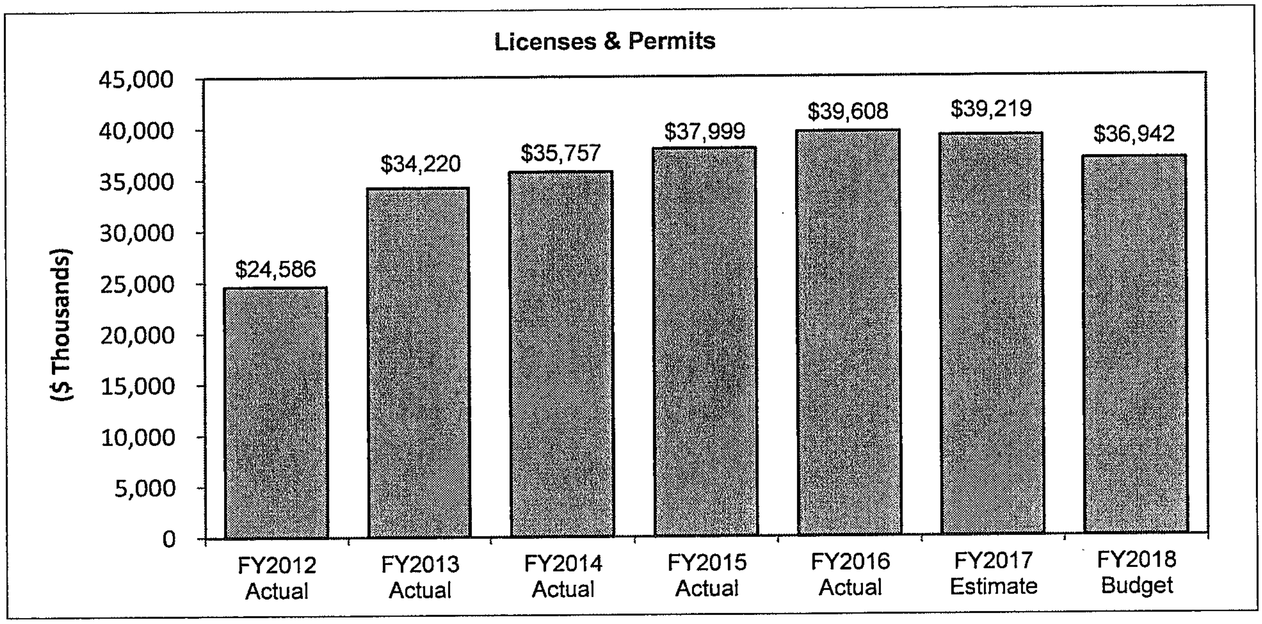
Solid Waste Hauler Franchise Fees

Solid waste haulers pay fees to compensate the City for the use of City streets. Approximately 122 active solid waste hauler franchises pay 4% of gross revenues from transporting commercial solid and industrial wastes that originate within the City limits. The FY2017 estimate for solid waste hauler franchise fees is $7.6 million, exclusive of audit recoveries. The FY2018 estimate of $7.7 million assumes a slight increase in revenues as a result of stabilization of the local economy.

Other Revenues

Licenses and Permits

The Licenses and Permits category includes such items as special fire, food dealer, burglar alarm, dumpster permits, and many other permits. The FY2018 revenue is estimated at $36.9 million, which is approximately $2.3 million lower than FY2017 estimate of $39.2 million.



Ambulance Fees

City of Houston Code of Ordinance Chapter 4 permits the City to provide Emergency Medical Services including ambulance transport to the public and permits the City to partially recover the cost of providing those services. The base and variable fee structure is addressed under Section 4.13.

The City contracts with a third-party vendor for the billing and collection of Emergency Medical Services. The present contract is with Digitech Computers, Inc. At the end of the four-year contract term (August 2017), the City can opt to renew the contract for up to four successive one-year terms.

The revenue projection for Emergency Medical Services provided by the City of Houston for FY2018 is $46.2 million, a decrease of $300,000 or approximately 1% lower than the FY2017 estimate of $46.5 million.

Other Charges for Services

Other charges for services include miscellaneous copy fees, public safety report fees, vending machine concessions, vehicle storage, hazardous material response, and others. For FY2018, revenues of $13 million are projected, an increase of approximately $411,000 or 3.3% higher than the FY2017 estimate of $12.6 million.

Interfund Direct Charges

The General Fund charges the Houston Airport System for airport police service, which is the responsibility of Houston Police Department (HPD). The FY2018 projection of $26 million is $469,000 lower, or approximately 2% lower than the FY2017 estimates of $26.5 million.

The Aviation Enterprise Fund also pays for fire protection provided by the Fire Department to the Houston Airport System. The FY2018 projection of $20.4 million, which remains unchanged from the FY2017 estimate.

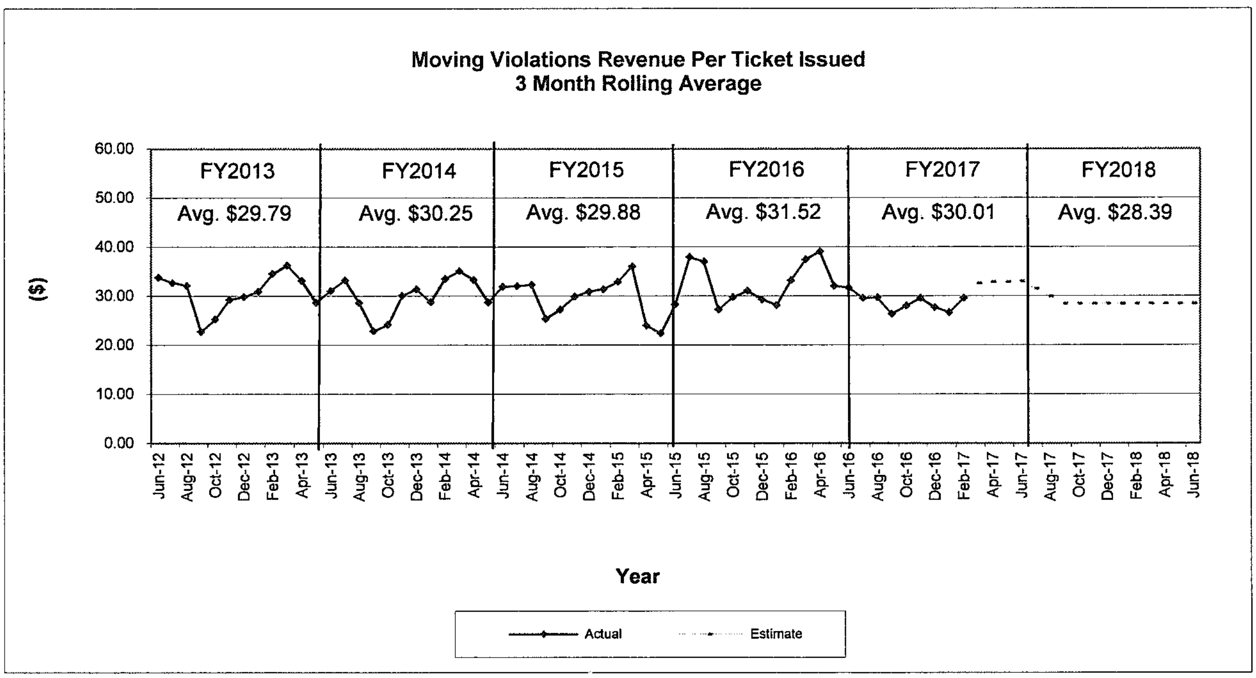
Payments received for other direct services performed by the General Fund are recovered throughout the year. The FY2018 projection of $8.5 million is approximately $253,000 lower than the FY2017 estimate of $8.7 million.

Indirect Cost Recovery

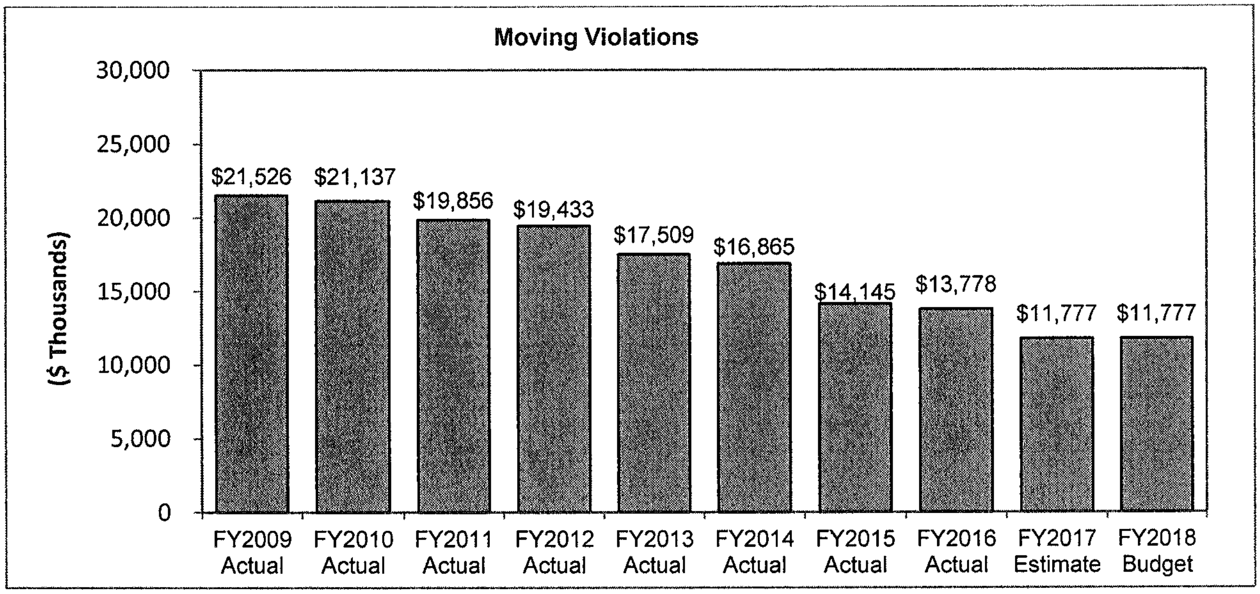
The General Fund provides citywide central support services and recovers the cost of these services through allocation of indirect costs. These amounts are determined through the preparation of an annual cost allocation plan, which distributes administrative overhead costs to General Fund operating departments and to other funds. For FY2018, the proposed plan calls for cost recoveries totaling $29 million, an increase of $1.8 million in indirect interfund revenue from the FY2017 estimate of $27.2 million.

Moving Violations

In FY2018, we project 414,770 tickets to be issued. Total Moving Violations revenue budgeted is $11.8 million, which results in an average of $28.39 for tickets issued in FY2018.



The graph below provides a ten-year comparison of the City's Moving Violations revenue.



Other Municipal Courts Fines and Forfeitures

The FY2018 Municipal Court Fines and Forfeitures are projected at $9.6 million.

Miscellaneous/Other

The FY2018 revenue is estimated at $13.1 million, which is approximately $4.9 million lower than FY2017 estimate of $18 million.

All Other Revenues

Estimated revenues in remaining categories have been calculated using simple trend analysis, as well as operational and collections information from the collecting department. These revenues are estimated at $8.9 million in FY2018, and $9.9 million for FY2017.

A detailed listing of General Fund revenues by category are presented in the appendices.

APPENDIX B

ORDINANCE NO. 19-14-2197

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF SOUTH MIAMI, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Commission of the City of South Miami, Florida recognizes that the City of South Miami (the "City") and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City does not desire to undertake to provide such services at this time; and

WHEREAS, Florida Power & Light Company ("FPL") is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, there is currently in effect a franchise agreement between the City and FPL, the terms of which are set forth in City Ordinance No. 7-84-1202, passed and adopted May 15, 1984, and FPL's written acceptance thereof dated May 18, 1984 granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"). As a result of short extensions passed and adopted by the City on May 14, 2014 and on August 19, 2014, respectively, and accepted by FPL, the Current Franchise Agreement expires on September 18, 2014; and

WHEREAS, FPL and the City (collectively, the "Parties") desire to enter into a new agreement ("New Franchise Agreement") providing for the payment of fees to the City in exchange for the nonexclusive right and privilege of supplying electricity within the City free of competition from the City, pursuant to certain terms and conditions; and

WHEREAS, the City Commission deems it to be in the public interest to enter into this agreement addressing certain rights and responsibilities of the Parties as they relate to the use of the public rights-of-way within the City's jurisdiction.

NOW, THEREFORE, BE IT ORDAINED BY THE MAYOR AND CITY COMMISSION OF THE CITY OF SOUTH MIAMI, FLORIDA:

Section 1. The foregoing recitals are hereby found to be true and correct, and are incorporated herein and adopted and approved as if set out at length.

Section 2. There is hereby granted to FPL, its successors and assigns, for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, rights-of-way and other public places (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City and its successors, in accordance with FPL's customary practices, and practices prescribed herein, with respect to construction and maintenance of the electrical light, power and related facilities, including, without limitation, conduits, underground conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to FPL's provision of electricity and other services (hereinafter called "facilities") to the City and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 3. (a) FPL's facilities shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transporation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(b) To minimize such conflicts with the standards set forth in subsection (a) above, the location, relocation, installation, construction or erection of all facilities shall be made as representatives of the City may prescribe in accordance with all applicable federal and state laws, and pursuant to the City's valid rules and regulations with respect to utilities' use of public rights-of-way relative to the placing and maintaining in, under, upon, along, over and across said public rights-of-way, provided such rules and regulations:

(i) shall be for a valid municipal purpose;

(ii) shall not prohibit the exercise of FPL's rights to use said public rights-of-way for reasons other than conflict with the standards set forth above;

(iii) shall not unreasonably interfere with FPL's ability to furnish reasonably sufficient, adequate and efficient electric service to all its customers while not conflicting with the standards set forth above; or

(iv) shall not require relocation of any of FPL's facilities installed, before or after the effective date hereof, in any public right-of-way, unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way causes the facilities to unreasonably interfere with the convenient, safe, or continuous use, or the maintenance, improvement, extension, or expansion of any such public "road," or unless such relocation is required by state or federal law.

(c) Such rules and regulations shall recognize that FPL's above-grade facilities installed after the effective date hereof should, unless otherwise permitted, be installed near the outer boundaries of the public rights-of-way to the extent possible.

(d) When any portion of a public right-of-way is excavated, damaged or impaired by FPL or any of its agents, contractors or subcontractors because of the installation, inspection, or repair of any of its facilities, the portion so excavated, damaged or impaired shall, within a reasonable time and as early as practicable after such excavation, be restored to a condition equal to or better than its original condition before such damage by FPL at its expense.

(e) The City shall not be liable to FPL for any cost or expense incurred in connection with the relocation of any of FPL's facilities required under this Section, except, however, that FPL may be entitled to reimbursement of its costs and expenses from others and as provided by law.

Except as expressly provided, nothing herein shall limit or alter the City's existing rights with respect to the use or management of its rights-of-way that are not otherwise preempted by the state or federal government.

Section 4. The acceptance of this New Franchise Agreement shall be deemed an agreement on the part of FPL to the following: (a) to indemnify and save the City harmless from any and all damages, claims, liability, losses and causes of action of any kind or nature arising out of a negligent error, omission, or act of FPL, its Contractor or any of their agents, representatives, employees, or assigns, or anyone else acting by or through them, and arising out of or concerning the construction, operation or maintenance of its facilities hereunder; (b) to pay all damages, claims, liabilities and losses of any kind or nature whatsoever, in connection therewith, including the City's attorney's fees and expenses in the defense of any action in law or equity brought against the City, including appellate fees and costs and fees and expenses incurred to recover attorney's fees and expenses from FPL, arising from the negligent error, omission, or act of FPL, its Contractor or any of their agents, representatives, employees, or assigns, or anyone else acting by or through them, and arising out of or concerning the construction, operation or maintenance of its facilities hereunder.

Section 5. All rates and rules and regulations established by FPL from time to time shall be subject to such regulation as may be provided by law.

Section 6(a). As a consideration for this franchise, FPL shall pay to the City, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the City against FPL's property, business or operations and those of its subsidiaries during FPL's monthly billing period ending 60 days prior to each such payment will equal six percent of FPL's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the City for the monthly billing period ending 60 days prior to each such payment. In no event shall payment for the rights and privileges granted herein exceed 6 percent of such revenues for any monthly billing period of FPL. For clarity, actual write-offs will be subtracted from FPL's billed revenues. In the event FPL subsequently collects previously written-off billed revenues from the sale of electrical energy to residential, commercial, and industrial customers, FPL shall pay to the City a franchise payment on such revenues in accordance with the formula set forth above in this Section 6(a). FPL shall continue to remit payment in a manner consistent with the Current Franchise Agreement until the first payment is due under this New Franchise Agreement.

The City understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 7-84-1202, to the precise revenues described therein, and that such revenues do not include, by way of example and not limited to: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

(b) If during the term of this franchise FPL enters into a franchise agreement with any other municipality located in Miami-Dade County or Broward County, Florida, where the number of FPL's meters for active electrical customers does not exceed the number of meters for FPL's active electrical customers within the incorporated area of the City by more than one hundred and fifty (150) percent, the terms of which provide for the payment of franchise fees by FPL at a rate greater than 6 percent of FPL's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under substantially similar terms and conditions as specified in Section 6(a) hereof, FPL, upon written request of the City, shall negotiate and enter into a new franchise agreement with the City in which the percentage to be used in calculating monthly payments under Section 6(a) hereof shall be no greater than that percentage which FPL has agreed to use as a basis for the calculation of payments to the other municipality, provided however, that such new franchise agreement shall include additional benefits to FPL, in addition to all benefits provided herein, at least equal to those, if any, provided by its franchise agreement with the other municipality. Subject to all limitations, terms and conditions specified in the preceding sentence, the City shall have the sole discretion to determine the percentage to be used in calculating monthly payments, and FPL shall have the sole discretion to determine those benefits to which it would be entitled, under any such new franchise agreement.

(c) The City reserves the unilateral right at its sole discretion and at any time during the term of this franchise, but only once per calendar year, to reduce or increase the franchise fee percentage rate upon 120 days written notice to FPL, provided that the franchise fee percentage rate shall in no event exceed 6 percent or be reduced to zero percent.

(d) The City's options hereunder shall be limited solely to the percentages or calculations of the amount of the franchise fee to be paid by FPL as consideration for this franchise as specifically set forth in this Section 6. Except as provided in this Section 6, no other Section of this New Franchise Agreement may be altered, amended or affected by the City without the written concurrence of FPL, and nothing herein shall require the City to exercise any of its options hereunder.

Section 7. (a) As a further consideration, during the term of this franchise or any extension thereof, the City agrees: (a) not to engage in the distribution and/or sale, in competition with FPL, of electric capacity and/or electric energy to any other ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by FPL other than the City, and (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate FPL to transmit and/or distribute electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies). Nothing specified herein shall prohibit the City from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

(b) Nothing herein shall prohibit or limit a customer of FPL, including the City, if permitted by law, from installing an approved renewable generation system to generate electric energy for use at the customer's or the City's premises respectively. Furthermore, nothing herein shall prohibit or limit a person, including the City, if permitted by law, from selling renewable energy or capacity to FPL.

Section 8. If the City grants a right, privilege or franchise to any other person to provide retail electric service within any part of the incorporated areas of the City in which FPL may lawfully serve or compete on terms and conditions which FPL reasonably determines are more favorable than the terms and conditions contained herein, FPL may at any time thereafter terminate this franchise if such terms and conditions are not revised within the time period provided hereafter. FPL shall give the City at least one hundred eighty (180) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for FPL herein, advise the City of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The City shall then have ninety (90) days in which to correct or otherwise remedy the terms and conditions complained of by FPL. If FPL determines that such terms or conditions are not remedied by the City within said time period, FPL may terminate this franchise agreement by delivering written notice by Certified United States Mail to the City's Clerk with copies to the Mayor, the City Manager and the City Attorney and termination shall be effective on the date of delivery of such notice. Nothing contained herein shall be construed as constraining the City's rights to legally challenge at any time FPL's determination leading to termination under this section.

Section 9. 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 who offers retail electric service to the public is permitted to provide electric service within the incorporated areas of the City to any applicant for electric service within any part of the incorporated areas of the City in which FPL may lawfully serve, and FPL reasonably 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, FPL may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage resulting from this fanchise is not remedied within the time period provided hereafter. FPL shall give the City at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for FPL herein, advise the City of the consequences of such action which resulted in the competitive disadvantage. The City shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the City within said time period, either by a franchise agreement with such other person or otherwise, FPL may terminate this franchise agreement by delivering written notice to the City's Clerk and termination shall take effect on the date of delivery of such notice. Agreement by the City with such other person to enter into a franchise containing substantially the same terms as those provided herein shall be a sufficient, but not exclusive, remedy precluding FPL's termination of this franchise. Nothing contained herein shall be construed as constraining the City's rights to legally challenge at any time FPL's determination leading to termination under this section.

Section 10. Failure on the part of FPL to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by FPL until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that FPL has failed to comply in a substantial respect with any of the provisions of this franchise, and FPL shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the City at its discretion to grant such additional time to FPL for compliance as necessities in the case may warrant.

Section 11. Failure on the part of the City to comply in substantial respect with any of the provisions of this New Franchise Agreement, including but not limited to: (a) denying FPL use of public rights-of-way for reasons other than as set forth in Section 3 of this New Franchise Agreement; (b) imposing conditions for use of public rights-of-way contrary to Federal or Florida law or the terms and conditions of this franchise; (c) unreasonable delay in issuing FPL a use permit to construct its facilities in public rights-of-way, shall constitute breach of this franchise. FPL shall notify the City of any such breach in writing sent by Certified United States Mail or via nationally recognized overnight courier and the City shall then remedy such breach as soon as practicable. Should the breach not be timely remedied, FPL shall be entitled to seek a remedy available under law or equity from a court of competent jurisdiction, including the withholding of the payments provided for in Section 8 as a court of competent jurisdiction determines to be just and reasonable under all the circumstances hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination dispositive of the matter.

Section 12. The Parties to this franchise agree that it is in each of their respective best interests to avoid costly litigation as a means of resolving disputes which may arise hereunder. Accordingly, the Parties agree that prior to pursuing their available legal remedies, they will meet at the senior management level in an attempt to resolve any disputes. If such informal efforts are unsuccessful after a reasonable period of time, or when an impasse is declared by the Parties, then the Parties may exercise any of their available legal remedies.

Section 13. The City may, upon reasonable notice and within 90 days after each anniversary date of this franchise, at the City's expense, examine the records of FPL relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at FPL's office where such records are maintained. Records not prepared by FPL in the ordinary course of business or as required herein may be provided at the City's expense and as the City and FPL may agree in writing. Information identifying FPL's customers by name or their electric consumption shall not be taken from FPL's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the City, shall be reported to FPL. The City's right to examine

FPL's records in accordance with this Section shall not be conducted by any third party employed by the City whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

The City waives, settles and bars all claims relating in any way to the amounts paid by FPL under the Current Franchise Agreement embodied in Ordinance No. 7-84-1202, however, this provision shall not be construed to waive, settle or bar claims relating to any amounts due after the effective date of this New Franchise Agreement, including those amounts to be paid in a manner consistent with the terms of the Current Franchise Agreement until the first payment is made under this New Franchise Agreement.

Section 14. The provisions of this ordinance are interdependent upon one another and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect by a court of competent jurisdiction (after the expiration of all rights of appeal), such finding or adjudication shall not affect the validity of the remaining provisions for a period of ninety (90) days, during which, this agreement may be amended by the Parties. If an agreement to amend the ordinance is not reached at the end of such ninety (90) day period, this entire ordinance shall then become null and void, and of no further force or effect.

Section 15. The City acknowledges it is fully informed concerning the existing franchise granted by Miami-Dade County, Florida, to FPL, and accepted by FPL as set out in Ordinance No. 60-16 adopted on May 3, 1960, and subsequently renewed and accepted by FPL as set out in Ordinance No. 89-81 adopted on September 5, 1989 by the Board of County Commissioners of Miami-Dade County, Florida. The City agrees to indemnify and hold FPL harmless against any and all liability, loss, cost, damage and expense incurred by FPL in respect to any claim asserted by Miami-Dade County against FPL arising out of the franchise set out in the above referenced ordinances for the recovery of any sums of money paid by FPL to the City under the terms of this New Franchise Agreement. FPL acknowledges and the City hereby relies, in part, on then Dade County Resolution No. R-709-78 adopted on June 20, 1978 in the granting of this franchise.

Section 16. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 17. Ordinance No. 7-84-1202, passed and adopted May 15, 1984 and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

Section 18. This New Franchise Agreement shall be governed and construed by the laws and administrative rules of the State of Florida and the United States. In the event that any legal proceeding is brought to enforce the terms of this franchise, it shall be brought by either party hereto in Miami-Dade County, Florida, or, if a federal claim, in the U.S. District Court in and for the Southern District of Florida, Miami Division.

Section 19. This New Franchise Agreement is intended to constitute the entire agreement between the City and FPL with respect to the subject matters hereof, and it supersedes all prior drafts and verbal or written agreements, commitments, or understandings, which shall not be used to vary or contradict the expressed terms hereof.

Section 20. Except in exigent circumstances, and except as otherwise may be specifically provided for in this franchise, all notices by either party shall be made by Certified United States Mail or via nationally recognized overnight courier service. Any notice given by facsimile or email is deemed to be supplementary, and does not alone constitute notice hereunder. All notices shall be addressed as follows:

To the City:

City Manager
City Hall, 1st Floor
6130 Sunset Drive
South Miami, FL 33143

Copy to:

City Attorney
1450 Madruga Avenue
Suite 202
Coral Gables, FL 33146

To FPL:

Vice President, External Affairs
700 Universe Boulevard
Juno Beach, FL 33408

Copy to:

General Counsel
700 Universe Boulevard
Juno Beach, FL 33408

Any changes to the above shall be in writing and provided to the other party as soon as practicable.

Section 21. As a condition precedent to the taking effect of the New Franchise Agreement, FPL shall file its acceptance hereof with the City's Clerk within 30 days of adoption of this ordinance. The effective date of the New Franchise Agreement shall be the date upon which FPL files such acceptance.

Ord. No. 19-14-2197

PASSED AND ENACTED this 16th day of September, 2014.

ATTEST:	APPROVED:
CITY CLERK	MAYOR
1st Reading - 9/2/14	
2nd Reading - 9/16/14	

READ AND APPROVED AS TO FORM, LANGUAGE, LEGALITY AND EXECUTION THEREOF

CITY ATTORNEY

COMMISSION VOTE:	4-1
Mayor Stoddard:	Yea
Vice Mayor Harris:	Yea
Commissioner Edmond:	Nay
Commissioner Liebman:	Yea
Commissioner Welsh:	Yea

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 19-14-2197
BY FLORIDA POWER & LIGHT COMPANY

City of South Miami, Florida October 1, 2014

Florida Power & Light Company does hereby accept the electric franchise in the City of South Miami, Florida, granted by Ordinance No. 19-14-2197, being:

> AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF SOUTH MIAMI, AND PROVIDING FOR AN EFFECTIVE DATE.

which was passed and adopted on September 16, 2014.

This instrument is filed with the City Clerk of the City of South Miami, Florida, in accordance with the provisions of Section 21 of said Ordinance.

FLORIDA POWER & LIGHT COMPANY

By Pamela M. Rauch
Pamela M. Rauch, Vice President

STATE OF FLORIDA
COUNTY OF PALM BEACH

The foregoing instrument was acknowledged before me this 30 day of September, 2014 by Pamela M. Rauch of Florida Power & Light Company, a Florida corporation, on behalf of the corporation, who is personally known to me.

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Beverly A Calderon
My Commission EE017269
Expires 10/18/2014

Beverly A. Calderon
NOTARY PUBLIC Signature

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 19-14-2197 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City of South Miami, Florida on this 1st day of October, 2014.

(SEAL)

Maria M. Menendez
City Clerk, City of South Miami, Florida

MIAMI DAILY BUSINESS REVIEW

Published Daily except Saturday, Sunday and
Legal Holidays
Miami, Miami-Dade County, Florida

STATE OF FLORIDA
COUNTY OF MIAMI-DADE:

Before the undersigned authority personally appeared MARIA MESA, who on oath says that he or she is the LEGAL CLERK, Legal Notices of the Miami Daily Business Review f/k/a Miami Review, a daily (except Saturday, Sunday and Legal Holidays) newspaper, published at Miami in Miami-Dade County, Florida; that the attached copy of advertisement, being a Legal Advertisement of Notice in the matter of

CITY OF SOUTH MIAMI
NOTICE OF PUBLIC HEARING FOR 9/16/2014

in the XXXX Court,
was published in said newspaper in the issues of

09/05/2014

Affiant further says that the said Miami Daily Business Review is a newspaper published at Miami in said Miami-Dade County, Florida and that the said newspaper has heretofore been continuously published in said Miami-Dade County, Florida, each day (except Saturday, Sunday and Legal Holidays) and has been entered as second class mail matter at the post office in Miami in said Miami-Dade County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he or she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before me this

05 day of SEPTEMBER , A.D. 2014

B. Thomas

(SEAL)

MARIA MESA personally known to me

B. THOMAS
Notary Public - State of Florida
My Comm. Expires Nov 2. 2017
Commission # FF 034747
Bonded Through National Notary Assn.

CITY OF SOUTH MIAMI INCORPORATED 1927 FLORIDA

CITY OF SOUTH MIAMI
NOTICE OF PUBLIC HEARING

NOTICE IS HEREBY given that the City Commission of the City of South Miami, Florida will conduct Public Hearing(s) at its regular City Commission meeting scheduled for Tuesday, September 16, 2014 beginning at 7:00 p.m., in the City Commission Chambers, 6130 Sunset Drive, to consider the following item(s):

An Ordinance granting to Florida Power & Light Company, its successors and assigns, an electric franchise, imposing provisions and conditions relating thereto, providing for monthly payments to the City of South Miami, and providing for an effective date.

An Ordinance amending Section 20-7.12 of the City of South Miami Land Development Code concerning parking requirements for restaurants within the Hometown District Overlay (HD-OV) Zone.

An Ordinance of the City of South Miami, Florida, amending Section 2-7, Administrative department; functions and duties; creating a cost recovery administrative program; providing for repeal of ordinances in conflict; and providing an effective date.

An Ordinance relating to the fee schedule; amending ordinance 04-11-2077 to change the title to "Schedule of Fees and Fines" and to increase some fees, adding new fees, and deleting some fees from the schedule.

ALL interested parties are invited to attend and will be heard.

For further information, please contact the City Clerk's Office at: 305-663-6340.

Maria M. Menendez, CMC
City Clerk

Pursuant to Florida Statutes 286.0105, the City hereby advises the public that if a person decides to appeal any decision made by this Board, Agency or Commission with respect to any matter considered at its meeting or hearing, he or she will need a record of the proceedings, and that for such purpose, affected person may need to ensure that a verbatim record of the proceedings is made which record includes the testimony and evidence upon which the appeal is to be based.

9/5 14-3-345/2341375M

POLICE REPORT

• SOUTH MIAMI

A vandal painted red graffiti on the sign at the Rosie Lee Wesley Health Center at **6601 SW 62nd Ave.** between 7 p.m. July 18 and 7:45 a.m. July 21. Damage was estimated at $220.

A thief shattered the front passenger window of a black 2010 Audi TT and stole a backpack, an Apple MacBook Pro, and a Duofold pen, all valued at $2,365, in a parking lot in the **6200 block of South Dixie Highway** between 5:15 and 6:30 p.m. July 22.

• PINECREST

A woman reported damage to her 2012 Hyundai when she arrived at the police department at 2:15 p.m. July 28. The woman, who lives in the **11800 block of Southwest 69th Avenue**, said the vehicle had been parked in an unfenced driveway since July 26 and had not been moved again until she discovered the damage, which is valued at $2,300.

Police were called to the Bank of America at **9101 S. Dixie Hwy.** about 4:15 p.m. July 28 in reference to verbal threats. The victim reported that a customer had verbally threatened her. The victim told police that when the offender arrived at the bank and inquired why his accounts had been closed, he became loud and offensive. When the offender was asked to leave, he was reported to have said, "Don't worry, I will take care of you." The offender was not on the scene when police arrived and contact was not made with him.

A mail carrier called police about 12:30 p.m. Aug. 14 after he noticed a broken window at a residence in the **8200 block of Southwest 133rd Street.** Police determined that a thief broke into the house and took an unknown number of items.

• KENDALL

A thief smashed the left rear window of a white 2012 Cadillac Escalade EXT and stole all four rims and tires while the vehicle was in the driveway of a residence in the **12000 block of Southwest 100th Avenue** between 9 p.m. Aug. 4 and 8:45 a.m. Aug. 5. Damage and loss were estimated at $3,000.

• PALMETTO BAY

A woman called police in reference to a personal identification fraud. The woman, who lives in the **8900 block of Southwest 150th Street**, said that someone used her personal identification information to try to change her home and email addresses on record at her bank on Aug. 18.

Police were called in reference to a bank fraud after a man, who lives in the **7200 block of Southwest 174th Street**, fraudulently cashed a forged check to his bank account on Aug. 11.

• CORAL GABLES

One or more thieves broke into and ransacked a residence in the **2000 block of Red Road** between noon and 6:45 p.m. Aug. 7.

A thief broke into and ransacked a residence in the **100 block of Oak Avenue** between noon Aug. 7 and 9:30 a.m. Aug. 9.

A 20-year-old woman was arrested and charged with grand theft after she tried to steal $3,088 worth of merchandise from the Nordstrom Department store at **4310 Ponce de Leon Blvd.** between 2:30 and 3 p.m. Aug. 6.

A 51-year-old woman became a victim of a strong arm robbery in the **500 block of Biltmore Way** between 3 and 3:15 p.m. Aug. 6.

• CUTLER BAY

A thief broke into a gray 2013 Toyota Tundra and stole tools valued at $2,000 from the driveway of a residence in the **10500 block of Southwest 200th Terrace** between 6 p.m. July 30 and 10 a.m. July 31.

A thief broke into a silver 2007 Toyota RAV4 and stole $5 in change while the vehicle was parked in the driveway of a residence in the **18500 block of Southwest 87th Court** between 4 p.m. July 24 and 9:30 a.m. July 25.

A thief broke into a black 2007 Dodge Ram 3500 parked along the roadside near **Southwest 103rd Avenue and Caribbean Boulevard**, and stole several tools and a wallet, all valued at $9,100, between 12:45 and 1 a.m. July 19.

This list is a sampling of crimes reported in Miami-Dade County cities. The information is taken from official police reports, which may not contain statements from all parties involved.

CITY OF SOUTH MIAMI
COURTESY NOTICE

NOTICE IS HEREBY given that the City Commission of the City of South Miami, Florida will conduct Public Hearing(s) at its regular City Commission meeting scheduled for Tuesday, September 16, 2014 beginning at 7:00 p.m., in the City Commission Chambers, 6130 Sunset Drive, to consider the following item(s):

An Ordinance granting to Florida Power & Light Company, its successors and assigns, an electric franchise, imposing provisions and conditions relating thereto, providing for monthly payments to the City of South Miami, and providing for an effective date.

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An Ordinance relating to the fee schedule; amending ordinance 04-11-2077 to change the title to "Schedule of Fees and Fines" and to increase some fees, adding new fees, and deleting some fees from the schedule.

ALL interested parties are invited to attend and will be heard.

For further information, please contact the City Clerk's Office at: 305-663-6340.

Maria M. Menendez, CMC
City Clerk

Pursuant to Florida Statutes 286.0105, the City hereby advises the public that if a person decides to appeal any decision made by this Board, Agency or Commission with respect to any matter considered at its meeting or hearing, he or she will need a record of the proceedings, and that for such purpose, affected person may need to ensure that a verbatim record of the proceedings is made which record includes the testimony and evidence upon which the appeal is to be based.

NOTICE OF PUBLIC HEARING
CITY OF SOUTH MIAMI

Planning and Zoning Department
6130 Sunset Drive; South Miami, Florida 33143
Phone: (305) 663-6326; Fax #: (305) 666-4591

On Thursday September 18, 2014 at 7:00 P.M., the City of South Miami's Planning Board will conduct public hearings in the City Commission Chambers at the above address on the following items:

1. PB-14-008
Applicant: Ponce Davis, LLC.
A Resolution of the City of South Miami relating to a request to allow for the creation of parcels A and B on property specifically located at 5980 SW 80th Street; South Miami, Florida within an RS-3; Low Density Single-Family Residential Zoning District, pursuant to provisions pertaining to "Waiver of Plat" set forth in Section 20-4.2(B) of the City of South Miami Land Development Code, and Section 28-4 of the Miami-Dade County Code; for the purpose of constructing two new single family homes; and providing for a legal description.

2. PB-14-009
Applicant: City of South Miami
Discussion of the compatibility between new single family home sizes, and existing homes within the single family zoning districts, and possible recommendations for changes to the City's land development code.

All interested parties are urged to attend. Objections or expressions of approval may be made in person at the hearing or filed in writing prior to or at the hearing. The Planning Board reserves the right to recommend to the City Commission whatever the board considers in the best interest for the area involved. Interested parties requesting information are asked to contact the Planning and Zoning Department by calling 305-663-6326 or writing to the address indicated above.

You are hereby advised that if any person desires to appeal any decision made with respect to any matter considered at this meeting or hearing, such person will need a record of the proceedings, and for such purpose may need to ensure that a verbatim record of the proceedings is made, which record includes the testimony and evidence upon which the appeal is to be based (F.S. 286.0105). Refer to hearing number when making any inquiry.

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LEE COUNTY ORDINANCE NO. 14-06

AN ORDINANCE OF LEE COUNTY GRANTING TO THE LEE COUNTY ELECTRIC COOPERATIVE, INC. ("LCEC"), ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC UTILITY FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING FOR FRANCHISE FEE PAYMENTS TO LEE COUNTY; PROVIDING FOR SEVERANCE, CONFLICTS, SEVERABILITY, AND AN EFFECTIVE DATE.

WHEREAS, the Lee County Board of County Commissioners is the governing body in and for Lee County, Florida ("County"), a political subdivision and Charter County of the State of Florida; and

WHEREAS, the Board of County Commissioners is lawfully authorized to enter into non-exclusive franchise agreements with electric utilities defining terms and conditions for the use of County Public Rights-of-Way and other County property for the purpose of supplying electricity and electric utility services (hereafter, "Grantor," "County," or Board"); and

WHEREAS, the Lee County Electric Cooperative, Inc. ("LCEC"), a not-for-profit electric cooperative organized under Chapter 425, F.S., is authorized to conduct business in the State of Florida and Lee County, and as such, is an electric utility desiring to enter into a non-exclusive franchise agreement with the County for such purpose (hereafter, "Grantee" or "LCEC"); and

WHEREAS, the County desires to grant a non-exclusive franchise to LCEC relating to LCEC's use of the County's Public Rights-of-Way and other County property for the purpose of supplying its customers with electricity within its service territory in unincorporated Lee County free of competition from Lee County.

