FIEC

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

2019

Financial Impact Estimating Conference

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

Serial Number 18-10

Table of Contents

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Authorization

RON DESANTIS
Governor

JENNIFER KENNEDY
Interim Secretary of State

January 30, 2019

Financial Impact Estimating Conference
c/o Amy Baker, Coordinator
Office of Economic and Demographic Research
111 West Madison Street, Ste. 574
Tallahassee, Florida 32399-6588

Dear Ms. Baker:

Section 15.21, Florida Statutes, provides that the Secretary of State shall submit an initiative petition to the Financial Impact Estimating Conference when a sponsoring political committee has met the registration, petition form submission and signature criteria set forth in that section.

The criteria in section 15.21, Florida Statutes, has now been met for the initiative petition titled **Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice**, Serial Number **18-10**. Therefore, I am submitting the proposed constitutional amendment petition form, along with a status update for the initiative petition, and a chart that provides a statewide signature count and count by congressional districts.

Sincerely,

Jennifer Kennedy

Jennifer Kennedy
Interim Secretary of State

RECEIVED 1/30/19
Carolyn Coleman
EDR

JK/am/ch

pc: James A. Patton Jr., Chairperson, Citizens For Energy Choices

Enclosures

FLORIDA DEPARTMENT *of* STATE

RON DESANTIS
Governor

JENNIFER KENNEDY
Interim Secretary of State

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FLORIDA DEPARTMENT OF STATE
DIVISION OF ELECTIONS

SUMMARY OF PETITION SIGNATURES

Political Committee: **Citizens for Energy Choices**

Amendment Title: **Right to Competitive Energy Market for Customers of Investor-Owned Utilities;**

Congressional District	Voting Electors in 2016 Presidential Election	**For Review** 10% of 8% Required By Section 15.21 Florida Statutes	**For Ballot** 8% Required By Article XI, Section 3 Florida Constitution	Signatures Certified	
FIRST	386,504	3,093	30,921	177	
SECOND	360,098	2,881	28,808	2,812	
THIRD	356,715	2,854	28,538	482	
FOURTH	428,190	3,426	34,256	1,071	
FIFTH	316,115	2,529	25,290	6,045	***
SIXTH	385,918	3,088	30,874	560	
SEVENTH	370,466	2,964	29,638	2,493	
EIGHTH	409,569	3,277	32,766	3,075	
NINTH	362,593	2,901	29,008	3,374	***
TENTH	320,548	2,565	25,644	1,559	
ELEVENTH	417,253	3,339	33,381	1,074	
TWELFTH	386,775	3,095	30,942	7,898	***
THIRTEENTH	367,818	2,943	29,426	16,020	***
FOURTEENTH	336,289	2,691	26,904	10,039	***
FIFTEENTH	340,331	2,723	27,227	8,132	***
SIXTEENTH	403,805	3,231	32,305	3,922	***
SEVENTEENTH	360,061	2,881	28,805	1,366	
EIGHTEENTH	388,772	3,111	31,102	496	
NINETEENTH	389,415	3,116	31,154	982	
TWENTIETH	291,984	2,336	23,359	896	
TWENTY-FIRST	355,842	2,847	28,468	841	
TWENTY-SECOND	361,305	2,891	28,905	962	
TWENTY-THIRD	342,784	2,743	27,423	598	
TWENTY-FOURTH	269,446	2,156	21,556	1,589	
TWENTY-FIFTH	269,983	2,160	21,599	431	
TWENTY-SIXTH	294,742	2,358	23,580	1,325	
TWENTY-SEVENTH	304,012	2,433	24,321	913	
TOTAL:	**9,577,333**	**76,632**	**766,200**	**79,132**	

Date: 1/30/2019 11:47:21 AM

Attachment for Initiative Petition

Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice
Serial Number 18-10

1. **Name and address of the sponsor of the initiative petition:**
   James A. Patton Jr., Chairperson
   Citizens for Energy Choices
   Post Office Box 1101
   Alachua, Florida 32616
2. **Name and address of the sponsor's attorney, if the sponsor is represented:** Unknown

3. **A statement as to whether the sponsor has obtained the requisite number of signatures on the initiative petition to have the proposed amendment put on the ballot:** As of January 30, 2019, the sponsor has not obtained the requisite number of signatures to have the proposed amendment placed on the ballot. A total of 766,200 valid signatures are required for placement on the 2020 general election ballot.

4. **If the sponsor has not obtained the requisite number of signatures on the initiative petition to have the proposed amendment put on the ballot, the current status of the signature-collection process:** As of January 30, 2019, Supervisors of Elections have certified a total of 79,132 valid petition signatures to the Division of Elections for this initiative petition. This number represents more than 10% of the total number of valid signatures needed from electors statewide and in at least one-fourth of the congressional districts in order to have the initiative placed on the 2020 general election ballot.

5. **The date of the election during which the sponsor is planning to submit the proposed amendment to the voters:** Unknown. The earliest date of election that this proposed amendment can be placed on the ballot is November 3, 2020, provided the sponsor successfully obtains the requisite number of valid signatures by February 1, 2020.

6. **The last possible date that the ballot for the target election can be printed in order to be ready for the election:** Unknown

7. **A statement identifying the date by which the Financial Impact Statement will be filed, if the Financial Impact Statement is not filed concurrently with the request:** The Secretary of State forwarded a letter to the Financial Impact Estimating Conference in the care of the coordinator on January 30, 2019.

8. **The names and complete mailing addresses of all of the parties who are to be served:** This information is unknown at this time.

CONSTITUTIONAL AMENDMENT PETITION FORM

Note:

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

Your name: ____

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

Your address:

____

City______________________ **Zip**__________ **County**______________

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

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

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

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

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

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

FULL TEXT OF THE PROPOSED CONSTITUTIONAL AMENDMENT:

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

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

[TEXT CONTINUES ON OTHER SIDE]

[TEXT BEGINS ON OTHER SIDE]

(c) IMPLEMENTATION. By June 1, 2023, the Legislature shall adopt complete and comprehensive legislation to implement this section in a manner fully consistent with its broad purposes and stated terms, which shall take effect no later than June 1, 2025, and which shall:

(1) implement language that entitles electricity customers to purchase competitively priced electricity, including but not limited to provisions that are designed to (i) limit the activity of investor-owned electric utilities to the construction, operation, and repair of electrical transmission and distribution systems, (ii) promote competition in the generation and retail sale of electricity through various means, including the limitation of market power, (iii) protect against unwarranted service disconnections, unauthorized changes in electric service, and deceptive or unfair practices, (iv) prohibit any granting of either monopolies or exclusive franchises for the generation and sale of electricity, and (v) establish an independent market monitor to ensure the competitiveness of the wholesale and retail electric markets.

(2) Upon enactment of any law by the Legislature pursuant to this section, all statutes, regulations, or orders which conflict with this section shall be void.

(d) EXCEPTIONS. Nothing in this section shall be construed to affect the existing rights or duties of electric cooperatives, municipally-owned electric utilities, or their customers and owners in any way, except that electric cooperatives and municipally-owned electric utilities may freely participate in the competitive wholesale electricity market and may choose, at their discretion, to participate in the competitive retail electricity market. Nothing in this section shall be construed to invalidate this State's public policies on renewable energy, energy efficiency, and environmental protection, or to limit the Legislature's ability to impose such policies on participants in competitive electricity markets. Nothing in this section shall be construed to limit or expand the existing authority of this State or any of its political subdivisions to levy and collect taxes, assessments, charges, or fees related to electricity service.

(e) EXECUTION. If the Legislature does not adopt complete and comprehensive legislation to implement this section in a manner fully consistent with its broad purposes and stated terms by June 1, 2023, then any Florida citizen shall have standing to seek judicial relief to compel the Legislature to comply with its constitutional duty to enact such legislation under this section.

DATE OF SIGNATURE

SIGNATURE OF REGISTERED VOTER

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

If paid petition circulator is used:

Circulator's name______________________

Circulator's address______________________

For Official Use Only:

Serial Number: 18-10

Date Approved: 10/5/2018

Tab 2

Current Law

Select Year: 2018 Go

The 2018 Florida Statutes

Title XIV
TAXATION AND FINANCE

Chapter 203
GROSS RECEIPTS TAXES

View Entire Chapter

CHAPTER 203
GROSS RECEIPTS TAXES

203.001 Combined rate for tax collected pursuant to ss. 202.12(1)(a) and 203.01(1)(b).—In complying with ss. 1-3, ch. 2010-149, Laws of Florida, the dealer of communication services may collect a combined rate of 5.07 percent, composed of the 4.92 percent and 0.15 percent rates required by ss. 202.12(1)(a) and 203.01(1)(b)3., respectively, if the provider properly reflects the tax collected with respect to the two provisions as required in the return to the Department of Revenue.

History.—s. 5, ch. 2010-149; s. 8, ch. 2015-221.

[1]**203.0011 Combined rate for tax collected pursuant to ss. 203.01(1)(b)4. and 212.05(1)(e)1.c.**—In complying with the amendments to ss. 203.01 and 212.05, relating to the additional tax on electrical power or energy, made by this act, a seller of electrical power or energy may collect a combined rate of 6.95 percent, which consists of the 4.35 percent and 2.6 percent required under ss. 212.05(1)(e)1.c. and 203.01(1)(b)4., respectively, if the provider properly reflects the tax collected with respect to the two provisions as required in the return to the Department of Revenue.

History.—s. 6, ch. 2014-38.

[1]**Note.**—Also published at s. 212.05011.

203.01 Tax on gross receipts for utility and communications services.—

(1)(a)1. A tax is imposed on gross receipts from utility services that are delivered to a retail consumer in this state. The tax shall be levied as provided in paragraphs (b)-(j).

2. A tax is levied on communications services as defined in s. 202.11(1). The tax shall be applied to the same services and transactions as are subject to taxation under chapter 202, and to communications services that are subject to the exemption provided in s. 202.125(1). The tax shall be applied to the sales price of communications services when sold at retail, as the terms are defined in s. 202.11, shall

be due and payable at the same time as the taxes imposed pursuant to chapter 202, and shall be administered and collected pursuant to chapter 202.

3. An additional tax is levied on charges for, or the use of, electrical power or energy that is subject to the tax levied pursuant to s. 212.05(1)(e)1.c. or s. 212.06(1). The tax shall be applied to the same transactions or uses as are subject to taxation under s. 212.05(1)(e)1.c. or s. 212.06(1). If a transaction or use is exempt from the tax imposed under s. 212.05(1)(e)1.c. or s. 212.06(1), the transaction or use is also exempt from the tax imposed under this subparagraph. The tax shall be applied to charges for electrical power or energy and is due and payable at the same time as taxes imposed pursuant to chapter 212. Chapter 212 governs the administration and enforcement of the tax imposed by this subparagraph. The charges upon which the tax imposed by this subparagraph is applied do not include the taxes imposed by subparagraph 1. or s. 166.231. The tax imposed by this subparagraph becomes state funds at the moment of collection and is not considered as revenue of a utility for purposes of a franchise agreement between the utility and a local government.

(b)1. The rate applied to utility services shall be 2.5 percent.

2. The rate applied to communications services shall be 2.37 percent.

3. An additional rate of 0.15 percent shall be applied to communication services subject to the tax levied pursuant to s. 202.12(1)(a), (c), and (d). The exemption provided in s. 202.125(1) applies to the tax levied pursuant to this subparagraph.

4. The rate applied to electrical power or energy taxed under subparagraph (a)3. shall be 2.6 percent.

(c)1. The tax imposed under subparagraph (a)1. 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 distribution company shall report and remit to the Department of Revenue by the 20th day of each month the taxes levied pursuant to this paragraph during the preceding month.

2. To the extent practicable, the Department of Revenue must distribute all receipts of taxes remitted under this chapter to the Public Education Capital Outlay and Debt Service Trust Fund in the same month as the department collects such taxes.

(d)1. Each distribution company that receives payment for the delivery of electricity to a retail consumer in this state is subject to tax on the exercise of this privilege as provided by this paragraph unless the payment is subject to tax under paragraph (c). For the exercise of this privilege, the tax levied on the distribution company's receipts for the delivery of electricity shall be determined by multiplying the number of kilowatt hours delivered by the index price and applying the rate in subparagraph (b)1. to the result.

2. 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.

3. Tax due under this paragraph shall be administered, paid, and reported in the same manner as the tax due under paragraph (c).

4. The amount of tax due under this paragraph shall be reduced by the amount of any like tax lawfully imposed on and paid by the person from whom the retail consumer purchased the electricity, whether imposed by and paid to this state, another state, a territory of the United States, or the District of Columbia. This reduction in tax shall be available to the retail consumer as a refund made pursuant to s. 215.26 and does not inure to the benefit of the person who receives payment for the delivery of the electricity. The methods of demonstrating proof of payment and the amount of such refund shall be made according to rules of the Department of Revenue.

(e)1. A distribution company that receives payment for the sale or transportation of natural or manufactured gas to a retail consumer in this state is subject to tax on the exercise of this privilege as provided by this paragraph. For the exercise of this privilege, the tax levied on the distribution company's receipts for the sale or transportation of natural or manufactured gas shall be determined by dividing the number of cubic feet delivered by 1,000, multiplying the resulting number by the index price, and applying the rate in subparagraph (b)1. to the result.

2. The index price is the Florida price per 1,000 cubic feet for retail consumers in the previous calendar year as published in the United States Energy Information Administration Natural Gas 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.

3. Tax due under this paragraph shall be administered, paid, and reported in the same manner as the tax due under paragraph (c).

4. The amount of tax due under this paragraph shall be reduced by the amount of any like tax lawfully imposed on and paid by the person from whom the retail consumer purchased the natural gas or manufactured gas, whether imposed by and paid to this state, another state, a territory of the United States, or the District of Columbia. This reduction in tax shall be available to the retail consumer as a refund pursuant to s. 215.26 and does not inure to the benefit of the person providing the transportation service. The methods of demonstrating proof of payment and the amount of such refund shall be made according to rules of the Department of Revenue.

(f) Any person who imports into this state electricity, natural gas, or manufactured gas, or severs natural gas, for that person's own use or consumption as a substitute for purchasing utility, transportation, or delivery services taxable under subparagraph (a)1. and who cannot demonstrate payment of the tax imposed by this chapter must register with the Department of Revenue and pay into the State Treasury each month an amount equal to the cost price, as defined in s. 212.02, of such electricity, natural gas, or manufactured gas times the rate set forth in subparagraph (b)1., reduced by the amount of any like tax lawfully imposed on and paid by the person from whom the electricity, natural gas, or manufactured gas was purchased or any person who provided delivery service or transportation service in connection with the electricity, natural gas, or manufactured gas. The methods of demonstrating proof of payment and the amount of such reductions in tax shall be made according to rules of the Department of Revenue.

(g) Electricity produced by cogeneration or by small power producers which is transmitted and distributed by a public utility between two locations of a customer of the utility pursuant to s. 366.051

is subject to the tax imposed by subparagraph (a)1. The tax shall be applied to the cost price, as defined in s. 212.02, of such electricity and shall be paid each month by the producer of such electricity.

(h) Electricity produced by cogeneration or by small power producers during the 12-month period ending June 30 of each year which is in excess of nontaxable electricity produced during the 12-month period ending June 30, 1990, is subject to the tax imposed by subparagraph (a)1. The tax shall be applied to the cost price, as defined in s. 212.02, of such electricity and shall be paid each month, beginning with the month in which total production exceeds the production of nontaxable electricity for the 12-month period ending June 30, 1990. As used in this paragraph, the term “nontaxable electricity” means electricity produced by cogeneration or by small power producers which is not subject to tax under paragraph (g). Taxes paid pursuant to paragraph (g) may be credited against taxes due under this paragraph. Electricity generated as part of an industrial manufacturing process that manufactures products from phosphate rock, raw wood fiber, paper, citrus, or any agricultural product is not subject to the tax imposed by this paragraph. The term “industrial manufacturing process” means the entire process conducted at the location where the process takes place.

(i) Any person other than a cogenerator or small power producer described in paragraph (h) who produces for his or her own use electrical energy that is a substitute for electrical energy produced by an electric utility as defined in s. 366.02 is subject to the tax imposed by subparagraph (a)1. The tax shall be applied to the cost price, as defined in s. 212.02, of such electrical energy and shall be paid each month. This paragraph does not apply to electrical energy produced and used by an electric utility.

(j) Notwithstanding any other provision of this chapter, with the exception of a communications services dealer reporting taxes administered under chapter 202, the department may require:

1. A quarterly return and payment when the tax remitted for the preceding four calendar quarters did not exceed $1,000;

2. A semiannual return and payment when the tax remitted for the preceding four calendar quarters did not exceed $500; or

3. An annual return and payment when the tax remitted for the preceding four calendar quarters did not exceed $100.

(2)(a) In addition to any other penalty provided by law, any person who fails to timely report and pay any tax imposed on gross receipts from utility services under this chapter shall pay a penalty equal to 10 percent of any unpaid tax, if the failure is for less than 31 days, plus an additional 10 percent of any unpaid tax for each additional 30 days or fraction thereof. However, such penalty may not be less than $10 or exceed a total of 50 percent in the aggregate of any unpaid tax.

(b) In addition to any other penalty provided by law, any person who falsely or fraudulently reports or unlawfully attempts to evade paying any tax imposed on gross receipts from utility services under this chapter shall pay a penalty equal to 100 percent of any tax due and is guilty of a misdemeanor of the second degree, punishable as provided under s. 775.082 or s. 775.083.

(3) The tax imposed by subparagraph (1)(a)1. does not apply to:

(a)1. The sale or transportation of natural gas or manufactured gas to a public or private utility, including a municipal corporation or rural electric cooperative association, for resale or for use as fuel in the generation of electricity; or

2. The sale or delivery of electricity to a public or private utility, including a municipal corporation or rural electric cooperative association, for resale, or as part of an electrical interchange agreement or contract between such utilities for the purpose of transferring more economically generated power;

if the person deriving gross receipts from such sale demonstrates that a sale, transportation, or delivery for resale in fact occurred and complies with the following requirements: A sale, transportation, or delivery for resale must be in strict compliance with the rules of the Department of Revenue; and any sale subject to the tax imposed by this section which is not in strict compliance with the rules of the Department of Revenue shall be subject to the tax at the appropriate rate imposed on utilities under subparagraph (1)(b)1. on the person making the sale. Any person making a sale for resale may, through an informal protest provided in s. 213.21 and the rules of the Department of Revenue, provide the department with evidence of the exempt status of a sale. The department shall adopt rules that provide that valid proof and documentation of the resale by a person making the sale for resale will be accepted by the department when submitted during the protest period but will not be accepted when submitted in any proceeding under chapter 120 or any circuit court action instituted under chapter 72;

(b) Wholesale sales of electric transmission service;

(c) The use of natural gas in the production of oil or gas, or the use of natural or manufactured gas by a person transporting natural or manufactured gas, when used and consumed in providing such services; or

(d) The sale or transportation to, or use of, natural gas or manufactured gas by a person eligible for an exemption under s. 212.08(7)(ff)2. for use as an energy source or a raw material. Possession by a seller of natural or manufactured gas or by any person providing transportation or delivery of natural or manufactured gas of a written certification by the purchaser, certifying the purchaser's entitlement to the exclusion permitted by this paragraph, relieves the seller or person providing transportation or delivery from the responsibility of remitting tax on the nontaxable amounts, and the department shall look solely to the purchaser for recovery of such tax if the department determines that the purchaser was not entitled to the exclusion. The certification must include an acknowledgment by the purchaser that it will be liable for tax pursuant to paragraph (1)(f) if the requirements for exclusion are not met.

(4) The tax imposed pursuant to subparagraph (1)(a)1. relating to the provision of utility services at the option of the person supplying the taxable services may be separately stated as Florida gross receipts tax on the total amount of any bill, invoice, or other tangible evidence of the provision of such taxable services and may be added as a component part of the total charge. If a provider of taxable services elects to separately state such tax as a component of the charge for the provision of such taxable services, any person, including all governmental units, shall remit the tax to the person who provides such taxable services as a part of the total bill, and the tax is a component part of the debt of the purchaser to the person who provides such taxable services until paid and, if unpaid, is recoverable at law in the same manner as any other part of the charge for such taxable services. For a utility, the decision to separately state any increase in the rate of tax imposed by this chapter which is effective after December 31, 1989, and the ability to recover the increased charge from the customer is not subject to regulatory approval.

(5) The tax is imposed upon every person for the privilege of conducting a utility or communications services business, and each provider of the taxable services remains fully and completely liable for the tax, even if the tax is separately stated as a line item or component of the total bill.

(6) Any person who provides such services and who fails, neglects, or refuses to remit the tax imposed in this chapter, either by himself or herself, or through agents or employees, is liable for the tax and is guilty of a misdemeanor of the first degree, punishable as provided in s. 775.082 or s. 775.083.

(7) Gross receipts subject to the tax imposed under subparagraph (1)(a)1. for the provision of electricity must include receipts from monthly customer charges or monthly customer facility charges.

(8) Notwithstanding the provisions of subsection (4) and s. 212.07(2), sums that were charged or billed as taxes under this section and chapter 212 and that were remitted to the state in full as taxes shall not be subject to refund by the state or by the utility or other person that remitted the sums, when the amount remitted was not in excess of the amount of tax imposed by chapter 212 and this section.

(9) Any person who engages in the transportation of natural or manufactured gas shall furnish annually to the Department of Revenue a list of customers to whom transportation services were provided in the prior year. This reporting requirement does not apply to distribution companies. Any person required to furnish such a list may elect to identify only those customers who take direct delivery without purchasing interconnection services from a distribution company. Such reports are subject to the confidentiality provisions of s. 213.053. Any person required to furnish a customer list may instead comply by maintaining a publicly accessible customer list on its Internet website. Such list shall be updated no less than annually.

History.—ss. 1, 2, ch. 15658, 1931; CGL 1936 Supp. 1279(108), (109); s. 7, ch. 22858, 1945; s. 1, ch. 57-819; s. 7, ch. 63-253; s. 5, ch. 65-371; s. 2, ch. 65-420; ss. 21, 35, ch. 69-106; s. 10, ch. 75-292; s. 3, ch. 80-381; s. 15, ch. 83-137; ss. 1, 4, ch. 84-342; s. 29, ch. 85-116; s. 2, ch. 85-174; s. 2, ch. 86-155; s. 68, ch. 87-6; s. 41, ch. 87-101; s. 43, ch. 87-224; s. 7, ch. 89-292; s. 12, ch. 89-356; s. 14, ch. 90-132; s. 11, ch. 91-112; s. 234, ch. 91-224; s. 8, ch. 92-320; s. 10, ch. 93-233; s. 1054, ch. 95-147; s. 2, ch. 95-403; s. 12, ch. 96-397; s. 6, ch. 97-233; s. 11, ch. 98-277; ss. 40, 41, 58, ch. 2000-260; s. 10, ch. 2000-355; ss. 25, 38, ch. 2001-140; s. 1, ch. 2003-17; s. 178, ch. 2003-261; s. 1, ch. 2005-148; s. 7, ch. 2005-187; s. 2, ch. 2007-60; s. 3, ch. 2010-149; s. 9, ch. 2012-70; s. 4, ch. 2014-38; s. 57, ch. 2017-36.

203.0111 Application of tax increase.—With respect to utility services regularly billed on a monthly cycle basis, each increase in the gross receipts tax provided for in this act shall apply to any bill dated on or after July 1 in the year in which the increase becomes effective.

History.—s. 16, ch. 90-132.

203.012 Definitions.—As used in this chapter:

(1) "Distribution company" means any person owning or operating local electric or natural or manufactured gas utility distribution facilities within this state for the transmission, delivery, and sale of electricity or natural or manufactured gas. The term does not include natural gas transmission companies that are subject to the jurisdiction of the Federal Energy Regulatory Commission.

(2) "Person" means any person as defined in s. 212.02.

(3) "Utility service" means electricity for light, heat, or power; and natural or manufactured gas for light, heat, or power, including transportation, delivery, transmission, and distribution of the electricity or natural or manufactured gas. This subsection does not broaden the definition of utility service to include separately stated charges for tangible personal property or services which are not charges for the electricity or natural or manufactured gas or the transportation, delivery, transmission, or distribution of electricity or natural or manufactured gas.

History.—ss. 2, 6, ch. 84-342; s. 30, ch. 85-116; s. 3, ch. 85-174; s. 3, ch. 86-155; s. 44, ch. 87-224; s. 17, ch. 90-132; s. 13, ch. 91-112; s. 1, ch. 97-283; ss. 42, 58, ch. 2000-260; s. 38, ch. 2001-140; s. 2, ch. 2005-148.

203.02 Powers of Department of Revenue.—The Department of Revenue may audit the reports provided for in s. 203.01; and each and every such person shall submit all records, books, papers and accounts as to business done to the department or its duly authorized agents for examination or investigation upon demand.

History.—s. 3, ch. 15658, 1931; CGL 1936 Supp. 1279(110); s. 7, ch. 63-253; s. 5, ch. 65-371; s. 2, ch. 65-420; ss. 21, 35, ch. 69-106.

203.03 Penalties.—

(1) Any officer, agent, or representative of any such person who receives any payment for the furnishing of the things or the services above mentioned without first complying with the provisions of this chapter is guilty of a misdemeanor of the first degree, punishable as provided in s. 775.082 or s. 775.083.

(2) Any person who willfully violates or fails to comply with any of the provisions of this chapter is guilty of a misdemeanor of the first degree, punishable as provided in s. 775.082 or s. 775.083.

History.—s. 4, ch. 15658, 1931; CGL 1936 Supp. 7455(3); s. 108, ch. 71-136; s. 69, ch. 87-6; s. 42, ch. 87-101; s. 15, ch. 91-224.

203.04 Construction of laws granting exemptions or exceptions.—No statute or law, general, special, or local hereafter enacted which either directly or indirectly relates to exemptions or exceptions from taxation in this state shall be construed as including or extending to the gross receipts taxes imposed by this chapter unless its application to said chapter, either directly or indirectly, is clearly and specifically expressed and no repeals by implication shall be recognized in this connection. This is a rule of statutory construction to be applied to statutes and laws hereafter enacted.

History.—ss. 1, 2, 3, ch. 63-535; s. 49, ch. 91-45; s. 13, ch. 96-397.

203.06 Interest on delinquent payments.—Any payments as imposed in this chapter, if not received by the Department of Revenue on or before the due date as provided by law, shall include, as an additional part of such amount due, interest at the rate of 1 percent per month, accruing from the date due until paid.

History.—s. 5, ch. 76-261.

203.07 Settlement or compromise of penalties and interest.—The department, pursuant to s. 213.21, may settle or compromise penalties or interest imposed by this chapter.

History.—s. 6, ch. 81-178.

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166.231 Municipalities; public service tax.—

(1)(a) A municipality may levy a 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. Except for those municipalities in which paragraph (c) applies, the tax shall be levied only upon purchases within the municipality and shall not exceed 10 percent of the payments received by the seller of the taxable item from the purchaser for the purchase of such service. Municipalities imposing a tax on the purchase of cable television service as of May 4, 1977, may continue to levy such tax to the extent necessary to meet all obligations to or for the benefit of holders of bonds or certificates which were issued prior to May 4, 1977. Purchase of electricity means the purchase of electric power by a person who will consume it within the municipality.

(b) The tax imposed by paragraph (a) shall not be applied against any fuel adjustment charge, and such charge shall be separately stated on each bill. 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.

(c) The tax in paragraph (a) on water service may be applied outside municipal boundaries to property included in a development of regional impact approved pursuant to s. 380.06, if agreed to in writing by the developer of such property and the municipality prior to March 31, 2000. If a tax levied pursuant to the subsection is challenged, recovery, if any, shall be limited to moneys paid into an escrow account of the clerk of the court subsequent to such challenge.

(2) Services competitive with those enumerated in subsection (1), as defined by ordinance, shall be taxed on a comparable base at the same rates. However, fuel oil shall be taxed at a rate not to exceed 4 cents per gallon. However, for municipalities levying less than the maximum rate allowable in subsection (1), the maximum tax on fuel oil shall bear the same proportion to 4 cents which the tax rate levied under subsection (1) bears to the maximum rate allowable in subsection (1).

(3) A municipality may exempt from the tax imposed by this section any amount up to, and including, the first 500 kilowatt hours of electricity purchased per month for residential use. Such exemption shall apply to each separate residential unit, regardless of whether such unit is on a separate meter or a central meter, and shall be passed on to each individual tenant.

(4)(a) The purchase of natural gas, manufactured gas, or fuel oil by a public or private utility, either for resale or for use as fuel in the generation of electricity, or the purchase of fuel oil or kerosene for use as an aircraft engine fuel or propellant or for use in internal combustion engines is exempt from taxation hereunder.

(b) A municipality may exempt from the tax imposed by this section the purchase of metered or bottled gas (natural liquefied petroleum gas or manufactured) or fuel oil for agricultural purposes. As used in this paragraph, "agricultural purposes" means bona fide farming, pasture, grove, or forestry operations, including horticulture, floriculture, viticulture, dairy, livestock, poultry, bee, and aquaculture.

(5) Purchases by the United States Government, this state, and all counties, school districts, and municipalities of the state, and by public bodies exempted by law or court order, are exempt from the tax authorized by this section. A municipality may exempt from the tax imposed by this section the purchase of taxable items by any other public body as defined in s. 1.01, or by a nonprofit corporation or cooperative association organized under chapter 617 which provides water utility services to no more than 13,500 equivalent residential units, ownership of which will revert to a political subdivision upon retirement of all outstanding indebtedness, and shall exempt purchases by any recognized church in this state for use exclusively for church purposes.

(6) A municipality may exempt from the tax imposed by this section any amount up to, and including, the total amount of electricity, metered natural gas, liquefied petroleum gas either metered or bottled, or manufactured gas either metered or bottled purchased per month, or reduce the rate of taxation on the purchase of such electricity or gas when purchased by an industrial consumer which uses the electricity or gas directly in industrial manufacturing, processing, compounding, or a production process, at a fixed location in the municipality, of items of tangible personal property for sale. The municipality shall establish the requirements for qualification for this exemption in the manner prescribed by ordinance. Possession by a seller of a written certification by the purchaser, certifying the purchaser's entitlement to an exemption permitted by this subsection, relieves the seller from the responsibility of collecting the tax on the nontaxable amounts, and the municipality shall look solely to the purchaser for recovery of such tax if it determines that the purchaser was not entitled to the exemption. Any municipality granting an exemption pursuant to this subsection shall grant the exemption to all companies classified in the same five-digit NAICS Industry Number. As used in this subsection, "NAICS" means those classifications contained in the North American Industry Classification System, as published in 2007 by the Office of Management and Budget, Executive Office of the President.

(7) The tax authorized hereunder shall be collected by the seller of the taxable item from the purchaser at the time of the payment for such service. The seller shall remit the taxes collected to the municipality in the manner prescribed by ordinance. Except as otherwise provided in ss. 166.233 and 166.234, the seller shall be liable for taxes that are due and not remitted to the municipality. This shall not bar the seller from recovering such taxes from purchasers; however, the universities in the State University System shall not be deemed a seller of any item otherwise taxable hereunder when such item is provided to university residences incidental to the provision of educational services.

(8)(a) Beginning July 1, 1995, a municipality may by ordinance exempt not less than 50 percent of the tax imposed under this section on purchasers of electrical energy who are determined to be eligible for the exemption provided by s. 212.08(15) by the Department of Revenue. The exemption shall be administered as provided in that section. A copy of any ordinance adopted pursuant to this subsection shall be provided to the Department of Revenue not less than 14 days prior to its effective date.

(b) If an area that is nominated as an enterprise zone pursuant to s. 290.0055 has not yet been designated pursuant to s. 290.0065, a municipality may enact an ordinance for such exemption; however, the ordinance shall not be effective until such area is designated pursuant to s. 290.0065.

(c) This subsection expires on the date specified in s. 290.016 for the expiration of the Florida Enterprise Zone Act, except that any qualified business that has satisfied the requirements of this subsection before that date shall be allowed the full benefit of the exemption allowed under this subsection as if this subsection had not expired on that date.

(9) A purchaser who claims an exemption under subsection (4) or subsection (5) shall certify to the seller that he or she qualifies for the exemption, which certification may encompass all purchases after a specified date or other multiple purchases. A seller accepting the certification required by this subsection is relieved of the obligation to collect and remit tax; however, a governmental body that is exempt from the tax authorized by this section shall not be required to furnish such certification, and a seller is not required to collect tax from such an exempt governmental body.

(10) Governmental bodies which sell or resell taxable service to nonexempt end users must collect and remit the tax levied under this section.

History.—s. 1, ch. 73-129; ss. 1, 2, ch. 74-109; s. 1, ch. 77-174; s. 1, ch. 77-251; s. 4, ch. 78-299; s. 1, ch. 78-400; s. 1, ch. 82-230; s. 1, ch. 82-399; s. 24, ch. 84-356; s. 1, ch. 85-174; s. 1, ch. 86-155; s. 1, ch. 88-35; s. 1, ch. 88-140; s. 36, ch. 90-360; s. 1, ch. 93-224; s. 44, ch. 94-136; s. 1, ch. 95-403; s. 12, ch. 96-320; s. 47, ch. 96-406; s. 2, ch. 97-233; s. 2, ch. 97-283; s. 10, ch. 98-277; s. 64, ch. 99-2; s. 18, ch. 2000-158; ss. 36, 38, 58, ch. 2000-260; s. 5, ch. 2000-355; s. 28, ch. 2001-60; s. 38, ch. 2001-140; s. 2, ch. 2003-17; s. 13, ch. 2005-287; s. 2, ch. 2009-51.

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Title XIV TAXATION AND FINANCE	Chapter 212 TAX ON SALES, USE, AND OTHER TRANSACTIONS	View Entire Chapter

212.05 Sales, storage, use tax.—It is hereby declared to be the legislative intent that every person is exercising a taxable privilege who engages in the business of selling tangible personal property at retail in this state, including the business of making mail order sales, or who rents or furnishes any of the things or services taxable under this chapter, or who stores for use or consumption in this state any item or article of tangible personal property as defined herein and who leases or rents such property within the state.

(1) For the exercise of such privilege, a tax is levied on each taxable transaction or incident, which tax is due and payable as follows:

(a)1.a. At the rate of 6 percent of the sales price of each item or article of tangible personal property when sold at retail in this state, computed on each taxable sale for the purpose of remitting the amount of tax due the state, and including each and every retail sale.

b. Each occasional or isolated sale of an aircraft, boat, mobile home, or motor vehicle of a class or type which is required to be registered, licensed, titled, or documented in this state or by the United States Government shall be subject to tax at the rate provided in this paragraph. The department shall by rule adopt any nationally recognized publication for valuation of used motor vehicles as the reference price list for any used motor vehicle which is required to be licensed pursuant to s. 320.08(1), (2), (3)(a), (b), (c), or (e), or (9). If any party to an occasional or isolated sale of such a vehicle reports to the tax collector a sales price which is less than 80 percent of the average loan price for the specified model and year of such vehicle as listed in the most recent reference price list, the tax levied under this paragraph shall be computed by the department on such average loan price unless the parties to the sale have provided to the tax collector an affidavit signed by each party, or other substantial proof, stating the actual sales price. Any party to such sale who reports a sales price less than the actual sales price is guilty of a misdemeanor of the first degree, punishable as provided in s. 775.082 or s. 775.083. The department shall collect or attempt to collect from such party any delinquent sales taxes. In addition, such party shall pay any tax due and any penalty and interest assessed plus a penalty equal to twice the amount of the additional tax owed. Notwithstanding any other provision of law, the Department of Revenue may waive or compromise any penalty imposed pursuant to this subparagraph.

2. This paragraph does not apply to the sale of a boat or aircraft by or through a registered dealer under this chapter to a purchaser who, at the time of taking delivery, is a nonresident of this state, does not make his or her permanent place of abode in this state, and is not engaged in carrying on in this state any employment, trade, business, or profession in which the boat or aircraft will be used in this state, or is a corporation none of the officers or directors of which is a resident of, or makes his or her permanent place of abode in, this state, or is a noncorporate entity that has no individual vested with authority to participate in the management, direction, or control of the entity's affairs who is a resident

of, or makes his or her permanent abode in, this state. For purposes of this exemption, either a registered dealer acting on his or her own behalf as seller, a registered dealer acting as broker on behalf of a seller, or a registered dealer acting as broker on behalf of the purchaser may be deemed to be the selling dealer. This exemption shall not be allowed unless:

a. The purchaser removes a qualifying boat, as described in sub-subparagraph f., from the state within 90 days after the date of purchase or extension, or the purchaser removes a nonqualifying boat or an aircraft from this state within 10 days after the date of purchase or, when the boat or aircraft is repaired or altered, within 20 days after completion of the repairs or alterations; or if the aircraft will be registered in a foreign jurisdiction and:

(I) Application for the aircraft's registration is properly filed with a civil airworthiness authority of a foreign jurisdiction within 10 days after the date of purchase;

(II) The purchaser removes the aircraft from the state to a foreign jurisdiction within 10 days after the date the aircraft is registered by the applicable foreign airworthiness authority; and

(III) The aircraft is operated in the state solely to remove it from the state to a foreign jurisdiction.

For purposes of this sub-subparagraph, the term "foreign jurisdiction" means any jurisdiction outside of the United States or any of its territories;

b. The purchaser, within 30 days from the date of departure, provides the department with written proof that the purchaser licensed, registered, titled, or documented the boat or aircraft outside the state. If such written proof is unavailable, within 30 days the purchaser shall provide proof that the purchaser applied for such license, title, registration, or documentation. The purchaser shall forward to the department proof of title, license, registration, or documentation upon receipt;

c. The purchaser, within 10 days of removing the boat or aircraft from Florida, furnishes the department with proof of removal in the form of receipts for fuel, dockage, slippage, tie-down, or hangaring from outside of Florida. The information so provided must clearly and specifically identify the boat or aircraft;

d. The selling dealer, within 5 days of the date of sale, provides to the department a copy of the sales invoice, closing statement, bills of sale, and the original affidavit signed by the purchaser attesting that he or she has read the provisions of this section;

e. The seller makes a copy of the affidavit a part of his or her record for as long as required by s. 213.35; and

f. Unless the nonresident purchaser of a boat of 5 net tons of admeasurement or larger intends to remove the boat from this state within 10 days after the date of purchase or when the boat is repaired or altered, within 20 days after completion of the repairs or alterations, the nonresident purchaser applies to the selling dealer for a decal which authorizes 90 days after the date of purchase for removal of the boat. The nonresident purchaser of a qualifying boat may apply to the selling dealer within 60 days after the date of purchase for an extension decal that authorizes the boat to remain in this state for an additional 90 days, but not more than a total of 180 days, before the nonresident purchaser is required to pay the tax imposed by this chapter. The department is authorized to issue decals in advance to dealers. The number of decals issued in advance to a dealer shall be consistent with the volume of the dealer's past sales of boats which qualify under this sub-subparagraph. The selling dealer or his or her agent shall mark and affix the decals to qualifying boats in the manner prescribed by the department, before delivery of the boat.

(I) The department is hereby authorized to charge dealers a fee sufficient to recover the costs of decals issued, except the extension decal shall cost $425.

(II) The proceeds from the sale of decals will be deposited into the administrative trust fund.

(III) Decals shall display information to identify the boat as a qualifying boat under this sub-subparagraph, including, but not limited to, the decal's date of expiration.

(IV) The department is authorized to require dealers who purchase decals to file reports with the department and may prescribe all necessary records by rule. All such records are subject to inspection by the department.

(V) Any dealer or his or her agent who issues a decal falsely, fails to affix a decal, mismarks the expiration date of a decal, or fails to properly account for decals will be considered prima facie to have committed a fraudulent act to evade the tax and will be liable for payment of the tax plus a mandatory penalty of 200 percent of the tax, and shall be liable for fine and punishment as provided by law for a conviction of a misdemeanor of the first degree, as provided in s. 775.082 or s. 775.083.

(VI) Any nonresident purchaser of a boat who removes a decal before permanently removing the boat from the state, or defaces, changes, modifies, or alters a decal in a manner affecting its expiration date before its expiration, or who causes or allows the same to be done by another, will be considered prima facie to have committed a fraudulent act to evade the tax and will be liable for payment of the tax plus a mandatory penalty of 200 percent of the tax, and shall be liable for fine and punishment as provided by law for a conviction of a misdemeanor of the first degree, as provided in s. 775.082 or s. 775.083.

(VII) The department is authorized to adopt rules necessary to administer and enforce this subparagraph and to publish the necessary forms and instructions.

(VIII) The department is hereby authorized to adopt emergency rules pursuant to s. 120.54(4) to administer and enforce the provisions of this subparagraph.

If the purchaser fails to remove the qualifying boat from this state within the maximum 180 days after purchase or a nonqualifying boat or an aircraft from this state within 10 days after purchase or, when the boat or aircraft is repaired or altered, within 20 days after completion of such repairs or alterations, or permits the boat or aircraft to return to this state within 6 months from the date of departure, except as provided in s. 212.08(7)(fff), or if the purchaser fails to furnish the department with any of the documentation required by this subparagraph within the prescribed time period, the purchaser shall be liable for use tax on the cost price of the boat or aircraft and, in addition thereto, payment of a penalty to the Department of Revenue equal to the tax payable. This penalty shall be in lieu of the penalty imposed by s. 212.12(2). The maximum 180-day period following the sale of a qualifying boat tax-exempt to a nonresident may not be tolled for any reason.

(b) At the rate of 6 percent of the cost price of each item or article of tangible personal property when the same is not sold but is used, consumed, distributed, or stored for use or consumption in this state; however, for tangible property originally purchased exempt from tax for use exclusively for lease and which is converted to the owner's own use, tax may be paid on the fair market value of the property at the time of conversion. If the fair market value of the property cannot be determined, use tax at the time of conversion shall be based on the owner's acquisition cost. Under no circumstances may the aggregate amount of sales tax from leasing the property and use tax due at the time of conversion be less than the total sales tax that would have been due on the original acquisition cost paid by the owner.

(c) At the rate of 6 percent of the gross proceeds derived from the lease or rental of tangible personal property, as defined herein; however, the following special provisions apply to the lease or rental of motor vehicles:

1. When a motor vehicle is leased or rented for a period of less than 12 months:

a. If the motor vehicle is rented in Florida, the entire amount of such rental is taxable, even if the vehicle is dropped off in another state.

b. If the motor vehicle is rented in another state and dropped off in Florida, the rental is exempt from Florida tax.

2. Except as provided in subparagraph 3., for the lease or rental of a motor vehicle for a period of not less than 12 months, sales tax is due on the lease or rental payments if the vehicle is registered in this state; provided, however, that no tax shall be due if the taxpayer documents use of the motor vehicle outside this state and tax is being paid on the lease or rental payments in another state.

3. The tax imposed by this chapter does not apply to the lease or rental of a commercial motor vehicle as defined in s. 316.003(13)(a) to one lessee or rentee for a period of not less than 12 months when tax was paid on the purchase price of such vehicle by the lessor. To the extent tax was paid with respect to the purchase of such vehicle in another state, territory of the United States, or the District of Columbia, the Florida tax payable shall be reduced in accordance with the provisions of s. 212.06(7). This subparagraph shall only be available when the lease or rental of such property is an established business or part of an established business or the same is incidental or germane to such business.

(d) At the rate of 6 percent of the lease or rental price paid by a lessee or rentee, or contracted or agreed to be paid by a lessee or rentee, to the owner of the tangible personal property.

[1](e)1. At the rate of 6 percent on charges for:

a. Prepaid calling arrangements. The tax on charges for prepaid calling arrangements shall be collected at the time of sale and remitted by the selling dealer.

(I) "Prepaid calling arrangement" has the same meaning as provided in s. 202.11.

(II) If the sale or recharge of the prepaid calling arrangement does not take place at the dealer's place of business, it shall be deemed to have taken place at the customer's shipping address or, if no item is shipped, at the customer's address or the location associated with the customer's mobile telephone number.

(III) The sale or recharge of a prepaid calling arrangement shall be treated as a sale of tangible personal property for purposes of this chapter, regardless of whether a tangible item evidencing such arrangement is furnished to the purchaser, and such sale within this state subjects the selling dealer to the jurisdiction of this state for purposes of this subsection.

(IV) No additional tax under this chapter or chapter 202 is due or payable if a purchaser of a prepaid calling arrangement who has paid tax under this chapter on the sale or recharge of such arrangement applies one or more units of the prepaid calling arrangement to obtain communications services as described in s. 202.11(9)(b)3., other services that are not communications services, or products.

b. The installation of telecommunication and telegraphic equipment.

c. Electrical power or energy, except that the tax rate for charges for electrical power or energy is 4.35 percent. Charges for electrical power and energy do not include taxes imposed under ss. 166.231 and 203.01(1)(a)3.

2. Section 212.17(3), regarding credit for tax paid on charges subsequently found to be worthless, is equally applicable to any tax paid under this section on charges for prepaid calling arrangements, telecommunication or telegraph services, or electric power subsequently found to be uncollectible. As used in this paragraph, the term "charges" does not include any excise or similar tax levied by the Federal Government, a political subdivision of this state, or a municipality upon the purchase, sale, or recharge of prepaid calling arrangements or upon the purchase or sale of telecommunication, television

system program, or telegraph service or electric power, which tax is collected by the seller from the purchaser.

(f) At the rate of 6 percent on the sale, rental, use, consumption, or storage for use in this state of machines and equipment, and parts and accessories therefor, used in manufacturing, processing, compounding, producing, mining, or quarrying personal property for sale or to be used in furnishing communications, transportation, or public utility services.

(g)1. At the rate of 6 percent on the retail price of newspapers and magazines sold or used in Florida.

2. Notwithstanding other provisions of this chapter, inserts of printed materials which are distributed with a newspaper or magazine are a component part of the newspaper or magazine, and neither the sale nor use of such inserts is subject to tax when:

a. Printed by a newspaper or magazine publisher or commercial printer and distributed as a component part of a newspaper or magazine, which means that the items after being printed are delivered directly to a newspaper or magazine publisher by the printer for inclusion in editions of the distributed newspaper or magazine;

b. Such publications are labeled as part of the designated newspaper or magazine publication into which they are to be inserted; and

c. The purchaser of the insert presents a resale certificate to the vendor stating that the inserts are to be distributed as a component part of a newspaper or magazine.

(h)1. A tax is imposed at the rate of 4 percent on the charges for the use of coin-operated amusement machines. The tax shall be calculated by dividing the gross receipts from such charges for the applicable reporting period by a divisor, determined as provided in this subparagraph, to compute gross taxable sales, and then subtracting gross taxable sales from gross receipts to arrive at the amount of tax due. For counties that do not impose a discretionary sales surtax, the divisor is equal to 1.04; for counties that impose a 0.5 percent discretionary sales surtax, the divisor is equal to 1.045; for counties that impose a 1 percent discretionary sales surtax, the divisor is equal to 1.050; and for counties that impose a 2 percent sales surtax, the divisor is equal to 1.060. If a county imposes a discretionary sales surtax that is not listed in this subparagraph, the department shall make the applicable divisor available in an electronic format or otherwise. Additional divisors shall bear the same mathematical relationship to the next higher and next lower divisors as the new surtax rate bears to the next higher and next lower surtax rates for which divisors have been established. When a machine is activated by a slug, token, coupon, or any similar device which has been purchased, the tax is on the price paid by the user of the device for such device.

2. As used in this paragraph, the term “operator” means any person who possesses a coin-operated amusement machine for the purpose of generating sales through that machine and who is responsible for removing the receipts from the machine.

a. If the owner of the machine is also the operator of it, he or she shall be liable for payment of the tax without any deduction for rent or a license fee paid to a location owner for the use of any real property on which the machine is located.

b. If the owner or lessee of the machine is also its operator, he or she shall be liable for payment of the tax on the purchase or lease of the machine, as well as the tax on sales generated through the machine.

c. If the proprietor of the business where the machine is located does not own the machine, he or she shall be deemed to be the lessee and operator of the machine and is responsible for the payment of the tax on sales, unless such responsibility is otherwise provided for in a written agreement between him or her and the machine owner.

3.a. An operator of a coin-operated amusement machine may not operate or cause to be operated in this state any such machine until the operator has registered with the department and has conspicuously displayed an identifying certificate issued by the department. The identifying certificate shall be issued by the department upon application from the operator. The identifying certificate shall include a unique number, and the certificate shall be permanently marked with the operator's name, the operator's sales tax number, and the maximum number of machines to be operated under the certificate. An identifying certificate shall not be transferred from one operator to another. The identifying certificate must be conspicuously displayed on the premises where the coin-operated amusement machines are being operated.

b. The operator of the machine must obtain an identifying certificate before the machine is first operated in the state and by July 1 of each year thereafter. The annual fee for each certificate shall be based on the number of machines identified on the application times $30 and is due and payable upon application for the identifying device. The application shall contain the operator's name, sales tax number, business address where the machines are being operated, and the number of machines in operation at that place of business by the operator. No operator may operate more machines than are listed on the certificate. A new certificate is required if more machines are being operated at that location than are listed on the certificate. The fee for the new certificate shall be based on the number of additional machines identified on the application form times $30.

c. A penalty of $250 per machine is imposed on the operator for failing to properly obtain and display the required identifying certificate. A penalty of $250 is imposed on the lessee of any machine placed in a place of business without a proper current identifying certificate. Such penalties shall apply in addition to all other applicable taxes, interest, and penalties.

d. Operators of coin-operated amusement machines must obtain a separate sales and use tax certificate of registration for each county in which such machines are located. One sales and use tax certificate of registration is sufficient for all of the operator's machines within a single county.

4. The provisions of this paragraph do not apply to coin-operated amusement machines owned and operated by churches or synagogues.

5. In addition to any other penalties imposed by this chapter, a person who knowingly and willfully violates any provision of this paragraph commits a misdemeanor of the second degree, punishable as provided in s. 775.082 or s. 775.083.

6. The department may adopt rules necessary to administer the provisions of this paragraph.

(i)1. At the rate of 6 percent on charges for all:

a. Detective, burglar protection, and other protection services (NAICS National Numbers 561611, 561612, 561613, and 561621). Fingerprint services required under s. 790.06 or s. 790.062 are not subject to the tax. Any law enforcement officer, as defined in s. 943.10, who is performing approved duties as determined by his or her local law enforcement agency in his or her capacity as a law enforcement officer, and who is subject to the direct and immediate command of his or her law enforcement agency, and in the law enforcement officer's uniform as authorized by his or her law enforcement agency, is performing law enforcement and public safety services and is not performing detective, burglar protection, or other protective services, if the law enforcement officer is performing his or her approved duties in a geographical area in which the law enforcement officer has arrest jurisdiction. Such law enforcement and public safety services are not subject to tax irrespective of whether the duty is characterized as "extra duty," "off-duty," or "secondary employment," and irrespective of whether the officer is paid directly or through the officer's agency by an outside source. The term "law enforcement officer" includes full-time or part-time law enforcement officers, and any auxiliary law enforcement officer, when such auxiliary law enforcement officer is working under the direct supervision of a full-time or part-time law enforcement officer.

b. Nonresidential cleaning, excluding cleaning of the interiors of transportation equipment, and nonresidential building pest control services (NAICS National Numbers 561710 and 561720).

2. As used in this paragraph, "NAICS" means those classifications contained in the North American Industry Classification System, as published in 2007 by the Office of Management and Budget, Executive Office of the President.

3. Charges for detective, burglar protection, and other protection security services performed in this state but used outside this state are exempt from taxation. Charges for detective, burglar protection, and other protection security services performed outside this state and used in this state are subject to tax.

4. If a transaction involves both the sale or use of a service taxable under this paragraph and the sale or use of a service or any other item not taxable under this chapter, the consideration paid must be separately identified and stated with respect to the taxable and exempt portions of the transaction or the entire transaction shall be presumed taxable. The burden shall be on the seller of the service or the purchaser of the service, whichever applicable, to overcome this presumption by providing documentary evidence as to which portion of the transaction is exempt from tax. The department is authorized to adjust the amount of consideration identified as the taxable and exempt portions of the transaction; however, a determination that the taxable and exempt portions are inaccurately stated and that the adjustment is applicable must be supported by substantial competent evidence.

5. Each seller of services subject to sales tax pursuant to this paragraph shall maintain a monthly log showing each transaction for which sales tax was not collected because the services meet the requirements of subparagraph 3. for out-of-state use. The log must identify the purchaser's name, location and mailing address, and federal employer identification number, if a business, or the social security number, if an individual, the service sold, the price of the service, the date of sale, the reason for the exemption, and the sales invoice number. The monthly log shall be maintained pursuant to the same requirements and subject to the same penalties imposed for the keeping of similar records pursuant to this chapter.

(j)1. Notwithstanding any other provision of this chapter, there is hereby levied a tax on the sale, use, consumption, or storage for use in this state of any coin or currency, whether in circulation or not, when such coin or currency:

a. Is not legal tender;

b. If legal tender, is sold, exchanged, or traded at a rate in excess of its face value; or

c. Is sold, exchanged, or traded at a rate based on its precious metal content.

2. Such tax shall be at a rate of 6 percent of the price at which the coin or currency is sold, exchanged, or traded, except that, with respect to a coin or currency which is legal tender of the United States and which is sold, exchanged, or traded, such tax shall not be levied.

3. There are exempt from this tax exchanges of coins or currency which are in general circulation in, and legal tender of, one nation for coins or currency which are in general circulation in, and legal tender of, another nation when exchanged solely for use as legal tender and at an exchange rate based on the relative value of each as a medium of exchange.

4. With respect to any transaction that involves the sale of coins or currency taxable under this paragraph in which the taxable amount represented by the sale of such coins or currency exceeds $500,

the entire amount represented by the sale of such coins or currency is exempt from the tax imposed under this paragraph. The dealer must maintain proper documentation, as prescribed by rule of the department, to identify that portion of a transaction which involves the sale of coins or currency and is exempt under this subparagraph.

(k) At the rate of 6 percent of the sales price of each gallon of diesel fuel not taxed under chapter 206 purchased for use in a vessel, except dyed diesel fuel that is exempt pursuant to s. 212.08(4)(a)4.

(l) Florists located in this state are liable for sales tax on sales to retail customers regardless of where or by whom the items sold are to be delivered. Florists located in this state are not liable for sales tax on payments received from other florists for items delivered to customers in this state.

(m) Operators of game concessions or other concessionaires who customarily award tangible personal property as prizes may, in lieu of paying tax on the cost price of such property, pay tax on 25 percent of the gross receipts from such concession activity.

(2) The tax shall be collected by the dealer, as defined herein, and remitted by the dealer to the state at the time and in the manner as hereinafter provided.

(3) The tax so levied is in addition to all other taxes, whether levied in the form of excise, license, or privilege taxes, and in addition to all other fees and taxes levied.

(4) The tax imposed pursuant to this chapter shall be due and payable according to the brackets set forth in s. 212.12.

(5) Notwithstanding any other provision of this chapter, the maximum amount of tax imposed under this chapter and collected on each sale or use of a boat in this state may not exceed $18,000 and on each repair of a boat in this state may not exceed $60,000.

History.—s. 5, ch. 26319, 1949; s. 3, ch. 59-289; s. 4, ch. 63-526; ss. 5, 6, ch. 68-27; ss. 8, 9, ch. 69-222; s. 4, ch. 71-360; s. 1, ch. 76-6; s. 2, ch. 78-74; s. 114, ch. 81-259; s. 4, ch. 82-154; s. 2, ch. 83-3; s. 7, ch. 85-174; s. 6, ch. 85-348; ss. 80, 81, ch. 86-152; ss. 6, 7, ch. 86-155; s. 3, ch. 86-166; ss. 10, 83, ch. 87-6; ss. 2, 9, ch. 87-99; ss. 12, 52, ch. 87-101; s. 7, ch. 87-402; ss. 7, 8, 9, ch. 87-548; s. 18, ch. 90-132; s. 89, ch. 90-136; s. 86, ch. 91-45; s. 1, ch. 91-66; s. 171, ch. 91-112; s. 239, ch. 91-224; ss. 10, 13, 16, ch. 92-319; s. 1, ch. 93-86; ss. 8, 17, ch. 94-314; s. 8, ch. 94-353; s. 1495, ch. 95-147; ss. 1, 2, ch. 95-302; s. 4, ch. 95-403; s. 3, ch. 95-416; s. 112, ch. 95-417; ss. 22, 28, ch. 96-397; s. 35, ch. 96-410; s. 12, ch. 97-54; s. 20, ch. 97-94; s. 28, ch. 97-96; s. 20, ch. 97-99; s. 1, ch. 97-121; s. 3, ch. 97-283; s. 5, ch. 98-140; s. 1, ch. 99-337; s. 2, ch. 99-363; ss. 45, 48, 58, ch. 2000-260; s. 38, ch. 2001-140; s. 15, ch. 2002-48; s. 13, ch. 2005-280; s. 20, ch. 2007-106; s. 3, ch. 2009-51; s. 1, ch. 2010-128; s. 5, ch. 2010-138; s. 7, ch. 2010-147; s. 20, ch. 2011-3; s. 1, ch. 2013-82; s. 2, ch. 2014-38; s. 13, ch. 2015-221; s. 10, ch. 2016-220; s. 63, ch. 2016-239; s. 23, ch. 2017-36; s. 12, ch. 2018-130.

[1]**Note.**—Section 3, ch. 2007-78, provides that "[s]ection 501.95(2)(a), Florida Statutes, as created in [ch. 2007-256] or similar legislation, does not apply to prepaid calling arrangements as defined in s. 212.05(1)(e), Florida Statutes, including prepaid cards for wireless or wireline telecommunications service."

Select Year: 2018 Go

The 2018 Florida Statutes

Title XXVII RAILROADS AND OTHER REGULATED UTILITIES | Chapter 366 PUBLIC UTILITIES | View Entire Chapter

366.14 Regulatory assessment fees.—Notwithstanding any provision of law to the contrary, each regulated company under the jurisdiction of the commission which was in operation for any part of the preceding 6-month period shall pay to the commission within 30 days following the end of each 6-month period a fee based upon its gross operating revenues for that period. The fee may not be greater than:

(1) For each public utility that supplies electricity, 0.125 percent of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, and rural electric cooperatives or any combination thereof;

(2) For each public utility that supplies gas (natural, manufactured, or similar gaseous substance), 0.5 percent of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities and municipal gas utilities or any combination thereof;

(3) For each municipal gas utility or gas district, 0.25 percent of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities and municipal gas utilities or any combination thereof; and

(4) For each municipal electric utility or rural electric cooperative, 0.015625 percent of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, or rural electric cooperatives or any combination thereof.

History.—ss. 16, 22, ch. 89-292; s. 4, ch. 91-429.

Tab 3

State Reports

Current Tax Revenue and Forecasted Collections from Investor Owned Utilities (IOU)

	Total IOU Tax Revenue	Growth Rate
2013-14	$432,879,419	
2015-14	$452,793,189	4.60%
2016-15	$444,988,006	-1.72%
2017-16	$440,795,116	-0.94%
2017-18	$460,927,867	4.57%
2018-19	$462,587,207	0.36%
2019-20	*$462,263,396*	*-0.07%*
2020-21	*$470,260,553*	*1.73%*
2021-22	*$477,549,592*	*1.55%*
2022-23	*$486,145,484*	*1.80%*
2023-24	*$495,430,863*	*1.91%*
2024-25	*$505,587,196*	*2.05%*
2025-26	*$512,715,975*	*1.41%*
2026-27	*$520,663,073*	*1.55%*
2027-28	*$527,900,290*	*1.39%*

Source: FDOR Gross Receipts Utilities Tax Returns, Form DR-133; Forecast form REC Gross Receipts and Communication Services Tax Nov. 29, 2018

Charge for Service

Home Rule Authority Granted by Article VIII, Section 2(b), Florida Constitution, and
Section 166.021, Florida Statutes

Article VIII, Section 2(b), Florida Constitution, provides:

> (b) POWERS. Municipalities shall have governmental, corporate and proprietary powers to enable them to conduct municipal government, perform municipal functions and render municipal services, and may exercise any power for municipal purposes except as otherwise provided by law. Each municipal legislative body shall be elective.

Section 166.021, Florida Statutes, grants extensive home rule power to municipalities. A municipality has the complete power to legislate by ordinance for any municipal purpose, except in those situations that a general or special law is inconsistent with the subject matter of the proposed ordinance.

Not all local government revenue sources are taxes requiring general law authorization under Article VII, Section 1(a), Florida Constitution. When a county or municipal revenue source is imposed by ordinance, the judicial test is whether the charge meets the legal sufficiency test, pursuant to Florida case law, for a valid fee or assessment. If not a valid fee or assessment, the charge is a tax and requires general law authorization. If not a tax, the fee or assessment's imposition is within the constitutional and statutory home rule power of municipalities and counties.

When analyzing the validity of a home rule fee, judicial reliance is often placed on the type of governmental power being exercised. Generally, fees fall into two categories. Regulatory fees, such as building permit fees, impact fees, inspection fees, and stormwater fees, are imposed pursuant to the exercise of police powers as regulation of an activity or property. Such regulatory fees cannot exceed the cost of the regulated activity and are generally applied solely to pay the cost of the regulated activity.

In contrast, proprietary fees, such as admission fees, franchise fees, user fees, and utility fees, are imposed pursuant to the exercise of the proprietary right of government. Such proprietary fees are governed by the principle that the feepayer receives a special benefit or the imposed fee is reasonable in relation to the privilege or service provided. For each fee category, rules have been developed by Florida case law to distinguish a valid fee from a tax.

Local governments may exercise their home rule authority to impose utility fees or charges for services for the privilege of receiving one or more services provided by a local government. The amount of revenue generated from such charges depends on which services the local government chooses to provide and the level of such services.

Summaries of prior years' charges for services revenues as reported by local governments are available.[1]

1. http://edr.state.fl.us/Content/local-government/data/revenues-expenditures/index.cfm

Reported Local Government Charge for Service - Electric Utility Revenues
Local Fiscal Years 2004-05 to 2016-17

Counties

Local FY	# Reporting Charge for Service-Electric Utility Revenue	Charge for Service-Electric Utility Revenue	Total Charge for Service Revenue	Charge for Service-Electric Utility as % of Total Charge for Service	Total Revenue from All Accounts	Charge for Service-Electric Utility as % of Total Revenue
2016-17	2	$ 9,147,187	$ 13,074,034,146	0.1%	$ 40,634,935,175	0.02%
2015-16	2	$ 13,590,834	$ 12,526,050,862	0.1%	$ 40,323,612,683	0.03%
2014-15	2	$ 18,564,928	$ 12,014,816,155	0.2%	$ 39,173,950,740	0.05%
2013-14	2	$ 20,286,676	$ 11,657,880,291	0.2%	$ 35,078,190,149	0.06%
2012-13	3	$ 16,118,157	$ 11,260,085,084	0.1%	$ 35,293,284,441	0.05%
2011-12	2	$ 16,199,004	$ 10,959,204,250	0.1%	$ 34,425,008,290	0.05%
2010-11	3	$ 16,817,589	$ 10,870,626,546	0.2%	$ 35,205,022,317	0.05%
2009-10	3	$ 17,324,453	$ 10,526,472,954	0.2%	$ 36,374,756,173	0.05%
2008-09	3	$ 16,770,866	$ 10,581,450,201	0.2%	$ 39,132,778,914	0.04%
2007-08	3	$ 14,393,534	$ 10,839,892,413	0.1%	$ 41,166,433,921	0.03%
2006-07	3	$ 10,901,237	$ 10,525,350,045	0.1%	$ 42,393,396,183	0.03%
2005-06	3	$ 10,701,388	$ 10,063,830,674	0.1%	$ 40,119,986,366	0.03%
2004-05	3	$ 9,498,953	$ 9,330,169,051	0.1%	$ 36,729,090,757	0.03%

Municipalities

Local FY	# Reporting Charge for Service-Electric Utility Revenue	Charge for Service-Electric Utility Revenue	Total Charge for Service Revenue	Charge for Service-Electric Utility as % of Total Charge for Service	Total Revenue from All Accounts	Charge for Service-Electric Utility as % of Total Revenue
2016-17	27	$ 2,833,717,064	$ 12,996,793,830	21.8%	$ 37,272,779,279	7.6%
2015-16	31	$ 3,021,063,237	$ 12,630,139,256	23.9%	$ 36,672,325,904	8.2%
2014-15	35	$ 3,059,195,092	$ 12,345,382,266	24.8%	$ 30,638,171,458	10.0%
2013-14	35	$ 3,173,230,801	$ 12,105,552,119	26.2%	$ 32,449,841,150	9.8%
2012-13	32	$ 3,006,781,530	$ 11,651,706,180	25.8%	$ 32,154,402,860	9.4%
2011-12	33	$ 3,105,841,525	$ 11,612,933,258	26.7%	$ 32,060,876,417	9.7%
2010-11	31	$ 3,395,712,702	$ 11,734,441,711	28.9%	$ 28,177,088,566	12.1%
2009-10	32	$ 3,459,928,764	$ 11,366,713,856	30.4%	$ 30,459,315,301	11.4%
2008-09	34	$ 3,451,878,036	$ 11,060,844,881	31.2%	$ 28,291,875,774	12.2%
2007-08	33	$ 3,250,701,725	$ 10,785,920,018	30.1%	$ 25,968,943,835	12.5%
2006-07	33	$ 2,934,314,903	$ 10,188,071,962	28.8%	$ 32,648,022,846	9.0%
2005-06	33	$ 2,892,194,407	$ 9,798,282,787	29.5%	$ 28,713,971,493	10.1%
2004-05	33	$ 2,442,390,082	$ 8,776,575,305	27.8%	$ 26,604,948,976	9.2%

Reported Local Government Charge for Service - Electric Utility Revenues
Local Fiscal Years 2004-05 to 2016-17

Special Districts and Other Agencies

Local FY	# Reporting Charge for Service-Electric Utility Revenue	Charge for Service-Electric Utility Revenue	Total Charge for Service Revenue	Charge for Service-Electric Utility as % of Total Charge for Service	Total Revenue from All Accounts	Charge for Service-Electric Utility as % of Total Revenue
2016-17	5	$ 1,477,895,221	$ 10,761,622,083	13.7%	$ 18,201,947,373	8.1%
2015-16	5	$ 1,436,937,021	$ 10,364,398,377	13.9%	$ 18,359,620,830	7.8%
2014-15	5	$ 1,473,924,070	$ 9,886,024,485	14.9%	$ 17,495,455,876	8.4%
2013-14	5	$ 1,571,517,327	$ 9,048,156,702	17.4%	$ 16,221,018,120	9.7%
2012-13	5	$ 1,463,436,022	$ 8,800,371,745	16.6%	$ 16,218,835,586	9.0%
2011-12	4	$ 1,480,432,127	$ 8,808,019,234	16.8%	$ 15,788,021,030	9.4%
2010-11	4	$ 1,544,549,763	$ 8,876,366,274	17.4%	$ 15,830,841,952	9.8%
2009-10	4	$ 1,559,396,237	$ 8,535,365,633	18.3%	$ 15,933,222,505	9.8%
2008-09	3	$ 1,661,471,818	$ 8,421,732,372	19.7%	$ 16,323,972,993	10.2%
2007-08	3	$ 1,701,396,898	$ 8,417,189,999	20.2%	$ 16,810,742,265	10.1%
2006-07	3	$ 1,493,787,242	$ 7,825,065,246	19.1%	$ 18,659,941,607	8.0%
2005-06	3	$ 1,431,839,976	$ 7,078,581,492	20.2%	$ 16,174,397,921	8.9%
2004-05	4	$ 1,412,696,891	$ 6,639,607,220	21.3%	$ 13,658,818,128	10.3%

Combined Total: Counties, Municipalities, and Special Districts

Local FY	# Reporting Charge for Service-Electric Utility Revenue	Charge for Service-Electric Utility Revenue	Total Charge for Service Revenue	Charge for Service-Electric Utility as % of Total Charge for Service	Total Revenue from All Accounts	Charge for Service-Electric Utility as % of Total Revenue
2016-17	34	$ 4,320,759,472	$ 36,832,450,059	11.7%	$ 96,109,661,827	4.5%
2015-16	38	$ 4,471,591,092	$ 35,520,588,495	12.6%	$ 95,355,559,417	4.7%
2014-15	42	$ 4,551,684,090	$ 34,246,222,906	13.3%	$ 87,307,578,074	5.2%
2013-14	42	$ 4,765,034,804	$ 32,811,589,112	14.5%	$ 83,749,049,419	5.7%
2012-13	40	$ 4,486,335,709	$ 31,712,163,009	14.1%	$ 83,666,522,887	5.4%
2011-12	39	$ 4,602,472,656	$ 31,380,156,742	14.7%	$ 82,273,905,737	5.6%
2010-11	38	$ 4,957,080,054	$ 31,481,434,531	15.7%	$ 79,212,952,835	6.3%
2009-10	39	$ 5,036,649,454	$ 30,428,552,443	16.6%	$ 82,767,293,979	6.1%
2008-09	40	$ 5,130,120,720	$ 30,064,027,454	17.1%	$ 83,748,627,681	6.1%
2007-08	39	$ 4,966,492,157	$ 30,043,002,430	16.5%	$ 83,946,120,021	5.9%
2006-07	39	$ 4,439,003,382	$ 28,538,487,253	15.6%	$ 93,701,360,636	4.7%
2005-06	39	$ 4,334,735,771	$ 26,940,694,953	16.1%	$ 85,008,355,780	5.1%
2004-05	40	$ 3,864,585,926	$ 24,746,351,576	15.6%	$ 76,992,857,861	5.0%

Note: This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 343.100 - Charges for Services-Electric Utility.

Source: EDR staff compilation of Annual Financial Report (AFR) data obtained from the Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Government.

Electric Utility Charge for Service Revenues Reported by Municipal Governments Having Municipal-Owned Utilities and Florida Municipal Power Agency

Local Fiscal Years 2003-04 to 2016-17

			Electric Utility Service Charges by Local Fiscal Year *													
	Municipal-Owned Utilities **	Respective County	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17
1	Alachua	Alachua	$ 8,570,033	$ 10,105,732	$ 11,595,733	$ 11,350,370	$ 14,563,814	$ 12,835,626	$ 14,673,991	$ 14,392,269	$ 12,519,393	$ 13,073,827	$ 15,171,323	$ 15,693,189	$ 15,129,466	$ 13,736,261
2	Bartow	Polk	$ 25,849,964	$ 29,956,677	$ 33,647,626	$ 33,910,762	$ 35,620,045	$ 39,101,205	$ 39,839,131	$ 37,329,501	$ 34,062,576	$ 34,963,687	$ 36,313,850	$ 35,871,975	$ 35,242,965	$ 35,696,824
3	Blountstown	Calhoun	$ 2,735,966	$ 2,878,295	$ 3,122,341	$ 3,737,940	$ 3,929,107	$ 5,043,810	$ 5,316,790	$ 5,339,222	$ 4,946,040	$ 4,529,676	$ 4,509,623	$ 4,571,723	$ 4,532,958	$ 4,427,024
4	Bushnell	Sumter	$ 2,457,451	$ 2,822,165	$ 3,222,612	$ 2,964,907	$ 3,392,154	$ 3,785,508	$ 3,725,048	$ 3,280,160	$ 3,038,143	$ 3,127,344	$ 3,255,251	$ 3,066,573	$ 3,088,518	$ 3,166,300
5	Chattahoochee	Gadsden	$ 3,377,309	$ 3,539,234	$ 3,900,076	$ 3,881,240	$ 4,232,208	$ 4,540,093	$ 5,107,373	$ 4,775,353	$ 4,221,971	$ 4,377,892	$ 3,882,655	$ 4,047,261	$ 3,642,222	$ 3,607,168
6	Clewiston	Hendry	$ 11,719,853	$ 12,977,342	$ 14,445,162	$ 13,649,400	$ 14,371,041	$ 13,977,724	$ 13,556,367	$ 12,125,134	$ 11,763,512	$ 11,104,199	$ 11,662,948	$ 10,885,957	$ 11,021,233	$ 11,562,979
7	Fort Meade	Polk	$ 4,782,808	$ 4,975,275	$ 5,742,263	$ 5,930,819	$ 5,619,170	$ 6,789,537	$ 6,846,191	$ 5,663,868	$ 5,861,120	$ 5,490,504	$ 5,448,973	$ 5,437,432	$ 5,341,155	$ 5,220,779
8	Fort Pierce (i.e., Fort Pierce Utilities Authority)	St. Lucie	$ 55,533,797	$ 58,021,199	$ 66,359,867	$ 67,638,814	$ 78,739,937	$ 79,006,490	$ 77,824,862	$ 68,900,541	$ 66,406,351	$ 65,387,812	$ 64,727,567	$ 61,820,383	$ 64,113,558	$ 65,665,869
9	Gainesville (i.e., Gainesville Regional Utilities or GRU)	Alachua	$ 170,231,708	$ 178,378,304	$ 209,365,100	$ 207,832,848	$ 252,291,821	$ 270,380,452	$ 270,956,992	$ 262,318,796	$ 246,572,935	$ 247,422,315	$ 305,904,342	$ 325,211,508	$ 327,020,803	$ 352,229,567
10	Green Cove Springs	Clay	$ 10,356,321	$ 11,396,744	$ 13,707,075	$ 13,215,441	$ 15,243,894	$ 16,457,329	$ 15,698,670	$ 13,757,010	$ 12,554,217	$ 13,510,774	$ 12,334,214	$ 11,994,907	$ -	$ -
11	Havana	Gadsden	$ 2,375,987	$ 2,542,939	$ 3,079,782	$ 3,018,657	$ 3,300,456	$ 3,488,295	$ 3,555,684	$ 3,253,862	$ 2,748,844	$ 2,896,307	$ 3,069,500	$ 2,884,775	$ 2,618,694	$ -
12	Homestead	Miami-Dade	$ 34,431,097	$ 40,278,721	$ 46,571,559	$ 49,317,046	$ 55,813,812	$ 53,772,181	$ 55,299,856	$ 56,707,781	$ 55,418,533	$ 56,580,587	$ 58,513,823	$ 61,234,156	$ 60,589,385	$ 61,040,092
13	Jacksonville (i.e., JEA)	Duval	$ 840,210,000	$ 973,326,000	$ 1,157,927,000	$ 1,203,126,000	$ 1,372,407,000	$ 1,569,451,000	$ 1,592,569,000	$ 1,667,118,000	$ 1,508,176,000	$ 1,416,652,000	$ 1,463,015,000	$ 1,353,970,000	$ 1,348,524,000	$ 1,411,654,000
14	Jacksonville Beach (i.e., Beaches Energy Services)	Duval	$ -	$ 81,001,696	$ 88,336,668	$ 84,795,349	$ 99,196,326	$ 101,923,937	$ 99,100,860	$ 87,081,295	$ 79,748,438	$ 87,111,496	$ 86,044,419	$ 81,754,108	$ 81,899,763	$ 80,809,355
15	Key West (i.e., Keys Energy Services - the utility provider for the Lower Florida Keys)	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Kissimmee (i.e., Kissimmee Utility Authority or KUA)	Osceola	$ -	$ -	$ -	$ -	$ -	$ 57,000	$ 8,525,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Lake Worth	Palm Beach	$ 43,567,311	$ 45,186,261	$ 51,988,553	$ 53,053,949	$ 56,268,104	$ 55,423,780	$ 57,422,429	$ 53,736,520	$ 52,783,018	$ 48,747,981	$ 53,842,329	$ 53,570,128	$ 56,112,042	$ 55,177,084
18	Lakeland (i.e., Lakeland Electric)	Polk	$ 298,189,689	$ 340,529,940	$ 377,047,401	$ 374,570,781	$ 384,493,828	$ 343,366,946	$ 354,215,696	$ 340,881,856	$ 290,336,885	$ 302,055,713	$ 306,337,851	$ 309,502,891	$ 296,552,463	$ 303,483,541
19	Leesburg	Lake	$ 45,347,288	$ 49,715,695	$ 60,196,916	$ 59,285,095	$ 68,365,313	$ 69,726,595	$ 66,048,276	$ 57,329,631	$ 54,119,794	$ 58,616,764	$ 57,266,494	$ 57,184,852	$ 58,705,987	$ 61,577,284
20	Moore Haven	Glades	$ 1,594,647	$ 1,846,777	$ 2,160,162	$ 2,115,319	$ 2,036,768	$ 2,062,286	$ 2,135,779	$ 2,096,439	$ 1,921,365	$ 1,847,439	$ 1,953,131	$ 2,097,016	$ 1,861,077	$ 1,670,877
21	Mount Dora	Lake	$ 7,813,649	$ 8,503,788	$ 10,115,125	$ 10,327,519	$ 10,530,781	$ 11,942,165	$ 12,915,244	$ 12,035,897	$ 10,997,916	$ 10,324,206	$ 10,682,392	$ 10,906,611	$ 9,683,948	$ 9,144,681
22	New Smyrna Beach (i.e., Utilities Commission or UCNSB)	Volusia	$ 32,893,546	$ 35,811,162	$ 44,285,794	$ 44,552,582	$ 48,241,274	$ 42,145,939	$ 44,766,297	$ 44,839,313	$ 39,356,823	$ 40,724,442	$ 42,458,741	$ 43,953,921	$ 43,416,397	$ 42,180,989
23	Newberry	Alachua	$ 2,630,126	$ 2,720,712	$ 3,502,312	$ 3,598,504	$ 3,953,824	$ 4,412,116	$ 4,554,954	$ 4,068,134	$ 3,815,974	$ 4,032,575	$ 3,934,479	$ 4,003,130	$ 4,075,824	$ 4,002,295
24	Ocala (i.e., Ocala Electric Utility)	Marion	$ -	$ 129,953,422	$ 160,561,852	$ 148,334,904	$ 174,769,660	$ 174,327,381	$ 169,237,791	$ 146,037,671	$ 151,138,238	$ 150,795,698	$ 151,550,185	$ 145,517,482	$ 145,463,587	$ 149,240,767
25	Orlando Utilities Commission (provides services to customers in the cities of Orlando, St. Cloud, and parts of Orange and Osceola counties)	Orange	$ 622,846,000	$ 700,009,000	$ 690,346,000	$ 671,388,000	$ 750,936,000	$ 704,483,000	$ 759,754,000	$ 769,776,800	$ 747,605,000	$ 718,551,000	$ 771,323,000	$ 747,160,000	$ 750,530,000	$ 761,916,000
26	Quincy	Gadsden	$ 13,784,490	$ 14,051,643	$ 16,328,999	$ 16,606,282	$ -	$ 16,542,140	$ 18,500,238	$ 15,955,950	$ 12,785,843	$ 13,871,208	$ 13,539,465	$ 14,642,590	$ 12,401,557	$ 12,538,999
27	Reedy Creek Improvement District (includes the Walt Disney Resort and the cities of Bay Lake and Lake Buena Vista)	Orange	$ 86,293,949	$ 93,472,604	$ 109,048,976	$ 117,653,242	$ 101,537,898	$ 124,428,818	$ 127,444,844	$ 124,865,192	$ 122,514,368	$ 121,025,545	$ 122,226,288	$ 113,226,215	$ 97,438,204	$ 96,815,152
28	St. Cloud (services provided by the Orlando Utilities Commission)	Osceola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Starke	Bradford	$ 7,633,937	$ 8,057,791	$ 9,667,287	$ 9,689,447	$ 10,178,845	$ 10,481,903	$ 10,270,280	$ 9,230,911	$ 8,791,963	$ 8,757,983	$ 8,661,335	$ 8,613,380	$ 8,697,569	$ -
30	Tallahassee	Leon	$ 253,765,000	$ 272,397,000	$ 337,436,000	$ 346,136,000	$ 368,564,000	$ 364,665,000	$ 334,353,000	$ 314,856,000	$ 283,650,000	$ 255,544,000	$ 277,000,000	$ 283,713,000	$ 267,889,000	$ -
31	Vero Beach (Florida Power & Light began providing electric service to city residents on 12/17/2018.)	Indian River	$ 66,335,928	$ 82,731,567	$ 95,214,719	$ 93,415,614	$ 99,150,320	$ 104,792,881	$ 99,845,837	$ 84,602,720	$ 86,941,142	$ 90,957,716	$ 93,252,348	$ 92,830,617	$ 91,981,478	$ 86,654,495
32	Wauchula	Hardee	$ 6,636,091	$ 7,164,138	$ 8,184,695	$ 8,201,165	$ 8,057,982	$ 8,248,738	$ 7,620,314	$ 7,859,666	$ 6,979,509	$ 6,390,270	$ 6,913,605	$ 7,067,760	$ 6,455,403	$ 6,310,212
33	Williston	Levy	$ 3,049,008	$ 3,270,826	$ 3,782,295	$ 3,829,791	$ 3,976,265	$ 4,615,823	$ 4,560,636	$ 4,076,380	$ 3,905,635	$ 3,817,083	$ 3,761,487	$ 3,688,885	$ 3,726,395	$ 3,578,453
34	Winter Park	Orange	$ -	$ 17,165,869	$ 42,184,076	$ 45,489,521	$ 43,322,647	$ 48,818,537	$ 52,762,581	$ 47,373,469	$ 41,600,877	$ 44,053,691	$ 44,409,853	$ 43,081,465	$ 42,849,016	$ 40,643,085
	Other Entities															
	Florida Municipal Power Agency (a wholesale power agency currently owned by 31 of the 34 above-listed municipal-owned utilities, excluding Jacksonville, Reedy Creek Improvement District, and Vero Beach) ****		$ 509,887,000	$ 617,449,000	$ 632,445,000	$ 704,746,000	$ 848,923,000	$ 832,560,000	$ 672,121,000	$ 649,832,000	$ 610,245,000	$ 623,719,000	$ 677,685,000	$ 613,103,000	$ 588,458,000	$ 618,649,000
	Totals		**$ 3,174,899,953**	**$ 3,842,237,518**	**$ 4,315,519,026**	**$ 4,417,363,308**	**$ 4,942,027,294**	**$ 5,103,654,235**	**$ 5,011,125,011**	**$ 4,931,497,341**	**$ 4,577,527,423**	**$ 4,470,060,734**	**$ 4,720,651,471**	**$ 4,532,306,890**	**$ 4,449,062,667**	**$ 4,302,399,132**
	% Change			**21.0%**	**12.3%**	**2.4%**	**11.9%**	**3.3%**	**-1.8%**	**-1.6%**	**-7.2%**	**-2.3%**	**5.6%**	**-4.0%**	**-1.8%**	**-3.3%**

Notes:
* This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 343.100 - Charges for Services-Physical Environment-Electric Utility.
** According to the Florida Municipal Electric Association, there are 33 municipal electric (public power) utilities in Florida that serve over three million Floridians. (see "Florida Municipal Electric Utilities" webpage, available at https://publicpower.com/municipal-members)
**** Florida Municipal Power Agency, "Members" webpage, available at https://fmpa.com/about/members/

Source: EDR staff compilation of Annual Financial Report (AFR) data obtained from the Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Government.

Public Service Tax

Sections 166.231-.235, Florida Statutes

Municipalities and charter counties may levy by ordinance 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.[1] The tax is levied only upon purchases within the municipality or within the charter county's unincorporated area and cannot exceed 10 percent of the payments received by the seller of the taxable item. Services competitive with those listed above, as defined by ordinance, can be taxed on a comparable base at the same rates; however, the tax rate on fuel oil cannot exceed 4 cents per gallon.[2] The tax proceeds are considered general revenue for the municipality or charter county.

All municipalities are eligible to levy the tax within the area of its tax jurisdiction. In addition, municipalities imposing the tax on cable television service, as of May 4, 1977, may continue the tax levy in order to satisfy debt obligations incurred prior to that date. By virtue of a number of legal rulings in Florida case law, a charter county may levy the tax within the unincorporated area. For example, the Florida Supreme Court ruled in 1972 that charter counties, unless specifically precluded by general or special law, could impose by ordinance any tax in the area of its tax jurisdiction that a municipality could impose.[3] In 1994, the Court held that Orange County could levy a public service tax without specific statutory authority to do so.[4]

The tax is collected by the seller of the taxable item from the purchaser at the time of payment.[5] At the discretion of the local taxing authority, the tax may be levied on a physical unit basis. Using this basis, the tax is levied as follows: electricity, number of kilowatt hours purchased; metered or bottled gas, number of cubic feet purchased; fuel oil and kerosene, number of gallons purchased; and water service, number of gallons purchased.[6] A number of tax exemptions are specified in law.[7]

A tax levy is adopted by ordinance, and the effective date of every tax levy or repeal must be the beginning of a subsequent calendar quarter: January 1st, April 1st, July 1st, or October 1st. The taxing authority must notify the Department of Revenue (DOR) of a tax levy adoption or repeal at least 120 days before its effective date. Such notification must be furnished on a form prescribed by the DOR and specify the services taxed, the tax rate applied to each service, and the effective date of the levy or repeal as well as other additional information.[8]

The seller of the service remits the taxes collected to the governing body in the manner prescribed by ordinance.[9] The tax proceeds are considered general revenue for the municipality or charter county. As previously mentioned, taxing authorities are required to furnish information to the DOR, which maintains an online database that can be searched or downloaded.[10]

Summaries of prior years' revenues reported by county and municipal governments are available.[11]

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1. Section 166.231(1), F.S.
2. Section 166.231(2), F.S.
3. Volusia County vs. Dickinson, 269 So.2d 9 (Fla. 1972).
4. McLeod vs. Orange County, 645 So.2d 411 (Fla. 1994).
5. Section 166.231(7), F.S.
6. Section 166.232, F.S.
7. Section 166.231(3)-(6) and (8), F.S.
8. Section 166.233(2), F.S.
9. Section 166.231(7), F.S.
10. http://floridarevenue.com/taxes/governments/Pages/mpst.aspx
11. http://edr.state.fl.us/Content/local-government/data/data-a-to-z/index.cfm

Reported County and Municipal Government Public Service Tax - Electricity Revenues
Local Fiscal Years 2004-05 to 2016-17

Counties

Local FY	# Reporting Public Service Tax-Electricity Revenue	Public Service Tax-Electricity Revenue	Total Public Service Tax Revenue	Public Service Tax-Electricity as % of Total Public Serv. Tax	Total Revenue from All Accounts	Public Service Tax-Electricity as % of Total Revenue
2016-17	14	$ 259,276,088	$ 298,837,744	86.8%	$ 40,634,935,175	0.6%
2015-16	14	$ 254,621,610	$ 292,422,209	87.1%	$ 40,323,612,683	0.6%
2014-15	14	$ 244,533,188	$ 281,148,099	87.0%	$ 39,173,950,740	0.6%
2013-14	14	$ 243,450,027	$ 279,209,387	87.2%	$ 35,078,190,149	0.7%
2012-13	14	$ 226,788,903	$ 260,438,801	87.1%	$ 35,293,284,441	0.6%
2011-12	14	$ 214,220,296	$ 248,870,242	86.1%	$ 34,425,008,290	0.6%
2010-11	14	$ 221,012,830	$ 256,985,431	86.0%	$ 35,205,022,317	0.6%
2009-10	14	$ 249,491,574	$ 289,065,380	86.3%	$ 36,374,756,173	0.7%
2008-09	14	$ 224,247,103	$ 262,199,672	85.5%	$ 39,132,778,914	0.6%
2007-08	13	$ 227,934,592	$ 280,094,341	81.4%	$ 41,166,433,921	0.6%
2006-07	13	$ 239,767,855	$ 299,441,458	80.1%	$ 42,393,396,183	0.6%
2005-06	12	$ 222,739,494	$ 278,902,292	79.9%	$ 40,119,986,366	0.6%
2004-05	12	$ 205,788,970	$ 257,256,077	80.0%	$ 36,729,090,757	0.6%

Municipalities

Local FY	# Reporting Public Service Tax-Electricity Revenue	Public Service Tax-Electricity Revenue	Total Public Service Tax Revenue	Public Service Tax-Electricity as % of Total Public Serv. Tax	Total Revenue from All Accounts	Public Service Tax-Electricity as % of Total Revenue
2016-17	329	$ 780,374,286	$ 967,851,932	80.6%	$ 37,272,779,279	2.1%
2015-16	337	$ 788,347,654	$ 960,874,090	82.0%	$ 36,672,325,904	2.1%
2014-15	341	$ 766,635,660	$ 935,987,552	81.9%	$ 30,638,171,458	2.5%
2013-14	336	$ 761,756,547	$ 936,010,677	81.4%	$ 32,449,841,150	2.3%
2012-13	333	$ 691,359,157	$ 869,795,356	79.5%	$ 32,154,402,860	2.2%
2011-12	334	$ 666,317,873	$ 837,408,227	79.6%	$ 32,060,876,417	2.1%
2010-11	335	$ 671,200,686	$ 830,044,048	80.9%	$ 28,177,088,566	2.4%
2009-10	328	$ 668,376,661	$ 948,885,749	70.4%	$ 30,459,315,301	2.2%
2008-09	325	$ 606,134,061	$ 912,265,351	66.4%	$ 28,291,875,774	2.1%
2007-08	324	$ 585,900,374	$ 834,889,954	70.2%	$ 25,968,943,835	2.3%
2006-07	318	$ 560,530,030	$ 808,793,559	69.3%	$ 32,648,022,846	1.7%
2005-06	308	$ 522,270,643	$ 772,981,528	67.6%	$ 28,713,971,493	1.8%
2004-05	305	$ 505,856,228	$ 741,201,140	68.2%	$ 26,604,948,976	1.9%

Combined Total: Counties and Municipalities

Local FY	# Reporting Public Service Tax-Electricity Revenue	Public Service Tax-Electricity Revenue	Total Public Service Tax Revenue	Public Service Tax-Electricity as % of Total Public Serv. Tax	Total Revenue from All Accounts	Public Service Tax-Electricity as % of Total Revenue
2016-17	343	$ 1,039,650,374	$ 1,266,689,676	82.1%	$ 77,907,714,454	1.3%
2015-16	351	$ 1,042,969,264	$ 1,253,296,299	83.2%	$ 76,995,938,587	1.4%
2014-15	355	$ 1,011,168,848	$ 1,217,135,651	83.1%	$ 69,812,122,198	1.4%
2013-14	350	$ 1,005,206,574	$ 1,215,220,064	82.7%	$ 67,528,031,299	1.5%
2012-13	347	$ 918,148,060	$ 1,130,234,157	81.2%	$ 67,447,687,301	1.4%
2011-12	348	$ 880,538,169	$ 1,086,278,469	81.1%	$ 66,485,884,707	1.3%
2010-11	349	$ 892,213,516	$ 1,087,029,479	82.1%	$ 63,382,110,883	1.4%
2009-10	342	$ 917,868,235	$ 1,237,951,129	74.1%	$ 66,834,071,474	1.4%
2008-09	339	$ 830,381,164	$ 1,174,465,023	70.7%	$ 67,424,654,688	1.2%
2007-08	337	$ 813,834,966	$ 1,114,984,295	73.0%	$ 67,135,377,756	1.2%
2006-07	331	$ 800,297,885	$ 1,108,235,017	72.2%	$ 75,041,419,029	1.1%
2005-06	320	$ 745,010,137	$ 1,051,883,820	70.8%	$ 68,833,957,859	1.1%
2004-05	317	$ 711,645,198	$ 998,457,217	71.3%	$ 63,334,039,733	1.1%

Note: This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 314.100 - Utility Service Tax-Electricity.

Source: EDR staff compilation of Annual Financial Report (AFR) data obtained from the Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Government.