NOW THEREFORE, BE IT ORDAINED BY THE LEE COUNTY BOARD OF COUNTY COMMISSIONERS that:

SECTION 1. The above recitations are hereby found to be true and accurate and are adopted and approved as if set out herein at length.

SECTION 2.

Lee County hereby grants to LCEC its successors and assigns, for the period of thirty (30) years from the Effective Date hereof, the nonexclusive right, privilege and franchise (hereafter, "Franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future County owned or held roads, streets, alleys, bridges, easements, and other County property (hereinafter, "Public Rights-of-Way") throughout the unincorporated area of Lee County. LCEC shall exercise its Franchise granted herein in accordance with its customary practices with respect to the construction and maintenance of the electric light and power related facilities, including, without limitation, conduits, underground conduits, poles, wires, communications facilities, transmission and distribution lines, fiber optic, and any other facilities installed in conjunction with or ancillary to all of LCEC's electric power operations (hereafter, "facilities"), for the purpose of supplying its customers with electricity within its service territory in unincorporated Lee County and persons beyond the limits thereof as may be authorized by law or agreement. The County recognizes that LCEC must construct, maintain and own or have the lawful use of sites and facilities for the transmission and distribution of electric power in order to adequately serve its customers in unincorporated Lee County, and that the County will not unreasonably withhold from LCEC, permits to construct such facilities within the County's Public Rights-of-Way or authorized County-held easements for such placement, unless the operation, construction and maintenance of such facilities would unreasonably interfere with the traveling public's safety and welfare. The County also recognizes and agrees that nothing in this Franchise constitutes or shall be deemed to constitute a waiver of LCEC's delegated and independent right of Eminent Domain.

SECTION 3.

(i) LCEC Facilities shall be installed, located or relocated, so as not to unreasonably interfere with the Public's travel over the Public Rights-of-Way or the reasonable egress from and ingress to abutting properties. To avoid conflicts with the Public's travel, the location or relocation of all LCEC Facilities shall be made in accordance with the County's adopted reasonable rules and regulations as they may be revised, amended, or re-numbered from time to time, for the placement and maintaining of electric utility infrastructure in, under, upon, along, over and across the County's Public Rights-of-Way.

(ii) The County's adopted rules and regulations for the placement of electric utilities in its Rights-of-Way (a) shall not unreasonably prohibit the exercise of LCEC's right to use said Public Rights-of-Way for reasons other than when such use creates an unreasonable interference with the safety of the Public's travel thereon, (b) shall not unreasonably interfere with LCEC's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of LCEC's Facilities installed before or after the Effective Date hereof in any County Public Rights-of-Way unless or until: (1) the County's widening or reconfiguring of the paved portion of any Public Rights-of-Way used by motor vehicles causes such installed LCEC Facilities to unreasonably interfere with motor vehicular traffic, or (2) the location of the LCEC Facilities constitutes an unavoidable hazard to non-motor vehicular traffic exercising reasonable care, taking into account established customs and practices with respect to the placement of utility facilities, and other structures or obstructions commonly installed or located in and around sidewalks and other non-motor vehicular travel ways.

(iii) The County's adopted rules and regulations for the County's electric utility construction permits will recognize and take into consideration that the installation of the above grade (surficial) LCEC Facilities that are installed or relocated in the County's Rights-of-Way after the Effective Date hereof will be installed or relocated at, or as close to the outermost boundaries of the Rights-of-Way to the extent most reasonably possible, unless otherwise permitted by the County in a writing.

(iv) The County will not be liable to LCEC for any costs or expenses relating to any installations or relocations of LCEC's Facilities made pursuant to subparagraphs (i) and (ii), above. However, if the County directs LCEC in a writing signed by the County Manager, to locate or relocate its Facilities in a manner that is not consistent with LCEC's then-existing standard construction methods for such installations or relocations, the County will then be liable to LCEC for those costs under LCEC's then-existing contribution-in-aid of construction policies, unless during the term of this Franchise Ordinance, there are changes in law or rules, or judicial determination(s) that dictate otherwise.

(v) If any construction work is performed in a portion of a County Public Right-of-Way by LCEC in the course of the location or relocation of any of its Facilities, the portion of the Public Right-of-Way where such construction work is performed shall be restored by LCEC at its sole cost and expense to as good a condition as it existed at the time immediately prior to the commencement of such construction work within thirty (30) days after its completion.

(vi) For so long as LCEC remains in substantial compliance with the provisions of this Section, the County will not unreasonably deny LCEC the use of the County's Public Rights-of-Way as defined herein, and will not deny LCEC the necessary County permits to construct, maintain and operate its Facilities within such Public Rights-of-Way, other than what will be reasonable and necessary for the County to preserve the traveling public's safety and welfare from time to time.

SECTION 4. The County by the grant of this Franchise to LCEC, shall in no way be liable to or responsible for in any manner whatsoever for, any accident, personal injury, property damage, or any claim or damage that may occur in the construction, installation, operation or maintenance by LCEC, its employees, agents, contractors, sublicenses or licensees for any of its facilities hereunder, except for any damage specifically caused by or arising solely out the negligence, strict liability, intentional torts or criminal acts of the County. For and in consideration of the sum of One-Hundred and 00/100 Dollars ($100.00) in hand paid, and other good and valuable consideration accepted by the County, LCEC agrees to indemnify and hold the County harmless from and against any and all liability, loss costs, damages or expenses, to include any reasonable attorney fees of the County which may accrue to the County as the result of or by reason of any negligence, default or misconduct by LCEC in the construction, operation and maintenance of its facilities hereunder in or on the County's Public Rights-of-Way or any other County granted properties. For the term of this Franchise, LCEC shall maintain general liability insurance in such amounts as are ordinary in the course of LCEC's electric utility business to further support this indemnification. Copies of LCEC's general liability insurance policies shall be provided to the County upon its written request.

SECTION 5.

(i) As a consideration for this Franchise and as reasonable rent for LCEC's use of the County's Public Rights-of-Way granted herein, LCEC shall pay to the County, beginning on the first day of the month immediately following the month in which the Ordinance becomes effective, and then thereafter at the end of each calendar quarter for the remainder of the term of this Franchise; an amount which when added to the amount of all County licenses, excises, assessments, fees or charges (except ad-valorem property taxes), levied or imposed by the County against LCEC's property, business or operations during the quarterly billing period ending 30 days prior to each such payment, will equal no more than four and one-half percent (4.5%) of LCEC's billed revenues, less actual write-offs, from the sale of electricity to residential, commercial and industrial customers located within the unincorporated areas of the County within LCEC's service territory for the quarterly billing period ending thirty (30) days prior to each such payment (hereinafter, "Franchise Fee").

(ii) It is hereby provided and agreed to by LCEC, that the County shall have the unilateral option after the fifth (5^{th}) anniversary date from the implementation of the Franchise Fee, or at any time thereafter, to increase the franchise percentage rate herein to no more than six percent (6.0%). Such increase will not be exercised more than twice by the County (if an initial increase is less than 6.0%) in years to be reasonably selected by the Board. The increase option(s) will be exercised through a County Ordinance, adopted by the Board at a duly advertised Public Hearing. A certified copy of which will be delivered to LCEC no later than ninety (90) days before the fifth (5^{th}) anniversary date hereof on which such increase is to become effective following the Board's adoption of the Ordinance. Any such ordinance shall provide that LCEC shall pay to the County, no later than thirty (30) days after the end of LCEC's first quarterly billing period occurring after the fifth (5^{th}) anniversary date as stated above, or after any subsequent year as the County may elect to exercise this option and the effective date of the County Ordinance establishing the new franchise rate percentage; and no later than thirty (30) days after the end of each succeeding quarterly billing of LCEC, an amount which, when added to the amount of all County licenses, excises, assessments, fees or charges (except ad-valorem property taxes), levied or imposed by the county against LCEC's property, business or operations during the quarterly billing period ending 30 days prior to each such payment, will equal no more than six percent (6.0%) of the billed revenues from the LCEC's sale of electricity, less actual write-offs, to residential, commercial and industrial customers located in the unincorporated area of the County within LCEC's service territory.

(iii) It is hereby further provided and agreed to by LCEC, that if during the term of this Franchise Agreement LCEC enters into a franchise agreement with any other municipality or county government, the terms of which provide for the payment of a Franchise Fee by LCEC at a rate greater than 6.0 percent of billed revenues from LCEC's residential, commercial and industrial customers under the same terms and conditions as specified in Section 5 (i) and (ii) hereof, then LCEC, upon written request of the County, shall negotiate and enter into a new franchise agreement with the County in which the percentage to be used in calculating the monthly payments under Section 5 (i) and (ii), using the same terms and conditions as specified in said Section, shall be at the greater rate being paid to the other municipality or county, provided however, that if the franchise with such other municipality or county contains additional benefits given to LCEC in exchange for the increased Franchise Rate, and such additional benefits are not contained within this Franchise Agreement, then LCEC shall have the option to include within such new franchise agreement with the County, the additional benefits included in the initiating franchise (i.e., the new municipality or county franchise that initiated the negotiation of the new franchise as contemplated above).

(iv) In the event during the term of this Franchise that LCEC recovers and collects previously written-off and uncollected billed revenues from the sale of electrical energy to residential, commercial, and industrial customers, LCEC shall pay to the County in accordance with this Section and other relevant terms of this Ordinance, the then applicable Franchise Fee payment on such revenues so collected and received, such payment to be made in the next quarterly Franchise Fee payment to the County pursuant to the terms herein following the recovery of the funds.

(v) The County reserves the unilateral right, at its sole discretion and at any time during the term of this Franchise to reduce the Franchise Fee, by providing to LCEC a certified copy of an Ordinance adopted by the County Commission at a duly advertised Public Hearing, amending the Franchise Ordinance to reduce the Franchise Fee. The certified copy of the Amended Ordinance shall be provided to LCEC no later than thirty (30) days following the Board's adoption of the Ordinance. The reduced Franchise Fee will be applied by LCEC to its customers as of the date of the adoption of the Franchise Fee Reduction Ordinance unless otherwise provided for in the terms of the Ordinance.

(vi) The County's options hereunder shall be limited solely to the percentages or calculations of the amount of the Franchise Fee to be paid by LCEC as consideration for this Franchise as specifically set forth in this Section. No other Sections or provisions of this Franchise ordinance may be altered, amended or affected by the County without the written concurrence of LCEC. Nothing herein shall require the County to exercise any of its options as outlined under this Section.

SECTION 6.

(i) As consideration during the term of this Franchise, the County agrees not to: (a) engage in the distribution and/or sale, in competition with LCEC, of electric capacity and/or electric energy as set out above to any ultimate consumer of electric utility service ("retail customer") or to any electrical distribution system established solely to serve any customer formerly served by LCEC, (b) participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate LCEC to transmit and/or distribute, electric capacity and/or electric energy from any third party to any other LCEC customer's facility, or (c) seek to have LCEC transmit and/or distribute electric capacity and/or electric energy generated by or on behalf of the County at one location to the County's facility at any other location(s).

(ii) However, nothing herein shall prohibit the County, if permitted by law, or judicial determination, from: purchasing electric capacity and/or electric energy from any third party, or (ii) seeking to have LCEC transmit and/or distribute to any facility of the County, electric capacity and/or electric energy purchased by the County from any third party; provided, however, that before the County elects to purchase electric capacity and/or electric energy from any third party, the County shall notify the LCEC in writing. Such written notice shall include a summary of the specific rates, terms and conditions of the proposed purchase which have been offered by the third party and identify the County's facilities to be served under the offer. LCEC shall thereafter have ninety (90) days to evaluate the offer and, if LCEC offers rates, terms and conditions to the County which are equal to or better than those offered by the third party, the County shall be obligated to continue to purchase electric power capacity from LCEC and/or electric energy to serve the identified facilities of the County at the revised rates, terms and conditions for a term no longer than the remainder term of this franchise. If LCEC does not agree to provide rates, terms and conditions which are equal to or better than the third party's offer, then the terms and conditions of this franchise shall continue to remain in full force and effect for its term, and the County shall have the right to proceed with the purchase of either electric capacity or electric energy from the third party; or prohibit the County from engaging with other utilities in wholesale transactions for the sale of any amount of the electric power generated by its Waste-to-Energy Facility.

SECTION 7. If the County grants a right, privilege or franchise to any other party or otherwise enables any other such party to construct, operate or maintain electric light and power facilities within any part of the service territory of LCEC within the unincorporated area of the County on terms and conditions which LCEC determines are more favorable than the terms and conditions contained herein, LCEC may at any time thereafter terminate this Franchise if such terms and conditions are not revised by the County within the time period provided for herein. LCEC shall give the County at least sixty (60) Business Days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for LCEC herein, advise the County of such terms and conditions offered to the other party that it considers more favorable. The County shall then have sixty (60) Business Days in which to correct or otherwise remedy the terms and conditions complained of by LCEC. If LCEC determines that such terms and conditions are not remedied by the County within said time period, LCEC may terminate this Franchise agreement by delivering written notice by Certified United States Mail to the Chairman of the Board of County Commissioners with copies to the County Manager, County Attorney and the Lee County Clerk of Courts, and thereafter shall not be obligated to pay any Franchise Fee to the County for the use of County Public Rights-of-Way.

SECTION 8. If as a direct or indirect consequence of any legislative, judicial, regulatory or other action by the United States or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) enacted after the Effective Date of this Ordinance, any person is permitted to provide electric service within LCEC service territory in the unincorporated area of the County to a customer then being served by LCEC, or to any new applicant for electric service within any part of the unincorporated area of the County in which LCEC may lawfully provide service, and LCEC 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 providing the electric service, LCEC may, at any time after the taking of such action, terminate this Franchise if such competitive disadvantage, and which is within the jurisdiction and authority of the County to remedy, is not remedied within the time period provided for in this Section 9. LCEC shall give the County at least sixty (60) Business Days advance written notice sent by United States Mail of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for LCEC herein, advise the County of the consequences of such action which resulted in the competitive disadvantage. The County shall then have sixty (60) Business Days or such other time as may be agreed to by LCEC in consultation with the County, for the County to correct or otherwise remedy the competitive disadvantage, if it is within the County's jurisdiction and authority to do so. If such competitive disadvantage is not remedied by the County within the determined time period and such remedy is within the County's jurisdiction and authority to do so, LCEC may terminate this Franchise agreement by delivering written notice by Certified United States Mail to the Chairman of the Board of County Commissioners with copies to the County Manager, County Attorney and Lee County Clerk of Courts, and thereafter shall not be obligated to pay any Franchise Fee to the County for the use of County Public Rights-of-Way.

SECTION 9. Failure on the part of LCEC to comply in any substantial respect with any of the provisions of this Franchise shall be grounds for a forfeiture of this Franchise by the County, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by LCEC through either administrative or judicial proceedings until there is final determination by a court of competent jurisdiction (after the expiration or exhaustion of all rights of appeal) that LCEC has failed to comply in a substantial manner with any of the provisions of this Franchise. Thereafter, LCEC shall have six (6) months after such final determination to remedy the default before a forfeiture shall result, with a right of the County at its sole discretion to grant such additional time to LCEC for its compliance, if found to be warranted. If the default is not cured within the prescribed time, LCEC shall then immediately forfeit this Franchise.

SECTION 10. Failure on the part of the County to substantially comply with any of the provisions of this Ordinance, including: (a) denying LCEC the use of County Public Rights-of-Way in the LCEC service territory for reasons other than the unreasonable interference with public travel; (b) imposing conditions for the use of Public Rights-of-Way contrary to Florida law or the terms and conditions of this Franchise; or (c) an unreasonable delay in issuing LCEC a use permit, if any such permit is required, to construct facilities in County Public Rights-of-Way pursuant to this Franchise, shall constitute a County breach of this Franchise. LCEC shall notify the County of any such breach in writing sent by United States Mail and the County shall then remedy such breach as soon as practicable, taking into account LCEC's obligation(s) to provide reasonably sufficient, adequate and efficient electric service to its customers; otherwise, within no later than thirty (30) Business Days. Should the breach not be remedied within the specified thirty (30) Business Days, LCEC shall be entitled to withhold up to the maximum of thirty percent (30%) of the payments to the County as provided for in Section 5 herein until such time as the use permit is issued, or a court of competent jurisdiction has reached a final determination with respect to the issue(s) in dispute. In the event that such final determination by the court is in favor of the County as to such issue(s) in dispute, LCEC shall promptly remit to the County all payments withheld hereunder together with simple interest, for the period withheld at the then established rate for judgments pursuant to Florida law.

SECTION 11. The Parties to this Franchise agree that it is in each of their respective best interests to avoid costly litigation as a means of resolving disputes which may arise hereunder. Accordingly, the Parties agree to notify one another in writing sent by United States Mail and any other available electronic means commonly used in the ordinary course of business when such dispute arises, and agree that prior to pursuing their available legal remedies, they will meet at the senior management level in an attempt to resolve any disputes within no later than thirty (30) Business Days from such notice. If such efforts are unsuccessful, and after an impasse is declared by either of the Parties, then the Parties may exercise any of their other available legal remedies.

SECTION 12. The County may, upon reasonable notice and within ninety (90) days after each annual anniversary date from the Effective Date of this Franchise, at the County's sole expense, examine the records of LCEC relating to the calculation of the franchise payments for the year preceding such anniversary date. Such examination shall be made during normal business hours at the LCEC office where such records are generally maintained. Records not prepared by LCEC in the ordinary course of its business may be provided to the County at the County's expense, and as the Parties may agree in writing. Any information identifying individual LCEC customers by name, address or individual electric consumptions shall not be recorded in any manner, or taken from LCEC's premises by County auditors. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the County, shall be reported to LCEC. The County's right to examine the records of LCEC in accordance with this section shall not be conducted by any third party employed by the County whose fee, in whole or in part, for conducting such audit is contingent upon the third party's findings of the audit.

SECTION 13. The provisions of this ordinance are hereby deemed by the Parties to be interdependent upon one another and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect by a court of competent jurisdiction (after the expiration of all rights of appeal), such finding or adjudication shall not affect the validity of the remaining provisions for a period of sixty (60) days, during which, this Ordinance may be amended by the Parties. If an agreement to amend the ordinance is not reached at the end of the such sixty (60) day period, this entire ordinance shall then become null and void, and of no further force or effect.

SECTION 14. Any County ordinances and/or parts of County ordinances in conflict herewith are hereby repealed to the extent that they may be in conflict with the terms and provisions as set out herein.

SECTION 15. This Ordinance shall be governed and construed by the Laws, Administrative Rules and judicial determinations of the United States and the State of Florida. Nothing in this Franchise shall be either construed or considered as an abrogation, surrender or mitigation by the County of any of its rights and authority to use and to require the relocation of any uses within its Public Rights-of-Way as provided in Section 3. In the event that any legal proceeding is brought to enforce the terms of this Franchise, it shall be brought by either Party hereto in state court in Lee County, Florida, or, if a federal claim, in the U.S. District Court in and for the Middle District of Florida, Fort Myers Division. In any legal action between the Parties arising out of this Franchise, any attempts to enforce this Franchise, or any breach of this Franchise, the prevailing Party may recover its expenses from such legal action including, but not limited to, costs of litigation and reasonable attorneys' fees from the other party together with reasonable fees and costs on appeal.

SECTION 16. Except in exigent circumstances, and except as otherwise may be specifically provided for in this Franchise, all notices by either Party shall be made by either depositing such notice into the United States Mail or by facsimile or other electronic transmission. Certified Mail shall be deemed delivered five (5) days following the date of such deposit into the United States Mail unless otherwise provided. Any notice given by facsimile or email is deemed to be received on the same Business Day. "Business Day" for purposes of this Ordinance shall mean Monday through Friday, with Saturday, Sunday and observed holidays excepted. All notices shall be addressed as follows:

To the County:
Chairman, Board of County Commissioners
2120 Main Street
Fort Myers, Florida 33901
Telephone: (239) 533-2227
Facsimile: (239) 485-2021
Email: dist3@leegov.com

Copy to:
Lee County Attorney
P.O. Box 398
Fort Myers, Florida 33902
Telephone: (239) 533-2236
Facsimile: (239) 485-2106
Email: rwesch@leegov.com

To LCEC:
Lee County Electric Cooperative, Inc.
Chief Executive Officer
4980 Bayline Drive
North Fort Myers, Florida 33917-3910
Telephone: (239) 995-2121
Facsimile: (239) 995-7904
Email: ceooffice@lcec.net

Copy to:
LCEC General Counsel
John Noland, Esq.
Henderson Franklin Starnes & Holt, P.A.
1715 Monroe Street
Fort Myers, Florida 33907
Telephone: (239) 344-1140
Facsimile: (239) 344-1515
Email: John.Noland@henlaw.com

Any changes to the Parties' representatives above shall be made in writing and provided to the other Party as soon as practicable by U.S. Mail or other electronic conveyance.

SECTION 17. This Ordinance is intended to constitute the entire agreement between the County and LCEC with respect to the subject matters herein, and supersedes all prior drafts and verbal or written agreements, commitments, or understandings, which shall not be used to vary or contradict the expressed terms hereof.

SECTION 18. As used herein for the purposes of this Franchise Ordinance, the term "person" means an individual, or, a partnership, corporation, business trust, joint stock company, trust, unincorporated association, joint venture, governmental authority or any other entity authorized to conduct business in Florida.

SECTION 19. The Board of County Commissioners intends that this Ordinance will be made part of the Lee County Code. Sections of this Ordinance can be renumbered or relettered and the word "ordinance" can be changed to "section," "article," or other appropriate word or phrase to accomplish such codification. Regardless of whether this Ordinance is ever codified, this Ordinance can be renumbered or relettered and typographical errors that do not affect the intent or substantive provisions herein may be administratively corrected upon the authorization of the County Manager and County Attorney, without the need for a further public hearing. Any such administrative revisions made hereto will be provided to LCEC within five (5) Business Days of their being made and incorporated into this Ordinance.

[REMAINDER OF THIS PAGE LEFT INTENTIONALLY BLANK]

SECTION 20.

(i) A certified copy of this Ordinance shall be filed by the County with the Florida Department of State within ten (10) days following its adoption.

(ii) As a condition precedent to the taking effect of this Ordinance, LCEC shall file a written acceptance hereof on its official letterhead stationery and executed by the Chief Executive Officer of LCEC, within thirty (30) days after the adoption of this Ordinance. The effective date ("Effective Date") of this Ordinance shall then be the date upon which LCEC files such written acceptance with the Clerk to the Lee County Board of County Commissioners, with copies to the Chairman of the Board of County Commissioners, the County Manager and the County Attorney.

The foregoing Ordinance was offered by Commissioner Manning who moved its adoption. The motion was seconded by Commissioner Mann and being put to a vote, the vote was as follows:

JOHN MANNING	Aye
CECIL PENDERGRASS	Nay
LARRY KIKER	Aye
BRIAN HAMMAN	Nay
FRANK MANN	Aye

DULY PASSED AND ADOPTED this 18th day of March, 2014.

ATTEST: LINDA DOGGETT
CLERK OF THE COURT

By: Marcia Wilson
Deputy Clerk

BOARD OF COUNTY COMMISSIONERS
LEE COUNTY, FLORIDA
SEAL

BOARD OF COUNTY COMMISSIONERS
OF LEE COUNTY, FLORIDA

By: ______________________
Larry Kiker, Chairman

APPROVED AS TO FORM:

By: ______________________
Office of the County Attorney

FLORIDA DEPARTMENT *of* STATE

RICK SCOTT
Governor

KEN DETZNER
Secretary of State

March 20, 2014

Honorable Linda Doggett
Clerk of the Circuit Courts
Lee County
Post Office Box 2469
Fort Myers, Florida 33902-2469

Attention: Lisa Pierce, Deputy Clerk

Dear Ms. Doggett:

Pursuant to the provisions of Section 125.66, Florida Statutes, this will acknowledge receipt of your electronic copy of Lee County Ordinance No. 14-06, which was filed in this office on March 20, 2014.

Sincerely,

Liz Cloud
Program Administrator

LC/elr

RECEIVED
MAR 20 - 14
MINUTES OFFICE

LCEC
PEOPLE. POWER. POSSIBILITIES.

Lee County Electric Cooperative, Inc.
Post Office Box 3455
North Fort Myers, FL 33918-3455
(239) 995-2121 • FAX (239) 995-7904
www.lcec.net

March 20, 2014

Ms. Linda Doggett
Clerk of the Circuit Court & Comptroller
Lee County Justice Center
1700 Monroe Street
Fort Myers, FL 33901

Dear Ms. Doggett:

Re: Lee County Ordinance No. 14-06

The Board of Trustees of Lee County Electric Cooperative, Inc. accepted Lee County Ordinance No. 14-06 at its meeting held on March 20, 2014. This letter serves as the written acceptance as required by paragraph 20 (ii) of the Ordinance.

Respectfully,

William D. Hamilton

William D. Hamilton
Executive Vice President
and Chief Executive Officer

cc: Larry Kiker, Chairman, Board of County Commissioners
Roger Desjarlais, County Manager
Richard Wesch, County Attorney
David M. Owen, Esq.
John A. Noland, Esq.

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expired
6-1-2036

City of Boca Raton

Incorporated 1925

This is a true copy. No. of Pages 10
IN WITNESS WHEREOF, I hereunto set my hand
and affix the Seal of the City of Boca Raton,
Florida, this 26th day of April
A.D., 20 06

City Clerk

ORDINANCE

4937

AN ORDINANCE OF THE CITY OF BOCA RATON GRANTING TO FLORIDA POWER AND LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING MONTHLY PAYMENTS TO THE CITY OF BOCA RATON; PROVIDING FOR REPEALER; PROVIDING AN EFFECTIVE DATE

WHEREAS, the City Council of the City of Boca Raton recognizes that the City of Boca Raton and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of Boca Raton does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, FPL and the City of Boca Raton desire to enter into a franchise agreement providing for the payment of fees to the City of Boca Raton in exchange for the nonexclusive right and privilege of supplying electricity and other services within the City of Boca Raton free of competition from the City of Boca Raton, pursuant to certain terms and conditions; and

WHEREAS, the City Council of the City of Boca Raton deems it to be in the best interest of the City of Boca Raton and its citizens to enter into the New Franchise Agreement prior to expiration of the Current Franchise Agreement; now therefore

THE CITY OF BOCA RATON HEREBY ORDAINS:

Section 1. There is hereby granted to Florida Power & Light Company, its successors and assigns (hereinafter called the "Grantee"), for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, rights-of-way and other public places (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City of Boca Raton, Florida, and its successors (hereinafter called the "Grantor"), in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (hereinafter called "facilities"), for the purpose of supplying electricity and other services to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 2. The facilities of the Grantee shall be installed, located or relocated so as to not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress from and ingress to abutting property. To avoid conflicts with traffic, the location or relocation of all facilities shall be made as representatives of the Grantor may prescribe in accordance with the Grantor's reasonable rules and regulations with reference to the placing and maintaining in, under, upon, along, over and across said public rights-of-way; provided, however, that such rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b) shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with motor vehicular traffic. Such rules and regulations shall recognize that above-grade facilities of the Grantee, installed after the effective date hereof, should be installed near the outer boundaries of the public rights-of-way to the extent possible. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation within the time provided in any permit for excavation issued by the Grantor or extension thereof or if no permit is issued within a reasonable time. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of this Section, except, however, the Grantee shall be entitled to reimbursement of its costs from others and as may be provided by law.

Section 3. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 4. All rates, rules, and regulations established by the Grantee from time to time shall be subject to such regulation as may be provided by law.

Section 5. As a consideration for this franchise, the Grantee shall pay to the Grantor, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which when added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending 60 days prior to each such payment will equal 5.9 percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment, and in no event shall payment for the rights and privileges granted herein exceed 5.9 percent of such revenues for any monthly billing period of the Grantee.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 2310, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; and (h) other service charges.

Section 6. As a further consideration, during the term of this franchise or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or electric energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies), and (c) not to seek to have the Grantee transmit and/or distribute electric capacity and/or electric energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at any other location(s). Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or electric energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or electric energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or electric energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have 90 days to evaluate the offer and, if the Grantee offers rates, terms and conditions which are equal to or better than those offered by the other person, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or electric energy to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to rates, terms and conditions which equal or better the other person's offer, all of the terms and conditions of this franchise shall remain in effect.

Section 7. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this franchise if such terms and conditions are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 120 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable. The Grantor shall then have 120 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice.

Section 8. If during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Palm Beach County, Florida, the population of which is equal to or less than that of the Grantor, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 6.0% of the Grantee's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under the same terms and conditions as specified in Section 5 hereof, the Grantee, upon written request of the Grantor, shall negotiate and enter into a new franchise agreement with the Grantor in which the percentage to be used in calculating monthly payments under Section 5 hereof shall be no greater than that percentage which the Grantee has agreed to use as a basis for the calculation of payments to the other County municipality, provided, however, that such new franchise agreement shall include additional benefits to the Grantee, in addition to all benefits provided herein, at least equal to those provided by its franchise agreement with the other Palm Beach County municipality. Subject to all limitations, terms and conditions specified in the preceding sentence, the Grantor shall have the sole discretion to determine the percentage to be used in calculating monthly payments, and the Grantee shall have the sole discretion to determine those benefits to which it would be entitled, under any such new franchise agreement.

Section 9. 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 incorporated 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 incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee 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. The Grantee shall give the Grantor at least 120 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice.

Section 10. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 11. Failure on the part of the Grantor to comply in substantial respect with any of the provisions of this ordinance, including but not limited to: (a) denying the Grantee use of public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms and conditions of this franchise; (c) unreasonable delay in issuing the Grantee a use permit, if any, to construct its facilities in public rights-of-way, shall constitute breach of this franchise and entitle the Grantee to withhold all or part of the payments provided for in Section 5 hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination in the matter. The Grantor recognizes and agrees that nothing in this franchise agreement constitutes or shall be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right.

Section 12. The Grantor may, upon reasonable notice and within 120 days after each anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee.

Section 13. The provisions of this ordinance are interdependent upon one another, and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect, the entire ordinance shall be null and void and of no force or effect.

Section 14. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 15. Ordinance No. 2310, passed and adopted October 12, 1976, and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

Section 16. As a condition precedent to the taking effect of this ordinance, the Grantee shall file its acceptance hereof with the Grantor's Clerk within 30 days of adoption of this ordinance. The effective date of this ordinance shall be the date upon which the Grantee files such acceptance, but not sooner than 10 days after the date of adoption of this ordinance.

PASSED AND ADOPTED by the City Council of the City of Boca Raton this 25th day of April, 2006.

CITY OF BOCA RATON, FLORIDA

ATTEST:

Steven L. Abrams, Mayor

Sharma Carannante, City Clerk

Approved as to form:

Diana Grub Frieser
City Attorney

COUNCIL VOTE	YES	NO	ABSTAINED
MAYOR STEVEN L. ABRAMS	✓		
DEPUTY MAYOR SUSAN WHELCHEL	✓		
COUNCIL MEMBER M. J. MIKE ARTS	✓		
COUNCIL MEMBER PETER BARONOFF	✓		
COUNCIL MEMBER BILL HAGER	✓		

100

101 Legal Notices

CITY OF BOCA RATON
NOTICE OF
REGULAR PUBLIC HEARINGS

NOTICE IS HEREBY GIVEN that the City Council of the City of Boca Raton. Florida will hold public hearings on the following proposed ordinances at the Regular Meeting on Tuesday. April 25. 2006 at 6:00 p.m.. or as soon thereafter as possible. at which time they will consider their adoption. Presentations may be made by staff at the City Council Workshop Meeting on Monday. April 24. 2006 at 1:30 p.m.. or as soon thereafter as possible.

Both meetings will be held in the Council Chamber at Boca Raton City Hall. 201 West Palmetto Park Road. Boca Raton. Florida. The ordinances in their entirety may be inspected at the Office of the City Clerk during regular business hours. All interested parties are invited to attend either or both meetings and be heard with respect to the proposed ordinances.

Ordinance No. 4936

An ordinance of the City of Boca Raton providing for the vacation and abandonment of the unimproved portion of Banyan Trail located south of N.W. Spanish River Boulevard and east of North Military Trail. as more specifically described herein: providing conditions for vacation and abandonment: providing for severability: providing for repealer: providing an effective date (AB-05-03)

Ordinance No. 4937

An ordinance of the City of Boca Raton granting to Florida Power and Light Company. its successors and assigns. an electric franchise: imposing provisions and conditions relating thereto: providing monthly payments to the City of Boca Raton: providing for repealer: providing an effective date

NOTICE: If any decision of City Council affects you. and you decide to appeal any decision made at this meeting with respect to any matter considered. you may need to ensure that a verbatim record of the proceedings is made. which record includes the testimony and evidence upon which the appeal is to be based. (The above NOTICE is required by State Law. If you desire a verbatim transcript. you shall have the responsibility. at your own cost. to arrange for the transcript.)

In accordance with the Americans with Disabilities Act and Florida Statutes 286.26. persons with disabilities

101 Legal Notices

needing special accommodation to participate in this proceeding should contact the Office of the City Clerk at 393-7741 at least three business days prior to the proceeding (whenever possible) to request such accommodation

Sharma Carannante CMC
City Clerk
City of Boca Raton Florida

PUBLISH: April 13. 2006
ACCOUNT NO. 98842
FURNISH PROOF OF PUBLICATION
PO30429 (49-A)

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 4937
BY FLORIDA POWER & LIGHT COMPANY

Boca Raton, Florida June 1, 2006

Florida Power & Light Company does hereby accept the electric franchise in the City of Boca Raton, Florida, granted by Ordinance No. 4937, being:

AN ORDINANCE OF THE CITY OF BOCA RATON GRANTING TO FLORIDA POWER AND LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING MONTHLY PAYMENTS TO THE CITY OF BOCA RATON; PROVIDING FOR REPEALER; PROVIDING AN EFFECTIVE DATE.

which was passed and adopted on April 25, 2006.

This instrument is filed with the City Clerk of the City of Boca Raton, Florida, in accordance with the provisions of Section 16 of said Ordinance.

FLORIDA POWER & LIGHT COMPANY

By______________________
Jeffrey S. Bartel
Vice President

ATTEST:

____
Jay W. Molyneaux, Assistant Secretary

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 4937 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City of Boca Raton, Florida, on this 1st day of June, 2006.

Shauna Carrante

____
City Clerk, City of Boca Raton, Florida

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ORDINANCE NO. 00-08

AN ORDINANCE OF THE CITY OF BONITA SPRINGS GRANTING FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, A NON-EXCLUSIVE ELECTRIC UTILITY FRANCHISE, IMPOSING CITY-WIDE PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF BONITA SPRINGS, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Council of the City of Bonita Springs ("City" or "Grantor") recognizes that the citizens of the City need and desire the benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company ("FPL" or "Grantee") is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, FPL and the City desire to enter into a franchise agreement providing for the payment of fees to the City in exchange for the nonexclusive right and privilege of supplying electricity and other services within the City free of competition from the City, pursuant to certain terms and conditions.

NOW, THEREFORE, THE CITY COUNCIL OF BONITA SPRINGS

HEREBY ORDAINS:

Section 1. There is hereby granted to Florida Power & Light Company, its successors and assigns (herein called the "Grantee"), for the period of 25 years from the effective date hereof, with one additional five (5) year extension at FPL's sole option the non-exclusive right, privilege and franchise, (herein called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, rights-of-way and other public places (herein called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City of Bonita Springs, Florida, and its successors (herein called the "Grantor"), in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (herein called "facilities"), for the purpose of supplying electricity and other services to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 2. The facilities of the Grantee shall be installed, located or relocated so as to not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress from and ingress to abutting property. To avoid conflicts with traffic, the location or relocation of all facilities shall be made as representatives of the Grantor may prescribe in accordance with the Grantor's reasonable rules and regulations with reference to the placing and maintaining in, under, upon, along, over and across said public rights-of-way; provided, however, that such rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b) shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with motor vehicular traffic. Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should be installed near the outer boundaries of the public rights-of-way to the extent possible. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of this Section, except, however, the Grantee shall be entitled to reimbursement of its costs from others and as may be provided by law.

Section 3. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 4. All rates and rules and regulations established by the Grantee from time to time shall be subject to such regulation as may be provided by law.

Section 5(a). As a consideration for this franchise, the Grantee shall pay to the Grantor, commencing sixty (60) days after the effective date of this Ordinance and each month thereafter for the remainder of the term of this franchise, an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending sixty (60) days prior to each such payment will equal three (3%) percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers within the incorporated areas of the Grantor for the monthly billing period ending sixty (60) days prior to each such payment, and in no event shall payment for the rights and privileges granted herein exceed three (3%) percent of such revenues for any monthly billing period of the Grantee.

Section 5(b): Notwithstanding the above, for the first eighteen months of this franchise, the Grantee shall pay to the Grantor an amount equal to four (4%) percent of the Grantee's billed revenues, as specified in Section 5(a).

Section 5(c). It is further provided that the Grantor shall have the option, subject to the limitations specified below, once each calendar year to increase or reduce the amount to be paid by the Grantee as consideration for this franchise, such option to be exercised by the adoption of an ordinance, a certified copy of which must be delivered to the Grantee no later than 90 days before any such increase or reduction is to become effective. Such ordinance shall provide that the Grantee shall pay to the Grantor, no later than thirty (30) days after the end of the Grantee's first billing period and no later than 30 days after the end of each succeeding monthly billing of the Grantee during the term of this franchise, an amount which when added to the amount of all City licenses, excise fees or charges (except ad valorem property taxes and non-ad valorem special assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending thirty (30) days prior to each such payment will equal five (5%) percent (or such lesser percentage as the Grantor may elect) of the Grantee's billed revenues, less actual write-offs, from the sale of electricity to residential, commercial and industrial customers within the incorporated areas of the Grantor for the monthly billing period ending thirty (30) days prior to each such payment, and in no event shall the Grantee's payment for the rights and privileges granted herein exceed five (5%) percent, or such percent of such revenues as specified by the Grantor in the exercise of its option, for any monthly billing period of the Grantee. In no event may the Grantor increase the amount by more than one (1%) percent from the percentage then being collected in any given year. The Grantor shall have the option to reduce the amount to be paid by the Grantee to zero, but in no event shall the Grantor have the option to increase the percentage used to calculate the amount to be paid by the Grantee as consideration for this franchise to any percentage which is greater than five (5%) percent. The Grantor's option hereunder shall be limited solely to the percentage to be used in the calculation of the amount to be paid by the Grantee as consideration for this franchise and as specifically set forth in this subsection, and no other section or provision of this franchise ordinance may be altered, amended or affected by the Grantor without the concurrence of the Grantee. Nothing herein shall require the Grantor to exercise its option hereunder.

Section 6. As a further consideration, during the term of this franchise or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or energy from any third party(ies) to any other retail customer's facility(ies), and (c) not to seek to have the Grantee transmit and/or distribute electric capacity and/or energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at any other location(s). Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have sixty (60) days to evaluate the offer and, if the Grantee agrees to meet or beat the other person's offer, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or energy to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to meet or beat the other person's offer, all of the terms and conditions of this franchise shall remain in effect.

Section 7. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this franchise if such terms and conditions are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least sixty (60) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable. The Grantor shall then have sixty (60) days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice.