Summary of Reported County Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alachua	$ 4,964,976	$ 5,493,288	$ 5,703,837	$ 6,013,936	$ 5,948,038	$ 6,555,386	$ 6,581,093	$ 6,090,689	$ 6,083,440	$ 6,169,583	$ 6,095,400	$ 6,061,220	$ 5,891,110
Baker	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bay	$ -	$ -	$ -	$ -	$ 62,302	$ 1,613,119	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bradford	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Brevard	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Broward	$ 3,383,000	$ 2,692,000	$ 1,136,000	$ 789,000	$ 762,000	$ 821,000	$ 796,000	$ 800,000	$ 874,000	$ 941,000	$ 957,000	$ 1,017,000	$ 1,011,000
Calhoun	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Charlotte	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Citrus	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clay	$ 2,509,546	$ 3,015,201	$ 2,992,327	$ 2,825,032	$ 2,922,524	$ 3,420,107	$ 3,594,741	$ 3,245,305	$ 3,178,068	$ 3,674,244	$ 3,915,622	$ 3,964,437	$ 3,772,645
Collier	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Columbia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DeSoto	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dixie	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,341	$ -	$ -	$ -	$ -	$ -	$ -
Duval	Refer to the separate municipal table for the consolidated City of Jacksonville/Duval County totals.												
Escambia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flagler	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Franklin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gilchrist	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Glades	$ -	$ -	$ -	$ 30,274	$ 26,416	$ 27,144	$ 28,313	$ 28,664	$ 29,391	$ 28,690	$ 28,303	$ 28,288	$ 29,054
Gulf	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hamilton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hardee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hendry	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hernando	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Highlands	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hillsborough	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jackson	$ 1,656,352	$ 1,897,070	$ 1,933,670	$ 2,410,652	$ 2,928,858	$ 3,158,920	$ 3,079,302	$ 2,710,502	$ 2,651,166	$ 2,869,421	$ 2,920,808	$ 2,730,092	$ 2,701,376
Jefferson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lafayette	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leon	$ 3,499,443	$ 3,910,747	$ 4,164,153	$ 4,500,799	$ 4,670,579	$ 4,897,113	$ 4,955,507	$ 5,819,459	$ 5,033,573	$ 4,315,227	$ 4,281,351	$ 5,720,930	$ 6,906,259
Levy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Liberty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Madison	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Manatee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Miami-Dade	$ 56,441,665	$ 63,287,321	$ 59,906,815	$ 62,688,547	$ 57,994,144	$ 62,519,724	$ 65,007,358	$ 64,927,166	$ 70,623,468	$ 76,705,857	$ 76,203,233	$ 78,897,233	$ 81,356,106
Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nassau	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Okaloosa	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Okeechobee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orange	$ 42,443,781	$ 45,479,490	$ 47,168,065	$ 48,568,837	$ 50,185,652	$ 58,786,397	$ 56,510,197	$ 52,525,005	$ 55,737,049	$ 59,817,032	$ 59,299,418	$ 62,069,744	$ 62,249,046
Osceola	$ 7,711,380	$ 8,697,086	$ 8,872,644	$ 9,085,078	$ 9,363,124	$ 10,487,000	$ 11,666,000	$ 10,654,000	$ 11,345,054	$ 12,294,428	$ 12,606,340	$ 13,425,228	$ 13,693,568
Palm Beach	$ 55,852,179	$ 56,212,835	$ 58,182,735	$ 58,336,517	$ 55,037,606	$ 58,278,194	$ 32,121,628	$ 31,919,775	$ 33,944,905	$ 37,216,961	$ 38,084,378	$ 39,415,285	$ 40,040,352
Pasco	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Polk	$ 17,296,429	$ 21,442,989	$ 21,433,098	$ 22,183,329	$ 23,476,400	$ 26,258,847	$ 24,648,508	$ 23,761,791	$ 24,509,459	$ 25,299,987	$ 26,042,717	$ 26,689,666	$ 27,157,219
Putnam	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Johns	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Lucie	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Santa Rosa	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sarasota	$ -	$ -	$ 17,752,108	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Seminole	$ 4,069,054	$ 4,337,460	$ 4,340,795	$ 4,330,234	$ 4,441,023	$ 5,310,617	$ 4,947,346	$ 4,480,029	$ 4,789,593	$ 5,122,696	$ 5,089,295	$ 5,294,530	$ 5,208,433
Sumter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Suwannee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taylor	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Volusia	$ 5,961,165	$ 6,274,007	$ 6,181,608	$ 6,172,357	$ 6,428,437	$ 7,358,006	$ 6,986,496	$ 6,463,405	$ 6,902,123	$ 7,790,251	$ 7,805,056	$ 7,938,498	$ 7,867,811
Wakulla	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 794,506	$ 1,087,614	$ 1,204,650	$ 1,204,267	$ 1,369,459	$ 1,392,109
Walton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary of Reported County Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

County		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total County Public Service Tax - Electricity		$ 205,788,970	$ 222,739,494	$ 239,767,855	$ 227,934,592	$ 224,247,103	$ 249,491,574	$ 221,012,830	$ 214,220,296	$ 226,788,903	$ 243,450,027	$ 244,533,188	$ 254,621,610	$ 259,276,088
% Change		-	8.2%	7.6%	-4.9%	-1.6%	11.3%	-11.4%	-3.1%	5.9%	7.3%	0.4%	4.1%	1.8%
# Reporting		12	12	13	13	14	14	14	14	14	14	14	14	14
Total County Public Service Taxes		$ 257,256,077	$ 278,902,292	$ 299,441,458	$ 280,094,341	$ 262,199,672	$ 289,065,380	$ 256,985,431	$ 248,870,242	$ 260,438,801	$ 279,209,387	$ 281,148,099	$ 292,422,209	$ 298,837,744
% Change		-	8.4%	7.4%	-6.5%	-6.4%	10.2%	-11.1%	-3.2%	4.6%	7.2%	0.7%	4.0%	2.2%
Electricity PST as % of All PST		80.0%	79.9%	80.1%	81.4%	85.5%	86.3%	86.0%	86.1%	87.1%	87.2%	87.0%	87.1%	86.8%

Note: This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 314.XXX - Utility Services Taxes.

Data Source: Florida Department of Financial Services.

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alachua	Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Archer	Alachua	$ 58,423	$ -	$ -	$ 14,520	$ 13,995	$ 79,149	$ 76,205	$ 69,488	$ 73,100	$ 78,238	$ 80,878	$ 78,395	$ 74,184
Gainesville	Alachua	$ 5,227,810	$ 5,419,732	$ 6,047,469	$ 7,246,954	$ 7,196,428	$ 8,458,312	$ 8,734,265	$ 8,336,629	$ 8,406,996	$ 7,982,965	$ 7,597,176	$ 7,788,443	$ 7,687,183
Hawthorne	Alachua	$ 65,465	$ 69,390	$ 65,855	$ 69,427	$ 79,927	$ 89,629	$ 86,815	$ 82,358	$ 84,758	$ 91,022	$ 84,098	$ 87,825	$ 95,163
High Springs	Alachua	$ -	$ 217,003	$ 247,618	$ 249,268	$ 266,325	$ 308,365	$ 294,411	$ 270,770	$ -	$ 311,668	$ 316,981	$ 321,966	$ 312,076
La Crosse	Alachua	$ 13,122	$ 13,804	$ 13,946	$ -	$ -	$ 9,605	$ 16,693	$ 9,412	$ 9,018	$ 15,126	$ 13,389	$ 13,253	$ 13,102
Micanopy	Alachua	$ 33,349	$ 34,166	$ 33,986	$ 34,027	$ 36,826	$ 44,938	$ 40,207	$ 34,311	$ 38,347	$ 39,852	$ 40,214	$ 40,863	$ 37,908
Newberry	Alachua	$ 205,100	$ 268,662	$ 275,437	$ 222,556	$ 190,214	$ 203,549	$ 189,522	$ 189,590	$ 187,990	$ 228,022	$ 460,725	$ 272,832	$ 261,818
Waldo	Alachua	$ -	$ 10,108	$ -	$ 116,699	$ 66,992	$ 59,504	$ 70,083	$ 59,859	$ 116,354	$ 67,097	$ 63,611	$ 65,028	$ 70,352
Glen St. Mary	Baker	$ -	$ 16,066	$ 30,021	$ 27,991	$ 33,865	$ 32,249	$ 33,196	$ 29,084	$ 31,371	$ 35,743	$ 44,248	$ 39,224	$ 40,428
Macclenny	Baker	$ -	$ -	$ -	$ 360,570	$ 409,269	$ 426,387	$ 424,378	$ 413,067	$ 428,975	$ 478,421	$ 496,062	$ 483,096	$ 504,318
Callaway	Bay	$ 717,917	$ 743,724	$ 749,924	$ 748,925	$ 749,711	$ 842,364	$ 828,560	$ 801,160	$ 818,126	$ 954,363	$ 1,037,744	$ 1,140,393	$ 1,099,969
Lynn Haven	Bay	$ 759,434	$ 876,757	$ 883,400	$ 935,839	$ 968,958	$ 1,074,572	$ 1,101,937	$ 1,092,407	$ 1,117,403	$ 1,248,284	$ 1,364,346	$ 1,514,593	$ 1,476,405
Mexico Beach	Bay	$ 14,284	$ 14,766	$ 14,888	$ 15,679	$ 16,821	$ 19,948	$ 21,408	$ 17,013	$ 18,343	$ 22,067	$ 22,841	$ 20,663	$ 50,804
Panama City	Bay	$ 2,614,508	$ 2,872,976	$ 2,855,178	$ 2,802,057	$ 2,812,818	$ 3,041,802	$ 3,198,731	$ 3,199,654	$ 3,254,038	$ 3,605,766	$ 3,893,236	$ 4,009,767	$ 4,039,799
Panama City Beach	Bay	$ -	$ 1,539,341	$ 1,754,700	$ 1,940,772	$ 2,041,188	$ 2,299,134	$ 2,332,026	$ 2,422,565	$ 2,523,330	$ 2,876,616	$ 3,154,997	$ 3,335,590	$ 3,330,435
Parker	Bay	$ 302,500	$ 330,212	$ 309,270	$ 325,513	$ 315,394	$ 347,789	$ 339,794	$ 327,998	$ 335,559	$ 384,868	$ 414,311	$ 413,691	$ 376,218
Springfield	Bay	$ 411,544	$ 443,533	$ 479,979	$ 421,317	$ 394,584	$ 454,303	$ 450,839	$ 430,865	$ 447,926	$ 505,229	$ 549,302	$ -	$ -
Brooker	Bradford	$ 6,934	$ 7,940	$ 7,814	$ 8,410	$ 8,527	$ 9,815	$ 8,219	$ 8,788	$ 8,881	$ 9,809	$ 10,563	$ 10,026	$ 9,694
Hampton	Bradford	$ 19,478	$ 22,212	$ 26,763	$ 14,479	$ 19,429	$ 26,508	$ 22,043	$ 20,150	$ -	$ -	$ -	$ -	$ -
Lawtey	Bradford	$ 34,198	$ 40,614	$ 43,544	$ -	$ -	$ -	$ 8,167	$ -	$ -	$ -	$ -	$ -	$ -
Starke	Bradford	$ 628,777	$ 837,538	$ 601,525	$ 560,748	$ 600,742	$ 566,589	$ 545,329	$ 517,257	$ 628,774	$ 769,655	$ 657,942	$ 709,454	$ -
Cape Canaveral	Brevard	$ 654,060	$ 663,166	$ 665,470	$ 663,907	$ 675,207	$ 759,112	$ 734,174	$ 726,005	$ 768,987	$ 837,136	$ 843,219	$ 886,213	$ 894,317
Cocoa	Brevard	$ 1,131,989	$ 1,144,990	$ 1,135,200	$ 1,083,088	$ 1,119,970	$ 1,207,944	$ 1,197,383	$ 1,188,420	$ 1,294,321	$ 1,249,863	$ 1,424,368	$ 1,483,126	$ 1,481,096
Cocoa Beach	Brevard	$ 1,116,649	$ 1,117,852	$ 1,093,321	$ 1,026,985	$ 1,072,109	$ 1,167,941	$ 1,144,195	$ 1,123,824	$ 1,206,461	$ 1,297,899	$ 1,317,974	$ 1,356,542	$ 1,346,797
Grant-Valkaria	Brevard	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Indialantic	Brevard	$ 242,376	$ 218,225	$ 223,607	$ 218,697	$ 220,891	$ 246,176	$ 240,487	$ 233,152	$ 250,129	$ 267,295	$ 269,392	$ 283,712	$ 280,407
Indian Harbour Beach	Brevard	$ 302,079	$ 307,749	$ 314,653	$ 315,058	$ 317,563	$ 353,378	$ 348,229	$ 351,566	$ 371,323	$ 403,834	$ 410,640	$ 423,040	$ 429,368
Malabar	Brevard	$ 192,387	$ 207,273	$ 198,180	$ 199,245	$ 203,045	$ 225,148	$ 221,787	$ 219,299	$ 248,057	$ 258,466	$ 266,984	$ 275,356	$ 285,988
Melbourne	Brevard	$ 5,238,322	$ 5,379,795	$ 5,479,476	$ 5,370,027	$ 5,562,352	$ 6,010,459	$ 6,047,410	$ 6,088,803	$ 6,553,097	$ 7,030,112	$ 7,172,554	$ 7,488,266	$ 7,701,350
Melbourne Beach	Brevard	$ 132,085	$ 131,031	$ 129,504	$ 126,853	$ 175,157	$ 206,394	$ 200,390	$ 197,392	$ 206,821	$ 225,324	$ 226,961	$ 237,084	$ 239,751
Melbourne Village	Brevard	$ 68,734	$ 70,236	$ 66,567	$ 66,251	$ 50,312	$ 53,014	$ 50,622	$ 49,165	$ 52,909	$ 57,302	$ 59,167	$ 58,466	$ 59,546
Palm Bay	Brevard	$ 4,710,289	$ 4,974,545	$ 5,077,132	$ 5,000,445	$ 5,182,844	$ 5,691,766	$ 5,523,218	$ 5,538,018	$ 5,994,198	$ 6,533,657	$ 6,597,099	$ 6,862,108	$ 7,050,646
Palm Shores	Brevard	$ 16,212	$ 17,931	$ 10,416	$ 17,062	$ 18,272	$ 18,181	$ 18,143	$ 18,395	$ 18,739	$ 19,701	$ 19,396	$ 21,917	$ 23,977
Rockledge	Brevard	$ 1,492,275	$ 1,538,038	$ 1,530,614	$ 1,536,119	$ 1,563,541	$ 1,703,889	$ 1,678,356	$ 1,686,760	$ 1,825,899	$ 1,974,294	$ 2,017,054	$ 2,024,959	$ 2,059,218
Satellite Beach	Brevard	$ 357,702	$ 360,294	$ 346,318	$ 344,084	$ 350,214	$ 391,748	$ 385,612	$ 375,068	$ 367,177	$ 440,914	$ 446,262	$ 744,597	$ 776,791
Titusville	Brevard	$ 2,295,824	$ 2,405,811	$ 2,613,553	$ 2,409,721	$ 2,484,379	$ 2,698,635	$ 2,669,080	$ 2,619,531	$ 2,816,416	$ 3,062,771	$ 3,147,876	$ 3,287,551	$ 3,482,721
West Melbourne	Brevard	$ 973,567	$ 1,038,193	$ 1,034,814	$ 1,079,069	$ 1,162,399	$ 1,329,283	$ 1,351,280	$ 1,425,836	$ 1,573,416	$ 1,661,388	$ 1,730,103	$ 1,834,180	$ 1,919,708
Coconut Creek	Broward	$ 2,533,479	$ 2,535,609	$ 2,621,320	$ 2,689,312	$ 2,689,329	$ 2,939,420	$ 2,915,427	$ 2,990,654	$ 3,202,512	$ 3,520,609	$ 3,599,094	$ 3,694,834	$ 3,802,429
Cooper City	Broward	$ 1,555,619	$ 1,603,056	$ 1,617,872	$ 1,637,183	$ 1,606,768	$ 1,768,837	$ 1,766,902	$ 1,857,074	$ 2,015,714	$ 2,236,441	$ 2,284,851	$ 2,309,788	$ 2,347,789
Coral Springs	Broward	$ 7,129,381	$ 7,279,670	$ 7,228,943	$ 7,226,793	$ 7,135,907	$ 7,690,085	$ 7,589,037	$ 7,731,839	$ 8,138,588	$ 8,819,225	$ 8,936,647	$ 9,056,316	$ 9,162,356
Dania Beach	Broward	$ 2,061,362	$ 2,061,164	$ 2,094,151	$ 2,097,524	$ 2,058,835	$ 2,251,162	$ 2,284,989	$ 2,284,368	$ 2,497,523	$ 2,744,101	$ 2,750,822	$ 2,824,380	$ 2,901,406
Davie	Broward	$ 5,606,601	$ -	$ 6,203,556	$ 6,237,902	$ 6,146,285	$ 6,587,206	$ 6,577,640	$ 6,750,255	$ 7,160,537	$ 7,908,191	$ 8,021,890	$ 8,208,936	$ 8,445,312
Deerfield Beach	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,273,138	$ 5,962,381	$ 6,469,732	$ 6,507,224	$ 6,604,413	$ 6,815,218
Fort Lauderdale	Broward	$ 14,495,903	$ 14,660,098	$ 15,014,546	$ 15,181,470	$ 15,016,127	$ 16,089,695	$ 16,252,773	$ 16,557,010	$ 17,705,388	$ 19,297,439	$ 19,464,714	$ 19,748,678	$ 20,213,066
Hallandale Beach	Broward	$ 2,291,071	$ 2,355,770	$ 2,454,572	$ 2,534,168	$ 2,493,406	$ 2,700,471	$ 2,787,178	$ 2,877,983	$ 3,071,668	$ 3,346,817	$ 3,378,630	$ 3,454,191	$ 3,534,079
Hillsboro Beach	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hollywood	Broward	$ 9,038,361	$ 9,109,196	$ 9,112,528	$ 9,091,160	$ 8,874,121	$ 9,543,254	$ 9,638,728	$ 9,787,753	$ 10,462,144	$ 11,416,632	$ 11,450,837	$ 11,694,627	$ 11,994,922
Lauderdale Lakes	Broward	$ 1,378,016	$ 1,389,752	$ 1,416,847	$ 1,405,424	$ 1,387,601	$ 1,502,365	$ 1,517,648	$ 1,549,135	$ 1,671,308	$ 1,848,505	$ 1,889,221	$ 1,933,776	$ 1,972,824
Lauderdale-By-The-Sea	Broward	$ 539,989	$ 537,575	$ 604,215	$ 657,572	$ 661,306	$ 711,954	$ 710,943	$ 715,447	$ 770,067	$ 836,312	$ 832,280	$ 839,060	$ 865,065
Lauderhill	Broward	$ 2,629,595	$ 2,827,823	$ 2,944,746	$ 2,931,648	$ 2,893,752	$ 3,175,869	$ 3,139,183	$ 3,208,185	$ 3,405,435	$ 3,779,724	$ 3,897,160	$ 3,964,796	$ 4,080,882
Lazy Lake	Broward	$ -	$ -	$ -	$ 2,954	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lighthouse Point	Broward	$ 853,362	$ 844,974	$ 863,493	$ 874,983	$ 864,896	$ 946,372	$ 944,078	$ 957,895	$ 1,015,477	$ 1,111,862	$ 1,103,900	$ 1,131,256	$ 1,154,348
Margate	Broward	$ 2,837,929	$ 2,862,747	$ 2,792,989	$ 2,746,230	$ 2,677,740	$ 2,914,470	$ 2,907,772	$ 2,986,147	$ 3,183,483	$ 3,511,077	$ 3,559,203	$ 3,666,209	$ 3,746,229
Miramar	Broward	$ 5,072,998	$ 5,351,779	$ 5,511,786	$ 5,693,534	$ 5,745,841	$ 6,391,527	$ 6,470,570	$ 6,688,747	$ 7,127,144	$ 7,910,064	$ 8,117,626	$ 8,289,639	$ 8,494,521
North Lauderdale	Broward	$ 1,518,796	$ 1,525,339	$ 1,535,645	$ 1,547,654	$ 1,509,085	$ 1,637,310	$ 1,646,739	$ 1,710,427	$ 1,855,295	$ 2,052,075	$ 2,087,070	$ 2,141,927	$ 2,187,583
Oakland Park	Broward	$ 2,190,240	$ 2,490,070	$ 2,576,877	$ 2,578,591	$ 2,486,855	$ 2,676,988	$ 2,677,832	$ 2,716,158	$ 2,908,653	$ 3,201,892	$ 3,257,549	$ 3,331,314	$ 3,392,416
Parkland	Broward	$ 1,209,038	$ 1,281,143	$ 1,365,030	$ 1,472,588	$ 1,462,725	$ 1,644,287	$ 1,629,998	$ 1,659,228	$ 1,774,608	$ 1,963,836	$ 2,069,606	$ 2,193,455	$ 2,299,642
Pembroke Park	Broward	$ 429,163	$ 469,531	$ 496,372	$ 559,027	$ 573,267	$ 595,073	$ 609,209	$ 630,499	$ 670,688	$ 748,405	$ 756,928	$ 771,355	$ 768,756
Pembroke Pines	Broward	$ 7,931,137	$ 8,084,904	$ 8,093,581	$ 8,220,015	$ 8,124,202	$ 8,840,661	$ 8,788,592	$ 9,076,627	$ 9,587,367	$ 10,461,326	$ 10,617,673	$ 10,772,090	$ 11,002,693
Plantation	Broward	$ 5,635,479	$ 5,847,452	$ 5,775,640	$ 5,781,447	$ 5,567,049	$ 6,119,327	$ 6,085,785	$ 6,188,100	$ 6,544,219	$ 7,123,208	$ 7,157,401	$ 7,254,085	$ 7,329,843
Pompano Beach	Broward	$ 7,523,375	$ 7,594,269	$ 7,638,627	$ 7,748,947	$ 7,572,270	$ 8,040,324	$ 8,074,816	$ 8,227,734	$ 8,840,851	$ 9,708,188	$ 9,868,395	$ 10,356,393	$ 10,679,088
Sea Ranch Lakes	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Southwest Ranches	Broward	$ 496,246	$ 521,151	$ 580,973	$ 586,114	$ 589,486	$ 652,854	$ 654,966	$ 675,133	$ 712,967	$ 771,363	$ 783,903	$ 798,646	$ 812,587
Sunrise	Broward	$ 5,200,422	$ 5,215,841	$ 5,209,406	$ 5,274,627	$ 5,283,127	$ 5,666,076	$ 5,662,601	$ 5,827,061	$ 6,204,168	$ 6,756,230	$ 6,858,087	$ 6,965,213	$ 7,131,902
Tamarac	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,185,834	$ 3,668,839	$ 3,802,920	$ 4,139,883	$ 4,253,953	$ 4,288,558	$ 4,421,908
West Park	Broward	$ -	$ -	$ 504,164	$ 555,015	$ 535,506	$ 585,131	$ 598,003	$ 611,255	$ 705,898	$ 769,956	$ 749,757	$ 759,687	$ 773,263
Weston	Broward	$ 4,010,465	$ 4,121,406	$ 4,120,628	$ 4,198,618	$ 4,158,022	$ 4,515,072	$ 4,427,926	$ 4,445,301	$ 4,707,507	$ 5,052,392	$ 5,032,124	$ 5,040,267	$ 5,131,272
Wilton Manors	Broward	$ 729,751	$ 731,591	$ 753,435	$ 772,129	$ 770,469	$ 861,322	$ 865,469	$ 880,877	$ 943,129	$ 1,035,711	$ 1,045,780	$ 1,053,091	$ 1,076,664
Altha	Calhoun	$ 32,300	$ 33,673	$ 28,840	$ 30,979	$ 31,546	$ 32,614	$ 45,331	$ 36,148	$ 28,760	$ 32,914	$ 38,829	$ 33,458	$ -

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Blountstown	Calhoun	$ 113,628	$ 128,921	$ 140,379	$ 149,296	$ 179,927	$ 199,470	$ 192,911	$ 179,343	$ 162,969	$ 168,308	$ 167,403	$ 163,232	$ 159,721
Punta Gorda	Charlotte	$ 1,111,653	$ 1,083,567	$ 1,093,829	$ 1,112,626	$ 1,163,039	$ 1,308,911	$ 1,281,050	$ 1,252,996	$ 1,358,740	$ 1,510,856	$ 1,547,257	$ 1,608,098	$ 1,649,461
Crystal River	Citrus	$ 405,109	$ 434,937	$ 426,778	$ 439,347	$ 448,570	$ 536,256	$ 516,014	$ 476,570	$ 498,234	$ 517,988	$ 506,362	$ 521,672	$ 502,155
Inverness	Citrus	$ 534,456	$ 549,106	$ 551,146	$ 554,037	$ 592,443	$ 680,862	$ 649,084	$ 639,648	$ 684,324	$ 720,312	$ 697,344	$ 710,151	$ 698,775
Green Cove Springs	Clay	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Keystone Heights	Clay	$ -	$ -	$ -	$ -	$ 58,029	$ 73,172	$ 93,886	$ 87,510	$ 86,607	$ 97,144	$ 102,680	$ 101,274	$ 93,847
Orange Park	Clay	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 445,160	$ 843,757	$ 830,864
Penney Farms	Clay	$ -	$ -	$ -	$ -	$ -	$ 30,948	$ 40,470	$ 38,978	$ 43,570	$ 46,952	$ 47,095	$ 45,022	$ 46,941
Everglades	Collier	$ 46,362	$ -	$ 44,943	$ 54,437	$ -	$ -	$ -	$ -	$ 92,145	$ -	$ -	$ -	$ -
Marco Island	Collier	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Naples	Collier	$ 2,336,099	$ 2,365,308	$ 2,354,298	$ 2,290,253	$ 2,392,073	$ 2,538,471	$ 2,537,330	$ 2,582,461	$ 2,794,311	$ 3,031,571	$ 3,006,208	$ 3,067,245	$ 3,154,420
Fort White	Columbia	$ -	$ 10,738	$ 3,171	$ 2,592	$ 3,818	$ 4,621	$ 6,090	$ 8,257	$ 7,181	$ 12,452	$ 13,017	$ 12,556	$ 11,703
Lake City	Columbia	$ 882,931	$ 920,112	$ 925,119	$ 962,516	$ 1,011,129	$ 1,068,131	$ 1,086,614	$ 1,055,645	$ 1,128,848	$ 1,232,903	$ 1,404,802	$ 1,292,991	$ 1,325,946
Arcadia	DeSoto	$ 317,877	$ 328,242	$ 317,658	$ 291,852	$ 296,889	$ 322,958	$ 320,874	$ 313,653	$ 331,079	$ 359,876	$ 376,829	$ 384,988	$ 392,405
Cross City	Dixie	$ 108,419	$ 115,720	$ 107,061	$ 114,851	$ 118,167	$ 128,020	$ 121,214	$ 106,806	$ 112,031	$ 126,938	$ 125,965	$ 123,466	$ 123,992
Horseshoe Beach	Dixie	$ -	$ 16,882	$ 19,922	$ 17,583	$ 17,582	$ 18,017	$ 17,751	$ 18,985	$ 19,096	$ 21,353	$ 14,263	$ 12,275	$ 11,537
Atlantic Beach	Duval	$ 367,186	$ 372,226	$ 363,285	$ 392,842	$ 430,774	$ 486,475	$ 487,585	$ 452,184	$ 459,672	$ 473,097	$ 476,997	$ 483,516	$ 475,895
Baldwin	Duval	$ 84,351	$ 84,722	$ 79,733	$ 89,011	$ 98,826	$ 106,759	$ 125,786	$ 102,305	$ 104,790	$ 99,046	$ 102,753	$ 104,379	$ 103,732
Jacksonville	Duval	$ 46,851,288	$ 48,130,818	$ 47,738,296	$ 56,386,853	$ 61,556,310	$ 69,336,843	$ 71,920,899	$ 67,278,923	$ 68,284,589	$ 70,075,177	$ 70,780,865	$ 73,025,642	$ 71,979,227
Jacksonville Beach	Duval	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Neptune Beach	Duval	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Century	Escambia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pensacola	Escambia	$ 4,091,458	$ 4,572,114	$ 4,512,314	$ 4,414,957	$ 4,554,938	$ 5,039,536	$ 5,099,161	$ 4,916,612	$ 5,015,463	$ 5,648,698	$ 5,962,719	$ 5,958,728	$ 6,130,379
Beverly Beach	Flagler	$ -	$ -	$ -	$ -	$ 27,138	$ 27,122	$ 25,736	$ 22,846	$ -	$ -	$ -	$ -	$ -
Bunnell	Flagler	$ 133,795	$ 159,450	$ 151,997	$ 180,010	$ 174,556	$ 192,068	$ 194,426	$ 188,006	$ 204,245	$ 229,350	$ 243,648	$ 260,429	$ 265,623
Palm Coast	Flagler	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marineland	Flagler/St. Johns	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flagler Beach	Flagler/Volusia	$ 312,400	$ 310,481	$ 290,928	$ 287,909	$ 301,825	$ 344,316	$ 336,540	$ 328,254	$ 359,903	$ 400,295	$ 411,078	$ 424,968	$ 425,819
Apalachicola	Franklin	$ 87,593	$ 94,233	$ 92,967	$ 90,987	$ 95,789	$ 94,760	$ 94,908	$ 96,129	$ 94,857	$ 96,884	$ 97,981	$ 98,366	$ -
Carrabelle	Franklin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 56,943	$ -	$ -
Chattahoochee	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Greensboro	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,317
Gretna	Gadsden	$ -	$ -	$ -	$ 56,992	$ 45,040	$ 73,822	$ 39,299	$ 48,837	$ 50,274	$ 111,710	$ 89,300	$ 77,880	$ 81,054
Havana	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Midway	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 74,943	$ 75,845	$ 90,329	$ 94,490
Quincy	Gadsden	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bell	Gilchrist	$ 20,619	$ 21,816	$ 22,365	$ 16,579	$ 16,479	$ 16,696	$ 15,330	$ 14,328	$ 13,553	$ 18,709	$ 20,570	$ 18,874	$ 21,427
Trenton	Gilchrist	$ 94,088	$ 107,224	$ 106,745	$ 108,247	$ 125,732	$ 134,531	$ 123,559	$ 111,748	$ 119,420	$ 132,790	$ 133,849	$ 144,253	$ 118,583
Fanning Springs	Gilchrist/Levy	$ 56,867	$ 64,574	$ 69,070	$ 54,505	$ 54,863	$ 59,255	$ 54,706	$ 50,702	$ 48,658	$ 64,733	$ 65,929	$ 63,156	$ 70,928
Moore Haven	Glades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Port St. Joe	Gulf	$ 167,278	$ 185,326	$ 190,456	$ 194,822	$ 200,729	$ 216,098	$ 228,076	$ 201,948	$ 217,343	$ 423,707	$ 439,713	$ 477,218	$ 428,829
Wewahitchka	Gulf	$ 117,147	$ 109,800	$ 120,410	$ 168,849	$ 167,361	$ 174,162	$ 170,251	$ 165,259	$ 187,075	$ 192,965	$ 196,423	$ 192,889	$ 188,833
Jasper	Hamilton	$ 67,130	$ 70,701	$ 71,514	$ 98,079	$ 69,647	$ 73,990	$ 111,393	$ 101,699	$ 71,572	$ 73,101	$ 73,967	$ 73,675	$ 74,188
Jennings	Hamilton	$ 43,144	$ 48,754	$ 42,641	$ 46,243	$ 48,754	$ 56,034	$ 54,294	$ 47,681	$ 48,208	$ 50,251	$ 48,108	$ 46,469	$ 46,142
White Springs	Hamilton	$ 27,894	$ 41,646	$ 38,097	$ 38,603	$ 41,036	$ 48,572	$ 45,674	$ 40,084	$ 44,296	$ 45,833	$ 43,825	$ 41,855	$ 41,222
Bowling Green	Hardee	$ 81,156	$ 84,995	$ 81,384	$ 97,201	$ 88,654	$ 109,965	$ 112,975	$ 89,593	$ 99,323	$ 109,288	$ 104,014	$ 108,933	$ 105,859
Wauchula	Hardee	$ 247,045	$ 263,471	$ 271,600	$ 274,006	$ 280,593	$ 283,360	$ 303,025	$ 227,855	$ 242,342	$ 276,202	$ 277,956	$ 305,320	$ 317,999
Zolfo Springs	Hardee	$ 41,438	$ 49,047	$ 44,129	$ 53,298	$ 45,833	$ 53,532	$ 55,568	$ 46,415	$ 51,825	$ 54,305	$ 52,739	$ 54,137	$ 52,919
Clewiston	Hendry	$ 571,135	$ 573,864	$ 572,070	$ 574,725	$ 546,593	$ 566,515	$ 549,331	$ 518,705	$ 499,638	$ 527,104	$ 516,029	$ 547,543	$ 540,973
LaBelle	Hendry	$ 150,034	$ 157,400	$ 159,685	$ 154,397	$ 156,077	$ 171,043	$ 170,173	$ 167,632	$ 172,992	$ 187,689	$ 192,490	$ 197,453	$ 204,084
Brooksville	Hernando	$ 539,151	$ 571,567	$ 564,326	$ 605,699	$ 672,993	$ 783,186	$ 717,829	$ 749,992	$ 705,080	$ 748,190	$ 740,997	$ 769,884	$ 775,089
Weeki Wachee	Hernando	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avon Park	Highlands	$ 459,486	$ 491,542	$ 514,077	$ 513,572	$ 545,661	$ 620,399	$ 571,403	$ 547,838	$ 578,857	$ 643,819	$ 666,373	$ 686,671	$ 697,578
Lake Placid	Highlands	$ 164,508	$ 178,983	$ 182,892	$ 186,539	$ 187,174	$ 217,411	$ 204,401	$ 195,929	$ 203,980	$ 221,051	$ 205,588	$ 237,540	$ 244,660
Sebring	Highlands	$ 756,730	$ 844,442	$ 912,865	$ 846,562	$ 931,699	$ 1,091,650	$ 1,034,196	$ 967,356	$ 1,001,595	$ 1,076,056	$ 1,053,814	$ 1,088,856	$ 1,081,981
Plant City	Hillsborough	$ 2,654,820	$ 2,527,112	$ 2,509,492	$ 2,717,426	$ 2,823,222	$ 3,119,806	$ 3,023,814	$ 2,990,240	$ 3,000,256	$ 3,163,935	$ 3,223,246	$ 3,320,989	$ 3,861,671
Tampa	Hillsborough	$ 26,441,509	$ 25,207,232	$ 24,752,937	$ 26,302,572	$ 28,282,581	$ 32,569,274	$ 30,983,435	$ 30,947,584	$ 30,374,339	$ 32,543,373	$ 32,521,891	$ 33,254,609	$ 34,022,849
Temple Terrace	Hillsborough	$ 1,590,578	$ 1,568,527	$ 1,692,601	$ 1,675,336	$ 1,861,447	$ 2,117,542	$ 1,984,452	$ 1,924,442	$ 1,908,035	$ 2,025,539	$ 2,099,997	$ 2,130,636	$ 2,212,177
Bonifay	Holmes	$ 151,535	$ 166,485	$ 167,742	$ 165,526	$ 166,241	$ 182,209	$ 179,942	$ 172,828	$ 176,177	$ 196,114	$ 209,231	$ 210,652	$ 214,571
Esto	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Noma	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,183	$ 11,988	$ 12,749	$ -	$ 12,235
Ponce de Leon	Holmes	$ 14,643	$ 15,889	$ 17,291	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,799
Westville	Holmes	$ -	$ -	$ -	$ -	$ -	$ 5,943	$ 6,590	$ 6,583	$ 5,952	$ 6,782	$ 5,439	$ 5,240	$ 5,521
Fellsmere	Indian River	$ 98,643	$ 114,097	$ 111,270	$ 120,544	$ 165,514	$ 181,696	$ 188,236	$ 194,777	$ 222,145	$ 254,613	$ 260,742	$ 271,109	$ 279,313
Indian River Shores	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orchid	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sebastian	Indian River	$ 1,008,541	$ 1,098,225	$ 1,113,771	$ 1,130,033	$ 1,174,792	$ 1,305,187	$ 1,276,549	$ 1,263,888	$ 1,366,798	$ 1,493,348	$ 1,545,946	$ 1,606,145	$ 1,640,256
Vero Beach	Indian River	$ 1,735,401	$ 1,958,001	$ 1,938,426	$ 1,874,121	$ 1,810,262	$ 1,758,675	$ 1,688,786	$ 1,702,265	$ 1,653,373	$ 1,632,328	$ 1,673,133	$ 1,636,089	$ 1,584,642
Alford	Jackson	$ 18,700	$ -	$ 21,185	$ 20,432	$ 22,091	$ 24,287	$ 21,019	$ 21,220	$ 21,476	$ 22,281	$ 25,345	$ 22,164	$ 20,958
Bascom	Jackson	$ 2,260	$ 2,091	$ 1,885	$ 2,383	$ 2,080	$ 2,429	$ 2,429	$ 2,637	$ 1,804	$ 1,431	$ 1,535	$ 1,427	$ 1,608

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Campbellton	Jackson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cottondale	Jackson	$ 37,136	$ 41,217	$ -	$ 40,454	$ 36,528	$ 42,643	$ 38,814	$ 35,179	$ 35,975	$ 36,922	$ 40,511	$ 40,189	$ 39,365
Graceville	Jackson	$ 121,600	$ 136,422	$ 147,368	$ 139,213	$ 133,077	$ 155,458	$ 151,725	$ 145,810	$ 149,338	$ 171,678	$ 184,267	$ 162,938	$ 172,126
Grand Ridge	Jackson	$ 36,019	$ -	$ 43,473	$ 46,937	$ 51,373	$ 54,438	$ 53,343	$ 49,227	$ 50,914	$ 54,692	$ 56,723	$ 52,720	$ 51,938
Greenwood	Jackson	$ -	$ -	$ -	$ -	$ 44,373	$ 42,958	$ 45,460	$ 36,671	$ 37,215	$ 37,982	$ 37,211	$ 40,917	$ 39,072
Jacob City	Jackson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Malone	Jackson	$ 22,734	$ 26,001	$ 22,971	$ 24,547	$ 24,652	$ 27,138	$ 25,285	$ 23,990	$ 24,547	$ 30,641	$ 27,620	$ 26,640	$ 25,922
Marianna	Jackson	$ 378,700	$ 381,300	$ 378,400	$ 409,994	$ 468,855	$ 524,394	$ 522,225	$ 492,885	$ 530,330	$ 530,173	$ 576,150	$ 560,301	$ 574,639
Sneads	Jackson	$ 86,418	$ 101,969	$ 104,560	$ 107,233	$ 117,740	$ 120,402	$ 113,263	$ 108,407	$ 106,101	$ 118,271	$ 117,459	$ 109,921	$ 107,096
Monticello	Jefferson	$ 164,946	$ 188,788	$ 171,159	$ 184,456	$ 194,291	$ 240,703	$ 203,532	$ 179,144	$ 15,082	$ 20,689	$ 18,870	$ 205,976	$ 205,132
Mayo	Lafayette	$ 26,036	$ 32,044	$ 30,111	$ 29,849	$ 31,831	$ 37,149	$ 32,921	$ 31,723	$ 33,061	$ 36,045	$ 35,394	$ 35,092	$ 32,489
Astatula	Lake	$ 98,051	$ 104,374	$ 108,500	$ 122,104	$ 100,360	$ 115,625	$ 110,856	$ 96,847	$ 97,616	$ 110,881	$ 111,437	$ 115,064	$ 111,463
Clermont	Lake	$ 1,276,893	$ 1,478,785	$ 1,559,824	$ 1,688,421	$ 1,846,153	$ 2,232,203	$ 2,197,178	$ 2,081,111	$ 2,121,508	$ 2,440,839	$ 2,472,148	$ 2,921,202	$ -
Eustis	Lake	$ 1,019,687	$ 1,103,845	$ 1,145,763	$ 1,169,908	$ 1,209,378	$ 1,431,847	$ 1,343,688	$ 1,232,641	$ 1,283,237	$ 1,470,458	$ 1,365,854	$ 1,538,967	$ 1,538,520
Fruitland Park	Lake	$ 194,538	$ 201,301	$ 240,832	$ 254,687	$ 279,826	$ 300,196	$ 300,729	$ 282,571	$ 296,418	$ 310,447	$ 333,354	$ 442,801	$ 510,397
Groveland	Lake	$ 229,123	$ 290,033	$ 350,312	$ 379,717	$ 404,586	$ 492,499	$ 479,241	$ 476,216	$ 503,680	$ 597,316	$ 655,673	$ 759,970	$ 750,352
Howey-in-the-Hills	Lake	$ 42,733	$ 51,096	$ 64,180	$ 63,047	$ 67,804	$ 80,611	$ 73,947	$ 66,621	$ 68,718	$ 74,752	$ 76,425	$ 87,049	$ 89,622
Lady Lake	Lake	$ 614,804	$ 658,276	$ 649,449	$ 677,439	$ 756,640	$ 935,571	$ 874,176	$ 808,249	$ 868,960	$ 955,588	$ 915,109	$ 975,687	$ 978,435
Leesburg	Lake	$ 2,955,112	$ 2,269,988	$ 2,858,214	$ 3,058,468	$ 3,126,744	$ 3,214,820	$ 3,182,188	$ 2,551,757	$ 2,634,335	$ 2,695,932	$ 2,826,412	$ 3,034,981	$ 2,965,788
Mascotte	Lake	$ 101,620	$ 104,810	$ 106,964	$ 116,449	$ 118,656	$ 134,398	$ 134,054	$ 125,758	$ 133,066	$ 144,968	$ 148,037	$ 170,084	$ 156,526
Minneola	Lake	$ -	$ 306,943	$ 311,194	$ 324,635	$ 350,173	$ 417,886	$ 414,097	$ 394,782	$ 389,944	$ 434,934	$ 441,695	$ 479,045	$ 493,502
Montverde	Lake	$ 33,541	$ 41,459	$ 37,907	$ 46,789	$ 37,070	$ 50,606	$ 50,669	$ 46,075	$ 50,259	$ 58,266	$ 54,828	$ 68,010	$ -
Mount Dora	Lake	$ 934,187	$ 954,794	$ 982,187	$ 1,002,885	$ 1,164,723	$ 1,253,910	$ 1,248,352	$ 1,162,193	$ 1,168,541	$ 1,228,578	$ 1,267,008	$ 1,350,382	$ 1,388,303
Tavares	Lake	$ 655,577	$ 677,960	$ 714,500	$ 743,373	$ 801,502	$ 931,102	$ 907,017	$ 846,893	$ 892,925	$ 977,990	$ 997,165	$ 1,077,235	$ 1,069,939
Umatilla	Lake	$ 163,093	$ 179,958	$ 177,144	$ 180,289	$ 193,940	$ -	$ 238,266	$ 221,190	$ 232,606	$ 280,397	$ 248,697	$ 283,635	$ 280,819
Bonita Springs	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cape Coral	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,229,414	$ 7,168,083	$ 7,250,872	$ 7,103,228
Estero	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fort Myers	Lee	$ 4,160,908	$ 4,357,551	$ 4,478,629	$ 4,431,504	$ 4,537,876	$ 4,870,988	$ 4,887,532	$ 5,030,023	$ 5,534,839	$ 6,115,060	$ 6,278,829	$ 6,577,766	$ 6,837,408
Fort Myers Beach	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 907,282	$ 1,004,732	$ 1,012,301	$ 786,661	$ 740,892
Sanibel	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tallahassee	Leon	$ 8,177,000	$ 9,108,000	$ 10,092,000	$ 10,303,000	$ 10,482,000	$ 10,968,000	$ 11,042,000	$ 10,634,000	$ 10,856,000	$ 11,815,000	$ 12,591,000	$ 12,438,000	$ 12,398,000
Bronson	Levy	$ -	$ -	$ 25,620	$ 22,924	$ 23,526	$ 23,574	$ 21,340	$ 22,133	$ 23,743	$ 24,691	$ 26,279	$ 24,747	$ 22,321
Cedar Key	Levy	$ 77,743	$ 79,346	$ 82,393	$ 67,128	$ 29,468	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,545	$ 43,701
Chiefland	Levy	$ 281,435	$ 302,068	$ 351,641	$ 265,076	$ 273,557	$ 281,686	$ 266,340	$ 254,823	$ 248,378	$ 315,094	$ 310,901	$ 289,351	$ 289,591
Inglis	Levy	$ 98,108	$ 106,024	$ 113,213	$ 83,719	$ 88,951	$ 88,055	$ 79,603	$ 76,681	$ 78,528	$ 97,179	$ 97,809	$ 90,390	$ 94,184
Otter Creek	Levy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Williston	Levy	$ 142,924	$ 149,494	$ 281,576	$ 269,295	$ 262,820	$ 267,323	$ 257,956	$ 252,800	$ 273,561	$ 263,425	$ 274,954	$ 269,530	$ 267,072
Yankeetown	Levy	$ 34,914	$ 32,725	$ 37,775	$ 25,905	$ 26,857	$ 26,660	$ 23,900	$ 22,679	$ 22,311	$ 29,646	$ 31,434	$ 29,924	$ 32,564
Bristol	Liberty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Greenville	Madison	$ 46,312	$ 63,056	$ 61,172	$ 53,614	$ 61,306	$ 61,610	$ 59,114	$ 54,188	$ 51,794	$ 51,960	$ 50,516	$ 47,898	$ 52,880
Lee	Madison	$ 22,500	$ 18,395	$ 19,868	$ 21,210	$ 21,374	$ 25,263	$ 23,165	$ 20,232	$ 21,574	$ 23,673	$ 23,726	$ 22,745	$ 22,462
Madison	Madison	$ 183,248	$ 223,201	$ 207,329	$ 230,208	$ 223,372	$ 269,293	$ 244,287	$ 237,935	$ 241,820	$ 109,794	$ 255,689	$ 254,394	$ 253,295
Anna Maria	Manatee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bradenton	Manatee	$ 2,965,162	$ 3,180,300	$ 2,987,853	$ 2,875,591	$ 2,910,649	$ 3,115,903	$ 3,129,561	$ 3,106,647	$ 3,342,040	$ 3,702,757	$ 3,743,382	$ 3,860,051	$ 3,933,614
Bradenton Beach	Manatee	$ 142,398	$ 139,896	$ 139,508	$ 159,383	$ 150,607	$ 165,690	$ 168,835	$ 165,776	$ 183,978	$ 200,492	$ 209,375	$ 214,001	$ 219,380
Holmes Beach	Manatee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palmetto	Manatee	$ 699,486	$ 720,594	$ 784,268	$ 786,221	$ 809,866	$ 886,900	$ 877,381	$ 874,216	$ 943,661	$ 1,043,368	$ 1,056,159	$ 1,072,168	$ 1,109,169
Longboat Key	Manatee/Sarasota	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belleview	Marion	$ 121,094	$ 135,987	$ 129,245	$ 138,163	$ 140,075	$ 148,962	$ 146,170	$ 142,327	$ 147,030	$ 151,667	$ 151,606	$ 155,964	$ 158,179
Dunnellon	Marion	$ 188,071	$ 203,227	$ 203,636	$ 202,213	$ -	$ 252,176	$ 234,822	$ 211,389	$ 225,961	$ 232,318	$ 227,924	$ 230,051	$ 231,111
McIntosh	Marion	$ 30,025	$ 31,564	$ 29,824	$ 30,531	$ 30,708	$ 34,259	$ 36,229	$ 29,909	$ 30,755	$ 39,067	$ 32,603	$ 36,465	$ 41,165
Ocala	Marion	$ 6,678,610	$ 6,445,774	$ 7,487,077	$ 8,018,318	$ 7,054,528	$ 9,376,714	$ 7,149,961	$ 7,817,303	$ 8,369,228	$ 8,404,440	$ 9,525,860	$ 8,914,819	$ 8,851,526
Reddick	Marion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jupiter Island	Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ocean Breeze Park	Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sewall's Point	Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Stuart	Martin	$ 1,415,784	$ 1,469,328	$ 1,527,888	$ 1,558,090	$ 1,560,149	$ 1,684,561	$ 1,734,911	$ 1,759,615	$ 1,857,777	$ 2,584,686	$ 2,067,315	$ 2,088,028	$ 2,133,307
Aventura	Miami-Dade	$ 3,232,737	$ 3,319,819	$ 3,363,499	$ 3,635,065	$ 3,706,940	$ 3,885,934	$ 3,923,703	$ 3,990,392	$ 4,259,017	$ 4,572,988	$ 4,453,953	$ 4,534,678	$ 4,635,614
Bal Harbour	Miami-Dade	$ 544,934	$ 551,774	$ 557,873	$ 578,391	$ 600,266	$ 630,356	$ 680,284	$ 762,411	$ 808,758	$ 879,218	$ 848,576	$ 843,928	$ 887,811
Bay Harbor Islands	Miami-Dade	$ 331,714	$ 336,370	$ 326,219	$ 340,978	$ 332,240	$ 366,402	$ 369,845	$ 379,088	$ 402,225	$ 439,939	$ 431,791	$ 437,085	$ 449,754
Biscayne Park	Miami-Dade	$ 108,302	$ 103,535	$ 106,122	$ 102,427	$ 98,841	$ -	$ 111,836	$ 111,510	$ 122,709	$ 135,431	$ 133,480	$ 158,507	$ 176,898
Coral Gables	Miami-Dade	$ 4,804,329	$ 4,875,856	$ 4,966,909	$ 5,024,381	$ 5,001,967	$ 5,351,951	$ 5,365,817	$ 5,487,578	$ 5,862,360	$ 6,407,592	$ 6,435,440	$ 6,432,878	$ 6,576,674
Cutler Bay	Miami-Dade	$ -	$ 1,089,066	$ 1,615,484	$ 1,931,744	$ 1,948,917	$ 2,136,783	$ 2,155,194	$ 2,225,104	$ 2,386,783	$ 2,641,296	$ 2,623,670	$ 2,706,697	$ 2,804,314
Doral	Miami-Dade	$ 2,328,733	$ 1,912,727	$ 3,685,954	$ 5,400,763	$ 5,514,694	$ 5,771,287	$ 5,852,712	$ 6,033,261	$ 6,492,296	$ 7,095,364	$ 7,060,657	$ 7,368,611	$ 7,503,946
El Portal	Miami-Dade	$ 61,951	$ 62,896	$ 64,919	$ 66,280	$ 60,786	$ 71,448	$ 71,081	$ 69,484	$ 72,481	$ 82,949	$ 80,504	$ 131,106	$ 80,176
Florida City	Miami-Dade	$ 444,280	$ 455,251	$ 461,630	$ 539,598	$ 554,273	$ 583,757	$ 596,604	$ 634,779	$ 686,294	$ 761,363	$ 777,178	$ 802,840	$ 840,813
Golden Beach	Miami-Dade	$ -	$ -	$ 92,140	$ 95,675	$ 95,877	$ 104,107	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hialeah	Miami-Dade	$ 9,782,673	$ 9,998,996	$ 10,115,832	$ 10,246,819	$ 9,949,659	$ 10,654,776	$ 10,993,230	$ 11,491,228	$ 14,330,394	$ 19,604,000	$ 19,381,487	$ 22,087,571	$ 14,139,043
Hialeah Gardens	Miami-Dade	$ 780,285	$ 802,826	$ 865,043	$ 969,996	$ 979,409	$ 1,022,858	$ 1,008,600	$ 1,056,283	$ 1,128,129	$ 1,232,187	$ 1,233,703	$ 1,268,255	$ 1,298,333

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Homestead	Miami-Dade	$ 1,085,451	$ 1,169,141	$ 1,221,947	$ 1,210,830	$ 1,165,048	$ 1,216,444	$ 1,165,934	$ 1,199,919	$ 1,186,812	$ 1,247,656	$ 1,277,138	$ 1,295,402	$ 1,197,434
Indian Creek	Miami-Dade	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key Biscayne	Miami-Dade	$ 1,160,977	$ 1,151,314	$ 1,119,692	$ 1,165,215	$ 1,159,583	$ 1,247,644	$ 1,253,484	$ 1,290,428	$ 1,371,430	$ 1,504,108	$ 1,478,999	$ 1,500,230	$ 1,545,124
Medley	Miami-Dade	$ 936,375	$ 1,035,414	$ 1,044,191	$ 1,034,095	$ 993,101	$ 964,572	$ 999,631	$ 1,001,455	$ 1,089,621	$ 1,209,642	$ 1,242,097	$ 1,277,204	$ 1,318,943
Miami	Miami-Dade	$ -	$ -	$ 21,585,108	$ 22,277,609	$ 22,599,760	$ 25,047,038	$ 26,195,243	$ 27,573,832	$ 29,639,931	$ 32,270,632	$ 32,502,537	$ 33,425,247	$ 34,919,488
Miami Beach	Miami-Dade	$ 7,582,795	$ 7,704,683	$ 7,718,812	$ 7,930,859	$ 8,124,934	$ 8,870,443	$ 9,002,020	$ 9,228,623	$ 10,138,226	$ 10,985,874	$ 10,938,084	$ 11,090,417	$ 11,354,269
Miami Gardens	Miami-Dade	$ 2,818,967	$ 3,753,741	$ 4,735,403	$ 5,032,682	$ 5,267,259	$ 5,473,141	$ 5,458,988	$ 5,578,789	$ 5,915,587	$ 6,444,502	$ 6,363,753	$ 6,568,238	$ 6,839,847
Miami Lakes	Miami-Dade	$ 2,053,024	$ 2,180,288	$ 2,119,404	$ 2,235,430	$ 2,255,833	$ 2,403,604	$ 2,450,483	$ 2,502,818	$ 2,668,536	$ 2,849,187	$ 2,801,937	$ 2,833,279	$ 2,922,956
Miami Shores	Miami-Dade	$ 648,460	$ 659,812	$ 660,762	$ 663,200	$ 663,258	$ 727,475	$ 737,523	$ 732,334	$ 793,025	$ 869,182	$ 859,197	$ 866,126	$ 869,145
Miami Springs	Miami-Dade	$ 892,535	$ 928,122	$ 937,710	$ 908,160	$ 776,029	$ 833,756	$ 812,000	$ 834,568	$ 893,573	$ 982,547	$ 972,776	$ 1,001,029	$ 1,011,633
North Bay	Miami-Dade	$ 301,701	$ 352,874	$ 328,621	$ 388,386	$ 391,473	$ 416,635	$ 416,635	$ 458,847	$ 494,010	$ 537,160	$ 559,998	$ 586,646	$ 604,737
North Miami	Miami-Dade	$ 2,319,486	$ 2,435,688	$ 2,433,234	$ 2,357,681	$ 2,335,833	$ 2,552,041	$ 2,595,995	$ 2,695,856	$ 2,894,331	$ 6,991,107	$ 3,404,235	$ 3,513,956	$ 3,516,154
North Miami Beach	Miami-Dade	$ 1,818,397	$ 1,916,695	$ 1,878,990	$ 1,940,915	$ 1,904,427	$ 2,102,783	$ 2,139,800	$ 2,175,878	$ 2,317,294	$ 2,531,716	$ 2,540,386	$ 2,652,499	$ 2,701,551
Opa-locka	Miami-Dade	$ 795,131	$ 825,201	$ 857,384	$ 851,004	$ 710,579	$ 832,380	$ 1,050,358	$ 811,650	$ 996,993	$ 1,116,248	$ 1,149,700	$ -	$ -
Palmetto Bay	Miami-Dade	$ 1,483,259	$ 1,468,227	$ 1,521,330	$ 1,678,953	$ 1,662,906	$ 1,811,204	$ 1,795,763	$ 1,833,218	$ 1,931,352	$ 2,086,917	$ 2,037,861	$ 2,081,975	$ 2,141,876
Pinecrest	Miami-Dade	$ 1,565,423	$ 1,567,345	$ 1,566,173	$ 1,622,205	$ 1,601,485	$ -	$ 1,714,422	$ 1,751,187	$ 1,845,433	$ 1,985,299	$ 1,934,373	$ 1,976,387	$ 2,034,871
South Miami	Miami-Dade	$ 873,360	$ 931,008	$ 954,566	$ 1,022,767	$ 1,034,327	$ 1,111,694	$ 1,136,433	$ 1,166,162	$ 1,276,842	$ 1,369,212	$ 1,367,020	$ 1,377,801	$ 1,411,169
Sunny Isles Beach	Miami-Dade	$ 1,287,797	$ 1,418,335	$ 1,512,932	$ 1,721,280	$ 1,864,430	$ 2,062,927	$ 2,107,901	$ 2,146,637	$ 2,322,488	$ 2,545,491	$ 2,469,148	$ 2,547,961	$ 2,688,835
Surfside	Miami-Dade	$ 407,360	$ 422,478	$ 422,132	$ 415,994	$ 403,591	$ 439,018	$ 447,280	$ 452,591	$ 477,566	$ 532,509	$ 550,309	$ 555,890	$ 610,459
Sweetwater	Miami-Dade	$ 476,702	$ 480,132	$ 482,868	$ 492,734	$ 478,309	$ -	$ 524,283	$ 557,808	$ 585,314	$ 637,832	$ 653,263	$ 767,264	$ 873,118
Virginia Gardens	Miami-Dade	$ 163,434	$ 186,321	$ 185,969	$ 189,223	$ 188,426	$ 201,654	$ 200,723	$ 207,230	$ 217,074	$ 251,491	$ 242,555	$ 246,668	$ 245,730
West Miami	Miami-Dade	$ 237,381	$ 236,138	$ 263,911	$ 272,024	$ 278,661	$ 303,300	$ 307,160	$ 316,256	$ 328,448	$ 361,977	$ 371,718	$ 385,701	$ 415,430
Islamorada	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key Colony Beach	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key West	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Layton	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marathon	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Callahan	Nassau	$ 10,311	$ 23,718	$ 11,115	$ 8,797	$ 7,837	$ 5,332	$ 7,370	$ 9,583	$ 9,117	$ 9,346	$ 8,619	$ 10,121	$ 10,993
Fernandina Beach	Nassau	$ 467,228	$ 477,774	$ -	$ -	$ -	$ -	$ 625,754	$ 617,285	$ 609,002	$ 626,419	$ 718,811	$ 716,005	$ 778,404
Hilliard	Nassau	$ 50,721	$ 59,580	$ 60,276	$ 61,847	$ 73,285	$ 67,683	$ 64,899	$ 61,843	$ 64,064	$ 70,876	$ 70,408	$ 63,967	$ 67,724
Cinco Bayou	Okaloosa	$ 28,725	$ 30,662	$ 30,197	$ 29,226	$ 29,372	$ 31,245	$ 31,148	$ 31,321	$ 32,156	$ 35,044	$ 36,198	$ 37,455	$ 36,258
Crestview	Okaloosa	$ 1,004,919	$ 1,161,740	$ 822,944	$ 1,199,066	$ 1,234,725	$ 1,466,245	$ 1,517,629	$ 1,542,798	$ 1,578,230	$ 1,790,415	$ 1,923,765	$ 1,916,895	$ 1,984,802
Destin	Okaloosa	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fort Walton Beach	Okaloosa	$ 1,191,418	$ 1,302,539	$ 1,291,185	$ 1,280,128	$ 1,592,831	$ 1,804,128	$ 1,845,820	$ 1,813,348	$ 1,813,966	$ 2,022,908	$ 2,215,717	$ 2,217,751	$ 2,266,788
Laurel Hill	Okaloosa	$ 14,082	$ 16,937	$ 19,034	$ 19,536	$ 22,845	$ 21,243	$ 38,908	$ 21,201	$ 21,815	$ 25,330	$ 24,855	$ 24,752	$ 22,860
Mary Esther	Okaloosa	$ 197,702	$ 203,391	$ 203,991	$ -	$ -	$ 197,664	$ 197,576	$ 198,755	$ 202,147	$ 211,065	$ 219,212	$ 222,738	$ 223,421
Niceville	Okaloosa	$ 731,877	$ 794,054	$ 796,529	$ 789,214	$ 797,613	$ 915,814	$ 937,145	$ 938,359	$ 958,499	$ 1,086,727	$ 1,161,762	$ 1,240,570	$ 1,271,094
Shalimar	Okaloosa	$ 46,291	$ 52,105	$ 53,006	$ 46,437	$ 49,729	$ 51,978	$ 52,656	$ 54,143	$ 55,078	$ 59,797	$ 63,746	$ 94,026	$ 73,420
Valparaiso	Okaloosa	$ 161,521	$ 166,694	$ 171,219	$ 167,460	$ 166,932	$ 174,570	$ 174,679	$ 177,601	$ 182,449	$ 192,406	$ 200,766	$ 200,711	$ 204,043
Okeechobee	Okeechobee	$ 319,444	$ 361,568	$ 427,430	$ 402,052	$ 406,558	$ 436,918	$ 425,421	$ 411,944	$ 436,682	$ 473,801	$ 486,181	$ 502,380	$ 519,268
Apopka	Orange	$ 1,632,856	$ 1,889,669	$ 1,943,196	$ 2,078,581	$ 2,079,707	$ 2,485,810	$ 2,416,441	$ 2,152,353	$ 2,396,409	$ 2,574,088	$ 2,638,693	$ 2,464,599	$ -
Bay Lake	Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belle Isle	Orange	$ 110,819	$ 115,206	$ 111,052	$ 122,368	$ 121,832	$ 148,837	$ -	$ 137,968	$ 140,572	$ 157,734	$ 156,291	$ 158,676	$ 159,706
Eatonville	Orange	$ 207,192	$ 253,576	$ 281,705	$ 316,938	$ 347,626	$ 398,184	$ 382,144	$ 368,132	$ 396,032	$ 406,128	$ 377,647	$ 380,527	$ 386,711
Edgewood	Orange	$ 219,905	$ 426,198	$ 284,103	$ 292,223	$ 311,612	$ 345,239	$ 332,976	$ 318,966	$ 326,053	$ 354,275	$ 343,245	$ 319,474	$ 307,425
Lake Buena Vista	Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maitland	Orange	$ 1,739,806	$ 1,904,457	$ 1,957,775	$ 1,940,598	$ 2,023,271	$ 2,378,189	$ 2,245,265	$ 2,085,118	$ 2,195,119	$ 2,277,147	$ 2,241,310	$ 2,238,921	$ 2,241,508
Oakland	Orange	$ 110,881	$ -	$ 130,846	$ 129,264	$ 134,331	$ 172,536	$ 147,810	$ 135,665	$ 146,156	$ 148,345	$ 164,795	$ 170,093	$ 165,639
Ocoee	Orange	$ 1,889,206	$ 2,135,535	$ 2,204,475	$ 2,268,895	$ 2,306,021	$ 2,670,345	$ 2,553,667	$ 2,364,736	$ 2,454,414	$ 2,708,105	$ 2,694,539	$ 2,811,941	$ 2,874,458
Orlando	Orange	$ 21,564,188	$ 22,446,087	$ 24,648,623	$ 25,576,240	$ 27,877,075	$ 30,130,307	$ 29,816,881	$ 28,858,045	$ 27,675,532	$ 28,833,231	$ 28,839,457	$ 29,971,123	$ 29,797,432
Windermere	Orange	$ 189,435	$ 210,667	$ 217,471	$ 225,128	$ 243,060	$ 291,280	$ 280,958	$ 259,930	$ 206,336	$ 227,291	$ 298,716	$ 300,591	$ 298,088
Winter Garden	Orange	$ 1,457,544	$ 1,739,803	$ 1,976,047	$ 2,156,980	$ 2,253,662	$ 2,803,332	$ 2,640,377	$ 2,419,663	$ 2,550,293	$ 2,995,652	$ 2,933,722	$ 3,167,385	$ 3,364,551
Winter Park	Orange	$ 2,625,437	$ 2,903,648	$ 2,963,353	$ 3,002,455	$ 3,114,873	$ 3,695,914	$ 3,525,012	$ 3,338,652	$ 3,360,006	$ 3,438,409	$ 3,462,331	$ 3,579,440	$ 3,484,023
Kissimmee	Osceola	$ 5,795,000	$ 2,937,000	$ 2,913,379	$ 3,133,000	$ 3,170,000	$ 3,207,000	$ 2,744,000	$ 3,415,000	$ 3,560,000	$ 4,025,000	$ 4,112,000	$ 4,324,087	$ 4,298,847
St. Cloud	Osceola	$ 1,133,352	$ 1,286,095	$ 1,489,295	$ 1,555,378	$ 1,710,981	$ 1,886,169	$ 1,868,378	$ 1,735,517	$ 1,617,406	$ 1,870,481	$ 1,955,188	$ 2,067,259	$ 2,087,980
Atlantis	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belle Glade	Palm Beach	$ 638,315	$ 635,518	$ 670,384	$ 695,634	$ 728,362	$ 778,405	$ 769,386	$ 765,648	$ 824,401	$ 886,040	$ 881,283	$ 894,187	$ 903,196
Boca Raton	Palm Beach	$ 9,332,787	$ 9,524,013	$ 9,750,757	$ 9,798,646	$ 11,445,225	$ 11,983,938	$ 11,844,844	$ 10,773,576	$ 11,446,261	$ 13,573,816	$ 13,609,977	$ 12,557,236	$ 11,591,687
Boynton Beach	Palm Beach	$ 4,057,187	$ 4,354,332	$ 4,264,467	$ 4,348,159	$ 4,318,365	$ 4,694,042	$ 4,680,999	$ 4,744,498	$ 5,178,324	$ 5,694,438	$ 5,787,405	$ 6,010,311	$ 6,200,908
Briny Breeze	Palm Beach	$ 10,773	$ 10,721	$ 10,296	$ 10,752	$ 9,814	$ 11,146	$ 11,567	$ 11,630	$ 11,992	$ 13,360	$ 15,369	$ 15,344	$ 15,552
Cloud Lake	Palm Beach	$ 4,229	$ 4,290	$ 4,381	$ 4,159	$ 3,898	$ 4,625	$ 4,526	$ 4,215	$ 4,389	$ 4,682	$ 4,928	$ 5,033	$ 5,125
Delray Beach	Palm Beach	$ 4,008,310	$ 4,198,555	$ 4,164,263	$ 4,152,517	$ 4,365,129	$ 4,840,836	$ 4,836,012	$ 4,930,270	$ 5,202,278	$ 5,762,273	$ 5,982,207	$ 6,055,065	$ 6,289,311
Glen Ridge	Palm Beach	$ 12,524	$ 13,281	$ 13,088	$ 14,050	$ 14,533	$ 16,538	$ 15,835	$ 16,167	$ 17,860	$ 24,248	$ 24,567	$ 26,179	$ 27,674
Golf	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Greenacres	Palm Beach	$ 1,491,468	$ 1,668,713	$ 1,635,216	$ 1,625,841	$ 1,631,646	$ 1,780,946	$ 1,785,411	$ 1,808,707	$ 1,930,995	$ 2,118,618	$ 2,147,932	$ 2,220,619	$ 2,294,157
Gulf Stream	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 66,319	$ 137,235	$ 148,267	$ 165,753	$ 185,390	$ 200,640	$ 191,353	$ 196,230
Haverhill	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Highland Beach	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 438,391	$ 424,682	$ -	$ -	$ -	$ 429,025	$ 410,632	$ 420,577
Hypoluxo	Palm Beach	$ 105,846	$ 24,761	$ 104,195	$ 105,765	$ 106,174	$ 117,726	$ 115,461	$ 116,503	$ 125,371	$ 138,330	$ 133,451	$ 250,605	$ 265,266
Juno Beach	Palm Beach	$ 241,854	$ 242,255	$ 233,552	$ 230,008	$ 237,717	$ 294,178	$ 330,249	$ 331,178	$ 356,089	$ 390,510	$ 390,365	$ 413,835	$ 424,489

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Jupiter	Palm Beach	$ 2,253,331	$ 2,406,940	$ 2,327,850	$ 2,380,624	$ 2,461,411	$ 2,688,946	$ 2,684,899	$ 2,754,579	$ 2,959,183	$ 3,262,486	$ 3,346,462	$ 3,464,482	$ 3,563,068
Jupiter Inlet Colony	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake Clarke Shores	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake Park	Palm Beach	$ 547,350	$ 560,625	$ 549,648	$ 563,614	$ 556,670	$ 607,096	$ 613,238	$ 621,259	$ 667,672	$ 736,795	$ 751,488	$ 771,884	$ 781,596
Lake Worth	Palm Beach	$ 2,250,201	$ 3,460,604	$ 2,379,179	$ 2,421,195	$ 2,270,891	$ 2,453,258	$ 2,637,397	$ 2,072,100	$ 1,896,128	$ 2,151,698	$ 1,966,219	$ 2,092,676	$ 2,057,814
Lantana	Palm Beach	$ 623,664	$ 649,352	$ 666,655	$ 682,295	$ 651,189	$ 711,388	$ 700,642	$ 704,225	$ 751,631	$ 834,615	$ 844,483	$ 873,194	$ 893,803
Loxahatchee Groves	Palm Beach	$ -	$ -	$ -	$ 114,600	$ 196,004	$ 209,777	$ 203,523	$ 203,118	$ 225,396	$ 255,191	$ 257,661	$ 263,868	$ 280,438
Manalapan	Palm Beach	$ 149,545	$ 164,713	$ 132,097	$ 129,082	$ 167,919	$ 182,001	$ 184,807	$ 186,585	$ 194,565	$ 209,557	$ 213,810	$ 215,653	$ 226,328
Mangonia Park	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 130,490	$ 128,717	$ 129,988	$ 144,340	$ 163,648	$ 184,226	$ 168,395	$ 177,654
North Palm Beach	Palm Beach	$ 914,354	$ 934,599	$ 938,550	$ 942,223	$ 934,198	$ 1,034,593	$ 1,017,774	$ 1,030,127	$ 1,091,884	$ 1,199,682	$ 1,207,006	$ 1,253,235	$ 1,289,385
Ocean Ridge	Palm Beach	$ 158,203	$ 164,998	$ 129,698	$ 148,498	$ 178,664	$ 206,888	$ 204,158	$ 205,909	$ 216,909	$ 242,584	$ 241,251	$ 248,102	$ 254,268
Pahokee	Palm Beach	$ 227,296	$ 218,783	$ 217,295	$ 214,140	$ 208,020	$ 229,144	$ 226,651	$ 222,199	$ 223,466	$ 240,861	$ 244,175	$ 249,348	$ -
Palm Beach	Palm Beach	$ 1,976,980	$ 2,035,294	$ 2,039,667	$ 2,060,247	$ 2,049,223	$ 2,187,115	$ 2,172,820	$ 2,221,874	$ 2,362,068	$ 2,568,843	$ 2,554,383	$ 2,592,663	$ 2,531,458
Palm Beach Gardens	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palm Beach Shores	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,436	$ 166,300
Palm Springs	Palm Beach	$ 763,784	$ 847,560	$ 873,368	$ 909,438	$ 930,056	$ 995,546	$ 1,049,360	$ 1,093,550	$ 1,428,048	$ 1,464,736	$ 1,528,623	$ 1,669,166	$ 1,775,636
Riviera Beach	Palm Beach	$ 1,874,850	$ 2,155,168	$ 2,240,764	$ 2,279,535	$ 2,471,640	$ 2,397,755	$ 2,397,373	$ 2,522,841	$ 2,801,998	$ 3,109,911	$ 3,128,177	$ 3,262,056	$ 3,366,657
Royal Palm Beach	Palm Beach	$ 1,749,565	$ 1,791,930	$ 1,899,349	$ 1,954,826	$ 1,996,922	$ 2,167,701	$ 2,147,928	$ 2,160,221	$ 2,340,259	$ 2,603,701	$ 2,650,189	$ 2,755,210	$ 2,804,492
South Bay	Palm Beach	$ 163,515	$ -	$ 178,672	$ 181,669	$ 180,641	$ 210,579	$ 189,758	$ 190,314	$ 204,378	$ 228,561	$ 240,732	$ 241,422	$ 251,660
South Palm Beach	Palm Beach	$ 112,183	$ 110,044	$ 106,896	$ 107,405	$ 99,416	$ 88,560	$ 114,819	$ 115,587	$ 122,718	$ 136,467	$ 136,329	$ 140,856	$ 142,044
Tequesta	Palm Beach	$ -	$ 363,620	$ 392,158	$ 397,931	$ 400,266	$ 444,370	$ 434,553	$ 431,414	$ 467,498	$ 508,479	$ 509,338	$ 522,752	$ 531,559
Wellington	Palm Beach	$ 3,075,162	$ 3,236,136	$ 3,249,554	$ 3,253,102	$ 3,277,599	$ 3,612,989	$ 3,700,672	$ 3,644,412	$ 3,938,138	$ 4,359,504	$ 4,428,072	$ 4,582,216	$ 4,627,142
West Palm Beach	Palm Beach	$ 7,854,526	$ 8,169,153	$ 7,823,657	$ 7,772,802	$ 7,656,138	$ 8,289,796	$ 8,304,419	$ 8,350,046	$ 9,126,197	$ 10,129,882	$ 10,248,562	$ 10,614,492	$ 10,993,612
Westlake	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dade City	Pasco	$ 420,757	$ 411,169	$ 425,078	$ 444,235	$ 478,534	$ 572,324	$ 540,774	$ 518,642	$ 519,209	$ 558,694	$ 539,801	$ 550,926	$ 553,206
New Port Richey	Pasco	$ 1,086,979	$ 1,178,701	$ 1,188,282	$ 1,162,320	$ 1,219,099	$ 1,432,186	$ 1,327,867	$ 1,210,723	$ 1,277,872	$ 1,356,940	$ 1,269,808	$ 1,325,774	$ -
Port Richey	Pasco	$ 286,942	$ 316,501	$ 317,975	$ 312,095	$ 30,721	$ -	$ 220,625	$ 318,735	$ 290,219	$ 302,277	$ 340,828	$ 363,937	$ 365,175
San Antonio	Pasco	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Leo	Pasco	$ -	$ -	$ 15,840	$ 31,703	$ 34,595	$ 39,942	$ 42,111	$ 39,656	$ 41,458	$ 37,379	$ 31,626	$ 32,238	$ 34,510
Zephyrhills	Pasco	$ 1,064,236	$ 1,186,068	$ 1,244,668	$ 1,248,153	$ 1,335,641	$ 1,515,999	$ 1,435,857	$ 1,369,763	$ 1,477,083	$ 1,518,661	$ 1,511,787	$ 1,541,461	$ -
Belleair	Pinellas	$ 320,261	$ 348,180	$ 34,699	$ 379,017	$ 415,012	$ 414,623	$ 380,691	$ 352,172	$ 224,919	$ 442,298	$ 423,379	$ 437,310	$ 438,410
Belleair Beach	Pinellas	$ 141,129	$ 152,877	$ 150,824	$ 153,067	$ 161,699	$ 193,984	$ 181,570	$ 164,216	$ 175,551	$ 196,722	$ 185,676	$ 187,771	$ 188,789
Belleair Bluffs	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 85,409	$ 114,114	$ 112,988
Belleair Shore	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clearwater	Pinellas	$ 8,085,037	$ 8,510,566	$ 8,592,224	$ 8,679,857	$ 9,091,973	$ 10,550,107	$ 9,946,131	$ 9,357,956	$ 9,928,059	$ 10,622,825	$ 10,299,861	$ 10,558,902	$ 10,679,169
Dunedin	Pinellas	$ 2,326,067	$ 2,517,186	$ 2,497,573	$ 2,481,842	$ 2,628,213	$ 3,069,542	$ 2,822,718	$ 2,611,204	$ 2,722,845	$ 2,971,322	$ 2,835,195	$ 2,910,941	$ 2,873,818
Gulfport	Pinellas	$ 694,986	$ 743,774	$ 722,653	$ 747,417	$ 767,047	$ 913,198	$ 861,760	$ 795,054	$ 823,812	$ 886,181	$ 881,166	$ 889,571	$ 883,299
Indian Rocks Beach	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Indian Shores	Pinellas	$ 168,831	$ 225,150	$ 224,442	$ 238,869	$ 258,636	$ 290,804	$ 280,536	$ 262,154	$ 272,674	$ 294,279	$ 293,009	$ 297,814	$ 296,879
Kenneth City	Pinellas	$ 137,368	$ 146,768	$ 138,546	$ 141,724	$ 148,609	$ 174,954	$ 168,417	$ 153,057	$ 248,025	$ 335,158	$ 318,787	$ 323,853	$ 329,872
Largo	Pinellas	$ 5,150,410	$ 5,589,000	$ 5,621,352	$ 5,736,472	$ 5,879,690	$ 6,859,799	$ 6,427,489	$ 5,894,160	$ 6,397,953	$ 6,763,518	$ 6,522,256	$ 6,848,804	$ 6,846,236
Madeira Beach	Pinellas	$ 437,112	$ 461,441	$ 475,015	$ 482,408	$ 512,353	$ 603,339	$ 564,244	$ 532,148	$ 563,875	$ 579,692	$ 592,342	$ 606,778	$ 607,355
North Redington Beach	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Oldsmar	Pinellas	$ 1,116,292	$ 1,069,993	$ 1,057,154	$ 1,111,598	$ 1,235,954	$ 1,384,771	$ 1,346,463	$ 1,307,348	$ 1,302,837	$ 1,366,234	$ 1,380,940	$ 1,403,136	$ 1,428,035
Pinellas Park	Pinellas	$ 3,865,478	$ 4,221,078	$ 4,260,449	$ 4,309,435	$ 4,427,434	$ 5,106,163	$ 4,820,268	$ 4,625,865	$ 4,916,890	$ 5,277,198	$ 5,202,066	$ 5,365,900	$ 5,416,593
Redington Beach	Pinellas	$ 78,440	$ 86,777	$ 84,847	$ 87,779	$ 94,571	$ 110,724	$ 103,931	$ 93,044	$ 100,119	$ 106,259	$ 106,632	$ 109,254	$ 110,382
Redington Shores	Pinellas	$ -	$ -	$ -	$ -	$ 203,496	$ 227,018	$ 209,225	$ 202,016	$ 197,277	$ 200,721	$ 214,827	$ 206,079	$ 196,902
Safety Harbor	Pinellas	$ 1,103,040	$ 1,220,986	$ 1,214,617	$ 1,241,042	$ 1,294,615	$ 1,501,797	$ 1,377,150	$ 1,304,600	$ 1,365,466	$ 1,492,333	$ 1,403,757	$ 1,426,285	$ 1,404,980
Seminole	Pinellas	$ 869,111	$ 941,243	$ 954,512	$ 969,311	$ 1,003,105	$ 1,137,362	$ 1,065,545	$ 999,293	$ 1,048,407	$ 1,111,089	$ 1,095,389	$ 1,130,497	$ 1,165,917
South Pasadena	Pinellas	$ 417,635	$ 438,324	$ 434,617	$ 437,759	$ 445,197	$ 513,981	$ 496,286	$ 466,924	$ 491,733	$ 508,426	$ 514,474	$ 526,612	$ 525,852
St. Pete Beach	Pinellas	$ 1,011,245	$ 1,077,984	$ 1,080,315	$ 1,094,847	$ 1,135,150	$ 1,336,815	$ 1,256,642	$ 1,181,426	$ 1,242,465	$ 1,314,149	$ 1,300,813	$ 1,330,716	$ 1,314,360
St. Petersburg	Pinellas	$ 16,989,020	$ 18,032,091	$ 18,064,761	$ 18,375,628	$ 19,250,219	$ 22,432,711	$ 21,112,967	$ 19,768,164	$ 21,044,031	$ 22,425,440	$ 21,616,371	$ 22,319,008	$ 22,282,684
Tarpon Springs	Pinellas	$ 1,579,595	$ 1,676,592	$ 1,717,458	$ 1,750,533	$ 1,800,168	$ 2,111,156	$ 1,962,501	$ 1,784,494	$ 1,939,631	$ 2,103,331	$ 2,048,678	$ 2,105,526	$ 2,099,759
Treasure Island	Pinellas	$ 396,565	$ 395,446	$ 398,900	$ 407,062	$ 670,145	$ 846,007	$ 806,956	$ 753,605	$ 795,139	$ 843,594	$ 827,378	$ 850,346	$ 847,614
Auburndale	Polk	$ 969,414	$ 956,854	$ 1,177,104	$ 1,259,398	$ 1,362,909	$ 1,652,178	$ 1,592,150	$ 1,587,642	$ 1,607,926	$ 1,752,115	$ 1,831,313	$ 1,906,457	$ 1,983,393
Bartow	Polk	$ 1,173,774	$ 1,261,735	$ 1,338,392	$ 1,299,835	$ 1,472,703	$ 1,540,203	$ 1,537,319	$ 1,437,468	$ 1,485,941	$ 1,584,074	$ 1,617,432	$ 1,622,916	$ 1,665,703
Davenport	Polk	$ 151,849	$ 164,940	$ 179,184	$ 219,533	$ 243,551	$ 286,542	$ 269,453	$ 262,358	$ 281,342	$ 298,569	$ 327,256	$ 365,677	$ 403,280
Dundee	Polk	$ 173,647	$ 192,080	$ 199,504	$ 213,037	$ 213,608	$ 245,980	$ 230,552	$ 232,027	$ 221,198	$ 242,234	$ 251,582	$ 262,858	$ 270,976
Eagle Lake	Polk	$ 79,203	$ 80,169	$ 86,418	$ 89,770	$ 104,031	$ 122,402	$ 118,104	$ 110,795	$ 111,762	$ 126,288	$ 125,754	$ 130,305	$ 147,169
Fort Meade	Polk	$ 320,473	$ 384,950	$ 478,404	$ 500,316	$ 585,345	$ 615,094	$ 379,857	$ 399,963	$ 409,810	$ 431,009	$ 437,879	$ 441,343	$ 414,767
Frostproof	Polk	$ 206,006	$ 223,603	$ 221,864	$ 207,563	$ 253,361	$ 296,640	$ 249,053	$ 227,516	$ 243,190	$ 276,356	$ 258,711	$ 266,797	$ 261,389
Haines City	Polk	$ 790,928	$ 914,378	$ 986,922	$ 1,013,034	$ 1,063,635	$ 1,230,949	$ 1,164,631	$ 1,092,348	$ 1,165,788	$ 1,242,415	$ 1,299,094	$ 1,346,073	$ 1,382,525
Highland Park	Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hillcrest Heights	Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake Alfred	Polk	$ 238,463	$ 230,261	$ 236,314	$ 255,580	$ 279,075	$ 324,124	$ 304,900	$ 290,107	$ 295,925	$ 296,385	$ 335,426	$ 361,834	$ 361,109
Lake Hamilton	Polk	$ 100,118	$ -	$ 131,967	$ 103,720	$ 121,693	$ 103,094	$ 128,371	$ 102,028	$ 108,705	$ 113,642	$ 111,606	$ 113,886	$ 107,308
Lake Wales	Polk	$ 942,474	$ 1,056,770	$ 1,112,497	$ 1,131,535	$ 1,174,440	$ 1,345,444	$ 1,292,313	$ 1,199,440	$ 1,252,229	$ 1,347,985	$ 1,320,081	$ 1,369,511	$ 1,351,075
Lakeland	Polk	$ 6,341,371	$ 6,598,518	$ 7,004,201	$ 7,324,452	$ 7,313,240	$ 7,706,494	$ 7,695,514	$ 7,323,308	$ 7,392,707	$ 7,687,510	$ 8,211,994	$ 8,405,192	$ 8,309,670
Mulberry	Polk	$ -	$ -	$ -	$ -	$ -	$ 418,899	$ 380,505	$ 349,281	$ 340,977	$ 347,782	$ 352,889	$ 356,823	$ 357,849
Polk City	Polk	$ 79,384	$ 78,491	$ 69,600	$ 86,608	$ 86,316	$ 95,148	$ 86,852	$ 79,089	$ 76,380	$ 78,899	$ 83,726	$ 86,290	$ 87,830

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Winter Haven	Polk	$ 2,317,657	$ 2,334,745	$ 2,367,826	$ 2,594,261	$ 2,802,430	$ 3,225,015	$ 3,024,470	$ 3,014,888	$ 3,077,286	$ 3,333,369	$ 3,378,071	$ 3,536,852	$ 3,705,185
Crescent City	Putnam	$ 54,790	$ 57,141	$ 55,685	$ 58,611	$ 98,359	$ 107,556	$ 107,771	$ 105,176	$ 112,737	$ 120,746	$ 122,275	$ 124,498	$ 126,826
Interlachen	Putnam	$ 55,304	$ 74,349	$ 73,618	$ 78,047	$ 82,626	$ 88,699	$ 83,462	$ 76,698	$ 82,286	$ 87,173	$ 89,855	$ 89,268	$ 89,975
Palatka	Putnam	$ 583,829	$ 633,747	$ 605,456	$ 1,504,085	$ 1,525,570	$ 1,533,060	$ 668,075	$ 639,950	$ 651,854	$ 750,858	$ 791,072	$ 789,299	$ 790,456
Pomona Park	Putnam	$ 11,524	$ 11,508	$ 11,706	$ 11,650	$ 11,518	$ 11,184	$ 11,726	$ 11,423	$ 11,268	$ 22,822	$ 31,725	$ 30,887	$ 31,987
Welaka	Putnam	$ 10,058	$ 10,381	$ 13,840	$ 58,600	$ 58,170	$ 57,544	$ 57,179	$ 14,125	$ 14,580	$ 15,035	$ 15,046	$ 15,106	$ 14,992
Gulf Breeze	Santa Rosa	$ -	$ -	$ 108,301	$ 88,179	$ 159,356	$ 245,884	$ 265,847	$ 277,043	$ 275,240	$ 356,121	$ 374,695	$ 521,934	$ 594,693
Jay	Santa Rosa	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Milton	Santa Rosa	$ -	$ 458,736	$ 470,455	$ 479,821	$ 486,737	$ 531,778	$ 585,741	$ 549,540	$ 554,710	$ 635,880	$ 675,019	$ 693,657	$ 720,500
North Port	Sarasota	$ 379,517	$ 435,921	$ 486,787	$ 510,880	$ 527,522	$ 580,486	$ 584,193	$ 589,511	$ 644,998	$ 715,620	$ 749,292	$ 788,561	$ 836,661
Sarasota	Sarasota	$ 4,263,406	$ 4,390,993	$ 4,309,733	$ 4,160,104	$ 4,207,847	$ 4,536,335	$ 4,575,547	$ 4,571,626	$ 4,927,990	$ 5,301,244	$ 5,306,305	$ 5,353,913	$ 5,465,224
Venice	Sarasota	$ 1,610,115	$ 1,702,806	$ 1,710,323	$ 1,711,690	$ 3,680,077	$ 1,910,683	$ 1,750,415	$ 1,915,864	$ 2,102,365	$ 2,324,080	$ 2,404,489	$ 2,468,997	$ 2,546,596
Altamonte Springs	Seminole	$ 2,715,763	$ 2,918,929	$ 2,957,002	$ 2,979,532	$ 3,071,673	$ 3,489,898	$ 3,289,114	$ 3,123,061	$ 3,299,787	$ 3,461,845	$ 3,377,082	$ 3,473,184	$ 3,453,262
Casselberry	Seminole	$ 1,581,327	$ 1,696,050	$ 1,692,191	$ 1,728,419	$ 1,724,396	$ 2,080,495	$ 1,929,886	$ 1,742,412	$ 1,855,485	$ 2,009,075	$ 1,956,128	$ 2,015,315	$ 1,999,103
Lake Mary	Seminole	$ 1,401,325	$ 1,555,394	$ 1,595,986	$ 1,599,976	$ 1,828,275	$ 2,036,420	$ 1,956,131	$ 1,850,581	$ 1,936,906	$ 2,039,809	$ 2,033,737	$ 2,081,455	$ 2,109,698
Longwood	Seminole	$ 1,036,538	$ 1,142,783	$ 1,155,913	$ 1,147,701	$ 1,159,863	$ 1,299,810	$ 1,240,610	$ 1,142,495	$ 1,133,005	$ 1,209,227	$ 1,204,675	$ 1,237,923	$ 1,232,803
Oviedo	Seminole	$ 1,702,101	$ 2,020,147	$ 2,072,853	$ 2,115,330	$ 2,223,291	$ 2,557,794	$ 2,382,520	$ 2,232,423	$ 2,378,906	$ 2,542,378	$ 2,550,423	$ 2,667,136	$ 2,705,488
Sanford	Seminole	$ 2,883,985	$ 3,135,929	$ 3,158,229	$ 3,200,167	$ 3,324,399	$ 3,576,967	$ 3,573,523	$ 3,531,396	$ 3,830,088	$ 4,249,088	$ 4,379,111	$ 4,498,458	$ 4,571,078
Winter Springs	Seminole	$ 1,711,162	$ 1,955,524	$ 1,916,949	$ 1,963,770	$ 1,919,916	$ 2,469,621	$ 2,196,504	$ 2,015,839	$ 1,951,447	$ 2,260,602	$ 2,269,767	$ 2,340,116	$ 2,327,250
Hastings	St. Johns	$ 104,714	$ 108,484	$ 118,242	$ 86,834	$ 29,884	$ 31,299	$ 32,963	$ 30,884	$ 33,497	$ 36,121	$ 37,450	$ 37,498	$ 40,045
St. Augustine	St. Johns	$ 643,310	$ 596,575	$ 711,370	$ 636,611	$ 643,040	$ 894,452	$ 980,395	$ 939,844	$ 1,029,195	$ 1,125,221	$ 1,146,071	$ 1,291,612	$ 1,445,175
St. Augustine Beach	St. Johns	$ 412,104	$ 425,673	$ 428,851	$ 424,021	$ 442,003	$ 497,780	$ 495,779	$ 484,811	$ 521,284	$ 567,095	$ 575,069	$ 585,202	$ 592,840
Fort Pierce	St. Lucie	$ 2,068,235	$ 1,949,793	$ 1,962,122	$ 2,238,087	$ 2,277,921	$ 2,429,431	$ 2,418,688	$ 2,332,780	$ 2,287,055	$ 2,349,705	$ 2,430,741	$ 2,566,731	$ 2,617,939
Port St. Lucie	St. Lucie	$ 3,180,531	$ 3,548,158	$ 3,799,014	$ 3,937,495	$ 4,010,779	$ 4,517,810	$ 8,634,159	$ 9,075,684	$ -	$ -	$ -	$ -	$ -
St. Lucie Village	St. Lucie	$ -	$ -	$ -	$ 59,880	$ 75,485	$ 69,878	$ 59,855	$ 54,558	$ 51,989	$ 53,621	$ 52,781	$ 51,012	$ 53,741
Bushnell	Sumter	$ 119,901	$ 144,690	$ 117,188	$ 123,975	$ 146,641	$ 157,348	$ 152,190	$ 134,292	$ 154,322	$ 162,804	$ 159,352	$ 162,650	$ 162,561
Center Hill	Sumter	$ 35,765	$ 37,490	$ 36,906	$ 37,678	$ 40,701	$ 51,873	$ 48,209	$ 44,113	$ 51,789	$ 50,980	$ 51,431	$ 55,358	$ 55,143
Coleman	Sumter	$ 33,171	$ 36,089	$ 35,376	$ 34,988	$ 38,067	$ 43,949	$ 41,771	$ 36,984	$ 38,117	$ 40,366	$ 40,357	$ 43,144	$ 43,911
Webster	Sumter	$ 33,928	$ -	$ 35,814	$ 33,080	$ 35,528	$ 44,013	$ 42,830	$ 42,687	$ 38,285	$ 25,925	$ 42,426	$ 45,461	$ 54,690
Wildwood	Sumter	$ 194,528	$ 226,217	$ 255,646	$ 274,173	$ 195,069	$ 182,460	$ 244,366	$ 310,577	$ 462,968	$ 577,292	$ 608,550	$ 1,418,595	$ 1,486,704
Branford	Suwannee	$ -	$ 52,588	$ 54,231	$ 53,511	$ 56,130	$ 66,515	$ 64,739	$ -	$ 68,668	$ 70,112	$ 69,431	$ 68,643	$ 61,338
Live Oak	Suwannee	$ 439,788	$ 519,318	$ 517,428	$ 528,944	$ 528,741	$ 527,019	$ 542,308	$ 522,393	$ 548,744	$ 589,937	$ 612,646	$ 594,315	$ 602,740
Perry	Taylor	$ 471,160	$ 497,151	$ 518,020	$ 473,336	$ 572,683	$ 663,647	$ 674,045	$ 481,003	$ 579,497	$ 658,676	$ 631,960	$ 618,171	$ 683,398
Lake Butler	Union	$ 25,514	$ 27,131	$ 26,687	$ 166,591	$ 27,867	$ 34,003	$ 31,541	$ 28,925	$ 31,424	$ 34,851	$ 34,943	$ 33,915	$ 34,068
Raiford	Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Worthington Springs	Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Daytona Beach	Volusia	$ 4,943,108	$ 5,053,145	$ 4,921,414	$ 4,866,065	$ 5,020,783	$ 5,422,020	$ 5,387,030	$ 5,293,930	$ 5,763,949	$ 6,246,746	$ 6,389,654	$ 6,602,091	$ 6,796,997
Daytona Beach Shores	Volusia	$ 353,000	$ 357,000	$ 371,137	$ 370,670	$ 383,554	$ 413,000	$ 410,000	$ 406,000	$ 426,000	$ 477,000	$ 531,000	$ 836,000	$ 819,000
DeBary	Volusia	$ 810,345	$ 1,027,356	$ 1,078,074	$ 1,115,172	$ 1,192,703	$ 1,405,249	$ 1,313,872	$ 1,173,050	$ 1,250,617	$ 1,349,550	$ 1,353,673	$ 1,435,669	$ 1,395,619
DeLand	Volusia	$ 1,861,145	$ 2,156,565	$ 2,242,273	$ 2,275,857	$ 2,388,677	$ 2,792,406	$ 2,607,528	$ 2,439,565	$ 2,601,981	$ 2,798,468	$ 2,779,787	$ 2,876,547	$ 2,888,536
Deltona	Volusia	$ 3,564,184	$ 3,846,663	$ 3,870,079	$ 3,799,154	$ 4,070,999	$ 4,556,219	$ 4,324,002	$ 4,032,863	$ 4,303,350	$ 4,616,697	$ 4,707,391	$ 5,125,471	$ 4,913,300
Edgewater	Volusia	$ 939,175	$ 1,008,726	$ 1,040,642	$ 887,308	$ 1,010,319	$ 1,113,484	$ 1,076,748	$ 1,055,571	$ 1,148,158	$ 1,250,162	$ 1,291,965	$ 1,328,340	$ 1,383,962
Holly Hill	Volusia	$ 757,813	$ 785,546	$ 780,932	$ 793,872	$ 797,913	$ 856,356	$ 847,841	$ 835,424	$ 903,270	$ 985,536	$ 1,018,529	$ 1,036,293	$ 1,042,000
Lake Helen	Volusia	$ 125,774	$ 139,334	$ 141,122	$ 139,150	$ 151,238	$ 179,122	$ 168,684	$ 152,428	$ 165,151	$ 173,685	$ 177,062	$ 184,691	$ 181,189
New Smyrna Beach	Volusia	$ 1,555,858	$ 1,610,382	$ -	$ 1,648,500	$ 1,705,662	$ 1,843,561	$ 1,710,658	$ 1,661,109	$ 1,639,550	$ 1,784,610	$ 1,850,161	$ 1,948,518	$ 1,893,032
Oak Hill	Volusia	$ 54,113	$ 57,829	$ 59,167	$ 58,420	$ 59,310	$ 64,873	$ 66,165	$ 64,431	$ 72,164	$ 98,390	$ 136,944	$ 146,199	$ 147,609
Orange City	Volusia	$ 616,603	$ 689,801	$ 720,360	$ 759,816	$ 821,553	$ 949,406	$ 927,054	$ 888,770	$ 943,623	$ 983,998	$ 954,349	$ 979,080	$ 981,261
Ormond Beach	Volusia	$ 2,882,000	$ 2,989,000	$ 2,908,000	$ 2,865,000	$ 2,942,000	$ 3,203,000	$ 3,184,000	$ 3,090,000	$ 3,286,000	$ 3,543,000	$ 3,673,000	$ 3,775,337	$ 3,788,243
Pierson	Volusia	$ 32,183	$ 35,264	$ 35,675	$ 36,464	$ 37,976	$ 44,718	$ 42,348	$ 37,700	$ 40,299	$ 42,086	$ 41,890	$ 45,628	$ 42,544
Ponce Inlet	Volusia	$ 258,543	$ 262,641	$ 257,508	$ 254,049	$ 265,640	$ 292,496	$ 288,628	$ 282,913	$ 306,805	$ 330,249	$ 331,824	$ 343,427	$ 341,785
Port Orange	Volusia	$ 2,894,309	$ 2,967,560	$ 3,130,715	$ 2,903,612	$ 3,032,649	$ 3,408,623	$ 3,401,701	$ 3,314,238	$ 3,620,861	$ 3,971,420	$ 4,103,884	$ 4,209,725	$ 4,255,511
South Daytona	Volusia	$ 732,410	$ 736,579	$ 715,327	$ 699,932	$ 710,495	$ 773,158	$ 763,292	$ 732,553	$ 794,673	$ 870,918	$ 901,025	$ 922,456	$ 928,639
Sopchoppy	Wakulla	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Marks	Wakulla	$ 27,455	$ 25,460	$ 15,189	$ 26,188	$ 29,784	$ 34,923	$ 29,380	$ 27,355	$ 30,466	$ 32,916	$ 30,683	$ 29,124	$ 29,512
DeFuniak Springs	Walton	$ 263,733	$ 286,698	$ 403,948	$ 459,763	$ 466,623	$ 478,470	$ 502,715	$ 456,265	$ 463,590	$ 523,638	$ 580,440	$ 538,295	$ -
Freeport	Walton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Paxton	Walton	$ -	$ 11,613	$ 12,880	$ 22,781	$ 15,061	$ 16,559	$ 15,764	$ 14,316	$ 14,700	$ 16,046	$ 16,877	$ 14,814	$ 14,961
Caryville	Washington	$ -	$ -	$ -	$ 4,476	$ -	$ -	$ 12,008	$ 11,139	$ -	$ 13,553	$ 14,950	$ 18,045	$ -
Chipley	Washington	$ 201,425	$ 226,213	$ 224,543	$ 219,492	$ 221,433	$ 245,828	$ 248,241	$ 237,131	$ 241,695	$ 264,750	$ 278,879	$ 271,335	$ 277,151
Ebro	Washington	$ -	$ -	$ -	$ -	$ 42,428	$ 36,600	$ 36,600	$ 34,434	$ 37,009	$ 30,340	$ 35,770	$ -	$ -
Vernon	Washington	$ 30,921	$ 37,913	$ 34,259	$ 33,914	$ 33,560	$ 38,467	$ 39,623	$ 39,708	$ 39,494	$ 44,429	$ 47,722	$ -	$ -
Wausau	Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,585	$ 33,537	$ 30,573

Summary of Reported Municipal Public Service Tax - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total Municipal Public Service Tax - Electricity		$ 505,856,228	$ 522,270,643	$ 560,530,030	$ 585,900,374	$ 606,134,061	$ 668,376,661	$ 671,200,686	$ 666,317,873	$ 691,359,157	$ 761,756,547	$ 766,635,660	$ 788,347,654	$ 780,374,286
% Change		-	3.2%	7.3%	4.5%	3.5%	10.3%	0.4%	-0.7%	3.8%	10.2%	0.6%	2.8%	-1.0%
# Reporting		305	308	318	324	325	328	335	334	333	336	341	337	329
Total Municipal Public Service Taxes		$ 741,201,140	$ 772,981,528	$ 808,793,559	$ 834,889,954	$ 912,265,351	$ 948,885,749	$ 830,044,048	$ 837,408,227	$ 869,795,356	$ 936,010,677	$ 935,987,552	$ 960,874,090	$ 967,851,932
% Change		-	4.3%	4.6%	3.2%	9.3%	4.0%	-12.5%	0.9%	3.9%	7.6%	0.0%	2.7%	0.7%
Electricity PST as % of All PST		68.2%	67.6%	69.3%	70.2%	66.4%	70.4%	80.9%	79.6%	79.5%	81.4%	81.9%	82.0%	80.6%

Notes: This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 314.100 - Utility Service Tax - Electricity and 314.XXX - Utility Services Tax.