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 incorporated 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 incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee 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. The Grantee shall give the Grantor at least ninety

(90) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have ninety (90) days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice.

Section 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right in the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 10. Failure on the part of the Grantor to comply in substantial respect with any of the provisions of this ordinance, including: (a) denying the Grantee use of public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms and conditions of this franchise;

(c) unreasonable delay in issuing the Grantee a use permit, if any, to construct its facilities in public rights-of-way, shall constitute breach of this franchise and entitle the Grantee to withhold all or part of the payments provided for in Section 5 hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination in the matter. The Grantor recognizes and agrees that nothing in this franchise constitutes or shall be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right.

Section 11. The Grantor may, upon reasonable notice and within ninety (90) days after each anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this section shall not be conducted by any third party employed by the Grantor whose fee for conducting such audit is contingent on findings of the audit.

Section 12. The provisions of this ordinance are interdependent upon one another, and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect, the entire ordinance shall be null and void and of no force or effect.

Section 13. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 14. All ordinances and parts of ordinances in conflict herewith are hereby repealed.

Section 15. As a condition precedent to the taking effect of this ordinance the Grantee shall file its acceptance hereof with the Grantor's Clerk within forty (40) days of adoption of this ordinance. The effective date of this ordinance shall be the date on which Grantee files its acceptance.

DULY PASSED AND ENACTED by the City Council of the City of Bonita Springs, Florida this 19th day of July, 2000.

AUTHENTICATION:

MAYOR

CITY CLERK

APPROVED AS TO FORM: ____________________ 7/20/00

City Attorney Date

Vote:				
	Arend	Aye	Piper	Aye
	Edsall	Aye	Wagner	Aye
	Nelson	Aye	Warfield	Aye
	Pass	Aye		

I CERTIFY THAT THIS IS A CORRECT COPY OF AN OFFICIAL PUBLIC RECORD ON FILE WITH THE CITY OF BONITA SPRINGS, FLORIDA.

Dianne J. Lynn, City Clerk
Date: 7/20/00

Date Filed with City Clerk: 7/20/00

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ORDINANCE NO. 91-1

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE TOWN OF GLEN RIDGE, AND PROVIDING FOR AN EFFECTIVE DATE.

BE IT ORDAINED BY THE TOWN OF GLEN RIDGE, FLORIDA:

Section 1. There is hereby granted to Florida Power & Light Company (herein called the "Grantee"), its successors and assigns, the non-exclusive right, privilege or franchise to construct, maintain and operate in, under, upon, over and across the present and future streets, alleys, bridges, easements and other public places of the Town of Glen Ridge, Florida (herein called the "Grantor") and its successors, in accordance with established practice with respect to electrical construction and maintenance, for the period of 30 years from the date of acceptance hereof, electric light and power facilities (including conduits, poles, wires and transmission lines, and, for its own use, telephone and telegraph lines) for the purpose of supplying electricity to the Grantor and its successors, and inhabitants thereof, and persons and corporations beyond the limits thereof.

Section 2. As a condition precedent to the taking effect of this grant, the Grantee shall have filed its acceptance hereof with the Grantor's Clerk within 30 days hereof.

Section 3. The facilities of the Grantee shall be so located or relocated and so erected as to interfere as little as possible with traffic over said streets, alleys, bridges and public places, and with reasonable egress from and ingress to abutting property. The location or relocation of all facilities shall be made under the supervision and with the approval of such representatives as the governing body of the Grantor may designate for the purpose, but not so as to unreasonably interfere with the proper operation of the Grantee's facilities and service. When any portion of a street is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the street so excavated shall, within a reasonable time and as early as practicable after such excavation, be replaced by the Grantee at its expense and in a condition as good as it was at the time of such excavation..

Section 4. Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 5. All rates and rules and regulations established by the Grantee from time to time shall at all times be reasonable and the Grantee's rates for electricity shall at all times be subject to such regulation as may be provided by law.

Section 6. No later than 60 days after the first anniversary date of this grant, and no later than 60 days after each succeeding anniversary date of this grant, the Grantee, its successors and assigns, shall have paid to the Grantor and its successors an amount which added to the amount of all taxes as assessed, levied, or imposed (without regard to any discount for early payment or any interest or penalty for late payment), licenses, and other impositions levied or imposed by the Grantor upon the Grantee's electric property, business, or operations, and those of the Grantee's electric subsidiaries for the preceding tax year, will equal six percent of the Grantee's revenues from the sale of electrical energy to residential, commercial and industrial customers within the corporate limits of the Grantor for the 12 fiscal months preceding the applicable anniversary date.

Section 7. Payment of the amount to be paid to the Grantor by the Grantee under the terms of Section 6 hereof shall be made in advance by estimated monthly installments commencing 90 days after the effective date of this grant. Each estimated monthly installment shall be calculated on the basis of 90% of the

Grantee's revenues (as defined in Section 6) for the monthly billing period ending 60 days prior to each scheduled monthly payment. It is also understood that for purposes of calculating each monthly installment, all taxes, licenses, and other impositions shall be estimated on the basis of the latest data available for all such amounts imposed on the Grantee, before being prorated monthly. The final installment for each fiscal year of this grant shall be adjusted to reflect any underpayment or overpayment resulting from estimated monthly installments made for said fiscal year.

Section 8. As a further consideration of this franchise, the Grantor agrees not to engage in the business of distributing and selling electricity during the life of this franchise or any extension thereof in competition with the Grantee, its successors and assigns.

Section 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this ordinance shall be grounds for forfeiture of this grant, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until a court of competent jurisdiction (with right of appeal in either party) shall have found that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after the final determination of the question to make good the default before a forfeiture shall result with the right in the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 10. Should any section or provision of this ordinance or any portion hereof be declared by a court of competent jurisdiction to be invalid, such decision shall not affect the validity of the remainder as a whole or as to any part, other than the part declared to be invalid.

Section 11. That all ordinances and parts of ordinances in conflict herewith be and the same are hereby repealed.

Section 12. This ordinance shall take effect on the date upon which the Grantee files its acceptance.

PASSED First Reading this 12th day of Sept 1991.

PASSED Second and Final Reading this 2nd day of Oct, 1991.

President of Council

ATTEST:

Town Clerk

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ORDINANCE NO. 95-3

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE VILLAGE OF LAZY LAKES, AND PROVIDING FOR AN EFFECTIVE DATE.

BE IT ORDAINED BY THE VILLAGE OF LAZY LAKES:

Section 1. There is hereby granted to Florida Power & Light Company (herein called the "Grantee"), its successors and assigns, the non-exclusive right, privilege or franchise to construct, maintain and operate in, under, upon, over and across the present and future streets, alleys, bridges, easements and other public places of the Village of Lazy Lakes, Florida (herein called the "Grantor") and its municipal successors, in accordance with established practice with respect to electrical construction and maintenance, for the period of thirty (30) years from the date of acceptance hereof, electric light and power facilities (including conduits, poles, wires and transmission lines, and, for its own use, telephone and telegraph lines) for the purpose of supplying electricity to the Grantor and its municipal successors, and inhabitants, and persons and corporations beyond the limits thereof.

Section 2. As a condition precedent to the taking effect of this grant, the Grantee shall have filed its acceptance hereof with the Grantor's Clerk within thirty (30) days hereof.

Section 3. The facilities of the Grantee shall be so located or relocated and so erected as to interfere as little as possible with traffic over said streets, alleys, bridges and public places, and with reasonable egress from and ingress to abutting property. The location or relocation of all facilities shall be made under the supervision and with the approval of such representatives as the governing body of the Grantor may designate for the purpose, but not so as to unreasonably interfere with the proper operation of the Grantee's facilities and service. When any portion of a street is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the street so excavated shall, within a reasonable time and as early as practicable after such excavation, be replaced by the Grantee at its expense and in a condition as good as it was at the time of such excavation.

Section 4. Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 5. All rates and rules and regulations established by the Grantee from time to time shall at all times be reasonable and the Grantee's rates for electricity shall at all times be subject to such regulation as may be provided by law.

Section 6. No later than sixty (60) days after the first anniversary date of this grant, and no later than sixty (60) days after each succeeding anniversary date of this grant, the Grantee, its successors and assigns, shall have paid to the Grantor and its successors an amount which added to the amount of all taxes as assessed, levied, or imposed (without regard to any discount for early payment or any interest or penalty for late payment), licenses, and other impositions levied or imposed by the Grantor upon the Grantee's electric property, business, or operations, and those of the Grantee's electric subsidiaries for the preceding tax year, will equal six percent of the Grantee's revenues from the sale of electrical energy to residential, commercial and industrial customers within the corporate limits of the Grantor for the twelve (12) fiscal months preceding the applicable anniversary date.

Section 7. Payment of the amount to be paid to the Grantor by the Grantee under the terms of Section 6 hereof shall be made in advance by estimated monthly installments commencing ninety (90) days after the effective date of this grant. Each estimated monthly installment shall be calculated on the basis of ninety (90%) percent of the Grantee's revenues (as defined in Section 6) for the monthly billing period ending sixty (60) days prior to each scheduled monthly payment. It is also understood that for purposes of calculating each monthly installment, all taxes, licenses, and other impositions shall be estimated on the basis of the latest data available for all such amounts imposed on the Grantee, before being prorated monthly. The final installment for each fiscal year of this grant shall be adjusted to reflect any underpayment or overpayment resulting from estimated monthly installments made for said fiscal year.

Section 8. As a further consideration of this franchise, the Grantor agrees not to engage in the business of distributing and selling electricity during the life of this franchise or any extension thereof in competition with the Grantee, its successors and assigns.

Section 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this ordinance shall be grounds for forfeiture of this grant, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until a court of competent jurisdiction (with right of appeal in either party) shall have found that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six (6) months after the final determination of the question to make good the default before a rfeiture shall result with the right in the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 10. Should any section or provision of this ordinance or any portion hereof be declared by a court of competent jurisdiction to be invalid, such decision shall affect the validity of the remainder and the franchise agreement shall be declared to be invalid.

Section 11. That all ordinances and parts of ordinances in conflict herewith be and the same are hereby repealed.

Section 12. This ordinance shall take effect on the date upon which the Grantee files its acceptance.

PASSED First Reading this 5 day of September, 1995.

PASSED Second and Final Reading this 19 day of September, 1995.

Signed [signature]
President of Village Council

ATTEST:

[signature], Village Clerk

Arthur R. Wintergren

Betty Bailey

[signature]

[signature]

Members of Village Council

CERTIFICATE

IN CONNECTION WITH ORDINANCE NO. 95-3, BEING AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE VILLAGE OF LAZY LAKE, AND PROVIDING FOR AN EFFECTIVE DATE, I HEREBY CERTIFY AS FOLLOWS:

a. The Village Council met on September 5, 1995 when proposed ordinance No. 95-3 granting a franchise to Florida Power and Light Company was read (by title/in full) for the first time. It was agreed to read it for the second time on September 19, 1995.

On September 19, 1995, the Village Council me and Ordinance No. 95-3 was read (by title/in full) for the second time. Those present were:

Joe McCallion, President of the Village Council
Betty Bailey, Village Council member
Arthur Westergren, Village Council member
Tim Ford, Village Council member
Joseph Fodera, Village Council member
John Heckathorne, Village Clerk
Dr. Bill Bailey, Mayor

The ordinance was adopted as Ordinance No. 95-3

b. On September 8, 1995, following passage at first reading, notice of proposed enactment of Ordinance No. 95-3 was mailed to the residents of the Village of Lazy Lake and the Ordinance No. 95-3 as proposed and adopted was maintained for inspection by the public at Village of Lazy Lake.

C. Upon final passage on September 19, 1995, Ordinance No. 95-3 was signed by the Presiding Officer of the Village Council and Village Clerk of the Village of Lazy Lake and recorded in a book kept for that purpose, and the respective votes of each member of the Village Council were recorded in the record of the meeting.

This 19th day of September, 1995.

President of Village Council for
Village of Lazy Lake, Florida

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 95-3
BY FLORIDA POWER & LIGHT COMPANY

VILLAGE OF LAZY LAKE, FLORIDA October ___, 1995

Florida Power & Light Company hereby accepts the electric franchise in the Village of Lazy Lake, Florida, granted by Ordinance No. 95-3, being:

> "AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE VILLAGE OF LAZY LAKE, AND PROVIDING FOR AN EFFECTIVE DATE"

which was passed and adopted on September 19, 1995.

This instrument is filed with the Village Clerk of the Village of Lazy Lake, Florida in accordance with the provisions of Section 2 of said ordinance.

FLORIDA POWER & LIGHT COMPANY

ATTEST:

BY J. J. Petillo
Vice President

Jean A. Howard
Assistant Secretary

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 95-3 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the Village of Lazy Lake, Florida on this 6 day of November, 1995.

John [illegible], Clerk
President of Village Council for Village for Lazy Lake, Florida

Lazylake.acc

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ORDINANCE NO. 2007-67

Expires October 1, 2037

AN ORDINANCE OF THE CITY OF MELBOURNE, BREVARD COUNTY, FLORIDA, GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF MELBOURNE; PROVIDING THAT THE GRANTOR SHALL NOT BE LIABLE FOR CERTAIN ACCIDENTS AND DAMAGE; PROVIDING THAT THE FRANCHISEE'S RATES AND REGULATIONS SHALL BE SUBJECT TO REGULATION AS PROVIDED BY LAW; SPECIFYING THE CONSIDERATION FOR THE FRANCHISE; PROVIDING FOR CERTAIN RESTRICTIONS UPON THE CITY; SETTING FORTH REQUIREMENTS WITH REGARD TO THE GRANTING OF FRANCHISES TO OTHER LEGAL ENTITIES; SPECIFYING CERTAIN CONDITIONS UNDER WHICH THE FRANCHISEE MAY WITHHOLD CERTAIN PORTIONS OF FRANCHISE FEE PAYMENTS TO THE CITY; SETTING FORTH THE RESULTS OF A DEFAULT BY THE CITY OR BY THE FRANCHISEE; PROVIDING FOR TERMINATION OF THE FRANCHISE AGREEMENT; PROVIDING FOR EXAMINATION OF THE FRANCHISEE'S RECORDS; REPEALING ORDINANCE NOS. 72-28 AND 78-07; PROVIDING FOR AN EFFECTIVE DATE; AND PROVIDING AN ADOPTION SCHEDULE.

WHEREAS, the City Council of the City of Melbourne, Florida, recognizes that the City of Melbourne and its citizens need and desire the continued benefits of safe, adequate, reliable, and efficient electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of Melbourne does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility, which has the demonstrated ability to supply electric services; and

WHEREAS, there is currently in effect a franchise agreement between the City of Melbourne and FPL, the terms of which are set forth in City of Melbourne Ordinance No. 72-

28, passed and adopted September 19, 1972, and FPL's written acceptance thereof dated October 1, 1972, granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"), and City of Melbourne Ordinance No. 78-07, passed and adopted on January 31, 1978, extending the term of the franchise grant contained in Ordinance No. 72-28 by a period of five years; and

WHEREAS, FPL and the City of Melbourne desire to enter into a new agreement (the "New Franchise Agreement" or "Franchise Agreement") providing for the payment of fees to the City of Melbourne in exchange for the nonexclusive right and privilege of supplying electricity and directly electric-related services within the City of Melbourne, free of competition from the City of Melbourne, pursuant to certain terms and conditions; and

WHEREAS, the City Council of the City of Melbourne deems it to be in the best interest of the City of Melbourne and its citizens to enter into the New Franchise Agreement prior to expiration of the Current Franchise Agreement.

BE IT ENACTED BY THE CITY OF MELBOURNE, FLORIDA:

SECTION 1. Grant of Franchise. That there is hereby granted to Florida Power & Light Company, its successors and assigns (hereinafter called the "Grantee"), for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, public rights-of-way and other public places (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City of Melbourne, Florida, and its successors (hereinafter called the "Grantor"), in accordance with the National Electrical Safety Code and Grantee's customary practices with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, substations, foundations, supports, supporting and containing structures, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (hereinafter called "facilities"), for the purpose of supplying electricity and other directly electric-related services to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof.

SECTION 2. Location of Grantee's Facilities; Interpretation. (a) That the facilities of the Grantee shall be installed, located, removed or relocated so as to not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress from and ingress to abutting property. It is the intent of the foregoing provision that all lanes of travel shall remain accessible for use by vehicular traffic. To avoid conflicts with traffic, the location or relocation of all facilities shall be made as representatives of the Grantor may prescribe in accordance with the Grantor's reasonable rules and regulations, as revised, repealed, or promulgated from time to time, with reference to placing and maintaining said facilities in, under, upon, along, over and across said public rights-of-way; provided, however, that such rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b) shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate, safe, and efficient electric service to all of its customers; and (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until either (i) widening or other work changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with motor vehicular traffic. It is agreed that unless replaced, supplemented, repealed, suspended, terminated, or amended by the Grantor, the Grantor's reasonable rules and regulations to be used by the Grantee shall include, but not be limited to, the Manual of Uniform Minimum Standards for Design, Construction, and Maintenance for Streets and Highways, May 2005 edition, and published by the Florida Department of Transportation; and the Utility Accommodation Guide, dated August 2004, also published by the Florida Department of Transportation; and such other rules and regulations as may be applicable, in all cases as any such rules and regulations, including the aforementioned Manual of Uniform Minimum Standards and Utility Accommodation Guide may be amended or issued in new editions from time to time. Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should be installed near the outer boundaries of the public rights-of-way to the extent possible. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of this Section, except, however, the Grantee shall be entitled to reimbursement of its costs from others and as may be provided by law, as such laws may be amended from time to time.

SECTION 3. Grantor's Liability. That the Grantor shall in no way be liable or responsible for any accident, personal injury, property damage or any claim or damage that may occur in the construction, installation, operation, removal, repair, relocation, or maintenance by the Grantee, its employees, agents, contractors, subcontractors, sublessees or licensees of any of the Grantee's facilities or operations, or that may occur as the result of any omission to do any of the foregoing by the Grantee, its employees, agents, contractors, subcontractors, sublessees or licensees, in connection with or relation to its facilities hereunder. The acceptance of the franchise granted pursuant to this New Franchise Agreement by the Grantee shall be deemed an agreement on the part of the Grantee to indemnify the Grantor, its officials, employees, and agents, and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee or other third party arising from the construction, installation, operation, removal, repair, or maintenance of its facilities hereunder. The Grantor agrees that neither it nor its officers, employees, or agents, all in their official capacity, shall be indemnified to the percentage of its or their fault in an accident or other occurrence that Grantor or its officers, employees, agents, or volunteers, all in their official capacity, is responsible for in any incident for damages or injuries (including but not limited to injury or death) arising from the gross negligence and wanton, willful, and intentional misconduct of the Grantor or its officers, employees, agent, or volunteers. For an additional Ten Dollars ($10.00) paid to the Grantee, and for other good and valuable consideration, the receipt of which is hereby acknowledged by the Grantee, the Grantee agrees that it has received sufficient consideration for its agreement to indemnify the Grantor as set forth above.

SECTION 4. Notice to Grantor of Proposed Changes in Rules or Rates. That except as otherwise provided by this Franchise Agreement, all rates and rules and regulations established by the Grantee from time to time shall be subject to such regulation as may be provided by law.

SECTION 5(a). Consideration for Franchise. That as a consideration for this franchise, the Grantee shall pay to the Grantor, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this Franchise Agreement, an amount which, when added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending 60 days prior to each such payment will equal to 5.9% of the Grantee's billed revenues, less actual write-offs, from sales of electrical energy within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment, and in no event shall payment for the rights and privileges granted herein exceed 5.9% of such revenues for any monthly billing period of the Grantee.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 72-28, amended by Ordinance No. 78-07, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

<u>SECTION 5(b)</u>. That if during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Brevard County, Florida or within any contiguous county to Brevard County, where the number of Grantee's active electrical customers is 50,000 or less than the number of Grantee's active electrical customers within the incorporated area of the Grantor, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 5.9% of the Grantee's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under the same terms and conditions as specified in Section 5(a) hereof, the Grantee, upon written request of the Grantor, shall negotiate and enter into a new franchise agreement with the Grantor in which the percentage to be used in calculating monthly payments under Section 5(a) hereof shall be equal to that percentage which the Grantee has agreed to use as a basis for the

calculation of payments to such other municipality described above, provided, however, that such new franchise agreement shall include additional benefits to the Grantee, in addition to all benefits provided herein, equal to those provided by its franchise agreement with such other municipality described above. Subject to all limitations, terms and conditions specified in the preceding sentence, the Grantor shall have the sole discretion to determine the percentage to be used in calculating monthly payments, and the Grantee shall have the sole discretion to determine those benefits to which it would be entitled, under any such new Franchise Agreement.

SECTION 6. Consideration; Non-Competition by City in the Provision of Electric Service. That as a further consideration, during the term of this Franchise Agreement or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or electric energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies); and (c) not to seek to have the Grantee transmit and/or distribute electric capacity and/or electric energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at any other location(s). Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or electric energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or electric energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or electric energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have 90 days to evaluate the offer and, if the Grantee offers rates, terms and conditions which are equal to or better than those offered by the other person, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or electric energy on such equal or better terms to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to rates, terms and conditions which equal or better the other person's offer, then Grantor may proceed with the other person's offered sale and purchase arrangement and all of the terms and conditions of this Franchise Agreement shall remain in effect except as otherwise provided herein.

SECTION 7. Grantor's Approval of Competing Electric Service. That if the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee reasonably determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this Franchise Agreement if such terms and conditions are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 150 days advance written notice, of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 150 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee reasonably determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this Franchise Agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice.

SECTION 8. Legal or Regulatory Change Authorizing Retail Competition in the Sale of Electricity. That 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 incorporated 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 incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee reasonably determines that its obligations hereunder, or otherwise resulting from this Franchise Agreement 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 Agreement if such competitive disadvantage is, in the reasonable determination of the Grantee, not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 150 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the specific consequences of such action which resulted in the competitive disadvantage, and the objective basis or bases of the competitive disadvantage. The Grantor shall then have 150 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is, in the reasonable determination of the Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this Franchise Agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Notwithstanding the foregoing, upon written request of the Grantor within the 150 day period for a face to face meeting between representatives of the Grantor and Grantee, Grantee agrees that it shall meet with Grantor prior to terminating the franchise agreement. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge FPL's reasonable determination of competitive disadvantage leading to termination under Sections 7 and/or 8.

<u>SECTION 9</u>. <u>Default</u>. That failure on the part of the Grantee to comply in any substantial or material respect with any of the provisions of this Franchise Agreement shall be grounds for forfeiture of this franchise, but no such forfeiture of this franchise shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is a final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require. Such final determination by a court of competent jurisdiction, including any final appellate determination or ruling, shall allow Grantor to proceed with its choice of remedies, provided, however, that the Grantor may, in its discretion, grant such additional time to the Grantee for compliance as the Grantor determines are in the best interests of Grantor and Grantor's citizens. Non-substantial or non-material defaults or failures by the Grantee shall be remediable pursuant to any available legal remedies.

<u>SECTION 10</u>. <u>Grantee's Remedies in the Event of Defaults by Grantor</u>. That failure on the part of the Grantor to comply in any substantial or material respect with any of the provisions of this ordinance, including but not limited to: (a) denying the Grantee use of public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms and

conditions of this Franchise Agreement; (c) unreasonable delay in issuing the Grantee a right-of-use permit, if any, to construct its facilities in public rights-of-way, shall constitute breach of this Franchise Agreement and entitle the Grantee to withhold all or part of the payments provided for in Section 5 hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination in the matter. The Grantor recognizes and agrees that nothing in this Franchise Agreement constitutes or shall be deemed to constitute a waiver of the Grantee's sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right.

SECTION 11. Termination and Renewal. That the Grantor and Grantee agree that the New Franchise Agreement created by this ordinance and Grantee's acceptance hereof, shall terminate by its own terms at 12:01 a.m. thirty (30) years after the effective date of the Franchise Agreement.

SECTION 12. Examination or Audit of Grantee's Records; Waiver of Claims. That the Grantor may, upon reasonable notice and within 90 days after each anniversary date of this Franchise Agreement, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained; provided that, in all events, Grantee agrees that all said records shall be made available at Grantee's expense to Grantor in Palm Beach County, Dade or Brevard County, Florida. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this Section shall not be conducted by any third party employed by the Grantor whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

Grantor may, upon reasonable notice given within one year following the Grantee's acceptance of this New Franchise Agreement, conduct a final audit of the Grantee's records relating to the calculation of the franchise payments that have been made to Grantor pursuant to the Current Franchise Agreement embodied in Ordinances No. 72-28 and No. 78-07. Other than any claims arising from alleged fraud, deceit, misrepresentation, intentional withholding of information, or other similar intentional misconduct by Grantee in relation to the calculation or remittance of the franchise payments under the Current Franchise Agreement, Grantor waives, settles and bars all claims relating to the amounts paid by the Grantee under the Current Franchise Agreement embodied in Ordinances No. 72-28 and No. 78-07. Grantor agrees that this instrument waives, settles and bars any claim by Grantee, its successors or assigns of, and any right of Grantee, its successors or assigns to claim, a breach, material or otherwise, of the franchise by the Grantor embodied in Ordinance Nos. 72-28 and No. 78-07.

<u>SECTION 13</u>. <u>Annexation</u>. That upon the Grantor's annexation of any property and appropriate written notice to Grantee, the portion of Grantee's electrical system located within such annexed territory, and in, under, over, and upon the streets, alleys, rights-of-way, or public grounds of such annexed territory, shall be subject to all the terms of this New Franchise Agreement within ninety (90) days of the Grantee's receiving written notice by U.S. certified mail return receipt requested of such annexation from the Grantor, which notice shall include the legal description(s) of the property annexed and the addresses of the individual properties within the annexed property to the extent that information is available to the City.

SECTION 14. Severability; Invalidation of Portions of Ordinance. That if any section, sentence, clause or phrase of this Ordinance is held to be invalid or unconstitutional by any court of competent jurisdiction, then said holding in no way affects the validity of the remaining portions of this Ordinance. Notwithstanding the foregoing, it is expressly provided that if any of the provisions of Sections 1, 2, 3, 5, 6, 7, 8, 9 or 10 are found or adjudged to be invalid, void or of not effect, the ordinance shall be null and void and of no force and effect.

SECTION 15. Repeal of Prior Franchise Ordinances. That Ordinance No. 72-28, passed and adopted September 19, 1972, Ordinance No. 78-07, passed and adopted on January 31, 1978, and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

SECTION 16. Venue. That this New Franchise Agreement shall be governed by and construed according to the laws of the United States and of the State of Florida, and venue shall be in Brevard County, Florida.

SECTION 17. Effective Date. That as a condition precedent to the taking effect of this ordinance, the Grantee shall file its acceptance hereof with the Grantor's Clerk within 30 days of adoption of this ordinance. The effective date of this ordinance shall be the date upon which the Grantee files such acceptance.

SECTION 18. Waiver. That failure or delay of either party hereto in giving a notice of default or seeking enforcement of this Agreement shall not constitute a waiver of any default. Except as otherwise expressly provided in this Agreement, any failure or delay by another party in asserting any of its rights or remedies as to any default shall not operate as a waiver of any default or of any such rights or remedies or deprive such party of its right to institute and maintain any actions or proceedings which it may deem necessary to protect, assert or enforce any such rights or remedies.

SECTION 19. Adoption Schedule. That this ordinance was passed on the first reading at a regular meeting of the City Council on the 28th day of August, 2007, and adopted on the second/final reading at a regular meeting of the City Council on the 11th day of September, 2007.

BY: [signature]
Harry C. Goode, Jr., Mayor

ATTEST:

[signature]

Catherine L. Baker, Assistant City Clerk

Ordinance No. 2007-67

STATE OF FLORIDA
COUNTY OF BREVARD
CITY OF MELBOURNE

This is to certify that the foregoing is a true & correct copy of Ordinance No. 2007-67, witness my hand and seal this 13th day of September, 2007.
Cathleen A. Wysor, City Clerk

By: [signature]
Catherine L. Baker
Assistant City Clerk

MELBOURNE * THE HARBOR CITY * 1969

THE SPACE COAST'S NEWSPAPER
FLORIDA TODAY
PUBLISHED IN BREVARD COUNTY

RECEIVED

Published Daily

SEP 6 2007

OFFICE OF CITY CLERK
Melbourne, Florida

STATE OF FLORIDA
COUNTY OF BREVARD

Before the undersigned authority personally appeared **MAUREEN MALECHUK** who on oath says that she is **LEGAL ADVERTISING CLERK** of the **FLORIDA TODAY**, a newspaper published in Brevard County, Florida; that the attached copy of advertising being a **LEGAL NOTICE** **(AD#892076-$207.43)** in the matter of **CITY OF MELBOURNE** The ______ Court **NOTICE OF ORDINANCES** was published in the **FLORIDA TODAY** in the issues of **SEPTEMBER 1, 2007** affiant further says that the said **FLORIDA TODAY** is a newspaper in said Brevard County, Florida, and that the said newspaper has heretofore been continuously published in said Brevard County, Florida, regularly as stated above, and has been entered as periodicals matter at the post office in **MELBOURNE** in said Brevard County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in said newspaper.

Maureen Malechuk
(Signature of Affiant)

Sworn to and subscribed before this **1ST DAY OF SEPTEMBER, 2007**

Linda L. Braud
(Signature of Notary Public)

LINDA L. BRAUD
MY COMMISSION EXPIRES May 4, 2009
#DD 422930
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

LINDA L. BRAUD
(Name of Notary Typed, Printed or Stamped)

Personally Known ✓ or Produced Identification ______
Type Identification Produced ______

AD#892076-9/1,2007

LEGAL NOTICE

Notice is hereby given that the Melbourne City Council, Brevard County, Florida intends to adopt the following ordinances:

ORDINANCE NO. 2007-66

AN ORDINANCE OF THE CITY OF MELBOURNE, BREVARD COUNTY, FLORIDA, AMENDING CHAPTER 28 OF THE CODE OF ORDINANCES, ENTITLED "STREETS, SIDEWALKS AND OTHER PUBLIC PLACES" AS IT RELATES TO THE ABANDONMENT OF PUBLIC RIGHTS-OF-WAY AND EASEMENTS; MAKING FINDINGS; PROVIDING FOR THE REPEAL OF SECTIONS 28-101 THROUGH 28-106; PROVIDING FOR A NEW SECTION 28-101, PURPOSES AND METHODS; PROVIDING FOR A NEW SECTION 28-102, DEFINITIONS; PROVIDING FOR A NEW SECTION 28-103, FILING FEE; PROVIDING FOR A NEW SECTION 28-104, PETITION APPLICATION PROCEDURES; PROVIDING FOR A NEW SECTION 28-105, REVIEW PROCEDURE; PROVIDING FOR A NEW SECTION 28-106, REVIEW CRITERIA; PROVIDING FOR A NEW SECTION 28-107, PUBLIC HEARING AND NOTICE REQUIREMENTS; PROVIDING FOR A NEW SECTION 28-108, COUNCIL ACTION EVIDENCED BY AN ORDINANCE; PROVIDING FOR A NEW SECTION 28-109, RECORDATION OF THE ABANDONMENT ORDINANCE; PROVIDING FOR THE REPEAL OF ORDINANCES IN CONFLICT HEREWITH; PROVIDING FOR SEVERABILITY AND INTERPRETATION; PROVIDING AN EFFECTIVE DATE; AND PROVIDING AN ADOPTION SCHEDULE.

ORDINANCE NO. 2007-67

AN ORDINANCE OF THE CITY OF MELBOURNE, BREVARD COUNTY, FLORIDA, GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF MELBOURNE; PROVIDING THAT THE GRANTOR SHALL NOT BE LIABLE FOR CERTAIN ACCIDENTS AND DAMAGE; PROVIDING THAT THE FRANCHISEE'S RATES AND REGULATIONS SHALL BE SUBJECT TO REGULATION AS PROVIDED BY LAW; SPECIFYING THE CONSIDERATION FOR THE FRANCHISE; PROVIDING FOR CERTAIN RESTRICTIONS UPON THE CITY; SETTING FORTH REQUIREMENTS WITH REGARD TO THE GRANTING OF FRANCHISES TO OTHER LEGAL ENTITIES; SPECIFYING CERTAIN CONDITIONS UNDER WHICH THE FRANCHISEE MAY WITHHOLD CERTAIN PORTIONS OF FRANCHISE FEE PAYMENTS TO THE CITY; SETTING FORTH THE RESULTS OF A DEFAULT BY THE CITY OR BY THE FRANCHISEE; PROVIDING FOR TERMINATION OF THE FRANCHISE AGREEMENT; PROVIDING FOR EXAMINATION OF THE FRANCHISEE'S RECORDS; REPEALING ORDINANCE NOS. 72-28 AND 78-07; PROVIDING FOR AN EFFECTIVE DATE; AND PROVIDING AN ADOPTION SCHEDULE.

The ordinances will be considered for adoption by the City Council at its September 11, 2007 meeting in the Council Chamber, Melbourne City Hall, 900 E. Strawbridge Avenue, Melbourne. The meeting will begin immediately following adjournment of the Budget Public Hearing scheduled at 6:30 p.m. Copies are available for inspection by the public in the City Clerk's Office in City Hall. All interested parties may appear at this meeting and be heard with respect to the adoption of the ordinances. Written comments may be submitted at or before the meeting. Correspondence should be addressed to the City Clerk, 900 East Strawbridge Avenue, Melbourne, FL 32901. The public hearing may be continued from time to time.

In accordance with the Americans with Disabilities Act and Section 286.26, Florida Statutes, persons with disabilities needing special accommodation to participate in this meeting should contact the City Clerk's Office (321-953-6255) at least 48 hours prior to the meeting.

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 2007-67
BY FLORIDA POWER & LIGHT COMPANY

City of Melbourne, Florida October 1, 2007

Florida Power & Light Company does hereby accept the electric franchise in the City of Melbourne, Florida, granted by Ordinance No. 2007-67, being:

AN ORDINANCE OF THE CITY OF MELBOURNE, BREVARD COUNTY, FLORIDA, GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF MELBOURNE, PROVIDING THAT THE GRANTOR SHALL NOT BE LIABLE FOR CERTAIN ACCIDENTS AND DAMAGE; PROVIDING THAT THE FRANCHISEE'S RATES AND REGULATIONS SHALL BE SUBJECT TO REGULATION AS PROVIDED BY LAW; SPECIFYING THE CONSIDERATION FOR THE FRANCHISE; PROVIDING FOR CERTAIN RESTRICTION UPON THE CITY; SETTING FORTH REQUIREMENTS WITH REGARD TO THE GRANTING OF FRANCHISES TO OTHER LEGAL ENTITIES; SPECIFYING CERTAIN CONDITIONS UNDER WHICH THE FRANCHISEE MAY WITHHOLD CERTAIN PORTIONS OF FRANCHISE FEE PAYMENTS TO THE CITY; SETTING FORTH THE RESULTS OF A DEFAULT BY THE CITY OR BY THE FRANCHISEE; PROVIDING FOR TERMINATION OF THE FRANCHISE AGREEMENT; PROVIDING FOR EXAMINATION OF THE FRANCHISEE'S RECORDS; REPEALING ORDINANCE NOS. 72-28 AND 78-07; PROVIDING FOR AN EFFECTIVE DATE; AND PROVIDING AN ADOPTION SCHEDULE.

which was passed and adopted on September 11, 2007.

This instrument is filed with the City Clerk of the City of Melbourne, Florida, in accordance with the provisions of Section 19 of said Ordinance.

FLORIDA POWER & LIGHT COMPANY

By________________________
Jeffrey S. Bartel, Vice President

ATTEST:

J. E. Leon, Assistant Secretary

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 2007-67 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City Clerk of the City of Melbourne, Florida on this ______ day of OCT 1 2007, 2007.

City Clerk, City of Melbourne, Florida

CATHY WYSOR, CITY CLERK

J:\JBGC\law\PMR\FPL\Franchise\Melbourne (City of)\FSE Acceptance.doc

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ORDINANCE NO. 60-2007

Expires: October 30, 2037

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF TITUSVILLE, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Commission of the City of Titusville, Florida recognizes that the City of Titusville and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of Titusville does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, there is currently in effect a franchise agreement between the City of Titusville and FPL, the terms of which are set forth in City of Titusville Ordinance No. 7-1983, passed and adopted January 11, 1983, and FPL's written acceptance thereof dated January 26, 1983 granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"); and

WHEREAS, FPL and the City of Titusville desire to enter into a new agreement (New Franchise Agreement) providing for the payment of fees to the City of Titusville in exchange for the nonexclusive right and privilege of supplying electricity and other services within the City of Titusville free of competition from the City of Titusville, pursuant to certain terms and conditions, and

WHEREAS, the City Commission of the City of Titusville deems it to be in the best interest of the City of Titusville and its citizens to enter into the New Franchise Agreement prior to expiration of the Current Franchise Agreement;

NOW, THEREFORE, BE IT ORDAINED BY THE CITY COMMISSION OF THE CITY OF TITUSVILLE, FLORIDA:

Section 1. Grant of Franchise. There is hereby granted to Florida Power & Light Company, its successors and assigns (hereinafter called the "Grantee"), for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, public rights-of-way and other public places (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City of Titusville, Florida, and its successors (hereinafter called the "Grantor"), in accordance with the National Electrical Safety Code and Grantee's customary practices with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, substations, foundations, supports, supporting and containing structures, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (hereinafter called "facilities"), for the purpose of supplying electricity and other directly electric-related services to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 2. Location of Grantee's Facilities; Interpretation. (a) The facilities of the Grantee shall be installed, located, removed or relocated so as to not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress from and ingress to abutting property. It is the intent of the foregoing provision that all lanes of travel shall remain accessible for use by vehicular traffic. To avoid conflicts with traffic, the location or relocation of all facilities shall be made as representatives of the Grantor may prescribe in accordance with the Grantor's reasonable rules and regulations, as revised, repealed, or promulgated from time to time, with reference to placing and maintaining said facilities in, under, upon, along, over and across said public rights-of-way; provided, however, that such rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b) shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate, safe, and efficient electric service to all of its customers; and (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until either (i) widening or other work changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with motor vehicular traffic. It is agreed that unless replaced, supplemented, repealed, suspended, terminated, or amended by the Grantor, the Grantor's reasonable rules and regulations to be used by the Grantee shall include, but not be limited to, the Manual of Uniform Minimum Standards for Design, Construction, and Maintenance for Streets and Highways, May 2005 edition, and published by the Florida Department of Transportation; and the Utility Accommodation

Guide, dated August 2004, also published by the Florida Department of Transportation; and such other rules and regulations as may be applicable, in all cases as any such rules and regulations, including the aforementioned Manual of Uniform Minimum Standards and Utility Accommodation Guide may be amended or issued in new editions from time to time. Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should be installed near the outer boundaries of the public rights-of-way to the extent possible. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of this Section, except, however, the Grantee shall be entitled to reimbursement of its costs from others and as may be provided by law, as such laws may be amended from time to time.

Section 3. Grantor's Liability. The Grantor shall in no way be liable or responsible for any accident, personal injury, property damage or any claim or damage that may occur in the construction, installation, operation, removal, repair, relocation, or maintenance by the Grantee, its employees, agents, contractors, subcontractors, sublessees or licensees of any of the Grantee's facilities or operations, or that may occur as the result of any omission to do any of the foregoing by the Grantee, its employees, agents, contractors, subcontractors, sublessees or licensees, in connection with or relation to its facilities hereunder. The acceptance of the franchise granted pursuant to this New Franchise Agreement by the Grantee shall be deemed an agreement on the part of the Grantee to indemnify the Grantor, its officials, employees, and agents, and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee or other third party arising from the construction, installation, operation, removal, repair, or maintenance of its facilities hereunder. The Grantor agrees that neither it nor its officers, employees, or agents, all in their official capacity, shall be indemnified to the percentage of its or their fault in an accident or other occurrence that Grantor or its officers, employees, agents, or volunteers, all in their official capacity, is responsible for in any incident for damages or injuries (including but not limited to injury or death) arising from the gross negligence and wanton, willful, and intentional misconduct of the Grantor or its officers, employees, agent, or volunteers. For an additional Ten Dollars ($10.00) paid to the Grantee, and for other good and valuable consideration, the receipt of which is hereby acknowledged by the Grantee, the Grantee agrees that it has received sufficient consideration for its agreement to indemnify the Grantor as set forth above.

Section 4. Notice to Grantor of Proposed Changes in Rules or Rates. Except as otherwise provided by this Franchise Agreement, all rates and rules and regulations established by the Grantee from time to time shall be subject to such regulation as may be provided by law.

Section 5(a). Consideration for Franchise. As a consideration for this franchise, the Grantee shall pay to the Grantor, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this Franchise

Agreement, an amount which, when added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending 60 days prior to each such payment will equal to 5.9% of the Grantee's billed revenues, less actual write-offs, from sales of electrical energy within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment, and in no event shall payment for the rights and privileges granted herein exceed 5.9% of such revenues for any monthly billing period of the Grantee.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 7-1983, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

<u>Section 5(b)</u>. If during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Brevard County, Florida, where the number of Grantee's active electrical customers is equal to or less than the number of

Grantee's active electrical customers within the incorporated area of the Grantor, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 5.9% of the Grantee's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under the same terms and conditions as specified in Section 5(a) hereof, the Grantee, upon written request of the Grantor, shall negotiate and enter into a new franchise agreement with the Grantor in which the percentage to be used in calculating monthly payments under Section 5(a) hereof shall be no greater than that percentage which the Grantee has agreed to use as a basis for the calculation of payments to the other Brevard County municipality, provided, however, that such new franchise agreement shall include additional benefits to the Grantee, in addition to all benefits provided herein, at least equal to those provided by its franchise agreement with the other Brevard County municipality. Subject to all limitations, terms and conditions specified in the preceding sentence, the Grantor shall have the sole discretion to determine the percentage to be used in calculating monthly payments, and the Grantee shall have the sole discretion to determine those benefits to which it would be entitled, under any such new franchise agreement.

Section 6. Consideration; Non-Competition by City in the Provision of Electric Service. As a further consideration, during the term of this Franchise Agreement or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or electric energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies); and (c) not to seek to have the Grantee transmit and/or distribute electric capacity and/or electric energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at any other location(s). Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or electric energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or electric energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or electric energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have 90 days to evaluate the offer and, if the Grantee offers rates, terms and conditions which are equal to or better than those offered by the other person, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or electric energy on such equal or better terms to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to rates, terms and conditions which equal or better the other person's offer, then Grantor may proceed with the other person's offered sale and purchase arrangement and all of the terms and conditions of this Franchise Agreement shall remain in effect except as otherwise provided herein.

Section 7. Grantor's Approval of Competing Electric Service. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee reasonably determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this Franchise Agreement if such terms and conditions are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 150 days advance written notice, of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 150 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee reasonably determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this Franchise Agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice.

Section 8. Legal or Regulatory Change Authorizing Retail Competition in the Sale of Electricity. 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 incorporated 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 incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee reasonably determines that its obligations hereunder, or otherwise resulting from this Franchise Agreement 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 Agreement if such competitive disadvantage is, in the reasonable determination of the Grantee, not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 150 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the specific consequences of such action which resulted in the competitive disadvantage, and the objective basis or bases of the competitive disadvantage. The Grantor shall then have 150 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is, in the reasonable determination of the Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this Franchise Agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Notwithstanding the foregoing, upon written request of the Grantor within the 150 day period for a face to face meeting between representatives of the Grantor and Grantee, Grantee agrees that it shall meet with Grantor prior to terminating the franchise agreement. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge FPL's reasonable determination of competitive disadvantage leading to termination under Sections 7 and/or 8.

Section 9. Default. Failure on the part of the Grantee to comply in any substantial or material respect with any of the provisions of this Franchise Agreement shall be grounds for forfeiture of this franchise, but no such forfeiture of this franchise shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is a final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require. Such final determination by a court of competent jurisdiction, including any final appellate determination or ruling, shall allow Grantor to proceed with its choice of remedies, provided, however, that the Grantor may, in its discretion, grant such additional time to the Grantee for compliance as the Grantor determines are in the best interests of Grantor and Grantor's citizens. Non-substantial or non-material defaults or failures by the Grantee shall be remediable pursuant to any available legal remedies.

Section 10. Grantee's Remedies in the Event of Defaults by Grantor. Failure on the part of the Grantor to comply in any substantial or material respect with any of the provisions of this ordinance, including but not limited to: (a) denying the Grantee use of public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms and conditions of this Franchise Agreement; (c) unreasonable delay in issuing the Grantee a right-of-use permit, if any, to construct its facilities in public rights-of-way, shall constitute breach of this Franchise Agreement and entitle the Grantee to withhold all or part of the payments provided for in Section 5 hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination in the matter. The Grantor recognizes and agrees that nothing in this Franchise Agreement constitutes or shall be deemed to constitute a waiver of the Grantee's sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right.

Section 11. Termination and Renewal. Grantor and Grantee agree that the New Franchise Agreement created by this ordinance and Grantee's acceptance hereof, shall terminate by its own terms at 12:01 a.m. thirty (30) years after the effective date of the Franchise Agreement.

Section 12. Examination or Audit of Grantee's Records; Waiver of Claims. The Grantor may, upon reasonable notice and within 90 days after each anniversary date of this Franchise Agreement, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained; provided that, in all events, Grantee agrees that all said records shall be made available at Grantee's expense to Grantor in Palm Beach County, Dade or Brevard County, Florida. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this Section shall not be conducted by any third party employed by the Grantor whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

Grantor may, upon reasonable notice given within one year following the Grantee's acceptance of this New Franchise Agreement, conduct a final audit of the Grantee's records relating to the calculation of the franchise payments that have been made to Grantor pursuant to the Current Franchise Agreement embodied in Ordinance No. 7-1983. Other than any claims arising from alleged fraud, deceit, misrepresentation, intentional withholding of information, or other similar intentional misconduct by Grantee in relation to the calculation or remittance of the franchise payments under the Current Franchise Agreement, Grantor waives, settles and bars all claims relating to the amounts paid by the Grantee under the Current Franchise Agreement embodied in Ordinance No. 7-1983. Grantor agrees that this instrument waives, settles and bars any claim by Grantee, its successors or assigns of, and any right of Grantee, its successors or assigns to claim, a breach, material or otherwise, of the franchise by the Grantor embodied in Ordinance No. 7-1983.

Section 13. Annexation. Upon the Grantor's annexation of any property and appropriate written notice to Grantee, the portion of Grantee's electrical system located within such annexed territory, and in, under, over, and upon the streets, alleys, rights-of-way, or public grounds of such annexed territory, shall be subject to all the terms of this New Franchise Agreement within ninety (90) days of the Grantee's receiving written notice by U.S. certified mail return receipt requested of such annexation from the

Grantor, which notice shall include the legal description(s) of the property annexed and the addresses of the individual properties within the annexed property to the extent that information is available to the City.

Section 14. Severability; Invalidation of Portions of Ordinance. If any section, sentence, clause or phrase of this Ordinance is held to be invalid or unconstitutional by any court of competent jurisdiction, then said holding in no way affects the validity of the remaining portions of this Ordinance. Notwithstanding the foregoing, it is expressly provided that if any of the provisions of Sections 1, 2, 3, 5, 6, 7, 8, 9 or 10 are found or adjudged to be invalid, void or of not effect, the ordinance shall be null and void and of no force and effect.

Section 15. Repeal of Prior Franchise Ordinances. Ordinance No. 7-1983 passed and adopted January 11, 1983, and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

Section 16. Venue. This New Franchise Agreement shall be governed by and construed according to the laws of the United States and of the State of Florida, and venue shall be in Brevard County, Florida.

Section 17. Effective Date. As a condition precedent to the taking effect of this ordinance, the Grantee shall file its acceptance hereof with the Grantor's Clerk within 30 days of adoption of this ordinance. The effective date of this ordinance shall be the date upon which the Grantee files such acceptance.

Section 18. Waiver. Failure or delay of either party hereto in giving a notice of default or seeking enforcement of this Agreement shall not constitute a waiver of any default. Except as otherwise expressly provided in this Agreement, any failure or delay by another party in asserting any of its rights or remedies as to any default shall not operate as a waiver of any default or of any such rights or remedies or deprive such party of its right to institute and maintain any actions or proceedings which it may deem necessary to protect, assert or enforce any such rights or remedies.

PASSED on first reading this 25th day of September, 2007.

PASSED AND ADOPTED on second reading this 9th day of October, 2007.

CITY OF TITUSVILLE, FLORIDA

By: Ronald G. Swank
Ronald G. Swank, Mayor

ATTEST:

By: Wanda F Wells
Wanda F. Wells, City Clerk

APPROVED AS TO FORM AND LEGALITY

Dwight Severs
Dwight Severs, City Attorney

I HEREBY CERTIFY THAT THE ABOVE AND FOREGOING IS A TRUE AND CORRECT COPY OF THE ORIGINAL ON FILE IN THIS OFFICE.
CITY CLERK'S OFFICE
CITY OF TITUSVILLE, FLORIDA
DATE 10-16-07
Wanda F Wells

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ORDINANCE NO. 98-33

AN ORDINANCE OF THE VILLAGE COUNCIL OF THE VILLAGE OF WELLINGTON, FLORIDA, GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE WITHIN THE INCORPORATED AREA OF THE VILLAGE; IMPOSING PROVISIONS AND CONDITIONS RELATING TO SUCH FRANCHISE; PROVIDING FOR ACCEPTANCE BY FLORIDA POWER & LIGHT; PROVIDING FOR AN EFFECTIVE DATE; PROVIDING FOR REPEAL OF ORDINANCES IN CONFLICT; PROVIDING FOR RATIFICATION OF PRIOR ORDINANCES IN THE EVENT FRANCHISE NOT ACCEPTED; AND FOR OTHER PURPOSES.

BE IT ORDAINED BY THE VILLAGE COUNCIL OF THE VILLAGE OF WELLINGTON, FLORIDA, that:

Section 1. There is hereby granted to Florida Power & Light Company, its successors and assigns (hereinafter called "Grantee") for the period of thirty (30) years, commencing June 25, 1996, the non-exclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, and rights-of-way, and other public places owned by the Village of Wellington (hereinafter called "Public Rights-of-Way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the Village of Wellington, Florida, and its successors (hereinafter called "Grantor") in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's electric light and power operations (hereinafter called "facilities"), for the purpose of supplying electricity and other services related to the supply of electricity to the Grantor, its successors, and persons within and beyond the boundaries thereof.

Section 2. The facilities of the Grantee shall be installed, located or relocated so as not to unreasonably interfere with drainage canals in Public Rights-of-Way which existed prior to the installation of Grantee's facilities, or with traffic over the Public Rights-of-Way or with reasonable egress from and ingress to abutting property. To avoid conflict with such drainage canals and traffic, the location or relocation of all facilities shall be made as representatives of the Grantee may prescribe in accordance with reasonable rules and regulations with reference to the placing and maintaining in, under, upon, along, over and across said Public Rights-of-Way; provided, however, that such rules or regulations shall not prohibit the Grantee's use of said Public Rights-of-Way or unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers. When any portion of a street is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the street so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation and in compliance with the standards under which the street was originally constructed. Grantor shall not be liable to the Grantee for any cost or expense in connection with such location or relocation of Grantee's facilities made necessary by the Grantor's improvement of any of the present and future Public Rights-of-Way used or occupied by the Grantee hereunder, except, however, the Grantee shall be entitled to reimbursement of its costs from funds available from sources other than the Grantor as may be provided by law and for costs resulting from improvement of any drainage canal not in existence on the effective date hereof.

Section 3. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its electric Facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage, or expense which may accrue to the Grantor by reason of the existence of Grantee's facilities in the Public Rights-of-Way or negligence, default or misconduct of the Grantee in the construction, operation, or maintenance of its electric Facilities hereunder.

Section 4. All rates, rules and regulations established by the Grantee from time to time shall at all times be reasonable and the Grantee's rates for electricity shall at all times be subject to such regulation as may be provided by law.

Section 5. As a consideration for this franchise, the Grantee shall pay to the Grantor no later than the end of Florida Power & Light Company's first monthly billing period ending after the effective date of this ordinance and no later than the end of each succeeding monthly billing period during the term of franchise, an amount which added to the amount of all licenses, excises, fees, charges, and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against Florida Power & Light Company's property, business or operations and those of its subsidiaries during Florida Power & Light Company's monthly billing period ending thirty (30) days prior to each such payment will equal five percent (5%) of Florida Power & Light Company's billed revenues, less actual writeoffs, from the sale of electrical energy to residential, commercial and industrial customers within the incorporated areas of the Grantor for the monthly billing period ending thirty (30) days prior to each such payment, and in no event shall payment for the rights and privileges granted in the franchise exceed five percent (5%) of such revenues for any monthly billing period of Florida Power & Light Company.

Section 6. As a further consideration of this franchise, the Grantor agrees (a) not to engage in the business of distributing and selling electricity at retail during the term of this franchise or any extension thereof in competition with the Grantee and (b) not to itself distribute, or seek to have the Grantee transmit and/or distribute, electric power generated by or on behalf of the Grantor at one location to the Grantor's or any other retail customer's facilities at any other location(s).

Section 7. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions that the Grantee considers more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this franchise. Such termination shall be effective on the last day of the month in which written notice termination is delivered to the Grantor's Clerk. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, inform the Grantor of such terms and conditions.

Section 8. If as a direct or indirect consequence of any legislative, regulatory or other action by the United State 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 incorporated 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 incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee 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. Such termination shall be effective on the last day of the month in which written notice of termination is delivered to the Grantor's Clerk. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, inform the Grantor of the circumstances which resulted in the exercise of its right to terminate.

Section 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this ordinance shall be grounds for forfeiture of this grant, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall, as soon as practicable and in any event not later than six (6) months after such final determination, make good the default before a forfeiture shall result with the right in the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 10. Failure on the part of the Grantor to comply in any substantial respect with any of the provisions of this ordinance, including: (a) denying the Grantee use of Public Rights-of-Way for reasons other than unreasonable interference with traffic, drainage system use, operation or maintenance; (b) imposing conditions for use of Public Rights-of-Way contrary to Florida law and contrary to FPL's standard practices; or (c) unreasonable delay in the issuance of a permit, if any, to construct its facilities in Public Rights-of-Way, shall constitute a breach of this franchise. Grantee shall notify the Grantor of any such breach in writing and the Grantor shall remedy such breach as soon as practicable and in any event by not later than ninety (90) days. Should the breach remain unresolved after ninety (90) days, FPL, at its the sole discretion, may withhold all or part of the payments provided for in Section 5 hereof until such time as the breach is remedied or a court of competent jurisdiction has reached a final determination in the matter. Grantor recognizes and agrees that nothing in this franchise constitutes or shall be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right to obtain a greater right than is granted herein.

Section 11. Grantor may, upon reasonable notice and within ninety (90) days after each anniversary date of this franchise, at Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this section shall not be conducted by any third party employed by the Grantor whose fee for conducting such audit is contingent on findings of the audit.

Section 12. The provisions of this ordinance are interdependent upon one another, and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect, the entire ordinance shall be null and void and of no further force or effect.

Section 13. As used herein, "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an unincorporated association, a joint venture, a governmental authority, or any other entity of whatever nature.

Section 14. The Grantee shall file its acceptance of the franchise with the Grantor's Clerk within 30 days of adoption hereof. The effective date of this ordinance shall be the date upon which the Grantee files such acceptance.

Section 15. Once the Grantee files its acceptance of the franchise granted herein, this ordinance shall replace Ordinance No. 96-17, as modified by Ordinance No. 97-07, and all ordinances and parts of ordinances in conflict herewith are hereby repealed. Until Grantor files its acceptance of this franchise, the franchise granted by Ordinance No. 96-17, as modified by Ordinance No. 97-07, shall remain in full force and effect and is hereby ratified.

PASSED this 10th day of November, 1998, on first reading.

PASSED AND ADOPTED this 24th day of November, 1998 on second and final reading.

VILLAGE OF WELLINGTON, FLORIDA

	FOR	AGAINST
BY: Dr. Carmine A. Priore, Mayor	✓	
Paul A. Adams, Vice Mayor	✓	
Mary K. Foster, Councilmember	✓	
Thomas Wenham, Councilmember	✓	
Albert Paglia, Councilmember	✓	

ATTEST:

By: Awilda Rodriguez, Village Clerk

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APPENDIX C

ERCOT — Your Power. Our Promise.

ERCOT 2018-19 Budget

The Electric Reliability Council of Texas (ERCOT), which operates the electric grid and manages the competitive electric market that serves most of Texas, has submitted its 2018-19 budget to the Public Utility Commission of Texas (PUC) for final approval. This biennial budget includes investments needed to enable the independent system operator (ISO) to continue providing electric power reliably and efficiently through an increasingly complex electric grid and electric market.

Budget summary

ERCOT anticipates maintaining a flat System Administration Fee for four years, through 2020. The 2018-19 budget is consistent with the approved 2016-17 biennial budget, and ERCOT will continue budgeting with a multi-year planning horizon.

The approved budget includes $222 million for 2018 and $228 million for 2019, including ERCOT operating expenses, project spending and debt service obligations for 2018 and 2019.

No change to System Administration Fee

Most of ERCOT's revenues come from a System Administration Fee, which is included in wholesale power bills and ultimately passed through to consumers. The approved budget includes no change to the System Administration Fee, which is 55.5 cents per MWh. The cost to operate the electric grid and market for most of Texas averages about 50-60 cents per month, or about $7 per year, for the average residential household.

Efficient operations

ERCOT management and staff are dedicated to running efficient operations. In recent years, ERCOT has increased its efforts to actively manage vendor relationships, reduce costs through competitive processes, and carefully examine every hiring decision.

ERCOT management continues to seek opportunities to improve operational efficiency. System consolidation, automation and fast-path projects are among the initiatives to maximize efficiency. ERCOT will continue cost-management initiatives that have enabled the ISO to postpone or minimize fee increases in spite of additional costs associated with the increasingly complex electric market.

Budget drivers

In addition to maintaining consistency with the 2016-17 budget, ERCOT is committed to maintaining or improving the ISO's long-term financial integrity by continuing to decrease outstanding debt. ERCOT also has incorporated key initiatives to help address the changing resource mix, improve training and maintain complex hardware and software systems.

ERCOT continues to develop new tools and adapt its operating practices to manage a changing resource mix. The ISO also works with stakeholders to identify and implement rules to deliver grid reliability and support the success of the competitive market.

Government Contact: Rob Orr, rob.orr@ercot.com;
Media Contact: Robbie Searcy, robbie.searcy@ercot.com, or Leslie Sopko, leslie.sopko@ercot.com

Schenker, Pamela

From: Paul Griffin -- Energy Fairness <paul@energyfairness.org>
Sent: Thursday, February 21, 2019 10:34 AM
To: Schenker, Pamela
Subject: Answer to question posed on February 11

Good Morning Pam, when I spoke before the FIEC on Monday, February 11, Mr. Ciupalo had asked **what portion of the higher rates in states with deregulated electricity markets were due to stranded costs when a state went from a regulated market to a deregulated market.**

In researching the answer to this question,

we found the following: If the reference data is purely the kwh charge in cents/kwh, the charge for stranded costs would not be included in the comparison [comparing deregulated to regulated rates]. Energy Information Administration data states that: ***The electric revenue used to calculate the average price of electricity to ultimate consumers is the operating revenue reported by the electric utility. Operating revenue includes energy charges, demand charges, consumer service charges, environmental surcharges, fuel adjustments, and other miscellaneous charges. Electric utility operating revenues also include State and Federal income taxes and taxes other than income taxes paid by the utility. It does not mention other government fees such as a transition charge***

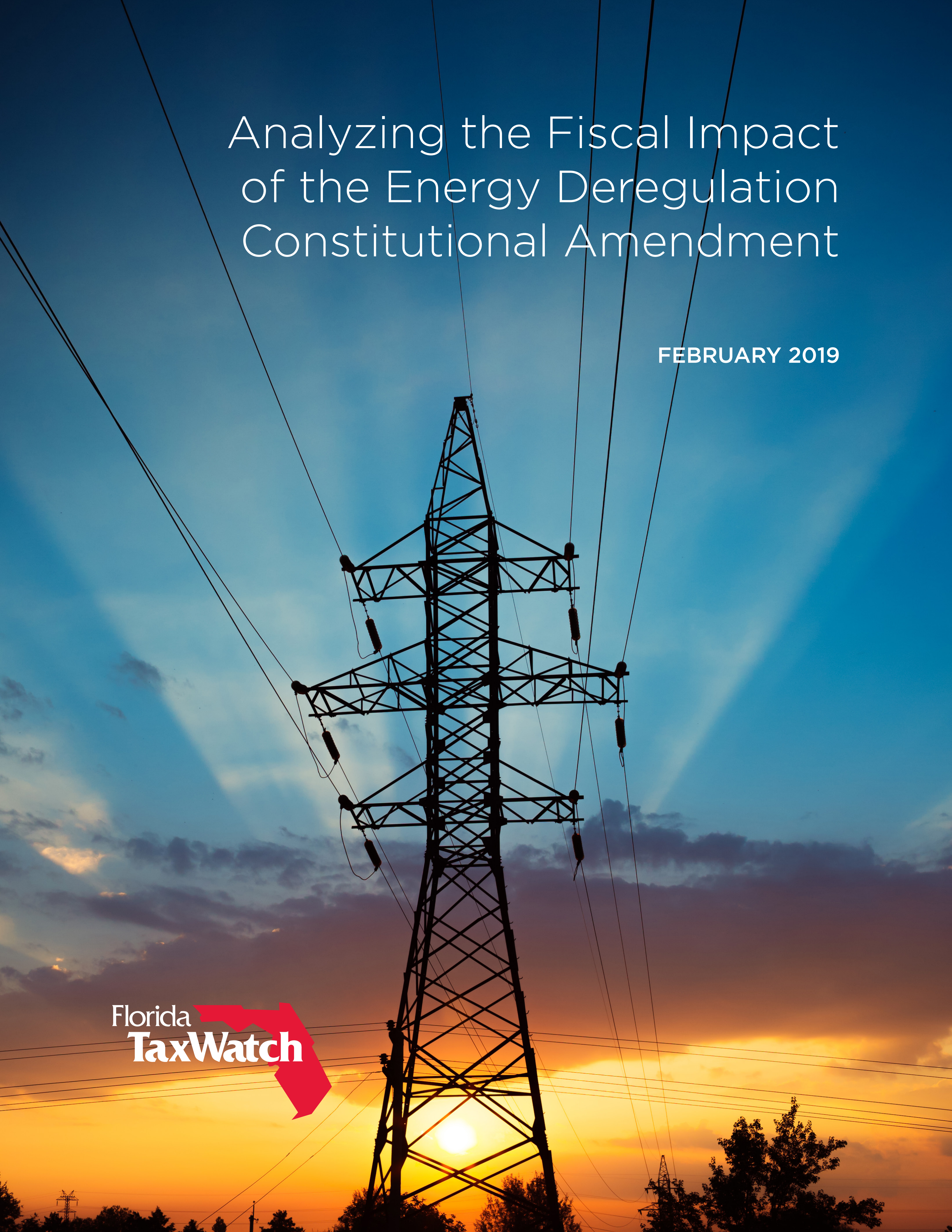
I hope that answers his question. Could you please forward this email to him and see if he needs additional information.

Thank you.

Paul Griffin
Energy Fairness
Executive Director
202-577-5454

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 25 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.

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energyfairness.org

February 21, 2019

Financial Impact Estimating Conference
Office of Economic and Demographic Research
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Tallahassee, Florida 32399-6588

FTI Consulting was retained by Energy Fairness to prepare a report for the Financial Impact Estimating Committee describing our analysis of the likely impacts that would follow passage of the Florida Changes to Energy Market Initiative.

FTI is a worldwide firm of more than 4,600 employees located in 28 countries on six continents. Our energy professionals have extensive experience addressing changes in the structure of the power industry that allow us to conduct this examination of the proposed initiative in Florida.

The attached report clearly supports the conclusion that passage of the Initiative will come at significant cost to state and local government. As you will find in the report, this impact to be a minimum of almost $1 billion per year. Additionally, we asked FTI to address issues surrounding stranded costs and the impact of the passing of Amendment 5 in 2018 on government ability to adjust for lost revenue. Finally, FTI has taken a thorough review of the oft referenced Perryman report and its failure to accurately predict costs to Floridians in a deregulated electricity market.

We appreciate the opportunity to present this information and hope that it informs the financial impact information that this Conference is required to provide concerning the Initiative.

FTI CONSULTING

FEBRUARY 21, 2019

POTENTIAL IMPACTS OF INITIATIVE #18-10 ON STATE AND LOCAL REVENUES IN FLORIDA

A REPORT TO THE FINANCIAL IMPACT ESTIMATING COMMITTEE
ON BEHALF OF ENERGY FAIRNESS

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Executive Summary

FTI Consulting ("FTI") has been retained by Energy Fairness ("EF") to prepare a report for the Financial Impact Estimating Committee ("FIEC" or "the Committee") describing our analysis of the likely impacts that would follow passage of the Florida Changes to Energy Market Initiative (Initiative #18-10, hereinafter "the Initiative"), which would create a new article in the state constitution that guarantees utility customers in Florida the right to choose their own energy provider, creating what is commonly referred to as a deregulated market.[1]

Herein, we report our findings and describe a number of major concerns with the proposed measure. We find that the following outcomes are likely to occur if the Initiative is passed when put to the voters later this year:

- Revenues for state and local governments will decrease by a minimum of about $930 million per year.
- Additional reductions for certain revenue streams are also possible.
- Costs to the State will increase to a degree that is not yet fully known since some costs cannot be reliably estimated and others may be passed on to electric customers in Florida rather than being borne directly by the government.
- The State will be exposed to significant risks, which do not presently lend themselves to quantification, if private industry's entrance in the market does not create the competitive conditions envisioned by proponents of the Initiative.
- The benefits that the proponents of the Initiative claim will accrue to Florida's electric customers from deregulation are largely based on a single study that may methodologically flawed, is at odds with current research, and is inconsistent with observations in other markets.
- Certain aspects of Florida, particularly the bar on the imposition of new taxes, create challenges to implementing competitive markets that do not exist in other states.

The $930 million total reduction in government revenues is based on reductions in revenue streams for which there is sufficient data to make reasonable estimates. Specifically, the reduction is comprised of reductions in payments by the energy industry for property taxes, franchise fees and Gross Receipts Taxes ("GRT"). Predictable losses are summarized below.

Table 1. Readily Quantifiable Financial Impacts of the Initiative

Cost/Revenue Category	**Estimated Impact** *($millions, annual)*
Property tax	177

[1] Such markets are also commonly known as "restructured" markets. The two terms are used interchangeably herein.

Franchise fees	437
GRT	317
Total	**930**

Other reductions are possible but have not been included in our estimate. We expect additional fiscal impacts to the State in the form of increased costs. Some of these costs can be reasonably estimated, others cannot; it is also unknown whether and to what degree the State will bear certain costs or whether those costs will be borne directly to the IOUs' current customers.

We respectfully request that the Financial Impact Statement ("FIS") attached hereto as Appendix A be added to the ballot alongside the Initiative.

Background

The FIEC held its first public meeting regarding the Initiative on February 11, 2019. There, proponents, opponents, employees of the Florida Public Service Commission ("PSC") and other state and local agencies, independent experts, and the public were given the opportunity to provide commentary and evidence regarding the Initiative's likely and potential impacts.

At that meeting, proponents of the Initiative indicated that their intention in crafting its language is to implement a market modeled after the one in use in Texas, which passed legislation known as Senate Bill 7 ("SB 7") in 1999 to deregulate its electric industry.[2] The Initiative's proponents claim that deregulation in Texas has been positive for customers and that Florida will enjoy similar success if the Initiative is passed. They claim that, among other things, electricity prices in Texas have been lower as a result of deregulation, and that reduced rates, improved customer satisfaction, and economic growth are likely to accrue to Florida electricity consumers. We find evidence to the contrary.

We note that much of the evidence put before the Conference is not strictly germane to its proceedings. Discussion of rate impacts in Texas and other jurisdictions, potential issues regarding reliability planning in a deregulated market, certain implementation costs, and other factors will not necessarily impact state and local revenues in a way that should be addressed by the FIS. Nonetheless, this report comments on some of these issues in an effort to clarify and, in some cases, correct the record of these proceedings.

Additionally, FTI expects to develop a report in the coming months that provides an analysis of likely costs and risks that would transfer to Florida's electric customers and to the electric industry in Florida as a whole, including increased energy costs, reductions in the reliability of the state's electric grid, and others if the Initiative is passed in November 2020.

[2] Houston Chronicle (2016). Texas' deregulated electricity market, explained. Available at: https://www.houstonchronicle.com/local/explainer/article/texas-electric-deregulation-ERCOT-TCAP-7971360.php

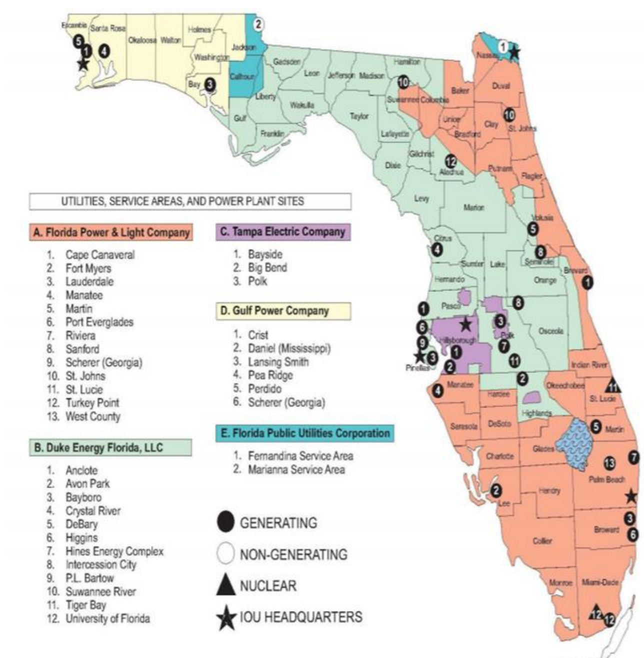
With regard to the matter of state and local revenues, the proponents claim that impacts cannot be known at this time since "[i]t is impossible to predict how the Legislature and local governments might approach" restructuring.[3] We disagree; while it is true that the Initiative provides almost no guidance regarding a host of important questions about how deregulation will be implemented, who will own what assets, and a number of other critical issues, the information available in the record of this proceeding and experiences in other jurisdictions clearly support the conclusion that passage of the Initiative will come at significant cost to state and local revenues.

The remainder of our report is organized as follows. First, we provide an overview of the electric industry in Florida and a brief discussion of the status of deregulation in other jurisdictions. Second, we discuss each of the findings outlined above. Third, we recap our findings regarding the impacts on state and local revenue and detail our conclusions.

Florida's Electric Industry

Florida is served by five IOUs, Florida Power & Light Company ("FP&L"), Duke Energy Florida ("Duke"), Tampa Electric Company ("TECO"), Gulf Power Company ("Gulf Power"), and Florida Public Utilities Corporation ("FPU"). Service territories for each IOU are shown below.

Figure 1. Florida IOU Service Territories[4]



[3] Florida Energy Choice (2019). Memorandum to FIEC from Citizens for Energy Choice. FIEC EDR Notebook, pg.593.
[4] Florida Public Service Commission (2017). Statistics of the Florida Electric Utility Industry, pg.4. Available at: http://www.psc.state.fl.us/Files/PDF/Publications/Reports/Electricgas/Statistics/2016.pdf

Each of the IOUs except FPU owns generation capacity to serve its customers. As of 2016, the IOUs owned approximately 70% of Florida's generating capacity, measured in net summer capacity. Generation assets for each of the other four IOUs are shown below:

Table 2. IOU Generation Capacity as of December 31, 2016 (MW)[5]

	Conventional Steam	Nuclear Steam	Combustion Turbine	Internal Combustion	Combined Cycle	Solar	Total
Duke	3,201	0	1,955	0	3,167	0	8,323
FP&L	4,382	3,453	2,018	0	16,156	131	26,140
Gulf Power	1,648	0	44	3	556	0	2,251
TECO	1,602	0	884	0	1,850	1	4,337
						Total	**41,051**

As of 2016, the IOUs owned nearly all of the solar generation in Florida and accounted for 96% of the total Demand Side Management ("DSM") programs in place in the state.[6] Approximately 72% of customer-owned solar facilities are connected to the IOU distribution networks, accounting for 76% of Florida's customer-owned generating capacity.[7] In total, approximately 79% of the load in Florida in 2016 was served by IOUs.[8, 9]

Florida's IOUs have delivered value to customers in the form of average rates for all customer classes that are comparable to, or lower than the U.S. average, a significant achievement for a market that needs to import most fuel for generation. According to data provided by the U.S. Energy Information Administration ("EIA"), the average electric cost in Florida for all customer classes was 10.42 c/kWh while the U.S. average was 10.48 c/kWh. [10]

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[5] Figures throughout this report may not add due to decimal rounding.
[6] Florida Public Service Commission (2017), p.32.
[7] Florida Public Service Commission (2017), p.31.
[8] Florida Public Service Commission (2017), p.16.
[9] IOU percentage of total sales calculated by FTI as total IOU sales as a percentage of total sales made within the Florida Reliability Coordinating Council footprint.
[10] EIA Data Browser (2018). Accessed on February 15th, 2019. Available at: https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=g000001&endsec=vg&linechart=ELEC.PRICE.US-ALL.A&columnchart=ELEC.PRICE.US-ALL.A&map=ELEC.PRICE.US-ALL.A&freq=A&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=

Our Findings

Our findings, detailed below, indicate that the passage of the Initiative would create significant risks for Florida's electric customers. Based on the language that will be put to the voters, the scope of the Initiative appears to be far broader than is the norm in deregulated markets in the U.S. Its passage would jeopardize important revenue streams for local governments by creating conditions under which the IOUs' assets would likely be sold at a loss compared to book values. State tax revenues are also likely to be affected. Additionally, electric consumers in Florida would bear significant startup and implementation costs if deregulation was enacted; these costs would be borne either directly by customers in the form of higher electric rates, indirectly through increased costs to the state, or both. Finally, Florida's long track record of affordable, reliable power discussed above would be at risk. Below, we discuss each of our specific findings that support these conclusions.

In this section, we address each of our five primary conclusions.

1. Deregulation of Florida's electric industry will reduce revenues to cities and counties. We estimate the revenue reduction to be $614 million per year.

Reductions in revenues to Florida's cities and counties will be one of the most significant and direct impacts of market deregulation. Currently, localities collect taxes from the IOUs in the form of property taxes, franchise fees, and public service taxes. These revenues, which constitute a large portion of the revenues that fund local governments, would be reduced by passage of the Initiative by more than $614 million per year, which includes reductions in payments for property taxes and franchise fees. Public service taxes could also be reduced, although we estimate the probability of that occurring and the magnitude of the potential reduction to be relatively low. Forcing the IOUs to divest their Transmission & Distribution ("T&D") assets along with their generation fleets would significantly increase losses in revenues from property taxes and franchise fees.

Property Taxes

Localities in Florida charge taxes on assets used for commercial purposes based on the value of the assets in service. For utilities, those assets include power plants, transmission lines, distribution assets, and other critical infrastructure necessary to generate and transport electricity to customers. According to data compiled by the Federal Energy Regulatory Commission ("FERC"), the four largest IOUs had approximately $76 billion of assets in service in Florida in 2017, for which they paid approximately $686 million in taxes to cities and counties.[11] Details for each of the IOUs that own generation are shown below.

[11] For purposes of clarity and simplicity, and because FPU does not own generation assets in the state, our focus is on the four largest IOUs in Florida. FPU is excluded from most calculations.

Table 3. 2017 Property Taxes Charged by Major Investor-Owned Utilities[12]

IOIU	Net plant in Service *($millions)*	Property Taxes Paid *($millions)*	Property tax as % of Net Plant in Service
Duke	15,901	129	0.81%
FP&L	47,067	475	1.01%
TECO	8,548	60	0.71%
Gulf Power	5,181	22	0.42%
Total	**76,698**	**686**	**0.89%**

Experience with deregulation in other jurisdictions indicates that, in the event of the forced divestiture associated with deregulation, plant values are likely to decrease. The book value (or net plant in service) of assets sold may differ from its market value as a standalone entity for a variety of reasons including prevailing and expected energy market conditions, investors' willingness to pay, the value the assets provide to an IOU's portfolio compared to their value as standalone entities, the investment environment in which the sale takes place, and other factors. In this instance, the investment environment in which the plants would be sold would be generally unfavorable. Of particular concern is the fact that in the event of a forced divestiture, the plants would have to be offered into the market regardless of investors' willingness to pay a reasonable cost for them and the IOUs would have no alternative to selling the plants at depressed values.

Upon the sale of the assets, their property value would be reset for tax valuation purposes. The difference between the book value of the assets and the market value as determined by the sale, is known as stranded costs.

Stranded costs = book value – market sale value

Stranded costs are impactful in two ways. First, because these plants have all been approved by the PSC, the IOUs are entitled to recovery of their cost plus the return they were authorized to earn on their asset base. As such, ratepayers will still pay for the unrecovered portion of the plants, usually over a period of between five and 20 years. Second, when the assets are re-valued for property tax purposes, a lower value means a reduced tax base for the cities and counties in which they're located. This translates directly to reduced revenues for local governments.

Observations from other jurisdictions indicate that stranded costs, which serve as a measure of how much the tax base has declined, are likely to be significant. Large stranded costs have been

[12] Federal Energy Regulatory Commission (2018). Form 1 - Electric Utility Annual Report. Accessed on February 18, 2019. Available at: https://www.ferc.gov/docs-filing/forms/form-1/data.asp?csrt=9690900342522796464

incurred in Pennsylvania, Maryland, New Jersey, California, and other jurisdictions that have undergone restructuring.