Data Source: Florida Department of Financial Services.

Franchise Fee

Home Rule Authority Granted by Article VIII, Section 2(b), Florida Constitution, and
Section 166.021, Florida Statutes

Article VIII, Section 2(b), Florida Constitution, provides:

> (b) POWERS. Municipalities shall have governmental, corporate and proprietary powers to enable them to conduct municipal government, perform municipal functions and render municipal services, and may exercise any power for municipal purposes except as otherwise provided by law. Each municipal legislative body shall be elective.

Section 166.021, Florida Statutes, grants extensive home rule power to municipalities. A municipality has the complete power to legislate by ordinance for any municipal purpose, except in those situations that a general or special law is inconsistent with the subject matter of the proposed ordinance.

Not all local government revenue sources are taxes requiring general law authorization under Article VII, Section 1(a), Florida Constitution. When a county or municipal revenue source is imposed by ordinance, the judicial test is whether the charge meets the legal sufficiency test, pursuant to Florida case law, for a valid fee or assessment. If not a valid fee or assessment, the charge is a tax and requires general law authorization. If not a tax, the fee or assessment's imposition is within the constitutional and statutory home rule power of municipalities and counties.

When analyzing the validity of a home rule fee, judicial reliance is often placed on the type of governmental power being exercised. Generally, fees fall into two categories. Regulatory fees, such as building permit fees, impact fees, inspection fees, and stormwater fees, are imposed pursuant to the exercise of police powers as regulation of an activity or property. Such regulatory fees cannot exceed the cost of the regulated activity and are generally applied solely to pay the cost of the regulated activity.

In contrast, proprietary fees, such as admission fees, franchise fees, user fees, and utility fees, are imposed pursuant to the exercise of the proprietary right of government. Such proprietary fees are governed by the principle that the feepayer receives a special benefit or the imposed fee is reasonable in relation to the privilege or service provided. For each fee category, rules have been developed by Florida case law to distinguish a valid fee from a tax.

Local governments may exercise their home rule authority to impose a franchise fee upon a utility for the grant of a franchise and the privilege of using a local government's rights-of-way to conduct the utility business. The franchise fee is considered fair rent for the use of such rights-of-way and consideration for the local government's agreement not to provide competing utility services during the term of the franchise agreement. The imposition of the fee requires the adoption of a franchise agreement, which grants a special privilege that is not available to the general public. Typically, the franchise fee is calculated as a percentage of the utility's gross revenues within a defined geographic area. A fee imposed by a municipality is based upon the gross revenues received from the incorporated area while a fee imposed by a county is generally based upon the gross revenues received from the unincorporated area.

Summaries of prior years' franchise fee revenues as reported by local governments are available.[1]

1. http://edr.state.fl.us/Content/local-government/data/data-a-to-z/index.cfm

Reported County and Municipal Government Franchise Fee - Electricity Revenues
Local Fiscal Years 2004-05 to 2016-17

Counties

Local FY	# Reporting Franchise Fees-Electricity Revenue	Franchise Fees-Electricity Revenue	Total Franchise Fee Revenue	Franchise Fees-Electricity as % of Total Franchise Fees	Total Revenue from All Accounts	Franchise Fees-Electricity as % of Total Revenue
2016-17	15	$ 151,120,281	$ 173,905,188	86.9%	$ 40,634,935,175	0.4%
2015-16	15	$ 153,979,517	$ 175,193,893	87.9%	$ 40,323,612,683	0.4%
2014-15	14	$ 151,906,861	$ 172,373,179	88.1%	$ 39,173,950,740	0.4%
2013-14	14	$ 143,673,995	$ 164,848,421	87.2%	$ 35,078,190,149	0.4%
2012-13	13	$ 138,982,436	$ 160,292,116	86.7%	$ 35,293,284,441	0.4%
2011-12	12	$ 142,141,297	$ 163,361,458	87.0%	$ 34,425,008,290	0.4%
2010-11	13	$ 141,763,538	$ 165,239,360	85.8%	$ 35,205,022,317	0.4%
2009-10	12	$ 157,531,114	$ 178,424,425	88.3%	$ 36,374,756,173	0.4%
2008-09	13	$ 157,892,282	$ 178,925,729	88.2%	$ 39,132,778,914	0.4%
2007-08	13	$ 154,336,228	$ 177,647,312	86.9%	$ 41,166,433,921	0.4%
2006-07	13	$ 140,330,361	$ 170,428,497	82.3%	$ 42,393,396,183	0.3%
2005-06	13	$ 142,123,668	$ 171,207,441	83.0%	$ 40,119,986,366	0.4%
2004-05	14	$ 123,553,216	$ 145,991,416	84.6%	$ 36,729,090,757	0.3%

Municipalities

Local FY	# Reporting Franchise Fees-Electricity Revenue	Franchise Fees-Electricity Revenue	Total Franchise Fee Revenue	Franchise Fees-Electricity as % of Total Franchise Fees	Total Revenue from All Accounts	Franchise Fees-Electricity as % of Total Revenue
2016-17	334	$ 570,291,737	$ 733,536,386	77.7%	$ 37,272,779,279	1.5%
2015-16	345	$ 581,823,259	$ 740,093,325	78.6%	$ 36,672,325,904	1.6%
2014-15	345	$ 590,465,562	$ 743,036,940	79.5%	$ 30,638,171,458	1.9%
2013-14	342	$ 573,990,007	$ 718,670,782	79.9%	$ 32,449,841,150	1.8%
2012-13	346	$ 547,873,544	$ 658,541,952	83.2%	$ 32,154,402,860	1.7%
2011-12	349	$ 563,206,940	$ 691,485,849	81.4%	$ 32,060,876,417	1.8%
2010-11	345	$ 571,030,032	$ 713,743,133	80.0%	$ 28,177,088,566	2.0%
2009-10	344	$ 565,453,359	$ 705,492,123	80.2%	$ 30,459,315,301	1.9%
2008-09	339	$ 600,243,133	$ 717,295,819	83.7%	$ 28,291,875,774	2.1%
2007-08	337	$ 550,626,447	$ 678,539,321	81.1%	$ 25,968,943,835	2.1%
2006-07	344	$ 546,883,232	$ 669,073,212	81.7%	$ 32,648,022,846	1.7%
2005-06	335	$ 514,540,702	$ 633,075,955	81.3%	$ 28,713,971,493	1.8%
2004-05	340	$ 434,429,008	$ 541,407,060	80.2%	$ 26,604,948,976	1.6%

Combined Total: Counties and Municipalities

Local FY	# Reporting Franchise Fees-Electricity Revenue	Franchise Fees-Electricity Revenue	Total Franchise Fee Revenue	Franchise Fees-Electricity as % of Total Franchise Fees	Total Revenue from All Accounts	Franchise Fees-Electricity as % of Total Revenue
2016-17	349	$ 721,412,018	$ 907,441,574	79.5%	$ 77,907,714,454	0.9%
2015-16	360	$ 735,802,776	$ 915,287,218	80.4%	$ 76,995,938,587	1.0%
2014-15	359	$ 742,372,423	$ 915,410,119	81.1%	$ 69,812,122,198	1.1%
2013-14	356	$ 717,664,002	$ 883,519,203	81.2%	$ 67,528,031,299	1.1%
2012-13	359	$ 686,855,980	$ 818,834,068	83.9%	$ 67,447,687,301	1.0%
2011-12	361	$ 705,348,237	$ 854,847,307	82.5%	$ 66,485,884,707	1.1%
2010-11	358	$ 712,793,570	$ 878,982,493	81.1%	$ 63,382,110,883	1.1%
2009-10	356	$ 722,984,473	$ 883,916,548	81.8%	$ 66,834,071,474	1.1%
2008-09	352	$ 758,135,415	$ 896,221,548	84.6%	$ 67,424,654,688	1.1%
2007-08	350	$ 704,962,675	$ 856,186,633	82.3%	$ 67,135,377,756	1.1%
2006-07	357	$ 687,213,593	$ 839,501,709	81.9%	$ 75,041,419,029	0.9%
2005-06	348	$ 656,664,370	$ 804,283,396	81.6%	$ 68,833,957,859	1.0%
2004-05	354	$ 557,982,224	$ 687,398,476	81.2%	$ 63,334,039,733	0.9%

Note: This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 323.100 - Franchise Fee-Electricity.

Source: EDR staff compilation of Annual Financial Report (AFR) data obtained from the Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Government.

Summary of Reported County Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Baker	$ 471,629	$ 575,612	$ 646,286	$ 666,262	$ 639,137	$ 612,403	$ 600,133	$ 546,738	$ 513,318	$ 558,719	$ 582,548	$ 557,980	$ 665,703
Bay	$ -	$ -	$ -	$ -	$ 72,693	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bradford	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Brevard	$ 12,532,188	$ 15,737,576	$ 15,487,500	$ 15,547,727	$ 15,863,455	$ 14,172,835	$ 13,812,429	$ 12,713,490	$ 12,601,382	$ 13,345,071	$ 13,671,199	$ 13,605,348	$ 13,715,714
Broward	$ 2,936,000	$ 2,418,000	$ 1,586,000	$ 1,248,000	$ 1,317,000	$ 1,128,000	$ 1,073,000	$ 1,051,000	$ 1,017,000	$ 807,000	$ 864,000	$ 829,000	$ 806,000
Calhoun	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Charlotte	$ 7,180,113	$ 8,255,981	$ 8,701,628	$ 8,456,735	$ 9,483,004	$ 8,750,773	$ 8,670,905	$ 8,098,035	$ 8,075,400	$ 8,777,834	$ 9,117,461	$ 8,948,092	$ 9,211,615
Citrus	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clay	$ 5,799	$ 6,247	$ 7,876	$ -	$ -	$ -	$ -	$ -	$ 6,889	$ 7,470	$ 8,089	$ 7,864	$ 7,369
Collier	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,867	$ -	$ -	$ -	$ -	$ -	$ -
Columbia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DeSoto	$ -	$ -	$ -	$ 1,268,980	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,224,621	$ 1,192,979	$ 1,250,425
Dixie	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Duval	Refer to the separate municipal table for the consolidated City of Jacksonville/Duval County totals.												
Escambia	$ 8,340,603	$ 9,159,224	$ 9,813,723	$ 9,960,518	$ 10,755,776	$ 11,211,278	$ 11,157,471	$ 10,625,833	$ 10,341,711	$ 11,273,510	$ 11,830,914	$ 11,540,340	$ 11,353,718
Flagler	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Franklin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gilchrist	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Glades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gulf	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hamilton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hardee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hendry	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hernando	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 39,371	$ -	$ -	$ -
Highlands	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hillsborough	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Indian River	$ 6,106,585	$ 7,343,260	$ 7,734,618	$ 7,193,822	$ 7,485,240	$ 7,088,093	$ 6,516,576	$ 6,421,975	$ 6,552,104	$ 6,930,957	$ 7,034,498	$ 7,070,693	$ 6,874,263
Jackson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jefferson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lafayette	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lee	$ 6,911,941	$ 8,835,607	$ 9,352,357	$ 9,161,456	$ 9,293,256	$ 8,406,940	$ 8,398,013	$ 8,012,996	$ 8,354,637	$ 16,330,498	$ 19,475,612	$ 17,369,400	$ 17,208,709
Leon	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Levy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Liberty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Madison	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Manatee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marion	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,536,591	$ 8,898,893
Miami-Dade	$ 36,616,071	$ 38,723,997	$ 51,813,365	$ 48,668,038	$ 44,241,336	$ 45,059,265	$ 31,608,060	$ 37,925,148	$ 35,535,854	$ 24,934,431	$ 25,682,784	$ 25,310,786	$ 19,114,968
Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nassau	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Okaloosa	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Okeechobee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Osceola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palm Beach	$ 20,836,584	$ 25,022,599	$ 25,495,545	$ 25,042,044	$ 29,913,714	$ 34,017,118	$ 33,262,458	$ 31,407,084	$ 31,120,934	$ 33,805,586	$ 34,386,028	$ 33,824,684	$ 34,546,077
Pasco	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Putnam	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Johns	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Lucie	$ 3,619,311	$ 4,658,497	$ 4,564,374	$ 3,624,277	$ 4,390,381	$ 4,068,691	$ 4,018,521	$ 3,923,615	$ 3,845,968	$ 4,047,263	$ 4,175,910	$ 4,024,278	$ 3,949,128
Santa Rosa	$ 4,247,337	$ 4,643,093	$ 5,110,630	$ 5,224,408	$ 5,807,671	$ 6,074,075	$ 5,976,614	$ 5,749,499	$ 5,670,573	$ 6,197,743	$ 6,544,713	$ 6,500,937	$ 6,514,054
Sarasota	$ 13,749,054	$ 16,743,975	$ -	$ 18,273,961	$ 18,629,619	$ 16,941,643	$ 16,576,491	$ 15,665,884	$ 15,346,666	$ 16,618,542	$ 17,308,484	$ 16,660,545	$ 17,003,645
Seminole	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sumter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Suwannee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taylor	$ -	$ -	$ 16,459	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Volusia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wakulla	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Walton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary of Reported County Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total County Franchise Fees - Electricity	$ 123,553,216	$ 142,123,668	$ 140,330,361	$ 154,336,228	$ 157,892,282	$ 157,531,114	$ 141,763,538	$ 142,141,297	$ 138,982,436	$ 143,673,995	$ 151,906,861	$ 153,979,517	$ 151,120,281
% Change	-	15.0%	-1.3%	10.0%	2.3%	-0.2%	-10.0%	0.3%	-2.2%	3.4%	5.7%	1.4%	-1.9%
# Reporting	14	13	13	13	13	12	13	12	13	14	14	15	15
Total County Franchise Fees	$ 145,991,416	$ 171,207,441	$ 170,428,497	$ 177,647,312	$ 178,925,729	$ 178,424,425	$ 165,239,360	$ 163,361,458	$ 160,292,116	$ 164,848,421	$ 172,373,179	$ 175,193,893	$ 173,905,188
% Change	-	17.3%	-0.5%	4.2%	0.7%	-0.3%	-7.4%	-1.1%	-1.9%	2.8%	4.6%	1.6%	-0.7%
Electricity Fees as % of All Fees	84.6%	83.0%	82.3%	86.9%	88.2%	88.3%	85.8%	87.0%	86.7%	87.2%	88.1%	87.9%	86.9%

Note: This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 323.100 - Franchise Fee - Electricity and 323.XXX - Franchise Fees.

Data Source: Florida Department of Financial Services.

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alachua	Alachua	$ -	$ -	$ -	$ 221,470	$ 236,906	$ 250,833	$ 253,450	$ 236,672	$ 230,053	$ 233,483	$ 251,082	$ 253,888	$ 242,171
Archer	Alachua	$ 42,584	$ 46,929	$ 43,557	$ 102,729	$ 114,766	$ 51,174	$ 46,598	$ 43,991	$ 40,481	$ 44,895	$ 50,730	$ 45,890	$ 41,351
Gainesville	Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hawthorne	Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
High Springs	Alachua	$ 421,902	$ 249,601	$ 275,776	$ 279,757	$ 344,761	$ 338,324	$ 318,119	$ 310,876	$ 617,836	$ 366,362	$ 377,531	$ 354,928	$ 345,617
La Crosse	Alachua	$ 6,890	$ 8,011	$ 7,500	$ -	$ -	$ 11,489	$ 9,334	$ 10,702	$ 9,730	$ 13,240	$ 14,423	$ 12,482	$ 11,746
Micanopy	Alachua	$ 26,727	$ 28,768	$ 28,868	$ 27,736	$ 32,724	$ 36,127	$ 30,964	$ 29,201	$ 31,741	$ 34,030	$ 34,474	$ 32,278	$ 29,918
Newberry	Alachua	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 210,221
Waldo	Alachua	$ 45,777	$ 55,606	$ 96,436	$ -	$ 63,365	$ 65,362	$ 58,640	$ 49,665	$ -	$ 45,026	$ 53,814	$ 53,439	$ 54,131
Glen St. Mary	Baker	$ 24,884	$ 29,568	$ 30,396	$ 29,949	$ 33,075	$ 32,954	$ 31,653	$ 26,712	$ 26,551	$ 27,057	$ 29,801	$ 28,222	$ 25,836
Macclenny	Baker	$ 320,576	$ 337,273	$ 345,846	$ 423,879	$ 534,578	$ 429,475	$ 433,130	$ 399,492	$ 379,615	$ 401,978	$ 416,328	$ 416,209	$ 418,356
Callaway	Bay	$ 566,622	$ 596,817	$ 645,870	$ 665,055	$ 747,509	$ 800,500	$ 771,923	$ 684,718	$ 660,398	$ 758,112	$ 813,587	$ 912,617	$ 802,541
Lynn Haven	Bay	$ 412,626	$ 452,796	$ 475,731	$ 938,208	$ 1,161,472	$ 1,277,240	$ 1,278,586	$ 1,147,966	$ 1,075,624	$ 1,213,660	$ 1,332,461	$ 1,611,511	$ 1,359,075
Mexico Beach	Bay	$ 112,246	$ 143,360	$ 143,833	$ 145,426	$ 165,277	$ 178,824	$ 188,487	$ 153,842	$ 165,432	$ 180,692	$ 194,274	$ 159,523	$ 150,787
Panama City	Bay	$ 1,328,777	$ 1,498,664	$ 1,610,843	$ 1,656,128	$ 1,933,048	$ 2,024,977	$ 3,616,998	$ 3,798,295	$ 4,066,491	$ 4,149,647	$ 4,409,263	$ 4,373,282	$ 4,112,022
Panama City Beach	Bay	$ -	$ 1,289,416	$ 1,595,319	$ 1,821,868	$ 2,194,752	$ 2,372,629	$ 2,346,487	$ 2,223,139	$ 2,151,668	$ 2,465,568	$ 2,710,209	$ 2,834,546	$ 2,615,947
Parker	Bay	$ 242,379	$ 271,618	$ 275,471	$ 296,601	$ 324,508	$ 341,383	$ 323,766	$ 287,959	$ 277,080	$ 320,962	$ 342,274	$ 324,682	$ 277,499
Springfield	Bay	$ 377,895	$ 416,517	$ 474,741	$ 438,737	$ 450,865	$ 492,224	$ 476,818	$ 423,864	$ 409,829	$ 457,797	$ 496,528	$ -	$ -
Brooker	Bradford	$ -	$ -	$ -	$ -	$ -	$ 903	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hampton	Bradford	$ 14,013	$ 10,197	$ 15,712	$ 12,253	$ -	$ 32,326	$ 22,547	$ 15,061	$ -	$ -	$ -	$ -	$ -
Lawtey	Bradford	$ -	$ -	$ -	$ 39,339	$ -	$ 38,543	$ 38,856	$ -	$ 33,675	$ 35,437	$ 37,228	$ 31,892	$ 32,334
Starke	Bradford	$ -	$ -	$ -	$ -	$ 8,345	$ 4,084	$ 3,828	$ 19,350	$ 34,733	$ 32,020	$ -	$ -	$ -
Cape Canaveral	Brevard	$ 557,666	$ 667,698	$ 683,177	$ 692,501	$ 683,523	$ 647,499	$ 649,510	$ 600,068	$ 587,974	$ 627,771	$ 638,452	$ 635,601	$ 632,246
Cocoa	Brevard	$ 1,046,610	$ 1,297,020	$ 1,297,886	$ 1,270,693	$ 1,300,709	$ 1,180,209	$ 1,191,963	$ 1,133,030	$ 1,129,476	$ 1,183,581	$ 1,218,407	$ 1,207,955	$ 1,221,895
Cocoa Beach	Brevard	$ 986,298	$ 1,190,868	$ 1,224,051	$ 1,156,673	$ 1,190,232	$ 1,091,702	$ 1,034,146	$ 1,116,122	$ 987,689	$ 1,048,598	$ 1,068,983	$ 1,045,043	$ 1,028,861
Grant-Valkaria	Brevard	$ -	$ -	$ 212,980	$ 230,885	$ 241,875	$ 228,574	$ 225,216	$ 207,602	$ 213,748	$ 225,085	$ 229,887	$ 233,323	$ 238,871
Indialantic	Brevard	$ 183,047	$ 217,583	$ 239,690	$ 226,691	$ 227,668	$ 213,818	$ 206,211	$ 189,684	$ 188,779	$ 200,135	$ 202,543	$ 203,529	$ 199,343
Indian Harbour Beach	Brevard	$ 413,390	$ 492,869	$ 538,792	$ 529,359	$ 539,290	$ 500,037	$ 475,557	$ 454,455	$ 442,029	$ 465,408	$ 479,759	$ 471,159	$ 463,758
Malabar	Brevard	$ 181,805	$ 213,100	$ 215,623	$ 213,516	$ 228,984	$ 198,329	$ 195,544	$ 186,807	$ 190,111	$ 196,829	$ 202,770	$ 199,960	$ 202,790
Melbourne	Brevard	$ 4,974,195	$ 6,173,236	$ 6,276,793	$ 6,293,070	$ 6,431,843	$ 5,778,051	$ 5,752,188	$ 5,467,971	$ 5,377,774	$ 5,713,369	$ 5,861,859	$ 5,765,184	$ 5,850,894
Melbourne Beach	Brevard	$ 176,876	$ 208,843	$ 216,154	$ 181,843	$ 205,226	$ 195,244	$ 189,737	$ 174,417	$ 171,134	$ 179,875	$ 183,681	$ 185,974	$ 183,082
Melbourne Village	Brevard	$ 61,907	$ 74,340	$ 75,082	$ 69,725	$ 53,202	$ 45,872	$ 44,471	$ 39,912	$ 39,718	$ 42,732	$ 43,914	$ 42,446	$ 41,632
Palm Bay	Brevard	$ 4,441,916	$ 5,562,896	$ 5,637,594	$ 5,573,179	$ 5,741,378	$ 5,163,119	$ 5,011,689	$ 4,697,001	$ 4,675,829	$ 5,046,794	$ 5,150,135	$ 5,079,825	$ 5,156,938
Palm Shores	Brevard	$ 34,364	$ 36,919	$ 37,230	$ 42,587	$ 49,075	$ 50,319	$ 50,065	$ 49,311	$ 48,827	$ 53,784	$ 58,962	$ 58,442	$ 64,995
Rockledge	Brevard	$ 1,377,667	$ 1,662,341	$ 1,700,134	$ 1,682,008	$ 1,716,625	$ 1,590,914	$ 1,531,273	$ 1,478,627	$ 1,429,138	$ 1,539,818	$ 1,575,938	$ 1,524,694	$ 1,537,099
Satellite Beach	Brevard	$ 547,440	$ 653,305	$ 643,476	$ 637,067	$ 644,669	$ 603,371	$ 590,433	$ 558,333	$ 536,203	$ 591,808	$ 585,295	$ 594,514	$ 585,329
Titusville	Brevard	$ 2,092,020	$ 2,291,105	$ 2,762,179	$ 2,918,736	$ 2,925,336	$ 2,703,754	$ 2,599,200	$ 2,691,962	$ 2,607,744	$ 2,520,448	$ 2,610,766	$ 2,559,321	$ 2,604,822
West Melbourne	Brevard	$ 910,862	$ 1,107,317	$ 1,284,738	$ 1,197,833	$ 1,292,131	$ 1,246,858	$ 1,239,494	$ 1,230,101	$ 1,230,206	$ 1,335,047	$ 1,376,438	$ 1,377,674	$ 1,429,668
Coconut Creek	Broward	$ 2,383,188	$ 2,833,018	$ 3,045,084	$ 3,063,821	$ 3,054,942	$ 2,800,613	$ 2,773,296	$ 2,707,920	$ 2,656,729	$ 2,908,265	$ 2,982,771	$ 2,910,052	$ 2,985,370
Cooper City	Broward	$ 1,587,067	$ 1,840,050	$ 1,908,140	$ 1,896,251	$ 1,846,252	$ 1,711,493	$ 1,720,391	$ 1,695,675	$ 1,695,029	$ 1,858,379	$ 1,874,763	$ 1,809,441	$ 1,835,783
Coral Springs	Broward	$ 6,507,760	$ 7,931,211	$ 8,095,887	$ 8,282,502	$ 8,039,262	$ 7,165,628	$ 7,050,212	$ 6,738,442	$ 6,609,005	$ 7,095,324	$ 7,138,457	$ 6,895,938	$ 7,054,850
Dania Beach	Broward	$ 1,872,196	$ 2,197,867	$ 2,268,676	$ 2,270,251	$ 2,246,823	$ 2,041,381	$ 2,022,391	$ 1,950,481	$ 1,949,911	$ 2,116,905	$ 2,119,605	$ 2,045,658	$ 2,144,665
Davie	Broward	$ 5,355,336	$ -	$ 7,017,500	$ 6,966,990	$ 6,860,451	$ 6,194,801	$ 6,124,735	$ 5,889,619	$ 5,841,186	$ 6,382,527	$ 6,483,796	$ 6,304,101	$ 6,359,295
Deerfield Beach	Broward	$ 4,263,366	$ 5,492,939	$ 6,983,852	$ 5,877,311	$ 5,686,502	$ 5,100,276	$ 5,049,066	$ 4,865,482	$ 4,717,719	$ 5,094,646	$ 5,120,792	$ 4,961,670	$ 5,094,936
Fort Lauderdale	Broward	$ 13,909,709	$ 16,761,929	$ 17,819,523	$ 17,797,219	$ 17,633,250	$ 17,872,611	$ 16,141,012	$ 15,561,277	$ 15,140,240	$ 16,345,514	$ 16,502,787	$ 15,966,459	$ 16,305,117
Hallandale Beach	Broward	$ 2,278,360	$ 2,577,780	$ 2,724,983	$ 2,786,854	$ 2,732,867	$ 2,481,413	$ 2,519,550	$ 2,456,175	$ 2,402,527	$ 2,590,058	$ 2,609,252	$ 2,546,413	$ 2,601,554
Hillsboro Beach	Broward	$ 188,267	$ 219,054	$ 257,900	$ 245,136	$ 246,339	$ 246,086	$ 237,383	$ 216,343	$ 206,694	$ 225,760	$ 224,842	$ 219,854	$ 227,182
Hollywood	Broward	$ 8,811,193	$ 10,434,800	$ 10,736,830	$ 10,594,802	$ 10,485,470	$ 9,392,210	$ 9,431,746	$ 9,035,845	$ 8,761,378	$ 9,488,793	$ 9,522,721	$ 9,141,779	$ 9,487,474
Lauderdale Lakes	Broward	$ 1,286,543	$ 1,539,269	$ 1,612,148	$ 1,565,488	$ 1,527,934	$ 1,406,787	$ 1,407,536	$ 1,356,543	$ 1,332,302	$ 1,457,741	$ 1,489,640	$ 1,455,573	$ 1,488,026
Lauderdale-By-The-Sea	Broward	$ 451,492	$ 622,572	$ 637,905	$ 673,126	$ 685,129	$ 633,159	$ 602,298	$ 589,980	$ 573,324	$ 614,670	$ 627,109	$ 594,731	$ 605,585
Lauderhill	Broward	$ 2,282,241	$ 2,922,651	$ 3,281,621	$ 3,034,828	$ 3,190,431	$ 2,969,527	$ 2,871,472	$ 2,753,763	$ 2,683,378	$ 2,979,302	$ 3,076,304	$ 2,963,761	$ 2,965,700
Lazy Lake	Broward	$ 1,000	$ -	$ -	$ -	$ 2,573	$ 2,224	$ 2,396	$ 2,488	$ 2,256	$ 2,169	$ 2,541	$ 2,800	$ 2,862
Lighthouse Point	Broward	$ 713,584	$ 831,451	$ 918,936	$ 895,238	$ 900,765	$ 849,827	$ 812,192	$ 865,227	$ 767,419	$ 826,952	$ 839,349	$ 812,578	$ 819,340
Margate	Broward	$ 2,586,517	$ 3,045,228	$ 3,070,973	$ 2,971,816	$ 2,927,185	$ 2,684,419	$ 2,614,197	$ 2,553,154	$ 2,482,056	$ 2,686,948	$ 2,763,334	$ 2,705,628	$ 2,740,965
Miramar	Broward	$ 4,708,895	$ 5,839,055	$ 6,148,674	$ 6,318,987	$ 6,353,815	$ 6,044,951	$ 6,094,669	$ 5,886,026	$ 5,829,325	$ 6,389,778	$ 6,555,443	$ 6,396,005	$ 6,602,283
North Lauderdale	Broward	$ 1,372,313	$ 1,612,881	$ 1,642,869	$ 1,705,840	$ 1,624,932	$ 1,489,369	$ 1,490,409	$ 1,461,469	$ 1,440,963	$ 1,575,963	$ 1,616,533	$ 1,566,445	$ 1,614,948
Oakland Park	Broward	$ 2,012,204	$ 2,569,096	$ 2,856,998	$ 2,841,921	$ 2,768,332	$ 2,490,621	$ 2,455,175	$ 2,360,322	$ 2,318,315	$ 2,526,759	$ 2,555,527	$ 2,499,414	$ 2,541,188
Parkland	Broward	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pembroke Park	Broward	$ 390,415	$ 474,491	$ 578,462	$ 700,037	$ 650,134	$ 565,375	$ 578,242	$ 557,612	$ 549,335	$ 609,295	$ 616,862	$ 585,561	$ 596,657
Pembroke Pines	Broward	$ 7,448,243	$ 8,958,121	$ 9,184,098	$ 9,176,429	$ 9,208,117	$ 8,401,468	$ 8,339,056	$ 8,059,519	$ 7,852,194	$ 8,529,691	$ 8,577,202	$ 8,292,391	$ 8,507,143
Plantation	Broward	$ 5,579,266	$ 6,633,619	$ 7,566,031	$ 6,896,141	$ 6,751,937	$ 6,202,063	$ 6,028,547	$ 5,774,563	$ 5,006,920	$ 5,985,935	$ 6,672,109	$ 5,781,723	$ 5,862,402
Pompano Beach	Broward	$ 7,359,789	$ 8,670,163	$ 8,984,290	$ 8,995,884	$ 8,861,010	$ 7,817,129	$ 7,734,548	$ 7,474,946	$ 7,291,113	$ 7,067,710	$ 8,886,359	$ 8,003,831	$ 8,286,121
Sea Ranch Lakes	Broward	$ 55,812	$ 65,289	$ 69,858	$ 77,753	$ 80,030	$ 64,440	$ 63,791	$ 60,746	$ 59,356	$ 63,229	$ 63,081	$ 62,342	$ 61,340
Southwest Ranches	Broward	$ 412,328	$ 518,384	$ 577,507	$ 578,628	$ 585,780	$ 571,442	$ 573,740	$ 555,873	$ 544,508	$ 585,412	$ 585,282	$ 594,422	$ 593,117
Sunrise	Broward	$ 5,292,515	$ 5,928,168	$ 6,131,307	$ 6,139,228	$ 6,234,903	$ 6,165,104	$ 5,495,708	$ 5,322,020	$ 5,282,356	$ 5,603,231	$ 5,648,641	$ 5,458,527	$ 5,590,624
Tamarac	Broward	$ 3,060,737	$ 3,603,109	$ 3,652,848	$ 3,590,765	$ 3,525,046	$ 3,247,694	$ 3,126,258	$ 3,058,986	$ 4,714,972	$ 3,112,666	$ 3,241,970	$ 3,145,708	$ 3,202,430
West Park	Broward	$ 150,645	$ 542,031	$ 581,035	$ 559,939	$ 550,073	$ 512,727	$ 505,968	$ 495,192	$ 484,197	$ 471,534	$ 524,775	$ 533,015	$ 556,735
Weston	Broward	$ 3,519,731	$ 4,263,679	$ 4,347,976	$ 4,326,474	$ 4,305,680	$ 4,129,670	$ 4,101,096	$ 3,902,012	$ 3,741,992	$ 4,006,947	$ 4,006,341	$ 3,838,753	$ 3,888,555
Wilton Manors	Broward	$ 628,226	$ 747,103	$ 719,424	$ 1,009,522	$ 811,339	$ 757,399	$ 750,266	$ 726,228	$ 717,779	$ 782,349	$ 788,662	$ 760,857	$ 770,075

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Altha	Calhoun	$ 20,600	$ 19,773	$ 20,657	$ 36,526	$ 41,326	$ 51,746	$ 31,712	$ 31,921	$ 38,897	$ 30,978	$ 40,959	$ 43,595	$ -
Blountstown	Calhoun	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Punta Gorda	Charlotte	$ 1,097,441	$ 1,304,970	$ 1,316,010	$ 1,350,700	$ 1,435,888	$ 1,340,371	$ 1,311,751	$ 1,217,206	$ 1,198,571	$ 1,322,464	$ 1,356,841	$ 1,347,826	$ 1,372,943
Crystal River	Citrus	$ 366,429	$ 428,137	$ 432,817	$ 421,803	$ 457,393	$ 495,655	$ 465,007	$ 423,928	$ 432,058	$ 460,426	$ 466,331	$ 436,921	$ 427,606
Inverness	Citrus	$ 509,407	$ 604,374	$ 608,068	$ 592,095	$ 658,800	$ 691,761	$ 637,754	$ 604,242	$ 635,238	$ 673,481	$ 675,374	$ 636,388	$ 616,270
Green Cove Springs	Clay	$ -	$ -	$ -	$ -	$ -	$ 63,280	$ 33,840	$ 33,615	$ -	$ -	$ -	$ -	$ -
Keystone Heights	Clay	$ 55,432	$ 53,113	$ 60,811	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orange Park	Clay	$ 545,738	$ 671,564	$ 670,748	$ 735,938	$ -	$ 858,724	$ 914,739	$ 819,554	$ 782,043	$ -	$ -	$ 768,322	$ 741,193
Penney Farms	Clay	$ 30,469	$ 36,650	$ 38,680	$ 37,030	$ 39,065	$ 36,882	$ 37,289	$ 34,270	$ 32,749	$ 35,692	$ 36,176	$ 32,700	$ 33,435
Everglades	Collier	$ 23,433	$ -	$ -	$ -	$ 31,605	$ 92,363	$ 2,932	$ 2,079	$ -	$ -	$ -	$ -	$ -
Marco Island	Collier	$ 1,531,856	$ 1,882,013	$ 1,913,134	$ 1,920,620	$ 1,610,117	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Naples	Collier	$ 3,141,221	$ 3,791,989	$ 3,832,371	$ 3,703,141	$ 3,903,008	$ 3,420,527	$ 3,394,918	$ 3,286,415	$ 3,215,470	$ 3,482,532	$ 3,459,483	$ 3,352,393	$ 3,426,061
Fort White	Columbia	$ 22,542	$ 31,925	$ 39,676	$ 38,206	$ 45,927	$ 42,971	$ 43,344	$ 38,125	$ 38,304	$ 35,217	$ 36,974	$ 33,927	$ 32,817
Lake City	Columbia	$ 944,156	$ 1,133,685	$ 1,242,297	$ 1,248,149	$ 1,339,765	$ 1,210,237	$ 1,170,416	$ 1,096,609	$ 1,051,855	$ 1,113,851	$ 1,243,488	$ 1,128,322	$ 1,150,784
Arcadia	De Soto	$ 458,043	$ 624,740	$ 647,771	$ 494,464	$ 475,917	$ 428,920	$ 418,752	$ 389,506	$ 376,476	$ 436,729	$ 457,200	$ 437,918	$ 446,949
Cross City	Dixie	$ 102,805	$ 111,821	$ 110,328	$ 106,056	$ 109,016	$ 131,586	$ 124,547	$ 113,188	$ 108,049	$ 116,883	$ 120,235	$ 110,439	$ 109,017
Horseshoe Beach	Dixie	$ 15,101	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Atlantic Beach	Duval	$ 613,049	$ 717,986	$ 696,477	$ 769,237	$ 893,612	$ 901,589	$ 930,890	$ 832,138	$ 799,803	$ 826,988	$ 823,306	$ 800,345	$ 767,689
Baldwin	Duval	$ 89,735	$ 98,992	$ 94,774	$ 115,957	$ 126,766	$ 131,332	$ 124,174	$ 140,715	$ 112,040	$ 89,709	$ 121,621	$ 119,129	$ 104,959
Jacksonville	Duval	$ -	$ -	$ -	$ -	$ 31,000,365	$ 30,706,114	$ 32,591,566	$ 29,461,951	$ 27,888,771	$ 29,264,768	$ 29,463,637	$ 28,812,166	$ 27,709,859
Jacksonville Beach	Duval	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Neptune Beach	Duval	$ 283,515	$ 256,220	$ 211,846	$ 233,985	$ 227,387	$ 239,409	$ 241,795	$ 224,175	$ 218,353	$ 224,558	$ 224,030	$ 224,274	$ 216,038
Century	Escambia	$ 53,258	$ 103,990	$ 86,617	$ 92,898	$ 104,633	$ 80,823	$ 133,653	$ 103,019	$ 91,366	$ -	$ 106,663	$ 96,028	$ 93,336
Pensacola	Escambia	$ 4,062,816	$ 4,623,060	$ 4,972,086	$ 5,049,347	$ 5,802,384	$ 6,240,353	$ 6,158,610	$ 5,504,301	$ 5,152,478	$ 5,792,684	$ 6,110,497	$ 5,879,605	$ 5,687,912
Beverly Beach	Flagler	$ 19,804	$ 21,689	$ 21,641	$ 20,864	$ -	$ -	$ -	$ -	$ 28,338	$ 28,795	$ 30,597	$ 29,349	$ 30,334
Bunnell	Flagler	$ 135,832	$ 181,023	$ 205,104	$ 260,068	$ 243,315	$ 213,722	$ 239,362	$ 219,767	$ 221,422	$ 242,530	$ 251,213	$ 252,194	$ 255,283
Palm Coast	Flagler	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marineland	Flagler/St. Johns	$ 9,670	$ 12,934	$ 11,017	$ 9,323	$ 30,666	$ 16,345	$ 15,837	$ 14,008	$ 13,690	$ 17,547	$ 19,424	$ 20,126	$ 19,696
Flagler Beach	Flagler/Volusia	$ 262,263	$ 314,509	$ 288,629	$ 283,642	$ 304,667	$ 302,196	$ 296,516	$ 271,454	$ 277,502	$ 304,516	$ 309,318	$ 309,847	$ 303,935
Apalachicola	Franklin	$ 130,216	$ 156,752	$ 165,060	$ 163,278	$ 173,127	$ 185,173	$ 182,341	$ 147,570	$ 144,720	$ 156,442	$ 158,518	$ 134,423	$ -
Carrabelle	Franklin	$ 115,433	$ 138,501	$ 107,993	$ 90,401	$ 106,105	$ 101,375	$ 107,971	$ 96,004	$ 91,476	$ 100,619	$ 102,735	$ 93,717	$ 90,404
Chattahoochee	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Greensboro	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gretna	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Havana	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Midway	Gadsden	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Quincy	Gadsden	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bell	Gilchrist	$ 31,453	$ 40,552	$ 40,595	$ 64,873	$ 63,304	$ 67,432	$ 67,028	$ 61,275	$ 58,621	$ 59,871	$ 61,573	$ 60,129	$ 61,064
Trenton	Gilchrist	$ 85,008	$ 94,309	$ 99,592	$ 94,389	$ 100,020	$ 121,120	$ 107,697	$ 97,223	$ 89,719	$ -	$ 118,362	$ 123,005	$ 93,139
Fanning Springs	Gilchrist/Levy	$ 42,345	$ 51,352	$ 51,343	$ 51,126	$ 54,446	$ 58,636	$ 55,347	$ 51,665	$ 48,687	$ 55,492	$ 57,813	$ 54,304	$ 56,287
Moore Haven	Glades	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Port St. Joe	Gulf	$ 141,148	$ 180,497	$ 186,951	$ 184,489	$ 203,889	$ 199,083	$ 204,749	$ 186,408	$ -	$ -	$ -	$ -	$ -
Wewahitchka	Gulf	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jasper	Hamilton	$ 82,364	$ 102,084	$ 104,064	$ 71,153	$ 101,208	$ 108,640	$ 72,674	$ 69,071	$ 104,919	$ 112,851	$ 116,007	$ 104,446	$ 102,260
Jennings	Hamilton	$ 36,124	$ 47,405	$ 39,224	$ 41,097	$ 45,734	$ 48,438	$ 44,136	$ 41,082	$ 38,537	$ 42,526	$ 41,522	$ 37,095	$ 36,233
White Springs	Hamilton	$ 34,648	$ 36,863	$ 34,106	$ 33,897	$ 37,933	$ 41,096	$ 37,318	$ 31,209	$ 28,966	$ 40,206	$ 39,481	$ 33,968	$ 33,314
Bowling Green	Hardee	$ 74,524	$ 85,606	$ 81,610	$ 93,521	$ 91,212	$ 101,561	$ 102,384	$ 82,509	$ 85,771	$ 92,385	$ 92,853	$ 85,507	$ 84,552
Wauchula	Hardee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Zolfo Springs	Hardee	$ 56,298	$ 72,527	$ 65,990	$ 76,289	$ 71,678	$ 83,296	$ 78,086	$ 65,278	$ 64,829	$ 73,444	$ 70,928	$ 71,207	$ 67,682
Clewiston	Hendry	$ 5,091	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LaBelle	Hendry	$ 272,485	$ 291,926	$ 337,799	$ 332,997	$ 343,360	$ 326,532	$ 312,146	$ 292,228	$ 276,535	$ 297,308	$ 306,739	$ 303,257	$ 321,001
Brooksville	Hernando	$ 501,562	$ 580,514	$ 574,367	$ 594,958	$ 706,233	$ 739,233	$ 672,875	$ 726,801	$ 603,249	$ 646,379	$ 663,932	$ 641,199	$ 657,603
Weeki Wachee	Hernando	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Avon Park	Highlands	$ 429,904	$ 501,246	$ 525,566	$ 506,834	$ 573,547	$ 588,423	$ 532,794	$ 523,526	$ 497,712	$ 557,744	$ 598,581	$ 564,046	$ 566,678
Lake Placid	Highlands	$ 155,241	$ 184,963	$ 189,504	$ 188,267	$ 202,111	$ 211,300	$ 195,032	$ 191,865	$ 183,986	$ 193,588	$ 187,211	$ 196,222	$ 200,239
Sebring	Highlands	$ 715,861	$ 879,373	$ 956,317	$ 845,665	$ 996,516	$ 1,052,651	$ 979,805	$ 944,095	$ 874,166	$ 941,890	$ 962,883	$ 904,630	$ 891,448
Plant City	Hillsborough	$ 2,081,123	$ 2,297,086	$ 2,477,595	$ 2,450,539	$ 2,474,062	$ 2,432,326	$ 3,506,028	$ 3,491,415	$ 3,415,770	$ 3,649,778	$ 3,743,714	$ 3,850,723	$ 3,767,920
Tampa	Hillsborough	$ 21,686,857	$ 24,214,731	$ 25,926,448	$ 25,702,784	$ 27,122,835	$ 27,209,322	$ 25,246,733	$ 31,646,686	$ 30,893,083	$ 32,525,857	$ 32,599,520	$ 32,865,597	$ 31,414,082
Temple Terrace	Hillsborough	$ 1,423,006	$ 1,602,668	$ 1,919,658	$ 1,776,564	$ 1,958,555	$ 1,971,044	$ 1,840,769	$ 1,764,912	$ 1,683,010	$ 1,754,960	$ 1,794,871	$ 1,796,658	$ 1,733,206
Bonifay	Holmes	$ 93,394	$ 100,198	$ 108,955	$ 110,444	$ 124,905	$ 135,269	$ 134,433	$ 120,152	$ 112,491	$ 183,648	$ 258,360	$ 247,285	$ 244,075
Esto	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,823	$ -
Noma	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,308	$ -
Ponce de Leon	Holmes	$ 23,129	$ 27,623	$ 31,453	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,648
Westville	Holmes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fellsmere	Indian River	$ 83,687	$ 108,161	$ 106,683	$ 131,557	$ 178,358	$ 169,327	$ 170,944	$ 168,876	$ 176,807	$ 194,322	$ 203,444	$ 206,795	$ 204,114
Indian River Shores	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Orchid	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sebastian	Indian River	$ 836,694	$ 1,203,191	$ 1,055,082	$ 1,140,994	$ 1,260,484	$ 1,159,433	$ 1,117,525	$ 1,052,299	$ 1,040,067	$ 1,119,166	$ 1,164,863	$ 1,163,216	$ 1,169,540
Vero Beach	Indian River	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Alford	Jackson	$ 15,000	$ -	$ 21,267	$ 26,115	$ 32,898	$ 40,856	$ 33,918	$ 35,174	$ 31,015	$ 31,403	$ 30,886	$ 31,466	$ 29,489
Bascom	Jackson	$ 2,337	$ 2,609	$ 2,626	$ 3,685	$ 4,078	$ 4,626	$ 4,626	$ 3,827	$ 4,152	$ 3,977	$ 3,837	$ 3,752	$ 3,967
Campbellton	Jackson	$ 6,071	$ 6,460	$ 6,630	$ 6,506	$ 9,052	$ 9,411	$ 8,965	$ 7,932	$ 7,727	$ 14,981	$ 18,990	$ 16,829	$ 15,863
Cottondale	Jackson	$ 46,966	$ 48,895	$ -	$ 60,446	$ 82,853	$ 102,409	$ 84,788	$ 73,002	$ 71,522	$ 72,628	$ 78,379	$ 76,928	$ 74,834
Graceville	Jackson	$ 61,000	$ 69,367	$ 80,094	$ 77,302	$ 98,497	$ 102,036	$ 100,544	$ 91,883	$ 86,886	$ 97,454	$ 103,083	$ 101,380	$ 101,238
Grand Ridge	Jackson	$ 25,676	$ -	$ 30,273	$ 31,947	$ 36,707	$ 35,780	$ 36,427	$ 33,977	$ 33,801	$ 35,698	$ 36,992	$ 33,466	$ 33,376
Greenwood	Jackson	$ 11,690	$ 16,862	$ 26,861	$ 33,203	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jacob City	Jackson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Malone	Jackson	$ 32,491	$ 45,623	$ 52,088	$ 67,090	$ 76,598	$ 92,546	$ 79,672	$ 82,734	$ 75,304	$ 74,869	$ 86,209	$ 82,715	$ 79,915
Marianna	Jackson	$ 353,100	$ 369,000	$ 379,800	$ 552,285	$ 913,484	$ 916,846	$ 870,207	$ 806,691	$ 864,387	$ 888,528	$ 960,777	$ 939,971	$ 936,425
Sneads	Jackson	$ 75,615	$ 87,875	$ 88,827	$ 93,408	$ 98,118	$ 102,155	$ 97,326	$ 93,438	$ 93,395	$ 103,797	$ 102,895	$ 97,955	$ 94,203
Monticello	Jefferson	$ 127,809	$ 154,488	$ 139,631	$ 148,340	$ 166,959	$ 185,515	$ 177,768	$ 172,509	$ 201,362	$ 229,885	$ 204,396	$ 168,713	$ 165,963
Mayo	Lafayette	$ 41,575	$ 50,101	$ 58,137	$ 51,346	$ 56,306	$ 58,752	$ 50,198	$ 49,889	$ 45,411	$ 49,980	$ 56,597	$ 51,710	$ 52,629
Astatula	Lake	$ 69,523	$ 80,935	$ 76,071	$ 86,312	$ 68,349	$ 74,042	$ 71,216	$ 61,173	$ 58,415	$ 58,427	$ 66,483	$ 67,504	$ 68,255
Clermont	Lake	$ 1,169,638	$ 1,494,872	$ 1,599,583	$ 1,678,227	$ 1,933,677	$ 2,154,843	$ 2,068,814	$ 1,995,234	$ 1,899,998	$ 2,128,620	$ 2,222,476	$ 2,448,126	$ -
Eustis	Lake	$ 932,538	$ 1,107,760	$ 1,166,947	$ 1,146,237	$ 1,249,754	$ 1,336,960	$ 1,219,537	$ 1,177,526	$ 1,092,308	$ 1,279,837	$ 1,235,257	$ 1,265,415	$ 1,262,384
Fruitland Park	Lake	$ 211,320	$ 257,771	$ 278,894	$ 318,612	$ 348,609	$ 342,910	$ 320,396	$ 284,303	$ 301,254	$ 318,062	$ 323,494	$ 298,477	$ 483,903
Groveland	Lake	$ 228,587	$ 318,178	$ 355,694	$ 379,150	$ 421,006	$ 474,517	$ 455,872	$ 459,279	$ 467,171	$ 534,539	$ 590,042	$ 609,882	$ 691,037
Howey-in-the-Hills	Lake	$ 55,793	$ 75,980	$ 63,240	$ -	$ 67,980	$ 74,741	$ 67,024	$ 63,960	$ 58,440	$ 63,234	$ 67,233	$ 70,846	$ 71,287
Lady Lake	Lake	$ 772,785	$ 946,571	$ 938,773	$ 958,601	$ 1,117,179	$ 1,264,885	$ 1,177,072	$ 1,111,871	$ 1,091,998	$ 1,198,983	$ 1,189,796	$ 1,170,898	$ 1,162,809
Leesburg	Lake	$ 12,770	$ 15,714	$ 25,498	$ 37,835	$ 42,496	$ 48,296	$ 48,180	$ 54,384	$ 54,995	$ 63,162	$ 157,912	$ 185,916	$ 207,474
Mascotte	Lake	$ 117,995	$ 157,286	$ 162,663	$ 171,220	$ 189,378	$ 203,607	$ 195,880	$ 180,958	$ 178,907	$ 193,502	$ 202,020	$ 221,722	$ 193,265
Minneola	Lake	$ -	$ 377,611	$ 387,161	$ 394,580	$ 442,793	$ 490,096	$ 476,418	$ 448,954	$ 442,249	$ 490,840	$ 511,750	$ 516,167	$ 523,144
Montverde	Lake	$ 63,561	$ 82,007	$ 76,205	$ 96,672	$ 88,946	$ 95,431	$ 89,669	$ 86,033	$ 87,477	$ 93,516	$ 93,342	$ 106,841	$ -
Mount Dora	Lake	$ 268,101	$ 319,110	$ 340,261	$ 359,160	$ 412,893	$ 447,214	$ 444,303	$ 415,892	$ 398,975	$ 481,834	$ 456,144	$ 469,055	$ 465,258
Tavares	Lake	$ 667,328	$ 812,941	$ 840,086	$ 872,361	$ 969,699	$ 1,039,617	$ 1,000,206	$ 945,806	$ 921,014	$ 1,000,695	$ 1,031,992	$ 1,042,067	$ 1,045,062
Umatilla	Lake	$ 149,507	$ 181,141	$ 177,160	$ 173,359	$ 197,579	$ -	$ 216,346	$ 205,115	$ 195,522	$ 235,143	$ 217,540	$ 229,059	$ 223,685
Bonita Springs	Lee	$ 1,477,608	$ 1,829,649	$ 1,952,087	$ 1,957,041	$ 1,974,467	$ 1,782,542	$ 2,042,563	$ 1,967,312	$ 1,950,904	$ 1,866,256	$ 1,918,396	$ 1,940,148	$ 2,554,862
Cape Coral	Lee	$ 3,774,618	$ 4,589,753	$ 5,025,118	$ 5,003,339	$ 5,351,886	$ 5,646,428	$ 5,496,923	$ 5,429,804	$ 5,148,353	$ 5,539,844	$ 5,546,040	$ 5,603,329	$ 5,361,712
Estero	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,713,134	$ 2,058,820
Fort Myers	Lee	$ 4,032,445	$ 5,082,057	$ 5,579,511	$ 5,788,331	$ 5,893,656	$ 5,161,624	$ 5,197,931	$ 5,016,768	$ 4,948,431	$ 5,369,141	$ 5,456,566	$ 5,418,009	$ 5,656,824
Fort Myers Beach	Lee	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sanibel	Lee	$ 389,993	$ 444,188	$ 508,879	$ 510,284	$ 512,625	$ 568,000	$ 583,639	$ 561,067	$ 540,803	$ 537,436	$ 546,098	$ 550,647	$ 522,715
Tallahassee	Leon	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bronson	Levy	$ -	$ -	$ 69,979	$ 71,518	$ 80,064	$ 85,580	$ 80,699	$ 75,418	$ 75,598	$ 78,562	$ 82,943	$ 82,967	$ 83,913
Cedar Key	Levy	$ 38,709	$ 45,913	$ 44,464	$ 44,262	$ 47,155	$ 51,491	$ 49,661	$ 48,574	$ 47,533	$ 51,384	$ 54,698	$ 52,692	$ 49,775
Chiefland	Levy	$ 202,238	$ 235,927	$ 241,669	$ 255,643	$ 272,373	$ 289,815	$ 277,629	$ 269,271	$ 257,118	$ 271,254	$ 271,325	$ 263,939	$ 245,999
Inglis	Levy	$ 79,987	$ 94,262	$ 91,067	$ 94,903	$ 105,657	$ 108,871	$ 98,519	$ 89,800	$ 87,571	$ 92,382	$ 91,004	$ 83,621	$ 78,448
Otter Creek	Levy	$ 4,983	$ 6,099	$ 5,658	$ 5,542	$ 5,962	$ 6,443	$ 6,491	$ 5,819	$ 5,762	$ 5,472	$ 5,295	$ 5,621	$ 5,233
Williston	Levy	$ 31,540	$ 40,195	$ 39,294	$ 40,125	$ 27,008	$ 31,070	$ 36,685	$ 36,484	$ 21,784	$ 42,365	$ 47,931	$ 52,877	$ 47,931
Yankeetown	Levy	$ 31,333	$ 41,836	$ 35,627	$ 36,046	$ 38,268	$ 42,912	$ 40,063	$ 36,359	$ 35,278	$ 37,523	$ 40,927	$ 41,410	$ 41,827
Bristol	Liberty	$ 29,291	$ 27,202	$ 27,455	$ 42,366	$ 52,464	$ 61,006	$ 59,634	$ 54,854	$ 47,860	$ 48,647	$ 51,970	$ 51,463	$ 62,728
Greenville	Madison	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lee	Madison	$ 14,997	$ 17,394	$ 18,300	$ 18,773	$ 19,975	$ 21,441	$ 19,164	$ 16,942	$ 16,207	$ 17,830	$ 21,089	$ 18,607	$ 18,325
Madison	Madison	$ 167,162	$ 208,651	$ 212,023	$ 206,579	$ 230,267	$ 246,112	$ 228,525	$ 209,380	$ 200,640	$ 223,501	$ 225,966	$ 205,181	$ 201,231
Anna Maria	Manatee	$ 126,755	$ 153,259	$ 154,795	$ 153,423	$ 164,901	$ 160,657	$ 160,652	$ 154,131	$ 160,786	$ 182,150	$ 191,395	$ 191,153	$ 198,852
Bradenton	Manatee	$ 2,728,834	$ 3,465,543	$ 3,391,904	$ 3,261,363	$ 3,304,933	$ 2,970,333	$ 2,963,536	$ 2,830,719	$ 2,770,869	$ 2,983,206	$ 3,052,001	$ 2,991,554	$ 3,030,672
Bradenton Beach	Manatee	$ 118,529	$ 160,590	$ 141,116	$ 123,196	$ 166,263	$ 140,735	$ 158,312	$ 107,915	$ 134,681	$ 145,973	$ 155,871	$ 151,421	$ 154,824
Holmes Beach	Manatee	$ 333,174	$ 391,610	$ 443,043	$ 405,387	$ 424,017	$ 402,298	$ 407,989	$ 386,992	$ 388,512	$ 434,568	$ 446,657	$ 438,404	$ 450,764
Palmetto	Manatee	$ 497,608	$ 656,332	$ 745,697	$ 745,800	$ 775,603	$ 708,104	$ 801,522	$ 824,763	$ 802,827	$ 847,041	$ 896,789	$ 839,318	$ 875,583
Longboat Key	Manatee/Sarasota	$ 871,853	$ 1,008,427	$ 1,037,110	$ 1,020,078	$ 1,045,372	$ 957,198	$ 925,048	$ 843,299	$ 752,764	$ 900,863	$ 938,891	$ 904,202	$ 900,983
Belleview	Marion	$ 292,307	$ 380,290	$ 354,307	$ 369,038	$ 398,092	$ 427,006	$ 475,789	$ 378,532	$ 367,674	$ 390,348	$ 404,093	$ 379,596	$ 372,900
Dunnellon	Marion	$ 167,490	$ 198,972	$ 199,958	$ 192,324	$ 434,495	$ 230,817	$ 209,157	$ 191,867	$ 184,393	$ 191,182	$ 193,097	$ 175,111	$ 174,215
McIntosh	Marion	$ 28,420	$ 28,878	$ 27,570	$ 27,117	$ 28,658	$ 28,797	$ 30,122	$ 25,694	$ 25,368	$ 32,475	$ 29,271	$ 29,008	$ 32,240
Ocala	Marion	$ 76,165	$ 132,042	$ 179,252	$ 262,381	$ 311,401	$ 369,415	$ 346,496	$ 343,946	$ 340,139	$ 364,479	$ 511,755	$ 498,888	$ 507,360
Reddick	Marion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jupiter Island	Martin	$ 120,759	$ 145,953	$ 180,090	$ 177,390	$ 208,723	$ 206,102	$ 220,983	$ 201,155	$ 89,492	$ -	$ -	$ -	$ -
Ocean Breeze	Martin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sewall's Point	Martin	$ 135,362	$ 163,592	$ 167,490	$ 168,628	$ 191,253	$ 182,553	$ 171,957	$ 184,122	$ 148,903	$ 172,688	$ 173,363	$ 188,527	$ 176,370
Stuart	Martin	$ 1,322,769	$ 1,751,010	$ 1,744,532	$ 1,748,832	$ 1,873,808	$ 1,596,946	$ 1,625,007	$ 1,564,982	$ 1,519,687	$ 1,707,844	$ 1,665,419	$ 1,606,853	$ 1,628,841
Aventura	Miami-Dade	$ 1,980,272	$ 2,906,200	$ 3,760,394	$ 3,762,159	$ 3,130,232	$ 3,196,576	$ 2,212,081	$ 2,580,362	$ 2,328,313	$ 1,730,392	$ 1,758,766	$ 1,780,409	$ 1,367,326
Bal Harbour	Miami-Dade	$ 511,693	$ 617,026	$ 637,186	$ 657,595	$ 669,745	$ 579,548	$ 637,215	$ 665,588	$ 652,063	$ 809,083	$ 664,606	$ 635,369	$ 646,820
Bay Harbor Islands	Miami-Dade	$ 291,150	$ 330,646	$ 357,864	$ 358,628	$ 345,739	$ 318,734	$ 339,235	$ 323,705	$ 326,737	$ 348,953	$ 340,093	$ 328,791	$ 337,858
Biscayne Park	Miami-Dade	$ 107,703	$ 122,750	$ 125,523	$ 115,686	$ 112,916	$ 120,595	$ 122,163	$ 111,947	$ 112,685	$ 124,651	$ 126,385	$ 123,214	$ 136,790
Coral Gables	Miami-Dade	$ 4,416,461	$ 5,338,021	$ 5,518,767	$ 5,518,706	$ 5,470,371	$ 4,682,462	$ 4,498,854	$ 4,606,645	$ 4,546,595	$ 4,924,276	$ 4,932,774	$ 4,695,166	$ 4,718,492
Cutler Bay	Miami-Dade	$ -	$ 960,000	$ 1,373,216	$ 1,563,517	$ 1,625,066	$ 1,669,404	$ 1,219,797	$ 1,415,237	$ 1,314,553	$ 991,457	$ 1,034,676	$ 1,070,875	$ 840,932
Doral	Miami-Dade	$ 1,480,502	$ 1,774,080	$ 2,398,014	$ 4,704,277	$ 4,945,893	$ 4,991,887	$ 3,563,838	$ 4,136,741	$ 3,804,585	$ 2,893,883	$ 2,998,896	$ 3,033,418	$ 2,464,185
El Portal	Miami-Dade	$ 76,869	$ 108,453	$ 108,819	$ 106,811	$ 93,404	$ 89,342	$ 87,700	$ 83,557	$ 81,770	$ 88,794	$ 88,141	$ 82,830	$ 87,623
Florida City	Miami-Dade	$ 403,923	$ 493,908	$ 503,862	$ 579,217	$ 650,397	$ 537,019	$ 501,814	$ 559,738	$ 550,210	$ 602,210	$ 612,573	$ 608,833	$ 636,789

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Golden Beach	Miami-Dade	$ 94,450	$ 108,905	$ 119,340	$ 121,120	$ 131,809	$ 116,581	$ 112,680	$ 108,876	$ 108,619	$ 117,302	$ 119,175	$ 117,232	$ 120,051
Hialeah	Miami-Dade	$ 8,574,100	$ 10,548,228	$ 11,469,814	$ 11,344,580	$ 11,174,635	$ 9,957,417	$ 10,104,878	$ 9,972,894	$ 9,828,418	$ 10,627,308	$ 10,692,680	$ 15,723,781	$ 10,615,985
Hialeah Gardens	Miami-Dade	$ 668,185	$ 820,764	$ 906,639	$ 1,017,141	$ 1,051,650	$ 914,010	$ 909,495	$ 906,820	$ 877,192	$ 968,124	$ 1,034,644	$ 993,258	$ 1,017,980
Homestead	Miami-Dade	$ 1,682,412	$ 2,548,933	$ 2,548,933	$ 2,095,401	$ 2,065,706	$ 2,056,218	$ 2,083,687	$ 2,176,224	$ 2,261,120	$ 2,228,348	$ 2,296,795	$ 2,376,211	$ 2,545,411
Indian Creek	Miami-Dade	$ 28,442	$ 38,014	$ 47,279	$ 46,440	$ 53,892	$ 52,520	$ 50,127	$ 51,713	$ 49,394	$ 49,408	$ 50,472	$ 46,818	$ 46,632
Key Biscayne	Miami-Dade	$ 705,810	$ 1,088,929	$ 1,113,194	$ 1,064,666	$ 992,997	$ 1,006,415	$ 735,519	$ 846,252	$ 780,245	$ 574,639	$ 595,196	$ 603,889	$ 479,194
Medley	Miami-Dade	$ 852,039	$ 1,105,592	$ 1,175,680	$ 1,226,641	$ 1,072,289	$ 883,416	$ 863,375	$ 836,114	$ 840,745	$ 913,199	$ 951,582	$ 938,015	$ 948,886
Miami	Miami-Dade	$ 25,463,385	$ 22,676,598	$ 24,606,313	$ 24,797,619	$ 25,131,826	$ 25,119,661	$ 26,500,677	$ 26,257,819	$ 25,754,584	$ 27,749,562	$ 27,759,575	$ 27,245,268	$ 28,160,663
Miami Beach	Miami-Dade	$ 6,384,499	$ 7,448,932	$ 8,169,741	$ 8,218,820	$ 8,651,684	$ 7,928,026	$ 7,505,515	$ 8,795,911	$ 7,323,875	$ 7,797,977	$ 7,919,096	$ 7,610,697	$ 7,677,290
Miami Gardens	Miami-Dade	$ 2,423,973	$ 4,069,708	$ 3,477,481	$ 4,188,860	$ 3,978,584	$ 4,038,941	$ 2,957,525	$ 3,358,782	$ 3,023,802	$ 2,182,229	$ 2,251,440	$ 2,304,714	$ 1,782,675
Miami Lakes	Miami-Dade	$ 1,263,596	$ 1,579,595	$ 2,079,921	$ 2,001,376	$ 1,967,915	$ 2,008,171	$ 1,444,179	$ 1,673,746	$ 1,550,625	$ 1,147,889	$ 1,160,066	$ 1,179,362	$ 925,699
Miami Shores	Miami-Dade	$ 550,245	$ 675,768	$ 696,434	$ 675,811	$ 673,853	$ 708,239	$ 652,393	$ 624,427	$ 613,880	$ 662,529	$ 665,046	$ 646,550	$ 629,267
Miami Springs	Miami-Dade	$ 797,020	$ 966,572	$ 961,583	$ 889,258	$ 903,118	$ 816,375	$ 798,665	$ 789,584	$ 776,757	$ 833,793	$ 828,120	$ 803,217	$ 817,653
North Bay	Miami-Dade	$ 285,868	$ 412,621	$ 349,850	$ 407,627	$ 406,972	$ 366,318	$ 366,318	$ 358,848	$ 363,253	$ 408,755	$ 420,796	$ 421,858	$ 432,855
North Miami	Miami-Dade	$ 2,310,141	$ 2,905,463	$ 3,032,246	$ 2,863,689	$ 2,834,321	$ 2,607,189	$ 2,676,516	$ 2,550,538	$ 2,550,826	$ -	$ 2,791,495	$ 2,470,978	$ 2,788,249
North Miami Beach	Miami-Dade	$ 1,396,019	$ 1,733,317	$ 1,845,440	$ 1,823,667	$ 2,253,705	$ 2,166,762	$ 1,947,075	$ 1,883,861	$ 1,838,292	$ 1,999,296	$ 2,004,278	$ 1,993,250	$ 2,051,760
Opa-locka	Miami-Dade	$ 655,753	$ 1,210,496	$ 1,121,431	$ 872,976	$ 1,075,527	$ 963,009	$ 1,028,182	$ 986,134	$ 964,279	$ 1,059,655	$ 1,092,685	$ -	$ -
Palmetto Bay	Miami-Dade	$ 828,052	$ 837,003	$ 1,169,359	$ 1,371,130	$ 1,308,472	$ 1,345,736	$ 960,331	$ 1,101,516	$ 1,016,281	$ 829,882	$ 787,127	$ 800,852	$ 599,893
Pinecrest	Miami-Dade	$ 950,314	$ 1,367,111	$ 1,746,727	$ 1,705,563	$ 1,317,317	$ 1,343,813	$ 986,201	$ 1,119,946	$ 1,033,041	$ 766,046	$ 785,242	$ 800,440	$ 631,386
South Miami	Miami-Dade	$ 784,923	$ 977,142	$ 1,083,944	$ 1,115,721	$ 1,197,171	$ 1,069,053	$ 1,036,304	$ 1,018,050	$ 981,428	$ 1,022,439	$ 1,239,099	$ 1,069,285	$ 1,069,314
Sunny Isles Beach	Miami-Dade	$ 762,516	$ 1,129,812	$ 1,528,521	$ 1,627,264	$ 1,426,449	$ 1,564,781	$ 1,098,671	$ 1,284,676	$ 1,188,084	$ 885,727	$ 919,150	$ 934,540	$ 728,466
Surfside	Miami-Dade	$ 361,722	$ 434,977	$ 442,273	$ 432,283	$ 416,728	$ 385,837	$ 391,566	$ 376,976	$ 368,011	$ 412,044	$ 419,414	$ 402,903	$ 449,757
Sweetwater	Miami-Dade	$ 408,908	$ 483,341	$ 502,933	$ 502,566	$ 490,957	$ 447,544	$ 432,233	$ 474,525	$ 446,972	$ 477,809	$ 491,605	$ 560,563	$ 764,055
Virginia Gardens	Miami-Dade	$ 146,208	$ 188,657	$ 209,940	$ 209,356	$ 212,043	$ 183,864	$ 177,425	$ 178,588	$ 170,325	$ 192,512	$ 188,497	$ 181,378	$ 179,368
West Miami	Miami-Dade	$ 202,746	$ 235,603	$ 284,491	$ 287,745	$ 297,570	$ 278,762	$ 270,730	$ 268,655	$ 257,628	$ 277,061	$ 287,248	$ 298,317	$ 313,659
Islamorada	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key Colony Beach	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Key West	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Layton	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marathon	Monroe	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Callahan	Nassau	$ 121,497	$ 142,147	$ 152,804	$ 153,303	$ 163,298	$ 145,655	$ 129,464	$ 130,610	$ 128,457	$ 120,156	$ 133,584	$ 127,118	$ 119,785
Fernandina Beach	Nassau	$ 822,067	$ 831,604	$ 1,292,915	$ 1,467,039	$ 1,758,124	$ 1,847,508	$ 1,206,131	$ 1,252,097	$ 1,347,538	$ 1,307,307	$ 1,419,178	$ 1,449,522	$ 1,394,334
Hilliard	Nassau	$ 160,670	$ 191,408	$ 201,040	$ 198,340	$ 222,850	$ 212,351	$ 204,627	$ 188,739	$ 183,582	$ 192,590	$ 194,150	$ 178,552	$ 177,294
Cinco Bayou	Okaloosa	$ 44,798	$ 50,211	$ 51,767	$ 51,495	$ 57,942	$ 59,420	$ 58,617	$ 53,246	$ 49,799	$ 56,927	$ 60,688	$ 59,577	$ 59,425
Crestview	Okaloosa	$ 611,381	$ 784,002	$ 1,346,141	$ 822,091	$ 967,560	$ 1,346,925	$ 1,590,235	$ 1,497,581	$ 1,407,475	$ 1,590,540	$ 1,692,711	$ 1,701,295	$ 1,600,483
Destin	Okaloosa	$ 1,088,202	$ 1,155,561	$ 1,283,015	$ 1,295,396	$ 1,482,122	$ 1,602,758	$ 1,574,434	$ 1,469,746	$ 1,385,058	$ 1,581,981	$ 1,701,076	$ 1,693,465	$ 1,606,876
Fort Walton Beach	Okaloosa	$ 1,324,954	$ 1,491,680	$ 1,607,183	$ 1,649,285	$ 1,845,167	$ 1,900,433	$ 1,903,039	$ 1,710,393	$ 1,583,907	$ 1,764,152	$ 1,923,509	$ 2,002,283	$ 1,840,308
Laurel Hill	Okaloosa	$ 13,421	$ 14,220	$ 17,991	$ 20,359	$ 18,886	$ 23,342	$ -	$ 19,034	$ 18,394	$ 21,228	$ 21,031	$ 19,924	$ 17,842
Mary Esther	Okaloosa	$ 160,415	$ 178,681	$ 187,611	$ 173,846	$ 201,440	$ 209,471	$ 201,296	$ 183,037	$ 171,023	$ 191,177	$ 202,595	$ 199,157	$ 182,972
Niceville	Okaloosa	$ 685,527	$ 763,335	$ -	$ 844,002	$ 973,630	$ 1,051,432	$ 1,055,161	$ 982,931	$ 931,015	$ 1,051,268	$ 1,125,124	$ 1,165,450	$ 1,097,703
Shalimar	Okaloosa	$ 26,224	$ 29,483	$ 32,737	$ 29,010	$ 35,917	$ 36,364	$ 36,105	$ 33,877	$ 31,590	$ 35,299	$ 36,747	$ 50,546	$ 41,323
Valparaiso	Okaloosa	$ 173,338	$ 187,443	$ 206,265	$ 202,699	$ 228,330	$ 246,976	$ 241,216	$ 218,162	$ 208,668	$ 234,513	$ 254,570	$ 243,311	$ 238,284
Okeechobee	Okeechobee	$ 310,950	$ 424,690	$ 501,556	$ 475,603	$ 467,830	$ 431,792	$ 424,235	$ 383,620	$ 373,515	$ 402,172	$ 411,299	$ 404,787	$ 415,135
Apopka	Orange	$ 2,130,401	$ 2,685,384	$ 2,792,464	$ 2,847,123	$ 3,066,620	$ 3,403,044	$ 3,175,900	$ 2,978,723	$ 2,915,064	$ 3,177,726	$ 3,301,748	$ 2,872,537	$ 3,192,912
Bay Lake	Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belle Isle	Orange	$ -	$ -	$ -	$ -	$ 427	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Eatonville	Orange	$ 210,033	$ 278,943	$ 313,029	$ 343,554	$ 401,774	$ 409,789	$ 388,008	$ 385,866	$ 367,737	$ 384,624	$ 375,258	$ 340,489	$ 340,534
Edgewood	Orange	$ -	$ 250,000	$ 228,894	$ 235,534	$ 263,308	$ 272,927	$ 255,265	$ 250,680	$ 234,356	$ 258,056	$ 258,477	$ 246,323	$ 238,371
Lake Buena Vista	Orange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maitland	Orange	$ 1,624,735	$ 2,009,587	$ 2,075,992	$ 1,976,046	$ 2,188,184	$ 2,306,133	$ 2,147,420	$ 2,051,239	$ 1,928,829	$ 2,012,528	$ 2,056,964	$ 1,974,659	$ 1,874,741
Oakland	Orange	$ 98,045	$ -	$ 125,027	$ 117,245	$ 127,515	$ 149,253	$ 138,388	$ 114,914	$ 121,630	$ 148,908	$ 124,396	$ 115,934	$ 113,277
Ocoee	Orange	$ 1,704,297	$ 2,028,925	$ 2,129,237	$ 2,288,245	$ 2,340,420	$ 2,470,047	$ 2,282,166	$ 2,155,543	$ 2,037,602	$ 2,200,454	$ 2,354,229	$ 2,182,613	$ 2,159,538
Orlando	Orange	$ 20,686,024	$ 24,339,198	$ 24,909,003	$ 26,008,241	$ 28,066,279	$ 29,623,113	$ 29,800,148	$ 30,607,056	$ 30,316,649	$ 28,312,077	$ 29,329,613	$ 29,798,589	$ 29,469,261
Windermere	Orange	$ 165,571	$ 202,907	$ 213,284	$ 212,929	$ 243,127	$ 268,003	$ 249,753	$ 235,501	$ 172,648	$ 326,130	$ 251,758	$ 235,381	$ 225,470
Winter Garden	Orange	$ 1,138,137	$ 1,497,094	$ 1,715,447	$ 1,840,516	$ 2,157,770	$ 2,382,046	$ 2,216,903	$ 2,132,056	$ 1,967,896	$ 2,280,203	$ 2,357,122	$ 2,310,219	$ 2,335,885
Winter Park	Orange	$ 1,639,538	$ 278,153	$ 268,838	$ 244,533	$ 282,228	$ 301,803	$ 277,757	$ 263,156	$ 245,421	$ 263,940	$ 268,856	$ 256,218	$ 241,935
Kissimmee	Osceola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St. Cloud	Osceola	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Atlantis	Palm Beach	$ 261,697	$ 309,622	$ 328,950	$ 323,734	$ 329,853	$ 303,194	$ 288,442	$ 286,814	$ 274,271	$ 291,842	$ 301,914	$ 294,951	$ -
Belle Glade	Palm Beach	$ 628,762	$ 733,764	$ 804,532	$ 827,035	$ 835,557	$ 764,708	$ 722,271	$ 672,598	$ 664,174	$ 700,748	$ 829,135	$ 785,012	$ 794,249
Boca Raton	Palm Beach	$ 8,926,867	$ 11,742,047	$ 11,610,122	$ 11,548,212	$ 11,603,975	$ 10,394,821	$ 10,335,277	$ 9,930,026	$ 9,655,545	$ 10,361,852	$ 10,385,030	$ 9,974,368	$ 10,062,218
Boynton Beach	Palm Beach	$ 3,577,313	$ 4,492,552	$ 4,711,922	$ 4,709,893	$ 4,723,342	$ 4,299,833	$ 4,243,934	$ 4,053,788	$ 4,068,561	$ 4,419,648	$ 4,490,712	$ 4,411,417	$ 4,525,056
Briny Breeze	Palm Beach	$ -	$ -	$ -	$ -	$ 69	$ -	$ -	$ 4,249	$ -	$ -	$ -	$ -	$ -
Cloud Lake	Palm Beach	$ -	$ 5,964	$ 6,210	$ 6,067	$ 5,591	$ 5,647	$ 5,496	$ 4,426	$ 4,663	$ 5,013	$ 5,289	$ 5,333	$ 5,233
Delray Beach	Palm Beach	$ 3,714,312	$ 4,585,117	$ 4,965,588	$ 4,993,678	$ 4,995,821	$ 4,572,996	$ 4,446,425	$ 4,360,879	$ 4,243,489	$ 4,628,411	$ 4,750,759	$ 4,644,743	$ 4,697,065
Glen Ridge	Palm Beach	$ 13,783	$ 12,375	$ 15,473	$ 13,878	$ 14,659	$ 14,937	$ 13,618	$ 13,180	$ 13,066	$ 17,879	$ 18,313	$ 18,421	$ 19,749
Golf	Palm Beach	$ 52,883	$ 58,774	$ 94,722	$ 54,549	$ 74,667	$ 39,711	$ 65,488	$ 63,362	$ 57,341	$ 58,613	$ 63,169	$ 62,597	$ 61,041
Greenacres	Palm Beach	$ 1,267,295	$ 1,794,174	$ 1,803,341	$ 1,796,045	$ 1,806,735	$ 1,655,016	$ 1,634,914	$ 1,563,973	$ 1,550,831	$ 1,679,938	$ 1,706,622	$ 1,685,905	$ 1,744,014
Gulf Stream	Palm Beach	$ 102,213	$ 116,090	$ 128,911	$ 126,171	$ 125,957	$ 115,934	$ 117,428	$ 121,950	$ 123,554	$ 136,513	$ 150,402	$ 137,812	$ 139,950

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Haverhill	Palm Beach	$ 61,748	$ 84,248	$ 83,417	$ 85,056	$ 82,133	$ 77,986	$ 76,763	$ 74,874	$ 73,493	$ 80,149	$ 83,312	$ 91,237	$ 90,140
Highland Beach	Palm Beach	$ 386,038	$ 453,670	$ 467,708	$ 497,727	$ 489,055	$ -	$ -	$ 411,434	$ 409,721	$ 439,624	$ -	$ -	$ -
Hypoluxo	Palm Beach	$ 25,799	$ 99,893	$ 35,309	$ 32,150	$ 35,537	$ 31,959	$ 29,431	$ 34,252	$ 36,058	$ 39,006	$ 39,938	$ 53,884	$ 58,733
Juno Beach	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Jupiter	Palm Beach	$ 3,277,836	$ 3,988,849	$ 4,284,216	$ 4,605,769	$ 4,552,852	$ 4,250,214	$ 4,174,546	$ 4,099,937	$ 4,003,956	$ 4,340,189	$ 4,512,945	$ 4,459,482	$ 4,351,169
Jupiter Inlet Colony	Palm Beach	$ 36,656	$ 37,862	$ 37,074	$ 37,068	$ 36,927	$ 36,462	$ 34,901	$ 29,798	$ 36,177	$ 36,672	$ 36,499	$ 36,787	$ 36,077
Lake Clarke Shores	Palm Beach	$ 165,230	$ 197,576	$ 200,074	$ 197,772	$ 195,892	$ 205,476	$ 185,253	$ 178,610	$ 167,987	$ 185,095	$ 187,088	$ 189,018	$ 193,178
Lake Park	Palm Beach	$ 492,627	$ 600,953	$ 604,641	$ 609,578	$ 599,961	$ 547,504	$ 546,589	$ 521,720	$ 464,734	$ 613,022	$ 564,731	$ 560,962	$ 575,040
Lake Worth	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 322,242	$ 348,880	$ 379,622	$ 352,489	$ 318,119	$ 347,115	$ 369,012	$ -
Lantana	Palm Beach	$ 567,405	$ 704,607	$ 760,523	$ 788,261	$ 759,640	$ 679,844	$ 673,526	$ 628,615	$ 610,311	$ 660,062	$ 664,446	$ 654,026	$ 670,465
Loxahatchee Groves	Palm Beach	$ -	$ -	$ 65,728	$ 218,236	$ 224,342	$ 203,552	$ 196,426	$ 188,222	$ 185,002	$ 204,892	$ 210,515	$ 211,347	$ 236,037
Manalapan	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mangonia Park	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ 174,967	$ 172,849	$ 168,009	$ 171,420	$ 190,890	$ 167,971	$ 189,244	$ 196,701
North Palm Beach	Palm Beach	$ 678,543	$ 932,476	$ 967,104	$ 975,594	$ 999,894	$ 924,671	$ 904,190	$ 858,495	$ 849,522	$ 911,740	$ 921,424	$ 912,800	$ 930,408
Ocean Ridge	Palm Beach	$ 122,218	$ 140,729	$ 173,919	$ 173,034	$ 179,977	$ 166,934	$ 162,832	$ 155,573	$ 151,526	$ 167,505	$ 165,337	$ 160,962	$ 163,788
Pahokee	Palm Beach	$ 213,308	$ 237,524	$ 250,828	$ 235,782	$ 238,150	$ 215,575	$ 214,010	$ 200,583	$ 185,622	$ 192,712	$ 181,190	$ 190,427	$ -
Palm Beach	Palm Beach	$ 1,758,406	$ 2,146,494	$ 2,244,536	$ 2,217,498	$ 2,225,166	$ 1,992,824	$ 2,060,500	$ 1,900,717	$ 1,872,920	$ 2,012,907	$ 1,999,420	$ 1,939,949	$ 1,935,063
Palm Beach Gardens	Palm Beach	$ 3,773,233	$ 4,817,152	$ 5,163,100	$ 5,259,924	$ 5,353,322	$ 4,763,392	$ 4,674,054	$ 5,059,328	$ 4,854,693	$ 5,258,039	$ 5,321,490	$ 5,188,332	$ 5,326,127
Palm Beach Shores	Palm Beach	$ 127,340	$ 150,100	$ 171,289	$ 171,101	$ 171,448	$ 159,908	$ 152,925	$ 151,302	$ 144,636	$ 170,940	$ 175,263	$ 168,536	$ 166,738
Palm Springs	Palm Beach	$ 540,311	$ 780,483	$ 856,523	$ 923,506	$ 958,475	$ 917,182	$ 901,726	$ 898,301	$ 901,973	$ 1,084,407	$ 1,173,835	$ 1,268,797	$ 1,408,211
Riviera Beach	Palm Beach	$ 786,362	$ 1,627,858	$ 1,861,022	$ 1,785,163	$ 2,330,697	$ 1,470,445	$ 2,547,274	$ 2,467,133	$ 2,493,132	$ 2,700,299	$ 2,679,740	$ 2,564,420	$ 2,738,751
Royal Palm Beach	Palm Beach	$ 1,554,168	$ 1,995,325	$ 2,131,512	$ 2,152,419	$ 2,209,219	$ 2,017,142	$ 1,958,655	$ 1,867,777	$ 1,837,769	$ 1,999,458	$ 2,050,324	$ 2,027,444	$ 2,076,502
South Bay	Palm Beach	$ 181,613	$ -	$ 219,633	$ 212,148	$ 214,368	$ 223,331	$ 184,067	$ 175,312	$ 169,221	$ 183,892	$ 190,494	$ 186,155	$ 192,944
South Palm Beach	Palm Beach	$ 90,840	$ 100,938	$ 103,285	$ 96,046	$ 103,353	$ 114,651	$ 94,939	$ 93,415	$ 84,226	$ 92,695	$ 107,232	$ 99,716	$ 100,725
Tequesta	Palm Beach	$ 363,808	$ 405,774	$ 444,419	$ 462,296	$ 466,541	$ 435,766	$ 412,441	$ 393,734	$ 380,160	$ 401,859	$ 462,312	$ 449,126	$ 452,496
Wellington	Palm Beach	$ 2,744,351	$ 3,430,912	$ 3,512,575	$ 3,492,742	$ 3,594,701	$ 3,298,051	$ 3,266,018	$ 3,157,328	$ 3,205,140	$ 3,422,325	$ 3,474,875	$ 3,409,343	$ 3,479,865
West Palm Beach	Palm Beach	$ 7,068,140	$ 8,717,702	$ 8,598,349	$ 8,387,637	$ 8,220,306	$ 7,849,917	$ 7,367,062	$ 8,068,300	$ 7,922,637	$ 8,606,813	$ 8,745,791	$ 8,533,718	$ 8,585,553
Westlake	Palm Beach	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dade City	Pasco	$ 361,118	$ 413,416	$ 446,367	$ 434,134	$ 461,110	$ 625,560	$ 626,496	$ 595,133	$ 573,725	$ 607,273	$ 584,775	$ 595,362	$ 565,791
New Port Richey	Pasco	$ 1,016,715	$ 1,204,290	$ 1,213,353	$ 1,143,529	$ 1,274,827	$ 1,351,763	$ 1,234,178	$ 1,154,551	$ 1,092,832	$ 1,169,962	$ 1,142,892	$ 1,085,204	$ -
Port Richey	Pasco	$ 265,782	$ 320,804	$ 328,572	$ 308,766	$ 331,686	$ 347,590	$ 313,410	$ 302,754	$ 326,515	$ 352,568	$ 304,574	$ 302,133	$ 294,965
San Antonio	Pasco	$ 63,221	$ 60,966	$ 64,530	$ 65,802	$ 69,447	$ 66,435	$ 65,590	$ 59,739	$ 63,906	$ 66,641	$ 70,267	$ 71,914	$ 68,186
St. Leo	Pasco	$ 66,472	$ 69,590	$ 78,167	$ 85,611	$ 91,209	$ 90,789	$ 93,591	$ 85,973	$ 84,618	$ 78,860	$ 66,682	$ 77,776	$ 61,250
Zephyrhills	Pasco	$ 1,010,530	$ 1,239,299	$ 1,301,586	$ 1,265,283	$ 1,420,062	$ 1,450,421	$ 1,359,544	$ 1,325,328	$ 1,277,350	$ 1,331,812	$ 1,383,046	$ 1,279,726	$ -
Belleair	Pinellas	$ -	$ 791,944	$ 386,920	$ -	$ -	$ -	$ -	$ -	$ 339,314	$ 368,811	$ 367,005	$ 348,537	$ 346,025
Belleair Beach	Pinellas	$ 123,631	$ 143,514	$ 145,305	$ 142,618	$ 158,680	$ 174,310	$ 160,593	$ 148,629	$ 144,505	$ 162,258	$ 159,179	$ 148,865	$ 148,588
Belleair Bluffs	Pinellas	$ 157,190	$ 180,929	$ 184,157	$ 182,056	$ 201,263	$ 213,657	$ 197,113	$ 186,713	$ 180,767	$ 197,172	$ 194,766	$ 182,638	$ 178,612
Belleair Shore	Pinellas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Clearwater	Pinellas	$ 7,572,305	$ 8,724,750	$ 8,867,217	$ 8,633,587	$ 9,606,151	$ 9,970,713	$ 9,423,572	$ 9,039,274	$ 8,594,708	$ 9,250,223	$ 9,267,009	$ 8,737,053	$ 8,772,468
Dunedin	Pinellas	$ 2,125,645	$ 2,505,492	$ 2,497,847	$ 2,399,525	$ 2,697,564	$ 2,843,575	$ 2,616,312	$ 2,450,827	$ 2,297,545	$ 2,533,250	$ 2,510,737	$ 2,355,380	$ 2,308,782
Gulfport	Pinellas	$ 619,799	$ 716,025	$ 710,175	$ 706,680	$ 766,603	$ 843,095	$ 772,556	$ 728,839	$ 697,350	$ 736,298	$ 760,152	$ 703,388	$ 697,652
Indian Rocks Beach	Pinellas	$ 330,690	$ 383,417	$ 388,796	$ 375,420	$ 421,744	$ 448,273	$ 415,445	$ 395,382	$ 379,075	$ 416,741	$ 422,604	$ 401,813	$ 402,714
Indian Shores	Pinellas	$ 185,193	$ 217,342	$ 216,767	$ 220,289	$ 259,681	$ 269,597	$ 246,648	$ 237,607	$ 226,333	$ 244,503	$ 253,629	$ 236,576	$ 234,589
Kenneth City	Pinellas	$ 250,640	$ 284,039	$ 284,388	$ 272,912	$ 303,124	$ 323,303	$ -	$ -	$ 267,280	$ 280,206	$ 276,667	$ -	$ -
Largo	Pinellas	$ 4,732,653	$ 5,650,916	$ 5,703,179	$ 5,596,824	$ 6,087,481	$ 6,411,590	$ 5,903,509	$ 5,573,591	$ 5,434,523	$ 5,781,861	$ 5,804,256	$ 5,545,883	$ 5,507,181
Madeira Beach	Pinellas	$ 396,627	$ 458,107	$ 472,695	$ 463,715	$ 521,694	$ 555,870	$ 512,342	$ 498,580	$ 471,972	$ 487,908	$ 521,768	$ 488,622	$ 484,387
North Redington Beach	Pinellas	$ 119,487	$ 141,087	$ 145,334	$ 144,982	$ 162,961	$ 171,742	$ 157,486	$ 151,281	$ 145,898	$ 150,079	$ 151,698	$ 143,532	$ 144,039
Oldsmar	Pinellas	$ 1,159,864	$ 1,267,464	$ 1,380,863	$ 1,389,900	$ 1,568,598	$ 1,495,433	$ 1,421,900	$ 1,360,249	$ 1,308,911	$ 1,358,507	$ 1,380,432	$ 1,385,673	$ 1,314,272
Pinellas Park	Pinellas	$ 3,592,319	$ 4,301,521	$ 4,382,041	$ 4,275,861	$ 4,629,918	$ 4,859,474	$ 4,459,365	$ 4,429,739	$ 4,204,620	$ 4,537,161	$ 4,650,000	$ 4,379,962	$ 4,381,716
Redington Beach	Pinellas	$ 92,701	$ 108,660	$ 109,277	$ 109,464	$ 124,524	$ 132,818	$ 122,596	$ 112,331	$ 109,406	$ 116,795	$ 121,283	$ 114,509	$ 115,037
Redington Shores	Pinellas	$ 122,227	$ 161,167	$ 173,422	$ 180,016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Safety Harbor	Pinellas	$ 1,145,076	$ 1,363,738	$ 1,384,163	$ 1,357,917	$ 1,488,509	$ 1,552,134	$ 1,397,936	$ 1,366,752	$ 1,287,457	$ 1,402,282	$ 1,392,654	$ 1,283,273	$ 1,249,260
Seminole	Pinellas	$ 1,132,351	$ 1,340,149	$ 1,365,355	$ 1,335,388	$ 1,466,842	$ 1,513,548	$ 1,390,924	$ 1,333,793	$ 1,260,575	$ 1,347,420	$ 1,385,276	$ 1,307,571	$ 1,330,428
South Pasadena	Pinellas	$ 389,384	$ 441,736	$ 448,343	$ 433,306	$ 468,157	$ 490,319	$ 459,341	$ 443,319	$ 426,267	$ 436,028	$ 464,010	$ 441,485	$ 424,479
St. Pete Beach	Pinellas	$ 939,945	$ 1,096,959	$ 1,104,115	$ 1,078,827	$ 1,185,052	$ 1,260,830	$ 1,168,407	$ 1,128,415	$ 1,067,548	$ 1,138,705	$ 1,171,813	$ 1,095,536	$ 1,072,352
St. Petersburg	Pinellas	$ 15,815,954	$ 18,440,168	$ 18,545,819	$ 18,196,871	$ 20,211,279	$ -	$ 19,684,895	$ 18,940,068	$ 18,126,537	$ 19,422,567	$ 19,499,393	$ 18,327,585	$ 18,168,785
Tarpon Springs	Pinellas	$ 1,400,870	$ 1,649,244	$ 1,640,667	$ 1,608,984	$ 1,754,810	$ 1,867,360	$ 1,691,774	$ 1,578,758	$ 1,535,574	$ 1,681,130	$ 1,681,852	$ 1,569,396	$ 1,550,624
Treasure Island	Pinellas	$ 591,418	$ 640,887	$ 648,173	$ 640,658	$ 730,141	$ 769,614	$ 723,927	$ 693,506	$ 660,135	$ 704,669	$ 719,929	$ 678,582	$ 674,157
Auburndale	Polk	$ 602,695	$ 707,733	$ 995,737	$ 956,741	$ 998,277	$ 1,023,878	$ 918,107	$ 897,026	$ 868,885	$ 944,152	$ 1,588,447	$ 1,829,227	$ 1,748,620
Bartow	Polk	$ 35,676	$ 98,354	$ 107,532	$ 115,784	$ 144,620	$ 140,007	$ 143,205	$ 153,497	$ 127,727	$ 122,909	$ 120,550	$ 97,536	$ 94,103
Davenport	Polk	$ 144,001	$ 171,662	$ 185,957	$ 231,053	$ 259,456	$ 273,754	$ 257,040	$ 255,465	$ 245,168	$ 262,827	$ 298,538	$ 302,758	$ 328,735
Dundee	Polk	$ 182,858	$ 225,254	$ 236,798	$ 213,269	$ 250,740	$ 261,488	$ 239,889	$ 216,926	$ 224,964	$ 245,936	$ 248,258	$ 238,658	$ 246,617
Eagle Lake	Polk	$ 98,036	$ 110,646	$ 125,687	$ 126,299	$ 140,948	$ 146,841	$ 135,229	$ 133,297	$ 124,117	$ 134,232	$ 138,524	$ 140,606	$ 125,701
Fort Meade	Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Frostproof	Polk	$ 236,759	$ 303,043	$ 283,001	$ 204,585	$ 238,209	$ 282,395	$ 235,388	$ 220,301	$ 210,308	$ 241,430	$ 236,096	$ 219,812	$ 214,792
Haines City	Polk	$ 874,615	$ 1,166,386	$ 1,350,825	$ 1,348,220	$ 1,680,164	$ 1,805,492	$ 1,692,465	$ 1,671,100	$ 1,595,278	$ 1,675,552	$ 1,632,506	$ 1,534,412	$ 1,552,982
Highland Park	Polk	$ 11,719	$ 13,217	$ 12,718	$ 12,498	$ 14,044	$ 14,804	$ 13,532	$ 12,819	$ 12,212	$ 13,838	$ 13,716	$ 12,853	$ 12,896
Hillcrest Heights	Polk	$ 12,573	$ 15,046	$ 15,137	$ 14,349	$ 15,664	$ 17,054	$ 15,947	$ 14,519	$ 13,912	$ 15,229	$ 15,088	$ 13,703	$ 13,679
Lake Alfred	Polk	$ 172,041	$ 197,488	$ 251,012	$ 260,197	$ 287,299	$ 287,578	$ 259,539	$ 244,282	$ 234,530	$ 250,720	$ 318,130	$ 370,969	$ 344,096