Notably, significant stranded costs were also incurred when Texas deregulated. Excluding TXU Corporation ("TXU"), which represents an unusual case discussed below, the other three IOUs in Texas lost approximately 25% of their book value upon divestiture. Below, we compare the net book value for three utilities, Texas Central Company, a subsidiary of American Electric Power ("AEP"); CenterPoint Energy ("CenterPoint"), and Texas-New Mexico Power ("TNMP") to the stranded costs they were allowed to recover upon divestiture following deregulation.

Table 4. Texas IOU Stranded Costs (excluding TXU)[13]

IOU	Book Value of Assets in Texas *($billions)*	Authorized Stranded Cost Recovery *($billions)*[14]	Stranded Cost as a % of Net Book Value
CenterPoint	32.0	4.0	13%
AEP	4.9	2.5	51%
TNMP	0.9	0.1	14%
		Average	**26%**

The book values of the assets for the Texas IOUs shown above include the value of their T&D holdings as well as their generation assets. Assuming that the ratio of the value of the Texas IOUs' T&D assets to generation assets is approximately the same as the ratio for the Florida utilities, it is reasonable to assume that, if Florida IOUs were also required to divest their generation assets, the amount of stranded costs incurred would equal approximately 26% of the of net book value. Accordingly, the $686 million paid each year in property taxes to cities and counties by the Florida IOUs would also be reduced by 26%, or by approximately $177 million each year. Passage of deregulation rules that required the Florida IOUs to divest their T&D holdings would increase that amount of revenue loss.

<u>Stranded Costs and Affiliate Transactions</u>

Affiliate transactions and stranded costs were a subject of considerable discussion at the February 11 meeting of the FIEC. Here, we feel compelled to clarify that an IOU's divestiture of its assets to an affiliate does not mitigate the impact of stranded costs.

If the generation owned by an IOU is transferred to an affiliate entity, that affiliate is, by design, held at "arm's length" from the regulated company. From a regulatory perspective, the affiliate

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[13] Analysis by FTI using data from the Texas Coalition for Affordable Power (2019), p.162 and Capital IQ

[14] Texas Coalition for Affordable Power (2019). Deregulated Electricity in Texas, A Market Annual 2018 Edition. FIEC EDR Notebook, pg.162.

functions is as any other power producer in that it will pay market prices for the assets it buys, and it will sell electricity for whatever price the market will bear.

The divesting IOU would incur stranded costs in a transaction with an affiliate in exactly the same way it would in a transaction with a non-affiliated entity. The book value of the asset would be known, and the market value would be determined in the course of the sale process. The difference is the stranded cost, which would be borne by ratepayers.

Likewise, the affiliate entity making the purchase would have no motivation to execute the transaction at favorable terms in order to reduce stranded costs. An affiliate purchaser ultimately represents one or more investors who seek some required return in order to deploy capital. While an affiliate may be a likely purchaser due to familiarity with the assets and market, it would be under no obligation to buy any assets being divested and would have no reason to pay above-market prices for purposes of minimizing stranded costs.

In the course of the proceeding, TXU has been discussed as a company that transferred its assets to affiliates and in so doing seems to have avoided incurring stranded costs. In reality, ratepayers paid approximately $1.3 billion to reimburse TXU for the its stranded costs, but it did so through a financing mechanism known as securitization, whereby TXU estimated what its stranded costs would be prior to the implementation of deregulation, received authorization from the Public Utilities Commission of Texas ("the PUCT") to recover those costs from ratepayers, and then sold that guaranteed revenue stream to a third party. In so doing, TXU's stranded costs were "avoided" in the sense that that amount was covered before deregulation was implemented.[15]

As shown in Table 4, the CenterPoint transaction generated $4 billion in stranded costs. CenterPoint spun-off its generating assets to its shareholders, creating a distinct publicly traded affiliate. Pursuant to Texas rules, the market value of this affiliate was used as a mechanism to calculate stranded costs. The creation of this affiliate did not have any impact on the recognition and recovery of stranded costs.

In total, ratepayers absorbed approximately $6.6 billion in stranded costs, in addition to the TXU's recovery of costs that otherwise would have been stranded via securitization.

Franchise Fees

Franchise fees are another important source of revenues for localities in Florida that would be at risk if deregulation is enacted. IOUs pay franchise fees to municipal or county entities for exclusive access to serve customers within a given jurisdiction as well as for access to Rights of

[15] TXU Corp (2002). TXU Corporate Update, 2001: A year of Transformation and Performance. Available at: http://media.corporate-ir.net/media_files/irol/10/102498/presentations/txu_030602.pdf

Way ("ROWs"), locations where their assets are situated.[16] Franchise fees are typically based on a percentage of the IOU's revenue and established via long-term contracts. For example:

- FP&L currently holds 181 franchise agreements with various municipalities and counties in Florida with varying expiration dates through 2048. FPL reports that these franchise agreements cover approximately 88% of FPL's retail customer base in Florida.

- TECO has franchise agreements with 13 incorporated municipalities within its service territory. These agreements have expiration dates ranging from September 2017 through August 2043.

Based on reported information retrieved from FERC Form 1s filed by the state's four major IOUs, FTI estimates that the IOUs paid $628 million in franchise fees in 2017.

Table 5. 2017 IOU Franchise Fee Payments[17]

Utility	Franchise Fees *($millions)*	% of Revenue
Duke	98	2.16%
FP&L	445	3.84%
Gulf Power	41	2.72%
TECO	44	2.23%
Total	**628**	

Since franchise fees compensate the local government for the IOU's exclusive access to customers in a given jurisdiction, restructuring may violate the agreements in place. In turn, the IOUs would have the option to cancel and/or renegotiate the agreements. Since deregulation would necessarily erode the fundamental value proposition the agreements convey, it is reasonable to conclude that re-renegotiation would result in lower payments by the IOUs and less revenue for Florida's cities and counties.

To estimate how much the franchise fee payments would decline, we reviewed data regarding Floridians' energy cost by service provided by the EIA, which reports that in 2017, on average, the cost of generation accounted for approximately 70% of energy costs for customers within the footprint of the Florida Reliability Coordination Council ("FRCC"), which covers most of Florida.[18,]

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[16] While franchise fees are quite common, a small number of entities do not charge such fees.
[17] Federal Energy Regulatory Commission (2018). Form 1 - Electric Utility Annual Report. Accessed on February 18, 2019. Available at: https://www.ferc.gov/docs-filing/forms/form-1/data.asp?csrt=9690900342522796464
[18] Gulf Power is not part of the FRCC. A similar calculation for the Southeast Subregion of the SERC Reliability Corporation. of which Gulf Power is part, determined that in that region, generation accounts for 68% of customer costs. Given the consistency between these two observations and Gulf Power's relatively small size, we determined that no adjustment to the calculations shown above was required.

[19] The cost components reported by EIA are shown below; for comparison purposes, U.S. averages are also provided.

Table 6. Average 2017 Energy Cost Components for FRCC Customers[20]

	Florida (c/kWh)	% total	U.S. (c/kWh)	% total
Generation	7.2	70%	6.5	62%
Transmission	0.7	6%	1.3	12%
Distribution	2.5	24%	2.7	26%
Total	**10.4**	**100%**	**10.5**	**100%**

Because costs paid by customers translate to revenues earned by the IOUs, we conclude that the economic value of franchise agreements would be reduced by approximately 70% upon restructuring since IOUs would convey monopoly rights that would provide only for the collection of transmission and distribution revenues. Re-negotiation of franchise fees would reflect the reduced value. Therefore, we estimate that the $628 million currently paid annually in franchise fees would be reduced by approximately $437 million per year. It is unlikely that non-IOU retailers would enter into similar franchise agreements since those agreements are predicated on the exclusivity of a seller operating in a jurisdiction.

Municipal Public Service Taxes

Cities and counties in Florida are allowed to collect a MPST on the electricity purchased by customers in their jurisdictions. In jurisdictions where this tax is levied, the rate can be as high as 10% of the value of the electricity purchased. Not all transactions are taxable and not all jurisdictions choose to impose a MPST. The Florida Department of Financial Services reports total collections of MPST of approximately $1.04 billion in 2017 from all entities providing electricity. [21] Because IOUs account for roughly 75% of Florida's retail electricity sales, a reasonable estimate is that IOUs accounted for 75% of MPST paid in 2017, or $780 million.

If the electric industry is deregulated, generation would not be sold at retail. It is not clear whether current taxes that apply to the IOUs could be transitioned to electric retailers operating in a deregulated environment, whether new taxes would be required, and what the implications of either might be with regard to the complexity of collections.

2. Restructuring would put at least $317 million per year in state revenues at risk.

[19] EIA (2019). Annual Energy Outlook 2019 supporting tables. Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2019&region=3-2&cases=ref2019&start=2017&end=2050&f=A&linechart=&ctype=linechart&sourcekey=0

[20] Calculations by FTI using data retrieved from EIA's 2019 Annual Outlook, Tables 55, 55.2, and 55.14. Available at https://www.eia.gov/outlooks/aeo/tables_ref.php

[21] EDR Staff Compilation of Annual Financial Report (2018). Department of Financial Services, FY 2016-17.

Passage of the Initiative could significantly reduce the amount of taxes the State collects from the energy industry in Florida. Specifically, the payments made by IOUs for GRT and sales taxes may decline, become more complicated to collect, or both. Based on experience in other jurisdictions, we estimate the GRT impact to be $317 million per year. While reductions in collections of income are also likely if investors with strong incentives to report taxable earnings in Florida take ownership of the state's generation assets, we have not attempted to estimate the magnitude of this impact. Sales taxes could also be at risk, become more complicated to collect, or both; however, we expect that there is a relatively low probability of a major reduction in sales tax collections and have therefore not attempted to estimate the magnitude of this impact.

All of these assumptions assume that the IOUs would continue to own their T&D assets, consistent with restructuring in other jurisdictions. In the event that the language embedded in the Initiative would, upon passage, require the IOUs to divest those assets, these impacts would be significantly higher.

Gross Receipts Taxes

In Chapter 203.01 of the Florida Statutes, the state imposes a 2.5% GRT on utilities services that are delivered to retail customers. In 2017, the four major IOUs paid approximately $455 million in GRT to the state.[22]

Table 7. 2017 IOU GRT Payments[23]

Utility	GRT Payment *($millions)*
Duke	$103
FP&L	$273
Gulf Power	$32
Tampa Electric	$46
Total	**$455**

Current prices paid by retail customers reflect bundled charges that include generation, transmission, and distribution. Under restructuring, generation would be sold at wholesale cost into markets; retailers would then package wholesale purchases and sell them to retail customers pursuant to contractual arrangement. It is unclear whether such retail sales by retailers would be considered "utilities services" as defined in Chapter 203.01.

[22] State of Florida (2018). Department of Revenue, Revenue Collection Report. Available at: http://floridarevenue.com/taxes/PDF/MCR0618.pdf

[23] Federal Energy Regulatory Commission (2018). Form 1 - Electric Utility Annual Report. Accessed on February 18, 2019. Available at: https://www.ferc.gov/docs-filing/forms/form-1/data.asp?csrt=9690900342522796464

If retailers are found not to be providing "utilities services", as has been the case in a number of other jurisdictions (see discussion below), then GRT payments attributable to retailer sales would suffer a commensurate decline. Other markets have managed this problem by either increasing the rate of the distribution-level tax or by the creation of a new tax. For example, a tax could be imposed on generation that would offset the reduction of the GRT. In fact, this issue has already been analyzed in Florida. The State previously contemplated restructuring in the late 1990s. At that time, EDR undertook an analysis of the GRT, which was deemed particularly important because it was (and remains) a major revenue source for the Florida schools.[24] EDR envisioned precisely the scenario described above and determined that the most effective way to maintain revenue stability would be to either increase the GRT rate or to create a new, unit-based tax.[25] At the time of that study, the solutions proposed were more feasible than they are now due to the passage of Amendment 5 in late 2018. Because the Amendment has subsequently been passed, we conclude that GRT revenue streams would be likely to decline if restructuring were implemented. Below, we discuss Amendment 5 and its implications in detail.

We estimate that GRT payments to the State by IOUs would decline by $317 million per year. To reach that estimate, we applied the same 70% reduction factor we calculated using the data shown in Table 6, which reduces the $455 million in GRT currently paid by the IOUs by that amount.

Sales Taxes

Florida also collects sales tax on the sale price of any items sold at retail in the state. Typically, sales tax in Florida is 6%, although current regulations provide for a number of exemptions. FTI has determined that reported sales tax payments by electric utilities in federal filings are considerably lower than 6% of total sales. The Florida Department of Revenue reports that total sales tax from the "transportation and utilities" industry was close to $670 million in 2017.[26] The electric industry portion of this cannot be reliably estimated.

State Corporate Income Taxes

IOUs pay a nominal income tax of 5.5% in Florida, though actual payments reported by utilities are generally significantly less. [27, 28] Our research of publicly available documents reveals that

[24] Specifically, GRT receipts fund the Public Education Capital Outlay fund.
[25] Office of Economic and Demographic Research, the Florida Legislature (1998). Potential Fiscal impact of Electric Utility Deregulation on Florida's Public Education Capital Outlay (PECO) Program. Available at: http://edr.state.fl.us/content/special-research-projects/education/elec.pdf p. 49
[26] Florida Comprehensive Annual Financial Report (2017).
[27] StateofFlorida.com. Florida Tax Guide. Accessed on February 16, 2019. Available at: https://www.stateofflorida.com/taxes.aspx
[28] Federal Energy Regulatory Commission (2018). Form 1 - Electric Utility Annual Report. Accessed on February 18, 2019. Available at: https://www.ferc.gov/docs-filing/forms/form-1/data.asp?csrt=9690900342522796464

two of the four major IOUs two paid state income taxes in 2017 with total payments of approximately $31 million, however it is possible that this number is higher.[29]

Independent Power Producers ("IPP") and financial institutions (banks, investment funds, etc.) are among the most likely buyers of the assets the IOUs would be required to divest as part of a deregulation initiative. Eliminating IOU ownership in favor of these types of investors creates the distinct possibility of reductions in corporate taxes primarily because IPPs and banks are skilled at tax optimization and could structure transactions and subsequent operations in such a way as to report no taxable income to the State. At the very least, collection of taxes in the industry will become more complicated. Rather than taxing familiar companies, the State will need to apply taxes to companies who may have a strong incentive to reduce their reported earnings. As noted above and discussed below, the prospect of adjusting tax levels to maintain neutrality faces a significant barrier due to the passage of Amendment 5. We therefore conclude that state revenues from corporate taxes would be moderately at risk if the Initiative is passed.

3. The costs of implementing, operating, and overseeing a competitive market will be significant.

Implementing new markets is a complex, expensive undertaking. Before opening wholesale markets up to competition, Florida would need to create and operate an ISO, which we estimate will cost approximately $189 million with an additional outlay of $222 million per year. While costs of this magnitude are a near certainty, their impact on State finances is not since they are more likely to be passed on to Florida's electric customers rather than be funded directly by taxpayers. Florida will also need to create new capabilities to oversee competitive markets and the actions of its participants and to otherwise protect customer interests. The State will need to pay for these capabilities either through the creation of new agencies, expansion of existing ones, or both. Finally, if competitive markets lead to an increase in prices (including customer funding for ISO operations), the State's cost of doing business will increase insofar as it is one of the largest consumers of electricity in the market.

While we cannot know the exact magnitude of these costs nor the manner in which they will be allocated, it is certain that they will be significant and that they will be paid for by Floridians in one manner or another.

ISO Costs

[29] Federal Energy Regulatory Commission (2018). Form 1 - Electric Utility Annual Report. Accessed on February 18, 2019. Available at: https://www.ferc.gov/docs-filing/forms/form-1/data.asp?csrt=9690900342522796464

Primary functions of an ISO, a requisite of a competitive market, include the coordination, control, and operation of a regional transmission grid, oversight of wholesale electric markets, and monitoring and prevention of market power abuses.[30]

Designing and implementing ISOs includes both startup and ongoing costs. A reasonable estimate of the startup cost based on past experiences in other jurisdictions is $189 million. To reach this estimate, we averaged the startup costs reported for each of the California ISO ("CAISO"), ISO New England ("ISO-NE"), the New York ISO ("NYISO"), the Pennsylvania-Jersey-Maryland market ("PJM"), and the Midwestern Independent System Operator ("MISO").[31] Startup costs for each are shown below:

Table 8. ISO Startup Costs ($millions)[32]

ISO	Startup Cost
CAISO	396
ISO-NE	65
NYSIO	104
PJM	188
MISO	192
Average	**189**

Ongoing costs to cover staffing, software, and other overhead are also significant. We estimate that, on average, ISOs cost approximately $222 million per year to operate, based on the calculation below:

Table 9. ISO Operating Costs ($millions)[33]

ISO	Operating Cost
CAISO	195
ISO-NE	184
NYSIO	143
PJM	308
MISO	279
Average	**222**

While these costs do vary from ISO to ISO, they are not necessarily a function of market size. At a high level of abstraction, ISOs perform similar functions, regardless of the size of their footprint. Moreover, we note that there is no available insight on what the constitution or specific

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[30] For purposes of this report, an ISO can be considered synonymous with a Regional Transmission Organization, which performs similar functions, more typically across a multi-state area.

[31] MISO has since been renamed the Midcontinent System Operator.

[32] Blumsack, Seth (2007). Measuring the Benefits and Costs of Regional Electric Grid Integration. Energy Law Journal Vol 28:147. http://www.eba-net.org/assets/1/6/10-147-184.pdf

[33] Annual operating costs are derived from each ISO's 2017 audited financial statements.

responsibilities of Florida's ISO would be post-restructuring. As such, we conclude that a simple average of the startup and operating costs of these ISOs provides a reasonable indicator of the costs likely to be incurred in Florida.

We also note that these costs may be recovered via cost adders in the market. It is typical for ISOs to add a volumetric (*i.e*. $/MWh) charge to certain transactions that occur within its jurisdiction to fund its operations. Alternatively, Florida could choose to set up an ISO that is directly funded by the government. In either case, costs to the state would go up. If the cost to start and operate an ISO are recovered through the wholesale market, they will be passed on, in part, to the State insofar as it is a buyer of approximately $1 billion of energy every year. If the ISO is taxpayer-funded, direct costs would be higher. Regardless of the funding mechanism, the cost of an ISO will ultimately be funded by Florida's electric customers, either through higher energy charges, an increased tax burden, or both.

Indirect Administrative Costs

In addition to paying for an ISO, either directly or indirectly, the state will also need to fund additional capabilities to oversee new markets and to execute certain functions that may be required in a competitive jurisdiction. Other states have also had to adapt to restructuring. For example, in 2007, the Illinois Legislature created the Illinois Power Agency ("IPA") as a means of dealing with the highly volatile prices it observed in its competitive market. IPA's role is to oversee auctions for energy supplies in the competitive markets to ensure that customers can receive "…adequate, reliable, affordable, efficient and environmentally sustainable electric service at the lowest total cost over time…".[34] In Florida, this is currently one role of the IOUs who, as noted above, have historically performed it well. The IPA costs Illinois taxpayers around $3 million per year.[35,36] Other states, including Pennsylvania, Connecticut, and others, have either created similar agencies or outsourced these functions to consultants.

In other jurisdictions, agencies have been created to serve the state as a customer in deregulated markets. In New York, for example, the New York Power Authority ("NYPA") is a public-private benefit corporation that is tasked with generating and purchasing power for the state's public power systems, government agencies, and not-for-profit organizations, as well as a number of businesses in the state. At present, Florida has no equivalent agency.

The need to regulate new markets will also increase the State's costs as a result of added staffing at the Attorney General's office to respond to increased customer complaints, new agencies tasked with overseeing marketing practices by retail suppliers, increased costs of consultants and

[34] Public Act 095-1027, Illinois Power Agency Act Section 1-5. Available at: http://www.ilga.gov/legislation/publicacts/95/095-1027.htm
[35] Illinois Power Agency (2018). Annual Report, Fiscal Year 2017. Available at: https://www2.illinois.gov/sites/ipa/Documents/Annual-Report-Illinois-Power-Agency-FY2017.pdf
[36] Figures in 2017 prices.

advisors, and others. These costs do not lend themselves to quantification at this time, but they are likely to be significant.

If electric costs rise, so will the State's electricity bills

State government is one of the biggest electricity customers in Florida. Each year, the state spends approximately $1 billion on electricity, accounting for about 4% of the total retail market electricity expenditure.[37] If electricity costs increase upon implementation of deregulation, as they did in Texas, or if volatility increases, additional costs and risk exposure will be borne by taxpayers. FTI has not attempted to quantify the likely impact of this line item, but we note that given the magnitude of the value at risk, the costs could be significant.

4. Assumed savings to customers are not supported

Proponents of the Initiative claim that deregulation will reduce electricity prices in Florida by as much as 25%. Many of these claims are based on a December 2017 report by the Perryman Group entitled *Potential Economic Benefits of Statewide Competition in the Florida Power Market: A Preliminary Assessment* (the "Perryman Report").[38] We have reviewed the Perryman Report and related documentation and conclude that it relies on oversimplified and incorrect interpretations of the data on which it bases its conclusions and that those conclusions are inconsistent with a large body of academic research available in the public domain.

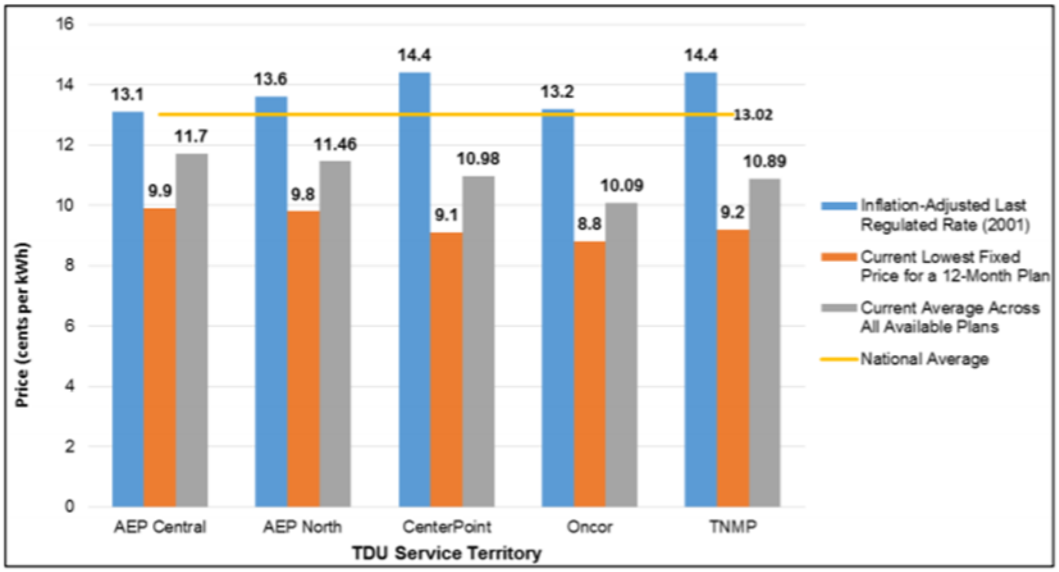
The Perryman Report presents analysis that is essentially comprised of two steps. First, the authors estimate the magnitude of expected rate savings in Florida based on their interpretation of outcomes in Texas, which are in turn based on data from the PUCT and on a June 2017 study by the Baker Institute for Public Policy at Rice University entitled *Electricity Reform and Retail Pricing* (the "Baker Institute Report"), both of which are included in the record of this proceeding.[39] Using these data, the Perryman Report estimates that restructuring will result in rate reductions for Florida's customers between 23.3% and 27.1%. Second, those estimated savings serve as inputs to an input-output ("I/O") economic model that predicts economic growth, unemployment, and other factors in a postulated, lower electric price environment. The flaw of the Perryman Report analysis lies in the first step. The PUCT data and the findings of the Baker Institute Report are both misinterpreted, rendering the resultant savings estimate unreliable and subsequent calculations irrelevant.

In interpreting the PUCT data, the authors of the Perryman Report incorrectly infer that the information compiled by the PUCT represents a counterfactual analysis of the savings that have accrued from competition. Regularly, the Texas Commission compares rates being currently

[37] FTI analysis of IMPLAN data provided by the U.S Bureau of Labor and Statistics.
[38] The Perryman Group (2017). Potential Economic Benefits of Statewide Competition in the Florida Electric Power Market: A Preliminary Assessment. FIEC EDR Notebook, pg.717.
[39] Hartley, Medlock, Jankovska (2017). Electricity Reform and Retail Pricing in Texas. Available at: https://www.bakerinstitute.org/research/electricity-reform-and-retail-pricing-texas/

offered by competitive retailers in the state to 2001 regulated electric rates, adjusted for inflation. Data from the PUCT's 2019 *Scope of Competition in Electric Markets in Texas, Report to the 86th Legislature*, which is included in the record of this proceeding, is shown below.

Figure 2. PUCT Comparison of Retail Offers and Inflation-Adjusted Regulated Rates[40]



The Perryman Report claims that these inflation-adjusted rates calculated by the PUCT represent the rates "that would likely prevail in a regulated framework".[41] However, the PUCT's reporting of these values makes no such claim. Rather, these values serve merely as a comparison of current offers to the *last* regulated rate, adjusted for inflation. In the case of the data shown in Figure 2, this means comparing current offers from retail suppliers to rates that were in place seventeen years ago with no adjustment for subsequent changes in market conditions.

Retail rates in Texas would have changed since 2001 based on the market's cost to generate electricity, regardless of whether the retail supplier was an IOU or not. In Texas, as in Florida, retail rates are closely correlated to natural gas prices. According to EIA data, the average citygate gas price in Texas in 2001 was $5.13/Mcf; the equivalent of $7.23/Mcf in current dollars when adjusted for inflation.[42,43] EIA indicates that the citygate gas price in June 2018 was $4.71/Mcf. It is unreasonable to assume that, during a period in which local gas prices fell by 35% in real terms, electricity prices would have risen with inflation if not for deregulation.

[40] PUCT (2019). Scope of Competition in Electric Markets in Texas: Report to the 86th Legislature. FIEC EDR Notebook, pg.266.
[41] The Perryman Group (2017). Potential Economic Benefits of Statewide Competition in the Florida Electric Power Market: A preliminary Assessment. FIEC EDR Notebook, pg.717.
[42] EIA Natural Gas Prices. Retrieved on February 17, 2019. Available at: https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_STX_m.htm
[43] CPI Inflation figures from the Reserve Bank of Minneapolis. Retrieved on February 17, 2019. Available at: https://www.minneapolisfed.org/community/financial-and-economic-education/cpi-calculator-information/consumer-price-index-and-inflation-rates-1913

The Perryman Report makes another, related error in interpreting the findings of the Baker Institute Report. Here, the Perryman Report's authors note that the Baker Institute reports that electric prices in competitive markets in Texas, adjusted for inflation, fell considerably over the period 2002 to 2016, while inflation-adjusted electric prices in regulated markets rose slightly. The authors attribute this reduction to the structural benefit of introducing competition and then infer that Florida would realize similar benefits. Omitted is the fact that in 2002, immediately following deregulation in Texas, competitive electric prices were dramatically higher than electric prices had been in 2002.[44] As such, rates have had much farther to fall in the ensuing fourteen years selected for comparison. Attributing this price reversion to a benefit of market competition is without support, as is the assertion that Florida prices will fall similarly if competition was to be introduced. Also omitted from the Perryman Report is the fact that, even following the significant decline in competitive electric prices, prices in regulated markets reported in the Baker Institute Report remain below those in competitive jurisdictions, as shown below.

Table 10. Comparison of Average rates in Competitive Markets and Regulated Markets in Texas ($2015/kWh)[45]

	2002 Average	2016 Average
Regulated Markets	0.089	0.099
Competitive Markets	0.114	0.100

Since neither of the two methods used in the Perryman Report to estimate the rate reduction in Texas attributable to restructuring can be supported, subsequent results of the I/O modeling support no reliable conclusions.

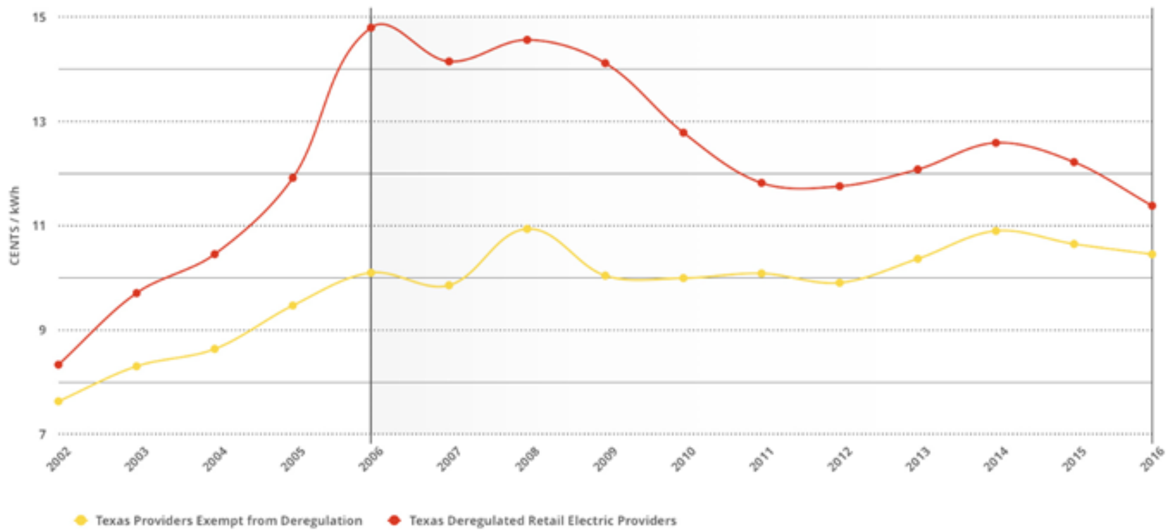
Current Research

In addition to the methodological shortcomings of the Perryman Report, we note its final conclusions as well as similar claims of falling prices made by proponents of the initiative are inconsistent with empirical observations and the body of academic research. Examples that contradict these conclusions, some of which are in the record of this proceeding, are listed below.

- The Texas Coalition for Affordable Power ("TCAP") observes that prices in deregulated markets in Texas have been consistently higher than have prices in regulated markets, findings that are directionally consistent with the Baker Institute Report data shown in Table 10. The figure below shows a comparison of regulated and deregulated markets from TCAP's April 2018 market report.[46]

[44] A key reason that prices in 2002 in Texas were so high is a price floor imposed by the Texas Commission known with the onset of restructuring. Known as the "Price to Beat", the floor was imposed to encourage the entrance of new market participants. Costs of the artificially inflated market prices were borne by Texas ratepayers.
[45] FTI calculations using data from Table 1 at p. 15 of the Baker Institute Report.
[46] TCAP (2018). Electricity Prices in Texas – A Snapshot Edition. FIEC EDR Notebook, pg. 22

Figure 3. TCAP Comparison of Regulated and Competitive Retail Rates[47]



- Borenstein concludes that "…while the restructuring era dawned with great hope that regulatory innovations, and the incentives provided by competition, would dramatically improve efficiency and greatly lower consumer costs, that hope was largely illusory…" and that changes in customers' electricity costs are driven by changes in natural gas prices and technology.[48]
- Craig and Savage find that competition has increased efficiency at some power plants, but that the effect is mostly limited to coal plants.[49] Utilities in Florida are currently retiring coal plants and considering the obsolescence of the ones that remain.[50,51,52]
- Borenstein and Bushnell find that restructuring has had no discernable impact on energy rates and that fuel prices are a primary driver of cost changes.[53] They also find that retail

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[47] We note that the TCAP data show the same trends and directional relationship but that TCAP shows a considerably higher spread between competitive and retail rates in 2016 that does the Baker Institute Report data shown in Table 10. FTI has not attempted to reverse engineer findings from either source and notes that differences in final reported results may be reasonable and attributable to averaging methods, sample selections, inclusion of non-electric costs (taxes, etc.), and other factors.

[48] The Energy Institute at Haas (2015). The U.S. Electricity Industry after 20 Years of Restructuring, pg.3. Available at: https://ei.haas.berkeley.edu/research/papers/WP252.pdf

[49] The Energy Journal (2013). Market Restructuring, Competition and the Efficiency of Electricity Generation: Plant-level Evidence from the United States 1996 to 2006. FIEC EDR Notebook, pg. 463.

[50] Spectrum News (2018). OUC Looks at Energy Future, Including Closing Coal Plants. Available at: https://www.mynews13.com/fl/orlando/news/2018/12/11/ouc-looks-at-energy-future--including-closing-coal-plants

[51] PowerMag (2017). FPL Will Close its Last Coal-fired Plant in Florida. Available at: https://www.powermag.com/fpl-will-close-its-last-coal-fired-plant-in-florida/

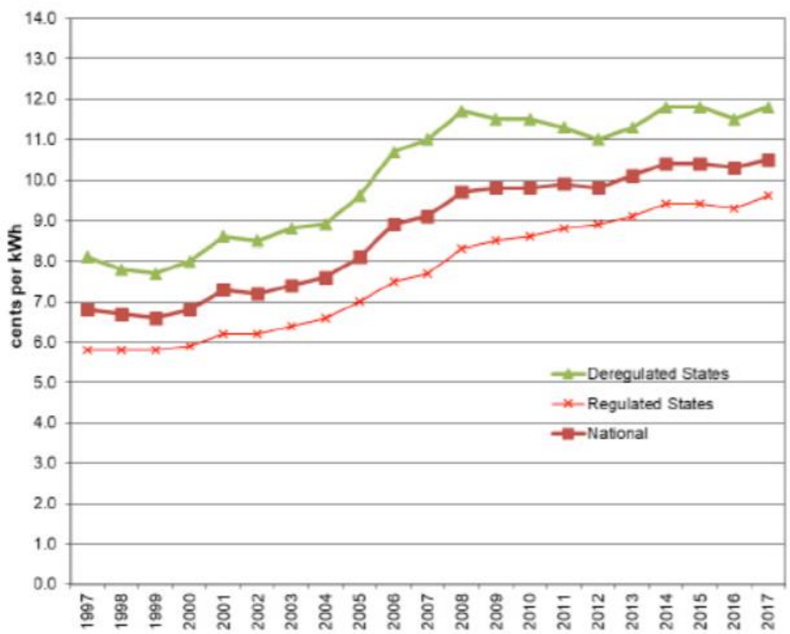
[52] Jacksonville.com (2018). Coal Plants Keep Shutting Despite Trump's Ordre to Rescue Them. Available at: https://www.jacksonville.com/nationworld/20180618/coal-plants-keep-shutting-despite-trumps-order-to-rescue-them/1

[53] Borenstein and Bushnell, National Bureau of Economic Research (2015). The U.S. Electricity Industry After 20 Years of Restructuring. FIEC EDR Notebook, pg. 484.

prices in states in which restructuring has been enacted are more responsive to volatile natural gas prices.[54]

- The American Public Power Association ("APPA") has compiled data indicating that average prices in regulated states have been lower than prices in deregulated states every year for the period 1997 to 2017 and that in 2017 deregulated states were approximately 23% more expensive.[55,56] APPA's year-by-year findings are shown below:

Figure 4. APPA Comparison of Retail Rates in Regulated and Deregulated States



- Morey and Kirsch report that "[r]etail choice states, from the beginning of retail choice up to the present, have had retail prices persistently higher than those in other states, with the price gap varying over time with changes in fuel prices and other factors."[57]

These and other data available in the public sphere clearly indicate that over time, local fuel prices, not market structure, are the primary determinant of energy costs and that, on average, retail costs in regulated markets in Texas and elsewhere have been consistently lower than have their competitive, deregulated counterparts.

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[54] Borenstein and Bushnell, National Bureau of Economic Research (2015). The U.S. Electricity Industry After 20 Years of Restructuring. FIEC EDR Notebook, pg. 484.
[55] American Public Power Association (2018). Retail Electric Rates in Deregulated and Regulated States: 2017 Update. Available at: https://www.publicpower.org/system/files/documents/Retail-Electric-Rates-in-Deregulated-States-2017-Update%20%28003%29.pdf
[56] 2017 percentage difference calculated by FTI using data provided by the APPA.
[57] Morey, Kirsch, Christensen Associates Energy Consulting, Electric Markets Research Foundation (2016). Retail Choice in Electricity: What Have We Learned in 20 years? Available at: https://hepg.hks.harvard.edu/files/hepg/files/retail_choice_in_electricity_for_emrf_final.pdf

5. Difficulty in managing impacts

The Initiative's proponents claim that their intention is to create a competitive market in the model of Texas and that the benefits they contend Texas has enjoyed will be imported to Florida along with competition. However, closer inspection suggests this measure is unlike the legislation that deregulated Texas and that there are important factors that differentiate Florida from Texas. Below, each of these key factors are discussed. While their review does not support a specific conclusion regarding the likely financial impacts to the State, we conclude that these issues create increased risks and obligations for the State that could create significant costs at some point in the future.

The Initiative appears to propose an extreme form of restructuring

The language of the Initiative could create an electric industry in Florida unlike any other in North America. Specifically, if passed, the Initiative would require the Legislature to enact laws that "[limit] investor-owned utilities to construction, operation, and repair of electrical transmission and distribution systems. Municipal and cooperative utilities may opt into competitive markets." Noteworthy in its absence in the text is the allowance of IOU *ownership* of the T&D network. If passed, this sentence would appear to require the divestiture by the IOUs of all their assets, not just their generation fleets.

There are no jurisdictions in North America in which the assets used for the distribution of electricity to customers are owned by any entity other than an IOU. IOUs own the distribution network in each of the seventeen restructured jurisdictions shown in Figure 5, including Texas.

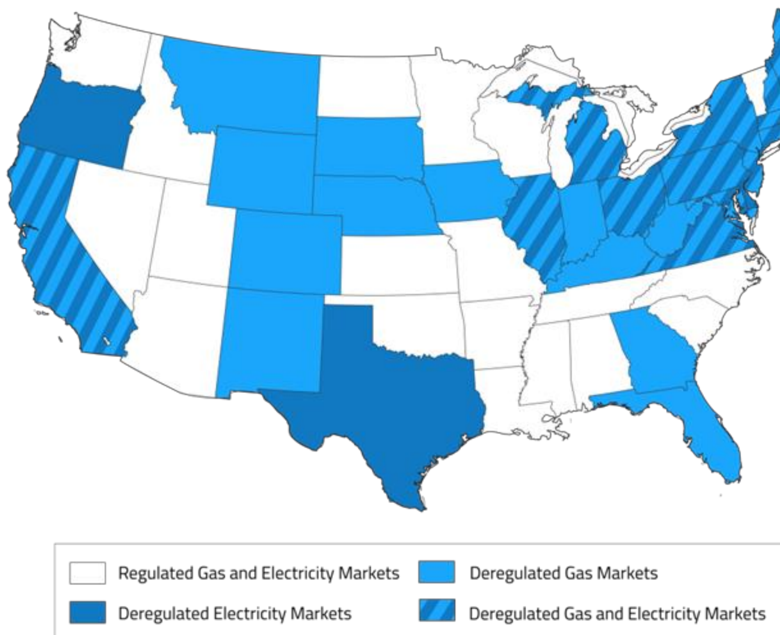
The proposed language does not mention which entities should, could, or will own the T&D assets in Florida. FTI is unaware of any analysis that has been undertaken by the Initiative's proponents that proposes some alternative ownership structure, nor are we aware of any other jurisdiction in the U.S. that has studied the matter.