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Lake Hamilton	Polk	$ 87,972	$ -	$ 124,718	$ 124,739	$ 98,723	$ 96,273	$ 128,526	$ 99,143	$ 100,866	$ 110,067	$ 111,739	$ 109,963	$ 102,815
Lake Wales	Polk	$ 864,226	$ 1,062,860	$ 1,092,301	$ 1,069,959	$ 1,151,213	$ 1,233,833	$ 1,127,705	$ 1,082,129	$ 981,696	$ 1,089,109	$ 1,115,026	$ 1,055,451	$ 1,032,474
Lakeland	Polk	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mulberry	Polk	$ -	$ -	$ -	$ -	$ -	$ 435,642	$ 406,332	$ 359,535	$ 344,368	$ 345,060	$ 353,119	$ 349,455	$ 328,184
Polk City	Polk	$ 61,080	$ 67,728	$ 73,005	$ 68,170	$ 72,604	$ 72,171	$ 65,845	$ 57,332	$ 53,795	$ 55,469	$ 59,668	$ 58,510	$ 57,166
Winter Haven	Polk	$ 1,938,565	$ 2,781,231	$ 2,991,273	$ 3,051,713	$ 3,215,035	$ 3,248,053	$ 2,994,236	$ 2,908,551	$ 2,847,840	$ 3,120,142	$ 3,187,530	$ 3,283,139	$ 3,195,925
Crescent City	Putnam	$ 79,447	$ 102,909	$ 108,771	$ 102,486	$ 105,707	$ 95,147	$ 104,415	$ 101,609	$ 99,399	$ 104,826	$ 108,668	$ 103,985	$ 104,119
Interlachen	Putnam	$ 68,050	$ 93,311	$ 97,712	$ 99,225	$ 116,871	$ 88,394	$ 89,796	$ 99,837	$ 93,955	$ 101,016	$ 112,890	$ 97,446	$ 95,828
Palatka	Putnam	$ 684,678	$ 911,188	$ 915,447	$ -	$ -	$ -	$ 886,166	$ 662,190	$ 904,958	$ 810,331	$ 837,391	$ 813,569	$ 799,700
Pomona Park	Putnam	$ 27,128	$ 40,425	$ 41,149	$ 39,053	$ 41,643	$ 38,479	$ 38,528	$ 34,221	$ 33,784	$ 38,131	$ 40,009	$ 37,504	$ 37,517
Welaka	Putnam	$ 29,240	$ 35,985	$ 40,954	$ -	$ -	$ -	$ -	$ 39,571	$ 38,771	$ 42,206	$ 43,481	$ 42,810	$ 43,931
Gulf Breeze	Santa Rosa	$ 211,325	$ 240,992	$ 279,313	$ 243,849	$ 293,431	$ 364,912	$ 334,218	$ 305,448	$ 288,767	$ 327,993	$ 349,323	$ 366,834	$ 327,060
Jay	Santa Rosa	$ 37,886	$ 42,080	$ 43,572	$ 41,059	$ 52,134	$ 48,884	$ 47,777	$ 47,977	$ 49,546	$ -	$ 53,627	$ 46,027	$ 49,824
Milton	Santa Rosa	$ 804,482	$ 492,232	$ 545,828	$ 549,504	$ 627,889	$ 669,429	$ 696,880	$ 608,794	$ 569,689	$ 644,602	$ 690,975	$ 678,472	$ 668,136
North Port	Sarasota	$ 1,695,328	$ 2,332,266	$ 2,622,881	$ 2,746,028	$ 2,856,743	$ 2,637,138	$ 2,654,895	$ 2,521,691	$ 2,549,869	$ 2,810,119	$ 2,918,342	$ 2,941,991	$ 3,121,469
Sarasota	Sarasota	$ 4,267,043	$ 5,277,456	$ 5,413,205	$ 5,075,916	$ 5,158,391	$ 4,760,356	$ 4,881,247	$ 4,488,238	$ 4,360,645	$ 4,673,079	$ 4,687,866	$ 4,484,082	$ 4,587,545
Venice	Sarasota	$ 1,437,967	$ 1,700,643	$ 1,889,769	$ 2,048,209	$ -	$ 1,766,902	$ 1,923,226	$ 1,671,449	$ 1,667,793	$ 1,829,199	$ 1,892,350	$ 1,848,743	$ 1,883,723
Altamonte Springs	Seminole	$ 3,182,984	$ 3,745,411	$ 3,812,356	$ 3,701,475	$ 4,043,506	$ 4,135,324	$ 3,829,531	$ 3,723,746	$ 3,525,885	$ 3,727,356	$ 3,786,353	$ 3,545,364	$ 3,490,504
Casselberry	Seminole	$ 1,453,522	$ 1,704,793	$ 1,701,686	$ 1,674,187	$ 1,774,061	$ 1,932,615	$ 1,762,461	$ 1,638,341	$ 1,606,416	$ 1,707,251	$ 1,725,863	$ 1,626,083	$ 1,604,151
Lake Mary	Seminole	$ 1,341,599	$ 1,678,032	$ 1,740,485	$ 1,722,653	$ 2,026,466	$ 2,009,483	$ 1,869,649	$ 1,770,383	$ 1,663,649	$ 1,737,776	$ 1,770,152	$ 1,682,124	$ 1,681,781
Longwood	Seminole	$ 1,065,866	$ 1,275,614	$ 1,327,796	$ 1,281,976	$ 1,373,822	$ 1,406,640	$ 1,310,637	$ 1,244,448	$ 1,136,706	$ 1,187,373	$ 1,227,030	$ 1,176,821	$ 1,201,695
Oviedo	Seminole	$ 1,685,862	$ 2,061,952	$ 2,126,951	$ 2,106,098	$ 2,322,719	$ 2,416,073	$ 2,185,142	$ 2,094,897	$ 2,013,511	$ 2,148,933	$ 2,220,931	$ 2,144,915	$ 2,153,587
Sanford	Seminole	$ 2,765,533	$ 3,598,576	$ 3,542,532	$ 3,421,078	$ 4,270,266	$ 3,892,899	$ 4,055,362	$ 3,452,242	$ 3,476,798	$ 3,753,954	$ 3,864,582	$ 3,780,352	$ 3,856,185
Winter Springs	Seminole	$ 1,436,996	$ 1,775,460	$ 1,759,245	$ 1,748,477	$ 1,823,706	$ 2,173,849	$ 1,873,785	$ 1,748,214	$ 1,541,741	$ 1,816,567	$ 1,941,840	$ 1,874,893	$ 1,812,388
Hastings	St. Johns	$ -	$ -	$ -	$ -	$ 43,630	$ 40,713	$ 39,977	$ 36,675	$ 35,825	$ 38,959	$ 39,329	$ 38,150	$ 39,247
St. Augustine	St. Johns	$ 1,102,834	$ 1,128,388	$ 1,377,959	$ 1,110,025	$ 1,296,215	$ 1,220,699	$ 1,211,390	$ 1,125,547	$ 1,125,547	$ 1,161,044	$ 1,209,505	$ 1,165,575	$ 1,148,152
St. Augustine Beach	St. Johns	$ 356,662	$ 432,051	$ 441,490	$ 432,761	$ 450,256	$ 416,651	$ -	$ 378,445	$ 383,647	$ 407,459	$ 416,421	$ 403,676	$ 399,099
Fort Pierce	St. Lucie	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Port St. Lucie	St. Lucie	$ 5,451,820	$ 7,370,278	$ 8,176,844	$ 8,363,948	$ 8,627,252	$ 7,987,044	$ 7,656,194	$ 8,161,246	$ 7,755,163	$ 8,534,011	$ 8,940,735	$ 8,836,471	$ 9,127,721
St. Lucie Village	St. Lucie	$ 43,270	$ -	$ 56,760	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bushnell	Sumter	$ 104,225	$ 135,330	$ 136,726	$ 140,713	$ 170,630	$ 169,044	$ 162,544	$ 153,767	$ 149,964	$ 154,507	$ 154,170	$ 152,814	$ 155,209
Center Hill	Sumter	$ 33,852	$ 35,855	$ 35,221	$ 33,591	$ 40,500	$ 47,260	$ 42,084	$ 59,917	$ 112,239	$ 110,478	$ 112,973	$ 87,489	$ 70,741
Coleman	Sumter	$ 29,426	$ 34,877	$ 34,207	$ 32,643	$ 37,768	$ 39,853	$ 37,161	$ 33,774	$ 32,064	$ 34,011	$ 35,261	$ 34,585	$ 35,010
Webster	Sumter	$ 36,365	$ -	$ 42,790	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,150	$ 44,013	$ 35,460
Wildwood	Sumter	$ 262,759	$ 413,205	$ 466,337	$ -	$ -	$ 530,313	$ 597,810	$ 573,140	$ 621,148	$ 716,823	$ 782,170	$ -	$ -
Branford	Suwannee	$ 91,305	$ 53,337	$ 55,409	$ 52,741	$ 58,341	$ 63,464	$ 60,518	$ 113,535	$ 60,407	$ 66,853	$ 64,406	$ 58,060	$ 61,367
Live Oak	Suwannee	$ 380,980	$ 458,927	$ 497,592	$ 504,508	$ 509,338	$ 473,128	$ 532,787	$ 506,808	$ 484,462	$ 478,941	$ 485,253	$ 456,003	$ 460,427
Perry	Taylor	$ 467,275	$ 560,200	$ 595,585	$ 619,089	$ 615,194	$ 674,009	$ 624,507	$ 575,582	$ 555,693	$ 598,958	$ 590,351	$ 533,398	$ 520,422
Lake Butler	Union	$ 109,011	$ 132,329	$ 139,336	$ -	$ 146,726	$ 147,801	$ 136,064	$ 123,170	$ 121,511	$ 132,883	$ 132,568	$ 129,132	$ 132,953
Raiford	Union	$ 9,095	$ 10,663	$ 11,345	$ 10,921	$ 10,449	$ 10,512	$ 10,705	$ 10,407	$ 19,072	$ 26,250	$ 26,735	$ 25,477	$ 23,168
Worthington Springs	Union	$ -	$ 19,948	$ 20,818	$ 21,570	$ 21,110	$ 23,578	$ 23,146	$ 22,198	$ 21,484	$ 23,233	$ 23,147	$ 19,443	$ 18,664
Daytona Beach	Volusia	$ 5,154,580	$ 6,265,693	$ 6,223,343	$ 6,200,040	$ 6,364,012	$ 5,703,685	$ 5,610,973	$ 5,207,599	$ 5,176,341	$ 5,531,549	$ 5,616,432	$ 5,514,708	$ 5,653,667
Daytona Beach Shores	Volusia	$ 517,000	$ 625,000	$ 675,399	$ 724,482	$ 662,530	$ 600,000	$ 570,000	$ 601,000	$ 538,000	$ 608,000	$ 665,000	$ 599,000	$ 591,000
DeBary	Volusia	$ -	$ -	$ 471,557	$ 721,497	$ 816,271	$ 869,091	$ 809,201	$ 733,119	$ 705,575	$ 765,130	$ 795,202	$ 770,265	$ 748,011
DeLand	Volusia	$ 1,810,686	$ 2,306,634	$ 2,397,041	$ 2,336,573	$ 2,596,915	$ 2,723,411	$ 2,495,352	$ 2,402,218	$ 2,283,921	$ 2,490,860	$ 2,572,975	$ 2,414,938	$ 2,397,953
Deltona	Volusia	$ 3,115,972	$ 3,883,319	$ 3,730,656	$ 3,732,717	$ 3,966,949	$ 4,052,016	$ 3,892,925	$ 3,412,062	$ 3,405,299	$ 3,742,292	$ 3,722,935	$ 3,559,802	$ 3,676,852
Edgewater	Volusia	$ 770,876	$ 969,336	$ 1,019,970	$ 905,599	$ 1,014,785	$ 935,435	$ 889,634	$ 819,855	$ 891,558	$ 946,126	$ 976,825	$ 961,267	$ 997,407
Holly Hill	Volusia	$ 703,538	$ 822,824	$ 846,168	$ 844,646	$ 838,839	$ 754,965	$ 791,706	$ 705,238	$ 708,344	$ 763,135	$ 785,848	$ 764,275	$ 765,787
Lake Helen	Volusia	$ 106,215	$ 128,740	$ 130,872	$ 127,285	$ 147,285	$ 158,574	$ 147,055	$ 136,899	$ 134,735	$ 143,832	$ 150,413	$ 141,110	$ 136,809
New Smyrna Beach	Volusia	$ 2,087,724	$ 2,490,845	$ 2,802,272	$ 2,763,854	$ 2,758,741	$ 2,972,858	$ 2,637,346	$ 2,482,873	$ 2,303,525	$ 2,529,925	$ 2,575,520	$ 2,697,524	$ 2,559,931
Oak Hill	Volusia	$ 72,507	$ 92,737	$ 94,865	$ 92,653	$ 93,479	$ 87,025	$ 85,189	$ 78,794	$ 81,374	$ 89,203	$ 94,402	$ 96,720	$ 99,574
Orange City	Volusia	$ 734,893	$ 909,839	$ 952,424	$ 958,850	$ 1,107,942	$ 1,169,914	$ 1,125,485	$ 1,094,789	$ 1,041,469	$ 1,103,324	$ 1,125,770	$ 1,049,346	$ 1,038,132
Ormond Beach	Volusia	$ 2,631,000	$ 3,189,000	$ 3,204,000	$ 3,125,000	$ 3,183,000	$ 3,131,000	$ 2,949,000	$ 2,679,000	$ 2,669,000	$ 2,841,000	$ 2,921,000	$ 2,894,631	$ 2,880,563
Pierson	Volusia	$ 72,808	$ 87,419	$ 88,798	$ 87,637	$ 97,004	$ 103,620	$ 96,325	$ 87,829	$ 84,514	$ 90,381	$ 91,361	$ 82,288	$ 84,799
Ponce Inlet	Volusia	$ 216,623	$ 255,806	$ 263,249	$ 254,508	$ 267,135	$ 250,319	$ 239,248	$ 220,402	$ 215,724	$ 225,065	$ 232,182	$ 227,149	$ 221,175
Port Orange	Volusia	$ 2,558,130	$ 3,145,480	$ -	$ 3,165,772	$ 3,369,242	$ 3,118,664	$ 3,128,578	$ 2,864,263	$ 2,893,287	$ 3,125,315	$ 3,230,972	$ 3,171,271	$ 3,207,131
South Daytona	Volusia	$ 615,078	$ 744,225	$ 738,459	$ 723,698	$ 709,452	$ 650,741	$ 635,672	$ 580,572	$ 588,317	$ 775,261	$ 794,366	$ 777,267	$ 676,327
Sopchoppy	Wakulla	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,131	$ 24,424	$ 23,826	$ 25,224	$ 26,293	$ 23,898	$ 23,452
St. Marks	Wakulla	$ 19,088	$ 23,324	$ 13,897	$ 25,082	$ 26,327	$ 32,764	$ 26,676	$ 25,542	$ 26,110	$ 28,289	$ 27,331	$ 21,517	$ 21,224
DeFuniak Springs	Walton	$ 181,919	$ 203,261	$ 224,490	$ 226,941	$ 274,447	$ 282,737	$ 279,918	$ 250,581	$ 231,563	$ 259,951	$ 277,477	$ 310,896	$ -
Freeport	Walton	$ 46,331	$ 50,877	$ 65,360	$ 73,518	$ 85,544	$ 83,795	$ 83,917	$ 89,064	$ 90,723	$ 94,814	$ 87,076	$ 92,310	$ 118,077
Paxton	Walton	$ 15,520	$ 17,805	$ 19,156	$ -	$ 25,047	$ 27,144	$ 25,596	$ 21,159	$ 21,158	$ 23,230	$ 24,236	$ 19,275	$ 21,147
Caryville	Washington	$ -	$ -	$ -	$ 5,934	$ -	$ -	$ 6,990	$ 6,176	$ -	$ 5,768	$ 6,186	$ 6,315	$ -
Chipley	Washington	$ 206,310	$ 228,151	$ 246,185	$ 246,950	$ 279,070	$ 309,667	$ 313,300	$ 273,275	$ 243,218	$ 269,184	$ 282,109	$ 267,096	$ 261,934
Ebro	Washington	$ 17,529	$ 20,293	$ 20,491	$ 23,766	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 33,174	$ 32,827
Vernon	Washington	$ 22,200	$ 26,033	$ 28,476	$ 28,487	$ 32,859	$ 35,712	$ 36,882	$ 32,525	$ 29,873	$ 42,377	$ 48,478	$ -	$ -
Wausau	Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Summary of Reported Municipal Franchise Fee - Electricity Revenues

Local Fiscal Years Ended September 30, 2005 - 2017

Municipality	County	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Total Municipal Franchise Fees - Electricity		$ 434,429,008	$ 514,540,702	$ 546,883,232	$ 550,626,447	$ 600,243,133	$ 565,453,359	$ 571,030,032	$ 563,206,940	$ 547,873,544	$ 573,990,007	$ 590,465,562	$ 581,823,259	$ 570,291,737
% Change		-	18.4%	6.3%	0.7%	9.0%	-5.8%	1.0%	-1.4%	-2.7%	4.8%	2.9%	-1.5%	-2.0%
# Reporting		340	335	344	337	339	344	345	349	346	342	345	345	334
Total Municipal Franchise Fees		$ 541,407,060	$ 633,075,955	$ 669,073,212	$ 678,539,321	$ 717,295,819	$ 705,492,123	$ 713,743,133	$ 691,485,849	$ 658,541,952	$ 718,670,782	$ 743,036,940	$ 740,093,325	$ 733,536,386
% Change		-	16.9%	5.7%	1.4%	5.7%	-1.6%	1.2%	-3.1%	-4.8%	9.1%	3.4%	-0.4%	-0.9%
Electricity Fees as % of All Fees		80.2%	81.3%	81.7%	81.1%	83.7%	80.2%	80.0%	81.4%	83.2%	79.9%	79.5%	78.6%	77.7%

Note: This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 323.100 - Franchise Fee - Electricity and 323.XXX - Franchise Fees.

Data Source: Florida Department of Financial Services.

Tab 4

Reports

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The Trouble With Electricity Markets: Understanding California's Restructuring Disaster

Severin Borenstein

Starting in June 2000, California's wholesale electricity prices increased to unprecedented levels. The June 2000 average of $143 per megawatt-hour (MWh) was more than twice as high as in any previous month since the market opened in April 1998. These high prices produced enormous profits for generating companies and financial crises for the regulated utilities that were required to buy power in the wholesale markets and sell at much lower regulated prices in the retail markets. The state's largest utility, Pacific Gas & Electric, declared bankruptcy in March 2001. The state of California took over wholesale electricity purchases and spent more than $1 billion per month buying power in the spring of 2001, with average prices more than ten times higher than they had been a year earlier. Accusations of price gouging and collusion among the sellers were widespread. Some observers blamed the problems on the format of the wholesale auctions in California, while others focused on the way that transmission capacity is priced and how prices varied by location. A number of economists, myself included, did studies that concluded that sellers exercised significant market power.

While some of these issues played a role in the difficulties that electricity markets encountered in California and elsewhere, the policy discussion thus far has not focused on the fundamental problem with electricity markets: In nearly all electricity markets, demand is difficult to forecast and is almost completely insensitive to price fluctuations, while supply faces binding constraints at peak times, and storage is prohibitively costly. Combined with the fact that unregulated prices for homogeneous goods clear at a uniform, or near-uniform, price for all sellers—regardless of their costs of production—these attributes necessarily imply that

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short-term prices for electricity will be extremely volatile. Problems with market power and imperfect locational pricing can exacerbate the fundamental trouble with electricity markets.

Two market design adjustments would greatly mitigate the fundamental trouble: long-term contracts between wholesale buyers and sellers; and real-time retail pricing of electricity, which indicates to the final customer on an hourly basis when electricity is more or less costly to consume. Historically, long-term contracts have been a standard feature of electricity markets, with cost-of-service regulation being the most detailed and extreme form of long-term contracting. Long-term contracts allow buyers to hedge against price booms and sellers to hedge against price busts.

While long-term contracts alone could be used to avoid situations like the California crisis, a much more efficient approach to the problem combines long-term contracting with real-time retail pricing. Variable retail prices can reflect real-time variation in the cost of procuring electricity, while monthly electricity bills can remain quite stable through the use of long-term contracts. Implementing real-time retail pricing would lower the total production capacity needed to meet peaks in demand and would substantially reduce the prices that buyers would need to offer to procure power on long-term contracts. Together, these two policy responses would help to produce an electricity market that operates in a smoother, more cost-effective and more environmentally responsible manner.

California's Road to Electricity Deregulation

California began serious consideration of restructuring its electricity market in 1994, motivated in part by the high electricity prices the state's customers faced at the time and in part by the example of electricity deregulation in the United Kingdom. In 1993, California's average retail electricity price was 9.7 cents per kilowatt-hour, compared to the national average of 6.9 cents. The state's high electricity prices were primarily the result of investment and procurement decisions that were made by the investor-owned utilities, with the oversight of the California Public Utilities Commission (CPUC), during the previous two decades. The utilities had built nuclear power plants that turned out to be far more expensive than originally forecast, and they had, under pressure from the CPUC, signed long-term contracts with small generators that committed them to very high wholesale purchase prices.

These mistakes were, for the most part, sunk costs, so restructuring couldn't eliminate them. Some of the customers supporting the change hoped that restructuring could be used to shift those sunk costs from ratepayers to the shareholders of the investor-owned utilities—Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). As potent political forces in the state, however, the utilities made sure that any restructuring bill would allow for full recovery of their sunk investments, just as would have occurred if no changes in regulation had taken place.[1] Thus, the 1996 restructuring bill that was passed by the California state legislature and signed by Governor Pete Wilson contained a scheme that most observers believed would permit the utilities full recovery of their bad investments, which were often referred to as "stranded costs."

The restructuring plan treated each of the components of the electricity industry quite differently. Electricity generation was to be deregulated, and the investor-owned utilities were to reduce substantially their ownership of generation facilities. Long-distance electricity transmission was to remain a regulated function, with the utilities owning the lines and receiving compensation for their use. Local distribution of electricity also remained a regulated utility function, but the financial aspects of retail markets were opened to competition among "energy service providers." These energy service providers could contract to sell electricity to end users, while the utilities would be compensated for carrying the power to these customers' locations.

The scheme implemented for stranded cost recovery was a "Competition Transition Charge." Instead of a simple fixed surcharge on electricity consumption, the Competition Transition Charge fixed the retail price for electricity at about 6 cents per kilowatt-hour.[2] It then required customers to pay for the wholesale price of electricity and, in addition, to pay to the investor-owned utilities the difference between 6 cents and the actual wholesale price of electricity, which was expected to be much lower than 6 cents.[3] The effect was to freeze retail rates for consumers and allow the recovery of stranded costs to vary inversely with the wholesale price of electricity. The Competition Transition Charge was to end for a utility at the point that it had recovered all of its stranded costs or in March 2002, whichever came first. When the charge ended for a given utility, the utility would then switch to simply passing through the (assumed lower) wholesale price of electricity.

San Diego Gas & Electric did, in fact, end its stranded cost recovery in 1999, so when wholesale prices jumped in June 2000, SDG&E passed them through to San Diego customers. These increases raised howls of protest, and the California legislature quickly reimposed the frozen retail price on SDG&E, though with the understanding that SDG&E would be reimbursed eventually for the additional costs. The other two utilities were still under the Competition Transition Charge in June 2000, when they found themselves buying power at prices averaging more than 10 cents per KWh and reselling to customers at the frozen rate of about 6 cents per KWh.

[1] Borenstein and Bushnell (2000) discuss at greater length the reasonable and the unsupported promises that have been made in support of electricity deregulation.

[2] This is the retail price just for electricity before adding in fees for transmission and distribution. Retail prices are usually expressed in cents per kilowatt-hour (KWh). Wholesale prices are usually expressed in dollars per megawatt-hour (MWh). One MWh is equal to 1000 KWh. One cent per KWh is equal to $10 per MWh.

[3] The customer was required to make this Competition Transition Charge payment to the utilities regardless of whether the customer switched to a retail provider other than the utilities.

Besides the scheme for covering stranded costs, the most controversial aspect of the restructuring was the design of the wholesale electricity market. Essentially, there were two models of how the market could operate, an electricity pool or a market based on bilateral trades. Joskow (2000) discusses the pros and cons of these organizational structures in detail. In an electricity pool, all producers sell their power into a centrally operated electricity pool, and all customers (or their retail providers) purchase from the pool. The pool market is run by an independent system operator that also controls the physical structure of the electricity grid and thus moves power to where it is demanded and adjusts prices to reflect the supply/demand balance at each point on the grid. Parties are still free to make financial arrangements to hedge price risk associated with the market. For instance, if a producer and customer wished to contract on price, they would still be required to sell to and buy from the pool at the pool spot price, but they could sign a contract that offset any variations in that pool price and thus locked in a buy and sell price in advance.

The alternative plan was for a bilateral market, with buyers and sellers striking one-on-one deals and then notifying the independent system operator where they intended to produce and consume power. The system operator would step in only if the transactions that were planned for a given time period would overload some part of the transmission grid. In that case, the system operator would set grid usage charges that would induce changes in transaction plans so that the grid would not become overloaded. Such transmission charges would determine the price difference between locations and would reflect the shadow value of capacity to carry power between those locations. The independent system operator would also run a real-time "imbalance market," which market participants would have to use to make real-time (more precisely, after the fact) transactions, since both production and consumption usually deviate at least slightly from the advance plan. Proponents argued that this was a more free-market approach to restructuring and that if a centralized pool was so valuable, the market would create one. In addition, if such a pool were created, it would be under constant pressure to operate efficiently to keep traders using the pool rather than trading bilaterally.

What came out of the 1996–1998 market design process was a hybrid of the two visions. The independent system operator was set up to operate with approximately the vision of those proposing the bilateral model. But the California Power Exchange was also created to run a day-ahead market as a pool. For the first four years, all three California utilities, who together had most of the retail customers and a large share of the production capacity, were required to transact all their business in the Power Exchange (or the independent system operator's imbalance market). The Power Exchange ran a day-ahead trading market with both demand and supply bids. Beginning in 1999, the Power Exchange also started to run a forward market in which power could be traded for delivery many months in advance. This forward market never achieved sufficient volume to be considered a reliable market.[4] The utilities purchased nearly all of their power in the Power Exchange day-ahead market.

On April 1, 1998, California's deregulated wholesale electricity market began operation. At that time, the three utilities owned most of the electricity generation capacity in the state, which included nuclear, hydroelectric, coal, natural gas and geothermal units. Under pressure from the state, the utilities sold off nearly all of their natural gas powered generation over the following year, capacity that at the time produced 30 to 40 percent of the state's power. Five companies purchased most of this capacity, with each ending up with between 6 and 8 percent of the state's generation capacity.

For the first two years, prices fluctuated substantially within a month and even within a day. On a few days, the market registered severe shortages, and the independent system operator's real-time market price shot up to its price cap, which was $250/MWh, until October 1, 1999, when it was raised to $750/MWh. Still, the average wholesale price was never greater than $50/MWh in any month. Then, in June 2000, the precarious balance that the market had maintained fell apart. Wholesale prices increased dramatically, the independent system operator found itself unable to purchase as much power as it needed through its real-time market, and the utilities were paying wholesale prices that vastly exceeded the retail prices they were allowed to charge. Many people were surprised by the market disruption, but in retrospect, the surprise should have been that the market, as it was designed, took two years to self-destruct.

Why are Electricity Prices so Volatile?

Because storage of electricity is extremely costly and capacity constraints on generation facilities cannot be breached for significant periods without risk of costly damage, there are fairly hard constraints on the amount of electricity that can be delivered at any point in time. Yet, because of the properties of electricity transmission, an imbalance of supply and demand at any one location on an electricity grid can threaten the stability of the entire grid and can disrupt delivery of the product for *all* suppliers and consumers on the grid.

Given these unusual characteristics on the supply side of the electricity market, it is all the more remarkable how little flexibility has been built in to the demand side of the market. Metering technology to record consumption on an hourly basis

[4] Attempts by other trading forums, including the New York Mercantile Exchange, to create futures markets for electricity have also met with little success. It is hard to see how futures markets in electricity could achieve the depth and liquidity of markets that exist for other commodities, such as oil, natural gas or gold. Because electricity is not storable and transmission can become congested, prices can fluctuate dramatically over time and location. Thus, trades for any given location and time will not be very useful in hedging the price of power at another place or time.

is widely available and has even been installed at many industrial and commercial customers. Thus far, however, the meters have seldom been used to charge time-varying retail prices that reflect the time-varying wholesale cost of procuring electricity. Nearly all customers in California, and the rest of the United States, receive either a constant price or a simple fixed peak/off-peak price that captures very little of day-to-day variation in the cost of procuring electricity.

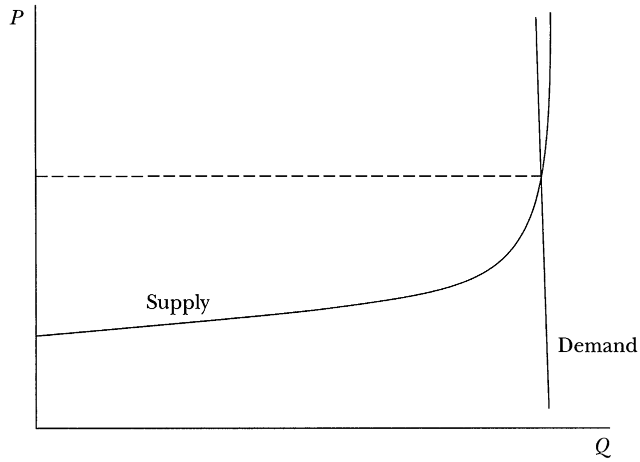
The price volatility resulting from inelastic demand and inelastic supply (when output nears capacity) is further exacerbated by the high capital intensity of electricity generation. Because a significant part of generation costs are fixed, the marginal cost of production will be well below the average cost for a plant operating at below its capacity. So long as the market price is above a plant's marginal operating cost, a competitive firm is better off generating than not. As a result, excess capacity in a competitive market will cause prices to fall to a level well below the average cost of producing electricity. This occurred in the capital-intensive memory chip industry in the early 1990s, when excess capacity caused prices of memory chips to collapse and producers to lose billions of dollars.

Figure 1 illustrates these characteristics of the electricity market graphically. Assume that the price at which the very inelastic supply and demand intersect allows the firm just to cover its fixed and variable costs. It is easy to see, however, that if capacity cannot adjust quickly and demand is difficult to forecast precisely, Figure 1 is an unlikely outcome. Even small changes will lead to a price boom or bust.

For example, a slight rightward shift of demand will cause price to skyrocket. Unlike, for instance, in the airline industry, where capacity on a route can adjust quickly and demand is responsive to price changes, there is no elasticity on the supply or demand side that allows the electricity market to adjust to such a mismatch. Extremely high prices may elicit a bit more output as generators run their plants harder—risking heavier maintenance costs—due to the tremendous profit opportunity. In nearly all current restructured markets, the demand response from high prices is primarily limited to actions by the independent system operator, which can reduce reserve margins (standby capacity it pays some generators to have ready on short notice) and can exercise contract rights it has to interrupt power to certain customers, an extreme measure that causes significant disruption to the affected customers.

The tight supply situation is exacerbated if markets are not fully competitive. Tight supply conditions in electricity markets put even a fairly small seller in a very strong position to exercise market power unilaterally, because there is very little demand elasticity and other suppliers are unable to increase their output appreciably (Borenstein, 2000). Because market power is easier to exercise in electricity markets when the competitive price would have been high anyway, it exacerbates the volatility of prices and further reduces the chance that prices will remain in a reasonable range.

Figure 1
Supply and Demand in the Electricity Market



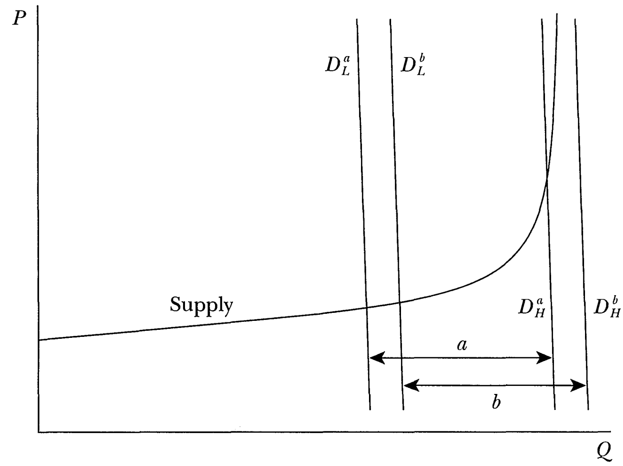
Many observers of deregulation have said that the root of the problem in California is that the state's expected surplus of capacity disappeared due to strong economic growth throughout the western U.S. electricity grid. If the surplus had remained, however, the result would have been a crisis of a different sort. A slight leftward shift of demand in Figure 1 causes price to collapse to the low marginal running costs of the marginal unit. These prices would almost certainly fail to cover the average costs of operating the plants, a situation similar to the 1990s memory chip market. In the newly deregulated electricity market, this outcome would surely have led to calls for subsidies to producers.

While Figure 1 and the discussion thus far has focused on one supply/demand interaction, the concept applies equally to a market in which demand varies by hour. In Figure 2, assume that demand in a month is distributed uniformly between D_L^a and D_H^a. Now, consider a relatively small rightward shift of the demand distribution to between D_L^b and D_H^b. This small shift replaces hours that were at very low prices on the left of the distribution with hours that are at extremely high prices at the right side of the distribution, causing the average price to increase drastically.

The discussion so far has assumed that all sellers in a short-term market for electricity receive the same price for delivery of power at the same time. In the policy debate, there was a great deal of discussion about the fact that sellers who have low production costs are paid a much higher market-clearing price. Some policymakers, and even a few economists, blamed this on the uniform-price auctions that were used by the Power Exchange and the independent system operator. This is, however, the way that all commodity markets work. Producers sell their output at the market price regardless of whether they are producing from low-cost or high-cost sources.

This demonstration of the law of one price is not a function of the auction

Figure 2
A Shift in Variable Demand in the Electricity Market



format or some design flaw in the electricity market.[5] It is true in all commodity markets, whether or not firms are able to exercise market power. Nonetheless, this outcome means that when a supply/demand mismatch causes extreme price volatility, it changes the price for all power being sold in the market at that time. This one-price outcome is in sharp contrast to the outcome under regulation, in which each production facility is compensated at its own average cost of production, and the price that consumers pay is set to cover the average of all of these production costs.

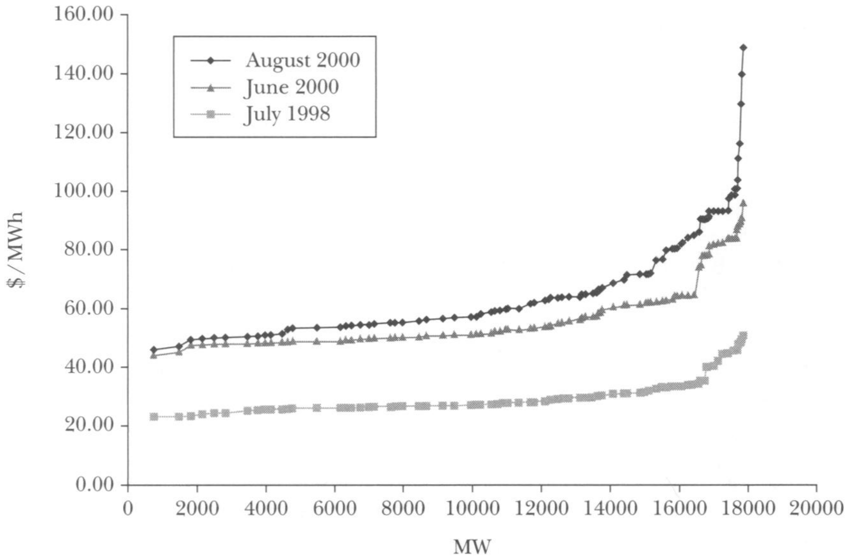
If production were just as efficient under regulation as in a competitive market, average-cost regulatory pricing would yield lower prices when supply is tight, because the marginal cost of production would be above the average cost. The difference would be even greater if the unregulated market were not completely competitive and unregulated prices were above marginal cost. California faced that situation in summer 2000. But in a situation of surplus capacity, marginal cost will be below average cost. In that case, the price from a market process may be below the price that regulation would produce, which is the situation that in 1996 many people believed California would face during the early years of restructuring.

The Upheaval in California's Electricity Market

California's summer 2000 electricity market illustrates the inherent volatility discussed in the previous section. A dryer-than-normal year, which reduced hydroelectric production, combined with a hotter-than-normal summer and continued

[5] Kahn, Cramton, Porter and Tabors (2001) analyze uniform-price versus pay-as-bid auctions in the California electricity market. Wolfram (1999) discusses the same issue in the U.K. electricity market.

Figure 3
California Thermal-Generation Supply Curve
(various months)



economic growth throughout the western United States shifted the supply/demand balance and caused the market to tighten up suddenly. Although the investor-owned utilities had by 2000 received permission to buy a limited amount of power under long-term contracts, they were doing very little of it. They were still procuring about 90 percent of their "net short" position—the power that they were not producing with their own generation and did not have under contracts that predated the restructuring—in the Power Exchange's day-ahead or the system operator's real-time market.

In addition, cost increases for thermal generating plants (in California, nearly all of which are natural-gas fueled) raised production costs and, importantly, did so much more for the marginal production units. Figure 3 shows the marginal cost curve from all thermal plant capacity in California. This omits production from nuclear and hydroelectric production, which are inframarginal in nearly all hours, and renewable sources (wind, solar and geothermal), which have less reliable production patterns. Thermal plant production is nearly always the marginal power source in California.

The lowest line is the marginal cost curve during July 1998, when gas prices were low and the costs of pollution permits for emitting nitrogen oxide were negligible. The next highest line shows costs during June 2000, when natural gas prices were almost double their 1998 levels. Not only has the curve shifted up, it has rotated, with the costs of the most expensive units increasing more, because the most expensive units convert natural gas to electricity at about half the efficiency rate of the least expensive generators. By August 2000, shown in the highest line, the problem was further exacerbated as the price of nitrogen oxide pollution permits increased from about $1 per pound to over $30 per pound (and gas prices increased further). The least efficient generators were also the biggest emitters of nitrogen oxide, so the rotation was even more pronounced.

Thus, even absent any exercise of market power, the cost and demand changes that took place during summer 2000 would have greatly increased market prices. The rotation of the supply curve meant that the increased price of natural gas and nitrogen oxide pollution permits not only raised electricity prices to cover increased costs, they also greatly increased the inframarginal rents that suppliers were able to earn. In July 1998, the most expensive gas-fired generators had costs $20/MWh greater than the least expensive plants. By August 2000, the difference was more than $100/MWh. Thus, when the high-cost plants needed to run, it created enormous inframarginal rents for low-cost producers.

Market Power in California's Wholesale Market

A number of empirical studies have concluded that sellers have exercised significant market power in California's wholesale electricity market (Borenstein, Bushnell and Wolak, 2001; Wolak, Nordhaus and Shapiro, 2000; Puller, 2001; Joskow and Kahn, 2001; Hildebrandt, 2001; Sheffrin, 2001). Harvey and Hogan (2000, 2001) have disputed these conclusions by suggesting that the studies did not appropriately control for costs and scarcity, but their work does not offer an alternative empirical analysis. This debate over market power has differed from those in many other industries because it has focused on unilateral exercise of market power by firms that have a comparatively small share of total production in the market. The unregulated generation owners that have been accused of exercising market power own between 6 and 8 percent of the production capacity in the independent system operator control area. The Federal Energy Regulatory Commission (FERC) has the power to monitor and to mitigate market power, but until 2001, it was committed to the view that firms with a market share below 20 percent could not exercise significant market power.

This focus on market share analysis ignores the reality that in a market with no demand elasticity and strict production constraints, a firm with even a small percentage of the market could exercise extreme market power when demand is high. On a hot summer afternoon, when the system operator needs 97 percent of all generators running to meet demand, a firm that owns 6 percent of capacity can exercise a great deal of market power. In fact, a seller will find it profitable to exercise market power any time the elasticity of residual demand the firm faces is sufficiently small. That elasticity is determined by the elasticity of market demand and the elasticity of supply from other producers.

Figure 3 shows that in summer 2000, beyond about 14,000 MW of thermal generation, the marginal cost curve becomes increasingly steep, implying a less elastic residual demand curve faced by any single producer. Restricting output becomes more profitable when the cost of the next highest cost generation unit exceeds the market price by a greater amount, that is, when the industry supply function is steeper.

Thus, while the exact degree of market power is an empirical question, a reasonable first-cut analysis leads one to ask why a seller with 3,000–4,000 MW of capacity *wouldn't* exercise market power. Borenstein and Bushnell (1999) simulated the market using a Cournot quantity-setting model. Even with an assumed demand elasticity of -0.1—larger than any plausible estimate under the California transition plan—we found the potential for very significant markups without any collusion among sellers.[6]

The Role of Long-Term Contracting

In unregulated markets that exhibit a great deal of spot-price volatility, buyers and sellers commonly smooth their transaction prices by signing long-term contracts. Nearly all electricity markets outside of California have taken this approach. In many cases, the sale of utility generation facilities to other firms has been accompanied by "vesting contracts" that require a certain amount of power sales back to the utility at a predetermined price. Also, the regulated utilities have in many cases retained some of their generation facilities. The price customers end up paying for the power from those facilities is then based on their costs of operation, not the market price. While California had virtually no vesting contracts, the California utilities did retain generation facilities, and they had some long-term contracts that predated restructuring. Together, these sources accounted for more than 60 percent of the power the California utilities delivered to customers.

Some participants in the debate have suggested that utilities in California and elsewhere will get systematically lower prices buying power on long-term contracts than they will get in the spot market. Spot prices, however, are very unlikely to exceed forward prices for power to be delivered on the same day in a systematic way, because such a situation would set up a profitable arbitrage opportunity. In summer 2000 in California, power contracted in advance was cheaper than spot power for the same delivery hour, but the reason sellers were willing to contract at those lower prices in advance—in late 1999 or early 2000—was that their best guess of summer 2000 prices was below the spot prices that actually resulted. In contrast, the forward prices for power to be delivered during 2001–2002 in California shot up in early 2001, and contracts signed at that time turned out to be well above the

[6] Some observers have argued that any capital-intensive industry will always be imperfectly competitive, so measuring margins above short-run marginal cost is meaningless. This is incorrect on both counts. First, even if markets are imperfectly competitive, measuring price-cost margins is the appropriate way to see how imperfect that competition is and to monitor changes in the degree of imperfection. Second, many capital-intensive industries are populated by price-taking firms. Gold mining, for instance, is a highly capital-intensive industry in which all sellers are price takers. In fact, the same is true for most of the goods listed on the commodities page of the *Wall Street Journal*, such as oil, natural gas, corn, oats, silver and coffee. This is also the page on which the *Journal* lists California electricity prices.

spot price for summer 2001, when spot prices collapsed. *On average, a purchaser buying power in forward markets (or through long-term bilateral contracts) will not receive lower power costs than a purchaser buying in the spot market.*[7]

The buyer's concern with long-term forward contracting, of course, is that it might lock in a higher price than it would have had to pay if it had purchased in nearer-term markets. This fear is especially large for regulated utilities acting as energy service providers in a restructured market. They are concerned that in such a situation the state regulatory agency might decide that the contract purchase price was "imprudent" and not allow the utility to pass through the costs to customers. Credible commitment by regulators is difficult. Nonetheless, it is clear that the correct standard for judging the prudence of these contracts is based on the information available at the time the contract is signed, not looking backward after the actual spot prices have become available. Such opportunistic behavior by regulatory agencies simply discourages prudent long-term contracting.

Long-Term Contracts and Market Power

While forward prices won't systematically beat spot prices, there is a potential price-lowering effect in *both* forward and spot markets if, in aggregate, buyers purchase more power through long-term contracts. Locking in some sales in advance reduces the incentives of multiple firms to behave less competitively among themselves (Allaz and Vila, 1993).

The idea is that if firms are maintaining high prices by foregoing aggressive price cutting, then the existence of many forums for trading, especially over time, makes it more difficult to maintain such mutual forbearance. The forbearance could take the form of implicit or explicit collusion, or it could be the result of unilateral decisions that result in a less competitive outcome, such as under Cournot competition. The possibility of selling in advance makes it more difficult for firms to restrain competition. Once a firm has sold some output in advance, it has less incentive to restrict its output in the spot market in an attempt to push up prices in that market, since it does not receive the higher spot price on the output it has already sold through a forward contract. Thus, in anticipation of more aggressive competition in the spot market—because some firms have presold a significant quantity in a forward market—firms are likely to price more aggressively in the forward market.

More generally, the incentive of a generating company to exercise market power will depend on its *net* purchasing position in the market at a given point in time. If a firm were a large net seller, it would likely have an incentive to restrict output to raise price. If it had sold much of its output under forward contracts, then it would have much less incentive to restrict its output to increase the spot price.

[7] The study by Borenstein, Bushnell, Knittel and Wolfram (2001) looks at the relationship between the California Power Exchange's day-ahead price and the California independent system operator's balancing market price. We note that prices in the forward market could be lower on average if sellers are systematically more risk averse than buyers, but we argue that this is unlikely.

The actual equilibrium impact of forward contracting on both spot and forward market prices is uncertain. It can do no more than eliminate the portion of price premia that are due to market power, and it might have a substantially smaller effect. Forward contracting cannot lower the average price a buyer pays to below the level that a buyer will obtain in a competitive market.

Long-Term Contracting is Only Part of the Solution

Long-term contracting is an important part of the solution to the fundamental problem of electricity markets, but it does not "solve" the mismatches between supply and demand. It just prevents large fluctuations in electric bills when those mismatches occur. It can, however, be used to pay for excess or standby capacity by assuring that the generating companies receive payments sufficient to cover their capital costs even if demand turns out to be low and some of the capacity does not get used.

In fact, this is what the old regulatory system did. Utilities were assured of revenues to cover their costs and in return built sufficient capacity to make sure that all contingencies could be covered. Supply always exceeded demand by a significant amount, and the cost of all that idle capacity was rolled into the price that customers paid for the power that they did use.

Many players in the California market now advocate a return to this type of system in a quasi-deregulated electricity market. Utilities could sign long-term contracts for power and capacity that assured generators they could recover their costs even if the capacity were not actually used. A number of state and federal policymakers have argued that the state should always make sure that capacity exceeds expected demand by at least 15 percent.

A policy of holding excess capacity would assure that spot prices were always very low (assuming that no generator held a large market share) and that many new "peaker" plants were built to assure excess capacity but virtually never used. This outcome would be unfortunate, since it does not make sense to hold such capacity if the customer's value of consuming the additional power when it is used is less than the full cost of making the power available. Real-time retail prices that reflect the cost imposed by additional consumption in each hour are the ideal mechanism for making that tradeoff.

Thus far, California and other states have attempted to make electricity markets work almost entirely on the supply side of the market. This approach has worked relatively well in some markets, but the California crisis has demonstrated the variety of constraints that exist on the supply side. Deregulating only the supply side of the market seems to be the equivalent of making an electricity market operate with one arm tied behind its back. Combining long-term contracts with real-time pricing can provide the right economic incentives to reduce demand at peak times when the system is strained, while still assuring customers of relatively stable monthly bills.

Real-Time Retail Price Signals and Stable Monthly Bills

Although the marginal cost of producing electricity varies tremendously over time and producers face hard capacity constraints, in very few electricity markets do retail prices reflect these cost variations. Peak/off-peak pricing is fairly common for commercial and industrial customers, but it is virtually always implemented as "time-of-use" pricing, a two- or three-price system with, for instance, one price for daytime usage and a lower price for nighttime usage. Real-time retail pricing, in contrast, allows prices to change with each given time interval, such as ten minutes or one hour, and prices need not be the same at a given time from one day to the next.[8] The effect of customers facing a single constant price for electricity is that they have no more incentive to conserve during peak consumption times, like a hot summer afternoon, than during low consumption times, like a cool afternoon or the middle of the night. They also have no incentive to shift consumption away from times when the production capacity of the grid is strained and production costs are highest. As a result, more capacity needs to be built to accommodate all of the demand at the highest peak times than would otherwise be the case. Real-time pricing would reduce the need to build new plants that would run for only a few days of peak demand each year.

While many people have advocated greater price responsiveness in demand through real-time retail electricity pricing, at the same time, there have been calls for greater protection of customers from price spikes. These goals may seem to conflict, but it is possible to expose customers to hourly price fluctuations, so that price-responsive demand will be meaningful, and still assure them of relative stability in their monthly bills. The key to meeting both of these goals is to recognize that the *average level* of prices can be stabilized without damping the variation in prices. For an energy service provider to offer both real-time retail price variation and monthly bill stability, without risking substantial losses, it needs to hedge a significant portion of its energy cost through long-term contracts.

To be concrete, assume that the energy service provider begins by engaging in no hedging. It charges customers a fixed per-kilowatt-hour transmission and distribution charge plus the spot price of energy in each hour. This approach satisfies the real-time pricing goal, but the monthly bills would be as variable as the month-to-month variation in the weighted-average spot energy prices. To attain the goal of monthly bill stability, the energy service provider would sign a long-term contract to buy some amount of power at a fixed price. Such a contract is likely to be at about the average spot price of the electricity that the parties anticipate over the life of the contract, but in any given month, the contract price could be greater or less than the average spot price.[9]

This contract can be considered a financial investment that is completely

[8] Borenstein (2001) discusses the large advantages of real-time pricing over time-of-use pricing.
[9] Alternatively, if the energy service provider owns generation capacity, it need only to hedge the price of fuel to run the generation. Capacity ownership itself hedges much of the electricity price risk.

independent of the retailing function. The critical point is that the energy service provider's return on this financial investment varies directly with the average spot price of energy, and that return can be applied to change the average level of customer bills. When viewed this way, it becomes clear that the long-term contract can affect the average price level without damping the price variation. The gains from the long-term contract (when the average spot price is higher than the contract price) or losses (when the average spot price is lower than the contract price) could be distributed to customers to stabilize bills. The distribution could be done with a constant (over the month) surcharge or discount on each kilowatt-hour sold during that month or—even more attractive to economists—as a lump-sum transfer based, perhaps, on the customer's past usage levels.

The most important impact of this approach would be that it would lower quantities demanded at peak times, and by doing so, it would lower the market prices at those times. Hearkening back to Figure 1, the demand curves would become much flatter, since customers would be able to see and to respond to high prices. This would prevent extreme price spikes. It would also reduce the financial incentive of sellers to exercise market power, since one firm's reduction of output would have a smaller effect on price than it does when demand is completely price-inelastic. Thus, real-time pricing would lower the overall average wholesale cost of power.[10]

The effect of real-time pricing also has very important implications for the negotiation of long-term contracts. If sellers, at the time of negotiation, believe that real-time pricing is likely, then they will reduce their forecasts of the average spot prices they would be able to earn if they did not sell through a long-term contract. As a result, the sellers will be willing to accept a lower long-term contract price than they otherwise would. Unfortunately, California did not make such a commitment to real-time pricing before it negotiated many long-term contracts in the spring of 2001.

Though real-time pricing has not been widely used in the United States, the technology is well established. Most large commercial and industrial customers in California have real-time meters already, and communication of the day-ahead or imbalance market price to those customers can easily take place through the Internet. In the near future, it may not be practical or necessary to include residential customers in a real-time pricing program, but as the cost of real-time meters declines, including residential customers can be straightforward. It is critical to understand that the *variation* in prices can be separated from the *average level* of prices. For any given level of flat retail price that is contemplated, the same systemwide average price level can be attained each month with real-time retail

[10] It is also worth noting that setting retail prices below the sum of the wholesale price and the transmission and distribution charge can move prices closer to the actual marginal cost, even if there is no market power present. Transmission and distribution is charged on a marginal basis, but these costs are largely fixed. Therefore, reducing price by up to the transmission and distribution fee that would otherwise be in the retail price has the effect of moving price closer to marginal cost.

pricing. Doing it with real-time pricing will reduce the cost of procuring the power and reduce the need to build more power plants, ultimately allowing lower retail prices.

While real-time pricing would increase total welfare, those customers who now consume disproportionately at times when the system demand is highest could be made worse off. Under the current flat pricing of electricity, these customers are subsidized by those that consume a smaller share of the system load at peak times than at off-peak times. In the case of California, this cross-subsidy roughly runs geographically from coastal communities that use less air conditioning to central valley communities that use more.

However, even with a moderate amount of price responsiveness, the wholesale electricity price at peak times would be reduced as demand at those times declines, so the increase in the retail price at peak times relative to flat retail pricing would not be nearly as great as one would infer from looking at price patterns during 2000. To the extent that policymakers wish to cross-subsidize areas that consume more power at peak times, this could be done through an explicit subsidy of power use in those areas, preferably one that does not continue to subsidize consumption at peak times most heavily. In the end, however, the only way absolutely to assure that *no one* will be made worse off by ending this cross-subsidy is to continue with flat pricing, which gives no incentive to reduce peak-time consumption

The Difference Between Real-Time Retail Pricing and Paying for "Negawatts"

Many alternative programs have been proposed that mimic, to some extent, the effect of real-time pricing. These programs generally are based on the idea of paying customers to reduce consumption at certain times. Paying for demand reduction at peak demand times may seem, at first, more attractive than real-time pricing, because it "rewards" those who conserve at peak times rather than "punishing" those who consume when the system is strained. The distinction is, of course, misleading, since the rewards are paid for through either electricity rate increases that are spread across all consumption or other taxes that are unrelated to the cost of electricity consumed.

While these programs can, in theory, offer many of the benefits of real-time pricing, in practice they offer much less benefit and about the same cost. On the cost side, implementing any sort of demand-reduction market requires the same real-time metering equipment and about as much information on price, quantity demanded or reserve margins as real-time pricing. You can't reward demand reduction unless you know when and how much reduction occurred.

The more difficult problem with paying for demand reduction is the baseline from which the payment is made. Unless the program is mandatory and the baseline is set based on information that is completely out of the control of the customer (such as demand information from a number of years earlier), the program will be subject to extensive manipulation and self-selection problems. The manipulation occurs if the baseline is set based on any consumption information that can be affected after the program is announced or anticipated. For instance, one recent suggestion in California would pay a customer on superpeak hot summer days to reduce demand from its average level over the previous x days. This plan would greatly diminish any incentive to reduce demand in other days, since such actions would lower the baseline the customer started from on the superpeak days.

The self-selection problem exists even if the baseline is set from truly exogenous information. The entities that would opt to sign up for these programs will disproportionately be the ones who know already that they will be reducing their demands, such as companies that are reducing their operations or that have already changed their production process to use less power.[11] Likewise, those entities whose baseline has been set inordinately high, due to some unusual activity during the period used for determining the baseline, would also be more likely to join the program.

The Role of Price Caps

In California and other wholesale electricity markets, price spikes have led to a debate about imposing price controls. In reality, price caps are, and will continue to be, a critical element of virtually all wholesale electricity markets. The extreme inelasticity of both supply and demand means that supply shortages, whether real or due to market power, can potentially drive prices many thousands of times higher than their normal level. Such outcomes would destroy the market. Therefore, the debate should be about the level of price caps and mechanisms for their adjustment.

Price cap opponents have said that such controls reduce investment in production facilities and reduce production from facilities that already exist. Both statements are potentially true. *If price caps are set too low, they will have detrimental effects.* The question is at what level these effects will occur.

In the short run, a price cap will deter production from an existing facility if the cap is below the short-run marginal cost of production. Until summer 2000 in California, suggestions that a \$250/Mwh price cap would deter production were hard to credit. During that summer, the additional cost of air pollution permits in the south coast may have pushed the incremental cost for the least efficient plants in that area above the cap and thus deterred them from producing. The problem became very salient in November and December 2000, when a spike in the price of natural gas—rising from \$4–\$6 per million BTU (British thermal units) to over \$30—put the incremental cost of nearly all natural gas plants above the price cap.

Price caps, however, can also deter the exercise of market power. A cap set at or above the competitive price, but below the price that would have resulted without the cap, will lower prices and *increase* aggregate output from the firms in the

[11] A very similar self-selection problem occurs if real-time pricing is implemented on a voluntary basis. Those entities that know they consume disproportionately at the peak times will not opt for the program and will thus continue to have no incentive to conserve when the system is strained.

market.[12] The intuition is that with a price cap in place, firms with market power do not have an incentive to restrict output any more than would be necessary to raise price to the cap. Thus, the appropriate level for price caps trades off the risk of setting them too low and deterring production with the risk of setting them too high and permitting the exercise of excessive market power.

The long-run impact of price caps is straightforward to analyze conceptually, but more difficult to study empirically. A price cap will deter investment in new capacity if it is set, or if investors believe it will be set, at a level that does not allow a return on investment that exceeds the investors' cost of capital. The data available on costs of building a power plant are necessarily rougher than the data on variable costs of production, because the costs of building a power plant are subject to many idiosyncratic factors related to location, siting restrictions and other attributes. Furthermore, the beliefs of investors play a critical role, because the return is calculated over the life of the plant. Just as under cost-of-service regulation, uncertainty about future regulatory intervention is likely to deter investment. Thus, price caps should be used with great caution.

Still, it is a well-established result that absent significant scale economies, a price cap that is set at or above the competitive price level in every hour will not deter efficient investment. In a fully restructured electricity market with price-responsive demand and long-term contracts, price caps should exist only as a backstop measure. The debate over price caps in California took place in a setting with no price-responsive demand and very limited use of long-term contracts.

Finally, economic analysis of price caps has generally assumed that an announced price cap is credible and is never breached. That was not the case in California during 2000; the independent system operator frequently violated the cap, both during the summer, when the competitive price was probably below the cap nearly all of the time, and in November and December 2000, when, for a few weeks, the competitive price almost certainly exceeded the cap due to soaring natural gas prices. In the latter situation, violation of the cap was the only reasonable action, since generators were better off shutting down than selling power at $250/MWh.

During summer 2000, however, the breaches of the cap made it very difficult to convince sellers that attempts to raise the price above the cap through exercise of market power would fail. Absent such credibility, the price cap creates a game of "chicken" between sellers and buyers. In the case of California, the independent system operator's unwillingness to curtail demand, and its inability to elicit demand-side response with real-time retail prices, put it in a very weak position in these showdowns.

[12] See Carlton and Perloff (1994, pp. 864–870) for an example. Also see Viscusi, Vernon and Harrington (2000, pp. 500–503).

The Aftermath of the California Electricity Crisis

Because retail electricity rates remained frozen through 2000, the California utilities lost millions of dollars per day buying power at high wholesale prices and selling at lower retail prices. In early 2001, with the utilities teetering on the edge of bankruptcy and no longer creditworthy, the state of California stepped in to become the wholesale power buyer for the utilities.

At the same time, the state and the California utilities pleaded with the Federal Energy Regulatory Commission to impose price caps on the wholesale market. The FERC had imposed "soft caps" in December 2000, which were largely ineffective due to half-hearted enforcement. Throughout spring 2001, the federal and state government were at loggerheads over the price cap issue, until May 2001, when FERC quite suddenly reversed its position and imposed price caps that were lower and more likely to be enforced.

During spring 2001, the state of California also signed long-term power contracts, ranging from one to 20 years, with nearly all of the major generators selling power in the California market. The contract prices are difficult to characterize easily due to the varying lengths and contract conditions, but they were clearly at prices that most observers would have considered astoundingly high a year earlier. In part, the high prices spread over many years were a way for the state to hide astronomical prices it was implicitly going to pay for power during summer 2001 and 2002.

In early June 2001, just as the new price cap policy was taking effect and the state was completing negotiation of the long-term contracts that covered most of the utilities' net short position for at least the next few years, the price of natural gas suddenly collapsed in California, falling from around $10 per million BTU to the $3 range, a level comparable to the eastern United States. Some observers argued that the sudden collapse, which coincided with a change in one company's transmission rights on the main pipeline into southern California, indicated that the price had been artificially inflated.

The collapse of gas prices occurred at nearly the same time that the California Public Utilities Commission finally raised retail electricity prices. The price increase was 40 percent to 50 percent for most industrial and commercial customers, but less than half that for most residential customers. In addition, the state instituted a summer 2001 rebate plan that rewarded customers who reduced consumption by at least 20 percent from summer 2000 levels.

Mild weather and aggressive conservation (which reduced weather-adjusted demand by 5 to 10 percent) combined with price caps, long-term contracts and, most importantly, the collapse of natural gas prices sent spot electricity prices tumbling in June 2001. By mid-summer 2001, spot electricity prices were back to pre-crisis levels, and the state was committed to over $40 billion worth of long-term electricity contracts at prices that are likely more than 50 percent above the expected future spot prices. These are the new stranded costs of the California electricity industry. Of course, many large customers then attempted to avoid paying for these costs by switching from the utility providers to other energy service providers, who could once again offer prices well below the utility prices that have the stranded cost recovery bundled in. Rather than imposing a non-bypassable charge to cover contract costs, the California Public Utilities Commission responded by canceling retail competition. In many ways, California has returned to 1996, albeit with customers many billions of dollars poorer.

Finally, during summer 2001, the state also established the California Public Power Authority. The CPPA has set about building state-owned "peaker" plants to assure that there won't be another shortage. Its goal is a 15 percent reserve capacity margin, which it argues is necessary to ensure a competitive wholesale market.

In spring 2001, California launched a $35 million program to install real-time meters at all large industrial and commercial customers. Despite that expenditure, real-time electricity pricing has stalled at the California Public Utilities Commission and at this writing seems unlikely to be adopted on even a widespread voluntary basis in the near future.

Conclusion

The movement toward restructuring of electricity markets was born from a history of well-supported dissatisfaction with outcomes under cost-of-service regulation. Nonetheless, electricity markets have proven to be more difficult to restructure than many other markets that served as models for deregulation—including airlines, trucking, natural gas and oil—due to the unusual combination of extremely inelastic supply and extremely inelastic demand. Real-time retail pricing and long-term contracting can help to control the soaring wholesale prices recently seen in California and can buy time to address other important structural problems that need to be solved to create a stable, well-functioning electricity market. These problems include creating a workable structure for retail competition, determining the most efficient way to set locational prices and transmission charges, implementing a coherent framework for investing in new transmission capacity and optimizing the procurement of reserve capacity.

Those states and countries that have not yet started down the road of electricity deregulation would be wise to wait to learn from the experiments that are now occurring in California, New York, Pennsylvania, New England, England and Wales, Norway, Australia and elsewhere. The difficulties with the outcomes so far, however, should not be interpreted as a failure of restructuring, but as part of the lurching process toward an electric power industry that is still likely to serve customers better than the approaches of the past.

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DEREGULATED ELECTRICITY IN TEXAS

A MARKET ANNUAL
2018 EDITION

A special research project by
Texas Coalition for Affordable Power

tcaptx.com

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This Report at a Glance

Deregulated Electricity in Texas tells the story of Senate Bill 7, the retail electric deregulation law. It's also "A Market Annual" because this report describes key electric market-related events in Texas, but organized chronologically in a year-by-year fashion. This report includes a preliminary section describing the period before to passage of SB 7 as well as 18 separate annual sections. The first version of this report was released to the Texas Legislature in 2008 under the title "The History of Electric Deregulation in Texas."

About TCAP

The Texas Coalition for Affordable Power ("TCAP"), a political subdivision corporation, enjoys a unique vantage point within the state's deregulated electricity market. Originally two separate non-profit corporations — the Cities Aggregation Power Project and the South Texas Aggregation Project — TCAP pools the resources of its more than 160 member political subdivisions to purchase electricity in bulk for the needs of local government authorities.

TCAP members purchase in excess of 1.3 billion kilowatt-hours of power each year for street lighting, office buildings, water plants and other municipal needs. An increase by even a single penny in electric rates can cost cities millions of dollars — money that can impact municipal budgets and the ability to fund essential services. High electric prices also can impact the welfare of city residents. TCAP wants what all Texans want: a fair system for delivering electricity.

- Deregulated Electricity in Texas includes subsections that highlight key issues. These subsections are interspersed chronologically throughout the report. They have blue backgrounds and are located along the right-hand margins of most pages.

- A description of the key components of Senate Bill 7 can be found in Appendix A. There are several other appendices, including those describing ERCOT, electricity complaints and utility unbundling.

- Deregulated Electricity in Texas includes charts and graphs that describe electric prices and complaint data. The charts also examine the effect of natural gas generation on the market, compare prices in regulated states versus deregulated states, and compare price increases among all states over time.

Executive Summary and Overview

On Jan. 1, 2002, precisely at the stroke of midnight, Texas broke with its long tradition of regulating most electric service. It was a colossal policy change. No longer would giant, vertically-integrated utilities maintain their monopoly grip on residential and business customers. No longer would Austin political appointees determine directly the price of air conditioning and lighting homes. Instead, new Retail Electric Providers (REPs) would vie for business in most parts of Texas. In theory, the free market and competition would keep a lid on rates. There would be more choices, and better service.

These were the promises of electric deregulation.

But have electric prices improved? Is service better? And what about the bumps along the way? With the luxury of hindsight, what can we say about the policies that worked and those that have not?

Deregulated Electricity in Texas: A Market Annual examines these questions and more.

THIS REPORT EXAMINES THE FACTS THAT:

- Average electricity prices in areas of Texas both inside and outside deregulation have declined in recent years. However, Texans in deregulated areas consistently have paid more for power than Texans outside deregulation.
- The number of electricity shopping choices has expanded greatly since the early years of the electric deregulation law, but comparison shopping remains a challenge.
- Transmission and distribution rates have increased in recent years at a pace greater than inflation. Although these rates are regulated, they contribute to electricity costs in deregulated areas.
- The Texas Legislature has failed to act on important reforms, including proposals to guard against market abuse.

KEY QUESTIONS RAISED IN DEREGULATED ELECTRICITY IN TEXAS:

- *What can be done to reduce confusion in the retail electricity market?*
- *What reforms would help guard the deregulated market against anti-competitive abuse?*
- *Regulated transmission and distribute rates impact electricity costs in deregulated areas. What can be done to ensure those regulated rates don't rise needlessly?*
- *What is the right balance between system reliability and cost?*
- *Deregulated Electricity in Texas, first published in 2009 but now updated and expanded, tells the story of electric deregulation from the beginning. It includes sections summarizing key milestones, new pricing charts and updated spotlight articles highlighting key policy challenges.*

Major Findings

Texans Lost Ground during the first 10 years of Retail Electric Deregulation in Texas

For the 10 years prior to the law, Texans paid average residential prices 6.4 percent below the national average. In the 10 years after deregulation, Texans paid prices 8.5 percent above the national average.

Texans in Deregulated Areas have Consistently Paid More for Electricity

All told, Texans living in deregulated areas would have saved nearly $25 billion dollars in lower residential electricity bills from 2002 through 2014 had they paid the same average prices during that period as Texans living outside deregulation. This "lost savings" amounts to more than $5,100 for a typical household. However, the difference between average residential electricity prices inside and outside deregulation has been trending downward since 2011.

Price-To-Beat Mechanism Failed to Protect Consumers

High natural gas prices, a flawed "price-to-beat mechanism" under Senate Bill 7, and a reluctance of Texas consumers to switch providers contributed to high average electricity prices in Texas during the early years of the deregulated era. Natural gas prices have come down in recent years and the Price-To-Beat has expired. This has contributed to lower average electricity prices since 2008.

Generators Shift Costs to Consumers

Deregulation-related charges known as stranded costs have added nearly $7 billion to consumer bills. In recent years generators have been lobbying for additional payments from consumers, in the form of capacity subsidies.

Renewable Energy Gains May be Tempered by Higher Costs for Consumers

Over the past 10 years Texas has become a leader in the development of wind power. However, the construction of transmission lines to serve West Texas wind generators will add to transmission costs for all Texans. The aggressive pursuit of wind power has created new reliability challenges.

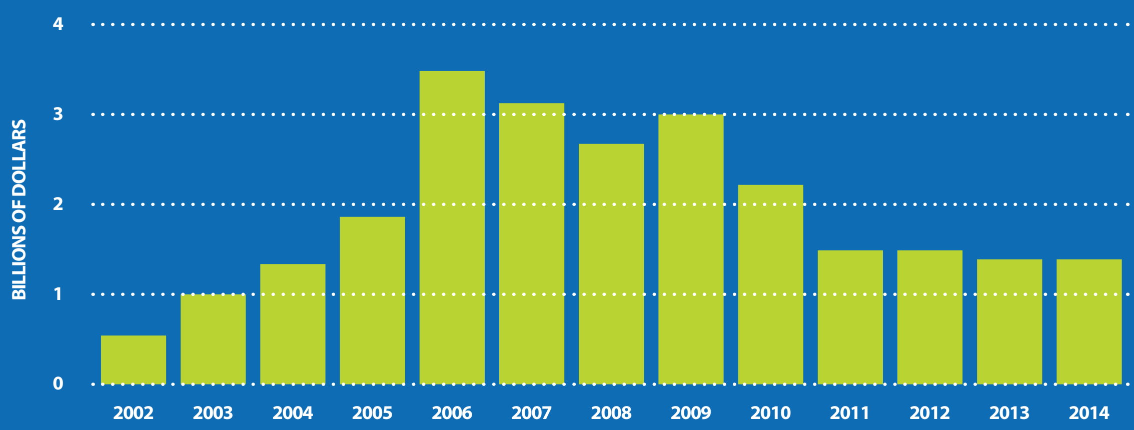
Transmission and Distribution Rates Impacting Deregulated Electricity Prices

Although monopoly transmission and distribution utilities operate under regulation, their rates impact electricity prices charged by competitive retail electric providers. Transmission and distribution charges paid around the Houston, Dallas and Fort Worth areas have increased at a pace outstripping inflation and comprise an increasing share of monthly electric bills.

Nearly $25 Billion in Lost Savings

This exhibit analyzes the most recent relevant pricing data from the U.S. Energy Information Administration, as of the time of publication. Only residential prices rates are examined.

Source: United States Energy Information Administration http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls



Average electric prices in Texas charged by deregulated providers have been consistently higher than average prices charged by providers exempt from deregulation. The exhibit above measures the potential impact of these higher prices. The green bars illustrate the aggregate savings that would have accrued to Texans in deregulated areas had they instead paid the lower average rates charged in areas outside deregulation. The lost savings ranges from about a half billion per year to more than $3.5 billion. Providers exempt from deregulation include municipally-owned utilities and electric coop-eratives. Also, investor-owned utilities operating within Texas but outside the ERCOT region are exempt. Only residential prices are considered.

Recommendations

TCAP members are committed to making electric deregulation work. Affordable power in a fully competitive market means economic development for our communities and a better life for our citizens. The Texas Coalition for Affordable Power proposes the following reforms to protect competition in the deregulated market and to encourage the delivery of affordable electricity to Texas homes and businesses.

Avoid Changes in the Market Structure that Increase Wholesale Costs

Policymakers should look for ways to stimulate growth in generation resources other than through price supports and subsidies that are inconsistent with the principles of competition and a free market. Policymakers should reject all proposals for "capacity markets" in which generators get paid even when they do not operate. This will only add to consumer bills.

Enhance Protections against Anti-Competitive Activities in the Wholesale Market

Anti-competitive behavior should be prohibited in the wholesale energy market, and legal loopholes that exempt some generators from prosecution should be closed. The submission of "hockey stick bids" and anti-competitive practices prohibited in other states by the Federal Energy Regulatory Commission should be outlawed in Texas. Penalties for anti-competitive activities should be increased. When market power abuses occur, market participants harmed by such anti-competitive activities should be given the right to participate in investigations and enforcement actions undertaken by regulators.

Promote Standard Offer Deals

All retail electric providers operating in Texas should offer a standard fixed-rate product, with terms and conditions set by the Texas Public Utility Commission. The REPs would be free to set their own price for the standard-offer product. Standard Offer Products will help reduce confusion in the retail electricity market and allow for apples-to-apples comparison shopping.

Improve the PowertoChoose.com Website

The PowertoChoose.com website, which is designed to facilitate comparison shopping, should be as complete as possible. The Public Utility Commission should maintain its vigilance against gaming of the site by unscrupulous retail electric providers. All retail electric providers that operate in Texas should be required to list at least one deal on the website, and to promote powertochoose.com through a printed notice on home electricity bills.

Oppose One-Way Ratemaking

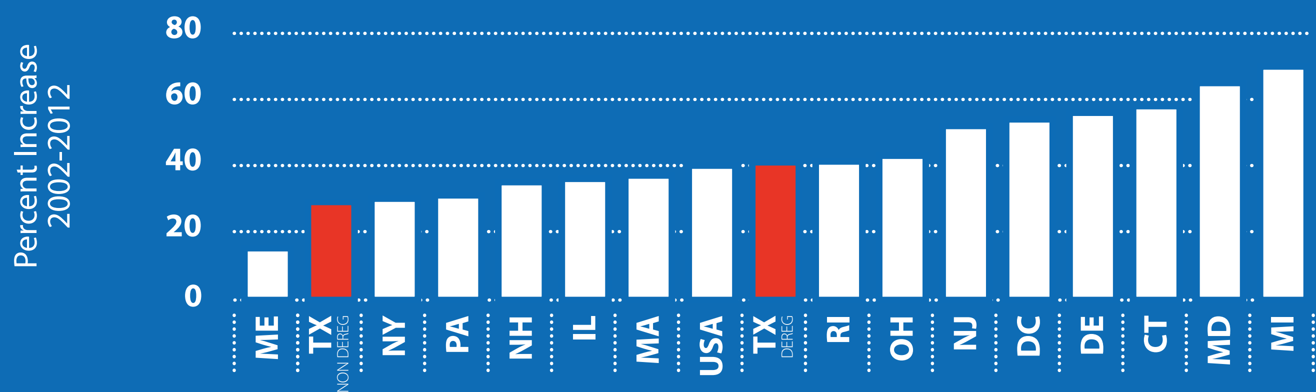
Utility proposals for "streamlined," "alternative" or "one-way" rate-setting for regulated distribution and transmission services should be rejected. These rate-making proposals are known as "one-way" because they work only in one way: against ratepayers. They would lead to higher overall bills — even in deregulated areas.

Re-regulation is Not the Answer

Policymakers should strive to make the state's deregulated electricity system as efficient and fair to Texas consumers as possible. Re-regulation is not the answer. Instead, the Public Utility Commission should pursue a balanced approach with regard to the state's electricity market. Consumer protection and affordability should have equal footing with the promotion of competition.

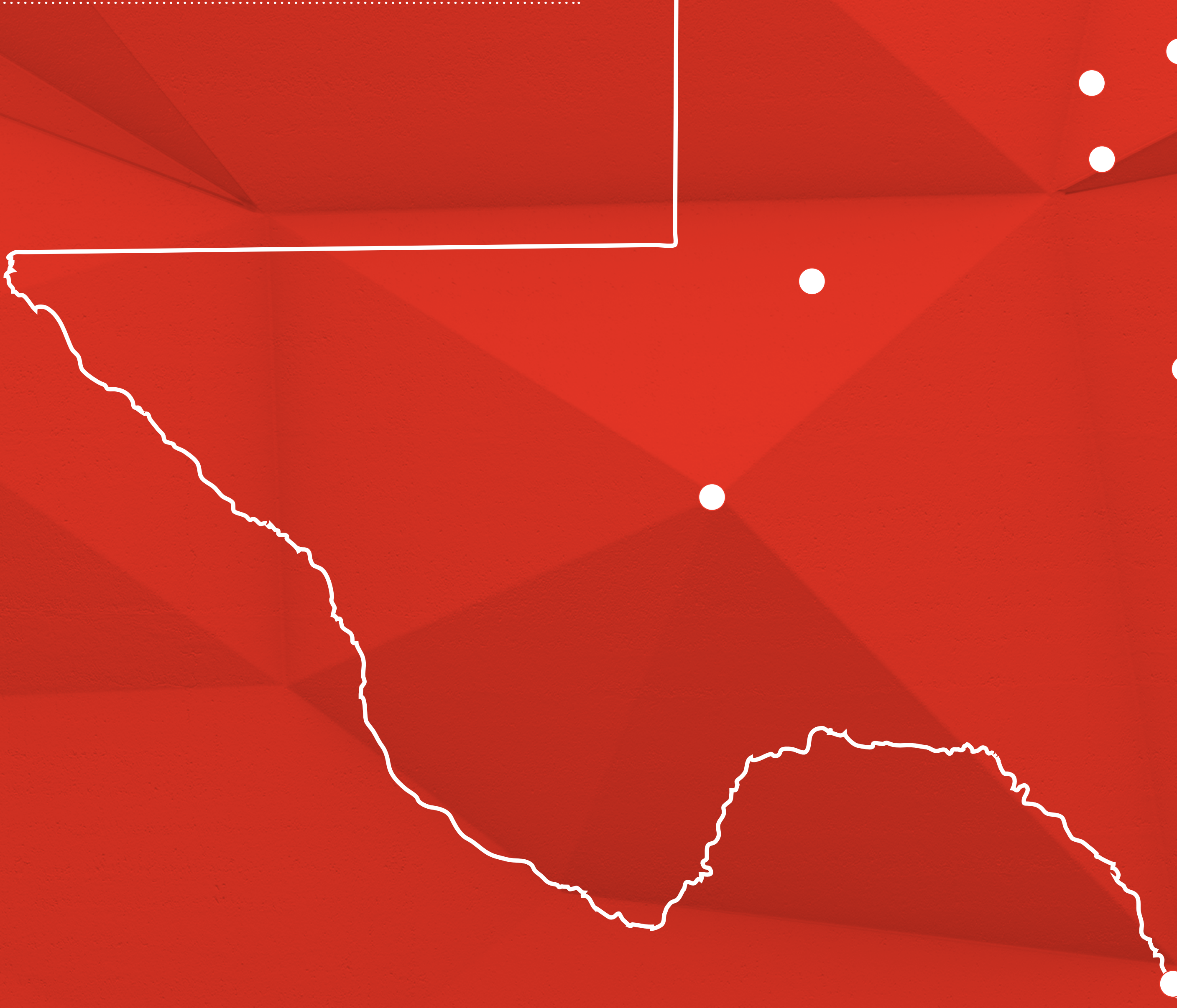
Residential Electricity Price Increases: 2002-2012

15 DEREGULATED STATES, INCLUDING DEREGULATED TEXAS
Source: United States Energy Information Administration http://www.eia.gov/cneaf/electricity/page/sales_revenue.xls



When it comes to price increases under deregulation, Texas fares better than 8 states and worse than 6. This exhibit compares changes in average residential price in deregulated areas of Texas with price changes in other dereregulated states. The time period is 2002 through 2012. This exhibit uses 2002 as a starting point because 2002 was the year deregulation took effect in Texas. It ends with 2012 because that year was the most recent (at the time of publication) for which there was relevant data to conduct the analysis.

TCAP members represent much of the great state of Texas



The Early Years

Electric deregulation — that is, the use of free-market principles to dictate prices — did not begin in Texas, nor did it arise in a vacuum. Rather, electric deregulation was a part of a larger nationwide trend that took hold during the 1970s and included the deregulation of railroads, airlines and telephone service.[1]

"With declining costs and the strong load growth in the State, it is likely that the commission could find itself facing a never-ending stream of rate cases in an attempt to harness utility over-earnings."

— PUC report to the 76th Texas Legislature

Most of the nation's electricity markets are governed by the Public Utility Holding Company Act, a Depression-era law that Congress adopted as a bulwark against anti-competitive behavior by power companies. Under that system, the states' public service commissions[2] — agencies like the Public Utility Commission ("PUC") in Texas — design rates sufficient to cover the monopoly utility's operating and investment costs, plus a reasonable level of profit.

The first meaningful change to the model came in 1978 with congressional passage of the Public Utility Regulatory Policies Act. Congress acted again in 1992 when it adopted the Energy Policy Act that led to the deregulation of wholesale markets.[3] In 1995 lawmakers passed legislation deregulating the wholesale power market in Texas.[4] The Federal Energy Regulatory Commission in 1996 also issued Order 888 requiring that utilities provide open access to their transmission lines to other power companies.[5]

Together these changes opened the door to a new market system, one clamored for by big industrial users. Utilities had invested in costly nuclear and coal generation during the 1970s. Industrial users wanted to be free to buy cheaper

Postage Stamp Pricing

Different electric companies in Texas have for years maintained interconnected transmission systems, and these companies would sometimes use their interconnections to transfer power between one another for reliability reasons. In 1995 state lawmakers adopted legislation that also opened these interconnections to any power company wishing to trade wholesale power. This was an important step on the road to more complete deregulation that would follow.

But moving power across a transmission system is not free. Lawmakers understood that in order for competition in the wholesale market to work, power must be able to move freely across the state. Electricity transportation costs that varied by transmission company could hamper the ability of a generator to sell power to buyers throughout ERCOT. The 1995 legislation attempted to address this issue through a policy of "postage stamp pricing."[20] Postage stamp pricing means that, like the price of a stamp on a piece of mail, the price to transmit one megawatt of power is the same whether the power is sent across the state or to the next city.

Moving power from parts of the state where power is plentiful to areas where it is needed most has become a major problem in the deregulated market. The transmission system in Texas was built to support the old monopoly system, not the dynamic deregulated market. Without enough transmission capacity, power cannot flow smoothly in some areas. Transmission bottlenecks and system constraints lead to congestion costs that are ultimately passed on to retail customers.

power from other generating units, but that could only happen if they could extricate themselves from rate regulation. Industrial users also predicted that their economic and organizational clout would allow them to negotiate better deals under a deregulated system.[6]

By 1996 Enron, the Houston-based energy company also had begun aggressively advocating for deregulation.[7]

Some economists perceived a potential benefit in electric deregulation, arguing that regulated utilities as monopoly providers lacked strong incentives to keep down costs and to pursue efficiencies in their operations. They argued that under the traditional regulated system, utilities had an economic incentive to build out their systems to the largest extent possible. They could then shift costs on to their captive ratepayers and, in the process, increase overall profits.

Others cautioned that technological and economic barriers unique to electric power make deregulating electric markets infeasible. Electricity — unlike most tradable commodities — cannot be stored. This means that in a deregulated system, consumers are captive to volatile price swings. And because electricity is essential to the public's welfare, dips in reliability or increases in prices can cause serious hardships, medical problems, or — in the most extreme cases — death.

CALIFORNIA DEREGULATES

California became the first state to move to deregulate its electric market when legislators there unanimously adopted Assembly Bill 1890 in August of 1996. AB 1890 had been pushed through the California legislature in just a few weeks at the urging of Enron, other power lobbyists and big business interests.[8] Perhaps indicative of the increased attention on the California electric market, Gov. Pete Wilson and other major political players in the California deregulation effort took in nearly three times the amount of political donations from utilities that year than they had just two years earlier.[9]

Problems appeared almost immediately. Enron and other new suppliers quickly realized that there was no profit in serving residential customers and so stopped signing them up. Three months after the power market deregulated the price for reserve power jumped from $1 to $2,500 per megawatt-hour. It then jumped to $5,000, stayed there for three hours and then mysteriously dropped back to $1. Four days later, it spiked again — this time to $9,999. The price stayed there for four hours and then dropped to one penny.[10]

"All of us saw those numbers and realized … there was nothing to stop someone from bidding infinity," said Jeffrey Tranen, then the chief executive for the California grid operator.[11]

Meanwhile in Texas, Gov. George W. Bush wanted to proceed beyond wholesale deregulation. He unveiled an Enron-

The Senator and the Napkin Doodle

Even state Sen. David Sibley, the Waco Republican now remembered as one of the architects of the Texas law, saw that the proposed system could be manipulated.

During the plane ride back from an early fact-finding mission to California, Sen. Sibley began doodling out some ideas on a napkin.

"We got a napkin, and it looked like you could game the power exchange," Sen. Sibley later told a reporter. "We had our (PUC) guy and our staff and people just started talking about how you could figure out how to withhold just enough electricity. We were just kind of toying with it, kind of war games things on the airplane".

"Now, I'm a dentist," Sen. Sibley said, "and if I could figure it out, it seemed like someone else could, too."[19]

supported bill[12] in 1997 that would deregulate the Texas retail electric market.[13] But big utilities like Texas Utilities Co. (later TXU) questioned whether the "Texas Consumer Power Act" would allow them to receive payments for investments they said would become uneconomical under the new system. Gov. Bush and Lt. Gov. Bob Bullock brokered a compromise that appeased the utilities, but the effort fell short, and the bill died in committee.[14]

Texas lawmakers continued studying the issue during the 1998 interim with a seven-member Senate committee going so far as to fly to England to examine that country's deregulation efforts. During this period, Enron, industrial users and Gov. Bush shored up political support for electric deregulation.[15]

New Hampshire, Rhode Island and Pennsylvania also had begun implementing retail deregulation in 1997.[16]

UTILITY OVEREARNINGS

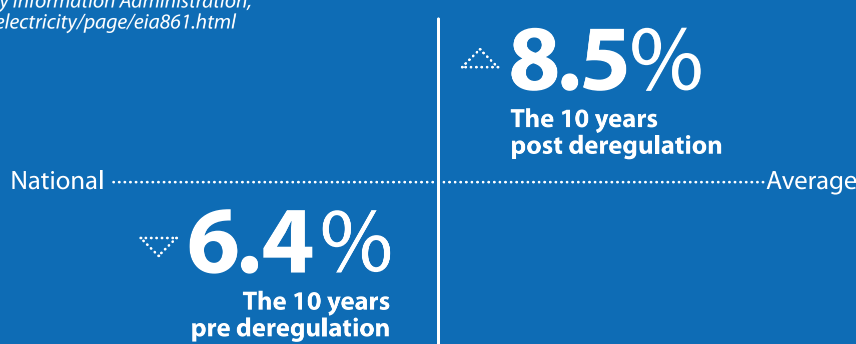
By 1999, the PUC, under then-Chairman Pat Wood, openly acknowledged that the rates charged by utilities were too high. In its Scope of Competition report, the PUC made clear that selling electricity in Texas was a declining-cost industry: "With declining costs and the strong load growth in the State, it is likely that the commission could find itself facing a never-ending stream of rate cases in an attempt to harness utility over-earnings."[17]

This meant that by 1999 utilities in Houston, Dallas and elsewhere were charging regulated rates that the PUC realized were producing profits in excess of what the commission had previously found reasonable. But instead of initiating proceedings to lower regulated rates, the PUC allowed the companies to continue charging the same amounts. The commission reasoned that in the event that the Legislature moved to deregulation, the utilities would demand certain payments for so-called "stranded investments" in such things like nuclear power plants that could become uneconomical in the new market. Under the commission's reasoning, extra revenue from the inflated regulated rates could be applied to accelerate debt payments on the stranded investments.[18]

These PUC-sanctioned over-earnings by utilities were intended to help facilitate the transition to deregulation. Instead, they became a contentious point during the upcoming legislative session when deregulation supporters began promising savings.

Texas Electricity Prices Before and After Deregulation

**Year to Date, Through June 2012*
Source: United States Energy Information Administration, http://www.eia.gov/cneaf/electricity/page/eia861.html



For the 10 years prior to the adoption of Senate Bill 7, Texans paid average residential electric prices that were 6.4 percent below the national average. In the most recent 10 years under the Texas electric deregulation law (through June 2012), Texans paid average rates that were 8.5 percent above the national average.

Year: 1999 The 76th Texas Legislature - Senate Bill 7 Becomes Law

On Jan. 20, 1999, during a packed press conference in a room just outside the Senate chambers, state Sen. David Sibley laid out his plan to deregulate the Texas electric market. The 76th legislative session was just getting under way. Sibley, co-sponsor of Senate Bill 7, would become a leading force behind the legislation that would fundamentally change how electricity is bought and sold in Texas. Sen. Sibley was clear in his intention.

"We want this bill to bring down the cost of electricity for all Texans," he said.[1] Building on that goal, Sen. Sibley later added that "if we don't get [for] consumers lower rates, then we have been a failure — I'll be the first to say it."[2] The Waco Republican also pledged his law "would benefit virtually everyone living within our state's borders."[3]

In announcing the landmark legislation, the governor underscored its purpose: 'Competition in the electric industry will benefit Texans by reducing monthly rates.'

Rep. Steve Wolens, champion of deregulation in the Texas House, acknowledged that while Texans already enjoyed relatively low electric rates, they spent more money on electricity than the national average. Never mind that the main reason for these bigger bills was not a flawed market design but rather Texans' reliance on air-conditioning to battle the state's famous summer heat — a fact no amount of electric deregulation could change.

"Lower electric rates will help Texas companies compete in the international marketplace, make more household money available for spending on non-energy goods and services and bring new investments into Texas," Wolens said.[4]

Deregulation proponents also predicted (incorrectly as it turned out) that the federal government could soon require retail deregulation nationwide. By adopting its own deregulation law first, Texas could avoid coming under federal jurisdiction, according to the proponents.[5]

Eventually Rep. Wolens and Sen. Sibley merged their ideas into a single piece of legislation, approximately 200 pages long. Enron was a big supporter of the legislation, as were traditional electric companies.[6] Consumer groups, however, expressed skepticism.

"I think it's the industry people who are pushing it, trying to create this kind of frenzy so that legislators feel like they have to act," said Consumers Union analyst Janee Briesemeister. "They're trying to create urgency by putting ads on television, trying to tell people what they want, even though people don't know they want it," she said.[7]

A few lawmakers also urged caution.

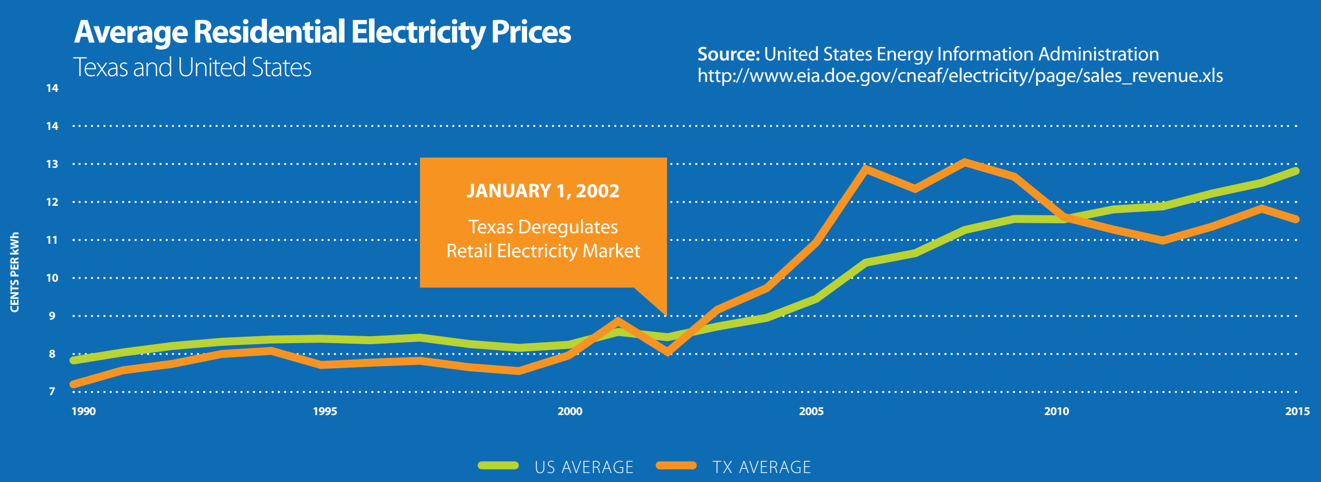
"I don't see the great public necessity for what we're doing," said one East Texas lawmaker. "Texas has some of the lowest rates in the nation. We have some of the best reliability in the nation … And obviously, we don't know what this will do."[8]

On March 8 a Senate committee adopted the legislation unanimously. On March 17 the full Senate gave its approval. Wolens' House committee signed off on the bill on May 12th and then it was adopted by the full House on May 21.[9] Gov. Bush signed Senate Bill 7 on June 18 proclaiming that "competition in the electric industry will benefit Texans by reducing monthly rates."[10]

SB 7 resulted in some of the most significant changes to the state's electricity market in history. It included more than a half dozen major provisions, including a wide expansion of wholesale electric deregulation, the first-ever authorization for competition among retail electric providers, new renewable energy mandates and a green light for utilities to seek billions of dollars in "stranded costs" payments. All of this had the potential to dramatically impact the consumer pocketbook. (Read a more complete description of Senate Bill 7 in Appendix A.)

Major environmental groups supported the law. Most major consumer advocacy organizations opposed it or

Average Residential Electricity Prices Texas and United States 1990-2015



Texans enjoyed average statewide electricity prices below the national average for many years prior to the implementation of the deregulation law. After the Texas electric market deregulated, average residential electricity prices increased above the national average and remained significantly above that mark for many years. Note that this exhibit does not differentiate between average prices inside and outside areas of Texas with deregulation. Rather, it compares average residential prices statewide with average prices nationwide.

As has been demonstrated separately, average residential prices in Texas outside deregulation remained consistently below the national average after 2002, while average prices in deregulated areas shifted above the national average [See Exhibit 1]. Therefore, the high residential electricity prices statewide relative to the nationwide average must be attributed to the deregulated sector of Texas.

Note that Exhibit 5 demonstrates that average residential prices in Texas spiked above the national average in 2001. Although that spike occurred before the deregulation of the state's retail electricity market, it was nonetheless a function of deregulation. This is because the Texas Public Utility Commission allowed utilities in 2001 to collect excess earnings and high fuel surcharges as a down payment on anticipated collections from the restructuring law. Average residential prices in Texas dropped after the deregulated market opened in 2002 because the fuel surcharges expired and because the deregulation law mandated a 6 percent cut in base rates. Average statewide residential prices then remained above the national average through 2011.

Source: United States Energy Information Administration — http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls

eyed it with deep skepticism.[11] A large majority of Texans said they were satisfied with the current regulated system, which for more than a decade had resulted in rates below the national average.[12]

In fact, most Texans in 1999 were probably unaware that electric deregulation was underway, or even contemplated. And yet with the passage of SB 7, electric deregulation is what they would get. (For summary of SB 7 see Appendix A).

Year: 2000 The California Crisis and the Texas Experience

With the turn of the century came the beginning of California's energy crisis, brought on by that state's electric deregulation law. Wholesale prices surged to unprecedented levels and some consumer bills increased three-fold.[1] California's largest utilities were brought to the brink of financial ruin. The state suffered rolling blackouts because power was unavailable or overscheduled.[2]

California had removed price controls in the wholesale market, but left them on retail rates. That pinched the utility companies. Adding to the woes was a spike in natural gas prices, a drought in the Northwest that reduced hydropower and — as was revealed later — price manipulation by Enron traders. "Every possible thing that could go wrong has happened," said Michael Worms, an energy-industry analyst with Gerard Klauer Mattison in New York.[3]

But unlike other states that began cautiously pumping the brakes on deregulation in the face of the unfolding disaster in California, Texas continued forward with its plans. "We don't foresee going back and working and doing any changes," said state Rep. Steve Wolens, during a legislative hearing on Aug. 22, 2000.[4]

Wholesale prices surged to unprecedented levels, and some consumer bills increased three-fold.

Rep. Wolens and state Sen. David Sibley rightly pointed out that their law differed in many respects from the Golden State legislation. They noted, for instance, that electric retailers in Texas had greater incentives to enter into long-term contracts. By entering into long-term contracts, retailers could more easily avoid the price spikes that can accompany seasonal increases in electricity demand. They also noted that Texas enjoyed healthy power reserves and that this extra generating capacity should help keep wholesale prices down.

STRANDED COSTS: CUSTOMERS OWE NOTHING?

In September 2000, an administrative law judge ruled that instead of owing $2.8 billion to TXU Electric for its stranded costs, that ratepayers instead may be due $1.45 billion in credits. The judge ruled that TXU ignored PUC instructions when it made its calculations.

TXU immediately blasted this preliminary ruling, claiming that it "robbed" the company of due process. "Our stranded costs are $2.8 billion, and we have the right to prove it," utility spokesman Christopher K. Schein said.[5]

Stranded costs, remember, represent the value of expenditures made by utilities in a regulated environment that would be recoverable from ratepayers over time under regulation but which might be unrecoverable in a competitive environment. The theory is that if generation assets become uneconomical burdens under deregulation, then ratepayers owe utilities the lost value of those assets.

Stranded costs are calculated by considering the difference under deregulation between the book value of a utility's generation assets like coal, lignite and nuclear generation plants and the market value of those assets. While the book value remains relatively constant (changing annually with depreciation accounting entries) during the transition to deregulation, market value changes daily. The calculation of market value is tied to natural gas commodity prices, which can directly impact the value of a utility's entire generation fleet.

Rep. Wolens and state Sen. David Sibley rightly pointed out that their law differed in many respects from the Golden State legislation. They noted, for instance, that electric retailers in Texas had greater incentives to enter into long-term contracts. By entering into long-term contracts, retailers could more easily avoid the price spikes that can accompany seasonal increases in electricity demand. They also noted that Texas enjoyed healthy power reserves and that this extra generating capacity should help keep wholesale prices down.[6]

"The Worst They'd Seen in 30 Years"

The California power crisis of 2000 was so profound that it put a quick end to the nationwide trend toward utility deregulation and even prompted many states that had passed deregulation laws to change course.

Wholesale electricity prices in California surged to unprecedented levels. Consumer electricity prices went up as well — in some cases bills tripled.[9] The state suffered rolling blackouts because power was unavailable or overscheduled. The deregulation disaster threatened the state's then-booming economy and nearly sank its biggest utilities. Said Paul Patterson, an analyst at Credit Suisse First Boston in New York: "No one wants to hold stock in a company that is subsidizing its customers — if PG&E has to swallow this loss, investors will run in droves."[10]

The crisis also led the state's Independent System Operator — California's version of ERCOT — to declare "energy emergencies" on an almost daily basis. But supplies continued to dwindle. Near the end of the year the system operator declared an unprecedented Stage 3 alert, a signal that power reserves had dropped so low as to become almost non-existent. "Operators here in the control room were saying this was the worst they'd seen in 30 years in the utilities business," said Stephanie McCorkle, a spokeswoman for the organization.[11]

Only by frantically pushing through power from other states at the last minute could the grid operator dodge system-wide blackouts.

To understand the judge's ruling, consider that when natural gas commodity prices are low — as they were in the years preceding deregulation — the cost to generate power using natural gas plants is also low compared to plants that use coal, lignite or nuclear fuel. That means that low natural gas commodity prices would tend to make a utility's standard fleet of coal, lignite and nuclear plants relatively less valuable in the market — and therefore increase the value of the utility's stranded costs.

By contrast, when natural gas commodity prices go up, plants that use coal, lignite and nuclear fuel become more attractive, and their market value increases. That would tend to decrease stranded costs or — theoretically — create negative stranded costs. Rather than owing billions of dollars to utilities for uneconomical plants, ratepayers instead may be owed billions of dollars in refunds for having helped finance lucrative generating plants that now put the incumbent utilities at an economic advantage in the deregulated market.

Generally speaking, this was the assessment of the administrative law judge when she ruled against TXU in the September case. The PUC staff likewise suggested the total value of some utilities' stranded costs may have become negative. "The increases in the cost of natural gas over the past year have resulted in revised stranded cost projections that for most utilities are much lower or negative amounts, based on the commission model," the agency noted in its 2001 Scope of Competition report. "Since the commission first estimated stranded costs, the magnitude of total stranded investment has been reduced—and, in fact, may have become negative."[7]

Of course, the mere suggestion of negative stranded cost refunds caused a ripple through the entire industry. Senate Bill 7 "only recognizes positive stranded costs," said TXU spokesman Schein, echoing the prevailing industry sentiment among incumbent utilities.[8] This policy divide – how to calculate stranded costs and whether ratepayers could receive credits if calculations produced a negative result—would foreshadow one of the bitterest regulatory fights of the decade.

Year: 2001 The 77th Texas Legislature — Saying No To Ratepayer Refunds

APPREHENSION ABOUT DEREGULATION

Lawmakers should apply the brakes: with the crisis in the news daily, that's what Texans were telling pollsters in 2001. More than 40 percent of respondents to a Scripps Howard survey said deregulation should be put on hold, and another 13 percent said plans to deregulate should be scrapped altogether; three-fourths of those surveyed said they were satisfied with the regulated electric system already in place.[1] There had never been a public groundswell in the first place — it was a market change pushed by and for big business — and now the public was calling for lawmakers to reconsider it. But the move toward deregulation in Texas continued undeterred.

During the 77th Texas Legislature, lawmakers rejected two measures that could have added significant consumer protections to SB 7.

The first of those consumer-friendly bills, House Bill 918 by state Rep. Sylvester Turner, would have allowed regulators to extend price limits on residential electricity, put limits on wholesale electric prices and suspend a number of deregulation-related collections from ratepayers. Also, importantly, HB 918 would have given regulators more authority to delay the Jan. 1, 2002 market opening.[2] Industry representatives warned against tampering with Senate Bill 7,[3] and the legislation died in House committee.

In February, Rep. Turner filed House Bill 2107. This bill addressed the issue of so-called "negative" stranded costs — that is, the ratepayer refunds that can theoretically result when market value exceeds book value of generation assets. Under some estimates, HB 2107 could have resulted in nearly $7 billion in customer refunds, or more than $300 for every man, woman and child living in Texas — an astronomical amount.[4]

The utilities argued that SB 7 never contemplated negative stranded costs, and that such refunds were out of order. Tom Baker, then president of TXU Electric, said all those billions of dollars in potential refunds belonged to the company's investors, not the ratepayers who funded the construction of the plants through the rates they paid — and that taking the money away from the company would constitute an illegal confiscation. "No legal or business model would support such a confiscation," he said.[5]

But the Public Utility Commission, in a report issued shortly before the legislative session, said the question of negative stranded costs was an open one. Chairman Pat Wood III, an architect of the deregulation law, said making utilities pay for their over-earnings "would be the fix that will make this whole thing work because, otherwise, you've got money that would make the market work going to the owners of the generators." Chairman Wood said SB 7 left open the question of whether consumers can be awarded negative stranded costs and that Rep. Turner's bill would clarify that issue.[6]

. . . in April, ERCOT officials received a confidential internal report warning that their systems were in disarray. . . it added, presciently, that ERCOT's upgrade project would go over-budget. It noted that ERCOT had failed to meet numerous project goals. . .

It was a wild ride for HB 2107. It made it through the House committee, just barely, and then improbably onto the floor of the House, where it won passage. But it was killed in early May before it could be considered by the full Senate. The coup de grace was a parliamentary move by state Sen. Tom Haywood. A spokesman for Sen. Haywood said that by killing the bill the senator was doing consumers a favor.[7]

Responded one consumer advocate: "How is it bad for consumers to get their own money back? When consumers overpay, decent responsible businesses usually give the money back."[8] (For more about stranded costs and related issues, see page 66 and Appendix C).

PROBLEMS AT ERCOT

In preparation for the new deregulated market, ERCOT, the operator of the Texas power grid, had consolidated its six regional centers into a single control facility near Austin. In addition to ensuring the power grid had exactly enough power moving across its lines to meet demand and prevent blackouts, ERCOT also assumed responsibility for overseeing a six-month deregulation pilot project to give its engineers an opportunity to test new computer systems. During the trial period, new retail electric providers could compete for up to 5 percent of the market. As it would be under full deregulation, ERCOT was responsible for transferring customers between companies participating in the pilot project.[9]

On Feb. 15, 2001—exactly on schedule—the PUC allowed new electric providers to begin signing up customers for the pilot project. Businesses began receiving information about the project in electricity bills that went out in February.[10] Residential customers received information a month later. Service in the trial market was to begin in June. "The time is right," said Jeannie Verkinnes, marketing manager for Shell Energy.[11]

ERCOT had spent months upgrading its systems in preparation for the pilot project. But in April officials there received a confidential internal report warning that their systems were in disarray. The report called for a host of last-minute changes. "Many of the changes identified ARE critical, and there is already a significant amount of risk in the marketplace," the April report stated. It added, presciently, that ERCOT's upgrade project would go over-budget. It noted that ERCOT had failed to meet numerous project goals and that ERCOT employees and contract workers required better management. But instead of discussing the report with the auditors, ERCOT officials got sidetracked and filed the report away.[12]

Two months after the first report, ERCOT received another internal draft report. It stated that the new system setup for deregulation "remains at high risk for (technical) and marketplace failures" and that "major delays were a result of systems that were not tested and/or ready." Like the previous report, it was authored by technical experts hired by ERCOT and was intended to guide the organization in its decisions as it prepared to handle customer switches once the market opened in January 2002. At the time of their release, very few people outside of ERCOT knew of either report's existence.[13]

As a result of its incorrect projections, the price of wholesale power appeared to spike to $15,000 per megawatt-hour when the cost was actually closer to $1.

Problems began to emerge even before the pilot project was underway. Power companies sent switch requests to ERCOT, but ERCOT's new computer systems couldn't handle them. So instead ERCOT officials turned to less technically sophisticated "work-arounds"—that is, they used emails and phone calls to process the switch requests. Customer switching was supposed to have begun by June, but problems at ERCOT led to repeated delays.[14] "There is a risk to the marketplace … this performance is unacceptable," PUC commissioner Brett Perlman told ERCOT leaders. He also said he had been regaled with complaints about giant billing errors generated by the organization. Industry insiders expressed alarm.[15]

The pilot project got underway on July 31st—two months behind schedule.[16] But even after delaying the pilot project three times, ERCOT still could not get its systems to work correctly. The organization had managed to get a computer center up and running on schedule but then could manage only to switch service for a handful of the 80,000 residential customers who signed up under the pilot project. ERCOT said the new system would be able to handle 20,000 switches daily once they got it to work properly.[17] But during the pilot project it was almost wholly incapable of managing any customer switches at all.

ERCOT's computer problems were harming not only residential customers and companies seeking to serve those customers — but companies not even participating in deregulation. Austin Energy, a municipally-owned utility outside the state's deregulated area, reported multi-million dollar errors on ERCOT-generated bills. "At the time of this filing, Austin Energy has not yet received a single accurate settlement," wrote Bob Kahn, Austin Energy vice president. "In fact, the statements we received contain gross allocation and calculation errors. In one case, Austin Energy received a statement for $90 million… when in fact it owed nothing."[18]

On July 31, the pilot project officially got under way. It had been delayed three times, was two months behind schedule and was immediately beset by problems.

An official at another municipally owned utility complained of "bigger than big" errors — errors so colossal that they could drive the utility to bankruptcy.[19]

ERCOT also drafted a budget that year that it kept almost entirely secret. It outlined its spending plans for 2002, the first full year of deregulation, and noted that spending would nearly double from the levels experienced in the previous few years. But other than that, details were scarce. "There is no accountability on the spending at ERCOT," Janee Briesemeister of Consumers Union said. "They adopt their budget in secret … and the budget results in a fee on every consumer electric bill."[20]

PRICE SPIKES IN THE WHOLESALE MARKET

Also in 2001, prices in the wholesale market began spiking. The magnitude of the price spikes —100 times typical price levels — were similar to spikes seen during the California crisis. The first occurred on July 31, the very first day of the pilot project, when power that had been selling for between $10 and $45 per megawatt-hour suddenly shot up to $1,000 per megawatt-hour. That price doubtlessly would have increased even more if not for caps established by the PUC to guard against the price-gouging witnessed in California.[21]

ERCOT officials blamed the first spike on an anomaly. "I don't think people are going to do it again," said Tom Noel, chief executive officer of ERCOT, referring to a supposed one-time mistake by power generators.[22] But then on Aug. 5 the market experienced more price spikes. In this new case, the power surged to 100 times its regular price. The prices could go no higher because of the regulatory cap.[23] On Aug. 8 wholesale prices spiked again — from a relatively typical level of less than $60 per megawatt-hour for balancing energy to $999. An hour later, the balancing energy price skyrocketed to $10,000 — but was adjusted downwards to $1,000 because of the price caps.[24]

Although the spikes impacted a relatively small segment of the wholesale market called the "Balancing Energy Market," they signaled big trouble. This is because the overall cost of power in the wholesale market — even the price of power in so-called longer-term bilateral contracts — parallels these spiking prices set in the smaller spot market. Also, under the ERCOT-managed spot market, the cost of the highest acceptable bid for power dictates the price to all successful bidders. For example, ERCOT might receive scores of bids ranging from $50 per megawatt-hour to $1,000 per megawatt-hour. If the grid operator needs 100 percent of that power to meet demand, then all bidders get the top price, or $1,000 per megawatt-hour — even those who submit bids offering to accept payment of $50 per megawatt-hour.

The price spikes experienced during the first week of the pilot project would prove pernicious, a problem that would plague the deregulated market for years. The spikes spurred regulatory investigations, lawsuits and bankruptcies. Underscoring the gravity of the situation and the uncertainty regarding appropriate controls, Danielle Jaussaud, the PUC's director of economic analysis, warned: "We don't know if the market is going to work — we don't know how well these rules are going to perform. … People ought to be concerned."[25]

Other warnings appeared in various reports to the PUC, ERCOT or in the comments of policy makers. One expert told the PUC in 2001 that under the Texas system, shortfalls could give electric companies "perverse incentives"

The Balancing Energy Market

The state's wholesale spot market, when it was known as the "Balancing Energy Market," established real-time prices at regular intervals, 24 hours a day. Through this market, ERCOT technicians ensured the continuous "balancing" of production and consumption of energy on the grid — hence the market's name.

Under ERCOT rules, generators bid power into the balancing market and then the highest-cost bid for required energy set the price for all other accepted bids. This meant that generators that produced relatively cheap coal-fired or wind energy still received payments as if they were producing more expensive power from natural gas-fired plants. These prices eventually got passed onto consumers. Said another way, under Senate Bill 7, the economic benefit of producing cheap electricity mostly has ended up in the pockets of generators as extra profits, not in the pockets of consumers as savings. This differs from a regulated cost-based system, whereby wholesale prices are linked more directly to the cost of production.

Balancing energy historically has comprised less than 10 percent of the energy bought and sold in the state's deregulated wholesale market, and yet it has been crucial in setting wholesale electricity prices overall. To the extent that balancing energy prices were higher than market conditions warranted, then it was a good bet that wholesale power prices overall also were too high.

Before Senate Bill 7, if a utility obtained power from both low-cost and high-cost generators, then the utility's rates reflected that mix of low-cost and high-cost power. But in the Balancing Energy Market — and indeed, in the restructured wholesale energy market overall — the direct link between energy prices and the cost of producing energy was severed.

In 2010 ERCOT replaced the Balancing Energy Market with a "Nodal" market (see page 53 for more details about the nodal market). However, many of the pricing principles of the Balancing Energy Market remain.

to inflate prices.[26] Another expert warned that some of the underlying premises behind Texas deregulation could be incorrect. Industry backers of Texas deregulation were blaming California's problems on a lack of generation capacity, but Harvard expert William W. Hogan and University of California-Berkeley expert Shmuel S. Oren told the PUC that more complicated factors in California that also impacted Texas were at play. In 2001, both Hogan and Oren forecasted possible price spikes, bureaucratic headaches and anti-competitive price inflation.[27]

SYSTEM RELIABILITY IS TESTED

Errors by ERCOT— an organization that literally has "reliability" as one of its middle names — also nearly caused blackouts during the pilot project. On the third, fourth and fifth day of the project, the organization grossly miscalculated the state's energy needs. As a result of its incorrect projections, the price of wholesale power appeared to spike to $15,000 per megawatt-hour when the cost was actually closer to $1. Grid operators went scrambling for the phones, frantically imploring power generators to ignore the erroneous computer data and ramp down production.

ERCOT officials attributed the miscalculations to human error and not to any defect in the market itself. No market participant actually paid the misstated prices.[28]

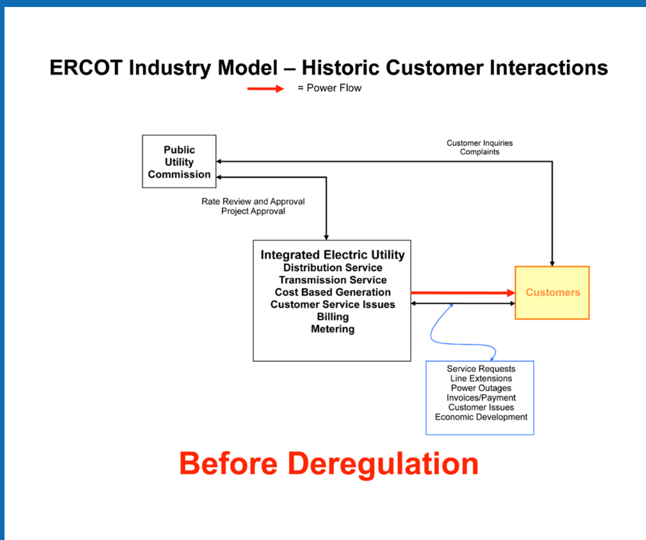
ERCOT blamed the next meltdown — on Aug. 9 — on a computer failure. It said an unknown problem shut down part of the wholesale market for four hours, a malfunction that was serious enough that officials had to make another round of urgent phone calls to generators to prevent blackouts.

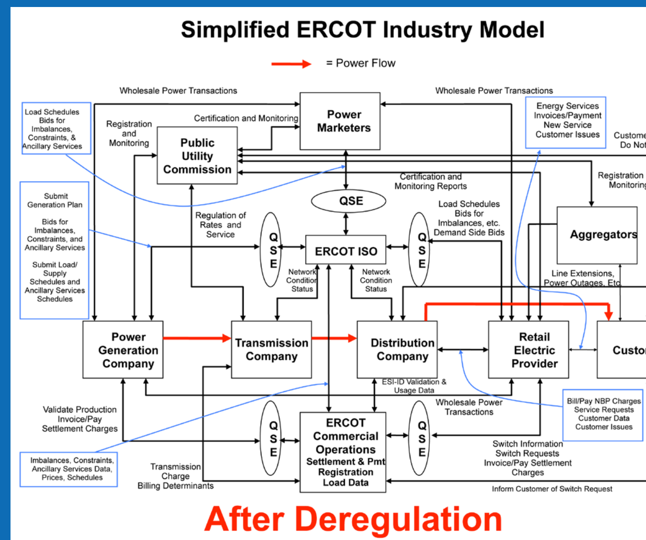
The pilot project was supposed to have given ERCOT an opportunity to test its systems, and give Texas a moment to take a deep breath before beginning the big show on Jan. 1. But as one consumer advocate wryly quipped: "They (ERCOT officials) don't appear to be ready to play with live ammo." Industry insiders began raising concerns about the readiness of ERCOT to handle the market going live in January.[30] Many would-be residential customers, commercial customers and other market participants echoed those concerns.

Sam Jones, the chief operating officer at ERCOT, said the problem was with the transmission system itself. He attributed the price spikes experienced during the pilot

New Market, New Complications

Source: ReSolved Energy Consulting





Sam Jones, then the chief operating officer for ERCOT, said in 2002 that "in exchange for an ability to shop around and get savings, (customers must allow) for a process that is more complicated than it used to be." The charts above illustrate graphically the complexity of the deregulated market in Texas. Under the previous system, electricity provided by the bundled utility flowed directly to the end-use customer. Under the Texas deregulated system, a much larger number of interconnected entities play a role in getting power to customers.

project to the lack of power lines: "We have a south-north constraint on the system, and people are trying to move a lot of power to the north — and it's driving prices up."[32]

Regulators had known for years that the lack of transmission could stymie deregulation. The wires system was never built to move power across vast regions of the state — a vital necessity if deregulation was going to efficiently lower wholesale power prices. Jones explained that without enough transmission, there would always be bottlenecks — especially during times of high demand, like during hot summer days.[33] Because of the bottlenecks, also called "congestion constraints," the cheapest power sometimes cannot get moved to parts of the state where it's needed most. And because electricity cannot be stored, power companies cannot keep cheap electricity in reserve.

STRANDED COSTS ARE SETTLED FOR TXU CUSTOMERS

One other highlight in 2001 bears note: an agreement reached late in the year between TXU and a coalition of cities, consumer groups and other market participants that is still seen today as one of the most far-reaching regulatory settlements in Texas history. Under the deal, TXU agreed to surrender billions of dollars in claims for "stranded" costs.

"I cannot think of a single case in Texas regulatory history that has been as comprehensive," TXU spokesman Christopher Schein said. "It settles, resolves or eliminates a dozen different lawsuits. We're looking at (an effect) going back as far as the Comanche Peak deal (of the '80s) and going forward for a decade."[34]

Under the terms of the deal, TXU would relinquish its claim on reimbursements for stranded investments — that is, those investments like nuclear power plants that utilities claim would become uneconomic under deregulation. SB 7 allowed companies like TXU to seek ratepayer reimbursements for such stranded investments. TXU at one time said it was owed more than $6 billion.[35]

The deal in 2001 recalculated the value of TXU's stranded costs to zero. TXU also agreed to surrender claim on about $350 million in fuel related charges. In exchange, consumer groups agreed to lift their objections to a bond-financing technique known as securitization that allowed the company to get up-front payment for over $1 billion in ratepayer obligations.[36] The PUC, with the support of consumer groups, had objected to the company's securitization claim, and prior to the settlement, the issue had been tied up in court.

…shortfalls could give electric companies 'perverse incentives' to inflate prices.

The settlement is now seen as an extremely significant consumer victory because companies other than TXU have subsequently argued successfully for billions of dollars in stranded costs. Houston's CenterPoint Energy, for instance, was awarded $4 billion[37] — money that every customer of CenterPoint would pay through surcharges on their transmission and distribution rates.

(For more information about stranded costs awards in Texas, see the chart on page 66).

The Enron Collapse

On Aug. 15, 2001, just months before the Texas market was set to open, Enron's chief executive Jeffrey Skilling unexpectedly announced his resignation. He had been in the CEO position only six months and by voluntarily resigning, he was surrendering what would have been a sizeable severance package. Predictably, the departure set off alarm bells on Wall Street. But Enron chairman Ken Lay, who announced he would resume his role as chief executive officer, told analysts to expect "no change in the performance or outlook of the company going forward." He said there was "absolutely no accounting issue" behind Skilling's departure — "no trading issue, no reserve issue, no previously unknown problem issues."[38]

Skilling sold 450,000 shares of Enron stock worth at least $33 million in the months before his departure. Enron stock surged in 2000 and for the early part of 2001 before dropping precipitously. By the time Skilling announced his resignation it was down nearly 50 percent for the year. In after-hours trading shortly before news of Skilling's departure was public, it fell again another 8 percent.[39] The value of Enron's shares dropped another 10 percent during the first week of September, bringing it down 62 percent for 2001.[40]

On Oct. 16 Enron posted a third-quarter loss of $618 million, the result of what it said was $1 billion in one-time charges for various businesses. Much of the losses were related to the poor performance of New Power, the complaint-maligned company set up to vie for retail business in deregulated markets.[41] On Oct. 23, in a conference call to nervous investors, Lay insisted the company had sufficient cash on hand to keep from writing off additional investments.[42]

By this point, analysts had begun asking questions about the company's labyrinthine business practices and financial reporting. The Securities and Exchange Commission initiated inquiries into transactions involving the company's chief financial officer, Andrew Fastow. Lay declined to provide details of those transactions during the conference call but nonetheless insisted that Enron board members "continue to have the highest faith and confidence in Andy." A day later, the board relieved Fastow of his duties.[43]

Time was running out for the once giant energy trader. The company consistently avoided giving straight answers to investors' questions, Moody's Investor Services lowered Enron's credit rating and shares continued to nosedive. It was becoming unclear whether the company could even raise enough cash to maintain day-to-day operations.[44]

On Nov. 9, rival Dynegy agreed to acquire Enron for about $8 billion.[45] It was a short-lived offer: after Enron's financial situation continued to deteriorate and more of Enron's questionable practices came to light, Dynergy pulled its offer. Once the world's largest energy trader and the seventh largest company in the country, Enron imploded. The company filed for bankruptcy on Dec. 2.[46]

In a story marking the company's end, *The New York Times* noted that the company's "decade-long effort to persuade lawmakers to deregulate electricity markets had succeeded from California to New York." *The Times* pointed out that Enron pioneered large-scale energy trading, a practice that had existed for less than a decade before the company's demise.[47]

The Times noted Enron's "ties to the Bush administration assured that its views would be heard in Washington." Enron, *The Times* noted, "dripped contempt for the regulators and consumer groups that stood between it and fully deregulated markets."[48] Enron's end came just days before Texas went forward with the deregulation system the company had pioneered.[49]

In August, not long before the collapse and just as Enron was attempting to open up electric transmission systems in the southeast, President Bush appointed former Public Utility Commission chairman Pat Wood III to chair the Federal Energy Regulatory Commission.[50] Enron CEO Lay had recommended Wood for that post, just as Lay earlier had recommended Wood's appointment to the PUC.[51] In June 2001, shortly before Enron went belly-up, Gov. Rick Perry appointed Max Yzaguirre, a former Enron executive, to chair the PUC.[52]

Year: 2002 The Market Opens

On Jan. 1, 2002, at precisely midnight, Texas opened its electricity markets to retail competition. Under the rules of Senate Bill 7, retail electric providers affiliated with the state's traditional utilities were required to charge 6 percent less than the regulated rates they charged prior to the start of competition.[1] This became the "Price To Beat" — that is, the price that new competitors tried to beat with lower rates. By undercutting the Price To Beat, the new competitors could steal away customers from the legacy electric providers. In theory, competition between the new providers all fighting to undercut the Price To Beat would keep prices down.[2]

That almost no residential customer paid a price other than the Price To Beat on the first day of deregulation was no surprise. Of course it would take time for customers to become comfortable with the deregulated market, investigate price offerings and make the switch. No one expected, however, that most customers would remain on the Price To Beat for years and years. The market remained "sticky," and customers remained cautious.

"In exchange for an ability to shop around and get savings, (customers must allow) for a process that is more complicated than it used to be…"

— ERCOT Chief Operating Officer Sam Jones

Deregulation's proponents claimed that Price To Beat customers were saving money. The enthusiasts pointed to the 6-percent cut, comparing the Price To Beat to the rates on Dec. 31, 2001 — the final day of the old regulated era. "The Price To Beat rates that we've established strike a good balance between immediate customer savings and attracting retail electric providers to enter our market and offer even greater savings and service innovations," said Max Yzaguirre, the Public Utility Commission chairman.[3]

But there's another side to the story. Consider this: while state regulators put potential savings to residential customers at more than $900 million, their analysis included savings attributed to the expiration of an unnecessary and overstated surcharge relating to fuel costs.[4] That surcharge would have expired even under the old regulated system (and the overcharges refunded to customers) and can't be attributed as customer savings from deregulation. In fact, when controlling for natural gas prices — as the state's Office of Public Utility Counsel (OPUC) did in one report — it becomes clear that customers ended up paying more for power on the first day of deregulation compared to regulated rates in place just prior the adoption of Senate Bill 7.

An example: a typical Dallas/Fort Worth Metroplex homeowner had paid about $74.08 a month for electricity in January, 1999. By January 2002, even with the rate cuts required by SB 7, that customer would pay $76.74, according to the OPUC analysis.[5]

The new Price To Beat rules also included a provision for calculating changes in fuel costs that would continue to drive up prices. Under it, companies could increase the Price To Beat rate twice a year to cover increases in the cost of natural gas, which fuels many of their plants.[6] But SB 7 — at least, as it was interpreted by the Texas Public Utility Commission — included no provision that would push the Price To Beat down in the event that natural gas prices decreased. As a consequence, the price paid by most Texans in the deregulated market went up, never down, for several years. If the price of natural gas increased, then the utilities increased Price To Beat rates. But if the natural gas price dropped, Price To Beat rates still remained high.[7] Rather than aggressively undercutting Price To Beat rates that were already out of step with the market, competitive retail electric providers inexplicably clustered their prices around Price To Beat rates.[8]

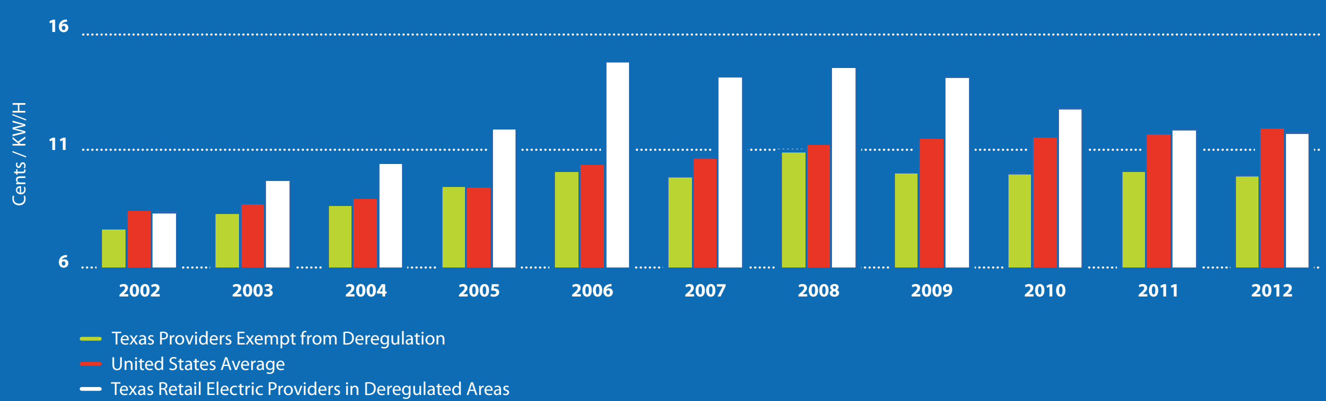
Another closely-related problem was that all adjustments made to the Price To Beat fuel factor were based entirely on changes in the price of natural gas. Generators use plenty of other fuel sources — including cheaper coal, lignite and nuclear generation — and the price of these fuels is much less volatile than natural gas. But lawmakers created SB 7 when natural gas prices were low and based the legislation upon the incorrect assumption that natural gas prices would stay that way. However, natural gas prices climbed steadily upward for many years after the passage of SB 7, and the Price To Beat prices marched up right behind them.

On April 23, 2002, TXU filed for its first increase under this controversial natural gas-based Price To Beat fuel factor mechanism.[9] The PUC approved that rate hike and others — nearly to 10 percent in some regions — within eight months of the market opening.[10] A spokesman for the electric company said increasing the Price To Beat would foster deregulation because new retailers would have more room to undercut it and still make a profit. Consumer advocates were skeptical.

"You have to raise rates to lower rates?" asked a puzzled Carol Biedrzycki, director of the Texas Ratepayers' Organization to Save Energy. "Competition was supposed to provide electricity at lower prices and with a higher level

Electricity Prices Higher Under Deregulation

AVERAGE RESIDENTIAL ELECTRICITY PRICES INSIDE AND OUTSIDE DEREGULATED AREAS OF TEXAS
(Providers exempt from competition include investor-owned utilities outside the ERCOT region, municipally-owned utilities and electric cooperatives.)
Source: United State Energy Information Administration http://www.eia.doe.gov/cneaf/electricity/page/eia861.html



Texans paid below-the-national-average electricity prices before the state deregulated its retail electricity market. But in 2002, the year that the deregulation law took effect, Texans in areas of the state participating in deregulation began paying above the national average, while Texans in areas exempted from deregulation continued paying below the national average.

Average residential rates in deregulated areas of Texas have been anywhere from 9 to 46 percent higher than average rates for areas of Texas outside deregulation. Moreover, average rates in deregulated areas of Texas have been generally higher than the nationwide average, while average rates in areas of Texas outside deregulation have been generally below the nationwide average. In 2012, for the first time in 10 years, average electricity prices in deregulated areas of Texas dipped below the nationwide average. The most recent relevant federal data available at the time of publication was used for this analysis.

of service. … If we have to raise [rates] so a competitor can afford to operate in the market place … [that] defeats the whole purpose of opening the market in the first place."[11]

DELAYED SWITCH REQUESTS, LATE BILLS AND EXCESSIVE SPENDING

ERCOT officials began the year by making bold promises. Despite the clunker of a pilot project and wholesale prices that went haywire, ERCOT officials said the organization was now up to the task of managing the new market. Sam Jones, the system's chief operations officer, predicted that ERCOT would be able to switch about 41,000 residential and business customers each day in January.[12] (Not that so many customers were choosing new providers. Rather, all customers in deregulated areas of ERCOT — even those who did not choose a competitive provider — had to get switched to the retail electric provider affiliated with the incumbent.)

The ratepayer-financed organization's 266 employees earned an average of $99,000 annually in salary and benefits, including fully paid health, vision and dental insurance. This compensation was well in excess of the state government employee average.

But problems persisted. In early January, in a report to regulators, Jones acknowledged that incorrect data entries, service switching mistakes and communication problems continued to hamper ERCOT operations. Jones went so far as to indicate that some inefficiencies would become permanent fixtures of deregulation. "In exchange for an ability to shop around and get savings, (customers must allow) for a process that is more complicated than it used to be," Jones said.[13]

ERCOT problems also prevented retail electric providers from delivering accurate and timely bills. — As many as 150,000 customers in the TXU service territory and 90,000 customers in the Reliant service territory were not getting their bills on time, according to company officials.[14] Sometimes the bills were delayed for several months.[15] Even some of deregulation's leading advocates began second guessing the grid operator. "In hindsight, we should have given deregulation a longer trial period before we plunged in," said TXU chairman Erle Nye.[16]

In April 2002, Public Utility Commissioner Brett Perlman said a multi-million dollar ad campaign designed to alert consumers to the new market should be put on hold. He warned that if the media blitz went forward as scheduled, a backlog of 100,000 switch requests could result. The campaign was to include a mass mailing of 5 million customer guides, as well as television advertising. Commissioner Perlman also complained that no one seemed willing to take responsibility for ERCOT's poor performance.[17]

Also in 2002, the public got its first real glimpse of ERCOT's financial dealings — and what they saw was alarming: $500,000 for marketing and advertising (even though the quasi-governmental organization had absolutely zero reason to advertise because it had no competitors); ratepayer money spent to send employees to baseball games and up to $10,000 per ERCOT employee-authorized travel expenses.[18] The ratepayer-financed organization also spent $29,000 for a holiday party at a four-star hotel in Austin and $18,500 on a sponsorship deal for a minor league hockey team. The ratepayer-financed organization's 266 employees earned an average of $99,000 annually in salary and benefits, including fully paid health, vision and dental insurance. This compensation was well in excess of the state government employee average.[19]

On June 11, ERCOT agreed to curb some of its most egregious spending.[20] A month later, however, ERCOT called for a near doubling of the ratepayer fee that supports its operations. The hike would come in addition to the Price To Beat increases requested by the state's major utilities. "Clearly, there needs to be greater oversight," said state Rep. Sylvester Turner, then vice chairman of the House panel overseeing deregulation.[21]

Wholesale Market

More details emerged in 2002 about the wholesale price spikes that occurred during the deregulation pilot project. A PUC investigation found that six companies had improperly profited by incorrectly projecting their own energy needs in late 2001. In one case, a company consistently missed its projections by incredible margins — between 75,000 percent and 400,000 percent.[22] By failing to accurately project their power needs, the companies would create the appearance that power demand did not match power availability and then get paid extra for relieving congestion that did not exist.

All told, the companies netted $29 million in improper revenues for engaging in activities similar to the illegal activities that Enron used in California.

The PUC declined to publicly identify these companies, claiming they were protected by privacy rules.[23] But gradually the companies identified themselves. Among them were: TXU, Constellation Power Source, Mirant Americas Energy Marketing, Reliant Energy Service and American Electric Power Service. In April, after being confronted by a reporter, the last company finally owned up. It was Enron.[24]

All told, the companies netted $29 million in improper revenues for engaging in activities similar to the illegal activities that Enron used in California. In Texas, TXU made the most money off the activities. The company and others claimed the overpayments were the result of start-up problems in the wholesale market. In terms of missed projections, Enron was — by far — the worst offender. According to PUC documents, Enron improperly received $1 million to $6 million

Enron's Illegal Market Manipulation

In October 2002, Timothy Belden, the chief energy trader for Enron's West Coast power trading desk, pleaded guilty to conspiracy to commit wire fraud. Belden was among several Enron traders who created schemes with nefarious sounding names like "Ricochet" and "Death Star." Their purpose was to manipulate California's energy markets in order to gain unfair profits.

"Beginning in approximately 1998, and ending in approximately 2001, I and other individuals at Enron agreed to devise and implement a series of fraudulent schemes through these markets," Belden admitted in his plea agreement. Toward that end, the company knowingly submitted false information to the system operator in California, he said.

"We intentionally filed schedules designed to increase congestion on California transmission lines," Belden stated in his plea agreement. "We were paid to 'relieve' congestion when, in fact, we did not relieve it. … We scheduled energy that we did not have, or did not intend to supply. As a result of these false schedules, we were able to manipulate prices in certain markets."

Belden would later testify that the activities resulted in as much as $1 billion in profits for Enron during the California energy crisis. In audio tapes that became public in 2004, Enron traders could be heard making jokes about stealing from "those poor grandmothers" in California and gleefully proclaimed "burn, baby, burn" when a fire on a transmission line allowed the company to increase profits.

Enron also allegedly engaged in market manipulation in Texas during this state's deregulation pilot project in 2001, according to the Public Utility Commission and the Office of Public Utility Counsel.

by over-scheduling transmission by an average of 66,000 percent for a period of 29 days. Municipally-owned utilities reported that they would have to pay about $10 million in excess charges as a result of Enron's activities and those of other power wholesalers.[25]

CUSTOMER PROTECTIONS TESTED: Enron Affiliate Abandons Texas Market and its Customers

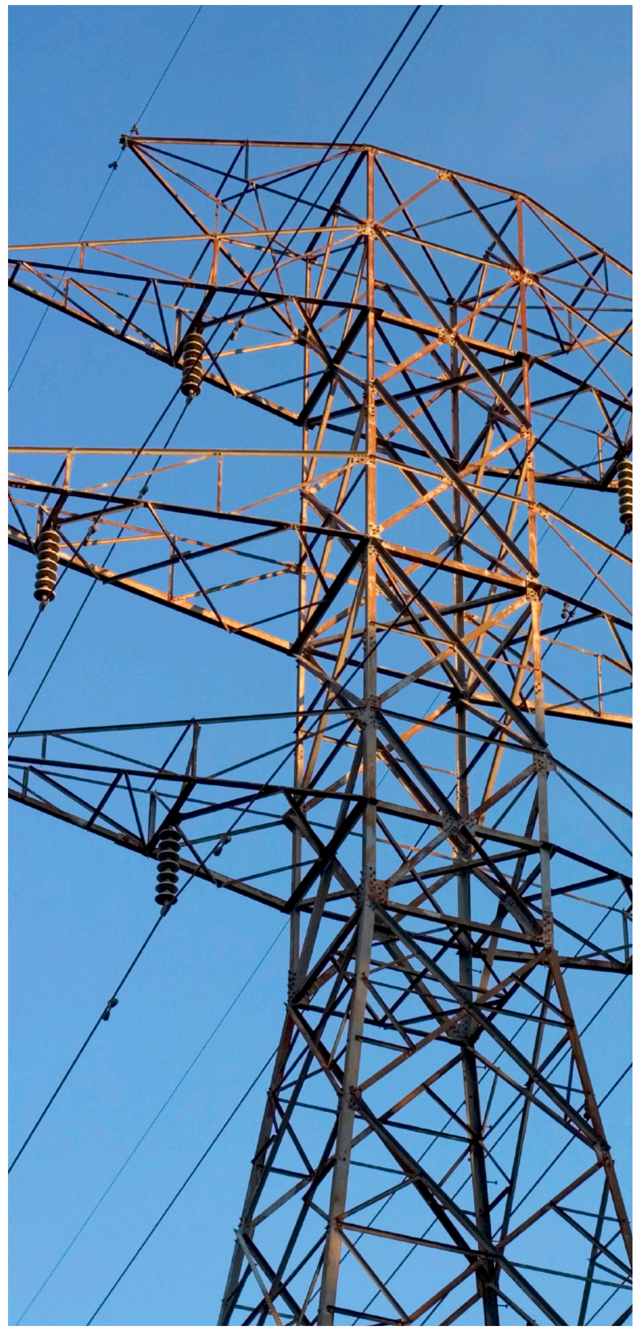
On June 10, 2002, New Power, the cash-strapped Enron affiliate, announced it was abandoning the state's electric market and switching its nearly 80,000 customers to other providers.[26] A day later, the company, which had lost $173 million during the first nine months of 2001, filed for bankruptcy.[27]

Until its implosion, New Power had been the most aggressive marketer of energy in Texas — so aggressive, in fact, that it also led all other electric retailers for the number of complaints lodged against it for signing up customers without proper authorization. In September, the PUC went after New Power for errors on about 46,000 bills.[28] PUC executive director Lane Lanford said in a letter to New Power that the agency sought to fine the company based on "the egregiousness and repetition of the violations, the seriousness of the violations, the resulting economic harm, previous history of violations and efforts to correct the violations."[29]

The company also figured in conflict-of-interest lawsuits filed during 2002. Max Yzaguirre, a former Enron executive, was serving as PUC chairman during December when the PUC was setting the initial Price To Beat rates. A coalition of cities argued that the PUC set those rates too high and that as such they unfairly benefited New Power. Two other city lawsuits alleged a similar conflict by Commissioner Brett Perlman, who had worked as an Enron consultant. The suits said both Commissioner Perlman and Commissioner Yzaguirre should have recused themselves because their actions, in effect, benefited the company that formerly wrote their paychecks.[20]

Although the suits were ultimately dismissed, Chairman Yzaguirre came under even more harsh criticism because he had failed to disclose the extent of his Enron connections and ultimately resigned from the PUC in early 2002.[31]

"This also calls into question the whole process as to how we establish rates," said Tom "Smitty" Smith, director of the Texas office of Public Citizen. "Is our goal to make electricity affordable for consumers, or is it to ensure profits for companies? Is our government designed to protect the people or the power companies?"[32]



Year: 2003 The 78th Texas Legislature — Staying the Course

Not long after the 78th Texas Legislative Session convened in January, state Sen. Gonzalo Barrientos, D-Austin, proposed Senate Bill 1792. It was designed to correct some of the flaws in the Price To Beat rule. State Rep. Sylvester Turner, D-Houston, likewise proposed House Bill 2335. It was designed to prevent electric companies from controlling too much of the market and manipulating prices.[1] The electric industry responded predictably. "Any further change to the system could upset the competitive electric market in Texas," said John Fainter, president of the Association of Electric Companies of Texas.[2] Despite price spikes during the opening days of the market, more suspicious spikes during a recent cold snap and increasing retail prices — industry representatives insisted the Texas market was a model for the rest of the nation. Both Senate Bill 1792 and House Bill 2335 failed.[3]

. . . In TXU's case, its first new rate hike of the year amounted to a 12-percent price increase – the largest in recent memory, far larger than any rate increases initiated under regulation.

But the Texas Legislature did manage to roll back one important consumer protection in 2003. As part of their negotiations with consumer representatives in 1999, lawmakers had created a special fund through Senate Bill 7 to provide bill-paying assistance for low-income Texans. This was known as the "System Benefit Fund." But in 2003 the Texas Legislature used $185 million of the $405 million so far accrued in the fund to certify the state's budget. As a consequence 700,000 low-income Texans ended up paying more for electricity than they otherwise would have. Ratepayers continued to financing the System Benefit Fund through regular surcharges on their home bills — even though much of the money was not being used for its intended purpose.[4]

PRICE TO BEAT INCREASES CONTINUE

Retail electric providers continued using the controversial Price To Beat mechanism in 2003 to ratchet up rates in lockstep with increases in natural gas prices. In TXU's case, its first new rate hike of the year amounted to a 12-percent price increase[5] — the largest in recent memory.[6] In August, the company increased its prices for a second time.[7] By any measure, Price To Beat customers would now be paying more for electricity than they did on the last day of the old regulated system. And this, even though the price of natural gas had gone down from the level it was before the market deregulated.[8] The flawed Price To Beat mechanism effectively became a one-way street for prices. Under the Price To Beat, prices went in only one direction: up.

WHOLESALE MARKET: Hockey Stick Bidding Causes Price Spikes

Prices in the wholesale market spiked during a cold snap in late February. The freezing temperatures hampered plant operations, curtailed natural gas supplies and sent wholesale spot prices soaring to $990 per megawatt hour for brief periods.[9] But the PUC also turned up evidence that energy traders took advantage of the unusual weather on Feb. 24, 25 and 26 to ratchet up prices and increase profits.[10]

How can this occur? ERCOT in 2003 was managing an automated bidding process for the spot market, called the "balancing energy market." Power companies would submit bids to ERCOT that reflected both the amount of power they could supply during given intervals and the price they were willing to receive for that power. ERCOT would accept the bids, starting with the lowest price bid first and continuing with higher priced bids until enough power was committed to cover demand during the interval.

But pursuant to its rules, the last accepted bid price—that is, the most expensive selected bid — gets paid to all successful bidders. That means a bidder who offered electricity for $1 per megawatt-hour could end up getting paid $1,000 for that same energy if the highest accepted bid was for $1,000 per megawatt-hour. This aspect of ERCOT rules leaves the market vulnerable to an improper bidding strategy known as "hockey stick" bidding. In its

The PUC and ERCOT

The Texas Legislature created the state's Public Utility Commission in 1975 to regulate telephone and electric service. The PUC is led by three commissioners, each appointed by the governor to serve six-year terms. The PUC's responsibilities include:

- Regulating rates for the monopoly transmission and distribution providers that operate within deregulated areas of the state.
- Overseeing the Electric Reliability Council of Texas, the organization that oversees most of the state's power grid.
- Overseeing the competitive electricity market within the area of the ERCOT grid.
- Adopting and enforcing rules relating to retail electric competition.
- Regulating retail rates in areas outside the boundaries of ERCOT.
- Licensing new transmission facilities for investor-owned utilities and cooperatives.
- Licensing retail electric providers.

The Electric Reliability Council of Texas was formed in 1970 to help enforce standards to ensure the reliability of the state's power grid. ERCOT was not considered to be a government entity that exercised state power, but rather a volunteer membership organization of electric utilities. ERCOT was given dramatic new responsibilities with the adoption of the state's electric deregulation law in 1999 and now functions as both the technical operator of the transmission grid and the decision-making organization that creates rules for the wholesale electricity market. ERCOT's responsibilities include:

- Managing the flow of electricity across a grid that covers 75 percent of the state's geographic territory, and 85 percent of the electricity market.
- Supervising transmission planning to meet existing and future electricity demands.
- Maintaining a database to record the relationship between retail electricity providers and their customers.
- Administering the state's Renewable Energy Credit Program.

For more about ERCOT, see Appendix E

Source: The Energy Report 2008, Office of Texas Comptroller, Chapter 27; Jared M. Fleisher, "ERCOT's Jurisdictional Status: a Legal History and Contemporary Appraisal," Texas Journal of Oil, Gas and Energy Law, March 19, 2008.

investigation of the February price spikes, the PUC determined that some companies were engaging in these sorts of practices. "Hockey stick bidding occurs when a market participant offers a small portion of its capacity or energy at an extremely high price," the PUC noted in a report on the February cold snap. "Under normal circumstances, these small amounts of energy and capacity are not needed, and therefore do not affect prices. However, during the extreme weather event, ERCOT needed the entire energy bid into the (wholesale spot market), and the resulting price was set by a hockey bid." The commission estimated that the hockey stick bidding cost the market an extra $17 million. [11]

Such manipulative strategies potentially can have other potential downsides. For instance, the price spikes experienced during the February ice storm led to the bankruptcy of a competitive electric provider, Texas Commercial Power. The company sued, alleging that TXU and other companies were unfairly manipulating the market in order to drive up revenues.[12]

ERCOT BEGINS MOVE TOWARD THE NODAL MARKET

In the wake of early price spikes in the wholesale market — spikes typically associated with congestion on the overburdened transmission system — the PUC gave the green light to a new market design. This proposed new system, a "nodal" system, would change how ERCOT oversees wholesale electricity transactions. It would replace the then-existing "zonal market" system whereby ERCOT supervises transactions as they occur in broad geographic regions (zones) of Texas with one where ERCOT would oversee transactions in thousands of smaller areas, or nodes. At the PUC's direction, ERCOT began ironing out the details in 2003.[13]

In the investigation of the February price spikes, the PUC determined that some companies were engaging in hockey stick bidding.

In theory, this new nodal system would allow the laws of supply and demand to bring more efficiency to grid operations. "This is the natural progression of things — the question is how far we need to go," said Tom Noel, the organization's chief executive officer.[14] But to implement this new system, ERCOT — an organization that as yet had failed to inspire much confidence with lawmakers and regulators — would have to traverse an ocean of complex technical hurdles. In discussions with policymakers in 2003, ERCOT officials said they expected the nodal market to "go live" within three years. A consultant hired at the direction of the PUC projected the costs to ERCOT for implementing the nodal market at between $59.8 million and $76.3 million.[15]

But the transition would have to take place without ERCOT CEO Tom Noel. Already under fire for the disastrous pilot project in 2001, the billing errors and the switching problems, Noel announced his resignation from ERCOT in October. Some lawmakers had openly called for it.[16]

BAD NEWS/GOOD NEWS: Consumers Complain to PUC in Record Numbers; State Exceeds Energy Efficiency Goals

The number of complaints regarding electric service filed at the Texas Public Utility Commission increased steadily since the market opening and peaked in July and August of 2003. Over the course of the fiscal year, the PUC's Customer Service Division received about 17,000 electricity complaints — about half relating to billing, although many consumers also complained about service disconnections and faulty service. This would mark an all-time high for the number of annual complaints under the Texas deregulation law.[17]

Also in 2003, the state exceeded an energy efficiency goal set forth in Senate Bill 7 by 11 percent. Under the legislation, regulated transmission utilities were to administer incentive programs designed to reduce by 10 percent annual increases in energy demand. In 2003, utilities spent $70 million on the program, according to the PUC.[18]

The agency reported that the demand reduction goal for 2003 was 135 megawatts, and utilities exceeded that target with an actual reduction of 151 megawatts. The PUC noted that the program equitably served residential, commercial and industrial customers.[19]

Year: 2004 The ERCOT Scandal — A "Crisis of Confidence"

DOMINANT TXU CAN DRIVE UP PRICES

In January 2004, the Texas Public Utility Commission issued a 33-page report concluding that at least one generator, TXU, owned or controlled so much generation capacity that it was capable of undermining a segment of the wholesale energy market. By virtue of the amount of power it could deploy or withhold, TXU was able to drive up prices, even if it did not intend to do so. The agency's report concluded the company's uniquely dominant position raised questions for the future of competition.

. . . while the megawatt-hour price of such energy typically sold for less than $50, it spiked to $990 during the study period...

The PUC report analyzed prevailing market conditions at the time of the price spikes in a segment of the wholesale market known as the balancing energy market. (For more about the Balancing Energy Market, see the sidebar on page 20.) It found that while the megawatt-hour price of such energy typically sold for less than $50, it spiked to $990 during the study period, which was between May 2002 and August 2003.

The analysis demonstrates that TXU routinely was guaranteed to have its bids selected — no matter the price — simply because it controlled so much power. "The results of this study show that TXU's market position is so pivotal that just about anything the company does with respect to (that segment of the wholesale market) will affect balancing energy prices, regardless of the reasons behind its decisions," the study said.[1]

Legislation considered during the 2003 session would have addressed pivotal provider problems by adding more market controls on wholesale providers. But generators successfully opposed the legislation, just as they opposed any suggestion of improper conduct raised by the price spikes. "Our position is that we do not have control over prices," TXU spokesman Chris Schein said. "They [the authors of the PUC report] are saying we have an impact on momentary prices, but there's no way that we can sustain control over prices."[2] In December, however, the PUC announced it was again looking at TXU for its involvement in a new round of price spikes. In the newest case, TXU had submitted bids to sell its power for $400 per megawatt-hour, although such power typically sold for about $50 at the time.

These price spikes occurred with shocking regularity. All told, power prices spiked nearly 100 times in late November and early December of 2004. The problem was so pronounced that PUC Chairman Paul Hudson threatened to call upon the Attorney General's Office or the Securities and Exchange Commission to investigate.[3]

ERCOT: COST-BENEFIT ANALYSIS OF THE NODAL PROJECT RAISES QUESTIONS

ERCOT and regulators continued working in 2004 on creating a "nodal" market. ERCOT hired a Massachusetts-based consulting firm to conduct a cost-benefit analysis of implementing a nodal market in Texas — a study that regulators said they wanted to see before giving their final OK.

However, the review did not include any consideration of the nodal system's potential impact on home bills.[4] "How can you do a cost-benefit study without knowing the impact on consumers? That doesn't make any sense at all," said Diane Weklar, executive director of the DFW Electric Consumer Coalition. ERCOT also declined to say publicly how much it spent on the report, even though (as with all ERCOT expenditures) it was Texas ratepayers who ultimately would foot the bill. "We're not in the habit of releasing information on ongoing business practices," Susan Vincent, corporate counsel for ERCOT, said in early July.[5]

The Procurement Scandal

Less than one month later, then ERCOT-board chairman Mike Green, a TXU executive, would be telling the PUC: "I want openness." But he wasn't responding to PUC inquiries about the nodal project or consultant's reports. Rather, Green was responding to inquiries about what then became a much more pressing matter: possible criminal activity.[6]

At issue were what ERCOT officials vaguely termed "vendor procurement irregularities."[7] ERCOT's CEO had learned about the irregularities on March 29, 2004, but waited two months before alerting the commission. The Department of Public Safety was also alerted, and ERCOT acknowledged its own investigation.[8]

Details remained elusive, although eventually it became clear that the allegations involved billing improprieties and possible self-dealing by ERCOT's cyber-security personnel. ERCOT failed to detect the criminal background of a former employee allegedly involved in improprieties. As a result of the allegations, several ERCOT staff members quit or were fired.

The criminal investigation began to focus on three managers in two firms that handled computer security for ERCOT. The two firms, Cyberensics Corp. and ECT Global Solutions Inc., had ERCOT contracts worth at least $2.5 million. Investigators attempted to ascertain whether the managers had stolen or laundered ERCOT funds.[9]

By June, PUC chairman Paul Hudson had declared a "crisis of confidence" with ERCOT's internal controls.[10] By July, more than four dozen witnesses had been interviewed by DPS investigators, and a grand jury in Williamson County had subpoenaed notes from an ERCOT lawyer.[11] In September, ERCOT was taking heat from a joint interim House-Senate committee for its lack of financial controls, for perceived arrogance among top officials in the face of these problems and for cutting checks to a contractor that had a dead man on its payroll.

"There appears to have been some serious breakdowns of internal controls and management practices at ERCOT," said Sen. Troy Fraser, R-Horseshoe Bay, chairman of one of the committees reviewing the organization.[12]

Continued Customer "Stickiness"

As of September 2004, fewer than 20 percent of residential customers were getting service from a power company not affiliated with one of the state's traditional utilities.[13]

Although more customers were testing the deregulated market than in 2003, the fact that such a small percentage of customers had switched from traditional electric providers illustrated the continued "stickiness" in the residential market.

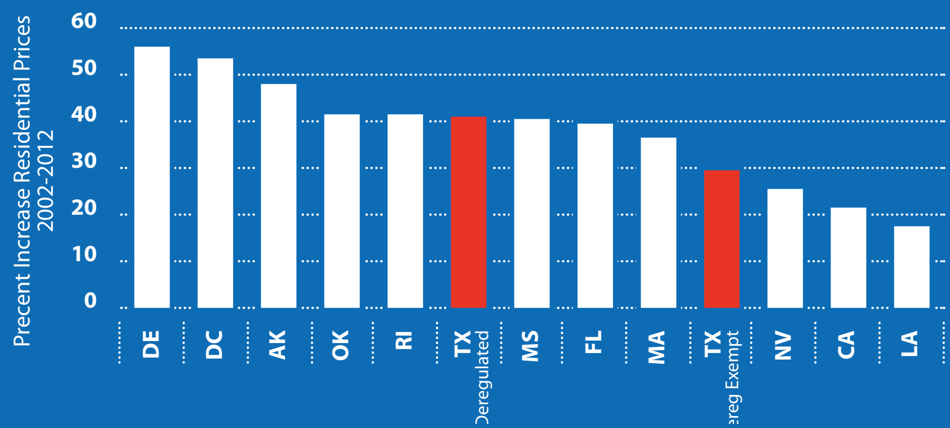
The PUC reported that between seven and 12 retail electric providers were serving residential customers in the state's major service territories.[14] The PUC blamed "substantial customer acquisition costs" — that is, the expense of advertising faced by electric competitors. The PUC also said competitors faced increasing investments for billing systems and call centers as well as added costs associated with resolving customer complaints.[15]

In September, ERCOT was taking heat from a joint interim House-Senate committee for its lack of financial controls, for perceived arrogance among top officials in the face of these problems and for cutting checks to a contractor that had a dead man on its payroll.

The PUC acknowledged that the Price To Beat rate paid by many Texans was above-market.[16] Repeated Price To Beat increases had driven up Price To Beat rates 20 to 35 percent between January 2003 and September 2004, according to the agency.[17] Competitive prices generally remained below the Price To Beat, but nonetheless rose in tandem with it.[18] The PUC also noted that since the market had opened to competition, the price of electricity in Texas had risen at a greater pace than it had in the United States as a whole.[19]

Price Increases: Residential Electric Rates vs. Natural Gas

Source: NYMEX Exchange, United States Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/page/eia861.html



This exhibit gives us a sense of pricing trends among states heavily reliant upon natural gas to fuel electric generating units. Electricity prices roughly parallel natural gas prices in such states. Here, deregulated Texas sits in the middle of the pack. This exhibit demonstrates that residents in six other gas-reliant states endured less onerous price increases than those endured by residents in deregulated Texas. Meanwhile, residents in five other gas reliant states endured greater price increases than those observed in deregulated Texas.

BILLIONS OF DOLLARS IN STRANDED COSTS ADDED TO ELECTRIC BILLS

In November, 2004, the Texas Public Utility Commission determined that ratepayers owed Houston's CenterPoint Electric Delivery Company $2.3 billion in stranded costs.[20] The PUC would also make similar determinations for other Texas generating companies — albeit for lesser amounts.[21]

Stranded costs, remember, are meant to represent the difference between the book value of a company's assets and the price that would be paid by someone buying the assets on the open market. Think of a company that pays $1 billion to build a nuclear power plant under regulation but then can only sell it for $500 million in a deregulated market. In this over-simplified example, the $500 million difference would be the "stranded cost" of the nuclear plant. Under Senate Bill 7, electric companies have the right to recover from ratepayers the stranded costs attributable to generation assets that the utilities were ordered to build but are no longer valuable. (For more about stranded costs payments, see page 66).

The idea behind stranded costs is that utilities should not be harmed by the transition to the deregulated market because they owe more for generating plants than what they could sell those plants for in the open market. Ultimately, it was decided that ratepayers would pay the utilities their "stranded investment" through surcharges that would be assessed against every customer. In exchange for paying stranded costs, it was rationalized that ratepayers would have access to better prices in the competitive market. In theory, the benefit of lower prices would far outweigh the burden of stranded cost surcharges.

But decisions relating to stranded costs for CenterPoint, Texas Central Company and Texas-New Mexico Power caused real harm to consumers. That's because clear evidence suggests that supposedly uneconomic plants were woefully undervalued.

For instance, in determining the stranded cost pay-out to Houston's CenterPoint, the PUC considered a partial stock sale by the company that established the value of its generating assets at $3.65 billion. But days after the PUC calculated CenterPoint's stranded costs, the company's equity owners resold those same generating assets for $8.3 billion.[22]

So what was the true value of those assets — $3.65 billion or $8.3 billion? If the PUC had used something closer to the $8.3 billion figure, the stranded costs associated with the assets would be very close to zero. Instead the $3.65 billion asset valuation was used. As a result, all customers of the former HL&P must pay billions of dollars in stranded costs for years to come.

. . . ratepayers who never received any benefit from the excess mitigation credits nonetheless were on the hook for paying them back. And these payments were to be added to already questionable multi-billion dollar charges to ratepayers for stranded costs.

In fact, all assets in Texas used to calculate the billions of dollars of stranded cost charges to ratepayers were resold at a substantial profit.

Also, remember that the PUC earlier projected that Texas electric companies would end up with negative stranded costs. In 2001, the PUC's economic modeling showed that assets like nuclear power plants would become more valuable, not less, and as a consequence the owners of those assets should surrender some money to reflect the windfall they would receive under deregulation.[23]

When legislation failed in 2001 that would have required electric companies to refund that projected windfall to ratepayers, the PUC stepped in and ordered generators to make corresponding payments in the form of "excess mitigation credits," or EMCs. But the credits for the most part ended up in the pockets of electric retailers, not ratepayers. The total value of the EMCs exceeded $2 billion.[24] The PUC then added the excess mitigation credits — again credits that never went to ratepayers — to their stranded cost calculations.[25] Said another way: Ratepayers who never received any benefit from the excess mitigation credits nonetheless were on the hook for paying them back. And these payments were to be added to already questionable multi-billion dollar charges to ratepayers for stranded costs. (For more about excess mitigation credits, see Appendix C).

Year: 2005 The 79th Texas Legislature — The Wind Power Initiative

In April 2005, Public Citizen, an environmental and consumer advocacy group, released a study showing that the price of electricity in deregulated areas of the state had increased at more than twice the rate as electricity prices outside deregulation.[1] In May, a consult hired by the Public Utility Commission concluded yet again that TXU had the ability to unilaterally drive up wholesale prices.[2] These factors together, plus clear problems with the defective Price To Beat mechanism and a scheduled top-to-bottom agency review of the Public Utility Commission,[3] increased expectations that the Texas Legislature would adopt major reforms in 2005.

In April 2005, Public Citizen released a study showing that the price of electricity in deregulated areas of the state had increased at more than twice the rate as electricity prices outside deregulation.

That none were forthcoming is all the more surprising given that industry representatives had convinced lawmakers during previous legislative sessions to put off the consideration of any important reforms until 2005, arguing that it made more sense to wait until the completion of an expected efficiency review of the PUC that year. But then after the completion of that review process — and with electric bills up nearly 50 percent since the beginning of deregulation[4] — utility lobbyists still argued against reform. As one utility representative said: "If it ain't broke, don't fix it."[5] Two important bills that lawmakers considered and ultimately rejected during the 79th session were Senate Bill 759 and Senate Bill 764. The first would have made it easier for cities to aggregate together their citizens into bulk-purchasing groups in order to negotiate for them better electricity deals.[6] The PUC reported that such aggregation projects in other states had resulted in ratepayer savings.[7] The second bill would have limited how much supply could be owned or controlled by generation companies. The legislation would have addressed market power issues by discouraging electric companies from unfairly controlling wholesale prices.[8]

But while both those bills failed, that's not to say that ratepayers would be unaffected by the actions of their lawmakers in 2005. Here are a few of the measures adopted during the 79th regular and special sessions. Some had the potential to increase bills.

- Money meant for the System Benefit Fund (which had been created as part of Senate Bill 7 to provide bill discounts for low-income Texans) was diverted to support the state's general revenue fund. The Texas Legislature had taken money from the ratepayer-supported fund once before, in 2003, to also help fill a budget gap that year. With the latest budget action, lawmakers used the last of the available money — and as a result, 350,000 low-income Texans ended up paying more for electricity than they otherwise would have.[9] The budget action also had the effect of converting what otherwise would be considered a surcharge on ratepayers' bills into a sales tax on electricity.[10]

- Senate Bill 5 was technically not an electric bill, but one relating to the telecommunications industry. Adopted during the second called special session of 2005, it permitted electric utilities to enter into deals to create broadband service over ratepayer-financed transmission systems. Broadband companies that sell the service could keep the revenue, although some of it would potentially flow back to the utility. Ratepayers who paid for the transmission system and made the arrangement possible would not be able to receive the broadband service unless they were to pay for it.[11] Ratepayers would also have to pay for the digital meters that work with the broadband service. Oncor Electric later would cite this bill and separate legislation[12] for its costly decision to order and install more than 100,000 digital meters before state operating standards were in place.[13] The obsolete meters were replaced by the company — although Oncor was still allowed to charge its customers for them.[14]

- Senate Bill 20, adopted during the first called special session, established special zones (called "Competitive Renewable Energy Zones" or CREZ for short) to mark the site of future transmission construction.[15] However, the new lines would not directly address the state's ongoing transmission shortage but rather would connect to sparsely populated areas of the Panhandle and far West Texas to support future wind generation. The cost of the CREZ transmission projects would reach into the billions of dollars. Such new wind construction also would lead to more reliability challenges for ERCOT.[16] Senate Bill 20 likewise expanded renewable energy goals included in Senate Bill 7 — from 2,880 megawatts of capacity by Jan. 1, 2009, to 3,272 megawatts — and established a new target of 10,000 megawatts of renewable energy capacity by 2025.[17]

STATE EXCEEDS SENATE BILL 7 TARGET FOR RENEWABLE ENERGY

Senate Bill 20 set forth other targets as well: 4,265 megawatts of renewable energy capacity by 2011, 5,256 by 2013 and 5,880 by 2015.[18] And lawmakers had plenty of reason to believe the state would meet those ambitious targets. The construction of renewable energy generation already had exceeded the goals set forth in Senate Bill 7 and the Public Utility Commission was estimating that there would be more than 1,300 megawatts of new renewable energy capacity online in 2005.[19] That exceeded the original target in SB 7 by more than 500 megawatts, or nearly 63 percent. The PUC reported that wind generation comprised the lion's share of the new renewable generation and linked much of the growth to federal tax credits.[20]

The PUC also reported success in its implementation of energy efficiency programs established by Senate Bill 7. Under the legislation, utilities were required to administer energy efficiency incentive programs with the goal of reducing annual growth in energy demand by at least 10 percent.[21] The PUC noted that the programs saved nearly 500,000 megawatt-hours of energy in 2005. Utilities exceeded their demand reduction goals in 2005 by 27 percent, according to the PUC.[22]

"Overall, program performance appears to have been successful," the PUC reported.[23]

The PUC also acknowledged that for part of 2005, the average price of competitive offers was actually higher than the Price To Beat.

Utilities spent roughly $78 million in ratepayer money on the program in 2005. The PUC estimated the potential 10-year savings from the program at $290 million.[24]

The ERCOT Procurement Scandal Continues

In January, a grand jury indicted six former ERCOT managers in the procurement scandal that had come to light in 2004. The officials were accused of having improperly billed $2 million to the organization for work that was never done. In August, prosecutors obtained a guilty plea from the former director of information technology and information services for ERCOT. The former executive admitted to conspiring with five others to set up shell security companies and using those companies to bilk ERCOT.[26] The Attorney General said some invoices corresponded to unperformed work or undelivered goods. The group also billed for work supposedly performed by non-existent employees, according to the AG's office.[27]

Responding to the scandal, lawmakers in 2005 adopted legislation giving the Public Utility Commission greater authority over ERCOT's finances and activities.[28]

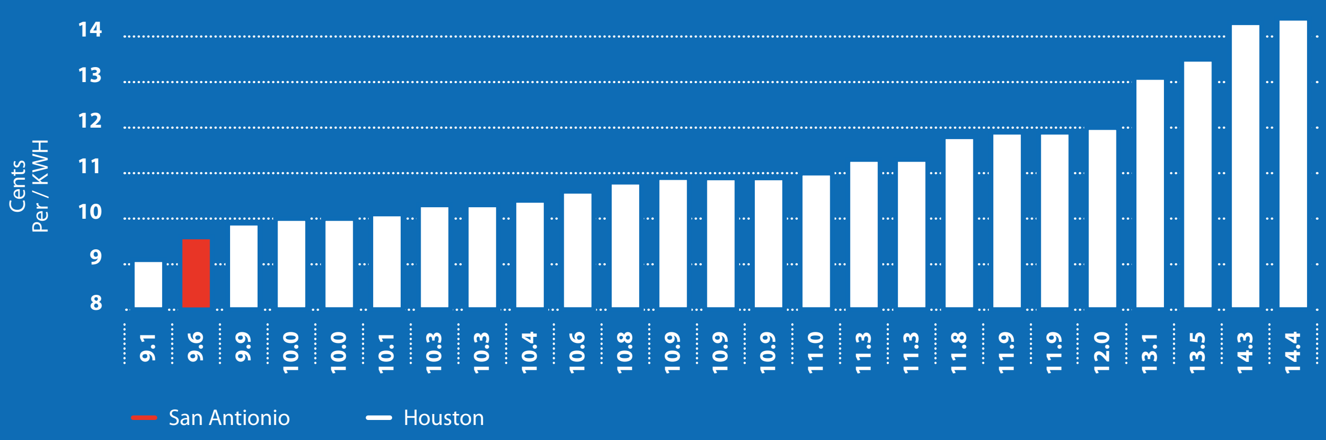
Customer Choice: Higher Prices than Regulated Rates, Plus More Complaints

By the end of 2005, after four years of deregulation, fewer than half of residential customers had switched off the above-market Price To Beat rate, according to PUC estimates.[29] In part, this reflected the inherent "stickiness" in the residential market. But many consumers also complained that the deals offered by competitors were less than enticing. "Guess what? There is only a cent or two difference in the cost between all providers," one frustrated resident wrote to PUC Chairman Paul Hudson.[30] The PUC also acknowledged that for part of 2005, the average price of competitive offers was actually higher than the Price To Beat.[31]

To make matters worse, Hurricanes Katrina and Rita disrupted natural gas production during the last months of 2005. That sent both natural gas and electricity prices to historically high levels.[32] In November, TXU began phasing in a 24-percent rate increaseto its Price to Beat rate.[33] Other companies followed suit with similar increases.[34] Because of the defective Price To Beat rule, electric rates would remain at those historically high levels even after natural gas production came back online and gas prices stabilized.

A Tale of Two Cities — Houston and San Antonio*

**Based on rate surveys by the Public Utility Commission.*



In Houston's deregulated market, dozens of retail electric providers compete for customers. In San Antonio, a single municipally-owned utility serves everyone. Houston is the state's largest Texas city with a deregulated retail electric market. San Antonio is the state's largest city outside retail deregulation. Where do customers get a better deal?

According to data from an December 2013 pricing survey by the Public Utility Commission, electricity sold through almost every fixed-rated deal in Houston costs more than electricity sold by the single municipally-owned utility in San Antonio. This follows a common trend. For instance, a PUC pricing survey from April 2011 showed that electricity then sold under Houston's very lowest fixed-rate deal was still more expensive than electricity sold by every municipally-owned utility surveyed by the agency, and more expensive than all but one investor-owned utility.

Year: 2006 Mixed Reviews and Rolling Blackouts

The year began with what the PUC touted as good news for consumers. According to a report released by the agency in February, Houston residents could have saved over $1,000 under deregulation and Dallas residents could have saved about $800.[1]

Not that Texans had actually saved this money under Senate Bill 7. Only that they *could have.*

The "savings" were created by comparing the last regulated rate — meaning the rate charged on Dec. 31, 2001 — to the lowest competitive offers in Houston, Dallas and Fort Worth for the years 2002, 2003, 2004 and 2005. The agency then calculated the difference, assuming that a hypothetical resident had selected the lowest-priced offer during each of those four years. A Dallas resident, for instance, could have saved 17 percent over what he would have paid under the old regulated system, according to the report.[2]

However the analysis was flawed. First, it was unclear how many customers would have been eligible for the lowest priced offers. Moreover, Texans receiving service through fixed-rate electricity contracts cannot willy-nilly switch providers without paying early termination penalties.

There is also the question of what is the appropriate benchmark price with which to make a comparison. By using the regulated rate charged on Dec. 31, 2001, the study relied upon a benchmark that was inflated by exorbitant fuel surcharges and excess earnings valued at hundreds of millions of dollars.[3] Utilities were allowed to keep charging this regulated rate in anticipation of deregulation.

Even if the study is accepted at face value, it is clear that the millions of ratepayers still paying the Price To Beat in 2006 were getting an awful deal by paying unnecessarily high prices. And indeed, a separate review of rate filings showed that by 2006, the Price To Beat had increased by 84 percent in the Metroplex, by 81 percent in Houston, by 101 percent in Corpus Christi and by a whopping 116 percent in West Texas.[4] Outside deregulated areas, price increases occurred over the same period but were much more modest. In Austin, with its municipally owned utility, rates increased by 19.4 percent, for example. That means the most commonly paid rate in deregulated Houston increased five times faster than the rate paid in Austin, which remained outside deregulation.[5]

"…without a doubt, (these environmental goals) could have been accomplished without going to full-scale deregulation … without creating the series of unnecessary middlemen, in the form of Retail Electric Providers."

— Tom "Smitty" Smith, Director of Public Citizen-Texas

The PUC analysis did not focus on the Price To Beat rate but rather the lowest-competitive offer in each service territory. But several reports from 2006 suggested that even those Texans who shopped around for electricity were paying too much for it. In March, for instance, AARP released a report showing that TXU and all of its cheapest North Texas competitors were charging rates out of line with fuel costs.[6] Another survey released later that same year demonstrated that rates offered to customers in deregulated areas of North Texas were higher, on average, than rates in areas that remain under regulation. The survey showed that the best offer under deregulation was still more expensive than rates from almost every company outside deregulation.[7] Likewise, Kenneth Rose, a senior fellow at Michigan State University and a leading expert on electric pricing and policy, released a nationwide survey in 2006 showing that electricity prices had gone up in Texas since deregulation, while those in regulated states had gone down.[8] Another expert concluded that under deregulation Texans had paid some of the highest rates in the nation, a reversal of a decade of relatively cheap power under the old system.[9]

The nationwide comparisons between regulated and deregulated prices were possible because the mix of markets provided for a control group to help answer a basic question: Does deregulation save money for consumers? Rose said the growing consensus among experts was that it does not. "Evidence that we're gathering (shows that the effectiveness of deregulation) — at least as we had originally thought it would work — is not bearing out from the customer perspective," Rose said.[10]

In response to these concerns, the chairman of the Public Utility Commission pushed a proposal in 2006 to lower the Price To Beat. Chairman Paul Hudson noted that the price of natural gas had gone down substantially since Hurricanes Katrina and Rita, but that the Price To Beat rates didn't reflect the decrease. He wanted to push down the Price To Beat shortly before it expired for good in January, 2007. "It would be a disservice if … residential customers remained on a final regulated rate (the Price To Beat rate) … that no longer reflected the market," said Chairman Hudson, also noting that natural gas prices then embedded in Price To Beat rates were at least 15 percent higher than the actual price of natural gas in the open market.[11]

The chairman's plan, which would have saved Texans an average of $17 on their monthly power bills, was ultimately rejected. The commission voted 2-1 against it. Two commissioners even voted to block agency staff from taking testimony on the issue.[12]

COMPLAINTS

In addition to concern about the Price To Beat, the PUC continued receiving thousands of complaints each year related to electricity service. Complaints had been on the rise ever since the state deregulated its market, peaking in 2003 and 2004 and then, after a dip in 2005, increasing again in 2006 to more than 10,000.[13]

Problems with customer switching motivated a significant portion of those complaints. It had become clear that a process that typically had taken a day under the previous regulated system now could take two weeks or longer. (See Appendix B for more about consumer complaints filed with the PUC.)

ROLLING BLACKOUTS

On April 17, shortly after 4 p.m., hundreds of thousands of Texans started losing power. The operator of the Texas power grid, the Electric Reliability Council of Texas, suddenly found itself without enough available generating capacity and ordered rolling blackouts across the state.[14] Although ERCOT acted quickly to avert a more serious system-wide outage, its response nonetheless raised serious management questions. "You can't be out there cowboying, operating on your own," state Sen. Troy Fraser told organization officials shortly afterwards.[15] Sen. Fraser and others complained that ERCOT had failed to alert key policymakers and law enforcement officials. He said regulators were caught flat-footed, and police officers were sent scrambling to direct cars after traffic signals unexpectedly stopped working.[16]

PUC Chairman Paul Hudson also blasted ERCOT's response, complaining that grid managers did not call him directly about the emergency. "My immediate one-word reply is a bit too colorful to restate," Hudson said. But the PUC chairman also said that when it came to dealing with ERCOT, such communications breakdowns were nothing new.[17]

The organization charged with scheduling power across 38,000 miles of transmission lines had done little to earn the confidence of lawmakers and regulators. Since the passage of SB 7 in 1999, ERCOT had mismanaged the deregulation pilot project, appeared incapable of efficiently processing switch requests for many months and drew fire for multi-million dollar billing errors. There were also problems with the organization's financial controls, as evidenced by the guilty pleas of several former executives on bribery and corruption charges.[18]

In May, ERCOT chief executive officer Thomas F. Schrader resigned amid questions about his leadership.[19] Schrader had, on occasion, bucked the PUC — even awarding raises to some employees over the objections of the commissioners.[20] Schrader, when he came on board in 2004, had followed the tenure of Tom Noel, another ERCOT CEO who left under pressure.

MARKET POWER ABUSES PERSIST

Enron agreed shortly before the beginning of the new year to pay more than $1.5 billion to settle claims that it had manipulated the California market. Federal regulators also accepted a $512 million settlement from Houston's Reliant Energy to resolve claims it charged unfairly high prices during the California energy crisis. In Texas, meanwhile, TXU Wholesale came under investigation for allegedly engaging in similarly questionable practices that "raise substantial competitive concerns." [22]

The 2006 review continued a history of such inquiries involving TXU. In 2003, for example, the company drew regulatory scrutiny when energy that typically sold for less than $50 a megawatt-hour in the spot wholesale market shot up to $990.[23] That same year TXU also was targeted in an unsuccessful lawsuit alleging market manipulation.[24] The next year the PUC focused on TXU's bidding practices after a series of price surges. The commission eventually concluded there was no manipulation involved, but nonetheless warned that the state's power system was vulnerable to abuse by the state's largest generation companies.[25]

TEXAS MEETS RENEWABLE ENERGY MILESTONES

Senate Bill 7 called for the creation of 2,880 megawatts of new renewable energy capacity by 2009. Texas exceeded that goal in 2006 — three years early — and was ahead of schedule for meeting updated renewable energy targets created by Senate Bill 20, adopted in 2005.[26] Texas also surpassed California in 2006 as the number one state in the nation for installed wind power. Worldwide, only Germany, Spain and Denmark had more wind power than Texas in 2006.[27]

About 2.1 percent of electricity generated in Texas came from renewable sources in 2006, up from 1.5 percent from 2005. Within the ERCOT region, renewable energy provided 2.1 percent of peak generation, up from 1.5 percent in 2005.[28]

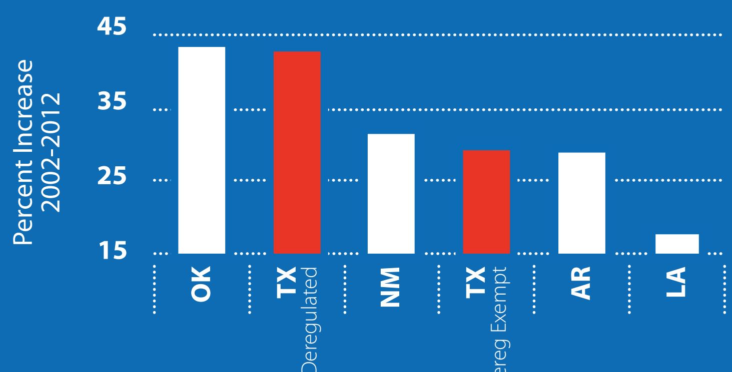
To foster the creation of new renewable generation, Senate Bill 7 established a system whereby electric retailers could earn and trade "Renewable Energy Credits" (RECs) for a portion of their energy sales. Under the program, electric retailers that do not acquire enough renewable energy to satisfy their obligations can purchase credits from other companies that have exceeded their obligations. Electric retailers that market so-called "green power" to customers also can obtain renewable energy credits for that purpose.

The RECs needed for the state to meet its renewable energy goals represented about 1.7 percent of energy sold to retail customers in 2006.[29]

"This has been more successful than any other provision of the bill," said Tom "Smitty" Smith, director of the Texas office of Public Citizen, referring to the environmental safeguards included in Senate Bill 7. He added, however, that "without a doubt, (these goals) could have been accomplished without going to full-scale deregulation … without creating the series of unnecessary middlemen, in the form of Retail Electric Providers." He also noted that much of the dramatic increase in wind power in Texas was attributable to federal tax credits.[30]

Price Increases in Texas and Adjoining States: 2002-2012

Source: United States Energy Information Administration, http://www.eia.gov/cneaf/electricity/page/sales_revenue.xls



Since 2002, average electricity prices increased more in deregulated areas of Texas than they increased in all adjoining states except Oklahoma. This exhibit examines residential prices only.