Deregulation by constitutional amendment is highly problematic

Proponents of the Initiative propose a constitutional amendment to expel the IOUs currently serving Florida from some or all of the electric industry in the state. This is highly unusual. There are currently sixteen U.S. states, plus the District of Columbia, that have deregulated electricity markets.[58] The figure below shows the states that have implemented electricity market deregulation.

[58] Excludes California, which maintains a very limited form of electric deregulation.

Figure 5. Status of U.S. Electric Deregulation[59]



The implications of deregulation through a constitutional process are profound. Enactment through legislation alone would reserve for the State, the option to reconsider restructuring if further analysis indicated that moving forward with divestiture would not be in the electricity consumers' best interests. This was the case in Oklahoma, Iowa, and other states, all of which passed legislation to study deregulation but later decided that the risks and/or costs to ratepayers were too high to move forward.[60] Other states, such as Arkansas and Montana, deregulated, found that the new market structure created an unworkable situation, and subsequently passed legislation to re-regulate their electric industries.[61,62] If deregulation in Florida proves to be too expensive, too volatile, or otherwise undesirable, no legislative remedy will be available to re-regulate and the only option would be the time-intensive, uncertain process of once again amending the State Constitution.

Additionally, the granting of a constitutional "right to choose" may expose the State to liabilities or additional expenses. If robust competition fails to materialize as it has in Maine, Massachusetts and other states, either because retailers chose not to enter the market, investors chose not to

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[59] Electric Choice (2018). Map of Deregulated Energy States & Markets (Updated 2018). Available at: https://www.electricchoice.com/map-deregulated-energy-markets/
[60] Energy Law Journal (2001). Electric Deregulation in Oklahoma: A Comparison of Differing Approaches. Available at: https://www.eba-net.org/assets/1/6/7-Vol22_No2_2001_Comment_Electric_Deregula.pdf
[61] Great Falls Tribune (2017). Don't Make Deregulation Mistake Again in Montana. Available at: https://www.greatfallstribune.com/story/opinion/2017/03/06/make-deregulation-mistake-montana/98802500/
[62] Energy Information Administration (2003). Status of State Electric Industry Restructuring Activity, Pg. 3. Available at: http://large.stanford.edu/publications/coal/references/docs/restructure.pdf

buy some or all of the divested assets, or both, former IOU customers could have some recourse to the state. The constitution's new article could compel the State to provide competition in some form. The Initiative offers no guidance on dealing with market failure.

Passage of Amendment 5 in 2018 creates additional risk to State cash flows

Impacts to tax revenues that arise from deregulation may be more difficult to mitigate in Florida than in other states. Many jurisdictions implementing deregulation have recognized that applying the new regulation to existing taxation laws will result in reductions to state and/or local revenues. An obvious solution is to either create new taxes to be applied to new market participants or to increase rates for existing taxes. For example, if a state's tax code calls for a volumetric tax (*i.e*. based on sales amounts) on utility sales to customers of 2%, and the language of the tax code indicates that upon deregulation, the generation portion of the sales revenues would be excluded from the calculation, this either creates a new tax to be levied on generators of 2% or increases the utility tax to some higher level; both methods could be used to maintain revenue neutrality.

Numerous examples exist of these types of mechanisms being implemented alongside deregulation. In Pennsylvania, generators pay a GRT.[63] In New Jersey, the legislation that enabled restructuring repealed the GRT and franchise tax on utilities and replaced them with a business tax on utilities and sales and use tax on generation.[64] Other states have utilized similar mechanisms to maintain revenue neutrality.

In Florida, such adjustments are challenged by the passage of Amendment 5, which is a constitutional amendment passed as a ballot initiative in November 2018.[65] Amendment 5 requires that any new tax or fee or any increase of an existing tax or fee can only be implemented upon passage with a two-thirds supermajority in both houses of the Florida legislature; the amendment also requires that any such proposed increases appear alone on bills brought up for votes.[66]

The likelihood of the passage of any particular measure by any particular legislature is uncertain, however, there is certainty in the fact that the State's ability to manage its tax code is complicated by Amendment 5. Moreover, the Initiative's language includes no provision to turn back deregulation in the event that the existing tax code cannot support revenue neutrality. One

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[63] PAPowerSwitch, Pennsylvania Public Utility Commission. Fundamentals of Swtiching Suppliers. Accessed on February 14, 2019. Available at: https://www.papowerswitch.com/frequently-asked-questions

[64] Woo, PMA OnLine Magazine (2000). Deregulation and its Impact on Taxation of Electric Services. Accessed on February 15, 2019. Available at: http://www.retailenergy.com/articles/deregtax.htm

[65] Ballotpedia (2018). Florida Amendment 5, Two-Thirds Vote of Legislature to Increase Taxes or Fees Amendment. Available at: https://ballotpedia.org/Florida_Amendment_5,_Two-Thirds_Vote_of_Legislature_to_Increase_Taxes_or_Fees_Amendment_(2018)

[66] Ballotpedia (2018). Florida Amendment 5, Two-Thirds Vote of Legislature to Increase Taxes or Fees Amendment. Available at: https://ballotpedia.org/Florida_Amendment_5,_Two-Thirds_Vote_of_Legislature_to_Increase_Taxes_or_Fees_Amendment_(2018)

possible outcome, then, is the passage of the Initiative coupled with the State's inability to implement the tax reforms required to ensure revenue neutrality, resulting in a reduction in revenue streams for the state and for localities that is impossible to offset. Insufficient information exists to make a reasonable estimate of the impact of such an outcome except to note that it could be significant and would be exacerbated by the requirement that the IOUs divest T&D assets in the state, as discussed above.

Fiscal Impacts Summary and Conclusions

Below, we summarize each of the potential impacts to state and local net revenues that could arise from passage of the Initiative in November. Impacts are separated into three separate categories. Table 11 shows our estimate for the annual impacts that we have determined are likely and for which sufficient data exists to reasonably determine their magnitudes. Table 12 shows those impacts that we think are likely but whose costs cannot be estimated with confidence at this time, in some cases because the cost is known but it is unclear who will bear them. For this category of impacts, we summarize the total amount that we believe to be at risk. Table 13 shows impacts with unknown probability or those which we do not believe will significantly impact state and local net revenues.

Table 11. Likely Fiscal Impacts That Can Be Readily Estimated

Cost/Revenue Category	Estimated Impact *($millions, annual)*
Property tax	177
Franchise fees	437
GRT	317
Total	**930**

Table 12. Impacts That Are Likely Whose Costs Cannot Be Readily Estimated

Cost/Revenue Category	Potential Impact *($millions, annual)*	Description
State income taxes	Unknown	High probability of revenue reductions if investors skilled at tax optimization assume ownership of the IOU generation fleet.
ISO Cost	222	The cost of an ISO will certainly be incurred, the uncertainty regards whether the State funds it, costs fall to customers, or both. Impact excludes $189 million in ISO startup costs.
Regulation	Unknown	The State will certainly need to expand its regulatory presence to monitor new markets. Costs of doing so are unknown at this time.

Table 13. Impacts with a Low or Unknown Probability of Occurrence

Cost/Revenue Category	Potential Impact *($millions, annual)*	Description
Sales taxes	0	Low probability of impact since the State's taxation nexus likely covers retailers.

MPST	0	Low probability of impact if municipalities and counties can likely adjust their tax regulation to remain revenue neutral.
Energy costs	Unknown	As a large consumer of electricity, the State's costs would increase if energy prices go up. FTI has not developed market price forecasts for a deregulation scenario in Florida.

Importantly, each of the estimates shown above assumes that deregulation in Florida follows models in other markets insofar as the IOUs would be allowed to retain ownership of their T&D assets. If the more extreme version of restructuring implied by the language in the Initiative is ultimately put into place, costs and risks associated with almost all of the impacts described above would increase.

In the final analysis, the Initiative offers a promise of benefits based on questionable analytical insight at odds with mainstream research that is, at best, speculative. At the same time, it requires acceptance of significant impacts to state and local finances, some of which can be readily quantified and others not, while creating new risks for the State. Acceptance of this value proposition requires the installation of a market structure that may be unlike any other in North America, using a mechanism that cannot be readily undone if unanticipated results arise. We conclude that the Initiative is highly likely to have a negative impact on state and local revenues and request that the Committee adopt the FIS proposed in Attachment A.

Attachment A - FIS

Based on current laws and administration, the amendment will result in decreased state and local government revenues of at least $930 million per year and potentially more. The timing and magnitude, while expected, cannot currently be determined because they are dependent on factors that cannot be predicted with certainty prior to implementation.

POTENTIAL IMPACTS OF INITIATIVE #18-10 ON STATE AND LOCAL REVENUES IN FLORIDA

Presentation to Financial Impact Estimating Conference

February 2019

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- Mining & Mining Services
- Real Estate & Infrastructure
- Retail & Consumer Products
- Telecom, Media & Technology

[1]Number of total shares outstanding as of February 15, 2018, times the closing share price as of February 23, 2018.

Background

- FTI Consulting ("FTI") has been retained by EnergyFairness ("EF") to prepare a report for the Financial Impact Estimating Committee ("FIEC" or "the Committee") describing our analysis of the likely impacts that would follow passage of the Florida Changes to Energy Market Initiative (Initiative #18-10, hereinafter "the Initiative"), which would create a new article in the state constitution that guarantees utility customers in Florida the right to choose their own energy provider, creating what is commonly referred to as a deregulated market.
- The FIEC held its first public meeting regarding the Initiative on February 11, 2019. At that meeting, proponents of the Initiative indicated that their intention in crafting its language is to implement a market modeled after the one in use in Texas, which passed legislation known as Senate Bill 7 ("SB 7") in 1999 to deregulate its electric industry.
- This report comments on some of these issues in an effort to clarify and, in some cases, correct the record of these proceedings.
- FTI expects to develop a report in the coming months that provides an analysis of likely costs and risks that would transfer to Florida's electric customers and to the electric industry in Florida as a whole, including increased energy costs, reductions in the reliability of the state's electric grid, and others if the Initiative is passed in November.

Summary of FTI Findings

- In total, we estimate that the fiscal impact to state and local governments in Florida is likely to be at least **$930 million** per year.

1. Deregulation of Florida’s electric industry will reduce revenues to local governments by **$614 million** per year

2. State revenues will be reduced by least **$317 million** per year

3. Costs to the State will increase, though the amount is unclear

4. Savings to offset these costs are speculative and inconsistent with observations

5. Managing impacts of the Initiative will be difficult

Property Taxes

- The Florida IOUs currently pay $686 million per year in taxes to cities and counties.
- In Texas, stranded costs as a result of deregulation were as follows.

IOU	Book Value of Assets in Texas ($billions)	Authorized Stranded Cost Recovery ($billions)	Stranded Cost as a % of Net Book Value
CenterPoint	32.0	4.0	13%
AEP	4.9	2.5	51%
TNMP	0.9	0.1	14%
		Average	**26%**

- Assuming an equivalent ratio of stranded costs to net book value, cities and counties in Florida can expect a reduction in taxes of 26% or **$177 million per year**.

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Franchise Fees

- Based on reported information retrieved from FERC Form 1s filed by the state's four major IOUs, the Florida IOUs paid $628 million in franchise fees in 2017.
- Generation costs comprise approximately 70% of customers' costs in Florida according to EIA data

	Florida (c/kWh)	% total
Generation	7.2	70%
Transmission	0.7	6%
Distribution	2.5	24%
Total	**10.4**	**100%**

- The value of franchise agreements may be reduced by approximately 70% upon restructuring, reducing local revenues by **$437 million per year**.

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Gross Receipt Taxes ("GRTs")

- IOUs currently pay the state approximately $455 million per year in GRT
- GRT payments attributable to retailer sales would suffer a commensurate decline if retailers are found not to be considered "utilities services" as defined in Chapter 203.01.
- Due to the passage of Amendment 5, GRT revenue streams would be likely to decline after restructuring.
- We estimate that GRT payments to the State by IOUs would decline by **$317 million per year**.
- Solutions proposed by EDR to maintain neutrality are less feasible now

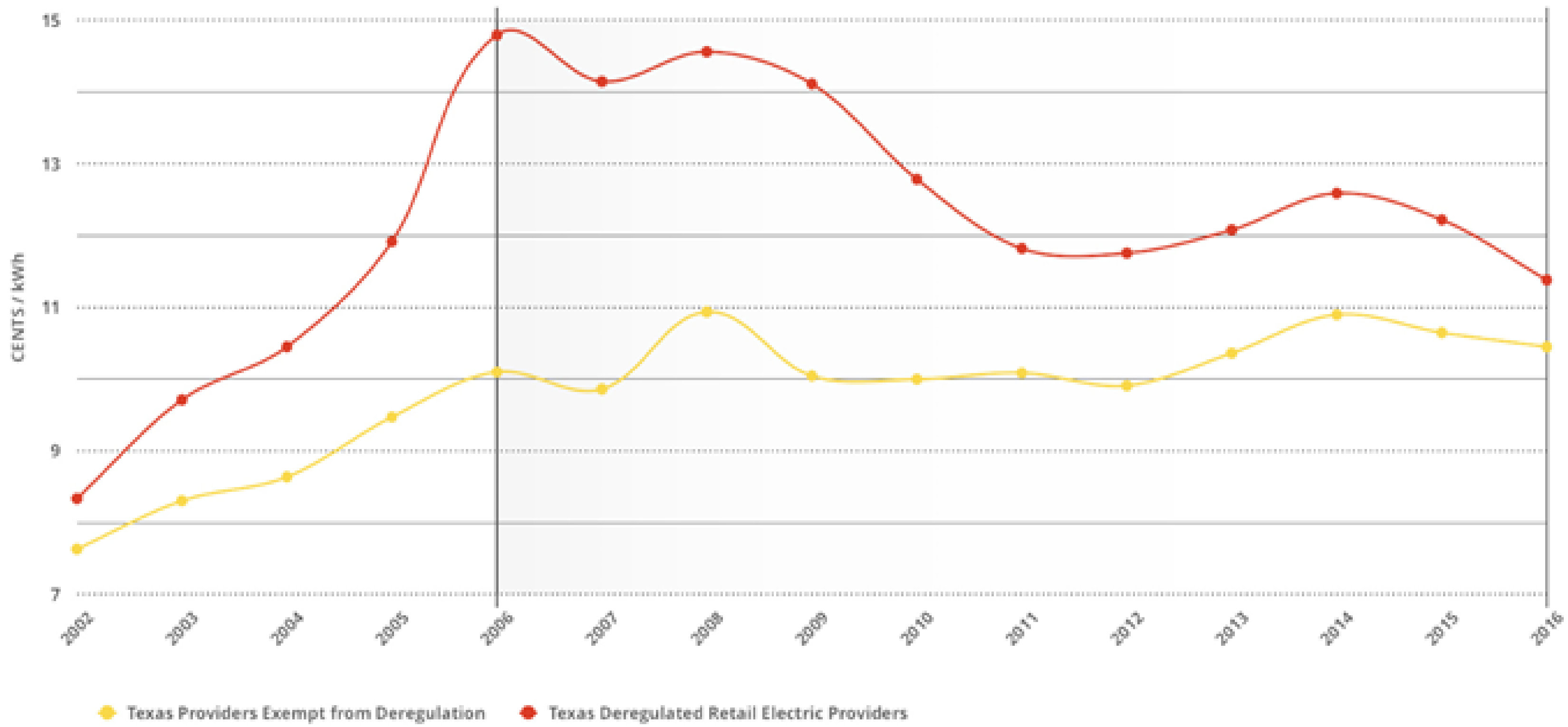
ISO Costs

	Startup Costs	Operating Cost
CAISO	396	195
ISO-NE	65	184
NYISO	104	143
PJM	188	308
MISO	192	279
Average	189	218

- The cost of developing an ISO could funded directly by taxpayer dollars through creation of a state agency. More likely, costs would be covered through a small charge applied to the wholesale market, in which case the state would pay its share as one of the largest customers in Florida and the remainder would fall to ratepayer
- We can be certain that it will cost about **$189 million** to startup an ISO and about **$218 million** per year to operate; what's uncertain is the cost allocation

Benefits are speculative

- Proponents of the initiative rely heavily on a single report that suggests that savings may be enough to offset all of these costs. We have concerns regarding the methods used by the authors of that report to reach their conclusions. Moreover, the finding that deregulation creates lower prices is at odds with academic research on the subject and inconsistent with observations in Texas and elsewhere.



Benefits are speculative *(cont'd)*

- The report is inconsistent with empirical observations and the body of academic research, such as:
  - **The Texas Coalition for Affordable Power ("TCAP") -** Prices in deregulated markets in Texas have been consistently higher than have prices in regulated markets
  - **Borenstein** - "…[W]hile the restructuring era dawned with great hope that regulatory innovations, and the incentives provided by competition, would dramatically improve efficiency and greatly lower consumer costs, that hope was largely illusory…" and that changes in customers' electricity costs are driven by changes in natural gas prices and technology.
  - **Craig and Savage -** Competition has increased efficiency at some power plants, but that the effect is mostly limited to coal plants. Utilities in Florida are currently retiring coal plants and considering the obsolescence of the ones that remain."
  - **Borenstein and Bushnell** - Restructuring has had no discernable impact on energy rates and that fuel prices are a primary driver of cost changes. Retail prices in states where restructuring has been enacted are more responsive to volatile natural gas prices.
  - **The American Public Power Association ("APPA")** - Average prices in regulated states have been lower than prices in deregulated states every year for the period 1997 to 2017 and that in 2017 deregulated states were approximately 23% more expensive.
  - **Morey and Kirsch** - "Retail choice states, from the beginning of retail choice up to the present, have had retail prices persistently higher than those in other states, with the price gap varying over time with changes in fuel prices and other factors."

Implementation Problems

Divestiture model

- The Initiative requires the divestiture by the IOUs of all their assets, not just their generation fleets.

Constitutional amendment

- The Initiative proposes a constitutional amendment to expel the IOUs currently serving Florida from some or all of the electric industry in the state.

Passage of Amendment 5

- The adjustments to tax or fee to maintain revenue neutrality after deregulation are challenged by the passage of Amendment 5. Thus, the State's ability to manage its tax code is complicated.

Difficulty in managing impacts

Revenue stream	Revenue reduction	Impact to
Property taxes	$177 million	Local governments
Franchise fees	$437 million	Local governments
GRT	$317 million	State
Total	**$930 million**	

Additional revenue reductions to the state likely but difficult to forecast

- Corporate income tax

Costs to the state likely to increase, magnitude and allocation of costs is difficult to forecast

- ISO funding, cost of new oversight functions

FTI CONSULTING

Draft FIS

EnergyFairness respectfully requests that the Committee consider the following FIS:

Based on current laws and administration, the amendment will result in decreased state and local government revenues of at least $930 million per year and potentially more. The timing and magnitude, while expected, cannot currently be determined because they are dependent on factors that cannot be predicted with certainty prior to implementation.

FTI CONSULTING™

EXPERTS WITH **IMPACT™**

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The Cautionary Tale of Texas:

Why Florida's Power Market Should Not Be Deconstructed based on Comparisons to Texas

February 2019



OUTLINE

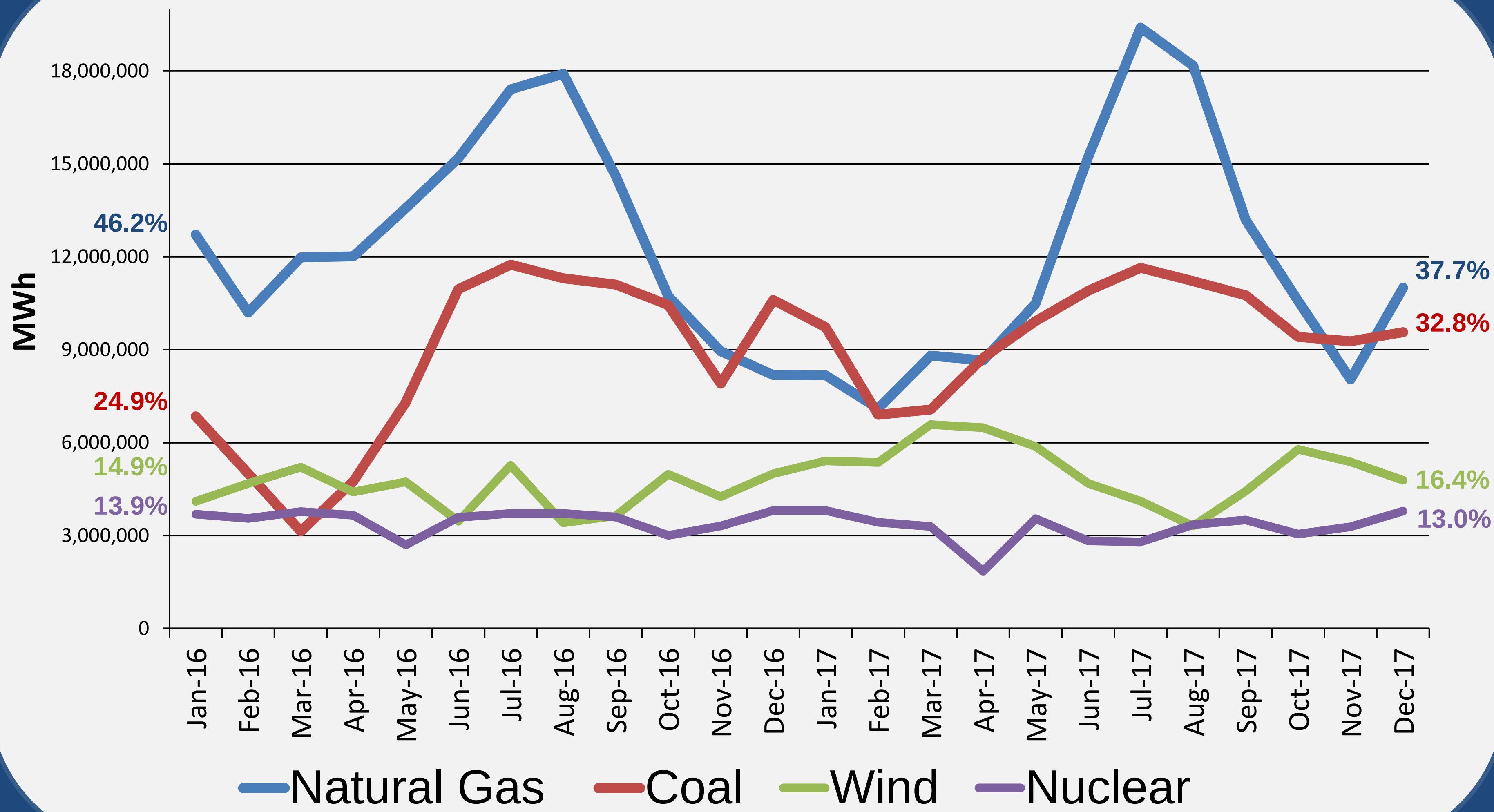
1. **Why Texas Deregulation is not Comparable to what is Currently Being Proposed in Florida.**
2. **Why the Texas Deregulation Experiment is Actually a Cautionary Tale & Not Over.**
3. **Why Estimates of the Total Cost of Retail Choice Must Include Public Power's Uncompensated Exposure to the Market's Call Option on Capacity.**

PART 1: Why Texas Deregulation is not Comparable to What is Currently Being Proposed in Florida.

1. Fuel, infrastructure, and industrial demand side management abundance has positioned Texas with an advantage that functions as a significant hedge against wholesale volatility.
2. Cost of transmission & ancillary service to connect & "balance" renewables have increased prices, but are hidden because they are socialized to entire market & masked by low natural gas.
3. Cost implications of legal distinctions between the Texas statute (SB 7) and proposed Constitutional Amendment should be fully assessed.

“All of the Above“Generation in ERCOT

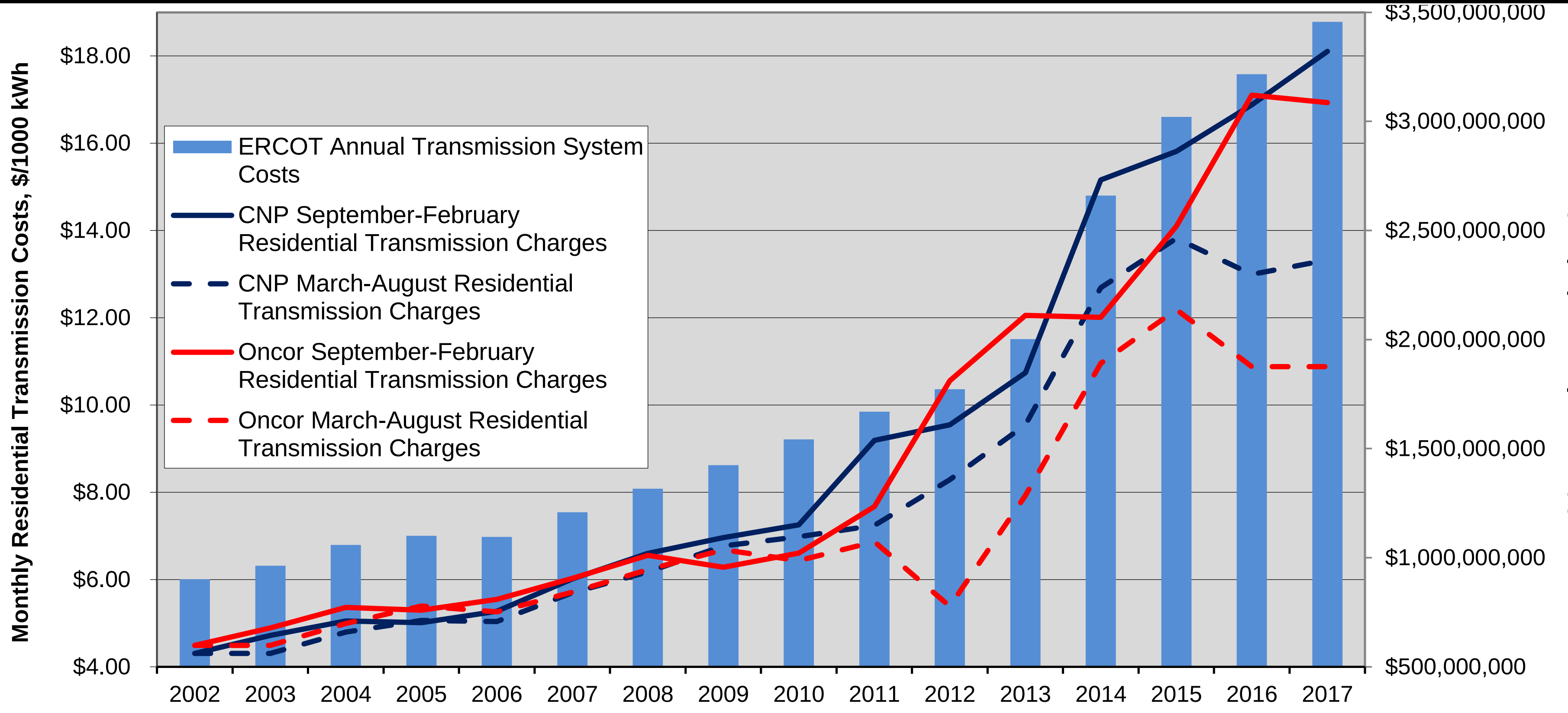
Fuel Abundance & Diversity Gave Texas a Natural Advantage



Source: ERCOT, 2016 and 2017 Demand and Energy Reports. Not listed generation includes: solar, water, net DC/BLT, and other, which make up approximately 1% of total generation.

TRANSMISSION & DISTRIBUTION COSTS IN TEXAS HAVE DOUBLED (& market is much more sensitive to fuel cost)

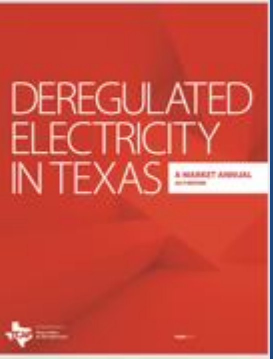
Competitive Renewable Energy Zone (CREZ): $7 billion in transmission capacity; 16 GW of wind in *Texas (and growing ?)*



2002 to 2017

83% <u>increase</u> in regulated charges (T&D)

16% <u>decrease</u> in competitive charges (energy)



PART 2: Data Showing That the Texas Deregulation Experiment is a Cautionary Tale & is Not Over

A. Texas Data Contradicting Claims of Cost Savings

- Texas Coalition for Affordable Power (TCAP)(2002-16)
- C.H. Guernsey Semiannual Data (2006-17)

B. Texas Reliability Challenges

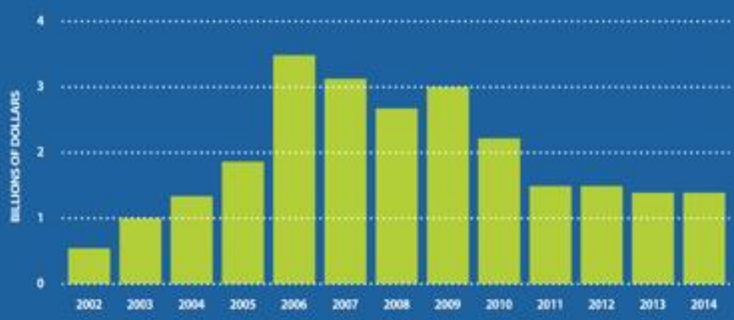
C. Local Governmental (& Cooperative) Burdens of Wholesale Deregulated Electricity Market

TCAP Study: Data Contradicts Assumption that Deregulation = Cheaper Power

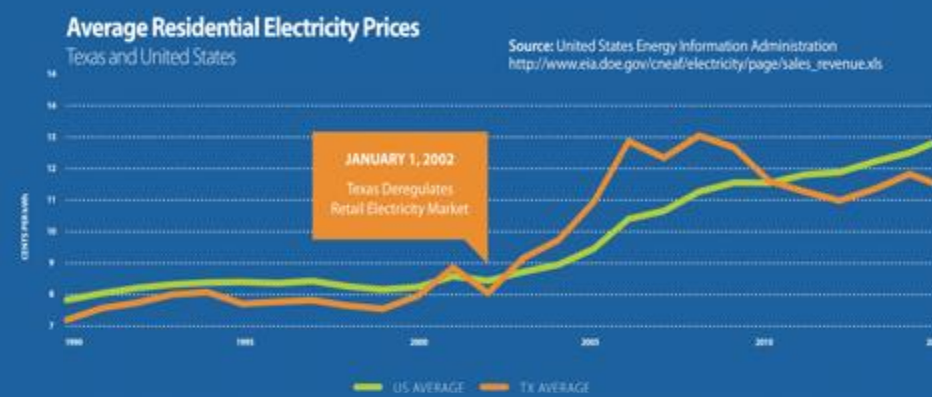
Nearly $25 Billion in Lost Savings

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

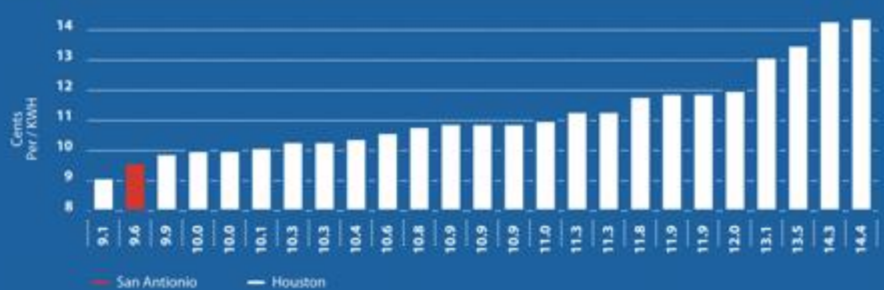


Average Residential Electricity Prices Texas and United States 1990-2015



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.

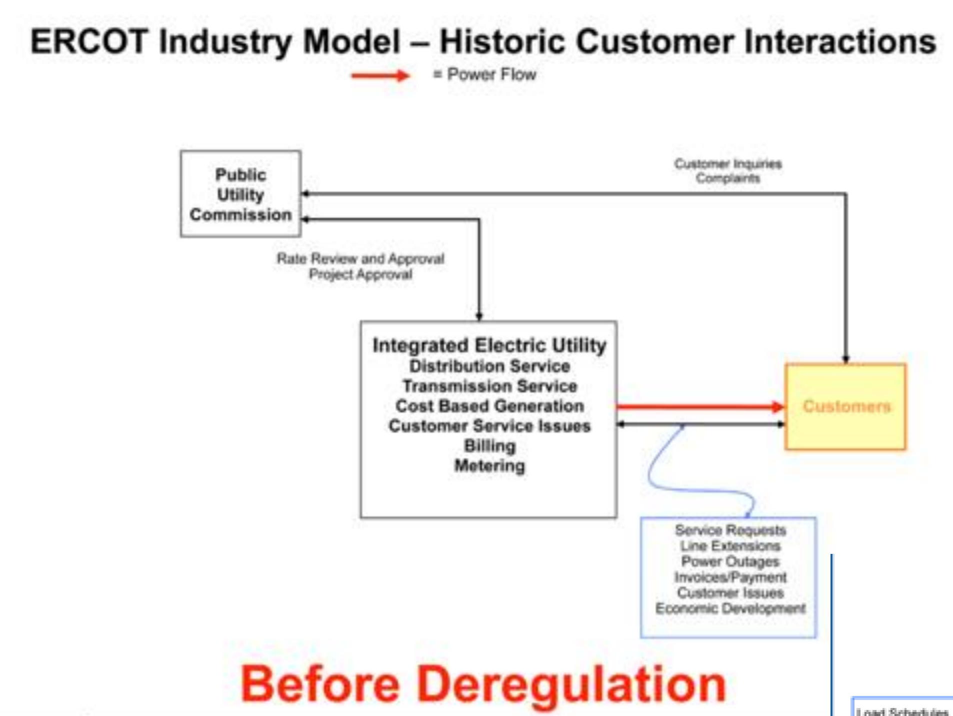
Average Residential Electricity Prices

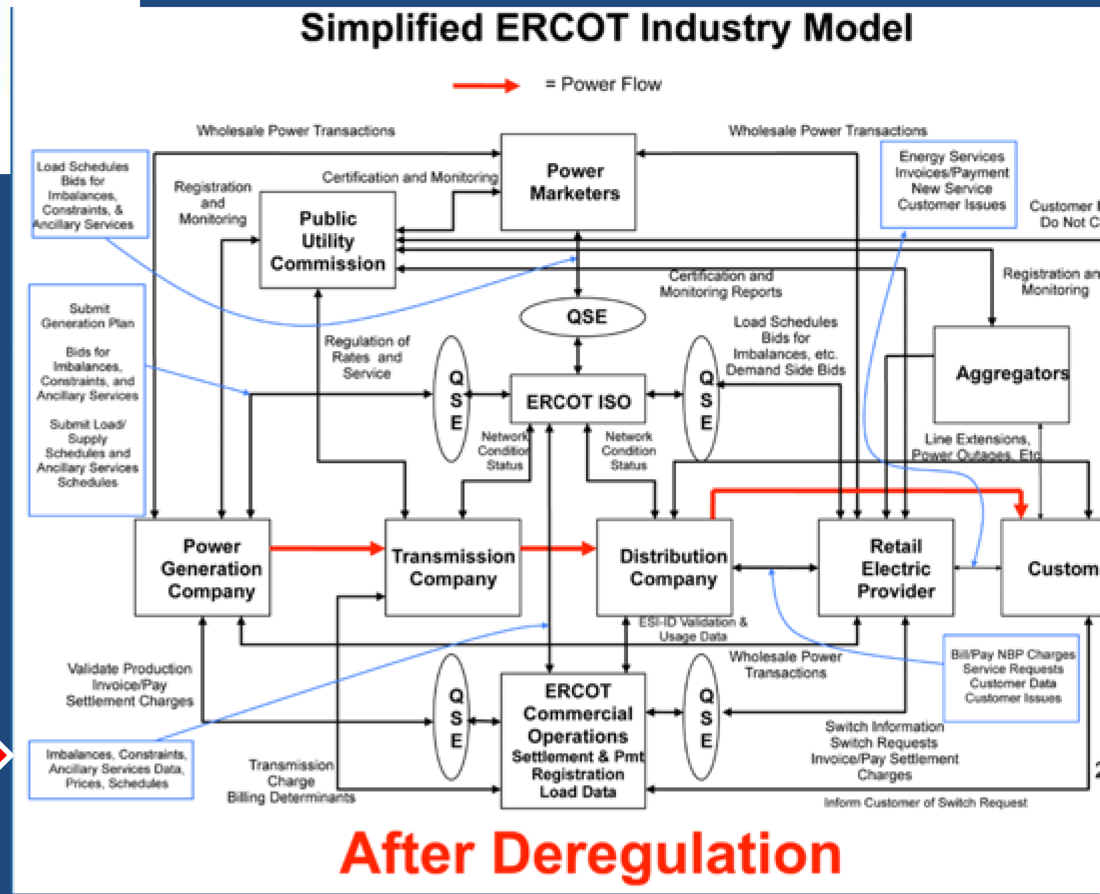
Inside & Outside Areas of Texas with Retail Electric Deregulation