Year: 2007 The 80th Texas Legislature — The TXU Buyout

Lawmakers in 2007 reported phone calls from hundreds of constituents irate about electric rates. The AARP said Senate Bill 7 had created a "deregulation mess" and made reform its No. 1 legislative priority.[1] Even key supporters of Senate Bill 7 began raising doubts. "There has been insufficient participation of lower-cost providers — unfortunately, we have not seen the Southwest Airlines of the electric industry," lamented former state Rep. Steve Wolens, the co-author of SB 7. He went on to say that "there are many, many issues, there are a ton of issues" with SB 7 and acknowledged that it had failed to create meaningful savings.[2]

This was particularly troublesome given that Texas in 2007 had passed one of the last major milestones under SB 7.

The AARP said Senate Bill 7 had created a deregulation mess…

On Jan. 1, the Price To Beat expired. TXU in Dallas, Reliant Energy in Houston and the other legacy providers had been allowed to offer a variety of rate packages for some time. But one of them always had to be the Price To Beat. No longer. Now the legacy providers had free rein to charge whatever they wanted. The brakes were completely off.

In theory, market forces would keep prices down now that there were no capped rates. But evidence emerged in 2007 that the deregulated market continued to have problems transitioning into a fully competitive one.

For instance, a survey of residential electric prices through 2007 showed that Texans paid below average rates in the years prior to Senate Bill 7 and then well above the national average after deregulation came into effect. The survey indicated that consumers in Texas paid on average more for electricity than consumers in all other deregulated states with retail competition.[3]

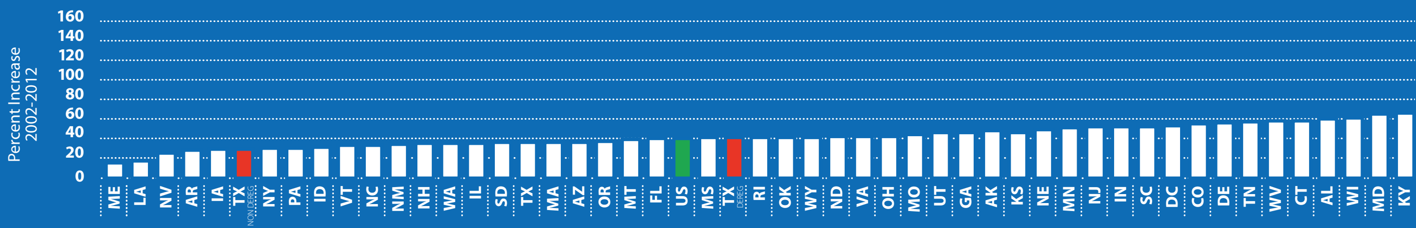
Industry representatives have consistently blamed high prices in Texas on the state's reliance on natural gas as a fuel source for generation. But the survey showed that regulated states with a similar dependence on natural gas, such as Louisiana, experienced residential rate increases smaller than those in Texas. The PUC likewise noted that CenterPoint's Price To Beat rate had been second highest among a sample of major providers that relied heavily on natural gas.[4]

These findings illustrate a central fact about pricing under deregulation: High prices in Texas are not simply a function of the market's reliance on natural gas but rather a function of *how* the market relies on natural gas. Under ERCOT's traditional rules all power accepted to meet demand in the spot market is paid for at the price of the most expensive power accepted to meet that demand. This becomes the "clearing price" on the wholesale spot market — and in most cases, it's a gas plant that sets it. So, natural gas prices help set the price for *all* spot energy in ERCOT. These spot prices then send ripples throughout the entire wholesale market, and in 2007 this meant higher residential bills.

By contrast, regulated investor-owned utilities are required to charge rates that reflect the *actual* cost to generate power, based on the average of *all* of the fuel used in the utility's generation fleet. This means that regulated retail rates include a fuel cost that is a blend of costs associated with several kinds of fuel, ranging from stable, low-priced lignite or coal, coal or nuclear generation to high-priced gas.

Residential Electric Price Increases — Texas vs. United States 2002-2012

Source: United States Energy Information Administration, http://www.eia.gov/cneaf/electricity/page/sales_revenue.xls



Residential electricity prices in deregulated areas of Texas increased by slightly more than 40 percent between 2002 and 2012.That's slightly more than the increase registered nationwide, and about 10 percentage points higher than the increase registered in areas of Texas exempt from deregulation. This exhibit uses 2002 as a starting point because that was the year deregulation took effect in Texas. It ends with 2012 because that year was the most recent (at the time of publication) for which there was relevant data to conduct the analysis. This exhibit considers prices only within continental US.

WHOLESALE ENERGY PRICES DOUBLE

The price of energy on the spot market more than doubled in September 2007, as compared to the price during the same month in 2006, according to an ERCOT report. This created revenues of $76 million for generators in September of 2007, as compared to $37.4 million during the same month in the previous year.[5] This price increase — and others — were made possible in part because of rule changes at ERCOT and by the Public Utility Commission. Among other things, the PUC increased the price caps at which generators can offer their energy into the wholesale spot market. Previously, the cap was set at $1,000 per megawatt-hour, a very high price and far in excess of the cost to operate any power plant on the system. After the PUC's decision, the cap went to an even higher level.[6]

As for ERCOT, the organization had earlier implemented market rules that allow for higher prices during the deployment of a particular form of capacity used to protect against power shortages.

That these changes contributed to the doubling of those September energy prices was not met with alarm by most market participants or by the PUC. That's because many market participants believed that higher prices represented a "truer" economic result under the theory that they provide an incentive for additional generation construction.[7] Far from raising questions about whether the ERCOT market works for consumers, under this view high prices (and consistent price increases) were seen as evidence that the market is correct from an economic standpoint.

Of course, higher spot energy prices eventually lead to

higher retail prices — that is, the prices that end-use consumers like homeowners pay. That's because ERCOT's spot market for energy heavily influences the prices paid by all wholesale buyers — whether they deal directly through that market or not.

In lawsuits, two former TXU power traders alleged a pattern of market manipulation by the power company.

This approach — that is, equating low prices with a problem in the market and higher prices as "success" — raised troubling questions for Texas electricity consumers. It was also an approach that continued to inform policy debates about the state's deregulated electricity market for years to come.[8]

ALLEGED MARKET POWER ABUSES IMPACT THE MARKET

TXU's trading practices remained an issue in 2007. In lawsuits, two former TXU power traders alleged a pattern of market manipulation by the power company. The traders said they notified their superiors about the improper activities, and the superiors condoned the behavior. The company denied wrongdoing.[9]

The PUC also concluded on March 12 that TXU Wholesale had engaged in unfair trading practices. An outside expert hired by the agency said that TXU during one period in 2005 had driven up some wholesale prices by 15.5 percent and racked up $19 million in unfair profits. The consultants found that "since TXU raised prices in the market and profited from its activities ... TXU's behavior constitutes market power abuse." [10] Two weeks later the PUC recommended $210 million in fines, a record for the agency.[11]

The very next month, on April 3, 2007, wholesale prices spiked to levels never before seen in Texas. ERCOT reported that balancing energy shot up to $1,500 per megawatt hour on three separate occasions. The prices could have gone even higher if not for an existing cap of $1,500. Typically, the power sells for less than $100.[12]

Later that same month a sister company of Houston's Reliant Energy improperly held back wholesale power. It later agreed to pay over $100,000 in penalties.[13]

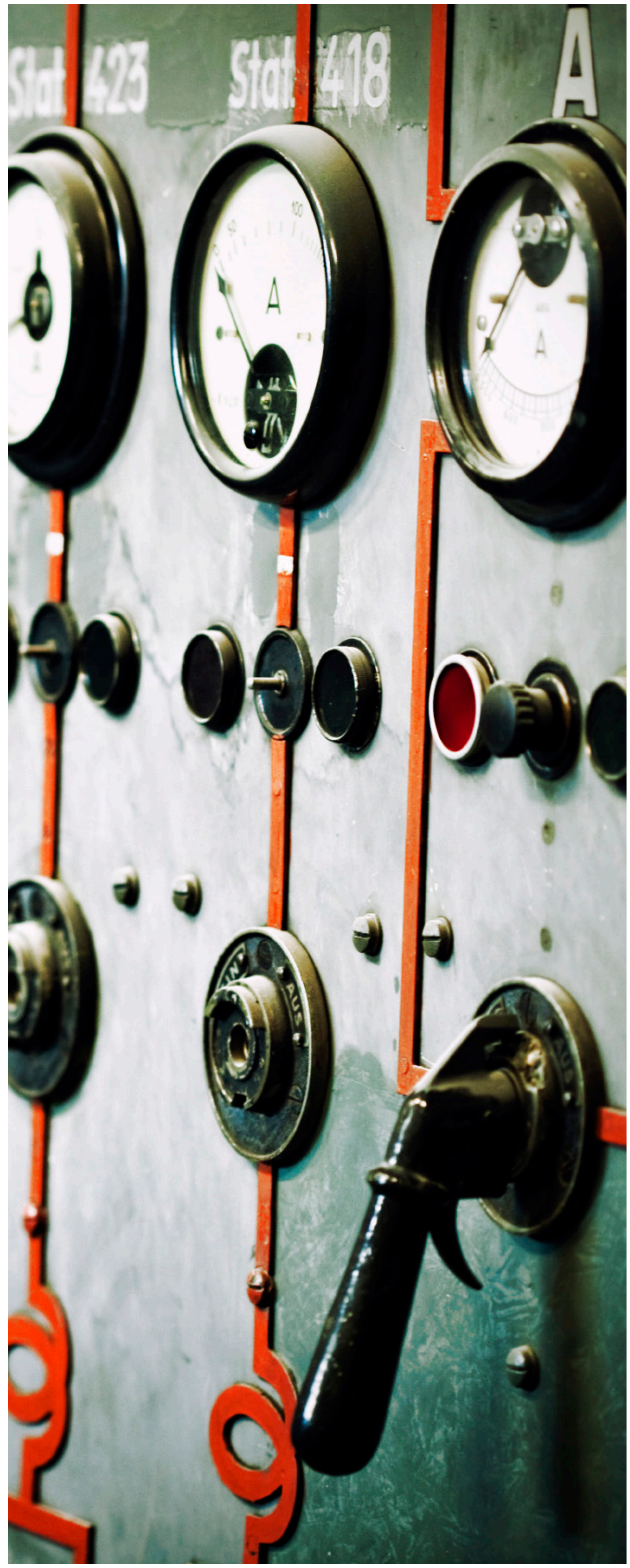
THE TXU BUYOUT: THE LARGEST LEVERAGED BUYOUT IN HISTORY

The 80th legislative session began with bold talk of reform. Many lawmakers reported complaints from constituents that the deregulated market was not living up to its potential. Lawmakers vowed to pursue changes to create real competition and to lower rates. They floated bills to establish new controls over potential market manipulation by wholesale generators, to create some price controls, and to allow municipalities to negotiate deals on behalf of large blocks of customers.[14] They received support from consumer groups across the state, some of whom mounted door-to-door campaigns.[15]

By contrast, industry representatives warned against changing SB 7. Despite the price spikes, the numerous findings of questionable conduct and evidence of ratepayer overpayments, the industry's position remained immutable: SB 7 was, for the most part, working as intended. Said John Fainter, president of the Association of Electric Companies of Texas: "You've got to be careful about what you do. We think that we have a well-designed market."[16]

Among the most important of the reform bills were Senate Bills 482 and 483, both by state Sen. Troy Fraser, R-Horseshoe Bay. The first would have made TXU split into separate entities to limit its dominance in Texas. It would also have given the Public Utility Commission power to cap residential rates if the agency found them out of line with market prices. As drafted, the second bill, SB 483, would have prohibited any company from controlling more than 20 percent of power generation in any of four distinct regions or zones within Texas. In the North Texas zone, TXU owned about 45 percent of the generation — and indirectly controlled much more than that.[17] Sen. Fraser unveiled both bills on Feb. 7, noting that SB 7 had not sufficiently helped residential ratepayers. "The legislation filed today will strengthen competitive forces and improve the residential market," he said.[18]

Other important bills included one that would reinstate the System Benefit Fund, one that would allow for the creation of a regulated rate if the PUC determined the market was insufficiently competitive, one that would create a regulated rate based on cost of service and one that called upon the PUC to recommend alternatives to deregulation.[19] But



the political landscape changed dramatically after word leaked out of a proposed business deal between TXU and Kohlberg Kravis Roberts & Co., a private equity firm. The outside investors were offering to buy TXU for $45 billion, including debt. If the deal went through, it would be the largest such transaction in history.[20]

The price of energy on the spot market more than doubled in September 2007, as compared to the price during the same month in 2006, according to an ERCOT report.

To garner support the buyout partners promised a host of inducements, including lower rates through 2008 and an agreement to build only three of 11 coal generating plants supposedly planned for construction by TXU. However the *Dallas Morning News* released an independent study on June 24 that concluded that TXU probably would have cut prices and shelved plans for the coal plants anyway — even without the buyout. The study concluded that ratepayers would eventually see higher bills and that the "the buyout of TXU provides no inherent benefits to the customer."[21]

Sen. Fraser feared as much and so drafted Senate Bill 896 that expressly granted the PUC authority to ensure the transaction was in the public interest. By mid-May, however, it was increasingly clear that that change in law — as well as any other legislation that was seriously opposed by TXU and KKR — would not survive the session.[22]

Energy companies typically employ plenty of lobbyists, but in 2007, with the buyout at stake, they deployed a vast army of them. According to one report TXU and its buyout partners spent $6 million for lobbyists, $11 million for advertising and $200,000 for legislative gifts. That figure was about twice what TXU had said it planned to spend before the announcement.[23]

Under intense lobby pressure, Senate Bill 482 was killed May 27 on the House floor.[24] Senate Bill 483 died during the waning days of the session after House and Senate negotiators failed to come up with a compromise.[25]

The deal closed on Oct.11, with the new company to be called Energy Future Holdings. It would be comprised of three major units: retail electric provider TXU Energy, wholesale power company Luminant, and regulated transmission and distribution utility Oncor.[26] The final deal included several important financial covenants intended to protect Oncor (and its captive ratepayers) should the whole enterprise go bust. [See Ring Fence article, page 48.]

And many observers felt this was a real possibility, given the massive debt used to finance the deal. Others simply warned about the potential fall-out for ratepayers, no matter how the new company fared. "To be honest — and this is a very un-Republican thing to say, but I'm going to say it anyway because I'm out of office now — very few of these mergers ever turned out very good for folks," said former PUC chairman Pat Wood III, speaking to the *Dallas Morning News.*

"You know, a lot of these things don't look great a year later," he said.[27]

System Benefit Fund provides some assistance to low-income Texans

Low-income ratepayers did, however, get one smallbit of good news. The System Benefit Fund had been financed through what is typically a $1 average fee on electric bills. It was created as part of SB 7 to finance discounts for low-income residents. Previous legislatures had raided the fund mercilessly, using the money for budget balancing purposes. But in 2007, at the urging of state Rep. Sylvester Turner, lawmakers appropriated about $170 million for the System Benefit Fund — meaning that it would again begin funding rate discounts for poor Texans.[28]

However, about $400 million in money already collected for the System Benefit Fund — plus another $100 million that would accrue over the next two-year budget cycle — was used for budget balancing purposes.[29]

Oncor's Ring Fence

Anyone living within its service territory and who wants electric service must, by necessity, become a customer of Oncor. As a state-sanctioned monopoly, the north Texas transmission and distribution utility is obligated to serve all homes and businesses in a wide swath of territory extending from just north of Austin to Wichita Falls, up through Dallas and Fort Worth and even westward into Midland and Odessa. Lacking a free-market choice, Oncor's customers — like customers of all monopoly utilities — are *captive*.

It is for this reason that the Texas PUC possesses regulatory authority over Oncor (and other electric transmission and distribution utilities in Texas), and it is for this reason that the agency has a say if the utility changes ownership. The utility was subject to such an ownership change in 2007 when it was swept up into leveraged acquisition of TXU.[30] As part of that deal — and at the urging of municipal groups and others — the PUC ordered the creation of a legal "ring fence" around Oncor that is meant to insulate the utility from any potential financial distress of its new parent company. Ratepayer organizations, municipal coalitions and other interested parties insisted on this extra level of protection out of concern regarding the massive debt employed in the buyout.[31]

In utility world parlance, a "ring fence" typically refers to financial and legal covenants that are intended to insulate consumers of essential services (such as gas, electric or water utility service) from the financial losses of a utility parent company that operates in the open market.

Some of Oncor's ring-fencing provisions include:

- Oncor's sale of a 19.75% equity interest to a separate entity.
- Maintenance by Oncor of separate books and records.
- A requirement that Oncor's board of directors be comprised of a majority of independent directors.
- Prohibitions against Oncor providing credit support to, or receiving credit support from, its open-market affiliates.
- Prohibitions against Oncor employing its assets to satisfy the debt or contractual obligations of free-market affiliates.

Year: 2008 ERCOT's Over-Budget and Behind-Schedule Market Overhaul

Research released in 2008 found that deregulated market structures in Texas and elsewhere had failed to produce lower prices. A study[1] released that September by the Technology Policy Institute, an independent Washington-based economics think tank, reviewed wholesale energy prices in ERCOT and other states that operate similar regional transmission organizations, or RTOs. These RTOs are an intrinsic feature of deregulated electricity markets.

The study demonstrated that almost without exception, wholesale electricity prices in states with RTOs had increased more steeply than in markets without them. The researchers confirmed that differences in fuel costs and start-up challenges in newly deregulated markets could not explain the differences. Many deregulation proponents had pointed to both factors as possible explanations for higher prices in deregulated markets relative to regulated ones. "Our results show that RTO membership is consistently related to higher average wholesale electricity prices," the authors determined. "With the exception of (New England), RTOs have failed to deliver lower wholesale electricity prices."

. . . the research shows that even by this measure, deregulation is missing the mark in Texas. The study reported that there were 58 electricity wholesalers in 1999, but only 46 in 2006.

Moreover, the authors found that the move to RTO-based retail competition had led to less wholesale competition, not more. Many proponents of deregulation have pointed to an increase in market competitors as evidence of success. But the research showed that even by this measure, deregulation was missing the mark. In Texas, for instance, the study reported there were 58 electricity wholesalers in 1999, but only 46 in 2006.

"There appears to be much more work still to do before the promise of competition is realized in areas that currently have organized wholesale markets," the authors concluded. "Regulators in regions still served by traditional markets would do well to wait for the results of these efforts to be evaluated before moving to develop and implement new RTOs."

PRICES SPIKES CONTINUE DURING TIMES OF SYSTEM STRESS

And as if to confirm those findings, wholesale prices in ERCOT spiked to unprecedented levels in 2008. Generation companies were prohibited by PUC rules from offering to sell their power into the spot market at prices above $2,250 per megawatt-hour. But on several occasions prices in the spot market hit that cap and even exceeded it. According to reports, the balancing energy price topped $3,800 per megawatt-hour in the Houston area on April 25th, and $3,460 and $4,233 in Houston and South Texas respectively on May 23rd.[2]

That spot market electricity was selling for such astronomical high prices (this is electricity that generally sells for less than $100 per megawatt-hour) was due to a quirk in ERCOT's pricing rules. Although generation companies could not *offer* their electricity for more than the 2008 cap of $2,250 per megawatt hour, they were not prohibited from *accepting* more per megawatt hour. And under certain circumstances ERCOT's market rules produced such above-the-offer-cap prices.[3]

ERCOT blamed several days of high temperatures and the loss of a number of plants and power lines, which were down for maintenance. "All of these factors contributed to higher wholesale prices during the spring," the PUC reported in its 2009 Scope of Competition Report.[4] And while isolated to a relatively small portion of the market, such dramatic price spikes do not occur without repercussions. In 2008 they contributed to failures of five retail electric providers, and, as a result, thousands of Texans served by those retailers ended up getting dumped to high-cost Provider Of Last Resort service.[5] Customers harmed in this way had taken action recommended by members of the Texas Public Utility Commission and deregulation proponents: they

The GE Study

Under the Competitive Renewable Energy Zone (CREZ) process, the Texas Public Utility Commission delineated various geographical regions for multi-billion dollar transmission construction to support wind generation. As part of the CREZ process, ERCOT hired General Electric to conduct a cost-benefit and reliability analysis to determine the amount of transmission to build. The GE study was largely glowing, with the company claiming that system reliability would not suffer with the addition of another 15,000 megawatts of wind power. GE said the new wind generation would reduce market prices.[51] Those supporting the transmission build-out cited the report often. But the study had various problems. For instance, the company did not account for the extra payments that would have to be made to gas generators that must stand ready to provide back-up power when the wind stops blowing.[52] GE also declined to release key background data and assumptions used in its computer models.[53]

Another point lost on many was that GE, as the nation's largest manufacturer of wind turbines, had a very large financial stake in Texas going forward with the Competitive Renewable Energy Zone process. This is because GE had entered into contracts with wind developers doing business in Texas, including T. Boone Pickens, whose Mesa Power had ordered 667 turbines from the company at a cost of $2 billion.[54] GE also had a $300 million equity investment in Horizon Wind Energy, a leading proponent of one of the CREZ transmission scenarios considered by the PUC.[55] For more about wind power, see Appendix F.

had shopped around in the open market and selected a competitive electric provider. But as a consequence of getting forced onto provider-of-last-resort service, many reported a doubling of the prices on their bills.[6]

Former state Rep. Steve Wolens, one of the co-authors of Senate Bill 7, was among those getting service from a competitive electric provider that failed in 2008. Mr. Wolens said he checked with the PUC after his company closed and was told not to pay his last bill. He ended up getting turned over to a collection agency.

Given his role in creating the restructured market, Wolens said: "It serves me right. I'm getting my just desserts."[7]

The Texas Public Utility Commission held emergency meetings in which they called for changes in market rules and more customer protections relating to Provider Of Last Resort service.[8] The proposed changes included requirements for higher capitalization standards for Retail Electric Providers and additional security for customer deposits to prevent their loss in the case of a company default.[9]

Reliant Energy, one of the state's largest electric retailers, also announced in October 2008 that it was looking for a buyer.[10] The company was soon acquired by NRG, an independent power producer with major holdings in the Houston area.[11]

MARKET "WATCHDOG" REPORTS PRICES ARE TOO LOW

Despite the clamor about high bills, a key regulatory advisor explicitly called for new rules that would not result in lower prices, but higher ones.[12]

In a report from August, the consultant hired to serve as the Independent Market Monitor recommended the use of mechanisms that would artificially increase wholesale prices. "More reliable and efficient shortage pricing could be achieved by establishing pricing rules that automatically produce scarcity level prices when defined shortage conditions exist on the system," he stated in the report.[13] In other words, the consultant called for new rules that would create wholesale price spikes.

The consultant, Potomac Economics of Delaware, was hired at the behest of the Texas Legislature in 2005 as an independent market watchdog.[14] The consultant's findings carry considerable weight with ERCOT and especially with the Texas Public Utility Commission, where commissioners have echoed many of the same concerns.

This proposal for higher prices was in no way an anomaly for Potomac. In annual reports for both 2007 and 2008,[15] Potomac concluded that without higher prices — and especially without higher prices during periods when power supplies run short — generators won't make enough money to invest in new construction.

The market monitor likewise concluded that the reason there aren't more spikes is because there's already too much generation. That is, the market monitor asserted that generation reserves were too high, which puts downward pressure on prices, which prevents companies from making enough money to build more generation. He said that the market needs to support the creation of more generation, but it can't because it already has too much generation.

In a report from August, the consultant hired to serve as the Independent Market Monitor recommended changes that would artificially increase wholesale prices.

The ERCOT "watchdog" did not express concern that price spikes of 2,000 percent that occurred in March of 2008 caused harm to consumers, but rather concern that there were not similar price spikes during an earlier period of scarcity.

The cap on wholesale prices in ERCOT's balancing energy market stood then at $2,250 per megawatt-hour, which was already more than twice the level of similar caps in other states and represented a price more than 20 times greater than typical energy prices. Generators had received that much for their power on numerous occasions, and stood to receive even more when the cap eventually went to $3,000 in 2011.[16]

MARKET ABUSE?

In November, Luminant — formerly TXU — agreed to pay a $15 million penalty for alleged abuses in the wholesale market.[17] While the $15 million penalty is one of the largest paid by a generator, the PUC had originally recommended penalties of more than $200 million. The PUC's own investigation found evidence that the company had profited by nearly $20 million through its improper activities and that the company's actions had cost the market at least $57 million.[18]

"Settling for pennies on the dollar just reinforces the belief that the PUC is unwilling or unable to stand up to electric companies," said Tim Morstad, a policy analyst for the AARP.[19]

THE NODAL MARKET: OVER PROMISED, OVER BUDGET AND BEHIND SCHEDULE

PUC commissioners and some industry representatives said an ambitious overhaul of the wholesale market would cure many of the problems. Supporters said the new market design —known as a "nodal" or "marginal locational pricing" market (see pages 53-54) — would reduce or eliminate gaming opportunities and produce incentives to build generation where it is needed most.

The PUC initially authorized nodal in 2003,[20] and expected to have it operational by the fall of 2006.[21] But that deadline came and went. The next deadline for the end of 2008 was also abandoned. Then, on the day before Thanksgiving, ERCOT announced that the project wouldn't be ready until at least the end of 2010, and estimated its cost at a whopping $660 million.[22] That was more than double the size of ERCOT's last estimate and far in excess of initial cost estimates for ERCOT of less than $100 million.[23]

"It's exceptionally disturbing," said Rep. Phil King, R-Weatherford, chairman of the House Regulated Industries Committee. "I don't want to see us strap $660 million on Texas consumers unless the savings exceed that."[24]

The new system is supposed to make the market more efficient by changing the assignment of wholesale costs associated with line congestion. That is, when complete, customers in the zones with the most congestion (where the demand for power outstrips the supply of available transmission lines) likely will end up paying more than they would under the old system.

...wind power is so unstable that ERCOT would only factor in only 9 percent of total available wind capacity when determining available power during summer peak hours.

A cost-benefit analysis commissioned by the PUC found that consumers would save $5.6 billion in wholesale power costs during the first 10 years of the nodal system. The Boston-based consulting firm, CRA International, said those savings did not reflect a system-wide benefit, but rather a "transfer of wealth" from generators to consumers. Generators have been among the greatest advocates of the market overhaul.[25]

A separate report commissioned by a coalition of West Texas and North Texas cities found that incorrect and speculative assumptions in the CRA report led to a massive over-estimation of benefits for consumers. The cities found that flaws in the CRA report were so pervasive as to call into question its conclusion that the nodal market would benefit consumers.[26]

Also a report by the American Public Power Association (APPA) found that proponents had oversold the benefits of nodal, and that similar markets elsewhere had not worked particularly well in practice. The APPA noted, for instance, that customers living in the Northeast had not realized any cost savings from a nodal system there. It also noted that implementing such a system does not guarantee competitive markets or prevent market abuse. Nor does a nodal market provide incentives for investment in some areas with the most overburdened power lines.[27] (For more about the nodal project, see pages 53-54.)

SYSTEM RELIABILITY AND WIND POWER

On February 26, 2008, ERCOT officials took emergency action to avoid blackouts. A sudden loss in wind power, coupled with other factors, sent grid operators scrambling. "This situation means that there is a heightened risk of … regular customers being dropped through rotating outages, but that would occur only if further contingencies occur, and only as a last resort to avoid the risk of a complete blackout," the state's command center for disasters stated in an e-mail notice to municipalities.[28]

It was a serious emergency for ERCOT, and one that illustrated the inherent challenges associated with wind power. Kent Saathoff, ERCOT's vice president for system operations, said because wind doesn't give advance notice before it stops blowing, grid engineers must remain nimble enough to respond quickly with replacement power.[29] Otherwise, blacouts occur.

That fickle nature of wind also means the state cannot forego building other sorts of generators — more polluting ones — to provide replacement power. Those generators have to remain on standby and ready to ramp up quickly. That's an extra expense to the system. In fact, wind power is so unstable that ERCOT factor in less than 9 percent of total available wind capacity when determining available power during summer peak hours.[30]

In its 2009 Scope of Competition report, the PUC suggested that wind generation has suppressed electric wholesale and retail prices. As evidence, it cited findings by the Independent Market Monitor that correlated wholesale prices on the one hand, and wind production, system load and fuel prices on the other.[31]

The monitor said that for each additional 1,000 megawatts of wind power produced, the clearing price in the balancing energy market fell by $2.38.[32]

However, that analysis didn't appear to tell the whole story. For instance, the calculation of balancing energy savings did not account for the multi-billion dollar expense of building new transmission.[33] Neither did it account for the increased cost of purchasing additional backup capacity, known in ERCOT as "ancillary services." ERCOT also has found separately that wind is one of the most expensive forms of power commonly used in Texas, with each megawatt of power costing $53 to generate.[34] And if one figures in the increased cost of purchasing additional backup capacity (known in ERCOT as "ancillary services) and other factors, then the cost of wind power goes to $70-$90 per megawatt hour — even after factoring in federal subsidies.[35]

In fact, for every $100 million of investment, wind-power developers receive more than $74 million in federal tax credits and other benefits, according to a study from the University of North Texas. Wind developers also receive corporate income tax breaks from the state and property tax abatements from local governments.[36]

The Houston Chronicle's Loren Steffy, in an analysis from July 2008, called wind power "an open trough of government subsidies, tax credits and state mandates." He described government and captive ratepayer sponsorship of wind in Texas "a massive corporate welfare effort that means big money for the wind-power developers and big costs for the rest of us."[37]

CREZ ZONES

The wind industry has grown exponentially in Texas. By 2008, Texas had 6,000 megawatts of installed generation capacity — an amount far exceeding that then existing in most other states, and even many nations.[38]

Texas was also planning through its Competitive Renewable Energy Zone process to construct enough new transmission lines to West Texas and the Panhandle for nearly 18,500 megawatts of additional wind generation. The PUC estimated the cost of building those lines at $4.9 billion[39] — a rather startling figure considering that all investment in ERCOT transmission since 1999 was only $3.9 billion.[40]

And while West Texans and residents of the Panhandle could clearly reap the benefits of economic development from that construction, ratepayers statewide would foot the bill. By some estimates, the new construction would cost typical Texas residents around $50 per year.[41] The Commission expected the new lines in service within four to five years. (For more about the CREZ transmission lines and wind power in Texas, see Appendix F.)

PROVIDERS AND PRICES

By July 2008 about 44 percent of Texans had switched to electric service other than that offered by the old legacy providers like TXU.[42] By comparison, only 14.3 percent of New Yorkers had switched in that state by the end of 2007.[43] "Though retail competition exists in a number of other states, including New York, Michigan, Illinois and several New England states, few REPs have attempted to compete for residential customers in those states and few residential customers have switched or changed providers," the PUC reported in its 2009 Scope of Competition Report.[44]

The same report noted that as of September 29, a customer visiting the state's PowerToChoose would find as many as 27 competitive retail electric providers in areas of Texas with deregulated retail electricity markets. It noted that these REPs offered 96 different plans in those various territories — including 23 different renewable energy options.[45]

The PUC said that this large number of competitors is an important indicator of success for the state's deregulated system. "The number of REPs has increased steadily since 2002," the report stated. "Residential customers have at least 50 percent more options than they did at the end of 2006."[46]

That switching activity, however, had not translated into lower prices. A survey by the Texas Coalition of Cities For Utility Issues in 2008 found that north Texans could shop around all they like — that is, they could switch to the very best deal in their area — and still not find more affordable electricity than that offered by municipally-owned utilities, cooperatives and Texas investor-owned utilities outside competition.[47]

The report considered all the best competitive offers in North Texas, and compared those prices to electric providers outside deregulation. The seven lowest rates in the survey were offered by providers outside competition. The average of typical monthly bills under competition was higher than the bill averages for customers in municipally-owned utilities, cooperatives and investor-owned utilities outside competition.

Noted the report: "Clearly, nothing about a deregulated system inherently drives prices lower than a non-competitive system. Otherwise, one might expect most — if not all — of the ten lowest rates in the survey to be offered by competitive REPs."[48]

POWER AGGREGATION

In 2008 a group of six West Texas cities located in deregulated areas of the state tried and failed to use a bulk purchasing strategy in order to lower rates for their constituents.

The strategy, known as opt-in aggregation, is explicitly authorized by Senate Bill 7. However, as the cities of Cisco, Comanche, Dublin, Eastland, Hamilton and Snyder discovered in 2008, the aggregation provision in the law doesn't work particularly well in practice.

The cities managed to sign up 1,600 households during an extensive outreach program and then attempted to negotiate a bulk rate power deal on their behalf. But citing the relatively small number of customers, electric providers either decided not to participate or would not offer prices lower than those already advertised on a website operated by the Texas Public Utility Commission.

Organizers of the bulk rate effort concluded that they would have been more successful using another bulk rate purchasing strategy, known as opt-out aggregation. However, opt-out aggregation is not permitted under Senate Bill 7 (see Appendix A).[50]

Opt-Out Aggregation

Many experts – including those at the Texas Public Utility Commission – report that consumers have saved money in states that permit a purchasing strategy known as "opt-out aggregation."[56] But while an unambiguous success in other deregulated markets, opt-out aggregation is not available to consumers in Texas.

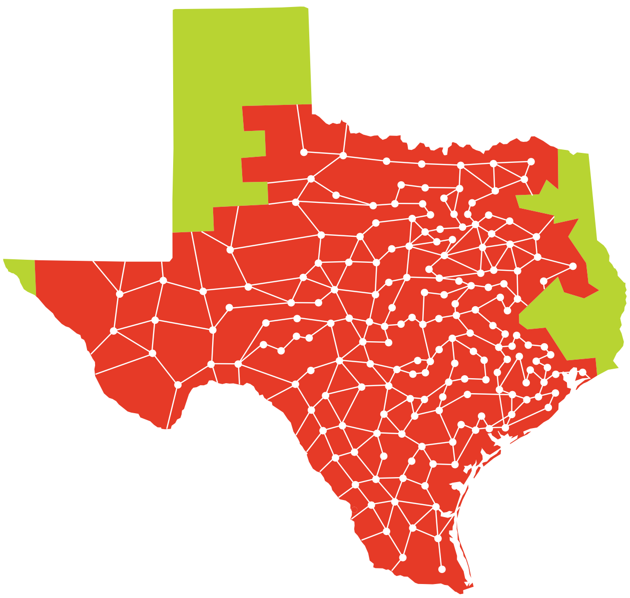
What is opt-out aggregation? In the simplest terms, it is a method that cities, counties or other political subdivisions deploy to purchase affordable power, in bulk, on behalf of their constituents. Under typical opt-out programs, the city council authorizes the aggregation of the residents' power needs through a public hearing and vote. Once approved, the political subdivision then mails notices to ratepayers advising them of the new energy aggregation program. Citizens who do not wish to participate in the program can check a box on the advisory and send it back, or can contact program organizers via the Internet or telephone. Those ratepayers who choose to participate need not take any further action at all. If the ratepayer doesn't respond within a given timeframe, it is assumed they want to participate and the political subdivision will negotiate a bulk-rate electricity deal on their behalf.

This is in contrast to opt-in aggregation, which is explicitly authorized by Senate Bill 7. Under opt-in aggregation, citizens must affirmatively sign up for service before their political subdivision will begin negotiations on their behalf. But opt-in aggregation creates an untenable conflict because large numbers of customers typically won't sign up for service unless they know how much money they will save, and retail electric providers won't offer substantial savings unless they have a reliable estimate of customers and the power to serve them.

A group of six West Texas cities tried and failed to use opt-in aggregation in 2007 and 2008. About 1,600 households in the cities of Cisco, Comanche, Dublin, Eastland, Hamilton and Snyder (in largely rural West Texas) agreed to participate after being contacted by their cities' representatives through a long, extensive and costly outreach program.[57] Most of the residents had never before negotiated electric contracts and many expressed enthusiasm about the sense of empowerment they received from the program. Their city representatives then attempted to negotiate a bulk rate deal. But competitive electric providers — some noting the relatively small number of residential participants — either declined to submit bids to serve them or would not beat the lowest prices already advertised on a website operated by the Texas Public Utility Commission.[58]

A study by the National Center for Appropriate Technology describes opt-out aggregation programs in states other than Texas as one of the few bright spots for consumers under electric deregulation.[59] In Ohio and Massachusetts, opt-out aggregation programs clearly led to lower prices, the study concluded.[60] The Texas Public Utility Commission likewise has acknowledged the success of opt-out aggregation programs and has suggested the creation of an opt-out aggregation in Texas as a way of enhancing the competitive market.[61] However, proposals to allow opt-out aggregation programs in Texas have been rejected by the state legislature.

What is Nodal?



Power lines can handle only so much electricity without overheating. This can become a problem when lines get congested, that is — when there is too much power and too few power lines. Under the system in place in 2008, ERCOT managed congestion by paying generators to ramp up or ramp down production during peak energy-use periods. ERCOT then determined the extra cost for this congestion management, and assigned the expense to those entities that purchase electricity in the wholesale market. However, the prices paid for congestion management were not assessed in a uniform fashion across the state, but rather varied by large areas within the state, known as zones.

This differed from a nodal market, which assigns costs in a more granular fashion. ERCOT and the Texas Public Utility Commission decided to replace the old zonal market with a nodal structure in the theory that it would reduce the overall cost of grid operations. Under nodal, ERCOT has the ability to charge entities responsible for "creating" congestion — that is, those that demanded more power than can be supplied over transmission lines in their area — and then re-allocate the money it collects to generators that relieve the congestion. This means that the new nodal market is designed to increase revenues to some market participants, like certain generators, while increasing costs to some entities that buy power.

Using a bank of computers and complicated software, the new system spits out rapid-fire calculations for electricity prices. The computers calculate these prices at thousands of points on the transmission grid, or "nodes", where power is either added or removed by wholesalers or users. The computerized nodal system also gives ERCOT the ability to model electricity demand and the ability to manage a trading system similar to those operated by eBay, which, in theory, will improve ERCOT's energy-management system to help guard against outages. It is claimed that the new technical systems also will improve ERCOT's ability to collect and aggregate technical data, which can help the organization guard against market abuses.

QUESTIONS REMAIN

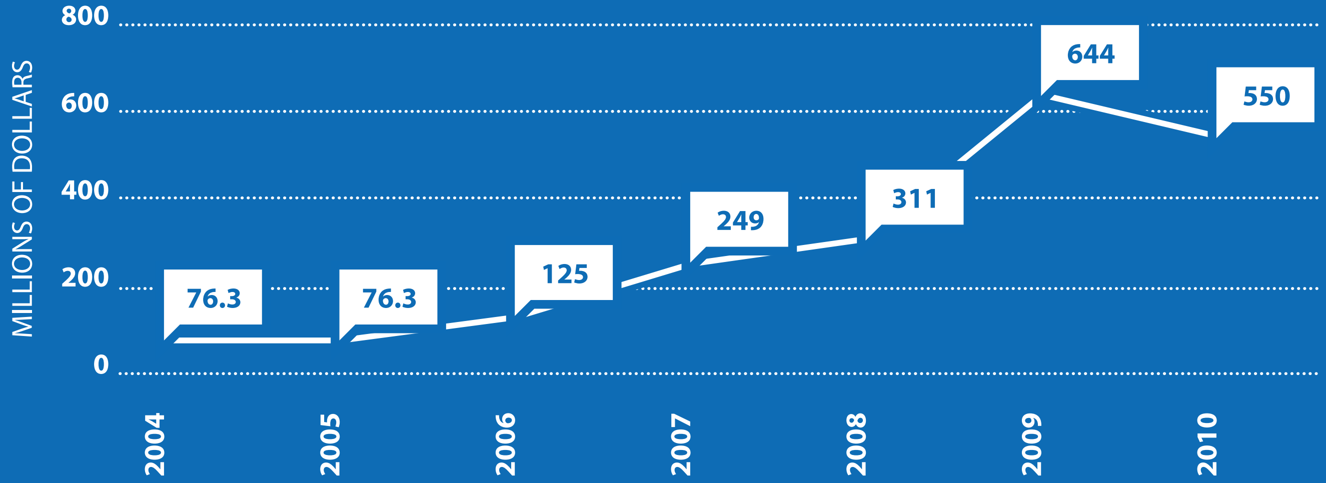
However, the PUC and ERCOT could have ordered many of the improvements now associated with the new nodal system without ever having gone forward with it. For instance, there is nothing "inherently nodal" with collecting and aggregating technical data. Also, the entire nodal system was proposed as a way of reducing congestion costs, but ERCOT's independent market monitor reported that congestion costs had already come down — from a high of about $275 million in 2004 to $186 million in 2008. This was probably the consequence of new strategies ERCOT employed for dealing with overburdened lines, and with the construction of new lines by utilities — not from a new-fangled nodal system.

And no one ever suggested that the nodal system will completely eliminate congestion costs.

Given the stunning expense and budget overruns, some questioned whether nodal was worth the trouble. The project once projected to cost less than $76.3 million ended up costing more than $500 million.

Nodal Project Final Costs Exceed Original Estimates By More Than 600 Percent

Source: ERCOT, "Nodal Timeline and Budget History," January 2011; Tabors, Caramanis, & Associates and KEMA Consulting, "Market Restructuring Cost-Benefit Analysis: Final Report," November 30th, 2004



An initial analysis commissioned by the Texas Public Utility Commission put the cost to ERCOT of transitioning from a zonal market to a nodal market at between $59.7 million and $76.3 million. The cost estimate eventually increased to $311 million, and by 2010 grew to $550 million.

Year: 2009 The 81st Texas Legislature

Residential electricity prices in Texas were down in 2009 compared to the previous year. Although this was good news for consumers, a look behind the numbers showed that the market was underperforming.[1] Consider, for example, the difference in average prices for Texans living inside and outside deregulated areas. Residential electricity prices dropped by 3.1 percent between 2008 and 2009 for Texans inside deregulated areas of the state, but dropped more than twice that much for customers in areas outside deregulation.[2] The declines in both areas were largely related to drops in the price of natural gas, which fuel many power plants in Texas. The regulated areas of Texas responded much more nimbly than the deregulated areas because of regulatory mandates that require fuel costs to be passed through to ratepayers, while retail electric providers in deregulated areas mark up their energy purchases from wholesale suppliers.

…the research shows that even by this measure, deregulation is missing the mark in Texas. The study reported that there were 58 electricity wholesalers in 1999, but only 46 in 2006.

Also, despite the short-term pricing drops, Texans in 2009 under deregulation continued paying more than the national average for electricity.[3] This disparity was in contrast to a long history of below-national-average prices before the adoption of the retail deregulation law, and in contrast to the below-average rates paid by Texans who resided in areas exempted from deregulation. These disparities were evidence that the market switch-over had yet to meaningfully benefit consumers. A survey of 21 major U.S. cities released in early 2009 also revealed that residents of Houston and Dallas were getting stuck with some of the highest electric bills in the nation. The survey found that summertime electricity bills in Houston and Dallas even exceeded those in scorching hot Las Vegas and Phoenix and surpassed those in northern cities like New York and Chicago during the winter months.[4]

THE TEXAS LEGISLATURE CONVENES

Lawmakers in 2009 convened for the 81st regular session of the Texas Legislature, the fifth since the state adopted Senate Bill 7 and the third since the opening of the restructured market. Electric prices in Texas had for the most

Electricity $488 more expensive in 2009 for Texans under deregulated system*

**Analysis compares average prices in areas of Texas inside and outside deregulation, and assumes 1,300 kw/h monthly usage.*

Source: US EIA, http://www.eia.gov/cneaf/electricity/p

Cents / KW/H

14.1

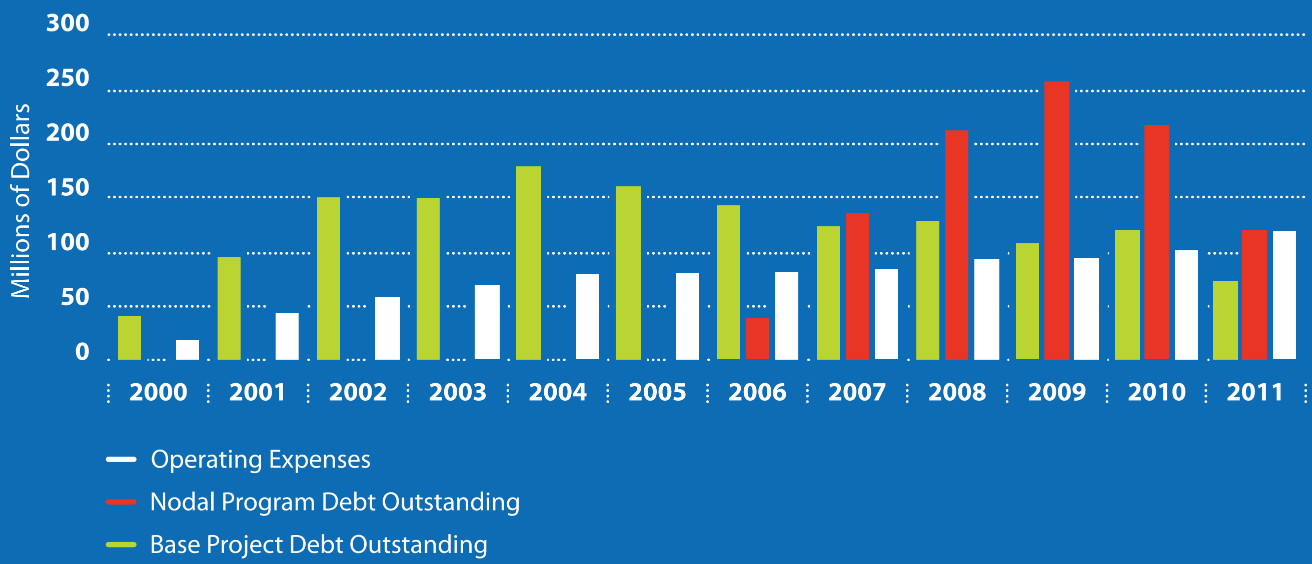
Average Price from Deregulted Retail Electric Providers

Average Price from Provider Exempt from Deregulation

10.1

Growth of ERCOT Debt and Operating Expenses

Source: ERCOT



Much of the debt incurred by ERCOT since 2006 is the result of the nodal project, which consistently ran over budget. The organization's overall outstanding debt has declined in recent years. ERCOT's operating expenses have gone up. For more about ERCOT, see Appendix E.

part increased during the intervening years, and problems continued relating to electric restructuring in general. But the legislature had declined to make significant changes in the market's structure. There was some indication that the 81st session would prove to be different — especially after lawmakers began promoting reform bills such as those to encourage competition by generators and those that would give the PUC greater authority to assess fines in market manipulation cases.[5] Some of the pro-consumer bills were pegged to an AARP study showing that with more market transparency, Texas electric consumers could potentially save nearly $1 billion annually — or more than $50 per year for the average household.[6] There were also bills that would have required a top-to-bottom review of ERCOT's operations and management, and to overhaul its board structure. Other promising pieces of legislation included House Bill 2781, by state Rep. Jim Keffer, and SB 1481, also by Sen. Wendy Davis. HB 2781 would have ended ERCOT's efforts to implement a dubious wholesale electricity pricing system, known as the nodal project.[7] The project was over-budget and behind schedule. Senate Bill 1481 would have facilitated the use of bulk electricity purchasing by cities on behalf of their citizens in order to help reduce their energy bills.[8]

But unfortunately, it would not be these bills that would win the day,[9] but rather Senate Bill 769, which would tend to increase energy bills. Under SB 769, utilities were granted authority to more quickly add extra charges onto home bills to help defray costs associated with disastrous weather. Regulated transmission utilities could obtain these rate hikes without the full scrutiny of a traditional rate case.[10] That is, SB 769 partially deregulated the monopoly part of the energy business in Texas. Houston's CenterPoint Energy was a leading proponent of SB 769, and a day after the bill became law, the company filed a request at the PUC for a nearly $678 million rate hike.[11]

One of the few bright spots for consumers was Senate Bill 2. This was not an energy bill per se, but rather a bill related to the legislative Sunset Advisory Commission that oversees the effectiveness of government agencies. An amendment added to SB 2 required ERCOT to come under special review by the Sunset Commission in 2010, and the conclusions of that review would then form the basis of ERCOT-related legislation in 2011.[12] Lawmakers in 2009 also adopted House Bill 1783, by state Rep. Burt Solomons, requiring ERCOT to broadcast its board meetings on the Internet[13]; and House Bill 1799, by state Rep. Dwayne Bohac, requiring retail electric providers to include on each residential customer's bill a statement directing the consumer to the powertochoose website , where they can find information regarding electric service options.[14]

THE NODAL PROJECT

The PUC in 2009 authorized another request from ERCOT to spend even more money on the nodal project. The new price tag: $644 million,[15] or about eight times the original cost estimate.[16] The new spending plan also included $58.6 million for "discretionary" spending and $77.7 million for financing costs.[17] Just the discretionary spending and financing costs alone were close to equaling the original cost estimate in 2004 for the entire nodal project.[18] The cost overruns may have contributed to a decision by ERCOT CEO Bob Kahn to quit the job. Kahn announced his resignation in September 2009 after two years in charge of the organization. The CEO had been heavily criticized by key lawmakers, including members of the Senate Business and Commerce Committee.[19] He was ERCOT's fourth CEO since 2000.

TEXAS SURPASSES ENERGY RECORDS

Texas energy consumption continued to increase during 2009, with the state hitting new records of 62,786 megawatts on July 8 and 63,400 megawatts on July 13.[20] As a result of the high summertime use of air conditioning and the unexpected outages of power plants, ERCOT declared an emergency alert on July 8 in which they called upon Texans to conserve energy.[21] Wholesale electricity spot market prices shot up July 8 to $500 per megawatt-hour.[22] This was far above the then-prevailing spot market prices and more than 50 times higher than the lowest retail electric rates at the time.

Texas surpassed another record on the evening of October 28, 2009. At precisely 8:19 p.m. Texas wind generators hit the 6,223-megawatt mark, which was the most wind power ever produced and successfully absorbed by the ERCOT grid. Wind power accounted for about 17.5 percent of all energy flowing across the grid at that time.[23] Earlier in the evening, wind power had accounted for an even greater proportion of total load — about 25 percent.[24]

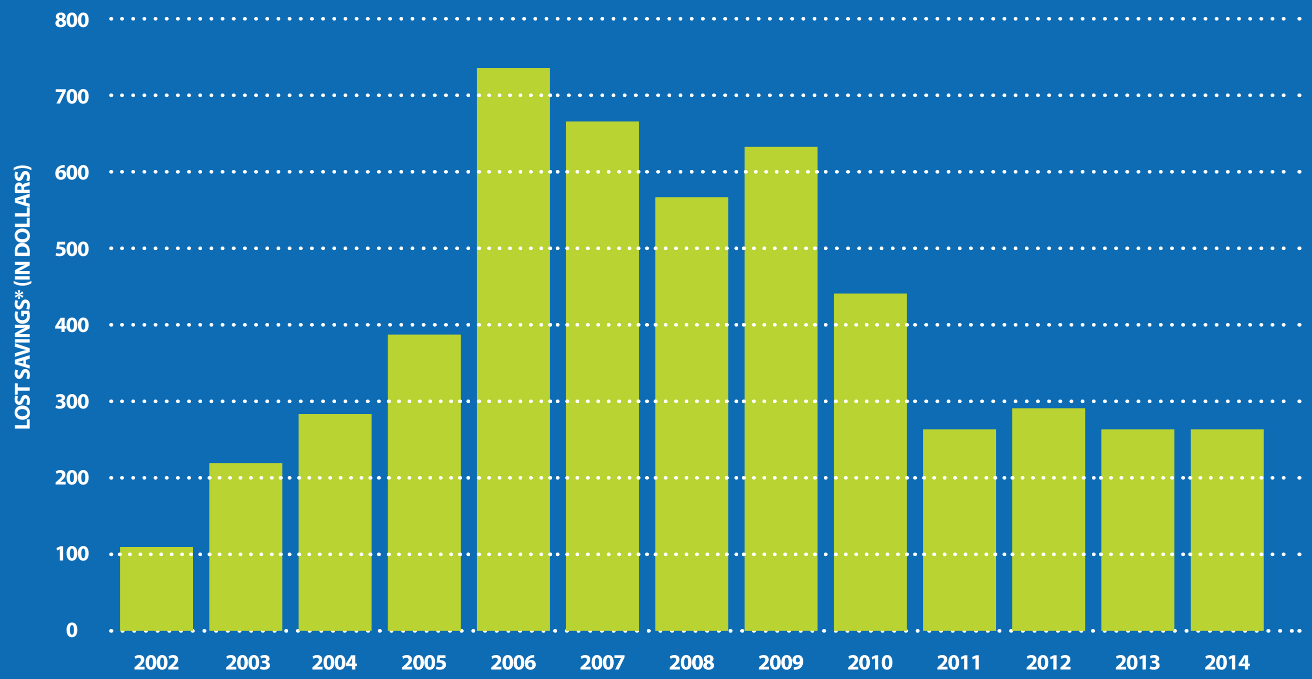
WIND GENERATION CHALLENGES

The increased development of wind power in the Lone Star State attracted the attention of Federal Energy Regulatory Commission (FERC) Chairman Jon Wellinghoff, who said policymakers should consider linking the ERCOT grid to other states. "If Texas could be more strongly interconnected to the Midwest, for example, they could integrate even more wind into the system," said Wellinghoff. The ERCOT power grid is wholly located within the boundaries of Texas and has very limited connections with outside grids, which makes it free from most federal oversight. Wellinghoff said that he understood the concern of many Texas policymakers that more connections could lead to federal control of ERCOT, but he insisted that such a takeover was not FERC's intention.[25]

Also in 2009, Texas billionaire oilman T. Boone Pickens announced his intention to scale back his much publicized plans to build the world's largest wind farm in Texas. Part of the problem was the drop in natural gas prices, he said. In an interview with the *Dallas Morning News*, Pickens said that he had already ordered an initial round of wind turbines (from his plan to purchase nearly 700 from GE), and that officials with his Mesa Energy were considering locating them in various sites in addition to Texas — including Wisconsin, Oklahoma and Kansas.[26]

More than $5,100 in Lost Savings*

Source: United States Energy Information Administration — http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls



This exhibit compares electricity costs for a typical customer paying average rates charged by deregulated retail electric providers in Texas, to costs for a customer with the same usage but paying average rates charged by Texas providers exempt from deregulation.

**For purposes of comparison, this exhibit assumes monthly electricity usage of 1,300 kWh.*

Year: 2010 Nodal Project Goes Live

WHOLESALE ENERGY PRICES

According to data collected by the federal government, residential customers in Texas paid, on average, 11 percent less for electricity than they paid in 2008.[1] The decline corresponded to a similar drop in the price of natural gas, which fuels many of the state's power plants. Overall, residential prices remained at about the same level as the national average in 2010.[2] This was a welcome change from nearly a decade of prices above the national average since the implementation of deregulation.

But it also became clear in 2010 that the state's largest electric provider depended upon these higher rates for its financial well-being. Energy Future Holdings had taken on a massive amount of debt in 2007 to acquire TXU Corp., the state's largest electric company, and the lower wholesale electricity prices were making it difficult to pay off that debt. In August, after EFH finalized plans to pay some lenders between 72 cents and 79 cents on the dollar, the company suffered a downgrade from all three debt-rating agencies.[3] In October, the company's debt was downgraded again. "EFH is likely to remain in financial distress," wrote analyst Jim Hempstead, on behalf of Moody's Investors Services.[4]

And while electricity prices may have declined over the short term, they were nonetheless up more than 50 percent since the adoption of the retail deregulation law.[5] Between 1999 (the year that Texas lawmakers adopted the deregulation law) and about the midway point of 2010, the percentage increase in electricity prices in Texas had outpaced increases in all but eight states. Electricity price increases also outpaced those in most other deregulated states. Electricity prices in Texas remained higher than prices in neighboring states, including those relying heavily upon natural gas to fuel generating plants.[6]

These higher prices meant that Texans had less to spend on other priorities. An analysis of federal data showed that Texas residential consumers could have saved more than $11 billion through 2010 had their electric prices remained more consistent with pre-deregulation levels. When higher electricity prices paid by commercial and industrial customers were factored in, the lost savings amounted to $16.4 billion.[7]

PUC's "Guard Rails"

New "guard rails" ordered by the PUC capped wholesale spot energy prices during the first 45 days of the new nodal market. These "guard rails" limited offers in this energy market to $185 per megawatt/hour, or a multiplier related to the price of natural gas. The temporary guard rails were largely favored by market participants, many of whom recalled the punishing price spikes of 2001 and 2002 during the initial transition to deregulation. Even greater price spikes in 2008 drove five retail electric providers into bankruptcy.

Upon the expiration of the guard rails in early 2011, a new $3,000 per megawatt/hour offer cap would come into place. Although intended to protect against price gouging, this new cap nonetheless allowed electric companies to seek prices about 60 times higher than those typically paid in the market. The cap also was three times higher than those in other states.

ERCOT

A consultant's report in June 2010 found evidence of "poor corporate governance, leadership and culture" at ERCOT, the organization that operates the Texas power grid.[8] Citing the "overall below-average quality of people" employed there, the consultants recommended 166 staff cuts, or about 24 percent of the organization's personnel.[9] Shortly afterwards ERCOT eliminated 37 positions, reductions that ERCOT President Trip Doggett said were part of the expected transition to the nodal market. The layoffs were fewer than those recommended by the consultants, but still amounted to about 5.5 percent of the organization's workforce.[10]

In a separate report released in April, staffers for a key legislative committee concluded that ERCOT lacked sufficient financial oversight.[11] Issued on behalf of the Sunset

Advisory Commission, the report noted that ERCOT's debt had ballooned from $40 million in 2000 to more than $360 million in 2009. It also questioned the wisdom of ERCOT's borrowing, citing specifically some of ERCOT's older debt that required a 14-year payout even though the underlying assets were in use for only three to five years. The Sunset staff recommended that ERCOT's annual budgets and borrowing become subject to PUC approval, and that ERCOT remove self-interested industry representatives from its board of directors. Some of these recommendations would become the subject of proposed legislation in 2011.

NODAL PROJECT STATUS

ERCOT certified late in 2010 that the nodal system was finally ready to go live.[12] (For an explanation of nodal, see pages 53-54.) ERCOT's engineers had conducted months of technical trials, including one lasting 168 hours. Although they continued to identify problems, the engineers determined none were significant enough to prevent easing forward with a partial "soft launch" on November 15, and then going completely live with the nodal systems on December 1.[13] The final price tag remained a source of displeasure for many. Including interest, the nodal project would end up costing Texas electricity customers nearly $548.6 million[14] — or more than five times more than original[15] estimates. The project was years behind schedule. "There were times, two and three years ago, when I did not think this was going to happen — and I'm still concerned about the cost," then-PUC Chairman Barry Smitherman said shortly after the launch.[16]

Anticipating glitches, ERCOT set aside an additional $25 million to make early fixes.[17] Several electricity retailers also added language to customer contracts allowing for extra nodal-related surcharges should the system go awry.[18] The PUC agreed to temporary "guard rails" in the wholesale market to guard against unintended price spikes (See sidebar on opposite page).[19] For the most part, however, the new systems became operational without incident.[20]

Average Residential Electricity Prices, 2010

AREAS OF TEXAS INSIDE AND OUTSIDE DEREGULATION*

**Providers exempt from deregulation include municipally-owned utilities, electric cooperatives and investor owned utilities outside of ERCOT.*

Source: United States Energy Information Administration

Cents / KW/H

Areas Inside Deregulation

12.8

10.0

Areas Outside Deregulation

As was the case during every year since 2002, average electricity prices in deregulated areas of the state in 2010 were higher than average electricity prices in areas of the state exempt from deregulation.

Year: 2011 The PUC Under Sunset Review

THE 82ND LEGISLATIVE SESSION

The Texas Legislature's 82nd regular session, the fifth since the deregulation of the state's retail electricity markets, convened on January 11, 2011. Although electricity prices and complaints had fallen in recent years, they nonetheless remained above pre-deregulation levels.[1] (For more about complaints, see Appendix B). Flaws in the state's wholesale energy market also remained uncorrected. Consumer groups hoped that lawmakers in 2011 would finally order reforms. The electric power industry either worked to maintain the status quo, or pushed for changes that would reduce regulatory oversight of their monopolistic transmission and distribution rates.

The single most anticipated piece of energy legislation was Senate Bill 661, which grew out of 2010 recommendations from the staff of the Sunset Advisory Commission. SB 661 included the Commission's reform proposals for the Texas Public Utility Commission, the Electric Reliability Council of Texas, and, to a lesser degree, the Office of Public Utility Counsel, which is a state agency charged with consumer oversight.[2]

If it had been adopted, SB 661 would have directed the PUC to exercise more fiscal oversight of ERCOT and would have required ERCOT to obtain approval from the PUC before borrowing money. Additionally, the legislation would have authorized the PUC to assess greater fines against electric companies that endanger grid reliability and also to issue emergency cease-and-desist orders against companies suspected of engaging in improper conduct.[3] Each of these proposed reforms were included in the Sunset staff report and were supported by consumer groups. On balance SB 661 was useful legislation — a bill that could have made some beneficial tweaks to the system. However it fell victim to an 11th-hour technical objection raised on the House floor.

Other helpful bills met similar fates. For instance, House Bill 1006 and Senate Bill 948 — legislation that would have required retail electric providers to offer a single standardized offer along with their other offers — did not even receive committee votes.[4] The companion bills were intended to simplify shopping in the deregulated electricity market, but died under a heavy industry lobbying effort. Lawmakers also rejected Senate Bill 319, which would have ensured that a special fund created under Senate Bill 7 was used for its intended purpose. The fund, financed through a charge on electricity and meant to finance bill discounts for low-income ratepayers, had been used in previous years for budget-balancing purposes.

However lawmakers did manage to adopt Senate Bill 1693, which was a top legislative priority for many within the energy lobby. SB 1693 was signed by the governor on May 28.[5] Under SB 1693, the state's transmission and distribution utilities — that is, the state's monopoly wires companies — received new authority to periodically hike rates pertaining to their distribution system without a comprehensive regulatory hearing, reversing decades of regulatory precedent. Like SB 769 from the previous legislative session, SB 1693 further benefited those electric companies that under the Texas deregulation law still retained their monopoly status. Lawmakers adopted the legislation despite warnings from consumer representatives and community leaders that it would lead to higher electric prices. "The intent of this legislation is to make it easy for electric utilities to raise rates every year with little documentation or justification," said Clifford Brown, the mayor of Corsicana.[6]

The Sunset Advisory Process in Texas

Under the Sunset process, the professional staffers assigned to the legislative Sunset Advisory Commission review state agencies, and then offer recommendations to state lawmakers. The lawmakers then vet the staff recommendations — accepting some, rejecting others — on their way to drafting legislation used to reauthorize state agencies.

There was one legislative accomplishment for consumers in 2011, and that was the passage of House Bill 2133, by state Rep. Burt Solomons. The legislation pertained to what consumer groups had come to describe as the "rip-off loophole" in the Public Utility Regulatory Act. That is, the PUC had claimed for many years that it lacked the legal authority to order restitution payments from companies found to have engaged in anti-competitive activities.[7] As a consequence, the state's largest electric company made nearly $4 million in profits in 2008 even after paying a settlement for allegedly engaging in anti-competitive behavior.[8] The PUC and Sunset staff said this loophole should be closed. Consumer groups agreed.

The bill was not perfect. For instance, the final version of HB 2133 barred city coalitions and other consumer representatives from participating in enforcement cases. It also gave electric companies a path to avoid future prosecution under certain circumstances.[9] But it was, on balance, helpful legislation and its adoption by the Texas Legislature marked a rare win for consumers. The governor signed the bill into law in June 2011.

RESERVE MARGINS

Grid operators and regulators often speak of "reserve margins," which refer to the ratio between the total potential output of electricity generation within a given system and the peak electricity usage in that system. That is, reserve margins measure the relationship between how much electricity generators theoretically can produce in a single instant, to predicted highest-case demand for electricity by consumers. Because power shortfalls can put a system at risk for blackouts — especially during extreme weather events — the reserve margin measurement is a good indicator of system reliability.

During the transition into deregulation, back in 2001, the state enjoyed the highest reserve margin in the nation. This helped to calm the anxieties of some Texas lawmakers and the public after California's market began collapsing during that state's transition to deregulation. Recall that electric price spikes and rolling outages in California had been blamed both on a flawed deregulation law and low reserve margins. But in Texas, lawmakers were assured in 2001, we had neither of these problems. "We have the highest electricity reserve margin of any region on the entire continent," said Pat Wood III, then the chairman of the PUC, in an attempt to reassure deregulation skeptics.[10]

His agency noted that Texas enjoyed excess capacity of up to 25 percent even during the hottest days of summer.[11]

But such a claim could not be made in 2011. The National Electric Reliability Corporation reported ERCOT's reserve margin ratio in 2011 at about 14 percent, which marked a nearly 40 percent decline from pre-deregulation levels and far below the national average in 2011 of around 25 percent.[12] In fact, after 10 years of deregulation the Lone Star State possessed the lowest reserve margin in the nation, according to NERC.[13]

The Texas reserve margin dwindled during 10 years of deregulation even as electricity prices increased. Was some aspect of the deregulated system contributing to this problem? Some observers seemed to think so, especially after the state suffered reliability crises during both the summer and winter of 2011. "Consumers were told (deregulation) would lower prices, but it didn't — now, it's becoming clear that even at those prices, the deregulated market can't deliver reliable power," wrote Loren Steffy, a business columnist for the *Houston Chronicle*.[14] The state's reliability challenges, wrote Steffy, exposed the "fundamental lie" of deregulation.

Dan Jones, a vice president of the consulting firm that serves as the independent monitor of the deregulated wholesale energy market, said the market was failing to produce high enough prices for certain sorts of energy. Writing in a 2011 report, Jones noted that these low prices "were insufficient to support new generation investment for any generation technology in any region of the ERCOT market."[15] His proposed solution was to create a system to encourage higher prices in the wholesale power market. That is, his prescribed cure was to create a system whereby consumers would pay more. Generation companies also recommended the creation of artificial price supports as well as the creation of a "capacity market," in which they could get paid even when their generators do not operate.[16]

Consumer groups expressed alarm, especially given that generation owners were offering no guarantees that these artificial price supports would lead to new plant construction. "This dynamic highlights a key risk to consumers: what if a mechanism is put into place to increase wholesale prices to ensure resource adequacy, but does not work?" warned one advocate for cities.[17] The proposals also raised issues of basic fairness. That is, generators pushed competition and supported it when prices were high, but eagerly sought artificial price supports when they felt the system was failing to deliver to them sufficient profits.[18] For consumers, generators were offering "a heads I win, tails you lose" vision of deregulation.

Those representing city coalitions, industrial users, and other consumer groups urged policymakers to exercise restraint when addressing these issues. While reserve margins had declined in recent years, consumers noted that they remained above safe levels. Representatives for large industrial customers likewise warned that the so-called "remedies" pushed by generation companies could lead to as much as a 93-percent increase in some wholesale energy prices. That would be bad news not just for big business customers, but for anyone who pays an electric bill. "These cost impacts are extreme and unjustified, and … will result in great harm to the market," stated the Texas Industrial Energy Consumers in a PUC proceeding.[19]

For consumers, generators were offering "a heads I win, tails you lose" vision of deregulation.

In October the PUC approved price floors for certain sorts of reserve energy that ERCOT deploys during emergency situations. But representatives for generation companies continued pressing for higher price floors and other artificial supports to further enhance their profits.[20]

DEREGULATION AND RELIABILITY

The resource adequacy issue received even more scrutiny in 2011 after a series of reliability emergencies. The first occurred in early February, when dozens of generating plants seized-up during a cold snap. At the same time usage peaked. ERCOT responded by ordering rolling blackouts and as a result, millions of Texans lost power. (For more on ERCOT, see Appendix E). All told, approximately one-third of the state's generation fleet was unavailable during the most difficult point of the crisis, according to federal officials.[21]

ERCOT also faced repeated grid emergencies in July and August, when the state broke demand records during a historic heat wave. Although ERCOT did not resort to rolling blackouts, it took other emergency action — such as disconnecting some big industrial consumers, and calling for the public to shut off appliances during peak hours. New statewide electricity usage records were set on Aug. 1st, 2nd and 3rd.

Although Luminant in North Texas claimed that it lost money during the February blackouts, the crises represented a potential profit bonanza for other generators.[22] That's because in both the summer and winter grid emergencies, prices in the wholesale electricity market shot up to a $3,000 per megawatt/hour cap[23] — or about 50-60 times higher than typical prices. Prices remained at those inflated levels for hours. That some companies were rewarded during the emergencies raised additional questions about the state's electricity market, especially given that ERCOT had been obligated to order statewide rolling blackouts twice in just five years under the system, but only once ordered similar rolling outages in its 30-plus years before deregulation.[24]

Robert McCullough, an Oregon-based economist, was among those raising questions. He noted, for instance, that the cold snap that led to the rolling outages in 2011 was not an unprecedented event. There were similar cold weather events in 1983, 1989, 2003, 2006, 2008 and 2010, but in only one of those instances — during the cold weather event of 1989 — had ERCOT resorted to rolling blackouts.[25] McCullough also questioned whether a lack of efficiency under the new nodal system played a role, noting that prices spiked to the nearly unprecedented levels shortly after the new nodal system went into effect, and only within a day of the lifting of price caps.[26]

However, a separate investigation by the state's Independent Market Monitor failed to find problems with the nodal system or any evidence of market manipulation.[27] A government organization known as the Texas Reliability Entity blamed the outages for the most part on inclement weather, although it said plant operators could have done a better job.[28] The North American Electric Reliability Corporation noted that "given the high demand and the huge loss of generation" it was not so surprising that prices hit the $3,000 per megawatt/hour cap.[29]

PRICES

Electricity prices declined in 2011, bringing some relief to Texas consumers. This continued a trend that had begun in 2009 and related to changes in the commodity cost of natural gas, which fuels many generating plants in Texas. All told, the average residential price of electricity was down a little less than 3 percent, compared to prices during the same period in 2010. Also, it appeared that annual average residential electricity prices in 2011 would dip below the national average. This is in contrast to the years of higher-than-average prices following deregulation.[30]

ERCOT Usage Records

Source: Electric Reliability Council of Texas

Aug 3, 2011
68,379 megawatts

Aug. 2, 2011
67,929 megawatts

Aug. 1, 2011
66,867 megawatts

Aug. 23, 2010
65,776 megawatts

One megawatt of power is enough electricity to power about 200 homes during hot weather.

This relief in prices only served to mask the market's relatively poor performance over the long term. For instance, data collected by the federal government revealed that the average price of electricity for residential consumers in Texas had gone up 45 percent between 2002 and 2011, but only 37 percent nationwide. Average electricity prices also remained significantly higher in Texas in 2011 than in adjoining states, even among those states with a similar reliance on natural gas.[31]

Wholesale spot electricity prices spiked to a regulatory cap of $3,000 per megawatt/hour during several intervals in September and October. These high spot market prices trickled down into the retail electricity market, which, when combined with high usage, contributed to punishingly high electric bills for many Texans. "My first reaction was there must be an error," said one Dallas resident after receiving a $1,200 bill after his rates tripled.[32] A 2011 survey by Whitefence.com, a commercial website, also found that electric bills in Houston were the second highest among 21 major cities nationwide. Dallas was ranked 6th in the survey.[33]

As of June 2012, average overall electricity prices in Texas were higher than average prices in adjoining states.

The number of complaints lodged against electric companies at the PUC fell somewhat in 2011, but remained more than three times higher than those filed on an annual basis before deregulation.[34] (See Appendix B). An industry survey also found that many Texans in 2011 remained confused about basic aspects of the deregulated market. "This demonstrates that after ten years of retail competition and deregulation, many people are unclear about the details of how the electric market in Texas works," the survey's authors concluded.[35]

STRANDED COSTS

Consumers were also hit in 2011 with additional deregulation-related costs as a consequence of important rulings by the Texas Supreme Court. Two major utilities — CenterPoint Energy serving the Greater Houston area, and American Electric Power Texas Central Company in south Texas — had asked the court to overturn earlier PUC rulings relating to the companies' requests for "stranded costs" reimbursements. The PUC had consented to more than $3.5 billion of these deregulation-related charges, but the companies wanted more. In 2011, the Texas Supreme Court awarded the utilities much of their request — and as a result, millions of Texans around Houston and elsewhere will get hit with additional charges on their home bills for at least another decade.[36]

In 1999, the PUC forecast that Texans would not be liable for more than about $5 billion in these deregulation costs.[37] It is now evident that Texans will be on the hook for more than $6.5 billion. It's also clear that if not for the hard work of city coalitions and other consumer representatives, the final tally could have been nearly $10 billion. That's because the state's largest utility in 2001 agreed to forfeit all stranded costs.[38] The value of this agreement alone might now be estimated as exceeding $4 billion. (For more on stranded costs, see Page 66).

Stranded Costs Awards in Texas

**North Texas customers of the utility formerly known as TXU owe no stranded costs thanks to a settlement negotiated with the company by a coalition of cities and other consumer representatives.*

Stranded costs and related charges by utility
(in Billions of Dollars)

TXU*	**$0**
CenterPoint	**$4**
AEP	**$2.5**
TNMP	**$0.129**

CenterPoint Energy had claimed under the terms of Senate Bill 7 that it was owed more than $4.25 billion in stranded costs and other related charges. (Stranded costs are the theoretical losses the company would accrue because its investments made under the previous regulated system would be less valuable under the new deregulated system.) Over the objections of a city coalition and other consumer representatives, the PUC in 2004 awarded CenterPoint $2.3 billion of its request. The company appealed to the courts. On March 18, 2011, after a series of lower court decisions, the Texas Supreme Court awarded the company approximately $1.7 billion more.

Combined, the PUC and Texas Supreme Court rulings were a tough blow for consumers. The generating assets that CenterPoint claimed had become less economic under deregulation were subsequently shown to be quite valuable. Through negotiations, city coalition attorneys and others representing consumers had managed to shave off hundreds of millions of dollars from the final stranded costs payment to the company — thereby ameliorating some of the price shock. But Houston-area residents will still be on the hook for around $4 billion, and as a consequence can expect to pay about $7.30 more per month for years to come.

The second major stranded cost case to conclude in 2011 involved Texas Central Company, a division of American Electric Power. Its customers are largely located around Corpus Christi and throughout South Texas. In 2006, the PUC authorized AEP to recover $1.5 billion in these deregulation-related costs from its customers. In July, 2011 the Texas Supreme Court awarded the company an additional $420 million, plus interest. Since the interest has been accruing for 10 years, the full amount to be collected from ratepayers could range from between $800 million and $1.2 billion. That puts AEP's customers on the hook for about $2.5 billion, for an average bill impact of approximately $7.45 per month.

The Texas Supreme Court in 2011 denied a petition to overrule the PUC in a third stranded cost case, this one involving Texas-New Mexico Power. The PUC earlier had awarded the company $129 million, but also denied it another $106 million at the urging of city coalitions. By denying the company's petition, that PUC decision remains final.

Year: 2012 Pricing and Reliability Challenges Continue

Residential electricity prices in areas of Texas with deregulated electricity service dipped below the national average for the first time in a decade. For Texas under deregulation, 2012 marked the fourth consecutive year of declining electricity prices.[1]

Although welcome news, a closer look behind the numbers revealed that serious challenges remained. For example, an analysis of federal data revealed that Texans in deregulated areas continued paying significantly more, on average, than Texans outside deregulation. In 2012 Texans in deregulated areas would have saved more than $1.5 billion collectively (and $280 individually) had they paid average residential prices that matched those paid by Texans in areas exempt from deregulation.[2] Relative to the national average, residential electricity customers in Texas received a better deal prior to the adoption of Senate Bill 7.[3]

"Nobody wants rolling blackouts (but) neither do we want higher electric bills"

— State Senator Wendy Davis

On a separate front, new power plant construction was just barely keeping up with demand, and some policy experts were diagnosing serious "structural" problems with the Texas market.[4] In 2012, the North American Reliability Council declared that the Lone Star State had the nation's least reliable grid.[5] This was in contrast to big generation reserves prior to the adoption of the Texas electric deregulation law.[6] Major generation companies like NRG and Luminant continued to clamor for regulatory intervention, complaining that the market was not producing sufficiently high prices to support new investment.[7] This was in contrast to the industry's earlier warnings against market intervention, when prices were sky high.[8] ERCOT officials released projections showing the state's reserve margins for generation capacity falling below safe levels within only a few years.[9]

The PUC took action in June by increasing the offer price cap on wholesale electricity by 50 percent.[10] This decision allowed generators to offer their power into the spot market at prices of up to $4,500 per megawatt hour, up from the previous cap of $3,000. The Commission reasoned that this change would deliver more revenues to generators and therefore spur new investment. But the Commission engaged in very little public deliberation of the potential bill impact on Texas consumers, despite very public concerns raised by the editorial boards of major newspapers and several state representatives.[11] "Nobody wants rolling blackouts (but) neither do we want higher electric bills," wrote Wendy Davis, a state Senator from Fort Worth, in a May 4th letter to the agency.[12] Moreover, some retail electric providers claimed the right to break fixed-rate deals with customers as a result of the change,[13] and at least one company apparently did so.[14]

Even before the increase, Texas had the highest wholesale offer cap in the nation by far. Spot market generation prices shot up to the previous $3,000 cap several times after it went into effect in 2011, and generators in 2012 also quickly hit the $4,500 cap, albeit for a brief period.[15] To put those prices in perspective, $4,500 per megawatt hour represents a price more than 100 times higher than those typically paid in the wholesale spot market. In November, the PUC

ERCOT's Energy Consultant: "Price is not Relevant"

On Oct. 24, during a meeting of the State Affairs Committee of the Texas House of Representatives, Brattle Group principal Sam Newell told lawmakers that price "is not relevant to the choice that you have to make" relating to generation reserves, reasoning that costs would rise with whatever option was selected. A representative for large scale electricity consumers disagreed, saying that price was extremely relevant to the debate — and that not all options proposed by Brattle would cost the same.[32]

agreed to phase in even more increases — to $5,000 in 2013, $7,000 in 2014 and finally to $9,000 in 2015.[16]

A coalition of industrial customers found that a $9,000 cap could cost the state an additional $14 billion annually. For its analysis, the industrial coalition assumed the extreme weather conditions of 2011. A separate analysis, using the same assumptions, calculated bill increases of $48 to $50 per month.[17] "These are staggering numbers and the impact of the Commission's decision … should not be trivialized or viewed as a purely academic exercise," wrote an attorney for the Texas Industrial Energy Consumers in a June 15th regulatory filing.[18]

In July a consulting firm known as The Brattle Group released a 135-page report analyzing the state's generation challenges. This Brattle report laid the framework for much of the ensuing policy debate in 2012, although — as with deliberations generally on the issue — it failed to include any comprehensive analysis of consumer costs.[19] The Brattle report enumerated various policy options and ranked them in terms of cost and complexity (see page 70). It also cautioned against implementing changes too quickly and without adequate analysis.

Among the more controversial proposed options in the Brattle report was a "capacity market," which is a market structure common in deregulated states in the northeast. Under a capacity market, generators are paid both when they produce energy, and for providing capacity — that is, they are paid for plants that simply exist and stand ready to produce energy. It would be akin to paying a supermarket for the groceries you buy, plus an extra fee for the supermarket shelf space.

Texas, by contrast, operates a variation of an "energy-only" market in which generators typically get paid only for the power they sell, and not for owning capacity. Energy-Only markets require much less regulatory intervention than capacity markets.

Capacity markets have been controversial and unpopular in the northeast because they layer additional costs on top of existing energy costs. Another complaint is that capacity markets are extremely complex, opaque, and prone to litigation about their outcomes. They also can lead to windfall revenues for power companies with large generation fleets — whether those power companies invest in new capacity or not.

Capacity markets have been controversial and unpopular in the northeast because they layer additional costs on top of existing energy costs.

The Brattle report in some ways seemed to lean toward the capacity market option, and during an Oct. 24th hearing Brattle principal Samuel Newell appeared to issue a full-throated endorsement of that option. "If you're very intolerant of (black-outs) … then a capacity market is unambiguously the best way," said Newell.[20] But consumer groups expressed alarm, calling a capacity market one of the costliest options. The Texas Industrial Energy Consumers, in a regulatory filing, also questioned the validity of some of the Brattle analysis, calling it "a result-oriented exercise that begins with … false assumptions."[21]

Another flash point in the debate was the reserve margin itself. Recall that the reserve margin is a measurement, expressed as a percentage, of the potential output of the state's generators beyond that which is needed to meet peak demand by consumers. As such, it measures surplus generation and is a useful gauge of system reliability. The higher the generation reserves, the lower the chance of blackouts. ERCOT had targeted a 13.75 percent reserve margin, under which it was thought the state would not endure more than one system-wide outage every 10 years.

But during a PUC hearing in July, Newell suggested that some of the publicly expressed concerns over blackouts had been exaggerated, and that even with a smaller reserve margin the blackout risk would not necessarily increase dramatically. For instance, with a 10 percent reserve margin, outages would increase by another 40 minutes per year per customer — even during a year with extreme heat and cold. "We are not talking about the doomsday scenario that we've seen described in the press that Texas is on the verge of having, you know, constant rolling blackouts — that's just an extreme exaggeration," said the Brattle Group principal.[22] The consultant also noted that Texans were already accustomed to several blackouts per year, but on the more limited distribution level.[23]

"We are not talking about the doomsday scenario that we've seen described in the press that Texas is on the verge of having, you know, constant rolling blackouts — that's just an extreme exaggeration,"

— Brattle Group principal.

ERCOT had released a report in May predicting that the state's reserve margins would dip below 10 percent by 2014.[24] However, in October the organization revised its projections upward, after accounting for planned new plant construction.[25] Separately, the Texas Industrial Energy Consumers concluded that when available mothballed generation plants were added to those calculations, the state's reserve margins would remain above safe levels through 2017.[26] PUC Commissioner Ken Anderson said forecasts showed healthy reserves through at least 2018.[27]

VOLUNTARY MITIGATION PLANS

Think Enron's bad behavior, market manipulation, gaming — what precisely constitutes market abuse can be hard to describe, but most would agree that it's bad when it happens. Under a number of proposals adopted by the PUC in 2012, generation companies obtained additional legal protections against such allegations.

Known as "Voluntary Mitigation Plans," these proposals are designed by the generation companies themselves and are meant to describe fair business practices. They typically include descriptions of bidding behaviors and other rules that, if followed, should signal to regulators that the generation company is playing by the rules. As long as the companies do not deviate from the actions they describe in the plans, the companies remain protected against prosecution for anti-competitive behavior. By October the PUC had approved voluntary mitigation plans for two companies, while another plan remained pending.

Voluntary mitigation plans present serious problems for consumers. First, they are extremely complex and no single entity will have the same understanding of these plans as the companies that devise them. This has raised concerns because each company that submits a voluntary mitigation plan has a direct interest in maximizing its own position in the market. So while these plans supposedly describe fair practices, theoretically they also could open the door to gaming opportunities.

Also, only the companies, the independent monitor of the state's electric market and PUC staff have been allowed to negotiate the details of these plans. No substantive input so far has been permitted from experts with entities that attempt to safeguard the market and protect ratepayers.

Another worry is that these plans may allow companies to further leverage the extremely high prices permitted in the state's wholesale energy market. Texas maintains the nation's highest wholesale price cap for energy, and that offer cap will continue to increase through at least 2015. Through these plans, the companies may gain an ability to more easily price power at these extreme levels. This, in turn, could lead to higher bills for businesses and homes.

The plans were authorized under House Bill 2133, adopted in 2011 by the Texas Legislature. Ratepayer groups generally supported HB 2133 because it closed a loophole in Texas law that allowed generation companies to profit from anti-competitive behavior.[28] But ratepayer groups had serious concerns regarding the voluntary mitigation plan provisions.

As *Houston Chronicle* columnist Loren Steffy pointed out, the "plans, combined with the PUC's earlier vote to raise the price limits on the wholesale market by 50 percent, will give big generators greater potential to control the market."[29] By October, the PUC had adopted voluntary mitigation plans by Houston's NRG and GDF-Suez.[30]

Brattle Report: Comparisons of Policy Options

Source: ERCOT Investment Incentives and Resource Adequacy, Brattle Group, June 2012, Table 1 pg. 5

Option	How Reliability Level is Determined	Who Makes Investment Decisions	Risk of Low Reliability	Investor Risks	Economic Efficiency	Market Design Changes
1. **Energy-Only with Market-Based Reserve Margin**	Market	Market	High in short-run; Lower in long-run	High	May be highest in long-run	Easy
2. **Energy-Only with Adders to Support a Target Reserve Margin**	Regulated	Market	Medium	High	Lower	Easy
3. **Energy-Only with Backstop Procurement**	Regulated (when backstop imposed)	Regulated (when backstop imposed)	Low	High	Lower	Easy
4. **Resource Adequacy Requirement**	Regulated	Market	Potentially Low	Med-High	Medium	Medium
5. **Resource Adequacy Requirement with Capacity Market**	Regulated	Market	Low	Med-High	Medium	Major

A report by a consulting firm known as The Brattle Group enumerated several policy options to address the state's generation challenges. The chart, above, summarizes some of those options. Brattle also cautioned in the 2012 report against implementing changes without adequate analysis.

On June 1, 2012 ERCOT made public a report prepared by The Brattle Group — a national energy consultancy — on the state's wholesale energy market. The consulting group had been charged with analyzing the market's ability to attract generation investment. ERCOT and the Public Utility Commission had begun considering such questions after the particularly difficult summer of 2011, when the state experienced power shortfalls and came close to rolling outages. The Brattle Report included a number of important findings. Among them:

- ERCOT and the PUC should revisit the 1-in-10 year blackout standard, under which the state's reserve margin targets are set in such a way as to avoid more than one major blackout every 10 years. ERCOT and the PUC have used this standard to justify a 13.75 percent target for reserve capacity. But ERCOT enforces a more stringent interpretation of the 1-in-10 standard than is employed elsewhere. That is, ERCOT interprets the standard to mean "1 outage event in 10 years," while other system operators interpret it to mean "24 outage hours in 10 years." These two interpretations may sound semantically similar, but in reality differ greatly: Brattle cited a case study in which the less stringent standard reduced reserve margin requirements by nearly 50 percent.[31] "The 1-in-10 standard is also poorly-defined with respect to the events it describes," Brattle noted, explaining that the standard makes no distinctions between small-scale blackout events and widespread events.
- In ERCOT, the resource adequacy target implies average outages of less than 1 minute per year, per customer. But customers are accustomed to much greater outage times caused by disturbances in the more local electricity distribution systems. "During storm events, annual outages durations can reach several hundred to several thousand minutes per customer," according to Brattle.
- As of the first half of 2012, the ERCOT market was not producing wholesale energy prices that were sufficiently high to maintain a 13.75 percent reserve margin. Increasing the offer cap on wholesale energy prices would stimulate investment, but at a level still insufficient to obtain that targeted reserve margin.
- Demand response — that is, programs under which customers can curtail their energy usage in exchange for a payment — could help meet the state's generation supply challenges. However, it will take too long to create sufficiently robust demand response programs to meet the state's near-term energy needs.
- A modified energy-only market could risk low reliability in the short term, but improved reliability in the long-term. Such a strategy also may have the highest economic efficiency over time — that is, Texans would get the best bang for their buck with regards to financing improved reliability.

Year: 2013 Texans Make Payments for Non-Existent Utility Taxes

An early 2013 report from TCAP found that Oncor, the North Texas electric utility, had charged its customers hundreds of millions of dollars for a non-existent federal tax liability.[1] Citing federal and state government filings, the report documented more than $500 million in payments by Oncor customers since 2008 — supposedly for the utility's federal income taxes. But the utility does not have a federal income tax obligation and its beleaguered majority owner, Energy Future Holdings, had not owed income taxes since at least 2008, the report showed.

Under state law then in effect, Texas regulators had the ability to recongnize the tax savings enjoyed by utlities when they file a tax return jointly with their parent and affliates. Although the Public Utility Commission had declined to exercise that authority with regards to Oncor, the PUC commissioners utilized it when considering the treatment of taxes in rates charged by other utilities.

TCAP issued a recommendation during the 2013 Legislative Session that money collected from electric ratepayers for federal taxes should be used to pay federal taxes — or the utilities should not collect the money at all.

Unfortunately the Texas Legislature in 2013 took the opposite tack. Bowing to industry pressure, lawmakers

Legislative Session

The 83rd Regular Session of the Texas Legislature concluded on May 27, 2013. Over 100 bills pertaining to the gas and electricity market were filed by lawmakers. Here are a few highlights:

- Electric and gas utilities pressed unsuccessfully for the passage of House Bills 1148 and 1149, which would have made it more difficult for cities to protect their citizens in utility rate cases. City and consumer groups testified in opposition to these bills, and with the help of the Texas Municipal League derailed them in committee.
- The Legislature adopted House Bill 1600, which reauthorizes operations at the Public Utility Commission. HB 1600 includes a handful of new reforms, including rules giving the PUC additional oversight authority to protect the electric power grid. During the debate over HB 1600, lawmakers also specifically directed the PUC to conduct a cost-benefit analysis before authorizing an expensive "capacity market" that could increase annually electric costs by billions of dollars. However, that provision was removed before final passage.
- Lawmakers adopted House Bill 7, which includes language to discontinue the System Benefit Fund that provides rate discounts for low-income customers. The System Benefit Fund is financed through a charge on electric bills, although lawmakers over the years had held back a sizable amount for state budget-balancing purposes. Under HB 7 the accrued funds will be paid out to low income customers through 2016, and then the System Benefit Fund will be discontinued.
- As noted above, the Texas Legislature adopted Senate Bill 1364, over the objection of municipal coalitions and consumer groups. SB 1364 limits the PUC's discretion over how much electric utilities charge to their customers for federal corporate income taxes.

adopted Senate Bill 1364 that deprived the PUC of an important ability to adjust rates for utilities with parent companies that file consolidated returns. Such consolidation results in tax savings that would be impossible otherwise. Previously the PUC could adjust rates to reflect the local utility's fair share of that savings. Under SB 1364, the PUC lost that ability and the utility or its parent company can now simply pocket the extra money. Adoption of the bill was a top priority of the Houston-based transmission and distribution utility, CenterPoint.

Approximately 100 additional bills relating to electricity and gas service were filed during the 83rd Legislative Session, including many bills harmful to consumer interests. The electric and gas utilities deployed their usual army of lobbyists, with between $5 million and $10 million spent on lobby contracts by five electric companies alone.[2] But despite the well-funded opposition, energy consumers won significant victories — including some reforms to the Public Utility Commission. Several bills harmful to the interests of municipal, business and residential energy consumers also failed during the waning days of the session.

> *"The good news is that this money collected to help low-income people for utility bills is going to be used — there's a tremendous need,"*
>
> **— AARP's Tim Morstad.**

LEGISLATURE DISCONTINUES SYSTEM BENEFIT FUND

In 1999, with the adoption of the electric deregulation law, the state legislature created the System Benefit Fund. Part of a negotiated deal with consumer groups, the main purpose of the fund was to provide rate discounts for low-income Texans. It was financed entirely through a fee on electricity bills.

But despite the agreement with consumers groups, lawmakers in subsequent years began holding back the money and reducing the bill discounts. Instead, the unappropriated funds were employed in an accounting trick to balance state budgets.[3] This occurred year after year. By 2013, approximately $800 million had accumulated in the System Benefit Fund, having served as offsets to spending elsewhere in the state budget.

But with the passage of House Bill 7, in 2013, that practice came to an end. The bill called for the disbursement of all System Benefit Fund money, and then the eventual discontinuance of the SBF after 2016. As a result, large bill discounts — $170 for a typical low-income user — began appearing in customer bills during the summer of 2013, with smaller discounts to be applied during the summers of 2014, 2015 and 2016.[4]

About 600,000 low-income Texans were eligible for the discounts. The discounts were so large in 2013 that for several months some bills were reduced to zero.[5] "The good news is that this money collected to help low-income people for utility bills is going to be used — there's a tremendous need," said AARP's Tim Morstad. "The not-so-good news is that in several years, the program will be terminated."[6]

Another potential bit of collateral damage with the loss of the System Benefit Fund could be the powertochoose.com website. The state-run website lists various retail electric providers, and was created by the PUC to help Texans shop for electricity. It is funded with proceeds from the System Benefit Fund. Whether the state would identify a separate source of revenue to fund the website remained an open question in 2013.[7]

NEW COMMISSIONER APPOINTED AND SUBSIDY MANDATES DEBATED

In August Gov. Rick Perry named his former chief of staff, Brandy Marty, to a position on the three-member Texas Public Utility Commission. Marty assumed a seat vacated

Capacity Subsidies

Under the subsidy proposals, generators would collect extra payments — potentially billions of dollars of extra payments — beyond what they otherwise would receive from selling electricity. There would be a government requirement that retail electric providers and other entities that serve customers pay these subsidies. Although promoted as a way to ensure generation investment and guard against future blackouts, critics questioned the effectiveness and expense of the proposed subsidies. Those critics include business, consumer, environmental and free-market groups.

by Rolando Pablos, who resigned in March.