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

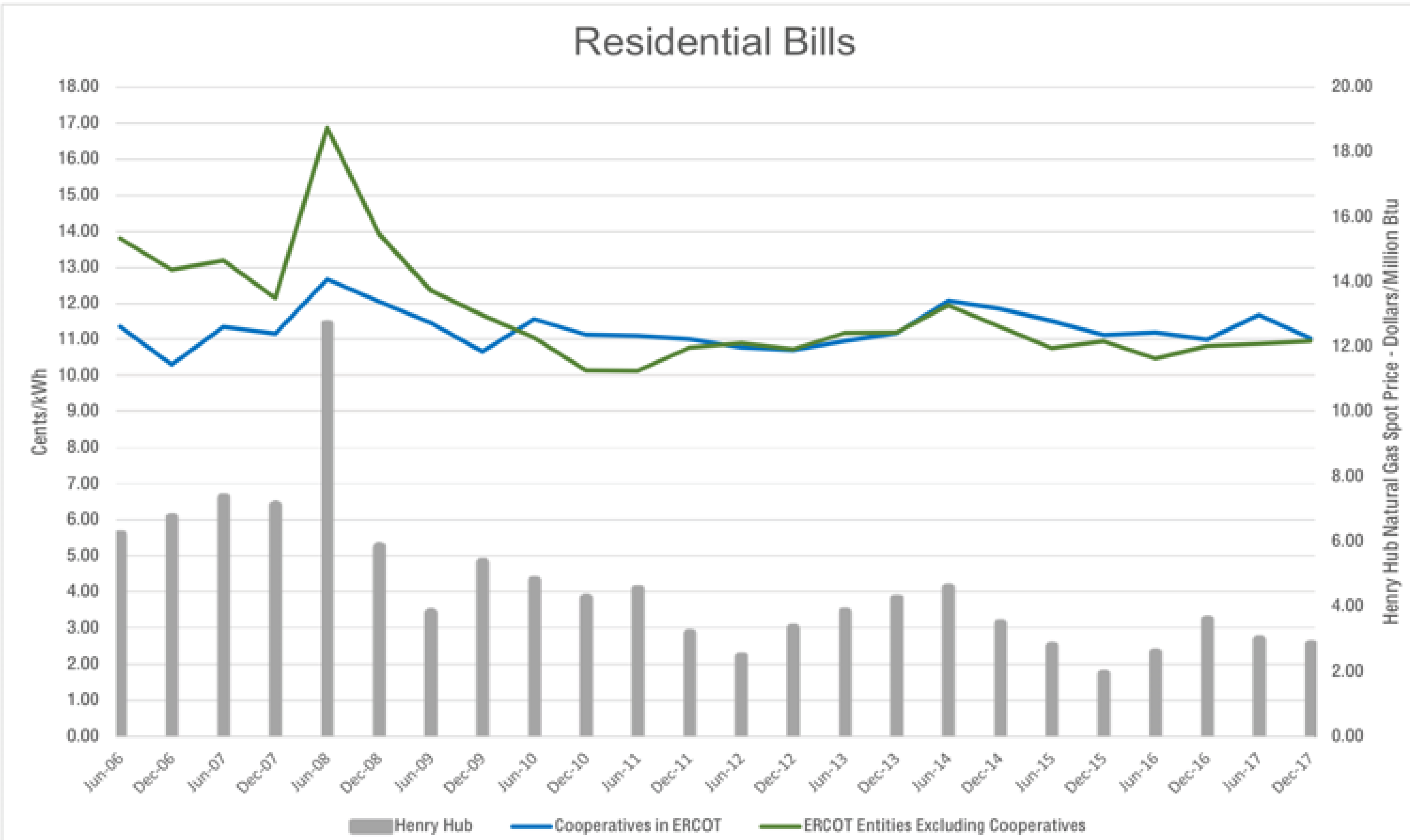
TCAP Study: Retail Choice is far from "Simple"





Guernsey Cooperative Data: Don't Need Deregulation to Deliver Stable, Cheap Power

Texas Electric Cooperatives
Your Touchstone Energy® Partner

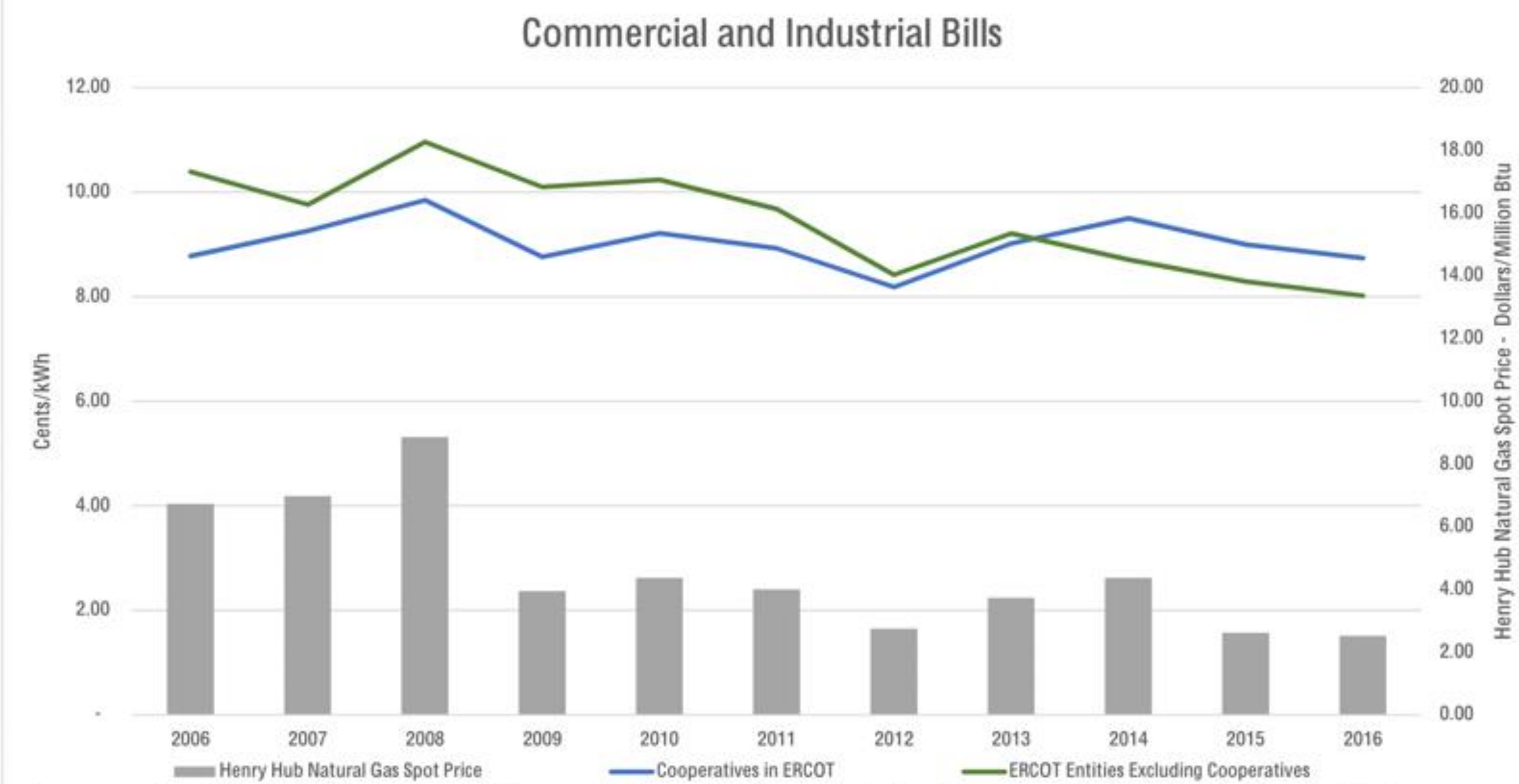


*Average cost/kWh for Cooperatives obtained from TEC bi-annual rate survey. Average cost/kWh for REP obtained from documents available on http://www.puc.texas.gov.

Guernsey Data (continued)

Texas Electric Cooperatives

Your Touchstone Energy® Partner



*Average cost per kWh obtained from data available on www.EIA.gov. Cost does not reflect a uniform comparison based on load size, load factor, consumption or rate structure. Any variability in those inputs will affect average cost/kWh. Since no metrics are provided for the inputs used to compute the average cost/kWh, it cannot be determined whether the costs shown are driven by rates or load characteristics. For example, two consumers billed under the same rate would yield two very different cost/kWh if one operated 600 hours per month and the other 200 hours per month. A utility may have many more consumers operating at higher load factors and thus have a lower cost/kWh but not necessarily a lower rate.

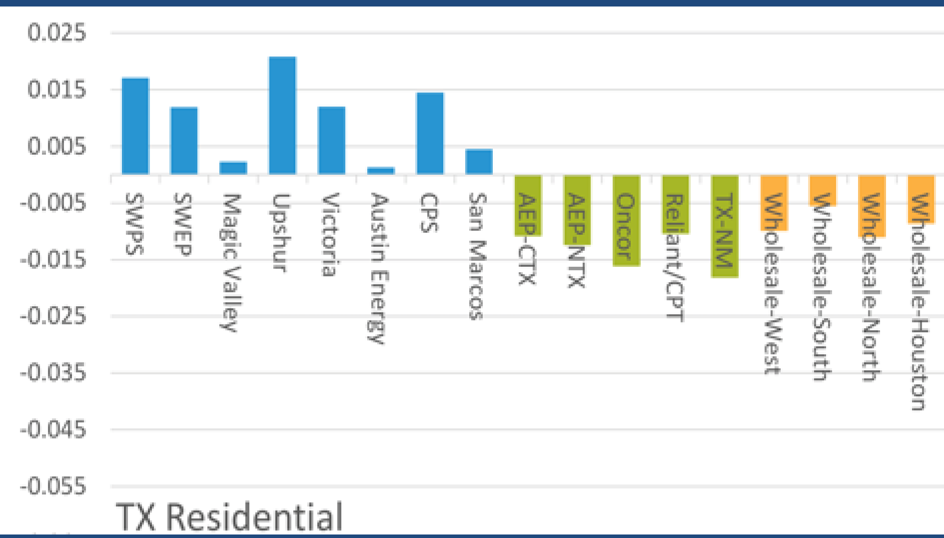
Competition Advocates Cherry-picking Data to Attribute Lower Prices to Retail Choice

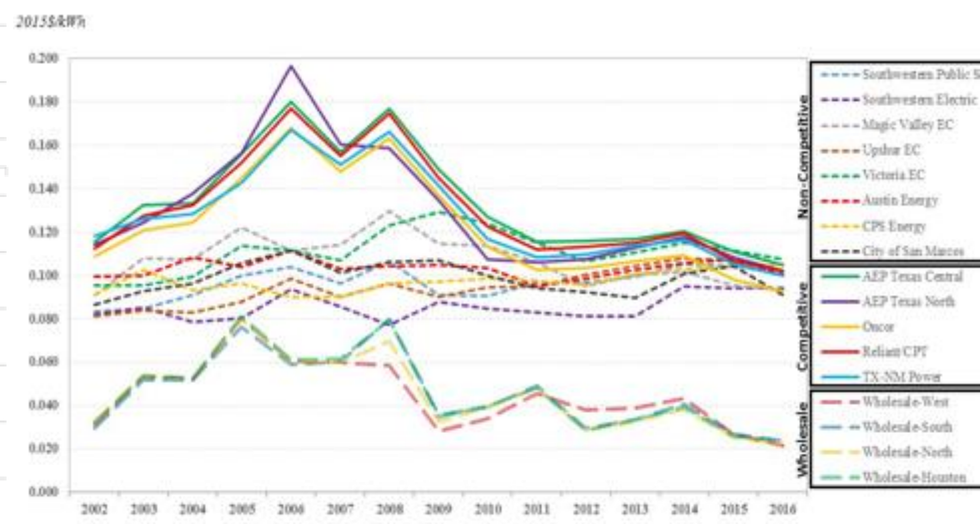
Competition Advocates Slides

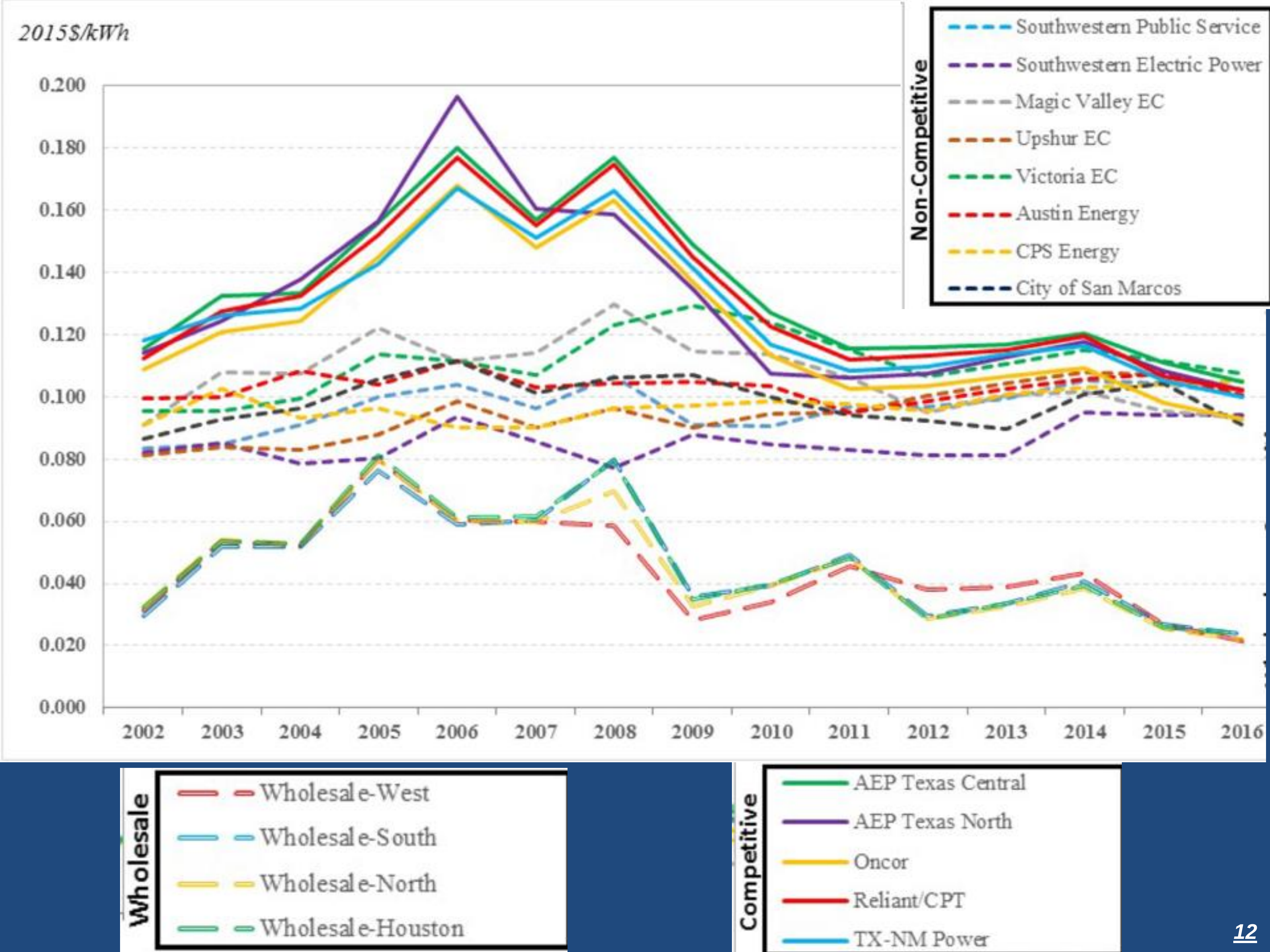
- *"Prices have declined [in competition] while they have increased in all non-competitive market areas."*
- Use just 2 data points (2002 & 16); ignores volatility during the intervening 15 years.
- No mention that residential customers have spent more total $ in competition.

Actual Rice Data

- *"Texas experience is not universally accepted as a success."* (p.3)
- The full data set is a story of stability and lower prices in regulated areas (Fig.6, p.13).
- Texas enjoys natural advantages that prevent volatility but retail customers in competition have still been exposed to more volatility than regulated areas.

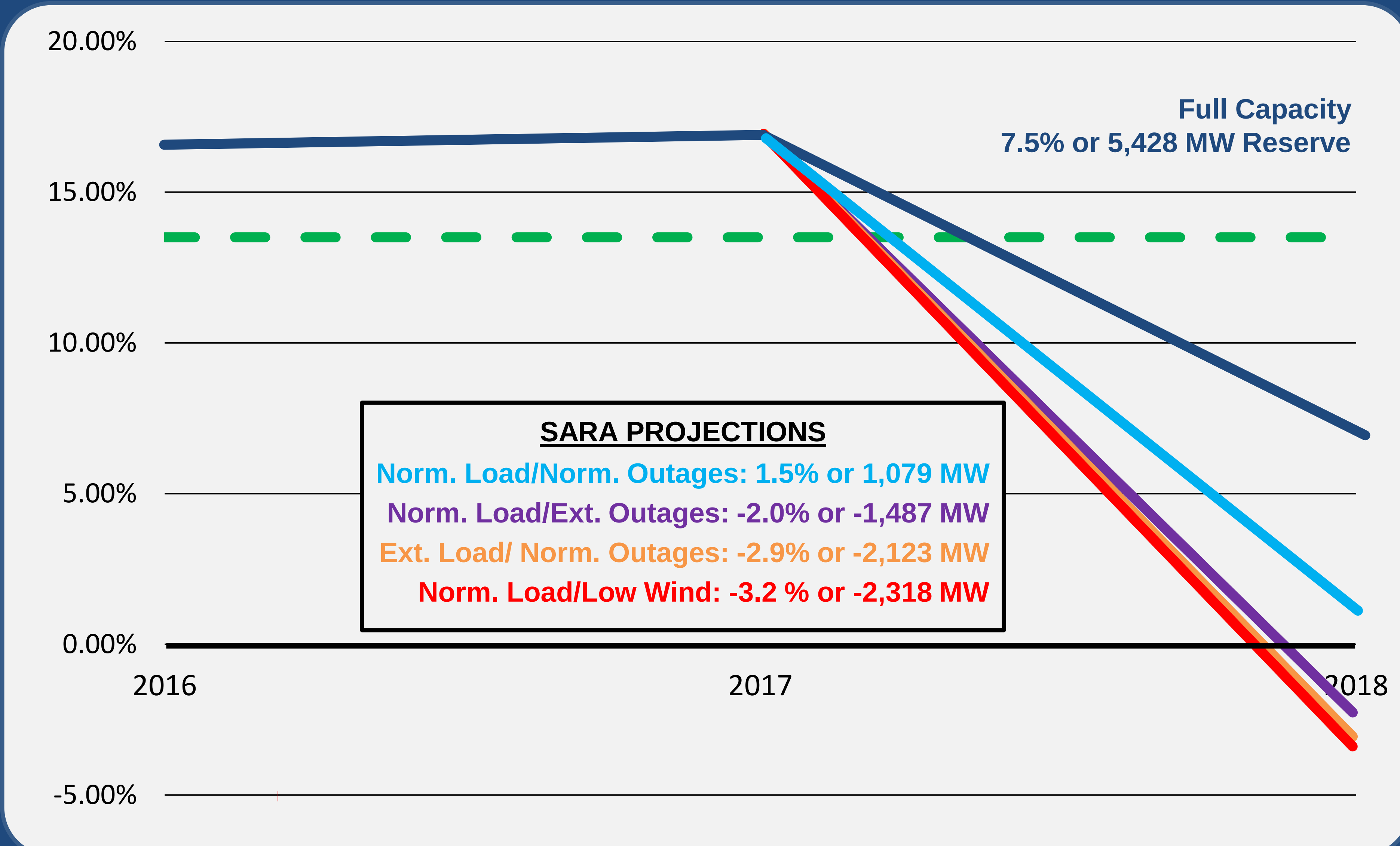






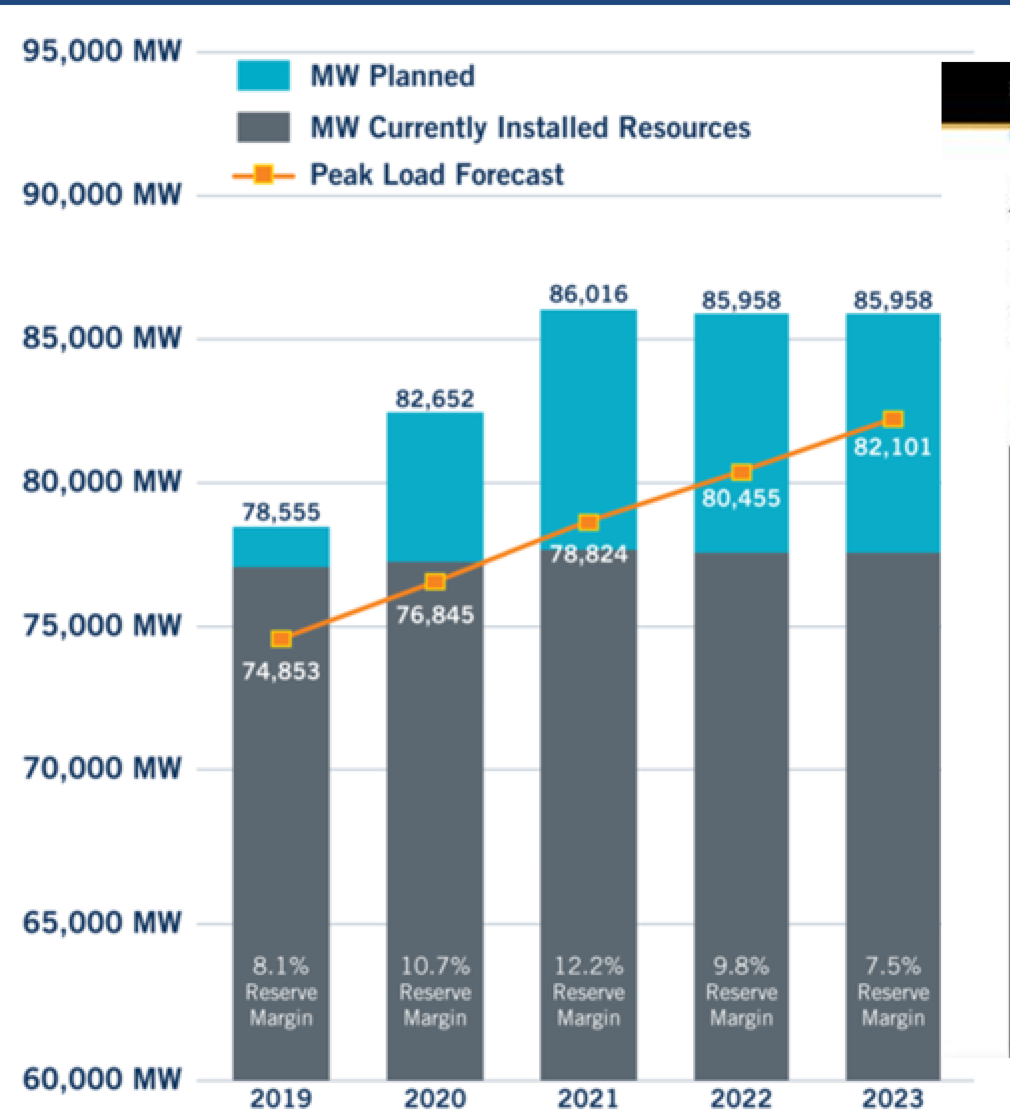
2015$/kWh
0.200
0.180
0.160
0.140
0.120
0.100
0.080
0.060
0.040
0.020
0.000
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
Non-Competitive
Southwestern Public Service
Southwestern Electric Power
Magic Valley EC
Upshur EC
Victoria EC
Austin Energy
CPS Energy
City of San Marcos
Wholesale
Wholesale-West
Wholesale-South
Wholesale-North
Wholesale-Houston
Competitive
AEP Texas Central
AEP Texas North
Oncor
Reliant/CPT
TX-NM Power

ERCOT RELIABILITY NOW IN QUESTION



Sources: ERCOT, Capacity, Demand and Reserves Reports, Winter Updates, 2007-2017; Seas. Assess. of Res. Adeq., Mar. 2018.

Capacity Reserve Margins at Historic Lows in Texas ERCOT Market



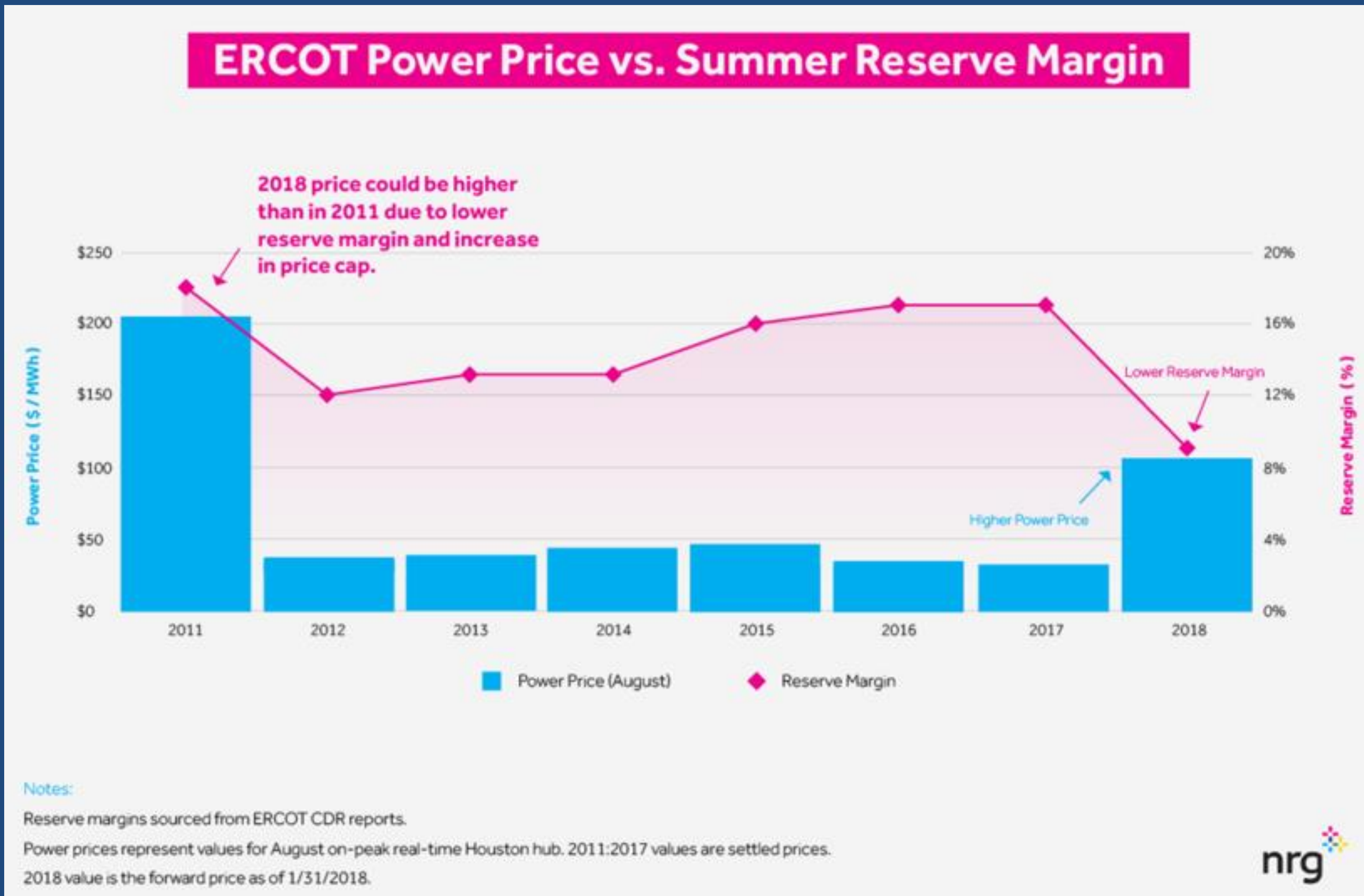
HOUSTON CHRONICLE

BUSINESS // ENERGY

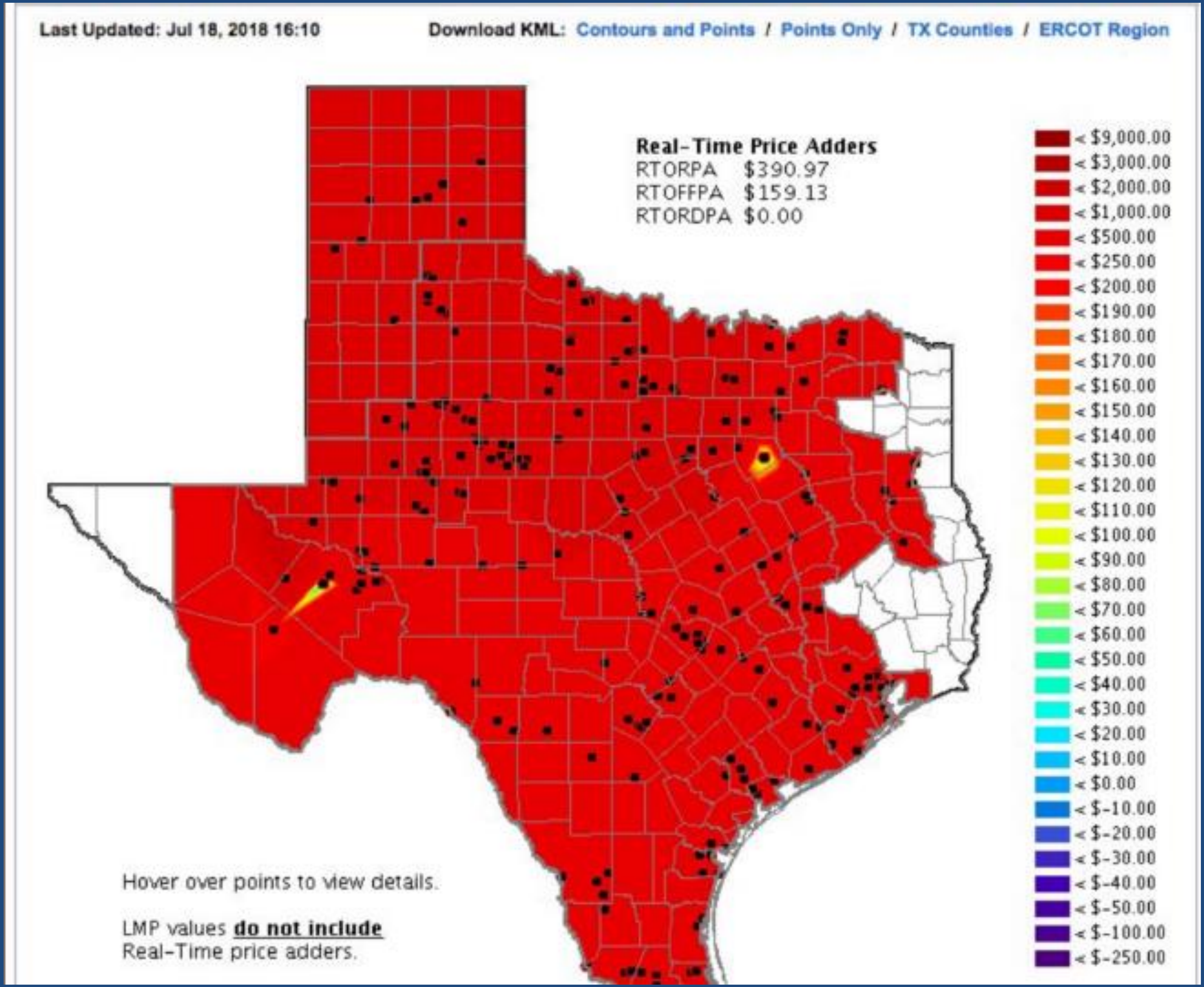
Another Texas power plant is mothballed, raising concerns over reserves and prices

L.M. Sixel | Jan. 7, 2019 | Updated: Jan. 7, 2019 6:08 p.m.

Thin Reserves Expose the Market to Significant Market Volatility



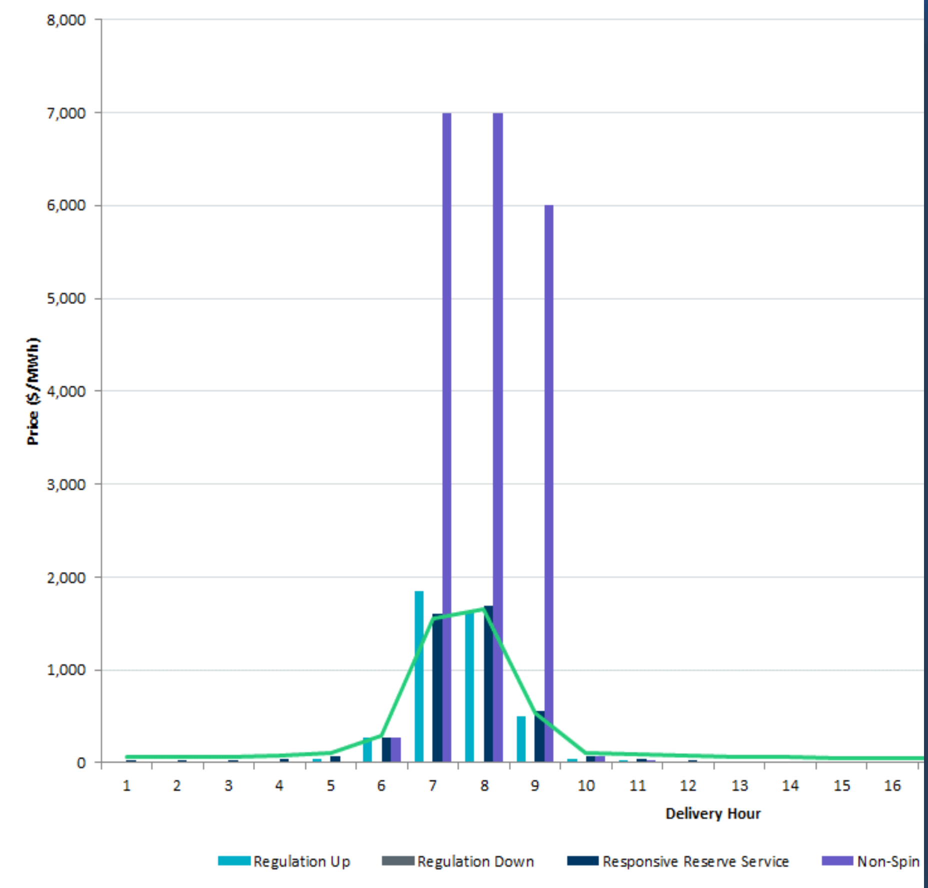
Tight Reserve Margins and Price Escalation



Prices Can Blow Out at Any Time

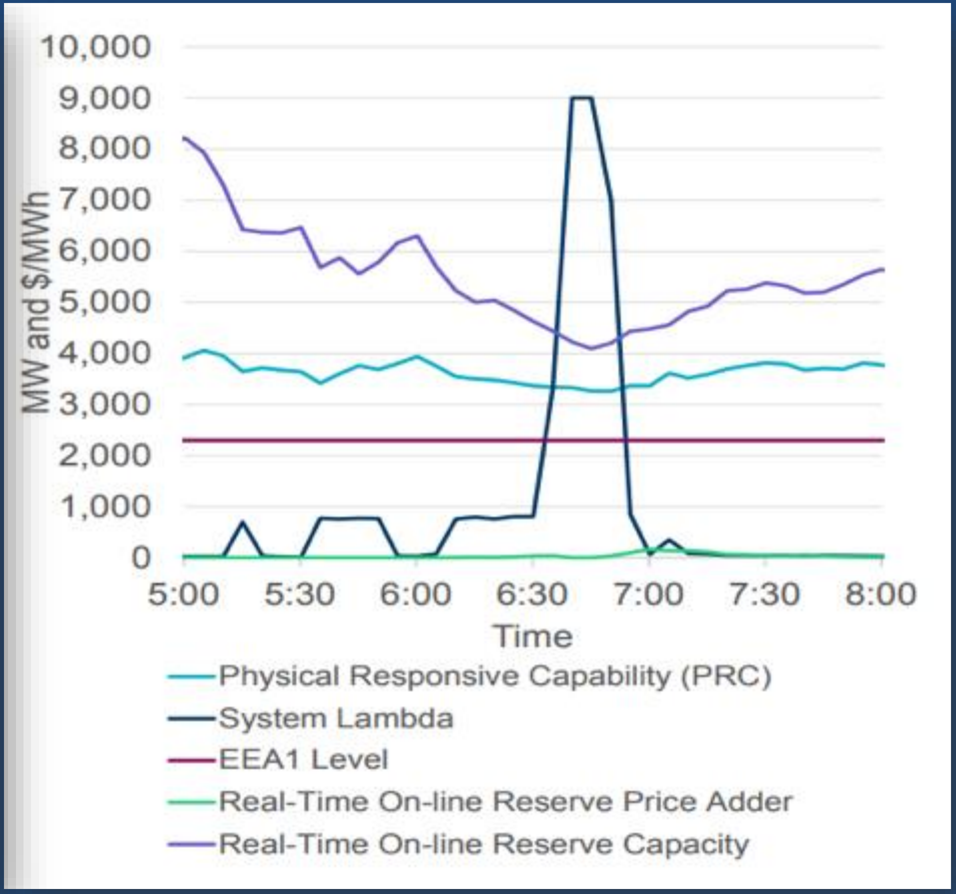
January 17, 2018

Day-Ahead Market (DAM)

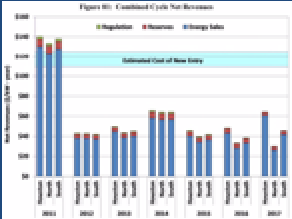


January 23, 2018

Real-Time Market (RTM)



Source: ERCOT 2/13/18 Report



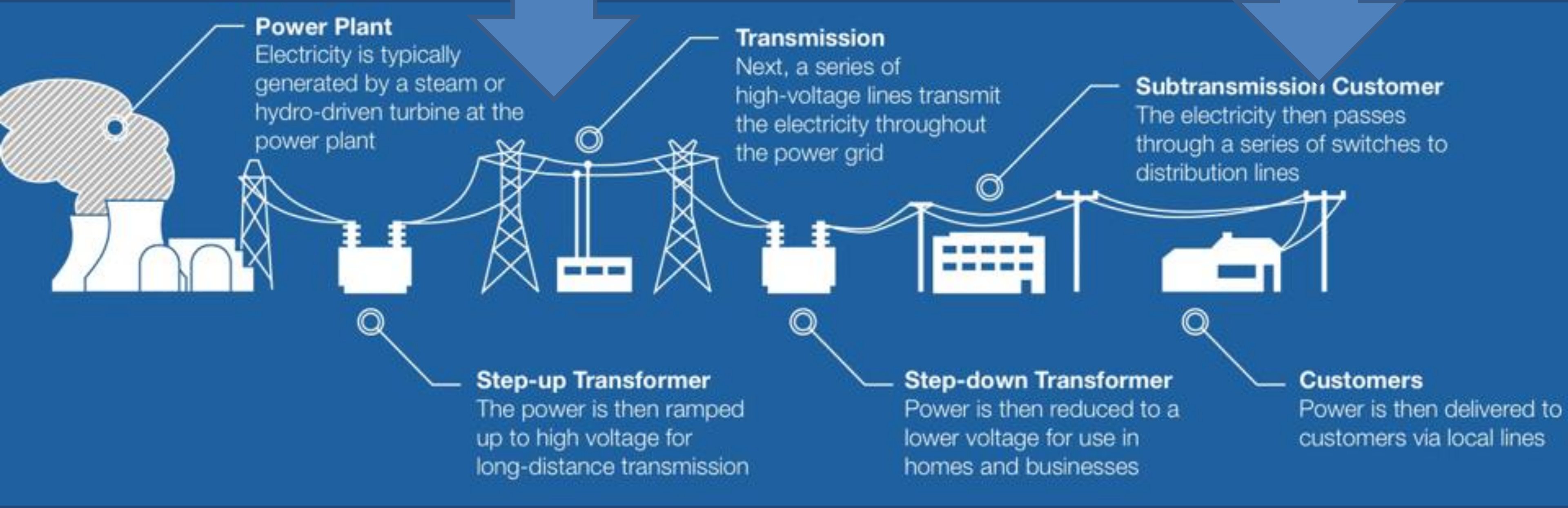
PART 3: Estimates of the Total Cost of Retail Choice Must Include Public Power's Uncompensated Exposure to the Market's Call Option on Capacity.