Marty had worked in various capacities with Gov. Perry, including as a policy director during his 2010 campaign.[8] She came to a divided commission, with PUC Chair Donna Nelson and Commissioner Kenneth Anderson remaining split on the controversy regarding proposed capacity subsidies to Texas power generators.[9] For many months Ms. Marty said little to reveal her thoughts regarding the issue, but in October Marty joined Chair Nelson in supporting a mandated reserve margin.[10] This was seen by many observers as a step toward the implementation of a capacity market.

In a heated exchange during the Oct. 25 meeting Commissioner Anderson blasted the decision.[11] "I am... opposed to mandatory reserve margins as uneconomic with the potential to destroy the economic engine that is Texas," he said.[12] The distinction between a mandated reserve margin and a targeted reserve margin is an important one. Under the deregulated electricity system, Texas has operated with a reserve margin target, not a reserve margin mandate. The reserve margin target represents ERCOT's goal for generation reserves. In Texas, no government requirement exists that the reserve margin target be met.

Free market groups and others complained that by favoring a mandated reserve margin, the PUC had retreated from the free market principles under which the state established its electric deregulation law in the first place.[13] The unofficial decision to mandate a reserve margin also drew the ire of Democrat Wendy Davis, a state senator running for governor, and Republican Troy Fraser, who chairs a key energy-related committee in the Texas Senate. Davis said it was wrong for the PUC to move forward without first conducting an analysis on consumer costs.[14] Fraser, during a meeting of his Senate Natural Resources Committee, claimed the PUC had overstepped its authority. "You are way ahead of yourself," he told the PUC chair.[15]

Whether targeted or mandated, reserve margins are expressed as percentages. These percentages express the ratio between the total amount of generating capacity available within a given service territory and the hypothetical greatest electricity demand within that area. In 2013, generators and some others pressed to increase the reserve margin target from 13.75 percent to 16.1 percent — a change that would potentially cost Texans more than $3 billion over 10 years.[16] ERCOT put the proposal on hold after it drew the ire of Sen. Fraser, who wrote in a letter that "an increase … of this scale could not help but serve the interests of those advocating for a capacity market, a system which would subsidize existing generation."[17]

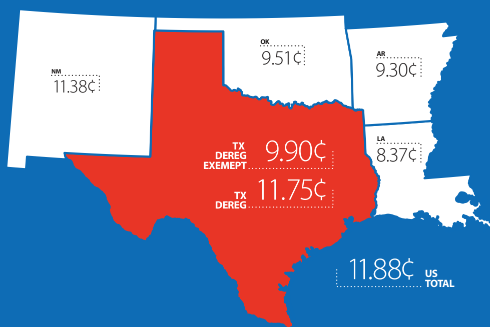
PUC Commissioner Anderson continued speaking out against the capacity market proposals throughout 2013.[18] That summer, for instance, he took aim at a study released by NRG that predicted multiple blackouts each year unless the PUC created a capacity payment system. The NRG study put the resulting cost to the Texas economy at more than $14 billion. Commissioner Anderson said NRG had baked bad math into its analysis, citing the work of his policy advisor who calculated the energy giant had overstated the costs "by at least a factor of 10 (likely by a factor of at least 40)."[19]

The generators themselves were not particularly consistent on the issue. In a June 2013 guest editorial, John Ragan, an executive for energy giant NRG, warned that Texas was falling behind with regards to generation construction and could face serious shortfalls unless they could collect subsidy payments. "We support the capacity market option," wrote NRG regional vice president.[20] But then in August, in an earnings report to investors, NRG CEO David Crane acknowledged that new generation construction was not supported in competitive electric markets anywhere in the U.S. — including in those jurisdictions that already allow capacity payments.[21] Ragan also appeared to have been contradicted in Arizona by an electric industry trade group, which claimed in written comments that the "outlook for dire consequences" with respect to generation reserves

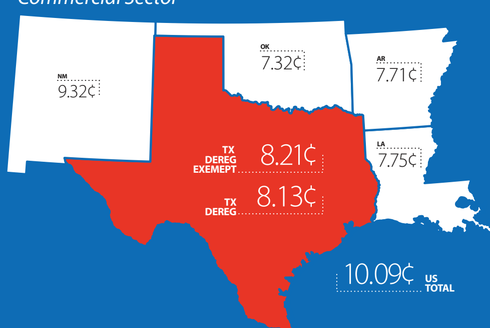
Electricity Prices in 2012: Texas and Adjoining States

Source: United States Energy Information Administration/ http://www.eia.doe.gov/cneaf/electricity/page/eia861.html

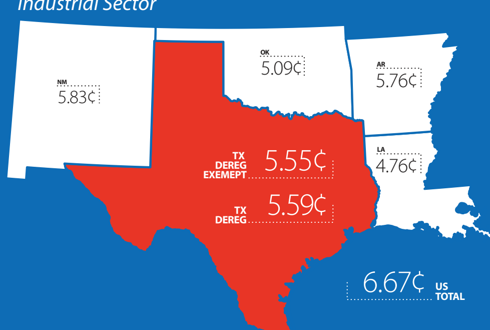
Residential Sector



Commercial Sector



Industrial Sector



in Texas "appears to be wholly overstated."[22] This trade group, the Retail Energy Supply Association, counts NRG among its members.[23]

PROBLEMS CONTINUE FOR ENERGY FUTURE HOLDINGS

Luminant, the state's largest electric generation company, agreed in November to pay $750,000 to settle charges relating to the statewide power outages. Staff at the Public Utility Commission said Luminant failed to comply with ERCOT's instructions during the outages, which occurred during a 2011 cold snap. Luminant's failure meant that the grid operator "did not receive capacity resources it needed," the PUC said.[24] As is usual with such cases, Luminant agreed to pay a penalty but declined to admit culpability.

The Luminant penalty came as more bad news for the failing Energy Future Holdings, the generation company's holding company. Although the Dallas-based company showed a modest profit during the third quarter of 2013,[25] it recorded $3.36 billion in losses in 2012 and nearly $2 billion in 2011. Many analysts predicted restructuring in 2014, when it faces a balloon payment on its massive debt acquired during the 2007 buyout of TXU.[26]

PRICES

TCAP released a report in 2014 showing that Texans in deregulated areas have continued paying significantly more, on average, than Texans outside deregulation. Texans in deregulated areas would have saved more than $22 billion collectively since 2002 had average residential electric prices under deregulation matched average prices outside deregulation. Over the course of deregulation, the computed savings for a typical customer under deregulation would have exceeded $4,500, according to the report.[27]

Year: 2014 Pause in the Debate Over Capacity Subsidies

After gaining steam for several years, a proposal to dramatically overhaul the state's deregulated electricity market stalled in 2014.

Generation companies had been calling for the overhaul, through which they would have received multi-million dollar "capacity payments" that theoretically would subsidize new power plant construction. But critics said the subsidies were unnecessary, would needlessly inflate electricity costs and would mark a departure from the free-market principles upon which the state's deregulated electricity system was premised.

That the PUC would adopt the complex proposals appeared increasingly certain — especially after two of the three commissioners expressed some level of support for them during previous years. But momentum stalled in January 2014 after the release of a Brattle Group report showing the current unsubsidized system was supporting relatively healthy supplies of generation.[1] Shortly afterwards ERCOT released a report concluding that the state would enjoy future reserves significantly greater than previously forecast.[2]

State Sen. Troy Fraser, chair of the Senate Natural Resources Committee, said "we don't have a crisis; the system's not broken."[3] PUC commissioner Brandy Marty, who during 2013 was seen by some observers as a proponent for the market overhaul, said early in 2014 that "our energy market seems to be healthy."[4]

Taken together, the new reports — as well as push back from key policymakers — ended the public push for the expensive market overhaul.

The PUC also had already taken other steps to encourage new generation construction, including raising a price limit for wholesale power offered into a segment of the ERCOT market. The cap at one time was set at $1,000 per megawatt hour — about typical for other parts of the nation — but was increased to $7,000 in June.[5]

[For more information about the Capacity Market debate, see the TCAP Snapshot Report, "A Retreat from Electric Competition," Nov. 2013. It can be found online at http://tcaptx.com/wp-content/uploads/2013/11/Capacity-Report.pdf.]

Did you know?

EFH's wholesale power unit, Luminant, controls approximately 18 percent of the market within ERCOT[12] — a share that was down slightly from previous years.[13] Under the 1999 electric deregulation law, no single generator can control more than 20 percent.[14] This prohibition against amassing too much market power should limit the ability of some of the state's larger generation companies from acquiring all of Luminant's assets in the EFH bankrpутcy.

STATE'S LARGEST ELECTRIC COMPANY GOES BUST

On April 29, just six years after it was formed through the buyout of the former TXU Corp., Energy Future Holdings filed for bankruptcy. This came as a surprise to approximately no one. EFH had been losing money for years.

But the financial collapse nonetheless was dramatic. Formed in what had been the largest leveraged buyout in U.S. history, EFH now was at the center of one of the largest-ever bankruptcies for a non-financial company.[6] Investors who led the $45 billion acquisition of TXU in 2007 saw their stake reduced in 2014 to less than 1 percent.[7] Many creditors were expected to be wiped out completely.[8]

What happened? In three words: a bad bet. The investors who borrowed so much money had wagered that natural gas prices would continue rising and in the process elevate wholesale electricity prices. Instead, new natural gas exploration technology led to a commodity glut. Natural gas prices fell, and along with them, electricity prices . . . and the fortunes of Energy Future Holdings.

According to reports, EFH owned more than $36 billion in assets when it filed for Chapter 11 protections. But it also owed more than $49 billion to creditors and had no way to keep up with its debt payments.[9]

Most of the losses were accrued by the generation side of the company — Luminant — which operated in the wholesale power market. But EFH still controlled a profitable retail electric arm, with more than 1.7 million customers,[10] and it also controlled an 80-percent stake in Oncor, the monopoly transmission and distribution utility in North Texas. Oncor continued making big profits through 2014 —more, in fact, than had been authorized by regulators. [See sidebar: Oncor's Overearnings on page 77.]

It remained unclear how the bankruptcy eventually would impact rates. For instance, it could contribute to lower rates if the company's fleet of coal, gas and nuclear plants were to be divvied up among several new owners. More diverse wholesale ownership means more wholesale competition, potentially putting downward pressure on prices.

However, the opposite could occur if the fleet were to be transferred, en masse, to a single buyer — especially one that already controlled generation assets in Texas.[11] The good news is that Senate Bill 7, the electric deregulation law, sets limits on how much generation can be owned by a single entity.

Also, thanks to the deregulation law, investors — as opposed to ratepayers — should shoulder much of the financial risk from the EFH collapse. Financial protections set in place at the time of the 2007 buyout — protections put in place at the insistence of cities and the Texas Public Utility Commission — likewise are designed to protect Oncor ratepayers.

But it is unlikely that such a debt-heavy buyout would have occurred in the first place in the absence of deregulation. Warren Buffet, who invested $2 billion in EFH, described his involvement in the debacle as a "major unforced error."[15]

ONCOR BATTERIES

Oncor made headlines of a different sort during 2014. In November the EFH-owned transmission and distribution utility announced an ambitious proposal to install large-scale batteries throughout Texas.[18] If given the green light, units with about 5,000 megawatts of storage capacity would be placed along transmission and distribution lines, at locations where they come to dead ends or near feeders that have consistent outage problems.

Although Oncor says the batteries would improve reliability, important questions remained unanswered about their costs and how they would impact the state's deregulated power system.

And because the batteries could be considered — at least, technically — as a generation source, the plan likely would require legislative authorization. Under the state's electric deregulation law, transmission and distribution utilities are barred from owning generation.

Oncor said the batteries would reduce costs associated with transmission line congestion — and thereby wholesale power costs overall. And to the extent that it helps drive down the

Good Work If You Can Get It

In October, over the objections of the federal bankruptcy monitor, U.S. District Judge Christopher Sontchi ruled that EFH could reward 26 of its top executives with up to $20 million in bonuses. Despite its historic collapse, the company described itself in bankruptcy court as "one of the best operated companies in the industry" and said it wanted to implement an executive bonus program to drive its "operational and financial excellence."[16] The bankruptcy judge — operating in court in Wilmington, Delaware, far from the company's employees, customers and assets in Texas[17] — agreed with the request.

ONCOR's Overearnings

Has Oncor systematically shortchanged its electric distribution system? That was the question from Public Utility Commissioner Kenneth Anderson, who wrote in an Oct. 17 memo that repeated outages on the Oncor system had him wondering whether the company was doing enough to maintain reliability.

The commissioner documented a nearly 5 percent drop in Oncor's distribution investment between 2005 and 2013.[20] Anderson also specifically referenced a controversial tax sharing agreement with Energy Future Holdings, and questioned whether too much money from Oncor's ratepayers was flowing upstream to the parent company.

Oncor responded with a Nov. 6 "Letter to Our Customers," which it had published as a full-page newspaper advertisement in Austin.[21] In it, the state's largest monopoly utility insisted that it takes very seriously the needs of its ratepayers.

"Some people ask whether we are willing to spend the money to enhance reliability. Of course we will, because we always have," the company's top executive wrote in the letter.

But the company also made at least one claim that appeared to have been contradicted by records at the Public Utility Commission. In defending itself in the open letter, the company wrote its "return to our investors (are) well below" authorized levels.

But in an Oct. 9 memo to Commissioners, agency experts said Oncor's revenue levels during 2013 were not "well below" authorized levels, but rather about $47 million higher than those deemed reasonable.[22] Oncor also has publicly reported healthy profits, including $355 million during 2013 — or about a 31 percent increase from 2008.[23]

cost of utility-scale batteries, the project could help kick start similar investments by other players.

But the technology also would cost billions of dollars.[19] Without an impartial cost-benefit analysis and more detailed plans from the company, it remained impossible to predict whether the proposal would save Texans money or add to their monthly bills.

The plan also marks a departure from deregulation, since Oncor is a regulated monopoly that would be using money from its captive ratepayers to invest in battery technology.

SMALL FISH SWIM FREE RULE

The PUC in 2014 reaffirmed a controversial rule that — according to critics — makes it easier for some companies to manipulate the Texas wholesale power market. The PUC's decision came in response to a complaint filed by a power trader that had accused a competitor of improperly driving up prices.

The rule in question is known as the "Small Fish Swim Free Rule." It was first established by the PUC in 2006. Under it, relatively small generation companies — i.e., the "small fish" — can engage in trading practices that might otherwise be construed as illegal market manipulation if they instead had been conducted by a larger company. The rule defines "small fish" companies as those that control 5 percent or less of the ERCOT market.

Under the logic of the rule, small-fish generators should not have the ability to manipulate the wholesale power market because their share of it is so small. But critics — such as Raiden Commodities that filed the PUC petition — say the rule lets small-fish generators off the hook for predatory practices.

In its April 21st petition, Raiden claimed that some small-fish competitors possess the ability to drive up prices when energy surpluses run short. To support their position Raiden cited findings by the independent monitor of the state's wholesale power market.

But PUC chair Donna Nelson said that if a "small fish" company were to attempt to bid its power into the market at excessively high prices, other generators would enter the market. "It's a short-term issue — and one that the market handles well," she said.[24]

Commissioner Kenneth Anderson said the panel vetted the issues raised by Raiden when it originally adopted the small-fish rule in 2006. "The question is: where do you draw the line?" he said, referring to the 5 percent threshold.

Commissioner Brandy Marty said Raiden had raised interesting points, but that she was not yet prepared to revisit the small-fish rule. "To the extent that a small fish is big enough to have an impact, we should keep an eye on it," she said.

The final PUC vote was 3-0 against Raiden. The company in 2014 also filed a separate lawsuit in federal court accusing a rival generator of manipulating the Texas market. As of late 2014, that lawsuit remained pending.

HOUSTON IMPORT PROJECT

The ERCOT board in April approved a massive transmission construction project that could lower electric prices in Houston.[25] That approval came over the objections of two major generation companies.

Dubbed the Houston Import Project, the new transmission lines will cost an estimated $590 million.[26] When complete, they will run 130 miles from the northern portion of the Houston metro area to east-central Texas.[27]

Power companies NRG and Calpine successfully opposed an earlier version of the project and continued opposing this most recent effort.[28] Their objections did not surprise observers given that both companies have a concentration of generation plants around Houston. The new lines could open the region to more competition and lead to a decline in wholesale power costs — and potentially cut into both companies' bottom lines.

NRG has argued that higher market prices around Houston encourage investors to build more power plants, which, in turn, could help the state serve future energy needs. But Houston's dense population and environmental restrictions there have severely limited the ability of investors to build new plants locally. And while NRG announced in November[29] that it would break ground on a relatively small 360-megawatt plant just southeast of Houston, the development was more the exception than the rule.

Consumer representatives active at the ERCOT board support the Houston Import Project. Although construction won't be cheap, the additional costs will be borne by ratepayers statewide. That means the per-customer cost of construction should be nominal, while the lines themselves should contribute to energy affordability and reliability in the Houston area.

ERCOT's technical experts recommended the project not for economic reasons, but rather to help ensure grid stability. The expansion project, which is scheduled for completion by 2018,[30] is similar to others given the green light for reliability purposes. These include projects around the Lower Rio Grande Valley.[31]

WIND POWER AND ENVIRONMENTAL PROTECTION AGENCY MANDATES

A June report from the United States Information Administration found that thousands of miles of new transmission lines in Texas had reduced instances in which wind generators were prevented from getting their power onto the statewide grid.

As a result of these new lines, wind turbines in Texas continued to generate record amounts of power during 2014. Nearly 30 percent of all electricity on the ERCOT grid during a brief period in March came from wind generators.[32] Over the last decade, wind power generation in Texas expanded more than 1,000 percent.[33]

Public Utility Commission chairwoman Donna Nelson, in a May 29 memo to her colleagues,[34] wrote that the continued expansion of wind power in Texas would require more transmission system upgrades and that the agency should consider shifting some expenses onto the wind industry.

"Should we ask electric customers to fund further investment in the transmission system to improve stability or should some of the risk be borne by generators?" she wrote.

In June, the U.S. Environmental Protection Agency announced a new "Clean Power Plan" that calls for a 39 percent reduction in carbon dioxide emissions from Texas power plants by 2030 as compared to 2012 levels.[35] The ERCOT grid operator released a report in November saying that the retirement of coal plants under the plan would undermine electric reliability. It also said the plan could increase electricity costs by 20 percent by 2020.[36]

Year: 2015 Hunt Bid to Buy Oncor

A federal judge in September authorized a plan for Energy Future Holdings ("EFH") to exit bankruptcy. Under the plan, EFH's competitive assets would go to its creditors and EFH's regulated transmission and distribution utility, Oncor, would go to a consortium that includes creditors as well Ray L. Hunt, the Dallas billionaire.[1]

But the proposed transfer of the regulated wires company drew heated criticism — and it remained unclear during 2015 whether it would receive needed regulatory approval. Without that approval, the EFH bankruptcy plan would almost certainly fail.[2]

Because Oncor is a public utility, state law requires that the Texas PUC approve its change of ownership. The agency has 180 days from a Sept. 29 regulatory filing by Hunt to certify that the sale does not violate the public interest. A major sticking point was Hunt's proposal to divide Oncor into two different companies — one to own the lines and poles; the other to lease the equipment and operate the company.

Consumer groups warned this bifurcated structure — a key necessity of a "Real Estate Investment Trust," or REIT — would create new ratepayer risk without providing offsetting benefits. In addition, the REIT structure would lead to dramatic, immediate and permanent corporate tax savings, but Hunt made no commitment to share those savings with ratepayers. One PUC expert said that if Hunt's proposal received regulatory approval, then millions of dollars in customer wealth would end up with the utility's owners.[3]

Oncor, which serves 10 million customers at 3 million meters,[4] is the state's largest transmission and distribution utility.

HOUSTON IMPORT PROJECT

A massive transmission project that could lower electric prices in Houston received approval from the Texas PUC in December— despite objections from two major generation companies.[5]

Dubbed the Houston Import Project, it will include transmission lines that will run 130 miles from the northern portion of the Houston metro area to east-central Texas. The estimated cost is $590 million.[6]

Wholesale power companies NRG and Calpine — two wholesale power companies with a concentration of generation plants around Houston — were among the principle opponents. Consumer representatives supported the project and noted that the companies' opposition wasn't surprising, given that the new lines could open the region to more suppliers and lead to a decline in wholesale power costs there.

Although construction won't be cheap, the additional costs will be borne by ratepayers statewide. That means the per-customer cost of construction should be nominal, while the lines themselves should contribute to energy affordability in and around Houston.

CenterPoint, the Houston-based transmission and distribution utility, estimated the project could increase utility rates by about five cents per month.[7] ERCOT earlier gave its approval to the Houston Import Project.[8]

"SMALL FISH" KEEP SWIMMING IN ERCOT

A federal judge in February 2015 dismissed a lawsuit involving the controversial "small fish swim free" rule.[9] This follows a similar ruling in 2014 by the Texas PUC.

Under the rule, relatively small energy companies — i.e., the "small fish" — can engage in wholesale energy trading practices that otherwise might be construed as illegal market manipulation if conducted by larger companies. The rule defines "small fish" as generation companies that control less than 5 percent of the wholesale power market within ERCOT.

Under the logic of the Small Fish rule, comparatively small generation companies cannot game the market because their share of it is so small. But critics disagree and cite findings by ERCOT's independent market monitor to support that position.[10]

Raiden Commodities and Aspire Commodities, two commodity trading companies, had alleged in their dismissed lawsuit that French trading company GDF Suez had improperly manipulated the Texas market. GDF is a "small fish" under the Texas rules.

Transmission and Distribution Charges

Although monopoly transmission and distribution utilities operate under regulation, their rates impact electricity prices charged by competitive retail electric providers. This is because transmission and distribution utility rates are non-bypassable, which means they are included in a uniform fashion in the rates charged by all retail electric providers that operate in the utility's service territory.

Rate increases since 2003 by the Oncor utility (operating in the Dallas-Fort Worth area) and the CenterPoint Electric utility (operating around Houston) have outpaced inflation. Transmission and distribution charges paid by Oncor and CenterPoint customers also comprise an increasing share of monthly electric bills.

Non-Bypassable Charges: CenterPoint
(September 2003 – September 2015)

2003	2016
$24.61	$42.41

TRANSMISSION & DISTRIBUTION CHARGES
(IN DOLLARS, ON 1,000KWH MONTHLY BILL)

Transmission and distribution utilities operate as regulated monopolies, even in areas of Texas with deregulation. The rates assessed by these utilities continue going up, sometimes at a rate well beyond that of inflation. For instance, rates charged by CenterPoint Electric in the Houston area have increased 73.4 percent between 2003 and 2016. In 2003, CenterPoint charges comprised 20.2 percent to 29.2 percent of a typical 1,000 kWh electric bill. In 2016, CenterPoint charges comprised 30.2 percent to 54.9 percent of a typical bill. All electric customers in deregulated areas around Houston must pay CenterPoint's rates, regardless of the retail electric provider the customer chooses for service.

Source: Archived TDU Rate Summaries, PUC
http://www.puc.texas.gov/industry/electric/rates/TDArchive.aspx

Non-Bypassable Charges: Oncor
(September 2003 – September 2015)

2003	2016
$23.01	$36.87

TRANSMISSION & DISTRIBUTION CHARGES
(IN DOLLARS, ON 1,000KWH MONTHLY BILL)

Rates charged by Oncor utility in the Dallas-Fort Worth area increased by more than 60 percent between 2003 and 2016. That rate outpaces the rate of inflation. In 2003, Oncor charges comprised 20.1 percent to 27.4 percent of a typical 1,000 kWh electric bill. In 2016, the charges comprised 28 percent to 53.6 percent of a typical bill. All customers in deregulated areas of the Dallas-Fort Worth region must pay Oncor's rates, regardless of the retail electric provider the customers choose for service.

Source: Archived TDU Rate Summaries, PUC
http://www.puc.texas.gov/industry/electric/rates/TDArchive.aspx

TEXAS LEGISLATURE

The 84th Session of the Texas Legislature convened on Jan. 13. State lawmakers considered scores of bills relating to the state's deregulated electricity market. Most failed, but one important piece of legislation, House Bill 1101, won approval.

HERE ARE A FEW HIGHLIGHTS FROM THE 84TH LEGISLATIVE SESSION:

- House Bill 1101, by state Rep. Sylvester Turner, will ensure that approximately $200 million left unspent in the System Benefit Fund will be used for its intended purpose: to assist low-income ratepayers. Funding for this program comes not from tax dollars, but from fees already paid on electric bills. Gov. Greg Abbott signed House Bill 1101 on June 17th.

- House Bill 2254, also by Rep. Turner, would have prohibited electric companies from applying minimum use fees to home bills. Although Rep. Turner couldn't get HB 2254 out of committee, the PUC took action shortly after the session to require disclosure of such fees on the powertochoose.org website. [11]

- Senate Bill 777, by Sen. Troy Fraser, would have given the PUC more tools to crack down on bad actors in the state's retail electric market. The Texas Coalition for Affordable Power joined the PUC staff in supporting this legislation. SB 777 emerged from the Senate, but died in the House.[12]

ENERGY CONSUMPTION IN ERCOT REGION GROWS

Texas businesses and homes consumed 2.2 percent more power in 2015 than they did the previous year — an increase driven by an unusually hot summer. The ERCOT grid operator also recorded a new record in peak usage during 2015.[13]

In all, five demand records were set inside ERCOT during 2015. "By summer's end, the system had new records for monthly energy use, July peak demand, weekend peak demand and all-time peak demand," the grid operator stated in a press release.[14]

TEXAS WIND BREAKS RECORDS DURING 2015

Texas wind power also broke records in 2015 — aided in large part by the completion of the expensive CREZ transmission network.[15] Here's a quick rundown of some of the year's broken records.

— At 11:07 a.m. on Dec. 22 Texas wind generators pumped out 13,883 MW of electricity, a new record.[16]

— A slightly smaller burst of wind power at 3:05 that same day accounted for 44.7 percent of the overall power on the ERCOT grid at that time. That set a new record for wind power's percentage of load.[17]

— Wind farms supplied about 18.4 percent of the electricity in November, a new monthly record. That beat the previous single-month record of 15.2 percent set in ERCOT during March of 2013.[18]

— On Nov. 25, wind generators pumped out 12,971 MW of power, a record at that time. This represented 36.9 percent of the load on the ERCOT grid.[19]

— On Oct. 22, wind generators produced 12,238 MW in ERCOT, a record at that time.[20]

— On Sept. 13, wind generators produced 11,467 MW in ERCOT, a record at that time.[21]

COMPLAINTS

Electricity complaints filed with state regulators dropped to a new post-electric deregulation low in 2015. Texans filed 6,973 electricity-related complaints or inquires with the PUC during the fiscal year, beating the previous low in FY 2013 when Texans filed 7,129.[22] However, complaints against a single company — Dallas-based Sharyland Utilities — shot up more than 800 percent during FY 2015. Sharyland is owned by many of the same parties seeking control of Oncor. The complaints against Sharyland were so numerous that the PUC opened a special proceeding that resulted in a slight rate decrease for some customers.[23]

New ERCOT Records

According to the grid operator, peak demand records set in 2015 were 69,877 MW on Aug. 10, 69,775 MW on Aug. 11, 68,979 MW on Aug. 6, 68,731 MW on Aug. 7 and 68,683 MW on Aug. 5. Also, homes and businesses in ERCOT consumed 347,522,948 megawatt-hours of electricity in 2015, as compared to 340,033,353 MW during 2014.

Year: 2016 NextEra Replaces Hunt in Oncor Bid

By year's end it appeared that Florida-based NextEra — and not a consortium that included Dallas billionaire Ray L. Hunt — had the inside track to take possession of Oncor.

Recall that the Hunt consortium had proposed a complicated and controversial tax structure for the utility. As it turned out, it was that tax structure that proved to be the deal's undoing. Consumer groups and others[1] had criticized the proposed structure (described in the Year 2015 chapter) because it would have delivered a multimillion-dollar windfall to the new utility owners, but at ratepayer expense. In March, the PUC approved the consortium's proposal[2], but also attached a slew of conditions[3] that prompted the prospective buyers to walk away.[4]

Florida-based NextEra then proffered an alternative deal, albeit one with more traditional financing. Some experts (including TCAP general counsel Geoffrey Gay) warned the NextEra proposal also could lead to a rate hike, and NextEra itself acknowledged it would seek new Oncor rates in 2017, if the deal closed.[5]

The PUC was expected to consider whether to approve the NextEra proposal or reject it during proceedings in early 2017. If finalized, the transaction would be valued at more than $18 billion and require $9.5 billion in financing.[6]

ALTERNATIVE RATEMAKING

Not necessary and maybe even a bad idea. Those were two of the bottom-line conclusions of PUC staff regarding proposals that would allow electric utilities to more easily increase rates. "No significant evidence suggests that the current ratemaking system is in major need of repair," Public Utility Commission staff wrote in an Oct. 21 agency filing.[7]

At issue were "alternative rate-making" proposals that would replace the current system for adjusting electricity rates. Although the proposals differed in their specifics, in general all of them would make it easier for monopoly utilities to obtain rate hikes. Transmission and distribution utilities have lobbied hard for such changes for years, and the Texas Legislature in 2015 directed the PUC to examine alternative rate-making proposals and report back.

In response, the PUC in 2016 hired a team of energy consultants to examine alternative rate-making proposals elsewhere in the country. The consultants released a white paper in May[8] describing "formula rate plans" (in which rates are adjusted automatically to keep utility revenues within a specified band), "straight fixed-variable rate" plans (in which utilities recoup their fixed costs through per-customer charges that are independent of the volume of electricity consumed) "lost-revenue adjustment mechanisms" (in which rates are adjusted periodically to compensate the utility for lost revenues resulting from consumer conservation) and other schemes.

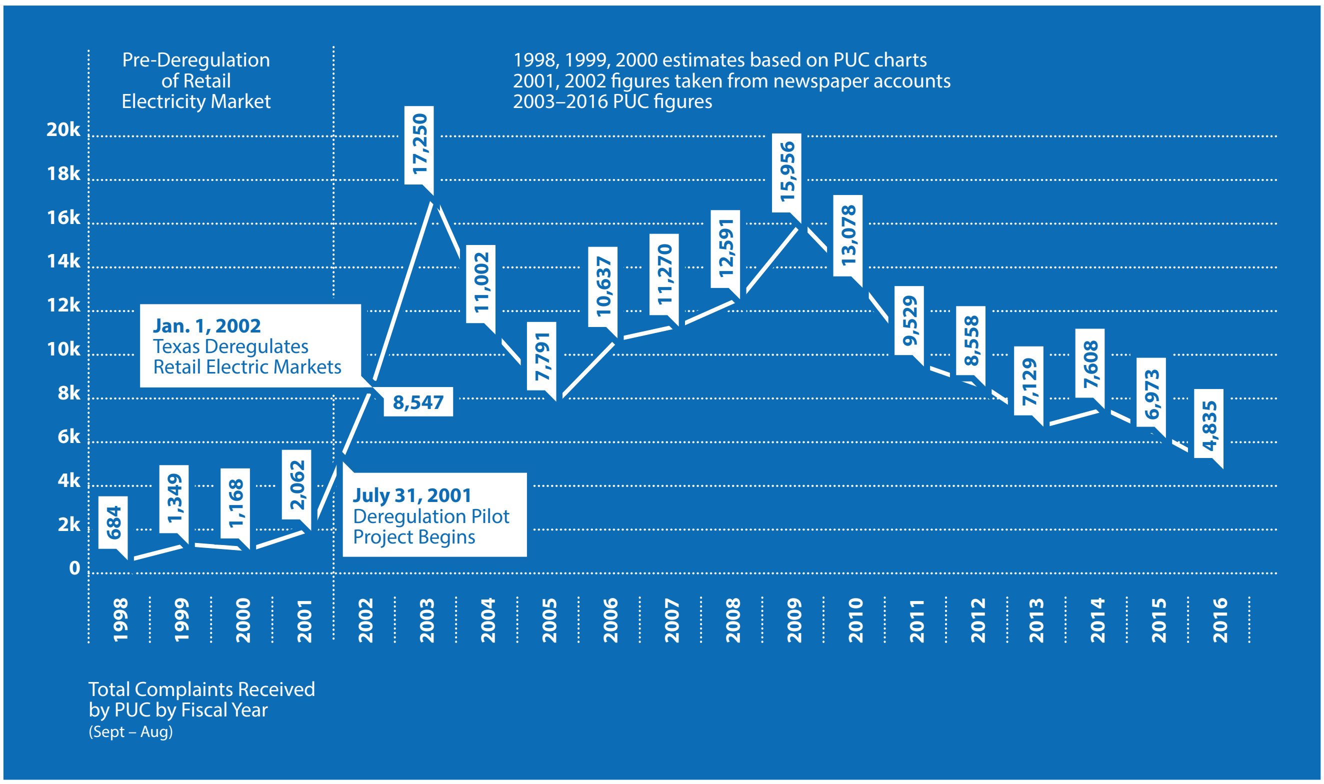
But upon reviewing the report, PUC Staff concluded that such changes weren't necessary. "The Commission believes that no compelling need currently exists for specific legislative authorization of a particular type or types of alternative ratemaking mechanisms," staff wrote.[9]

Staff noted further that "the use of inappropriate alternative ratemaking mechanisms could result in uncertain and unintended consequences for the Texas competitive retail market" and could interfere with the pricing strategies of retail electric providers.[10]

Those findings were in line with the opinions of various consumer groups and others who found that the proposed schemes would lead to higher prices for ratepayers, more paperwork for regulators and big headaches for retail electric providers.

ELECTRIC COMPLAINTS

The number of annual electricity-related complaints filed with Texas regulators dropped to a new low during the 2016 fiscal year. All told, Texans filed 4,835 electricity-related complaints or inquiries with the Texas Public Utility Commission during the 2016 fiscal year — down from the 6,973 electricity-related complaints or inquires filed in 2015. This nearly 31 percent year-over-year decline was among the steepest since the state deregulated most of its retail electricity market in 2002. The PUC also reported a drop in almost all discrete categories of electricity complaints.[11]



WIND CONTINUES TO SURGE

On Nov. 27, wind generation briefly surpassed the 15,000 megawatt mark — a first for Texas. The 15,033 MW output at 12:35 p.m. represented about 45 percent of all electricity transmitted on the state's main power grid at the moment.[12] The 15,033 MW also beat the state's previous record — 14,122 MW — which had been set only 10 days earlier. Wind producers in 2016 also set a new record for percentage of overall load when, on March 23, Texas turbines briefly produced 48.28 percent of all power on the grid.[13]

POWERTOCHOOSE REFORM

After receiving reports of potentially misleading offers on the powertochoose website, PUC chair Donna Nelson began pushing during 2016 to reform it. Among problems identified in press reports were deals featuring extremely low and unsustainable prices. Because the state's official electric shopping website sorts from lowest-priced to highest, these unrealistic deals were featured very prominently on powertochoose.org.

In response to recommendations from TCAP and others, Chair Nelson directed the agency to adjust the website query function in such a way as to reduce the prominence of misleadingly low-priced deals.[14] She also presided over several stakeholder meetings to identify additional improvements for powertochoose.org.

ELECTRICITY PRICES

Residents in areas of Texas with electric deregulation could choose from a growing number of comparatively low-priced power deals during 2016. However, a pricing analysis released by TCAP in June reaffirmed previous findings that Texans living in deregulated areas had historically paid more for electricity, on average, than Texans living in areas exempt from deregulation. From 2002 through 2014 the imputed “lost savings” from higher average electric costs in areas with retail electric competition exceeds $24 billion, according to the TCAP report. This confirmed findings from previous reports.[15]

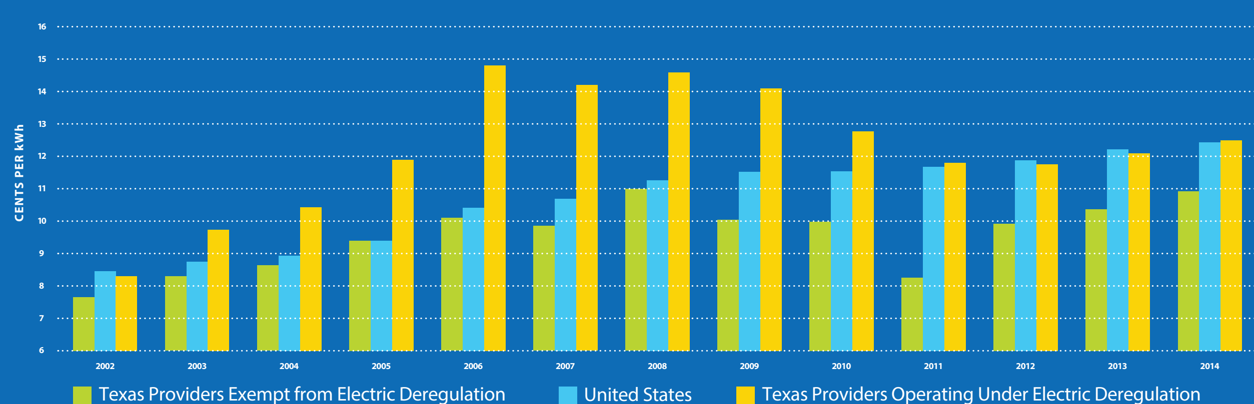
TCAP also found that rates charged by the state’s two largest transmission and distribution providers had increased in recent years beyond the level of inflation, and that these rates comprised a larger proportion of home residential bills than they had in previous years. Transmission and distribution charges are “non-bypassable,” which means that all electric customers in a given region must pay them, regardless of the retail electric provider the consumer has selected for service.[16]

Average Residential Electricity Prices

Inside & Outside Areas of Texas with Retail Electric Deregulation

EXHIBIT 1: Residential prices inside and outside deregulated Texas

Source: United State Energy Information Administration; http://www.eia.doe.gov/cneaf/electricity/page/eia861.html



Year: 2017 The Buyout Continues

The year began with Florida-based NextEra poised to take control of Oncor Electric, the state's largest transmission and distribution utility. But that bid — the second since Oncor went on sale in 2015 — fell short during 2017, as did two others. That left a fifth potential suitor in position to take control of the utility.

ONCOR on Sale

Oncor went up on the auction block after the bankruptcy of its erstwhile parent company, Energy Future Holdings. Because Oncor is a state-sanctioned monopoly — and because it was part of EFH — it cannot be sold without the consent of Texas regulators and a federal bankruptcy court. See "Oncor's Ring Fence" from the 2007 Chapter.

Here's a quick summary developments during 2017 relating to the potentially multi-billion-dollar sale of Oncor.

- In February the PUC quashed a bid by Florida-based NextEra to take control of Oncor after commissioners and consumer groups expressed concern that it would have undermined existing "Ring Fence" legal protections for the utility and its ratepayers. [To read more about the Oncor Ring Fence, see the 2007 chapter].
- On July 7 Berkshire Hathaway Energy, a unit of the investment conglomerate owned by Warren Buffett, announced it had tentatively agreed to a $9 billion all-cash deal to acquire Oncor. The Berkshire Hathaway offer was more straightforward than the NextEra offer and a previous offer made in 2016 from a consortium that included Dallas billionaire Roy Hunt. [See the 2016 chapter]. But the Berkshire Hathaway deal also failed under the weight of separate objections by Elliott Management, a New York City hedge fund that was the largest creditor of Energy Future Holdings.
- In early July Elliott floated a deal said to be worth $300 million more to creditors than that offered by Berkshire Hathaway. This briefly put Elliott in the lead position for Oncor.
- In August California-based Sempra Energy announced yet another offer, this one based both on cash and debt. Both Elliott Management and Energy Future Holdings threw their support behind this new deal. The federal bankruptcy court approved the Sempra offer in September. The PUC will review it in 2018 to determine whether it comports with the public interest.

MORE UTILITY NEWS

In September the PUC approved an important regulatory swap under which Oncor would begin serving customers of the beleaguered Sharyland utility, and Sharyland would take control of $380 million in transmission lines from Oncor. The deal also required Oncor to pay Sharyland $20 million, and for Sharyland to surrender to Oncor an electric distribution network that served retail customers.

Sharyland serves about 54,000 customers in West Texas and in portions of the Rio Grande Valley. Oncor serves nearly 10 million customers throughout Texas.[1] The agreement between the two utilities was expected to shave $50 or $60 per month from Sharyland customer rates, which, in 2017, were among the state's highest. [see 2015 chapter].

The swap — part of a broader rate case for Oncor — also was expected to slightly rate increase for Oncor's legacy customers.[2]

In October the PUC convened a special hearing to consider a number of technical proposals that could impact ERCOT operations. Included in a report sponsored by Houston energy giants NRG and Calpine, the proposed changes to wholesale power market rules also could lead to increased wholesale energy prices around Houston and other areas under certain circumstances. Although the PUC did not formally approve or reject the recommendations in 2017, the report and discussions around it signaled continued dissatisfaction among some big generators with wholesale power market prices.

The generators sponsoring the report argued that one unfortunate side effect of ordering extra power plants to come on line for system reliability purposes was that such action inappropriately dampened certain wholesale power prices. The generators argued for revised ERCOT pricing rules that they said would better incentivize new plant construction.

These arguments were reminiscent of earlier ones made by large generation companies seeking to create a capacity market in Texas. [See Year: 2012 chapter] NRG and Calpine also were the principal opponents of the Houston Import Project, a major transmission line project that could open that region to more suppliers and potentially lower wholesale power costs there [See the Houston Import Project articles in the Year: 2014 and Year: 2015 chapters].

Those opposing NRG and Calpine on the issue — including representatives of major industrial electricity users and consumer groups — said the companies' proposed changes (as outlined in the technical report) were unnecessary because the ERCOT market was functioning reasonably well. They said the NRG and Calpine proposals would prop up the companies' own power plants at the expense of electric customers within the Houston area and at the expense of competing generation companies outside of the Houston area.

Report Proposes ERCOT Technical Changes

Intimidatingly entitled *Priorities for the Evolution of an Energy-Only Market Design in ERCOT,* the NRG/Calpine report was prepared by William Hogan of Harvard and Susan Pope of FTI Consulting.[3] It included a menu of arcane changes relating to the ERCOT-managed market. Among them:

- Adjust the parameters of a complicated wholesale market mechanism known as the Operating Reserve Demand Curve, also known as the ORDC. Under the ORDC, generators receive an enhanced payment for electricity they sell during periods when other available power becomes scarce. Under the NRG/Calpine proposal, the sliding scale used to calculate this adder would be adjusted in such a way as to favor generators that relieve power scarcity.
- Adjust the allocation of costs associated with transmission line losses. This proposal relates to the engineering of power grids: that is, a certain amount of electricity is always lost during transmission, and that amount is in direct proportion to the length of transmission lines. This proposal would change existing rules under which costs associated with line losses are shared broadly among wholesale users across the ERCOT region. Under the proposed change, charges would be allocated on a more granular, local level — and calculated based upon line distances and associated line losses associated with serving that local area.
- Change policies with regards to the planning and financing of transmission projects, and amend the current rules under which transmission costs are spread out across the ERCOT system.

MORE POTENTIAL CHANGES IN THE ERCOT MARKET

In October Lubbock Power & Light submitted a formal application to the PUC seeking permission to link to the ERCOT power grid[4] and to disconnect from a separate grid that serves portions of West Texas, portions of New Mexico and several other states.[5] Lubbock Power & Light is the third largest municipal electric utility in Texas. It serves more than 104,000 electric meters, and owns and maintains 4,936 miles of power lines and three power plants.[6]

Also in October, Vistra Energy (the newly rebranded parent company for TXU Energy and Luminant)[7] announced it would be shuttering three of its coal-fired plants — Monticello, Sandow and Big Brown.[8] San Antonio's city-owned CPS Energy also announced plans to close its coal-fired plant, J.T. Deely. All the retirements were expected in 2018.

The retirements, the first for the Texas market since at least 2000, would mean the loss of nearly 5,000 megawatts of generating capacity. The retirements also followed a nationwide pattern: traditionally a dominant energy source, American coal nonetheless was losing ground to natural gas as the commodity cost of that resource remained comparitively low and power plants burning natural gas gained in efficiency. Technology improvements also were making renewable resources relatively more competitive.

However — even given the coal retirements, Texas was expected to have sufficient generating capacity through at least May 2018, according to a pair of reports released by ERCOT in November.[9]

RENEWABLE POWER MAKES GAINS

Wind power blew past coal during 2017 to become the second largest electricity source in the ERCOT market. The milestone was reached in October when a 155-megawatt wind farm in West Texas began commercial operations. This brought the state's wind power capacity to more than 20,000 megawatts. Texas coal-fired plants, by contrast, comprised only 19,300 megawatts of capacity, according to ERCOT.[10]

The solar industry also marked its strongest quarter ever in Texas, with 375 megawatts of new capacity added in the three months from April through June. A report by the Solar Energy Industries Association ranked Texas second among states for solar growth during the second quarter of 2017.[11]

ELECTRIC PRICES AND COMPLAINTS

Complaints from electricity consumers dropped to a new post-deregulation low during 2017. The PUC registered 4,175 electric-related complaints or inquiries during FY 2017, as compared to 4,835 during FY 2016. That marked a 14 percent year-to-year drop. A report issued by TCAP in October found that the number of complaints and inquiries filed by electric consumers had been falling more or less steadily since 2008, roughly paralleling a trend of lower electricity prices in Texas.[12]

A separate TCAP report issued in July[13] found that residential electric prices in areas of Texas with retail competition had declined during a recent 10-year period, while average prices in deregulation-exempt areas had increased during

Vistra/Dyndergy Merger

Vistra in 2017 announced it would merge with Houston-based Dynergy. The newly combined company would serve about 2.9 million customers, according to the *Dallas Morning News*.[14]

the same period. However — even accounting for those pricing shifts — average residential electricity prices in deregulated areas remained consistently higher during every year of the study period.

The TCAP analysis found that charges assessed by monopoly transmission and distribution providers comprised a growing portion of home bills, and that increases since 2003 had far outstripped the pace of inflation.

TEXAS LEGISLATURE: GOVERNOR SIGNS RATE CASE BILL

The Texas Legislature convened for its 85th Regular session in 2017. Although lawmakers considered scores of bills that potentially could impact electric ratepayers, few made it to the governor's desk. One exception was Senate Bill 735, which would require the PUC to establish a schedule under which it periodically reviews the fairness of electric utility rates. SB 735 included other changes to rate-setting procedures that, taken collectively, should be something of a mixed bag for ratepayers. The governor signed Senate Bill 735 on May 27.[15]

Appendix A: Senate Bill 7 — Key Components

When Gov. George Bush signed Senate Bill 7 into law in 1999, he instituted what some have called America's most audacious experiment in the deregulation of electric power. Gov. Bush was clear about his intentions. "Competition in the electric industry will benefit Texans by reducing rates and offering consumers more choices," he said.

No longer would the production and sale of electricity be considered monopoly enterprises. Instead, SB 7 called for "the establishment of a fully competitive electric power industry" where market forces dictate prices and service. The companies that own, operate and manage the transmission and distribution system remained regulated — but most regulation of companies that produce and sell electricity would end.

SB 7 states "the Legislature finds that the production and sale of electricity is not a monopoly warranting regulation of rates, operations and services and that the public interest in competitive markets requires that… electric services and their prices should be determined by customer choices and the normal forces of competition." The Legislature ordered far-reaching changes to the market.

STRUCTURAL CHANGES

The electric power industry has three main functions – generating power, transporting power over power lines to the customer, and interacting with the customer (billing, opening new accounts, resolving problems, etc.). Prior to deregulation, a single electric company performed these services for all customers within its designated service area. SB 7 made power generation and the provision of retail electric service subject to the normal forces of competition and customer choice. Transmission and distribution services remain regulated. Accordingly, the statute required the former monopoly provider to "unbundle" – that is, to separate – its operations into three distinct entities:

- The power generating company owns and operates the electric power plants and sells its power into the deregulated wholesale power market.
- The regulated transmission and distribution company owns and operates the wires to transport power from the plant to all customers within a certain geographical area.
- The deregulated retail electric provider purchases wholesale power from power-generating companies and re-sells the power to customers. The retail provider is responsible for most interaction with the customer, including billing the customer for transmission and distribution services and for the power purchases. However, a retail provider may not own generation.

At the very minimum, the former monopoly providers were required to create separate companies for each service although the new companies could remain under the same ownership.

SB 7 exempted municipally-owned utilities and cooperative utilities although those entities could opt into deregulation. Areas of Texas not covered by the state's main transmission grid remained outside deregulation unless they met certain requirements. The Panhandle, El Paso, the Golden Triangle and the far northeast corner of the state remain outside those areas where deregulation is mandated.

RECOVERY OF STRANDED COSTS

Before deregulation, utilities were required to build plants to serve the energy needs of their customers. In order to build a plant, a company would invest millions of dollars in construction costs. Once the Public Utility Commission (PUC) determined that the construction costs were prudently incurred, the company was allowed to recover all of its costs and a reasonable level of profit from ratepayers. However, because the costs were substantial, the utilities were not paid back immediately. The payback, with interest, was spread over the projected life of the plant — usually 30 years.

Once the electric market became deregulated, former monopoly providers could not continue to charge regulated rates to recover power plant construction costs they had already incurred to serve customers. Former monopoly providers feared that they would not be able to sell the power plants at a price that would offset the outstanding debt, and the companies would be forced to choose between two untenable options: charge high prices that could not compete or absorb all of the costs related to the uneconomic plants. The difference between the net book value of the plant and the price that the plant could fetch if sold in the market became the former monopoly providers' "stranded costs."

Lawmakers determined that former monopoly providers should have the right to recover so-called stranded costs from ratepayers. SB 7 includes several provisions regarding the calculation and collection of stranded costs. The statute also imposes some restrictions on the utilities' ability to recover stranded costs and stipulates that no utility would be allowed to over-recover stranded costs.

To minimize the impact to customers, SB 7 established a three-phase process for stranded cost recovery:

- First Phase (Sept. 1999 – Dec. 31, 2001) – Regulated rates that otherwise should have been reduced are frozen. All profits in excess of Commission-set levels are applied to buy down the uneconomic plants' book value.

- Second Phase (Jan. 1, 2002 – Dec. 31, 2004) – Preliminary estimates of potential stranded costs are developed for each utility to determine whether efforts taken in the first phase were successful. If the preliminary estimates indicate stranded costs are still possible, an initial fee is surcharged to the transmission and distribution utility. The fee to the transmission and distribution utility is passed on to customers by the retail electric provider and would be used to continue buying down the uneconomic plants' book value.

- Third Phase (Beginning January 2004) – Former monopoly providers are required to true-up the actual, final value of stranded costs, taking into account the efforts in the previous two phases. Unlike the stranded cost projections in the earlier phases that relied upon a mathematical model to calculate potential-stranded costs, SB 7 provided utilities four different options to derive a final market value for potentially stranded generation assets. If the net book value exceeds the final market value, then the utility is entitled to recover stranded costs. Stranded costs are to be recovered through a fee that will be surcharged to the regulated rates of all customers within the former monopoly provider's service area.

THE PRICE TO BEAT

SB 7 required utilities to freeze their rates beginning on Sept. 1, 1999. When the deregulated market opened on Jan. 1, 2002, retail electric providers affiliated with the utilities were required to charge a price that was six percent less than the regulated rate that existed on Dec. 31, 2001. Until 2005, this new rate (known as the "Price To Beat") was the only rate that the provider affiliated with the former monopoly company was allowed to charge residential and small commercial customers in the old service area. The Price To Beat created a target for competitors to undercut with lower prices. A provider affiliated with a former monopoly electric company was required to offer the Price To Beat rate until Jan. 1, 2007. However, it also could offer plans with alternative prices after Jan. 1, 2005, if it could demonstrate that it had lost more than 40 percent of its customers.

SB 7 offered one exception to the fixed Price To Beat rate providers must charge. Individual Price To Beat providers were able to increase or decrease the rate no more than twice each year to reflect changes in natural gas fuel prices, which fuel some generation plants. The decision to increase or decrease the Price To Beat rate and the timing of the change was left to the Price To Beat provider.

PROHIBITION AGAINST MARKET POWER ABUSES

SB 7 requires the PUC to monitor market power associated with the generation, transmission, distribution and sale of electricity and to protect against any company acquiring generation capacity sufficient to exercise market power in the newly deregulated market. A company with market power is capable of restricting, impairing, or otherwise reducing the level of competition in the market.

Market power abuses specifically prohibited by SB 7 include predatory pricing, withholding of power, precluding entry to the market, and collusion.

Because a company usually has market power by virtue of controlling a large portion of the market, no company is generally allowed to own and control more than 20 percent of generation capacity within a power region. If the PUC finds market power abuses, the statute requires that the offending company submit a plan to mitigate its market power. These market mitigation plans could require the company to sell assets, auction off capacity, or take other measures to decrease the amount of generation capacity they own and control.

ENVIRONMENT

SB 7 included two major provisions relating to the environment, and established new energy efficiency guidelines.

The first provision relates to older generating plants that had been exempted from obtaining clean air permits under the 1971 Texas Clean Air Act. SB 7 set a deadline of May 2003 for utilities to cut overall nitrogen oxide emissions on this fleet of generating plants by 50 percent, and sulfur dioxide emissions by 25 percent (with deeper cuts of nitrogen oxide and sulfur dioxide emissions in urban areas around Houston, Galveston, Dallas and Fort Worth). To accomplish the reductions, SB 7 created a "cap and trade" system. The statute allowed utilities to recover the cost to meet the new standards by including the expenditures in their calculations of stranded costs.

SB 7 also established new statewide mandates and corresponding deadlines for the use of renewable energy. The responsibility for meeting the mandates was assigned to electric retailers based upon their individual share of the overall market. To help carry out this provision, SB 7 created a Renewable Energy Credit trading program, which is managed by the Electric Reliability Council of Texas (ERCOT). Under the program, an electric retailer that acquires more than enough renewable energy to meet its own requirements can sell credits for its excess renewable energy to other companies that have fallen short.

Although the overall renewable energy mandates in this section have increased since SB 7 was first enacted, it was originally intended to foster the construction of 2,000 megawatts of additional renewable energy by 2009 — or enough to power about 1.6 million homes.

New energy efficiency requirements were also introduced in SB 7, including a requirement that regulated transmission utilities administer energy savings incentive programs, provide customers access to energy efficiency alternatives and provide incentives for electric retailers to engage in energy efficiency efforts. Under this provision, electric utilities were expected to reduce their annual growth in energy demand by at least 10 percent by Jan. 1, 2004.

CUSTOMER PROTECTIONS

The Provider Of Last Resort

It was critical to lawmakers that customers always receive power in the deregulated market, even if some providers went out of business or if there was a billing dispute. To ensure reliable service, SB 7 established the "Provider Of Last Resort" service for customers who cannot get power from other providers, or for customers of failed companies that abruptly leave the market. The Provider Of Last Resort is selected by the commission and charges a commission-approved fixed rate for standard service.

The System Benefit Fund

SB 7 established a user fee on electric service. Funds generated by this fee were to be deposited in a special account, known as the System Benefit Fund. The System Benefit Fund was intended to support electric rate discounts for low-income customers, finance energy efficiency programs for low-income households, fund a customer education media campaign relating to retail competition and compensate school districts for the loss of any property tax revenue attributable to the deregulation law.

The Price To Beat

SB 7 created the Price To Beat to serve as both a target for competitors to undercut in order to win new customers and to provide a modest rate cut for customers that were unwilling or unable to switch providers.

Registration and Certification of Market Participants

Although the production and sale of electricity to customers was no longer subject to regulation, SB 7 authorized the PUC to establish minimum requirements for registration and certification of entities operating in the deregulated market.

Aggregation

SB 7 specifically contemplates that multiple customers could join together for the purpose of negotiating better deals in the new market. For example, municipalities and other political subdivisions that procure electricity for their own purposes — consider the expense of lighting city buildings or powering a wastewater station — can join together to purchase electricity. SB 7 refers to entities that band customers together in this fashion as "aggregators." The law requires aggregators to register with the PUC.

Municipalities and other political subdivisions are authorized to act as aggregators to join together their citizens in order to purchase electricity on their behalf. Under this provision, the citizens must affirmatively request to be included in the aggregation group.

INDEPENDENT SYSTEM OPERATOR

SB 7 requires that an independent entity oversee important operational aspects of the new market. ERCOT was designated as an "Independent System Operator" to fulfill this function.

SB 7 stipulates further that the Independent System Operator remain independent from the individual buyers and sellers of electricity in the market. At the same time, the independent organization must ensure that such buyers and sellers have equitable access to the transmission network. Under SB 7, this organization also is charged with ensuring the reliability and adequacy of power.

As manager of the Texas power grid, ERCOT already was charged with maintaining reliability and adequacy of its operations. ERCOT also was already designated as an Independent System Operator under the provisions of the 1995 law that partially deregulated wholesale electricity.

But under SB 7, ERCOT's duties — especially those relating to its mission as an Independent System Operator — would expand greatly. Its responsibilities would include the management of new billing and settlement systems, the establishment of broad new rules for wholesale power transactions, and the creation of policies relating to the scheduling of power.

As an Independent System Operator under SB 7, ERCOT must:

- Provide an accurate accounting of electricity production and delivery among generators and wholesale buyers and sellers.
- Ensure that entities that require information relating to a customer's choice of retail electric provider receive that information in a timely fashion.
- Establish and enforce rules governing wholesale electricity transactions.

As the Independent System Operator, ERCOT also must set up a governing body comprised of four representatives of power generators, four representatives of transmission and distribution operators, four representatives of businesses that sell power, and three members representing consumers.

Appendix B: 2015 PUC Complaint Data

**Originally published as a TCAP Snapshot Report, October 2015*

Electricity complaints filed with the Texas Public Utility Commission have fallen to a new post-electric deregulation low, according to a review of agency data.

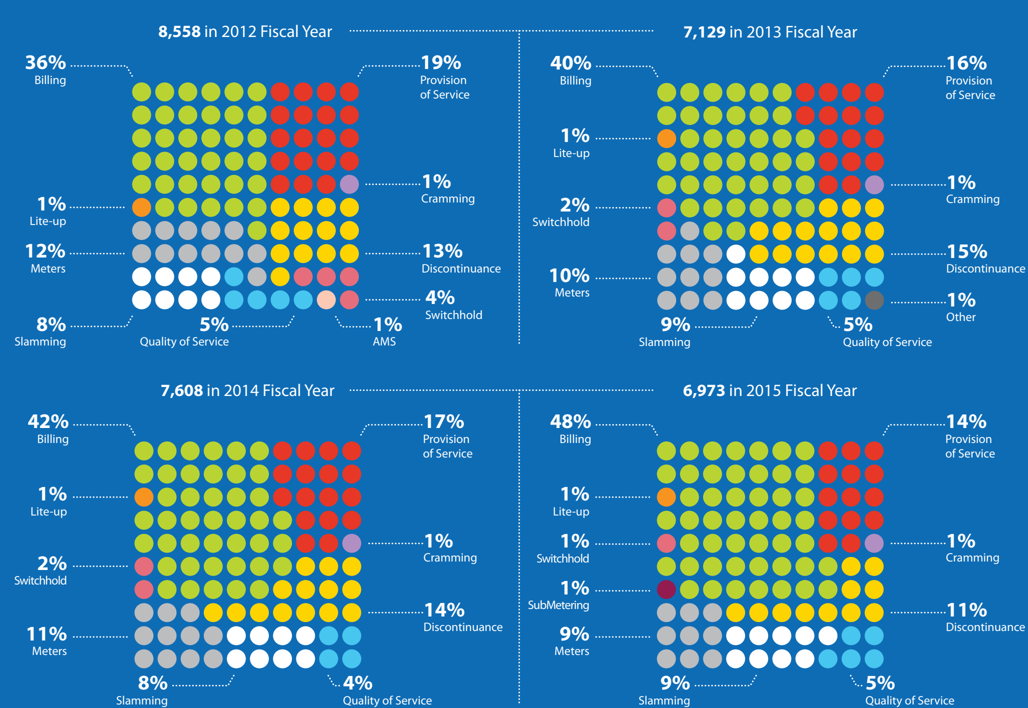
All told, Texans filed 6,973 electricity-related complaints or inquiries during the most recent fiscal year. The previous low during the electric deregulation era came in FY 2013, when the PUC tallied 7,129 complaints and inquiries. The state deregulated most of its retail electricity market in 2002.

But despite the encouraging numbers, complaints remain more numerous now than they were prior to the switch to deregulation. Also less encouraging is the dramatic uptick in complaints filed in FY 2015 against a single electric company — Dallas-based Sharyland Utilities.

This Snapshot Report is based upon a review of electricity complaints and inquiries filed with the PUC's Office of Customer Protection, which was established in July 1997. The Texas Coalition for Affordable Power reviews this data on an annual basis.

All data are given for fiscal years and have been obtained under the Texas Open Records law or extrapolated from publicly available PUC reports and from newspaper accounts. Data for 1998, 1999 and 2000 are estimated figures. TCAP considers both complaints and inquiries in order to gauge general consumer sentiment and also to maintain a uniform methodology across the study period.

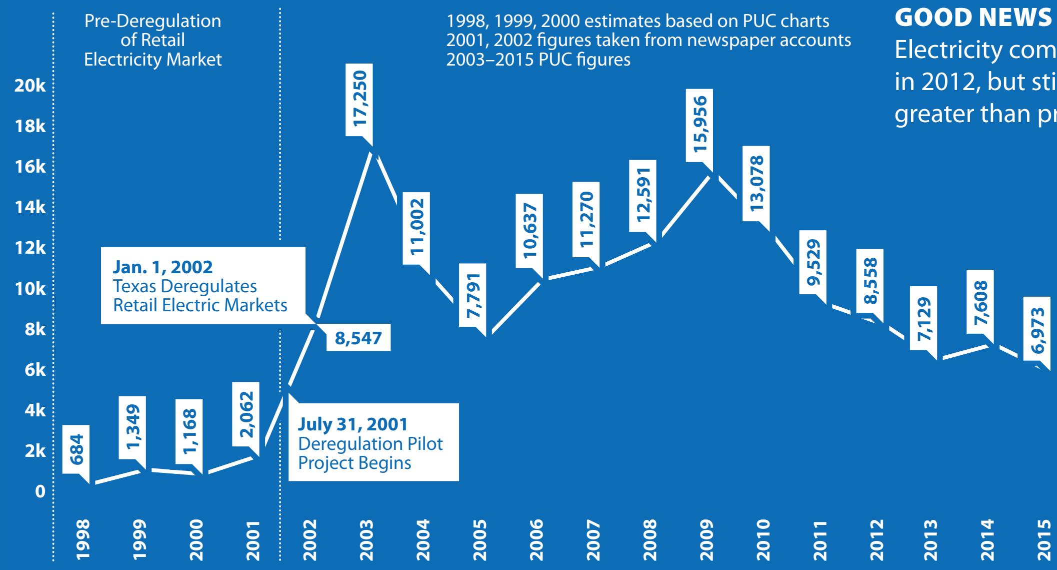
Electricity Complaints Filed with Texas PUC



KEY FINDINGS:

- The PUC recorded 6,973 electricity-related complaints or inquiries during the 2015 fiscal year. That's the fewest tallied by the agency since retail electric deregulation began in 2002.
- The average number of electricity-related complaints or inquiries filed on an annual basis since the retail electric deregulation law took effect is 10,566. The highest number of complaints filed during a single fiscal year was 17,250, during the second year of the retail electric deregulation law.
- The average number of electricity-related complaints and inquiries filed with the PUC during each fiscal year prior to electric deregulation was 1,315.8. However, there are only four years of data for that analysis.
- The average number of electricity-related complaints and inquiries filed with the PUC during each fiscal year prior to electric deregulation was 1,315.8. However, there are only four years of data for that analysis.
- Complaints quadrupled with the transition to deregulation in 2002 and have never returned to pre-deregulation levels. Although population growth and the increased use of the Internet to facilitate the complaint process can explain some of the increase, it's unlikely that those factors alone account for the dramatic differences — especially those registered during the early years of the deregulation law.
- Although Texans filed fewer complaints in FY 2015 than they did in FY 2014, they nonetheless received more complaint-generated refunds in FY 2015 than during the previous year. According to PUC records, Texans who filed complaints with the PUC received $450,183 in refunds during the 2015 fiscal year, or about 6.7 percent more than the $421,862 awarded during the 2014 fiscal year.
- The plurality of complaints and inquiries submitted to the PUC in FY 2015 relate to electric bills. Approximately 48 percent related to billing and another 14 percent related to provision of service. In FY 2014, 42 percent related to billing and 17 percent related to provision of service.
- The PUC received more than nine times the number of complaints and inquiries against Dallas-based Sharyland Utilities in FY 2015 than it received against the Dallas-based company in FY 2014. Sharyland serves retail customers in West Texas. Most of the complaints and inquiries relate to rates and bill charges.
- Complaints and inquiries were up from last year in a few discrete categories — including a nearly 5 percent increase related to billing. In FY 2015, billing complaints and inquiries numbered 3,332. That's up from the 3,178 in FY 2014 and 2,862 in FY 2013.
- The PUC in FY 2015 registered 953 complaints or inquiries for provision of service, 772 for discontinuance of service, 651 for meters and 628 for slamming, which is the practice of switching a consumer's service provider without authorization.
- The practice by some companies of ordering holds on customer accounts generated 82 complaints in FY 2015. Under controversial "switch hold" rules approved by the PUC, some households can be barred from the retail electric market if they get behind in their payments or if they are accused of tampering with their utility meters.
- According to recent weighted complaint rankings from the PUC (as of March 1, 2015 through August 31, 2015), retail electric providers with the worst complaint rankings included TruSmart Energy (formerly DPI Energy), Hino Electric, Potentia Energy (also known as Verde Energy) and Brooklet Energy Distribution (also known as Acacia Energy).
- Potentia and Hino also were among companies with the highest complaint ratings in a survey last year. Acacia Energy was among those with the highest complaint rates in a survey reported last year and in 2013. DPI Energy was among those with the highest complaint rates in surveys in 2014, 2013 and 2012.
- According to recent weighted complaint rankings from the PUC (as of March 1, 2015 through August 31, 2015) retail electric providers with the best complaint rankings were MP2 Energy Texas, Alliance Power (APC Electric), MidAmerica Energy, Iluminar Energy (Conservice Energy), Nueces Electric Coop (NEC Retail), Andeler, Hudson Energy Services, Our Energy, TXU Energy, WTU Energy and Reliant Energy.
- Alliance Power and MP2 Energy Texas also were among those with the best complaint rankings in a survey last year.

Customer Complaints



GOOD NEWS / BAD NEWS STORY
Electricity complaints continue decline in 2012, but still more than five times greater than pre-deregulation average.

UPBEAT NUMBERS FOR FY 2015

The FY 2015 data suggest that, overall, electric customer sentiment in Texas is improving. This year's findings build upon similar upbeat analyses conducted by TCAP during FY 2014 and FY 2013.

For instance, other than the 2015 fiscal year, the two post-deregulation years in which the PUC registered the fewest electricity complaints and inquiries were FY 2014 and FY 2013. The PUC tallied about 2 percent fewer electricity-related complaints and inquiries during FY 2015 than it tallied in FY 2013, the previous low-water mark during the deregulation era.

The PUC also reported a drop in various discrete categories of electric complaints over the last fiscal year. These include a drop in meter complaints, provision of service complaints and those relating to "switch-holds," which is the practice of blocking residential electric service.

While Texans filed fewer complaints in FY 2015, they nonetheless received more complaint-driven refunds in FY 2015 than during the previous fiscal year, according to PUC data.

However, one clear area of customer dissatisfaction relates to Sharyland Utilities, which is owned by the same party seeking to control the Oncor Electric utility as its parent Energy Future Holdings emerges from bankruptcy. Complaints against Sharyland skyrocketed to 437 in FY 2015 from 47 in FY 2014.

The complaints against the tiny utility were so numerous in 2015 that the Texas Public Utility Commission opened a special proceeding that resulted in a slight rate decrease for some customers.

For this analysis, TCAP reviewed all electricity-related complaints and electricity service inquiries reported to the PUC for each fiscal year since 1998. This analysis does not tabulate complaints filed directly with electric companies.

Texans can find complaint data for individual retail electric providers at the state's electricity shopping website, powertochoose.org. On the site, companies are assigned weighted complaint rankings that take into account both the number of customers the company serves and the number of complaints the PUC has received about that company.

Sharyland Complaints Skyrocket

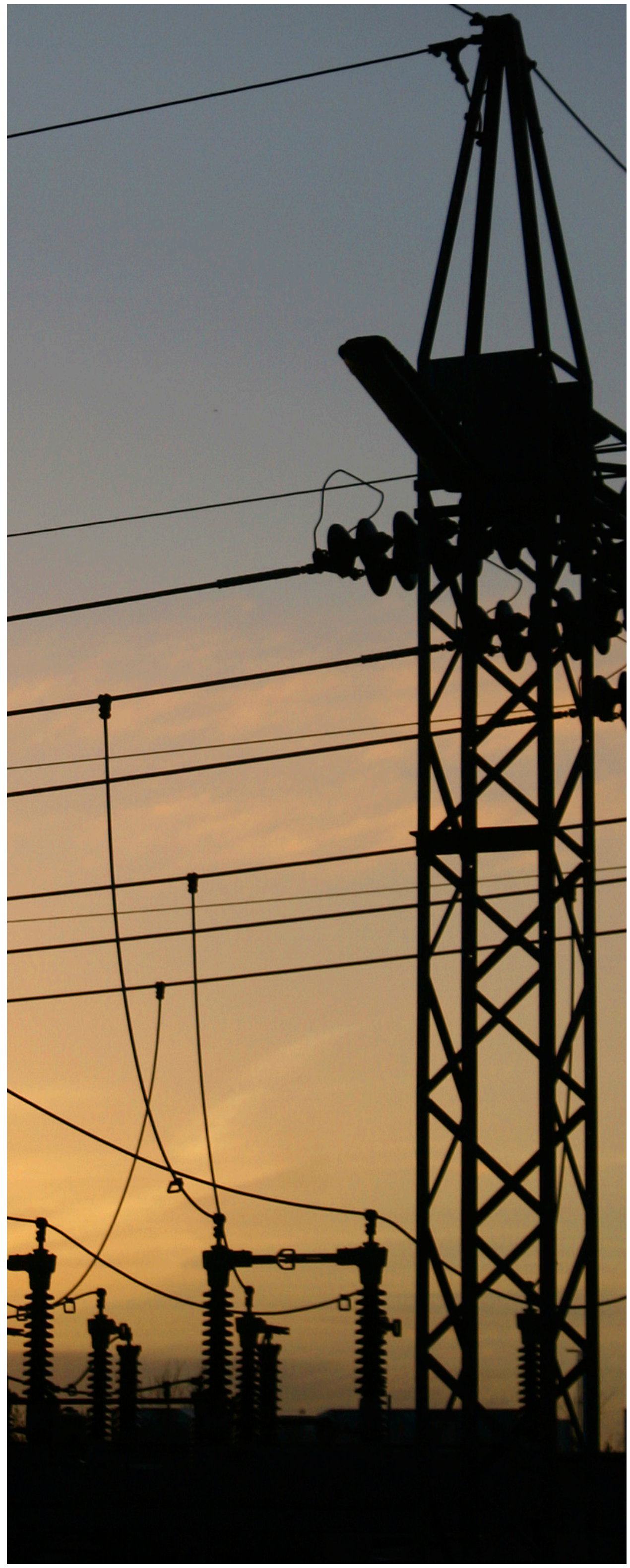
Media reports describe Sharyland electric bills as two or three times higher than those typically found elsewhere. In October, the PUC authorized a slight decrease in Sharyland rates.1 The owners of Sharyland are in negotiations to purchase Oncor, the state's largest transmission and distribution utility.[1]

How to Lodge a Complaint with the PUC

Under the PUC's complaint process, customers can file a complaint against a company with the agency's Office of Customer Protection. Agency employees then make an inquiry with the company, which has 21 days to respond. A PUC investigator evaluates the company's response to determine whether it failed to follow the law.

The Office of Customer Protection can be reached by calling 1-888-782-8477, by email at *customer@puc.state.tx.us*, or online at *puc.state.tx.us/consumer/complaint/Complaint.aspx*.

Texans can also review specific complaint data for competitive electric providers at powertochoose.org. TCAP recommends that consumers always check this complaint data when shopping for electricity.



Appendix C: Excess Mitigation Credits

The Public Utility Commission responded to the collapse of House Bill 2107 in 2001 with a decision that ultimately increased prices for ratepayers. In November, not long after the end of the 77th legislative session, the PUC ordered the payment of what became known as "excess mitigation credits." Termed "EMCs" in the alphabet soup of ratemaking, these credits represented the value of refunds that would have gone back to ratepayers had the Legislature adopted HB 2107 (the start of this section). But instead of flowing back to ratepayers, the PUC sent the money (through an indirect process) to electric retailers. These retailers had never suffered from the stranded cost overcharges, and yet they would now benefit from them. In many cases, the retailers were financially affiliated with the companies that were ordered to pay the EMCs.

HOW THEY WORK

Under the PUC-initiated excess mitigation credit ruling, generation companies affiliated with the incumbent monopoly provider that presumably over-collected for stranded costs were directed to return the money (in the form of EMCs) to transmission and distribution companies. Those transmission and distribution companies, in turn, were directed to make a corresponding reduction in rates they charged to electric retailers. But the retailers were not required to pass those savings onto customers. In fact, in some cases they were actually prohibited from doing so.

Remember: under SB 7, retailers affiliated with the state's traditional utilities charged the Price To Beat rate. Setting aside adjustments for fuel costs, the Price To Beat was a fixed rate. Customers on the Price To Beat paid that rate and only that rate — no more, no less — which meant they could not receive EMCs. But the Price To Beat retailers who served them were receiving almost all of the excess mitigation credits because these retailers then controlled 85 to 95 percent of the residential market. Said another way: the Price To Beat retailers took the EMCs but were prohibited by rule from passing along the benefit to their residential customers.

Because the retailers charging the Price To Beat typically remained affiliated with the incumbent generators who owed the excess mitigation credits, the effect of the PUC order was to require companies to take money due to ratepayers and instead pay it to a separate arm of the same company, a transfer sometimes characterized as moving ratepayer money from one company pocket to another.

The PUC ordered the collection of $55 million in excess mitigation credits from Central Power & Light in South Texas, $1.24 billion in excess mitigation credits from the predecessor of Houston's CenterPoint Energy and $888 million in excess mitigation credits from TXU in North Texas. Although most of this money ended up with retail electric providers affiliated with the state's traditional utilities, some of it ended up with competitive electric providers. The PUC argued that the competitors could use the money to lower prices and potentially steal away more customers. But there's little evidence that this worked or that these competitive retailers did anything but pocket the windfall.

The Public Utility Commission's EMC rule also led to even greater consumer expenditures in 2005, during final stranded cost decisions that year. (For more about stranded costs, see page 66.)

Under Senate Bill 7, consumers would end up paying: the expense of excess mitigation credits from which they derived no benefit, the expense of reimbursing energy companies for supposedly uneconomic investments that actually ended up becoming quite profitable for those companies, and the expense of overpriced power in the restructured market.

Here's how consumers lost with Excess Mitigation Credits and Stranded Costs:

1. Senate Bill 7 contemplated that as a result of deregulation, ratepayers eventually would owe stranded cost payments to utilities. The 1999 legislation provides methods for mitigating presumed future stranded costs by allowing utilities to overcharge ratepayers in the run-up to deregulation. For ratepayers in the Houston area, stranded costs will add about $7.30 to monthly bills for many years to come. Ratepayers in other parts of the state also face hefty stranded cost awards. (For more about stranded costs, see the chart on page 66.)
2. But in 2001, the PUC made a determination that utilities instead could face "negative" stranded costs — and as a consequence, it appeared that ratepayers were needlessly making overpayments to utilities.
3. This prompted the PUC to order generators to surrender the stranded-cost related overcharges they had received to that point. The refund of these overcharges became known as "excess mitigation credits." But because the Price To Beat prohibits any discounts, most of the credits went into the pockets of the electric retailers. Most customers weren't able to benefit.
4. Beginning in 2004, the PUC reversed course again and found that electric companies did not face negative stranded costs but rather positive ones. That is, the PUC agreed with electric companies — despite great evidence to the contrary — that key generating assets lost value in the transition to deregulation.
5. This finding, in turn, led the PUC to determine that the excess mitigation credits awarded in 2001 were unwarranted and should be returned.
6. The value of those credits — more than $2 billion — was added to already questionable stranded cost bills faced by ratepayers. This meant that ratepayers, most of whom never received the benefit of the excess mitigation credits in the first place, were nonetheless on the hook for paying them back. All told, the value of stranded costs in Texas (including the value of the excess mitigation credits) has been estimated at more than $6.5 billion. For ratepayers in the Houston area, stranded costs will add more than $7 to monthly bills for many years to come. Ratepayers in other parts of the state also face hefty stranded cost charges. (For more information about stranded costs, see chart on opposite page).
7. Meanwhile, the nuclear and coal plants that created billions of dollars in presumed stranded costs for electric companies end up becoming quite profitable in the newly restructured market. Instead of becoming uneconomic burdens, the plants proved to be efficient producers of relatively inexpensive power. But under the structure of the deregulated market, such relatively inexpensive coal and nuclear power got re-priced for retail customers as if generated by more costly natural gas-fired plants. Ratepayers lost again.

Appendix D: Unbundling

Under Senate Bill 7 vertically-integrated utilities operating within the ERCOT region were required to split into three discrete entities: generation companies, the still regulated transmission and distribution utilities, and retail electric providers. Under this "unbundling" provision, these entities were required to function separately — even if they remained under the same corporate ownership.

GENERATION COMPANIES

Under deregulation, generation companies are expected to compete with one another on price. However, some generation companies have begun pressing for price supports, claiming the current deregulated system is not providing them with enough revenue to justify new investment.

TRANSMISSION AND DISTRIBUTION UTILITIES

The power produced by generation companies travels across the system of wires owned by transmission and distribution utilities. These "wires" companies retain their monopoly status, and remain regulated under Senate Bill 7. The wires companies in recent years have obtained legislative changes that allow them to hike rates more rapidly, and with less regulatory oversight. These extra charges are passed onto retail electric providers, which then pass them onto end-use customers.

RETAIL ELECTRIC PROVIDERS

Senate Bill 7 allows for competitive Retail Electric Providers to sell power directly to home consumers. REPs are free to set their own price for power.

Texans have remained confused about the deregulated system. An industry survey in 2011 found that a majority of Texans did not clearly understand the division between their deregulated retail electric provider and their regulated transmission and distribution provider. Complaints filed against electric companies with the PUC also have increased significantly over pre-deregulation levels.

How electricity flows to its users

Major regulatory players

PUC (Public Utility Commission of Texas)
- Where applicable, sets rules for the deregulated electricity market
- Regulates investor-owned utilities within Texas but outside of the ERCOT service territory
- Implements electric and telecommunications legislation
- Oversees development of regulated transmission and distribution system for electricity
- PUC commissioners are appointed by the governor

ERCOT (Electric Reliability Council of Texas)
- A quasi-governmental organization
- Funded by ratepayers but technically a non-profit corporation managed by market participants
- Is overseen by the PUC

How electricity is sold (in a deregulated market)

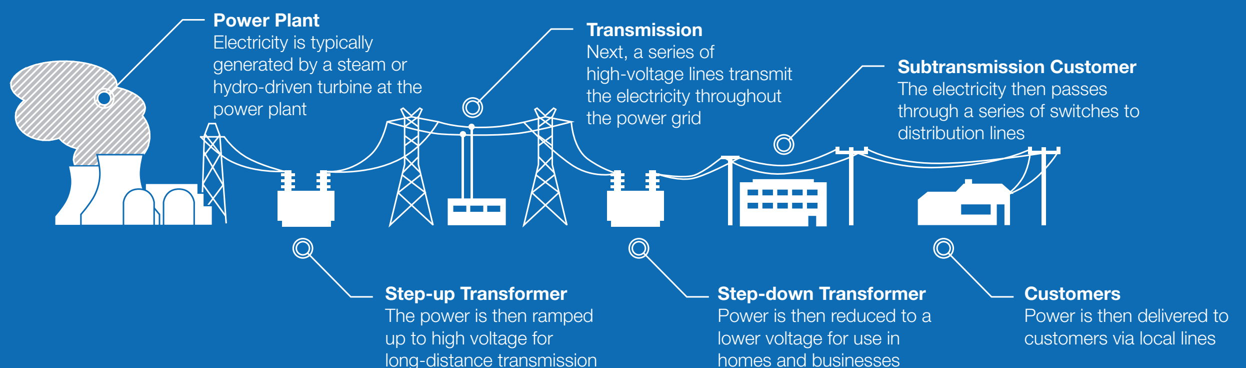
Power Plant
Power generation companies own and operate power plants, including nuclear plants or those fueled by natural gas, coal or from renewable resources such as the wind. Power generation companies sell their power in the wholesale market, where prices are deregulated.

Retail Electric Providers
REPs purchase electricity from power generation companies and sell that power to residential and business consumers. Electricity at the retail level is deregulated, meaning that REPs are free to set their own prices.

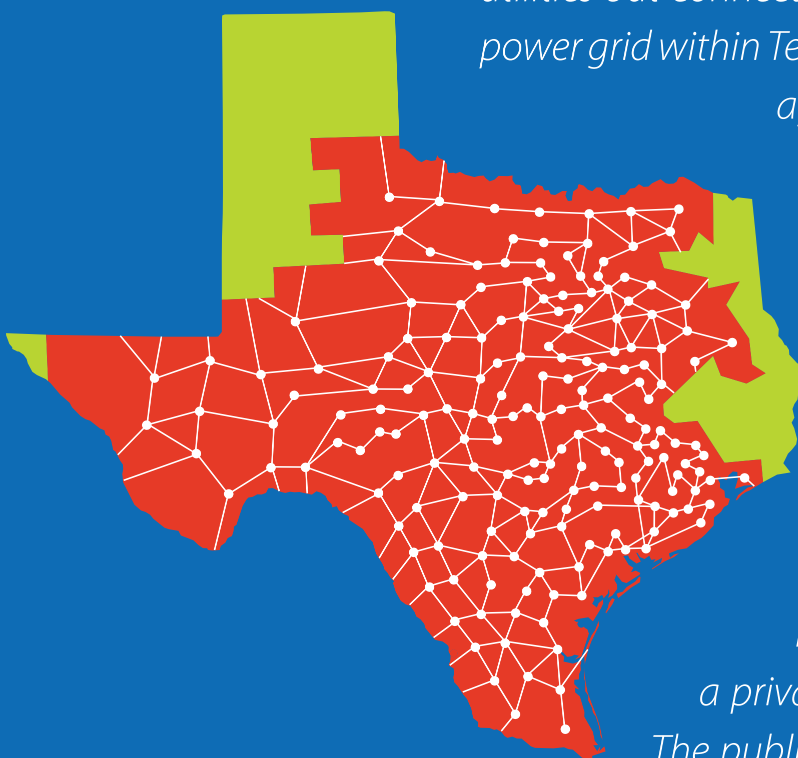
Transmission and Distribution Utilities
Transmission and distribution utilities own and operate the poles and wires that transport electricity in Texas. TDUs are monopolies, and remain regulated by the Public Utility Commission.

Your Home
Home consumers in deregulated areas of the state such as Houston or the Dallas/Fort Worth areas can choose between different electricity deals.

Flow of electricity



Appendix E: Electric Reliability Council of Texas



The network of transmission lines owned by different utilities but connected to each other forms a single power grid within Texas. The organization that manages most of this network is known as ERCOT, the Electric Reliability Council of Texas. There are two other power grids in the United States — an Eastern grid and a Western grid — but ERCOT is an island unto itself with only limited connections to the other grids. ERCOT is not a government agency, nor a private business, nor a court of law. The public does not elect its leaders, and yet those leaders make some of the state's most important public policy decisions. ERCOT does not spend tax dollars, and yet its policies impact what is inside every Texan's wallet. ERCOT decisions impact the health and welfare of all Texans, can benefit or greatly undermine the state's economy, and can mean the difference between massive blackouts or reliable service.

WHAT IS ERCOT?

Technically a non-profit corporation, ERCOT was created by the state in 1970. It has responsibility for managing the flow of power across 38,000 miles of transmission lines to more than 21 million Texans. It facilitates operations of the wholesale electricity market, supervises transmission planning, ensures that there is always adequate power on the grid and takes action to minimize congestion on transmission lines.

ERCOT has an approximately $171 million annual budget, which is financed through charges on electric bills. Stakeholders — that is, representatives of electric generators, transmission companies, consumers and other interested market participants set ERCOT policy and determine the rules by which the wholesale market operates.

WHAT ARE ERCOT'S RESPONSIBILITIES?

ERCOT functions both as the technical operator for the transmission grid and a decision-making organization that creates rules for the wholesale electricity market.

As an independent system operator, ERCOT employs technicians and engineers at two control centers in the Austin area. Using complex computer systems, ERCOT manages the flow of electricity on the grid by continually ordering generators to ramp up or ramp down production to match the amount of power demanded by consumers during any given 5-minute period. Because of the physics of electricity, if the amount of power scheduled to be consumed is not exactly in sync with the amount of power to be produced then load and generation become unbalanced, and blackouts can result.

ERCOT technicians also take actions to control congestion on transmission lines. During emergency situations, these actions can include the curtailment of electricity to certain big customers and the implementation of limited rolling blackouts.

As a decision-making forum, ERCOT depends upon interested market participants to study, debate and ultimately recommend or reject complicated wholesale market rules. These stakeholders — men and women representing power generators, commercial customers, industrial users, retailers and other interested parties — make recommendations to the full ERCOT board, which in turn makes binding decisions for the market.

ERCOT Board decisions can be overturned only by the Texas Public Utility Commission. The PUC also has limited authority over the ERCOT budget and general operations.

Because ERCOT's transmission grid serves only Texas and does not cross state lines, there is minimal federal jurisdiction that applies to ERCOT's day-to-day market operations.

HOW DOES ERCOT MAKE DECISIONS?

The most important and frequently made decisions by stakeholders involve ERCOT protocols, which are the complicated rules that govern the wholesale electricity market. Revisions to ERCOT protocols typically begin within a work group or task force. ERCOT work groups and task forces are comprised of interested stakeholders who make decisions by consensus. From there, recommended protocol changes go to the "Protocol Revision Subcommittee," then to the "Technical Advisory Committee" and finally to the ERCOT Board of Directors, which usually has the last word.

The ERCOT Board of Directors is made up of 16 men and women, most of whom represent various segments of the market. ERCOT stakeholders from each of those segments elect their own Board representatives. Non-voting board seats are reserved for the chief executive officer of ERCOT and the chairperson of the Texas Public Utility Commission.

Appendix F: Understanding Texas Wind Power

**Originally Published as a TCAP Snapshot Report, Aug. 2, 2012.*

The Lone Star State leads the nation in wind-generated power. *With an installed capacity totaling 10,648 megawatts in 2011, Texas boasts a fleet of wind generators dwarfing that in any other state. But while it appears likely that wind power may lower some wholesale energy costs, such potential savings may be outweighed by other necessary expenses. Wind power also presents tough challenges for the operators of the state's power grid. The Texas Coalition for Affordable Power offers this mini-report as a quick and easy primer on these and other issues. What you'll find here are key statistics, historical context – and a wide variety of views from the experts. As a matter of policy, TCAP supports the use of wind power, but urges regulators, lawmakers and other decision makers to remain mindful of the associated costs and reliability challenges.*

WIND POWER AND THE ENVIRONMENT

Various academic studies have concluded that the use of wind power reduces potentially harmful Carbon Dioxide (CO2) emissions. For instance, a study by R. Gross of the Imperial College of London states unambiguously "that wind energy can displace fossil fuel-based generation, reducing both fuel use and carbon dioxide emissions." Similarly, the National Renewable Energy Laboratory, in a 2008 report for the U.S. Department of Energy, noted that "choosing to build wind projects results in CO2 reductions from fewer new coal plants built and less natural gas consumption." A separate report by the U.S. Department of Energy examining the feasibility of expanded wind energy use through 2030 also predicts related drops in CO2 emissions.

However, many of the relevant studies assume that units of CO2-free electricity created by wind turbines have the effect of offsetting units of fossil-fuel electricity on a one-to-one basis. Separate research has found that this is not necessarily the case. In a 2006 study, the Institute of Electrical and Electronics Engineers (a non-profit professional association) found that fossil-fuel plants that provide backup power for wind generators must operate in ways that produce more emissions than they wound produce under ordinary circumstances. "Thus, it may be that some environmental benefits from wind power may be negated by an increase in emissions from combustion plants accommodating wind generation," the report stated. Similarly, physicist and mathematician Herbert Inhaber, in a report published in the Renewable and Sustainable Energy Reviews, concludes that "as wind penetration increases, the CO2 reduction will gradually decrease due to cycling of fossil fuel plants" that must be kept running and ready to produce energy when the wind stops blowing.

DOES WIND POWER SAVE MONEY FOR CONSUMERS?

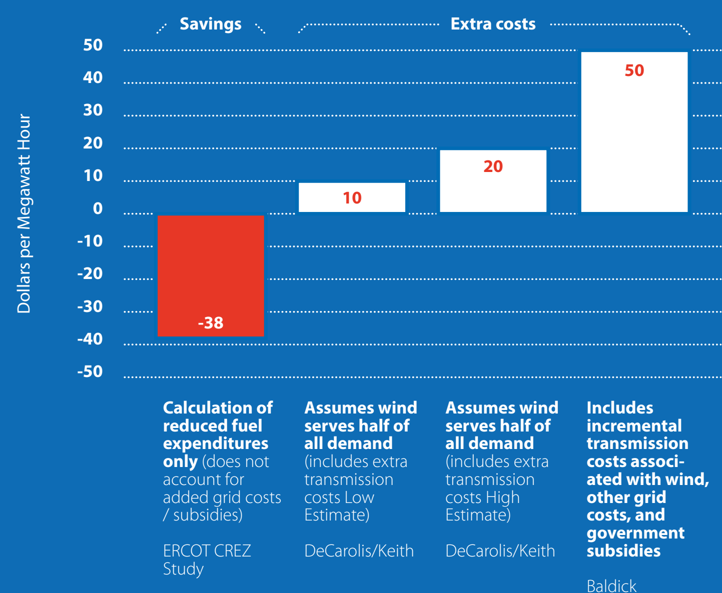
Whether wind power results in savings or extra costs for consumers is a question of perspective. For instance, wind generators have zero fuel costs and receive public subsidies in the form of tax credits for up to two-thirds the value of wind turbines, according to some estimates. As a consequence, wind generators often bid their power into the state's spot wholesale energy market at levels below what would otherwise be the prevailing marginal cost of energy set by the state's natural gas plants. Because of the nature of the deregulated electricity market, these lower wind prices on the spot market can then put downward pressure on wholesale spot energy prices overall.

This effect is most often observed in West Texas, where there exists a high concentration of wind turbines and insufficient transmission lines to move that energy into more populated areas of the state. West Texas wind producers even occasionally bid their power into the wholesale spot energy market at negative prices. A 2008 study by ERCOT concluded that Texas should save $38 per megawatt-hour in average fuel costs from wind power, assuming the completion of new power lines to serve those wind turbines in West Texas. That would equate to monthly savings of about $38 for a typical household, assuming the savings trickle down to the retail level.

However, such calculations do not tell the whole story. According to a 2008 report from the Texas Comptroller of Public Accounts, wind generators receive larger federal subsidies, as measured as a proportion of their sales, than do natural gas and coal-fired generators. Consumers also must pay the incremental cost of wind-related transmission construction and grid-reliability services. Joseph F. DeCarolis and David W. Keith, writing in the 2006 edition of Energy Policy, conclude that such incremental costs will only increase as the use of wind energy also increases. "We find that, with somewhat optimistic assumptions about the cost of wind turbines, the use of wind to serve 50 percent of demand adds 1-2 cents per kilowatt-hour to the cost of electricity, a cost comparable to that of other large-scale low-carbon technologies." Ross Baldick, a professor in the Department of Electrical and Computer Engineering at the University of Texas-Austin, calculates that the total unsubsidized cost of new wind energy in Texas at about $105-$110 per megawatt-hour. This figure includes the incremental cost of transmission lines to serve wind generators and extra charges to account for the intermittent nature of wind. He also accounts for the cost of federal tax subsidies. Thus, "wind adds about $50 per megawatt-hour to costs," concludes Dr. Baldick.