- Retail Deregulation is Optional, but Wholesale Deregulation is NOT.
  - I.E., Public Power Can "Opt-in" to Retail Competition, but cannot "Opt-out" of Erosive Wholesale Markets.
- Obligation to Serve Citizens and Properly Plan Leads to Uncompensated Call Option for Entire Market.
- Disparity of Exposure to Distribution-level Outages Has Proven in Texas to Make Market Rule Refinement to Improve Reliability Nearly Impossible.

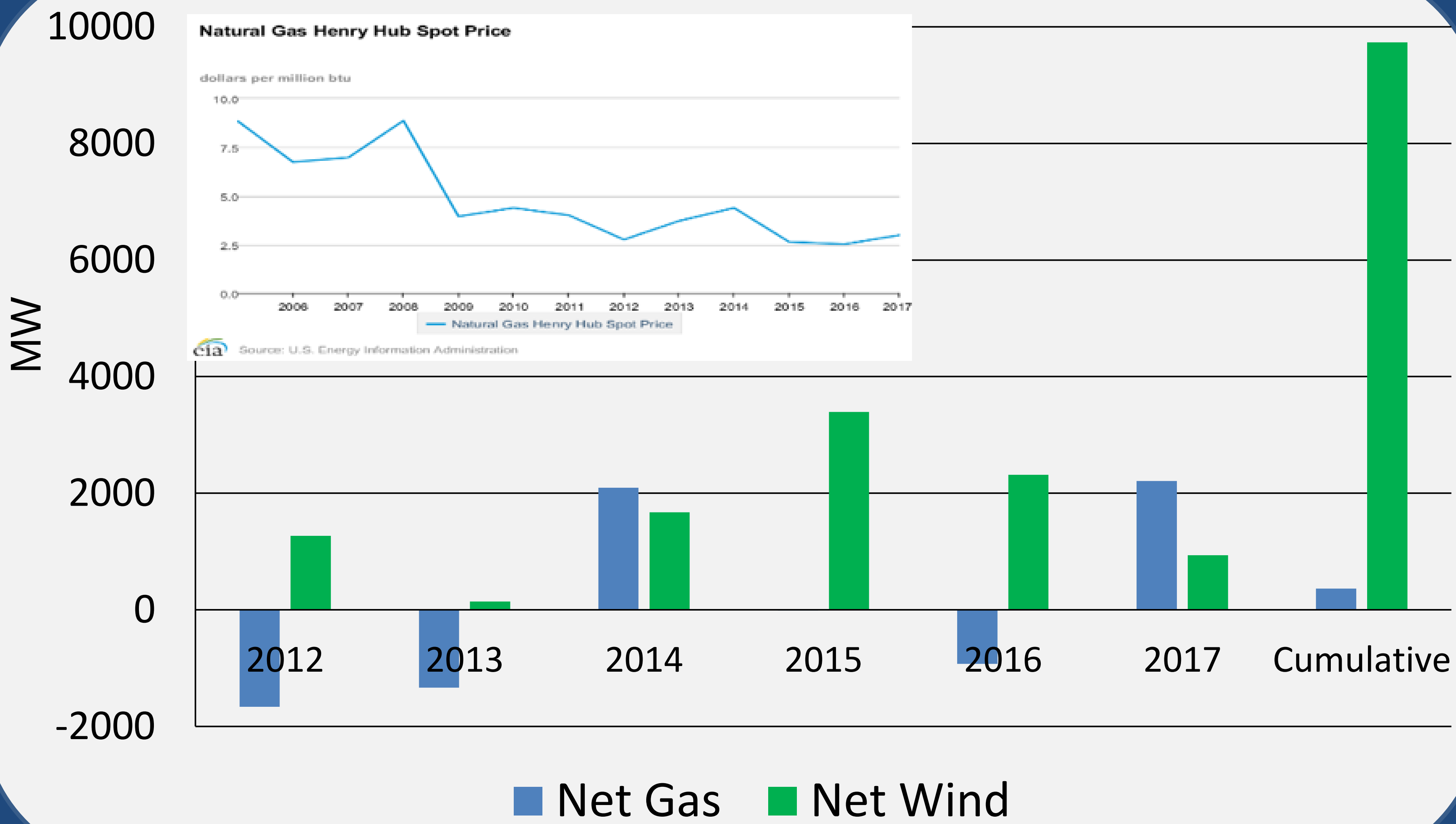
The Grid is not an "Opt-Out" Situation

Munis & Coops are Part of an Interconnected Grid So they Must Participate in the Deregulated Wholesale Market Which Means the Entire Market Has an Uncompensated Call Option on their Generation Resources

Opting in or out only determines who you pay for electricity.

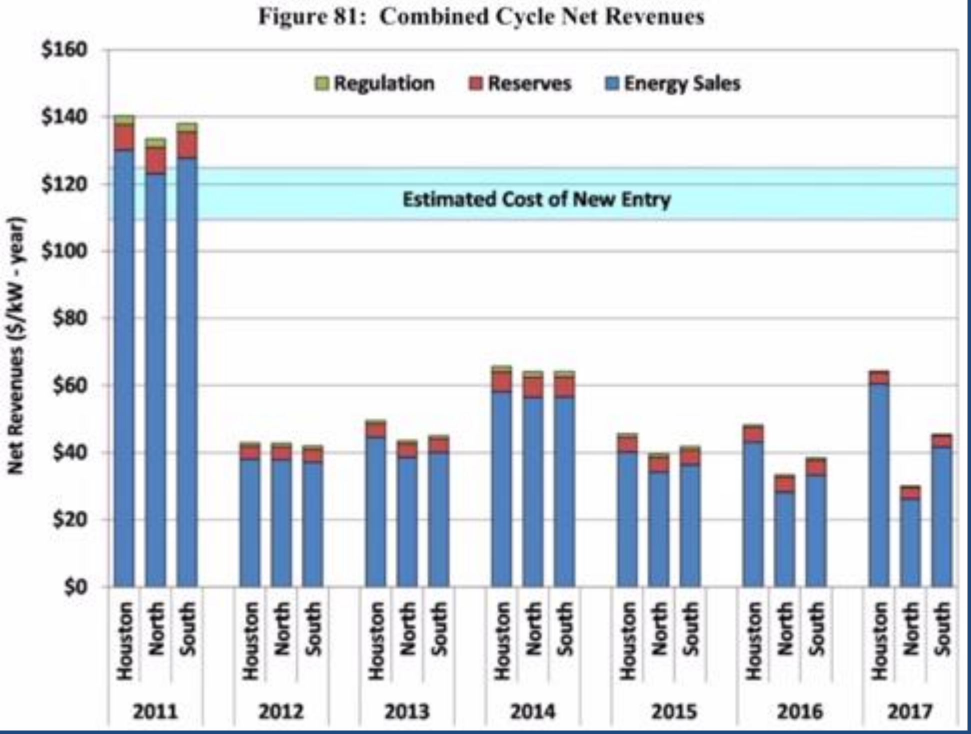


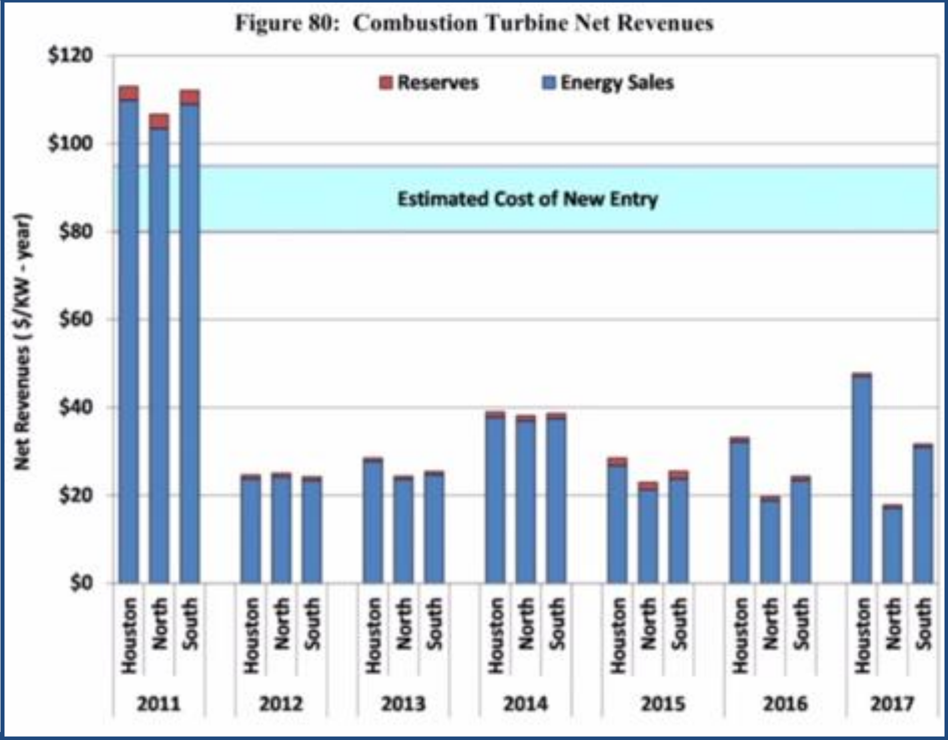
Market Disfunction Preventing Gas Builds



Sources: EIA-860M, October 2017. Installed capacities. Includes Electric Utility, IPP CHP, and IPP Non-CHP units; excludes industrial and commercial gen.

Erosive Effect of Market Distortions on Capacity and Reliability





Sources: ERCOT Independent Market Monitor

TAKE-AWAYS

1. Data Does NOT Support Claims that Retail Choice is the Reason ERCOT Rates Dropped.
2. Florida Should Closely Track Texas market volatility & reliability over the next 2 years.
3. As Florida Estimates Total Costs, it Must Include Public Power's Uncompensated Exposure to Call Option on Capacity.

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The Cautionary Tale of Texas:

Why Florida's Power Market Should Not Be Deconstructed based on Comparisons to Texas

QUESTIONS?

CRA Charles River Associates

Florida Electricity Markets
Restructuring Ballot Initiative

Report to FIEC – Summary and Discussion Exhibits

February 21, 2019

Context and Background

The Florida Chamber of Commerce retained Charles River Associates (CRA) to conduct an independent analysis to estimate the potential financial impact to state and local governments resulting from implementation of the proposed ballot initiative

Approach for the analyses

- Reviewed the impact of a transition to a restructured electricity market across other jurisdictions over the last 20 years
- Analyzed the potential financial impact of restructuring in FL, as prescribed by the ballot language, to state and local governments
- Used a top-down approach to develop potential outcome ranges based on historical precedents of restructuring in other jurisdictions, recent industry trends, and current status of the Florida electric system

Key questions to be addressed

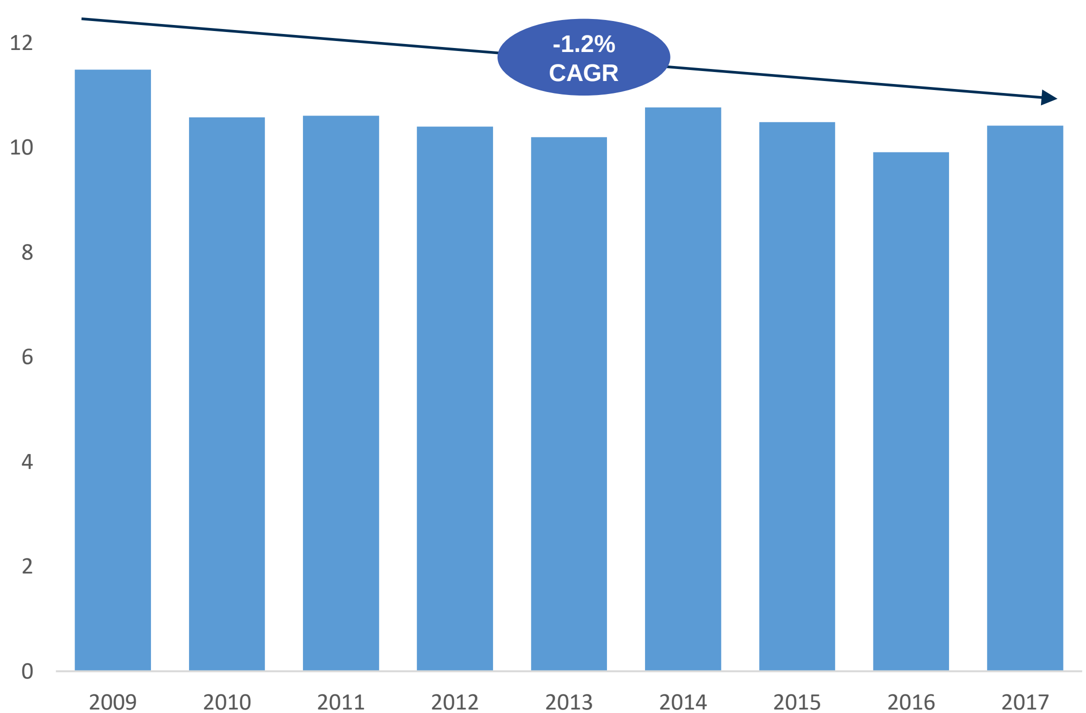
1. How has the Florida electricity market performed relative to the rest of the country? In terms of electricity rates, grid reliability, and administrative costs?
2. What has been the experience of electricity market restructuring in different states across the U.S.?
3. How did the electricity market restructuring impact performance in Texas? In terms of electricity rates, grid reliability, and administrative costs?
4. If implemented, what would be the potential impact of restructuring the electricity market in Florida?

1

Florida Electricity Market Performance

Florida's electricity markets have outperformed the rest of the country in terms of average electricity rates, grid reliability, and overall system administrative costs

Florida Average Retail Rate – All Sectors[1] ($ cents / KWh)



Florida Ranking Relative to Other States

PSC Cost per Capita[2]

Amongst the lowest cost states (5 of 23 analyzed)

Grid Reliability[3]

Amongst the best performing states (9 of 50)

Sources: [1] EIA Florida State Electricity Profile; [2] Population data from US Census Bureau and PSC costs from individual state budget office reports (ME, PA, NY, AL, OH, NV, CA, MI, IL, MD, UT, AR, MS, LA, IN, TN, FL, GA, TX, SC, and NC); [3] https://www.usnews.com/news/best-states/rankings/infrastructure/energy

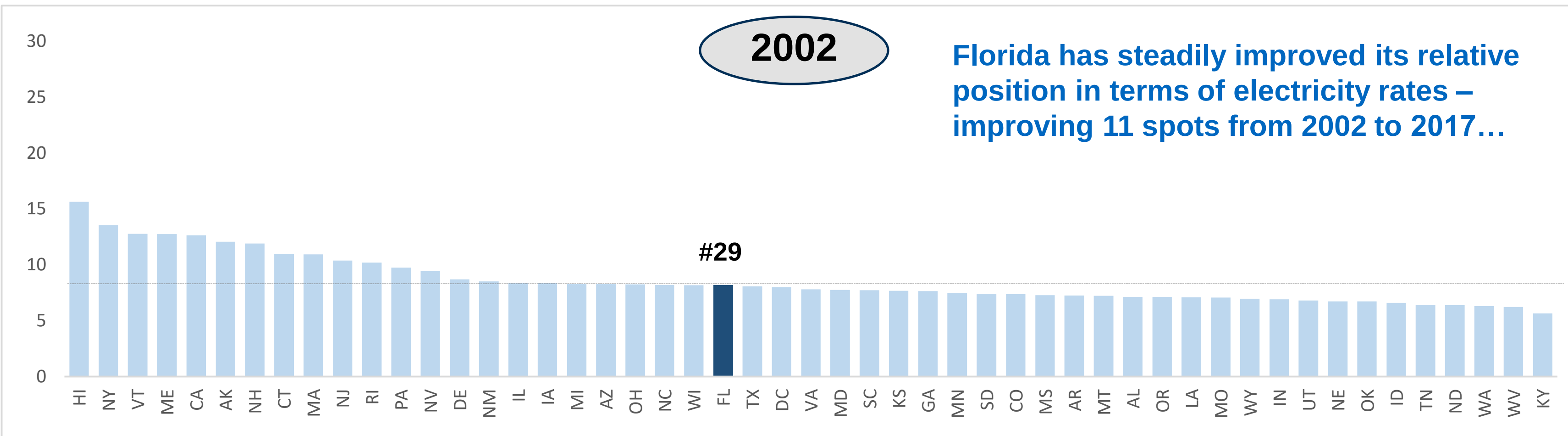
1

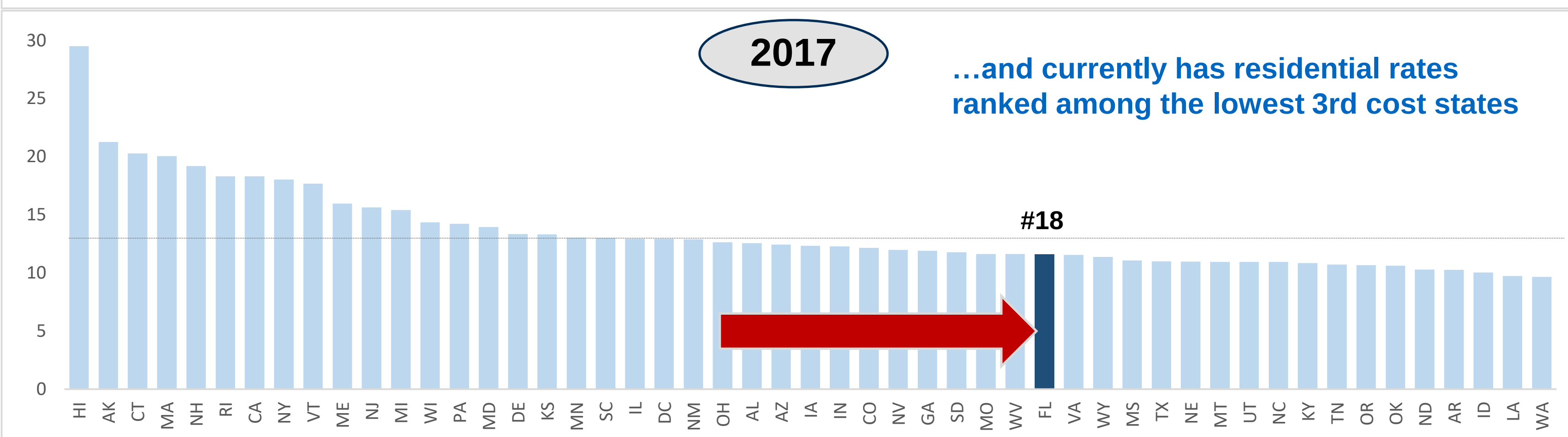
Florida Residential Rates – Comparison with National Average

Residential electricity rates in Florida have improved considerably relative to the national average between 2002 and 2017

Shift from all-classes to residential rates – most comparable across states and most important to average taxpayer

Florida Relative Rate Positioning (Residential rates; cents / KWh)





CRA Charles River Associates

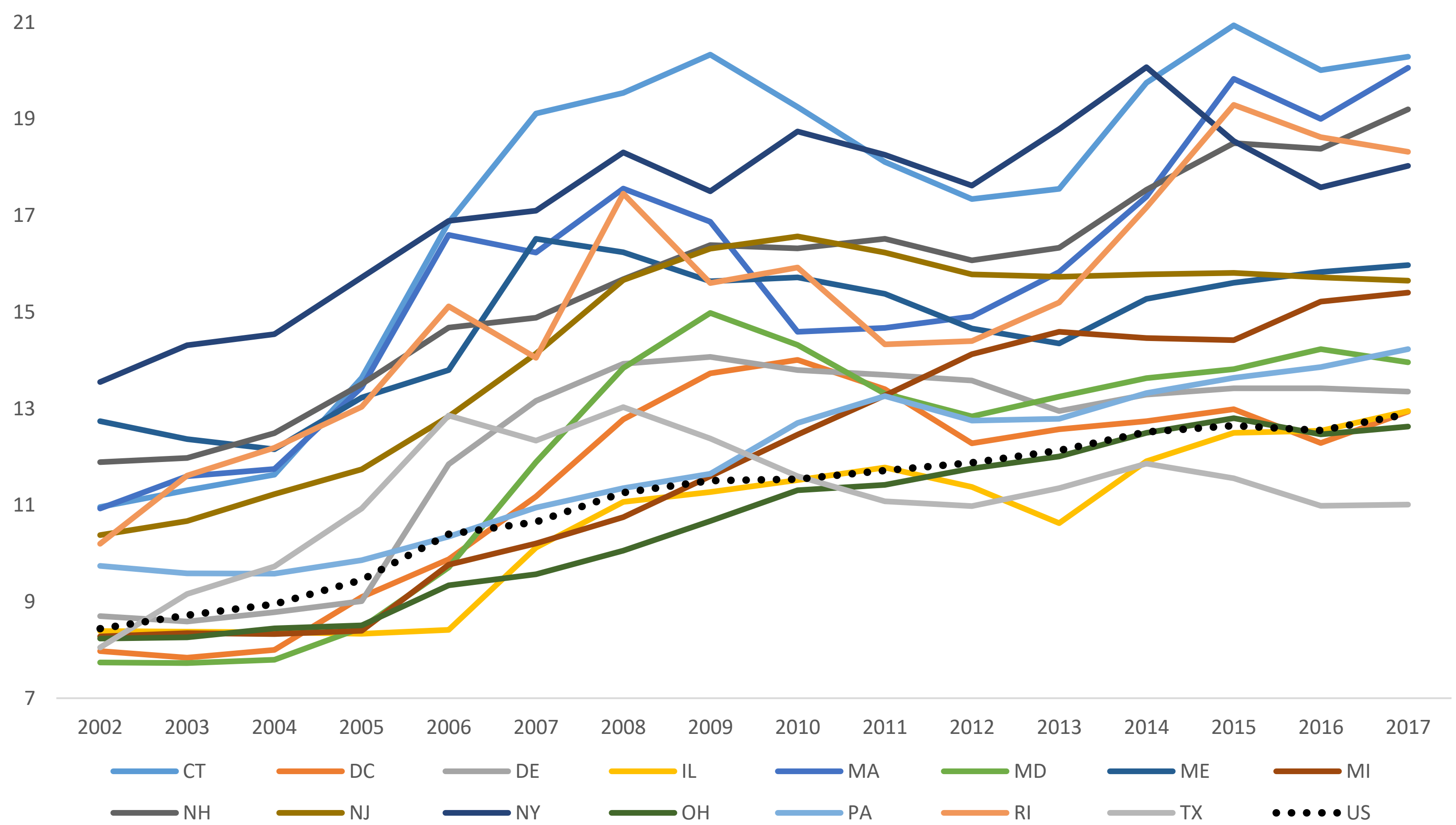
Sources: EIA State Electricity Market Data.

2

Impact of Restructuring in the U.S. – Electricity Rates

No jurisdiction, including Texas, was able to reduce residential rates consistently after restructuring its electricity markets

Average Annual Electric Rates – Restructured Jurisdictions (Residential; cents / KWh)



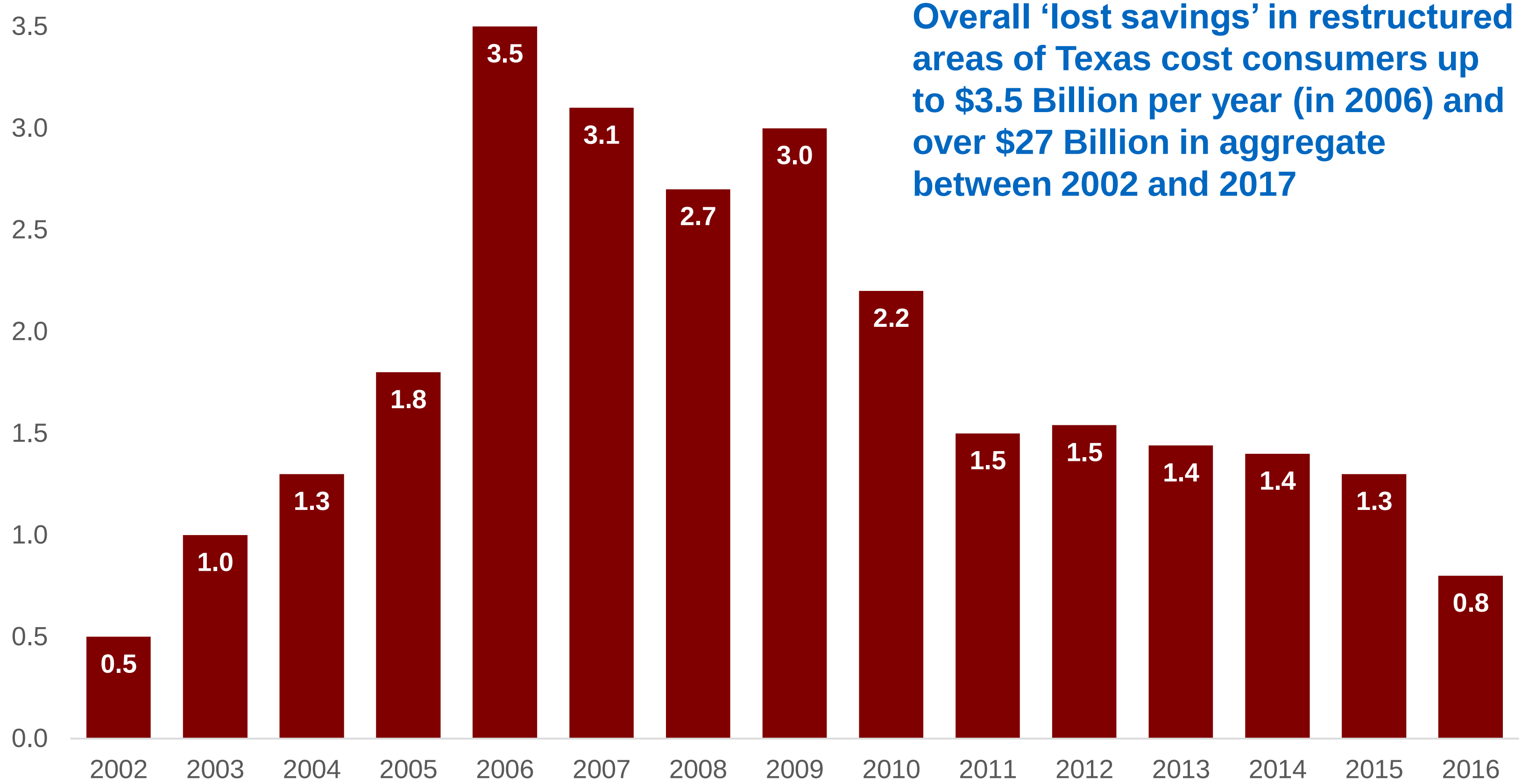
Sources: EIA State Electricity Market Data.

3

Impact of Restructuring in Texas – Electricity Rates

Texas consumers have consistently paid higher residential electricity prices in restructured areas, as compared to prices in areas exempt from deregulation

"Lost Consumer Savings' from Restructuring in Texas[1] ($ Billions)



Overall 'lost savings' in restructured areas of Texas cost consumers up to $3.5 Billion per year (in 2006) and over $27 Billion in aggregate between 2002 and 2017

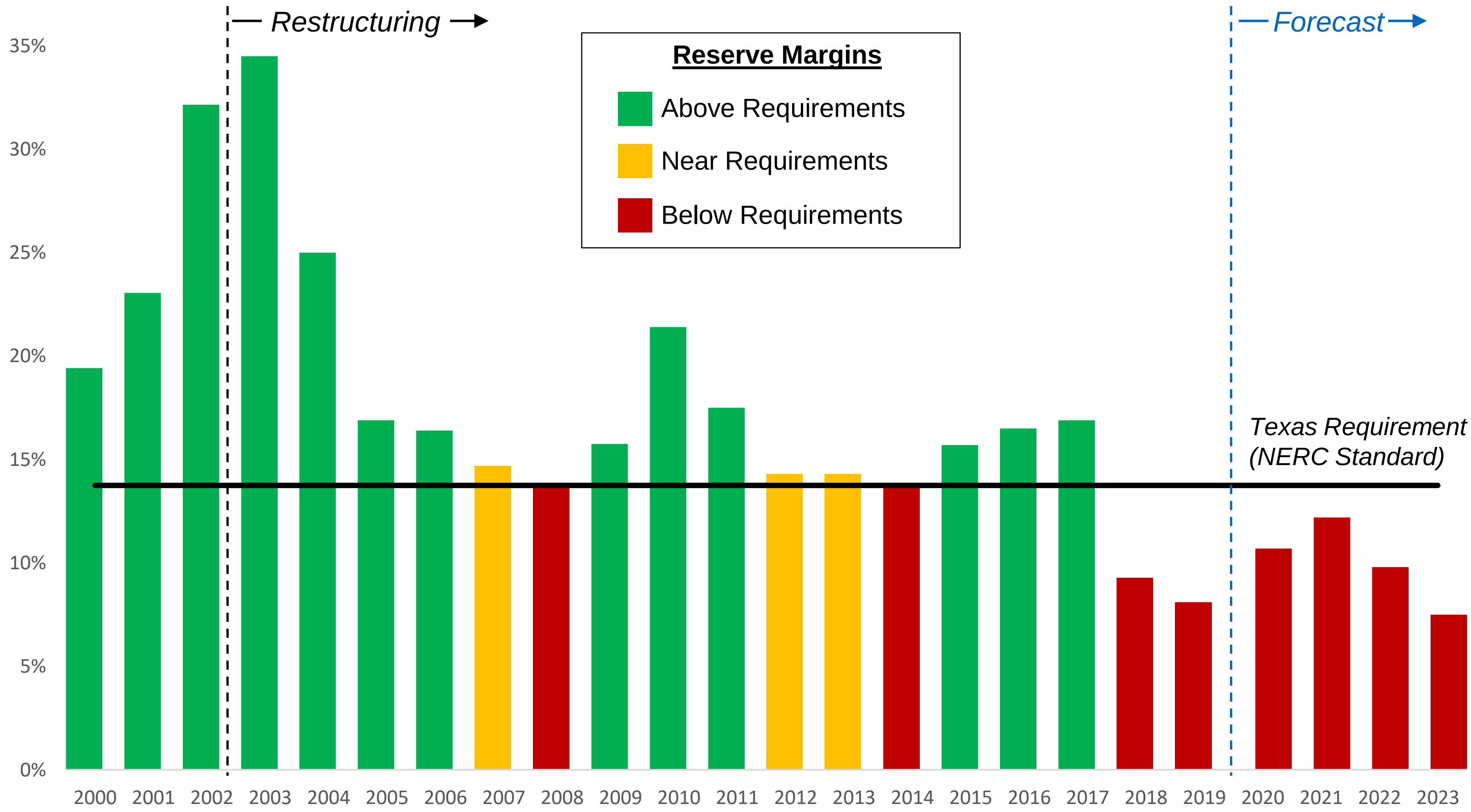
Sources: [1] Electricity Prices in Texas Snapshot Report – 2018; Texas Coalition for Affordable Power.

3

Impact of Restructuring in Texas – Generation Reliability

Market restructuring has severely impacted reserve margin adequacy – it is expected that Texas will see significantly higher costs or increased outages and blackouts

Impact of Restructuring on Reliability in Texas[1] (Reserve Margin %)



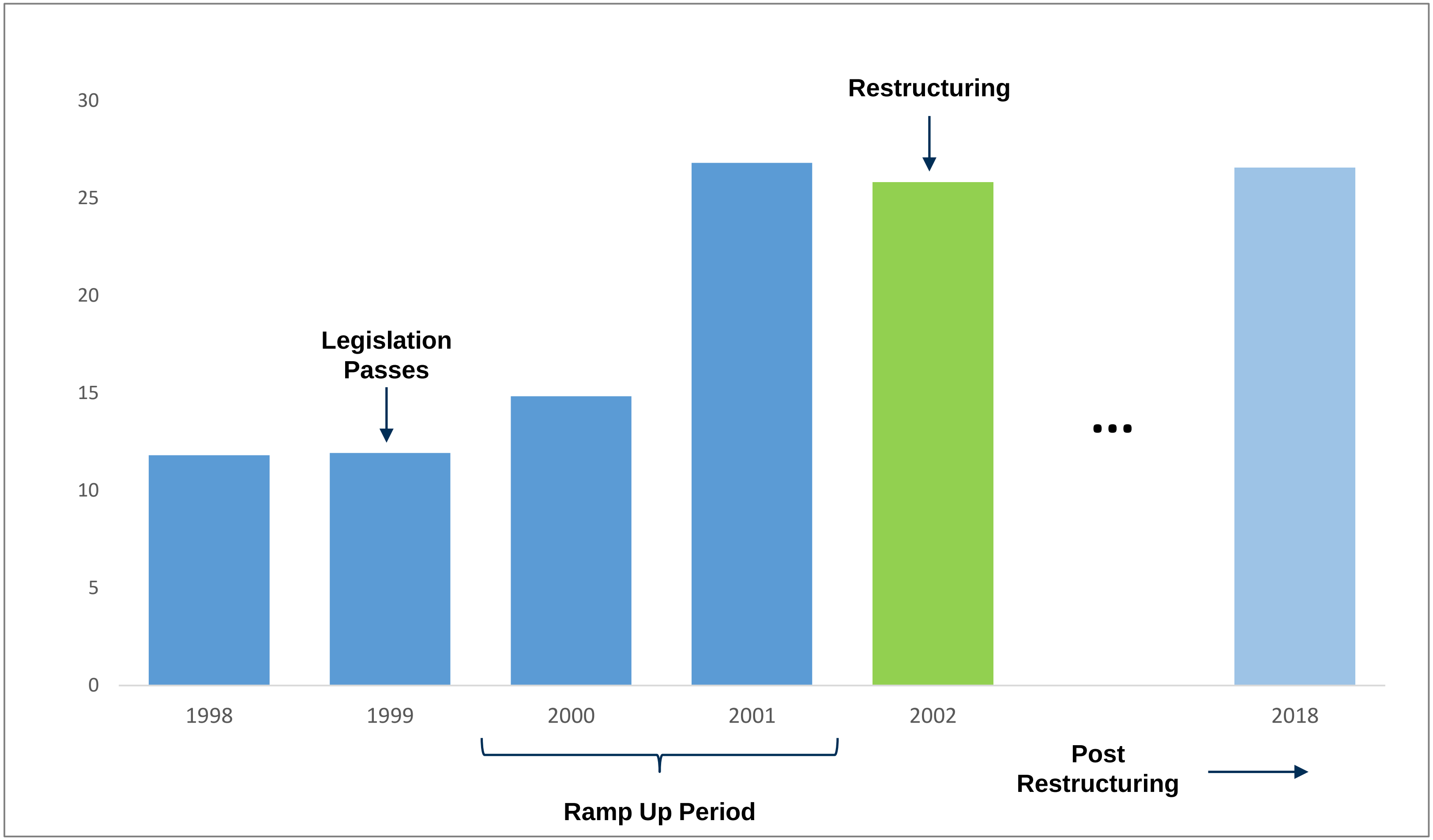
Sources: [1] http://www.ercot.com/gridinfo/resource

3

Impact of Restructuring in Texas – Administrative Costs

Texas PUC expanded resources significantly to prepare for the new market, ensure execution, and oversee the new market structure – resulting in more than double costs

Texas Public Utility Commission Cost – Impact of Restructuring ($ millions)



CRA Charles River Associates

Sources: Legislative Appropriations Request for Fiscal Years 2018 and 2019; Governor's Office of Budget, Planning and Policy; Legislative Summary Document Regarding PUC Texas – January 2003; State Auditor's Office (SAO 03-377); Legislative Summary Document Regarding PUC of Texas. January 2003. State Auditor's Office (SAO 03-377). Page 3; Legislative Appropriation Request submitted to the Governor's Office of Budget. Texas PUC, August 12, 2016. Page 11

4

Potential Impact to Florida Under a Restructuring Market Scenario

Findings from our research and analysis show that there is considerable negative risk associated with restructuring the Florida electricity market

- Electricity market restructuring in other jurisdictions has resulted in higher electric rates for consumers in general and significantly higher costs for states to develop new institutions to manage wholesale markets, educate consumers, ensure adequate supply and reliability, handle increased litigation, provide public assistance to low income ratepayers, and manage the overall higher regulatory complexity
- Given the language of the ballot petition, Florida state and local governments would likely experience a severe loss of tax revenues from Franchise Fees, Property Taxes, Municipal Public Service Taxes, and Gross Receipts Tax
- Additionally, based on the experience from other jurisdictions, Florida would also likely incur significantly higher administrative costs across state and local governments
- Negative financial implications across all scenarios and sensitivities – any potential increases in sales tax driven by higher rates are relatively insignificant compared to the other combined negative impacts of tax revenue losses and higher costs
- New state taxes would need to be implemented by the legislature (but would require a supermajority in both chambers to pass) to offset losses or result in a reduction of state government services across the state
- Offsetting local government tax losses and increased costs and/or preventing service reductions would also present a major challenge – requiring regulatory and contractual changes for each affected local jurisdiction across the state

4

Summary of Potential Annual Impact of Restructuring

Electricity market restructuring would have an adverse financial impact, in terms of lower tax revenues and increased costs, of $1.2 to $1.5 Billion or more per year to the Florida state and local governments – and ultimately, to taxpayers.

Annual Negative Financial Impact from Restructuring by Major Category to Florida State and Local Governments		Range Estimate ($ millions)	
		Low	High
Revenue Losses	Franchise Fees	650	650
	Gross Receipts Tax	270	320
	Municipal Public Service Tax	200	300
	Property Tax	60	140
Higher Costs	Administrative Costs	30	80
	RTO or ISO[1] – impact of higher rates	20	25
Total Potential Impact		**1,230**	**1,515**
Incremental impact from higher electricity rates – net impact of revenue and costs for every 10% rate increase		90 (GRT and government electricity bills)	

Notes: [1] Total RTO or ISO ongoing costs would run between $200 and $250 million annually would be recovered via higher rates – state and local governments account for 10% of demand and thus would see $20-$25M in the form of higher bills.

CRA Charles River Associates

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Additional Challenges with Further Potential Negative Impacts

The impact summary is not meant to be a comprehensive and represent a conservative view of the overall potential impact of restructuring the Florida electric market

Non-exhaustive list of additional challenges identified, but not quantified at this time, all of these would drive further negative impacts to Florida state and local governments:

- Public assistance for low income, elderly and fixed-income ratepayers
- Litigation, regulatory, and consumer advocacy cost for unfair practices
- Recovery of stranded costs for IOU generation assets
- Grid reliability investments and ancillary services
- Natural gas supply availability constraints and price risk
- Job loss impact of closures and lower government spend (driven by revenue losses)
- Economic impact of higher electric rates – e.g. job losses or slower economic growth
- Incentives required to attract sufficient Provider of Last Resort (‘POLR’) suppliers

Analyzing the Fiscal Impact of the Energy Deregulation Constitutional Amendment

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

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Analyzing the Fiscal Impact of the Energy Deregulation Constitutional Amendment

Assumptions

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

Sales Tax (State and Local)

Revenue Collected by IOU: $369 million (state) and $28 million (local)

- Assumption 1: 5 percent to 25 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)

Assumptions

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

- 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

Analyzing the Fiscal Impact of the Energy Deregulation Constitutional Amendment

Assumptions

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

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