Wind Power: Saving money for Texans or costing more?

DIFFERENT ASSUMPTIONS, DIFFERENT CONCLUSIONS



7 KEY THINGS TO KNOW ABOUT WIND ENERGY

FACT #1
TEXAS LEADS THE NATION FOR WIND POWER

Texas in 2011 was home to more than 10,000 megawatts of installed wind capacity, which is nearly three times that of any other state. Texas has more installed wind power capacity than all but five countries worldwide.

FACT #2
WIND POWER HAS ZERO FUEL COSTS

The wind blows free, which means that wind generators can sometimes bid into the wholesale spot energy market at very low prices. Because of federal tax credits, wind generators sometimes bid their energy into the spot market at negative prices. This sometimes reduces overall spot market prices for electricity In Texas, in particular in the western part of the state where there exists a high concentration of wind generators.

FACT #3
FACTORS OTHER THAN FUEL CAN DRIVE UP THE FINAL PRICE FOR WIND POWER

Consumers pay a number of incremental costs associated with wind energy, including the costs of extra backup power because wind turbines can quit suddenly when the wind stops blowing. Wind energy also receives taxpayer-supported subsidies and Texans are on the hook for billions of dollars in wind-related transmission projects. Also, because of the structure of the deregulated wholesale market in Texas, wind generators that submit relatively low-cost bids into the spot market typically receive higher-than-bid prices.

FACT #4
DEVELOPMENT OF TRANSMISSION FOR TURBINES WILL COST BILLIONS MORE THAN ANTICIPATED

ERCOT initially estimated the cost of transmission lines to serve the state's growing wind fleet at $4.9 billion. Those projected costs were understated by nearly $2 billion. All told, every customer within the areas of the state's principal power grid is on the hook for more than $1,000 to pay for the transmission lines.

FACT #5
WIND POWER CAN PROVIDE ECONOMIC BENEFITS TO LOCAL COMMUNITIES

Texas landowners that have wind turbines on their property typically receive ongoing compensation in the form of royalties, operating fees or monthly production payments. Landowners receive one-time payments for electric transmission lines that pass across their land, plus damages for lost property value. As with the case for other sorts of generating plants, the construction, maintenance and operation of wind generators also creates jobs, which in turn produces income for local businesses and communities.

FACT #6
WIND GENERATION CANNOT BE DISPATCHED AS RELIABLY AS MANY OTHER SOURCES OF ENERGY

For planning purposes, the organization that operates the state power grid counts on the state's wind power fleet to produce at less than 9 percent of its capacity during peak summer periods. Official figures show that wind comprises nearly 12 percent the overall generation capacity in Texas, but wind generators provide just 1.1 percent of available capacity during summer peaks. This makes wind power, at peak, much less dependable than energy from natural gas-fired plants, coal plants, nuclear plants or even biomass sources.

FACT #7
WIND POWER CANNOT COMPLETELY REPLACE OTHER GENERATION SOURCES

Because of the variability of the wind, fossil-fueled power plants are needed to provide replacement power. These plants are typically fueled by natural gas. This means that wind power can periodically displace the use of fossil- fuel plants, but with current technology cannot completely displace the construction of them.

WIND POWER AND RELIABILITY CHALLENGES

By its very nature, wind is fickle. It blows one moment, cuts off the next.

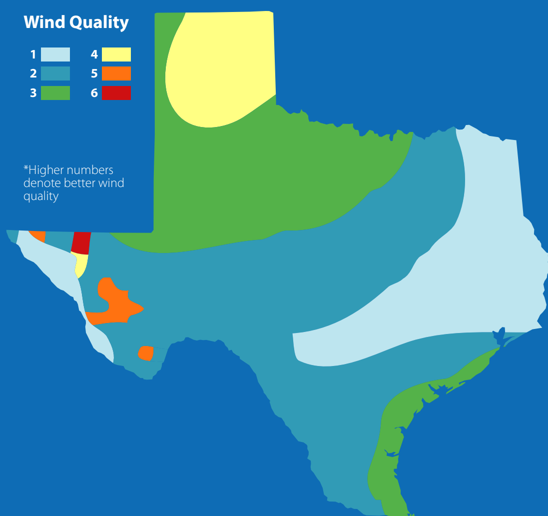
Because ERCOT must keep electricity supply and demand exactly balanced at all times on the grid, this intermittent nature can create challenges for the organization. In February 2008 a sudden drop off of wind coupled with other factors nearly led to blackouts. ERCOT also faced another near reliability crisis in January 2010 caused, in part, by the variability of wind.

The reliability challenges posed by the state's growing reliance on wind power have been acknowledged by the Texas Public Utility Commission, ERCOT and outside experts. In its 2011 Scope of Competition Report to the Texas Legislature, the PUC also noted that wind generators typically do not provide the same level of technical support to bolster grid reliability as is provided by traditional generators. Jay Zarnikau, an adjunct professor at the LBJ School of Public Affairs at the University of Texas-Austin, has noted that many wind generation operators have had little prior experience with electric operations. ERCOT has stated that such a "lack of understanding regarding the details of certain operational procedures … produced inconsistent results in unit responses to instructions and introduced operational challenges" for the organization's operators.

However ERCOT also has taken steps to mitigate many of these challenges. For instance, the grid operator adopted more advanced wind forecasting methods after the January 2010 incident. As a matter of policy, ERCOT also deliberately under-forecasts wind power output while simultaneously over-forecasting demand. The PUC has noted that various technical improvements on new turbines and the retrofitting on old ones may help mitigate some of the challenges.

Wind Classification

Source: seco.cpa.state.tx.us



FROM THE STATE ENERGY CONSERVATION OFFICE:

"The Panhandle contains the state's greatest expanse with high quality winds. Well-exposed locations atop the caprock and hilltops experience particularly attractive wind speeds. As in all locations throughout the state, determination of areas appropriate for development must include consideration of environmental and social factors as well as technical viability.

South of Galveston, the Texas coast experiences consistent strong sea breezes that may prove suitable for commercial development.

The mountain passes and ridgetops of the Trans-Pecos exhibit the highest average wind speeds in Texas. Since the wind in mountainous terrain can change abruptly over short distances, the best wind farm locations in West Texas are quite site specific."

THE DEVELOPMENT OF WIND POWER IN TEXAS

The use of wind power in Texas has grown substantially over the last decade — largely the result of important state mandates, the planned construction of expensive transmission lines, and favorable treatment for wind generators in the federal tax code.

THE MANDATE

Besides deregulating the state's retail electricity market, Senate Bill 7, adopted by the Texas Legislature in 1999, also included requirements for the use of renewable energy by retail electric providers. Companies that exceeded the mandate gained an ability to sell renewable energy credits to companies that fell short.

This credit program was designed to foster the creation of 2,000 megawatts of renewable energy by 2009, or enough to power about 1.6 million homes. But Texas easily surpassed the original target and so the Legislature adopted in 2005 Senate Bill 20 setting forth new goals: 3,272 megawatts of renewable energy by 2009, 4,264 megawatts by 2011, 5,256 by 2013, 5,880 by 2015 and 10,000 by 2025. Texas exceeded those goals as well.

FEDERAL TAX INCENTIVES

According to calculations by renewable energy expert Ed Feo, wind energy developers have received tax breaks valued at as much as two-thirds of the capital cost of wind turbines. Others have placed a smaller value on such subsidies. In sheer dollars, refined coal and nuclear power receive more federal energy subsidies, but wind power leads other energy sources for the size of federal subsidies as a ratio to energy output.

However, there remains some doubt whether Congress will extend the important federal production tax credits for wind which will expire at the end of 2012. This raises questions about the future profitability of wind power. Travis Miller, a Chicago-based utility analyst at Morningstar, Inc., estimates that natural gas commodity prices must rise above $6.50 per million British thermal units for unsubsidized wind generation to remain profitable. The United States Energy Information Administration projects that natural gas prices will remain below that level for many years to come.

TRANSMISSION LINES

Senate Bill 20, in 2005, also called for the creation of special zones, known as Competitive Renewable Energy Zones, to mark the site of future transmission construction to serve wind generators. The Public Utility Commission embarked on a vigorous process to delineate the borders of these zones, eventually settling on a plan that would support 18,500 megawatts of new wind generation. In establishing this plan the PUC used estimates, produced by ERCOT, that indicate the lines would cost $4.9 billion. Cities and other groups warned that the ERCOT numbers were flawed because they did not take into account financing costs, inappropriately assumed straight-line paths for the transmission construction, and other factors.

It later became clear that the cities' concerns were quite valid. In 2011, a PUC consultant determined that the CREZ lines will end up costing nearly $2 billion more than original estimates, for a total of $6,789,775.933. All told, these new lines will cost the state's residential, commercial and industrial users more than $1,000 each. Notes one expert: "Texas could have built 6,900 megawatts of new gas-fired capacity for what the state is now spending on wind-related transmission alone."

The Cost of Transmission Lines to Serve Wind Energy

Source: Elizabeth Souder, "Texas' multibillion dollar cost to build wind energy lines raises doubts," Dallas Morning News, Dec. 5, 2011

Texas is set to spend approximately $7 billion to build transmission lines to serve wind generators in West Texas and the Panhandle. What else could $7 billion pay for?

- The electricity bills for every household in Texas for about seven months.
- The construction of about 7,000 megawatts of natural gas-fired power plant generation — or enough extra capacity to keep the lights on during an extreme heat emergency.
- 175 million fluorescent light bulbs with LED lights, which could provide enough energy savings to shut down 10 coal plants.

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APPENDIX A

Based on a reading of Senate Bill 7, found online, at http://www.capitol.state.tx.us/tlodocs/76R/billtext/html/SB00007F.htm

APPENDIX B

This analysis found in this section is based on a review of electricity-related complaints received by the PUC for the 1998 through 2015 fiscal years. The PUC did not collect this data before 1998 and also reports that it discarded pre-2003 data under its documentation retention policy. As a consequence, estimates for complaints from 1998 through 2003 were obtained through journalistic accounts: a Dec. 14, 2002 article in the *Fort Worth Star-Telegram* entitled "Complaints from power customers pile up", and a Nov. 13, 2002 article in the *Dallas Morning News* entitled "Billing errors are down, but consumer complaints are up." It also includes data culled from page 106 of the 2003 *Scope of Competition Report*, produced by the PUC. Other data was obtained directly from the PUC, through a Freedom of Information request.

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APPENDIX C

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APPENDIX D

Appendix D draws information from a review of Senate

Bill 7, as well as information from a survey on consumer attitudes conducted by The Guild Group, for AEP Retail Electric. The Guild Group report was dated November 2011.

APPENDIX E

This appendix includes information gathered from the ERCOT and from a reading of Senate Bill 7. It also includes information from an ERCOT spreadsheet, included in a Dec. 8, 2011 email from ERCOT's public information officer to the author of this report. This section references a June 26, 2012 press release from ERCOT, entitled "ERCOT board approves pilot for new demand response option, budget for 2013."

APPENDIX F

Appendix F draws from several academic reports, including the "2010 Wind Technologies Market Report," by Ryan Wiser and Mark Bolinger, of the Lawrence Berkeley National Laboratory; "The Energy Report (2008)," by the Texas Comptroller of Public Accounts, published on May 6, 2008; "The Costs and Impacts of Intermittency," by R. Gross, et al., of the Imperial College in London, published in March 2006; "Why Wind Power Does Not Deliver the Expected Emissions Reductions," by Herbert Inhaber for the 2011 edition of *Renewable and Sustainable Energy Review*; "Wind Generation, Power System Operation and Emissions Reduction," by Eleanor Denny and Mark O'Malley, for the February, 2006 edition *IEEE Transactions on Power Systems* (Vol. 21, No. 1); "The Economics of Large-Scale Wind Power in a Carbon Constrained World," by Joseph F. DeCarolis and David W. Keith, for *Energy Policy 34* (2006); "Successful Renewable Energy Development in a Competitive Electricity Market: A Texas Case Study," by Jay Zarnikau, for *Energy Policy 39* (2011) and information drawn from page 22 of the "Wind Energy Update," by Larry Flowers of the National Renewable Energy Laboratory. That report is dated Jan. 23, 2008.

Appendix F also draws from presentations given by leading energy experts, including "Wind and Energy Markets: A Case Study of Texas," presented by Ross Baldick for the April 29, 2009 National Academy of Engineering Regional Meeting in College Station, Texas. Appendix F also draws from a Dec. 15, 2004 presentation by Ed Feo to the Renewable Energy Resources Committee of the American Bar Association; and information from Chicago-based utility analyst Travis Miller, which can be found online at: http://www.hellenicshippingnews.com/News.aspx?ElementId=f021ac64-4fd8-4fb6-9ce0-d063782f47d0.

Other reports, including those from official sources, include "CREZ Progress Report No. 4 (July Update)," prepared for the Public Utility Commission of Texas, July 2011; ERCOT'S "CREZ Transmission Optimization Study," April 2, 2008; "The Report to the 82nd Texas Legislature, Scope of Competition in Electric Markets in Texas," prepared by the Public Utility Commission of Texas, January 2011; the "Texas Renewables Implementation Plan: Quarterly Update for the 3-Month Period ending March 31, 2010," for the ERCOT Renewable Technologies Working Group of the ERCOT Technical Advisory Committee, April 2010; "Economic Benefits, Carbon Dioxide Emissions Reductions, and Water Conservation Benefits from 1,000 Megawatts of New Wind Power in Indiana," produced for the U.S. Department of Energy by the National Renewable Energy Laboratory and information from the United States Energy Information Administration.

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This Appendix included information from a May 31, 2011 press release by ERCOT, entitled "ERCOT Expects Adequate Power Supplies for Summer (Update)," and wind industry statistics from the American Wind Energy Association, a trade group.

Appendix F originally appeared as a stand-alone report, which was released by the Texas Coalition for Affordable Power in August 2012. The online version of the report — and more detailed sourcing information — can be found online at http://texaswindenergy.tcaptx.com/.

About the Author

Policy analyst R.A. “Jake” Dyer has spent more than a decade monitoring consumer issues in Texas, its energy markets and ERCOT. His long journalism career included nearly a decade with the *Fort Worth Star-Telegram*, where he was named reporter of the year in 2007, and nearly a decade with the *Houston Chronicle*, where he was nominated for a Pulitzer Prize.

In 2010 Dyer authored *Natural Gas Consumers and the Texas Railroad Commission*, a report on pocketbook and policy issues. In 2011 he authored *The Story of ERCOT*, a special report on the Texas grid operator, power market and prices. His work with the Texas Coalition for Affordable Power and its predecessor organizations began in 2008.

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ELECTRICITY PRICES IN TEXAS

tcaptx.com/reports/snapshot-report-electricity-prices-texas-april-2018

A Snapshot Report
2018 Edition

Executive Summary

Although average residential electric prices in areas of Texas with retail electric competition have remained consistently higher than prices in deregulation-exempt areas — the annual percentage price gap between these two areas has dwindled to the narrowest point ever.

Moreover, average residential electricity prices in areas of Texas with retail electric competition have declined during a recent 10-year period, while average prices in deregulation-exempt areas have increased.

Taken together, these developments suggest that the 16-year-old deregulated retail electric market in Texas is delivering some of its best results so far for residential consumers.

However, not all the pricing trends are positive for Texans living in areas with retail electric competition, also known as retail electric deregulation.

For instance, average residential electricity prices have remained consistently higher in those areas, as compared to prices in deregulation-exempt areas. This has been true for every year for which data exist to conduct this analysis.

Texas implemented its retail electric deregulation law in 2002. Under it, Texans in areas such as Houston and Dallas can choose among different electric providers. In other areas that remain exempt from the deregulation law residents receive service from a single provider.

This Snapshot Report on Electricity Prices, an update of similar analyses released by the Texas Coalition for Affordable Power, compares residential electricity prices in both deregulated areas of Texas and those in areas exempt from deregulation. It includes long-term pricing information, information about non-by-passable charges assessed by Texas wires utilities and a review of pricing trends nationwide.

About the Texas Coalition for Affordable Power

Unlike the sponsors of other reports about the state's deregulated power market, TCAP derives no profit from selling electricity. Instead, the more than 150 political subdivisions that comprise TCAP purchase electricity for their own governmental needs. TCAP understands how high-cost power can cause businesses to relocate out of state, and can place heavy burdens on home consumers. TCAP wants what all Texans want: an affordable and reliable supply of power and a vibrant economy.

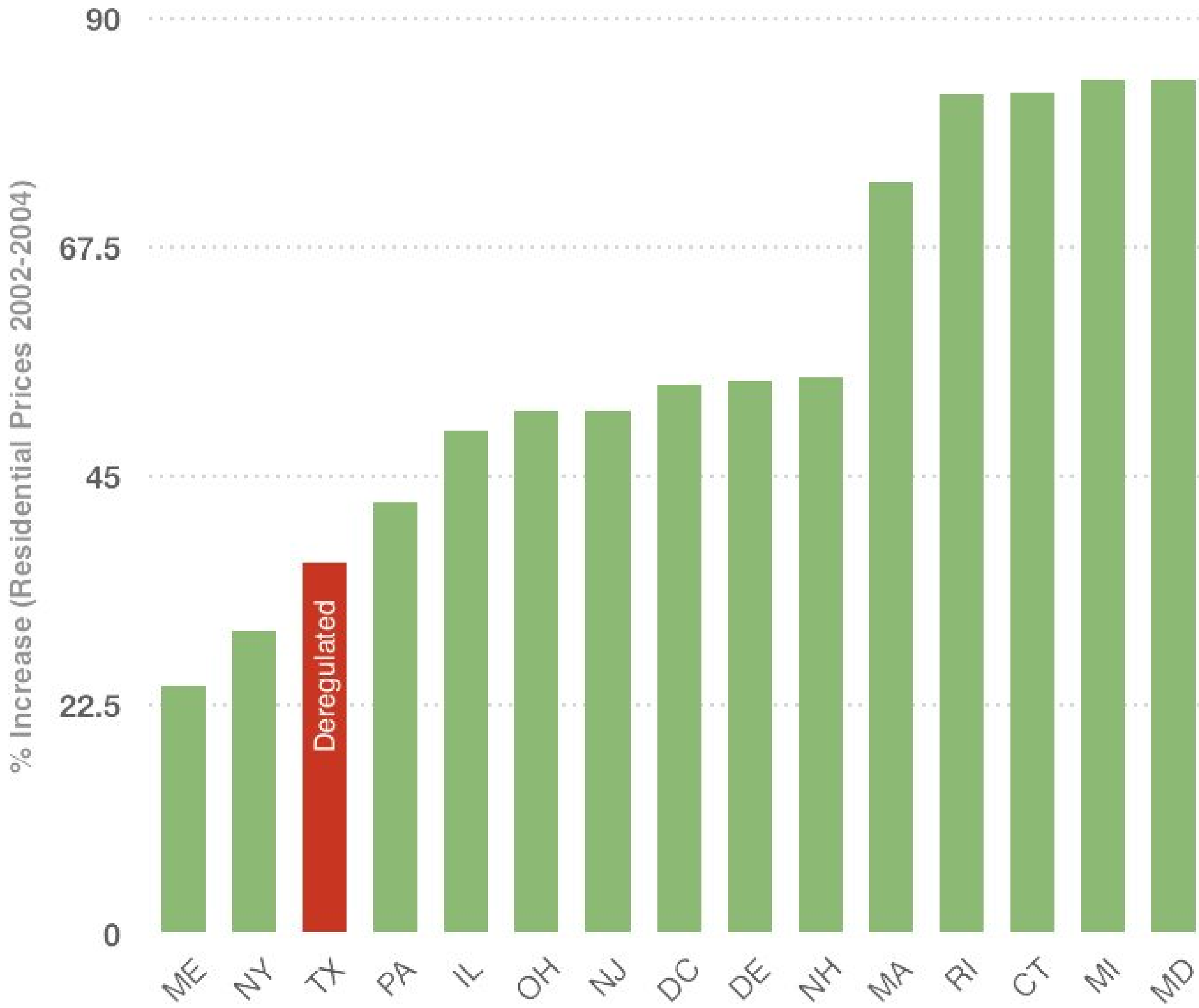
Major findings include:

- Texans consistently have paid higher average residential electric prices in areas with deregulation, as compared to prices in areas exempt from deregulation. This annual trend began during the very first year of the retail electric deregulation law in Texas, in 2002, and has continued through 2016, the last year for which data are available to conduct this analysis.
- However, *the gap* in residential electricity prices between areas of Texas with deregulation and areas without it has dwindled precipitously over the last 10 years — and the percentage gap now stands at its narrowest point since Texas began retail electric deregulation.
- Average residential electric prices in deregulated areas have declined by nearly 19.6 percent during the 10-year period from 2007 through 2016. By contrast, average residential prices in areas exempt from deregulation during the same period have increased by nearly 6.1 percent.
- Average residential prices have increased in both deregulated areas and deregulation-exempt areas over the longer term since the implementation of deregulation in 2002. However, the rate of increase has been slightly lower in deregulated areas. The percentage increase in areas with deregulation was 36.48 during that period; the percentage increase in areas without deregulation was 36.95.
- Texas continues to fare well in comparison to other states with deregulated retail electric markets. Average prices for deregulated electricity in Texas have increased at the third lowest rate among 15 states with deregulation.

- Texans now can find many low-priced individual deals inside deregulated areas that beat prices commonly paid in deregulation-exempt areas. These comparatively low-cost competitive deals are more numerous than in previous years.
- Increases in the charges assessed by the state's major regulated transmission and distribution utilities have outpaced inflation over the last 15 years. Although transmission and distribution rates are regulated, these increases nonetheless contribute to prices in deregulated areas of the state.

Residential Price Increases

Exhibit 2: For 15 Deregulated States, Including Texas 2002-2016



Source: United State Energy Information Administration Electricity Data Broswer

The Analyses

Under the Texas electric deregulation law, consumers in Houston, Dallas, Fort Worth, Corpus Christi and surrounding areas can choose among different retail electric providers. These providers compete for customers by offering different terms of service and prices. Many other parts of the state remain exempt from this competitive system. Exempt areas include those served by municipally-owned utilities (such as in San Antonio and Austin) and those served by electric cooperatives. Also exempt from retail electric deregulation are investor-owned utilities operating outside the area covered by the state's primary power grid, known as the Electric Reliability Council of Texas.[1]

The existence of this bifurcated electricity system — one in which some Texans receive service from competitive electric retailers and others do not — provides a unique opportunity to compare pricing outcomes. The Texas electric deregulation law was adopted in 1999 with the promise that it would lower rates. But as this analysis shows, the results have been mixed.

About the Report

This report includes five discrete analytical sections:

1) Benchmark Analysis of Long-Term Trends
2) Benchmark Analysis of 2016 Electric Prices
3) "Lost-Savings" Analysis
4) Transmission and Distribution Charges
5) Recent Prices

The benchmarking analyses and the "Lost-Savings" analysis employ data obtained from the United States Energy Information Administration. The long-term benchmarking and Lost-Savings analyses compare pricing outcomes inside and outside deregulated areas of Texas and begin with 2002 — the first year of retail electric deregulation in Texas — and continue through 2016. These analyses do not extend to 2017 and 2018 because the necessary US EIA data for those years are not yet available.

The Recent Prices section samples more up-to-date individual offers in deregulated areas around Houston and Dallas. Readers can find these pricing samples from 2018 rate surveys conducted by the PUC.

The section entitled "Transmission and Distribution Charges" includes rate comparisons from two separate years (2003 and 2018) for the state's two largest monopoly wires companies, Oncor and CenterPoint. Readers can find the underlying data for this analysis on the PUC website.

For readability purposes, this report employs certain words and phrases interchangeably to refer to areas served by competitive retail electric providers. These words and phrases include "areas with retail electric competition," "areas with retail electric deregulation," "competitive areas" and "deregulated areas." Unless otherwise noted, references to electricity prices are for residential customers.

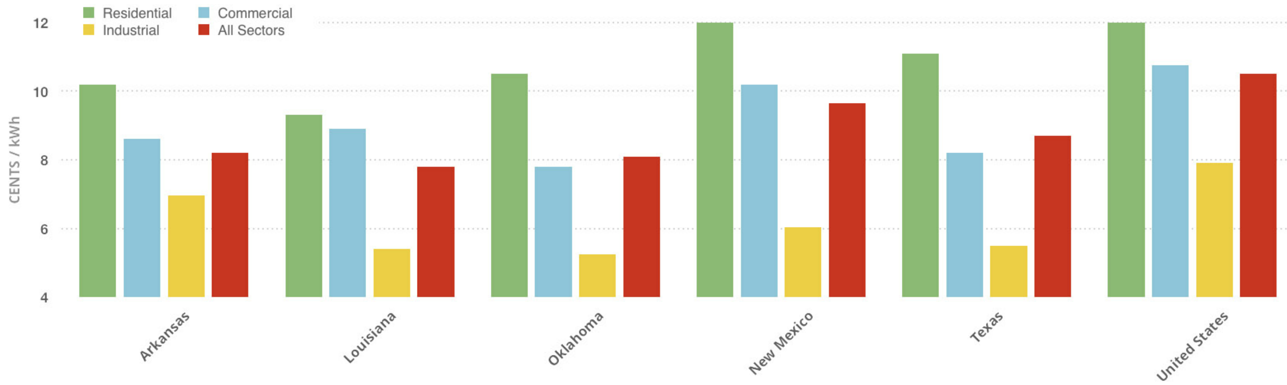
[1] See The Story of ERCOT, Februrary 2011

Background History

Texans enjoyed residential electricity rates below the national average for many years prior to the adoption of the retail electric deregulation law in 1999.[2] That trend flipped shortly after the law took effect, with average residential prices statewide rising above the national average in 2003 and remaining above the national average until 2011. [See Exhibit 8]

Average Electricity Prices 2017

Exhibit 3: Texas and Adjoining States



Source: United State Energy Information Administration & US EIA Electricity Data Browser

Some observers have said that the increase in statewide electricity prices after the deregulation law took effect is not related to the law, *per se*, but rather to an increase in natural gas prices. This is because natural gas prices are closely linked to wholesale electricity prices, and natural gas prices hit historically high levels after deregulation.[3]

However, fluctuations in natural gas prices alone cannot explain the historic disparity between average electricity prices inside and outside deregulated areas of Texas, particularly during the early years of the law. For every year for which data exist with which to conduct this analysis — that is, between 2002 and 2016 — average residential prices in deregulated areas of Texas have been higher than average prices in deregulation-exempt areas. [See Exhibit 1].

Moreover, average residential prices in Texas, statewide, remained below the national average for at least a decade prior to the implementation of retail electric deregulation in 2002. Shortly after the law took effect, in 2003, only residential prices in deregulated areas shot above the national average and for most years stayed there. Electric prices in areas exempt from deregulation continued below the national average after 2002 and, with the exception of one year, have stayed below it for the entire history of deregulation in Texas.

This report quantifies this gap in deregulated prices and those charged in areas exempt from deregulation through "lost savings" analyses found in Exhibit 4 and Exhibit 5. These analyses calculate the imputed savings that would have accrued to Texans living in areas of Texas with deregulation had they instead paid the same average prices as Texans living in areas exempt from deregulation.

Customer confusion about retail electric shopping, the details of rate offers and other aspects of the deregulated market may have contributed to historically higher prices there over time. Other contributing factors may include the cost of multi-million dollar marketing campaigns by some retail electric companies and increasing rates charged by monopoly transmission and distribution utilities. These "wires" rates comprise a growing portion of home electric bills in competitive areas.

However, the price gap between areas of Texas with electric deregulation and deregulation-exempt areas continues to narrow. In percentage terms, this differential was smaller during 2016 than during any other year since the beginning of retail electric deregulation in 2002.[4]

It remains unclear whether the gap has disappeared completely in 2017 and 2018 — or whether the trend of higher prices in deregulated areas has continued — given the unavailability of necessary data from those years for which to conduct the analysis.[5]

However, a survey of recent competitive pricing offers indicates that many such offers in Houston (the state's largest city operating under the retail electric deregulation) beat the price of electricity in San Antonio (the largest city in Texas exempt from deregulation). [See Exhibit 12 and See Exhibit 13]. The number of such offers that meet or beat prices in deregulation-exempt areas appears to be on the rise.

[3] Public Utility Commission Docket 40000, Item No.447, page 1, Memorandum to Commissioner Kenneth W. Anderson, Jr. from Chairman Donna Nelson.

[4] In absolute terms, as cents per kwh, the gap was smaller in 2002.

[5] In contrast to findings in this report, Rice University researchers, in a corrected May 2017 report, concluded that the average price paid for electricity by residential consumers in competitive areas during 2016 was "roughly equal, in the aggregate" to the average price paid by Texans in non-competitive areas. These findings appear to have been extrapolated from PUC website data, while TCAP's findings are extrapolated from US EIA data. For more about the use of US EIA and PUC Data, see the note below.

About US EIA Data and PUC Data

This analysis employs data collected by the United States Energy Information Agency, which is the statistical and analytical arm of the U.S. Department of Energy. U.S. EIA data is known to be impartial, and is widely cited by economists, scholars, industry experts, the news media and governmental agencies — including the Public Utility Commission of Texas.

The consistent manner in which the agency conducts its calculations across all 50 states allows analysts to make apples-to-apples market comparisons. How does the U.S. EIA calculate prices? First, it gathers both revenue and sales data from electricity providers in a given region. It then derives a kilowatt hour or megawatt hour price by dividing revenues in that region by the amount of energy sold there.

TCAP has employed granular U.S. EIA data to calculate average electricity prices inside and outside deregulated areas of Texas, inside and outside areas served by the state's principal power grid (the Electric Reliability Council of Texas) and for the state's residential, commercial and industrial customers.

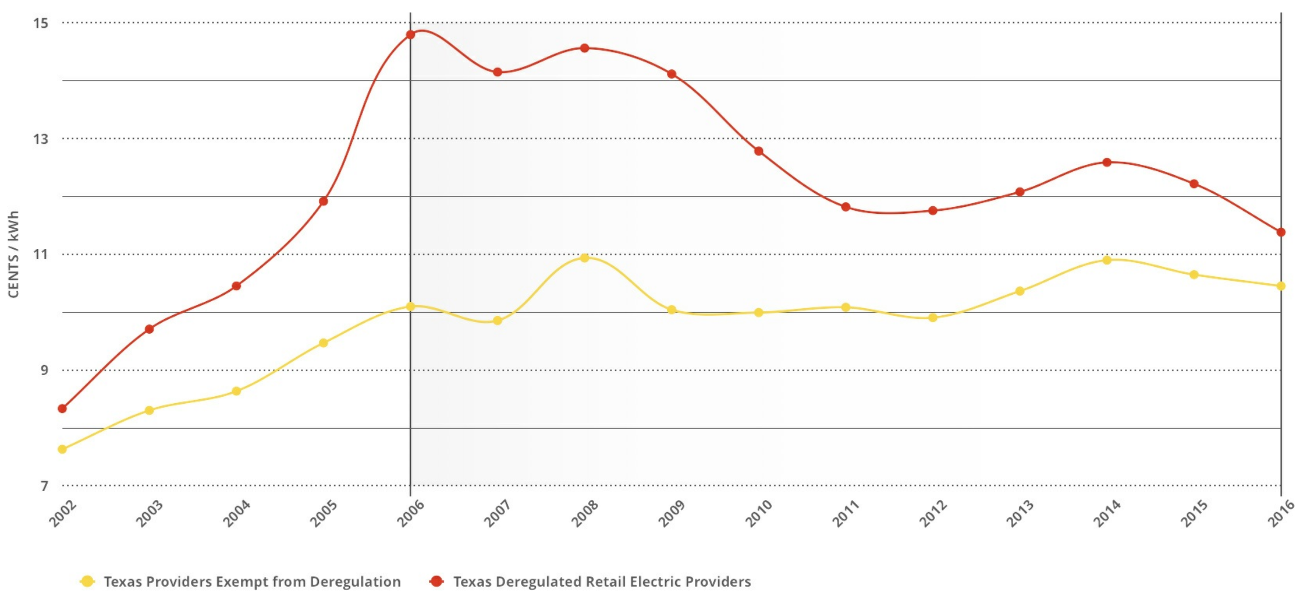
Employing U.S. EIA data in this fashion allows for calculations of average prices of consumed electricity, as opposed to average prices of individual offers made by electric companies. This distinction is important. The problem with averaging offers by electric companies — but without an understanding of how many customers take each offer — is that such an analysis can lead to conclusions that bear little resemblance to actual market outcomes. For instance, while it may be true that many low-cost offers are available in a given area, it may also be true that most Texans living in those areas do not or cannot avail themselves of those low-cost offers because of restrictions in their existing electricity contracts, or for a number of other reasons.

However, an examination of individual offers is nonetheless useful to gain a sense of commonly available electricity prices in deregulated areas, including prices found in fixed-rate and variable-rate deals. This report examines such individual pricing offers, as included in rate surveys conducted by the Texas Public Utility Commission.

This report also examines charges by the state's two largest transmission and distribution providers, as posted on the PUC website. Transmission and distribution charges by "wires" utilities are non-bypassable, meaning that these charges are imbedded in electricity prices paid by all consumers in the utility's service territory, regardless of the retail electric provider that the consumer selects for service.

Average Residential Electricity Prices

Exhibit 1: Inside and Outside Deregulated Areas of Texas



Average residential electric prices in deregulated areas of Texas consistently exceed average prices in deregulation-exempt areas. This was true in 2002 — the very first year of the deregulated retail electric market — and true in 2016, which was the last year for which data exist to conduct this analysis. It also has been true for every year in between.

The gap in residential electricity prices in deregulated and non-deregulated areas of Texas widened precipitously during the early years of the new market, but then narrowed by a similarly dramatic fashion in recent years.

During the first five years of deregulation in Texas — from 2002 through 2006 — prices in areas that remained deregulation-exempt increased by 32.3 percent. However, prices increased at more than twice that rate in deregulated areas, by 77.5 percent.

During the subsequent 10-year period, from 2007 through 2016, average residential prices in deregulation-exempt areas increased by 6.1 percent. However, they *decreased* by 19.6 percent in deregulated areas.

In 2016, the last year for which data exist to conduct these benchmark analyses, the difference in deregulated and non-deregulated residential prices narrowed to its smallest point on record: to 8.8 percent. However, the second smallest gap was observed in 2002, the first year of the deregulation law, when the difference stood at 9.2 percent. In absolute terms, as a difference in cents per kwh, the gap was smaller in 2002 (.7 cents) than it was in 2016 (.9 cents).

Source: United State Energy Information Administration & US EIA Electricity Data Browser

THE FINDINGS

Section 1: Long-Term Trends Benchmark Analysis

- Texans living in deregulated areas of the state have paid higher average rates for residential electricity than Texans living in areas exempt from deregulation. This is true for 2002 through 2016 — that is, for every year for which U.S. EIA data exist to conduct this analysis. [See Exhibit 8]. Over those years, average residential prices in deregulated areas have been between 9.2 percent (2002) and 46.5 percent (2006) higher than average prices in deregulation-exempt areas.
- From 2002 through 2016 average residential electricity prices increased at a greater rate at the national level than prices increased in both deregulated and deregulation-exempt areas of Texas. During that period, the percentage increase in average residential prices in deregulated Texas was very similar to the percentage increase in deregulation-exempt areas of Texas — 36.48 percent to 36.95 percent respectively. [See Exhibit 8].
- A shorter view — that is, confining the analysis to the 10 years from 2007 through 2016 — reveals that average residential prices have dropped in deregulated areas by 19.58 percent, while they have increased in areas exempt from deregulation by 6.05 percent. [See Exhibit 1].

- When it comes to residential pricing trends, deregulated Texas compares relatively well against other deregulated states. The 2002-2016 price increase observed in deregulated Texas stands as third lowest increase among 15 deregulated states during that period. This standing represents a slight improvement for Texas since TCAP's report last year. That report ranked Texas fourth among deregulated states for price increases. [See Exhibit 2].

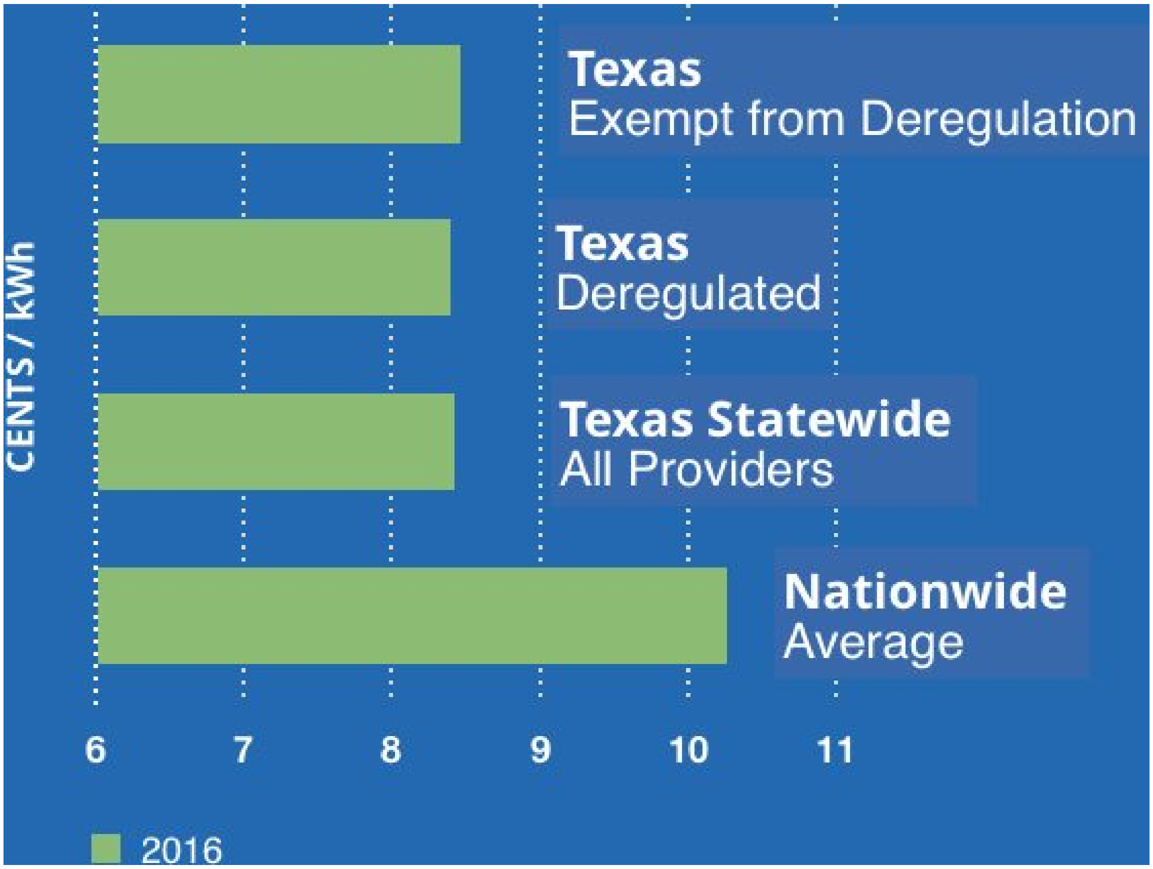
- Annual average residential electricity prices in deregulated areas of Texas have been higher than the nationwide average during 10 of the 15 years included in the benchmark analysis (2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011 and 2014). Annual average residential electricity prices in areas of Texas exempt from deregulation have been higher than the nationwide average once during those 15 years (2005). [See Exhibit 8].
- It remains unclear whether the historic disparity between average electric prices in deregulated and non-deregulated areas continues after 2016 because the necessary data to conduct those analyses are not available. However, rate surveys of more recent competitive offers show a substantial number meeting or beating prices in deregulation-exempt areas. [See Exhibit 10 and Exhibit 11].

Section 2: 2016 Electric Prices Benchmark Analysis

- In 2016 Texans in deregulated areas paid, on average, 11.38 cents per kilowatt hour for residential electricity, while the average price of electricity in areas of Texas exempt from deregulation was 10.45 cents per kilowatt hour. The corresponding nationwide average was 12.55 cents. [See Exhibit 8].
- In 2016, the average statewide price of electricity (both inside and outside areas of Texas with deregulation) for all customer classes (residential, commercial and industrial) was 8.4 cents. This beats the 10.3-cent nationwide average price. [See Exhibit 6].
- In 2016, average residential electricity prices charged by deregulated providers within the region served by the Electric Reliability Council of Texas (the state's primary power grid operator) were higher than prices charged by deregulation-exempt providers within that region. This also was the case in other recent years. [See Exhibit 7].

2016: All Customer Classes

Exhibit 6: Combined Residential, Commercial and Industrial Prices

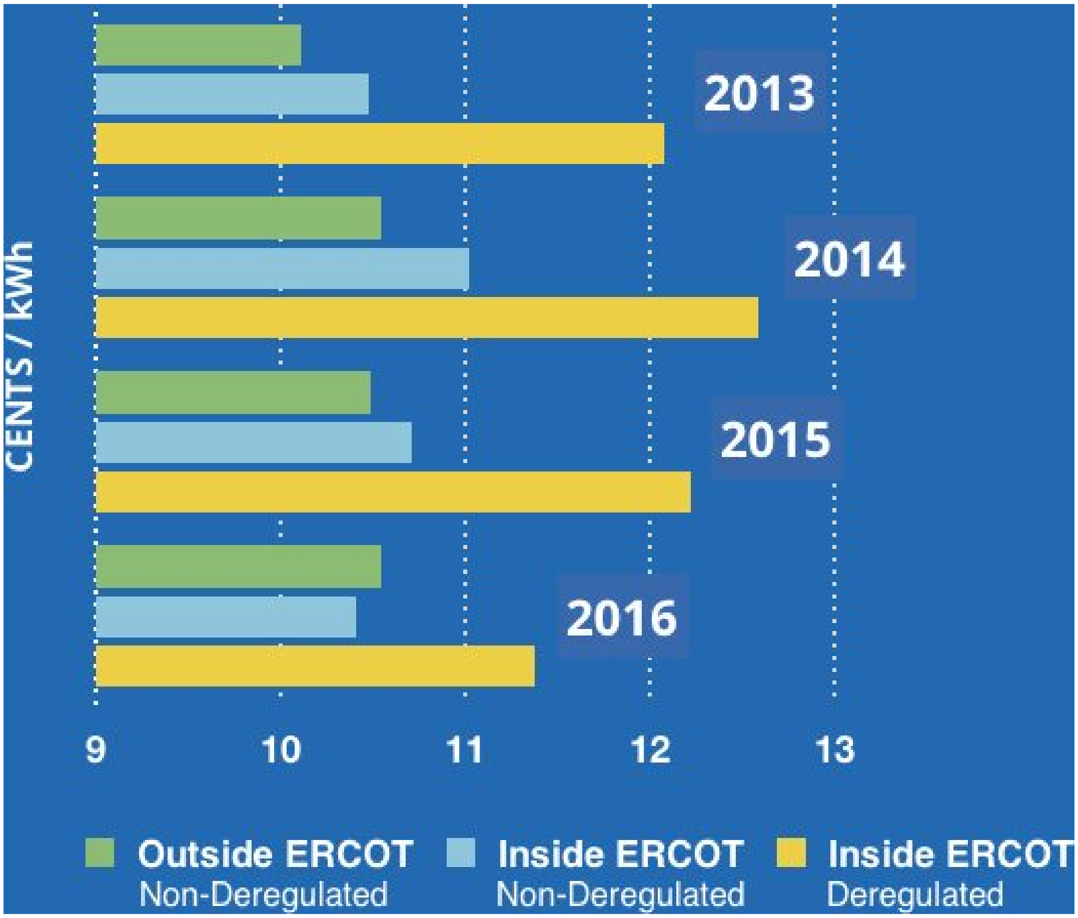


This exhibit depicts electricity prices among all customer classes (residential, commercial and industrial) during three years: 2013, 2014 and 2015. Average prices for these customer classes combined were lower in Texas during these years than they were nationwide. This exhibit also shows average prices inside and outside areas of Texas with deregulation.

Source: United States Energy Information Administration

2013-2016: Inside and Outside ERCOT

Exhibit 7: Residential Electric Prices

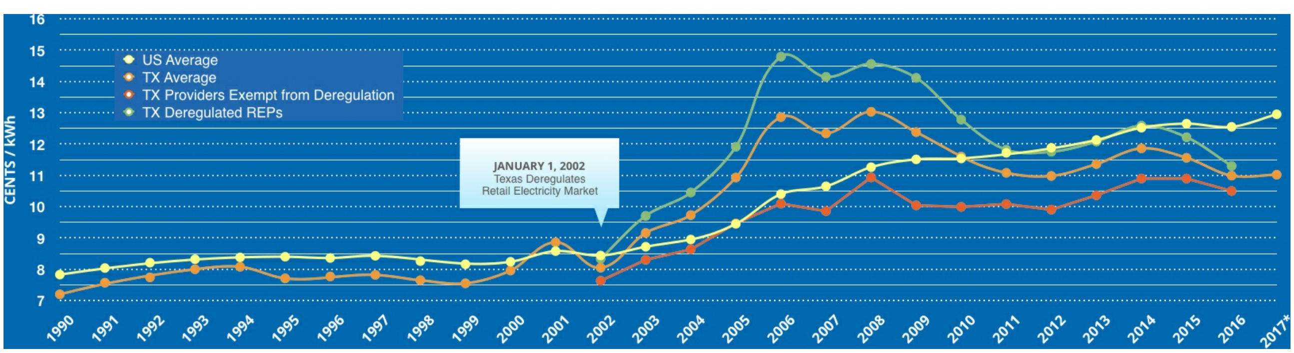


The state's primary grid operator, the Electric Reliability Council of Texas, oversees the transmission system in about 85 percent of the state. Deregulated service providers and those exempt from deregulation both operate within this service territory. In areas of the state outside of ERCOT, all service providers are exempt from deregulation. As this series of exhibits illustrates, average deregulated prices in Texas were significantly higher in 2013, 2014, 2015 and 2016 than those charged by providers exempt from deregulation — whether the deregulation-exempt providers operate inside or outside ERCOT.

Source: United States Energy Information Administration

Average Residential Electricity Prices

Exhibit 8: Texas and United States — 1990-2017*



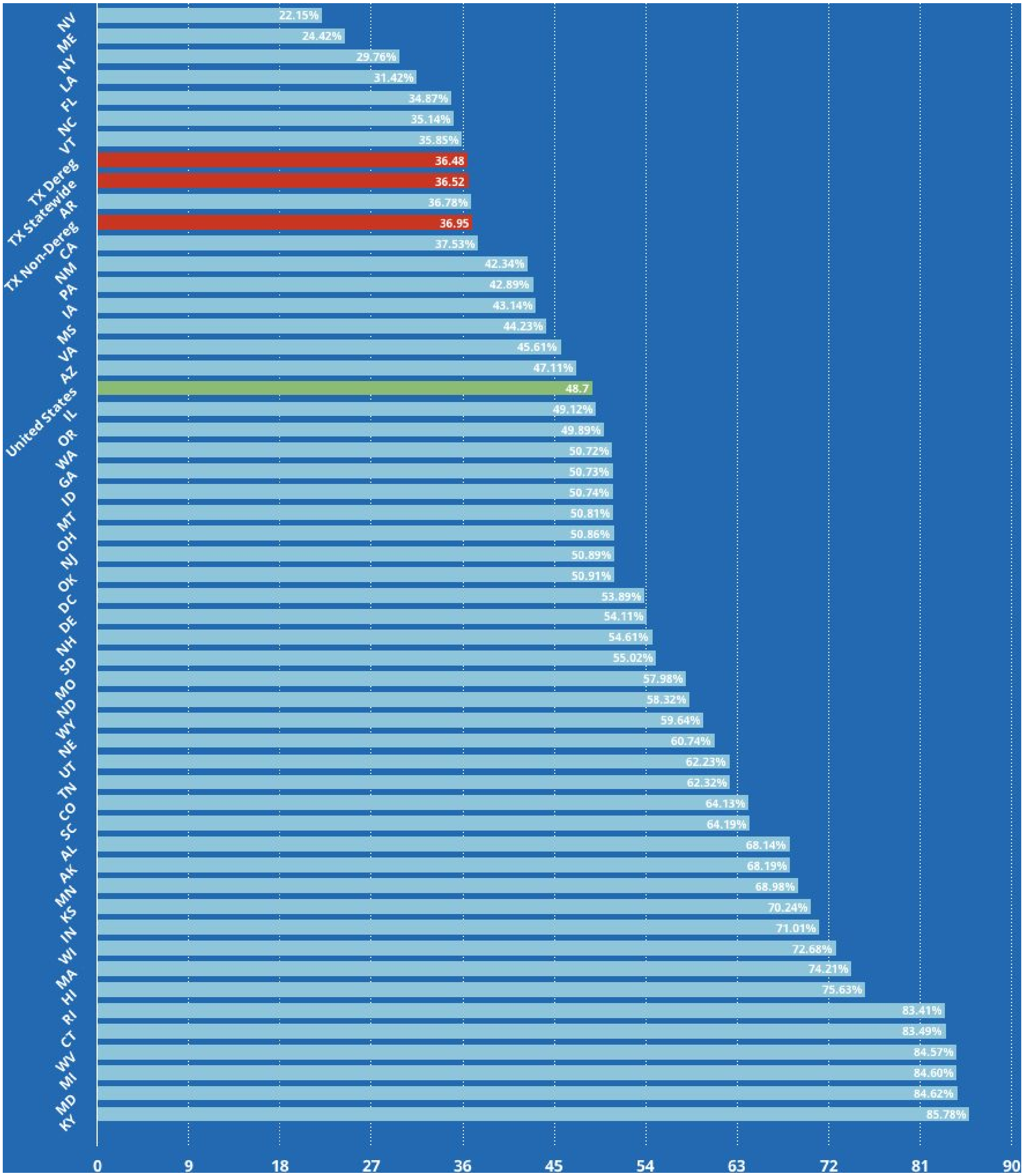
The statewide average price for residential electricity remained below the national average for many years prior to the implementation of the Texas deregulation law. But after Texas deregulated its retail electric market, the overall statewide average price for residential electricity surpassed the national average and remained significantly above that mark for many years. Note, however, that average residential prices in deregulation-exempt areas of Texas remained consistently below the national average after implementation of the deregulation law. By contrast, average prices in deregulated areas remained consistently above the national average for many years. This dynamic suggests that high residential electricity prices in deregulated Texas contributed to the comparatively high statewide average price after 2002.

This exhibit also shows average statewide residential prices in Texas spiking above the national average in 2001. Although that spike occurred before the deregulation of the state's retail electricity market, it likely was a function of deregulation. This is because the Texas Public Utility Commission allowed utilities in 2001 to collect excess earnings and high fuel surcharges as a down payment on anticipated collections from the restructuring law. Average statewide residential prices in Texas dropped after the deregulated market opened in 2002 because the fuel surcharges expired and because the deregulation law mandated a 6-percent cut in base rates. Average statewide residential prices then remained above the national average through 2010. [For more about this, see TCAP's separate report on the History of Texas Electric Deregulation.]

This exhibit does not distinguish between prices in areas of the state that are currently deregulated and non-deregulated prior to 2002. This is because the federal data to conduct that granular analysis are not readily available. The same is true for the years 2017 and 2018.

Source: United States Energy Information Administration & Electricity Data Browser

*2017 data through March 2017



Residential Electricity Prices

Exhibit 9: Percentage Increases 2002-2016

Residential electricity prices increased in deregulated areas of Texas from 2002 through 2016 by 36.58 percent, which is less than the 48.70 percent increase registered nationwide and also slightly less than the 36.95 percent increase registered in areas of the state exempt from deregulation.

Source: United States Energy Information Administration & Electricity Data Browser

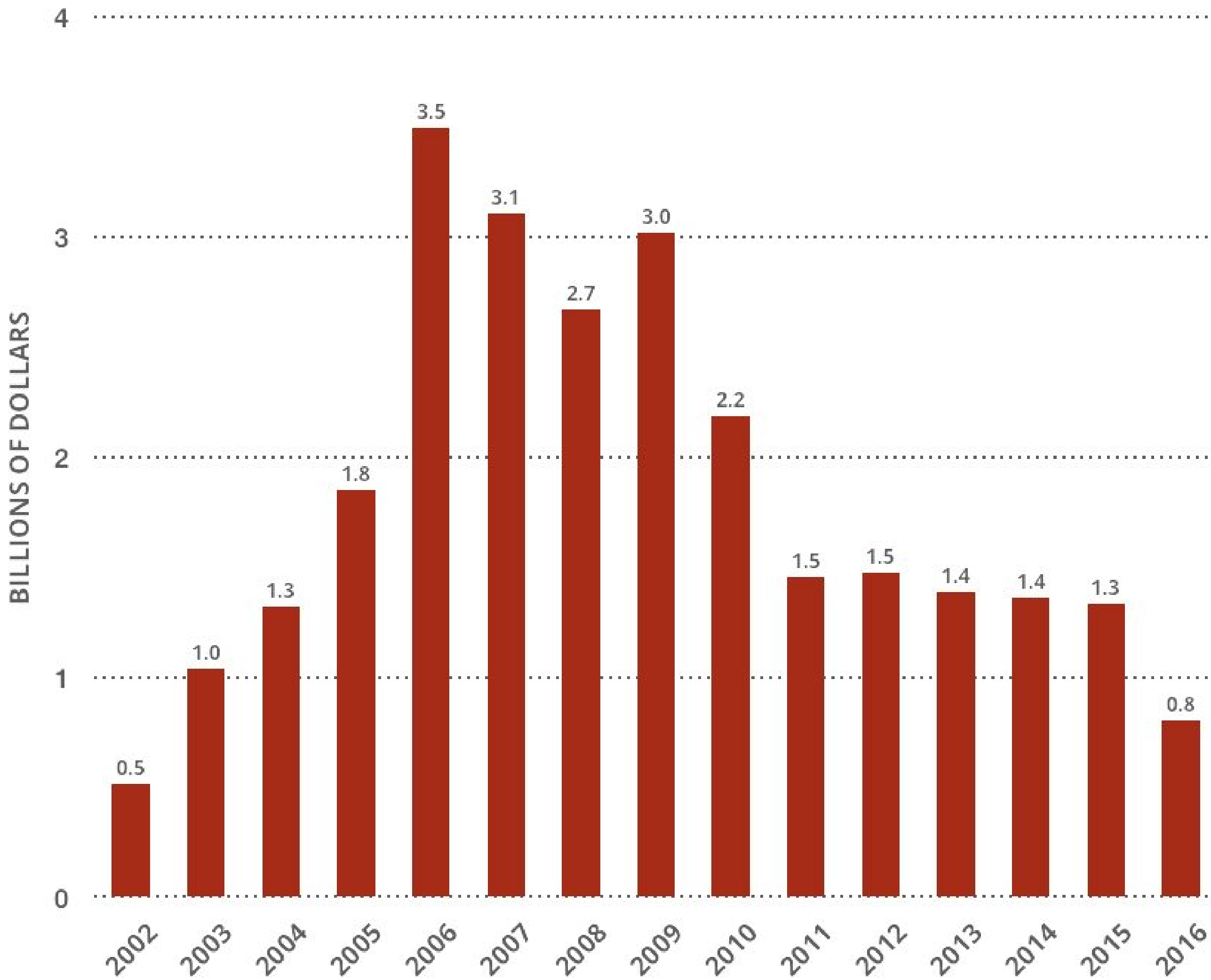
Section 3: Lost-Savings Analyses

"Lost savings," as defined in this report, is the imputed savings that would have accrued to Texans living in areas of Texas with deregulation had they paid the same average prices as Texans living in areas exempt from deregulation. The report examines lost savings both market-wide and on an individual level — and for each year for which data is available to conduct the analyses.

- All told, Texans living in deregulated areas would have saved more than $27 billion in lower residential electricity bills from 2002 through 2016 had they paid the same average prices as Texans living outside deregulation. For 2016 alone, that lost savings amounts to about $800 million. [See Exhibit 4].
- On an individual basis, a typical residential customer under deregulation (defined as a customer paying average deregulated prices and consuming 1,300 kilowatt hours of electricity every month) would have saved more than $5,500 from 2002 through 2016 had he or she paid the same average prices as those charged outside deregulation. This imputed "lost savings" amounts to about $144 for a typical household in 2016 alone. [See Exhibit 5].

The Aggregate Impact: Imputed Higher Costs Exceed $27 Billion In the Aggregate.

Exhibit 4: *Average electric prices in Texas charged by deregulated providers have been consistently higher than average prices charged by providers exempt from deregulation. The exhibit at right measures the potential impact of these higher prices. The bars illustrate the aggregate savings that would have accrued to Texans in deregulated areas had they instead paid the lower average rates charged in areas outside deregulation. The imputed "lost savings" ranges from about a half billion per year to more than $3.5 billion.*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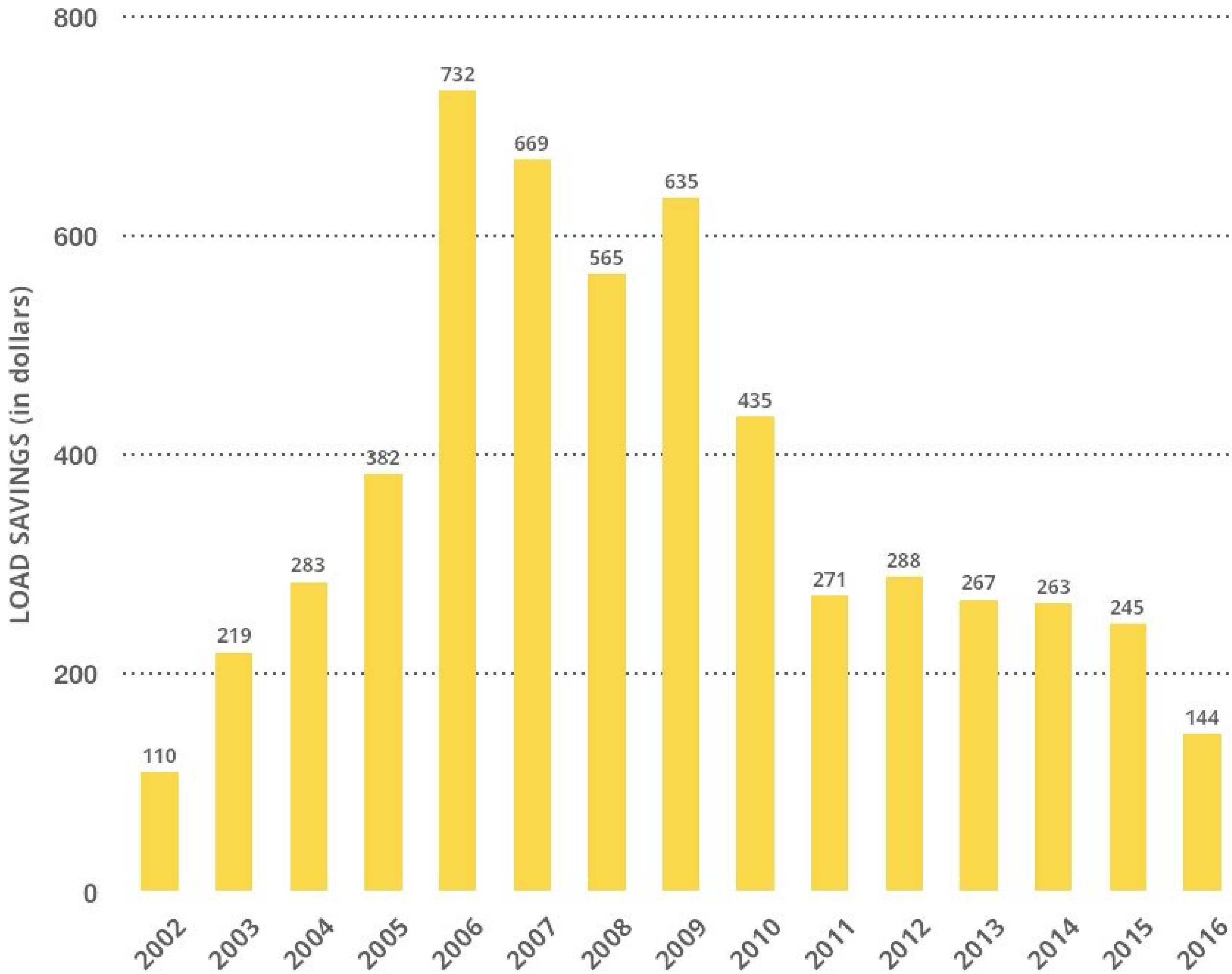


The Individual Impact: Imputed Higher Costs Exceeds $5,500 on Per-Customer Basis.

Exhibit 5: *This exhibit compares electricity costs for a typical customer paying average rates charged by deregulated retail electric providers in Texas, to costs for a customer with the same usage but paying average rates charged by Texas providers exempt from deregulation. Considered in this per-customer fashion, the imputed "lost savings" ranges from about a $110 per year, per customer, to $732 per year per customer. For purposes of comparison, this exhibit assumes monthly electricity usage of 1,300 kWh.*

Source: United States Energy Information Administration

Section 4: Transmission and Distribution Charges

Although monopoly transmission and distribution utilities operate under regulation, their rates impact electricity prices charged by competitive retail electric providers. This is because transmission and distribution utility rates are non-by-passable, which means they are included in a uniform fashion in the rates charged by all retail electric providers that operate in each utility's service territory.

Rate increases since 2003 by the Oncor utility (operating in the Dallas-Fort Worth area) and the CenterPoint Electric utility (operating around Houston) have outpaced inflation. Transmission and distribution charges paid by Oncor and CenterPoint customers also comprise an increasing share of monthly electric bills. [See Exhibit 10 and Exhibit 11 below].

Non-Bypassable Charges: CenterPoint

Exhibit 10: (September 2003 – March 2018)

Transmission and distribution charges
(in dollars, on 1,000kWh monthly bill)

Transmission and distribution utilities operate as regulated monopolies, even in areas of Texas with deregulation. The rates assessed by these utilities continue going up, sometimes at a rate well beyond that of inflation. For instance, rates charged by CenterPoint Electric in the Houston area have increased 89.3 percent since 2003. In 2003, CenterPoint charges comprised 20.2 percent to 29.2 percent of a typical 1,000 kWh electric bill. In March 2018, CenterPoint charges comprised 30.7 percent to 52 percent of a typical bill. All electric customers in deregulated areas around Houston must pay CenterPoint's rates, regardless of the retail electric provider the customer chooses for service.

Source: Archived TDU Rate Summaries, PUC

Non-Bypassable Charges: Oncor

Exhibit 11: (September 2003 – March 2018)

Transmission and distribution charges
(in dollars, on 1,000kWh monthly bill)

Rates charged by Oncor utility in the Dallas-Fort Worth area increased by nearly 69 percent since 2003. That rate outpaces the rate of inflation. In 2003, Oncor charges comprised 20.1 percent to 27.4 percent of a typical 1,000 kWh electric bill. In March 2018, the charges comprised 27.7 percent to 48.9 percent of a typical bill. All customers in deregulated areas of the Dallas-Fort Worth region must pay Oncor's rates, regardless of the retail electric provider the customers choose for service.

Source: Archived TDU Rate Summaries, PUC

Section 5: Recent Prices

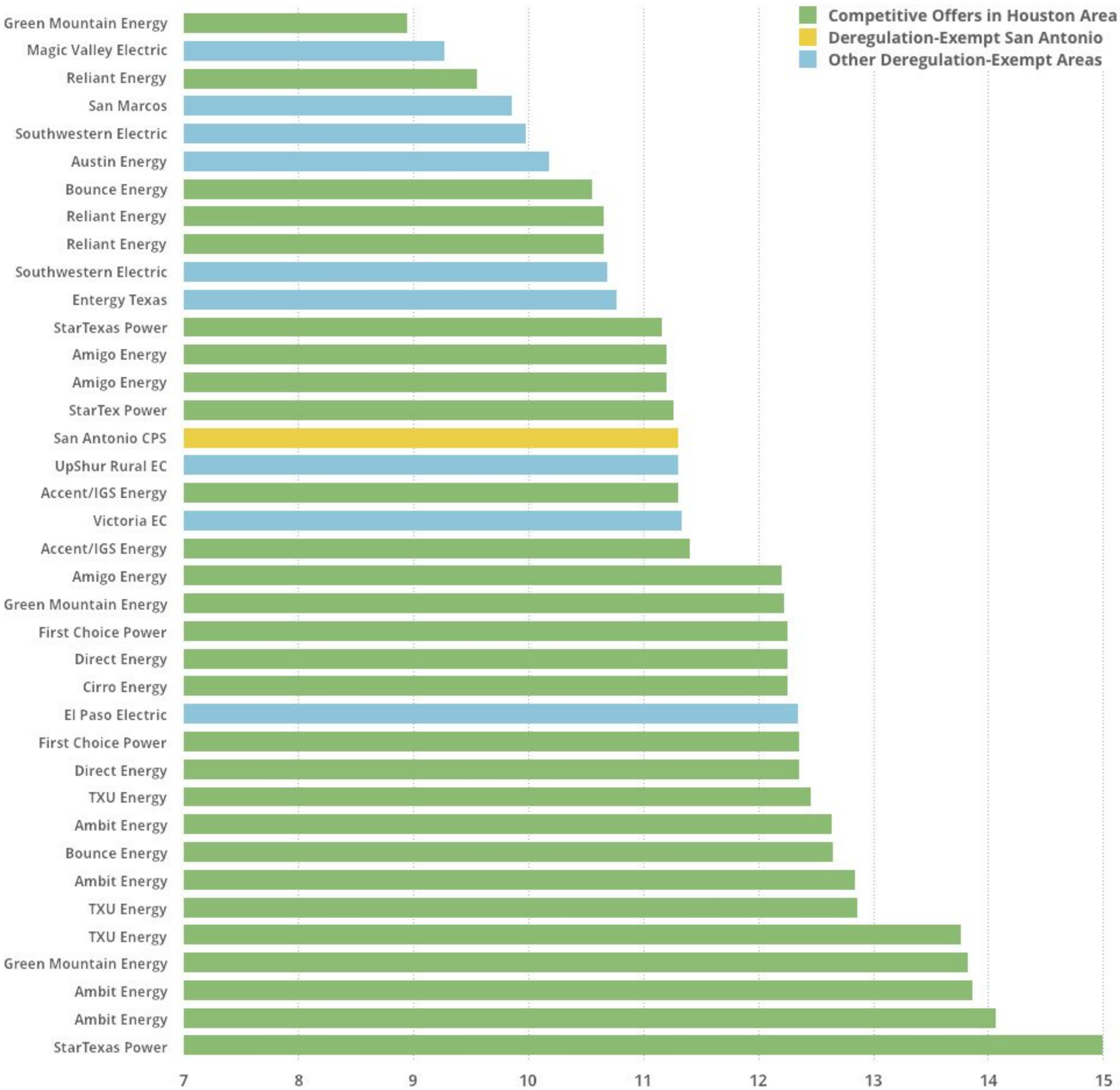
- Among adjoining states, residential prices in adjoining Oklahoma, Louisiana and Arkansas were lower during 2017 than in Texas. Residential electric prices in 2017 were higher in adjoining New Mexico and nationwide. [See Exhibit 3]
- Adjoining Louisiana and Oklahoma also enjoyed lower average industrial electric rates in 2017, while adjoining New Mexico and Arkansas had higher rates. [See Exhibit 3]
- Among all classes of customers (Residential, Commercial and Industrial Combined), lower average rates were to be found in adjoining Arkansas, Louisiana and Oklahoma during 2017, and higher in adjoining New Mexico and nationwide. [See Exhibit 3]

- A March 2018 Public Utility Commission survey of electricity deals in Houston reveals 9 competitive offers with prices lower than the electricity price paid in San Antonio. Houston is the largest city in Texas with deregulation. San Antonio is the largest city exempt from deregulation. [See Exhibit 12, below].
- A March 2018 Public Utility Commission survey of electricity deals in the Dallas-Fort Worth area reveals 18 competitive offers with prices lower than the electricity price paid in San Antonio. [See Exhibit 13, below].

Electricity Prices (Houston-Area)

Exhibit 12: Competitive Houston-Area Offers vs. Residential Prices in Deregulation-Exempt Area

(According to PUC Price Surveys, as of March 2018)

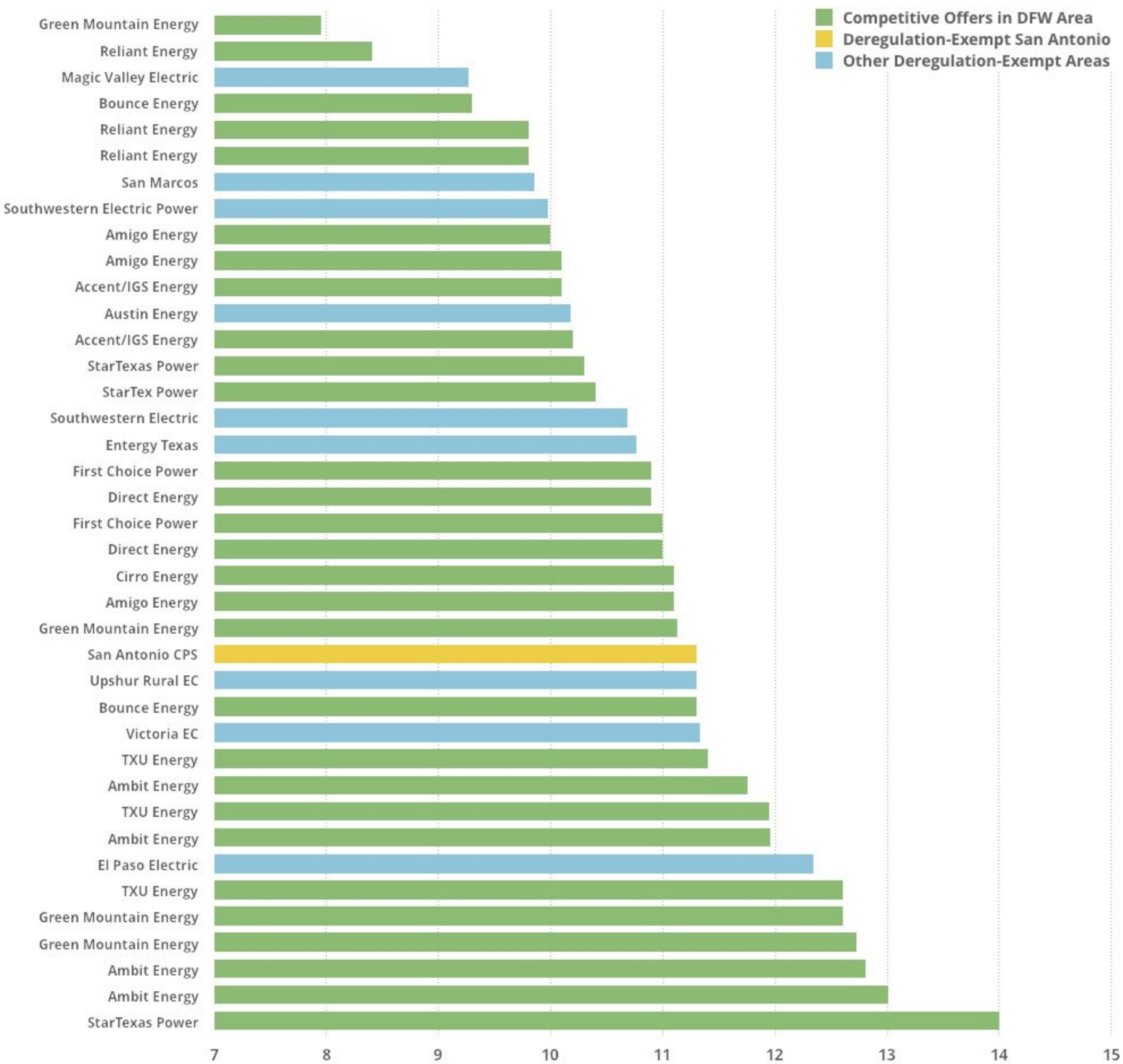


Average electricity prices paid by Texans living in areas outside deregulation have been consistently lower than average prices paid in deregulated areas. But that doesn't mean that Texans can't find plenty of good deals in deregulated areas. This exhibit shows a number of individual retail offers in the Houston area (as listed in a PUC rate survey for March 2018) that are lower than the residential price of electricity in San Antonio. Houston is the largest city in Texas with deregulation. San Antonio is the largest city exempt from deregulation. This finding is in contrast to the early years of the Texas deregulation law, in which PUC surveys revealed far fewer deals in Houston that were lower than the San Antonio regulated rate. This exhibit also lists electricity prices in other areas of Texas exempt from deregulation. All data has been retrieved from PUC rate surveys.

Electricity Prices (DFW-Area)

Exhibit 13: Competitive DFW-Area Offers vs. Residential Prices in Deregulation-Exempt Area

(According to PUC Price Surveys, as of March 2018)



This exhibit shows individual retail electric offers in the Dallas-Fort Worth area, as listed in a PUC rate survey for March 2018. Those offers are shown in green. Exhibit 13 also shows electricity prices in many deregulation-exempt areas of Texas. These are marked in blue. The price of electricity in San Antonio, which is the largest city in Texas exempt from deregulation, is shown in yellow.

About the Author

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Is a policy analyst for TCAP, a coalition of cities and other political subdivisions that purchase electricity in the deregulated market for their own governmental use. Because high energy costs can impact municipal budgets and the ability to fund essential services, TCAP, as part of its mission, actively promotes affordable energy policies. High energy prices also place a burden on local businesses and home consumers.

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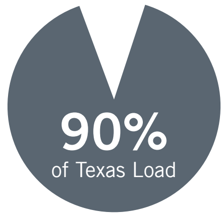
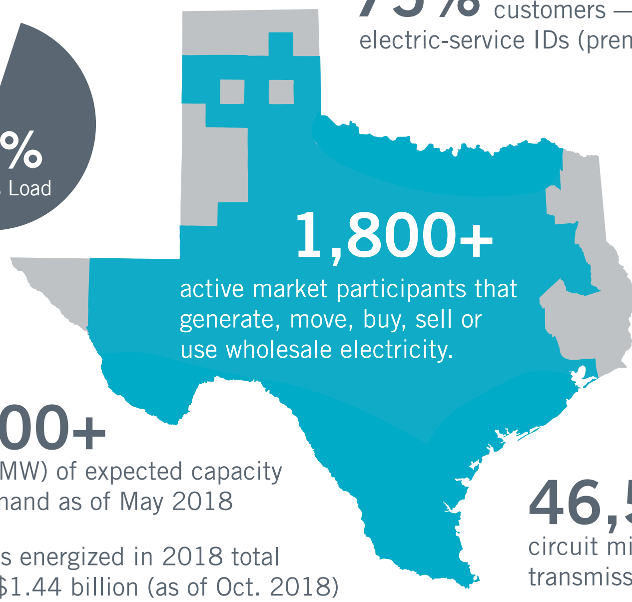
Quick Facts

The Texas Legislature restructured the Texas electric market in 1999 by unbundling the investor-owned utilities and creating retail customer choice in those areas, and assigned ERCOT four primary responsibilities:

- System reliability – planning and operations
- Wholesale market settlement for electricity production and delivery
- Retail switching process for customer choice
- Open access to transmission

ERCOT Region





75% of load is competitive-choice customers — nearly 8 million electric-service IDs (premises)

610+ generating units, excluding PUNs and battery storage

1,800+ active market participants that generate, move, buy, sell or use wholesale electricity.

More than **25** million consumers in the ERCOT region

78,000+ megawatts (MW) of expected capacity for peak demand as of May 2018

Projects energized in 2018 total about $1.44 billion (as of Oct. 2018)

46,500+ circuit miles of high-voltage transmission

73,473 MW	Record peak demand (July 19, 2018)
71,445 MW	Weekend demand record (July 22, 2018)

1 MW of electricity can power about 200 Texas homes during periods of peak demand.

Variable Generation

Wind Penetration record: 56.16 percent (Jan. 19, 2019)

Wind Generation record: 19,672 MW (Jan. 21, 2019)

- 21,751 MW of installed wind capacity, the most of any state in the nation.
- 1,719 MW of utility-scale installed solar capacity as of Dec. 2018

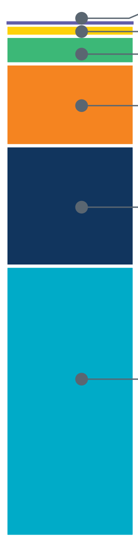
Demand response resources include:

- Load resources
- Emergency response service (commercial and industrial)
- Utility load management programs

Annual Energy Information

2019 Generation Capacity

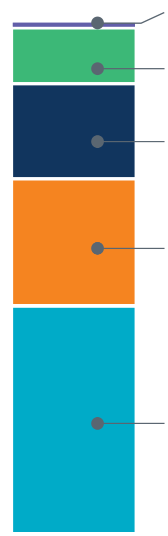
*Includes hydro, storage and biomass



2018 Energy Use

376 billion kilowatt-hours of energy used in 2018, a 5 percent increase compared to 2017.

*Includes solar, hydro, petroleum coke, biomass, landfill gas, distillate fuel oil, net DC-tie and Block Load Transfer imports/exports and an adjustment for wholesale storage load.



The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to more than 25 million Texas customers — representing about 90 percent of the state's electric load. As the independent system operator for the region, ERCOT schedules power on an electric grid that connects more than 46,500 miles of transmission lines and 600+ generation units. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly eight million premises in competitive choice areas. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. Its members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities, transmission and distribution providers and municipally owned electric utilities.

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President & Chief Executive Officer

Cheryl Mele
Senior Vice President & Chief Operating Officer

Jerry Dreyer
Senior Vice President & Chief Information Officer

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TDU Area

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Estimated Use

1,000 kWh

Price/kWh

¢ to ¢

Contract Length

to mo

Pricing and Billing

Show All Plans

Plans without a minimum usage fee/credit and plans without tiered pricing

Plan Type

Fixed Rate

Variable (Changing Rate)

Indexed (Market Rate)

Prepaid Plans

Show All Plans

Show Only Prepaid Plans

Do Not Show Prepaid Plans

Time Of Use Plans

Show All Plans

Show Only Time Of Use Plans

Do Not Show Time of Use Plans

Company Rating

1-116 OF 116 | SORT BY PRICE/kWh VIEW 10 PER ...

COMPARE	Company	Plan Details	Price/kWh	Pricing Details	Ordering Info
	LifeEnergy Company Rating History	PowerLife 3 ePlan 100% Green Fixed Rate 3 Months 100% Renewable New Customers	1,000 kWh 7.5¢ 500 kWh 8.1¢ 2000 kWh 7.2¢	Cancellation Fee: $0.00 Fact Sheet Terms of Service	Special Terms (844) 662-1222 OR SIGN UP
	Constellation Company Rating History	3 Month Texas Wind (No Min Usage Fee) Fixed Rate 3 Months 100% Renewable New Customers	1,000 kWh 7.5¢ 500 kWh 8¢ 2000 kWh 7.2¢	Cancellation Fee: $50.00 Fact Sheet Terms of Service	Special Terms (855) 797-8465 OR SIGN UP
	Brilliant Energy Company Rating History	Simple Plan (Web Enrollment Only) Fixed Rate 3 Months 11% Renewable New Customers	1,000 kWh 7.5¢ 500 kWh 8¢ 2000 kWh 7.2¢	Cancellation Fee: $0.00 Fact Sheet Terms of Service	Special Terms SIGN UP
	Express Energy Company Rating History	Speedy 3 Fixed Rate 3 Months 6% Renewable New Customers	1,000 kWh 7.6¢ 500 kWh 8.2¢ 2000 kWh 7.4¢	Cancellation Fee: $20 per month remaining Fact Sheet Terms of Service	Special Terms (844) 361-2075 OR SIGN UP
	Volt Company Rating History	PTC Move In 3 in CP Fixed Rate 3 Months 19% Renewable New Customers	1,000 kWh 7.6¢ 500 kWh 8.2¢ 2000 kWh 7.3¢	Cancellation Fee: $50.00 Fact Sheet Terms of Service	Special Terms (281) 369-5900 OR SIGN UP
	Texans Energy Company Rating History	SUPER SAVER 3 Fixed Rate 3 Months 19% Renewable New Customers	1,000 kWh 7.6¢ 500 kWh 7.6¢ 2000 kWh 7.6¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (281) 287-2901 OR SIGN UP
	Gexa Energy Company Rating	Gexa Choice Freedom 5 Fixed Rate 5 Months 6% Renewable	1,000 kWh 7.7¢ 500 kWh 8.3¢ 2000 kWh 7.4¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (866) 329-4392 OR SIGN UP

History | New Customers

Gexa Energy Company Rating (2 of 5 stars) History	Gexa Choice Freedom 4 Fixed Rate 4 Months 6% Renewable New Customers	1,000 kWh 7.7¢ 500 kWh 8.3¢ 2000 kWh 7.4¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (866) 329-4392 OR SIGN UP
Gexa Energy Company Rating (2 of 5 stars) History	Gexa Choice Green 4 Fixed Rate 4 Months 100% Renewable	1,000 kWh 7.7¢ 500 kWh 8.3¢ 2000 kWh 7.4¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (866) 329-4392 OR SIGN UP
Express Energy Company Rating (2 of 5 stars) History	Speedy 4 Fixed Rate 4 Months 6% Renewable New Customers	1,000 kWh 7.7¢ 500 kWh 8.3¢ 2000 kWh 7.5¢	Cancellation Fee: $20 per month remaining Fact Sheet Terms of Service	Special Terms (844) 361-2075 OR SIGN UP
Gexa Energy Company Rating (2 of 5 stars) History	Gexa Choice Green 5 Fixed Rate 5 Months 100% Renewable New Customers	1,000 kWh 7.7¢ 500 kWh 8.3¢ 2000 kWh 7.4¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (866) 329-4392 OR SIGN UP
Infuse Energy Company Rating (4 of 5 stars) History	Essential Infusion 3 Fixed Rate 3 Months 16% Renewable New Customers	1,000 kWh 7.7¢ 500 kWh 8.4¢ 2000 kWh 7.3¢	Cancellation Fee: $100.00 Fact Sheet Terms of Service	Special Terms (844) 463-8732 OR SIGN UP
4Change Energy Company Rating (2 of 5 stars) History	Power Saver 3 Fixed Rate 3 Months 6% Renewable New Customers	1,000 kWh 7.7¢ 500 kWh 8.3¢ 2000 kWh 7.5¢	Cancellation Fee: $20 per month remaining Fact Sheet Terms of Service	Special Terms (844) 840-1066 OR SIGN UP
4Change Energy Company Rating (2 of 5 stars) History	Planet Saver 4 Fixed Rate 4 Months 100% Renewable New Customers	1,000 kWh 7.8¢ 500 kWh 8.4¢ 2000 kWh 7.6¢	Cancellation Fee: $20 per month remaining Fact Sheet Terms of Service	Special Terms (844) 840-1066 OR SIGN UP
Eligo Energy No Scorecard Data History	3 Months Fixed Fixed Rate 3 Months 11% Renewable New Customers	1,000 kWh 7.9¢ 500 kWh 8.4¢ 2000 kWh 7.6¢	Cancellation Fee: $20 per month remaining Fact Sheet Terms of Service	Special Terms (888) 576-9473 OR SIGN UP

Renewable Energy

N/A

Electric Companies

All

REFRESH RESULTS

Company	Plan	1,000 kWh	500 kWh	2000 kWh	Cancellation Fee	Documents	Contact
APG&E Company Rating ★★★☆☆ History	TrueClassic 4 Fixed Rate 4 Months 6% Renewable New Customers	8.1¢	9.3¢	7.5¢	Cancellation Fee: $150.00	Fact Sheet Terms of Service	Special Terms (877) 544-4857 OR SIGN UP
First Choice Power Company Rating ★★★☆☆ History	You Got This 3 Fixed Rate 3 Months 16% Renewable New Customers	8.2¢	8.7¢	7.9¢	Cancellation Fee: $135.00	Fact Sheet Terms of Service	Special Terms (888) 676-9883 OR SIGN UP
windrose energy Company Rating ★★★★☆ History	Windrose Save Now Plan Fixed Rate 3 Months 19% Renewable	8.2¢	8.7¢	7.9¢	Cancellation Fee: $100.00	Fact Sheet Terms of Service	Special Terms (281) 845-2978 OR SIGN UP
Frontier Utilities Company Rating ★☆☆☆☆ History	Premier 3 Fixed Rate 3 Months 6% Renewable New Customers	8.6¢	9.8¢	8¢	Cancellation Fee: $75.00	Fact Sheet Terms of Service	Special Terms (877) 261-1024 OR SIGN UP
Infinite Energy Company Rating ★★★☆☆ History	3 Month Simple Plan Fixed Rate 3 Months 4% Renewable	9.1¢	9.6¢	8.8¢	Cancellation Fee: $50.00	Fact Sheet Terms of Service	Special Terms (877) 928-8766 OR SIGN UP
Veteran Energy Company Rating ★★★★☆ History	Basic 3 Month Fixed Rate 3 Months 4% Renewable	9.2¢	9.7¢	8.9¢	Cancellation Fee: $100.00	Fact Sheet Terms of Service	Special Terms (855) 856-7613 OR SIGN UP
Green Mountain Energy Company Rating ★★★★☆ History	Pollution Free e-Plus 6 Choice Fixed Rate 6 Months 100% Renewable	9.9¢	10.5¢	9.7¢	Cancellation Fee: $100.00	Fact Sheet Terms of Service	Special Terms (844) 854-2260 OR SIGN UP
spark energy Company Rating ★☆☆☆☆ History	Choice 6 Fixed Rate 6 Months 12% Renewable New Customers	10.2¢	10.7¢	9.9¢	Cancellation Fee: $175.00	Fact Sheet Terms of Service	Special Terms (877) 346-0861 OR SIGN UP

Company	Plan	Price	Details	Sign Up
Infuse Energy Company Rating ★★★★☆ History	Essential Infusion 6 Fixed Rate 6 Months 16% Renewable New Customers	1,000 kWh 10.3¢ 500 kWh 11¢ 2000 kWh 9.9¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (844) 463-8732 OR SIGN UP
ThinkEnergy by ENGIE Company Rating ★☆☆☆☆ History	THINK SIMPLE 24 Fixed Rate 24 Months 6% Renewable	1,000 kWh 10.4¢ 500 kWh 10.9¢ 2000 kWh 10.1¢	Cancellation Fee: $175.00 Fact Sheet Terms of Service	Special Terms (800) 481-9805 OR SIGN UP
First Choice Power Company Rating ★★★☆☆ History	You Got This 6 Fixed Rate 6 Months 16% Renewable New Customers	1,000 kWh 10.5¢ 500 kWh 11.5¢ 2000 kWh 9.9¢	Cancellation Fee: $135.00 Fact Sheet Terms of Service	Special Terms (888) 676-9883 OR SIGN UP
ThinkEnergy by ENGIE Company Rating ★☆☆☆☆ History	THINK SIMPLE 12 Fixed Rate 12 Months 6% Renewable New Customers	1,000 kWh 10.6¢ 500 kWh 11.1¢ 2000 kWh 10.3¢	Cancellation Fee: $79.00 Fact Sheet Terms of Service	Special Terms (800) 481-9805 OR SIGN UP
ThinkEnergy by ENGIE Company Rating ★☆☆☆☆ History	THINK SIMPLE 18 Fixed Rate 18 Months 6% Renewable New Customers	1,000 kWh 10.6¢ 500 kWh 11.1¢ 2000 kWh 10.3¢	Cancellation Fee: $175.00 Fact Sheet Terms of Service	Special Terms (800) 481-9805 OR SIGN UP
OurEnergy Company Rating ★★★☆☆ History	OUR FIX PLAN Fixed Rate 12 Months 13% Renewable New Customers	1,000 kWh 10.7¢ 500 kWh 11.2¢ 2000 kWh 10.4¢	Cancellation Fee: $200 Fact Sheet Terms of Service	Special Terms (888) 545-4687 OR SIGN UP
OurEnergy Company Rating ★★★☆☆ History	FIXALL ADVANTAGE PLUS Fixed Rate 12 Months 13% Renewable New Customers	1,000 kWh 10.7¢ 500 kWh 11.3¢ 2000 kWh 10.4¢	Cancellation Fee: $200 Fact Sheet Terms of Service	Special Terms (888) 545-4687 OR SIGN UP
windrose energy Company Rating ★★★★☆	Windrose Preferred Plan Fixed Rate 15 Months 19% Renewable	1,000 kWh 10.7¢ 500 kWh 11.2¢ 2000 kWh 10.4¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (281) 845-2978 OR SIGN UP

History

Company	Plan	Price	Fees / Documents	Contact
entrust energy Company Rating History	Texas Refresh 3 Fixed Rate 3 Months 100% Renewable	1,000 kWh 10.8¢ 500 kWh 11.9¢ 2000 kWh 10.3¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (800) 871-8100 OR SIGN UP
4Change energy Company Rating History	Power Saver 12 Fixed Rate 12 Months 6% Renewable New Customers	1,000 kWh 10.8¢ 500 kWh 11.4¢ 2000 kWh 10.6¢	Cancellation Fee: $20 per month remaining Fact Sheet Terms of Service	Special Terms (844) 840-1066 OR SIGN UP
Power of Texas No Scorecard Data History	Power of Texas Refresh 3 Fixed Rate 3 Months 100% Renewable New Customers	1,000 kWh 10.8¢ 500 kWh 11.9¢ 2000 kWh 10.3¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (888) 500-8348 OR SIGN UP
Power of Texas No Scorecard Data History	Power of Texas 3 Fixed Rate 3 Months 17% Renewable New Customers	1,000 kWh 10.8¢ 500 kWh 11.8¢ 2000 kWh 10.3¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (888) 500-8348 OR SIGN UP
windrose energy Company Rating History	Windrose Energy Saver Fixed Rate 28 Months 19% Renewable	1,000 kWh 10.8¢ 500 kWh 11.3¢ 2000 kWh 10.5¢	Cancellation Fee: $200.00 Fact Sheet Terms of Service	Special Terms (281) 845-2978 OR SIGN UP
V247 Power Company Rating History	Icy Savings 24 Fixed Rate 24 Months 16% Renewable New Customers	1,000 kWh 10.8¢ 500 kWh 11.3¢ 2000 kWh 10.5¢	Cancellation Fee: $325.00 Fact Sheet Terms of Service	Special Terms (855) 888-9888 OR SIGN UP
entrust energy Company Rating History	Entrust 3 Fixed Rate 3 Months 17% Renewable	1,000 kWh 10.8¢ 500 kWh 11.8¢ 2000 kWh 10.3¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (800) 871-8100 OR SIGN UP
windrose energy Company Rating	Winter Savings Plan Fixed Rate 24 Months 19% Renewable	1,000 kWh 10.9¢ 500 kWh 11.4¢ 2000 kWh 10.6¢	Cancellation Fee: $175.00 Fact Sheet Terms of Service	Special Terms (281) 845-2978 OR SIGN UP

History

Company	Plan	Price	Fees & Documents	Sign Up
VOLT Company Rating ★★☆☆☆ History	Move In Promo 12 Fixed Rate 12 Months 19% Renewable New Customers	1,000 kWh **10.9¢** 500 kWh 11.4¢ 2000 kWh 10.6¢	Cancellation Fee: $20 per remaining month Fact Sheet Terms of Service	Special Terms (281) 369-5900 OR SIGN UP
V247 Power Company Rating ★★★★☆ History	Icy Savings 12 Fixed Rate 12 Months 16% Renewable New Customers	1,000 kWh **11¢** 500 kWh 11.5¢ 2000 kWh 10.7¢	Cancellation Fee: $250.00 Fact Sheet Terms of Service	Special Terms (855) 888-9888 OR SIGN UP
Frontier Utilities Company Rating ★☆☆☆☆ History	Friends & Family 24 Green+ Fixed Rate 24 Months 100% Renewable New Customers	1,000 kWh **11¢** 500 kWh 11.6¢ 2000 kWh 10.7¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 261-1024 OR SIGN UP
4Change Energy Company Rating ★★☆☆☆ History	Planet Saver 12 Fixed Rate 12 Months 100% Renewable New Customers	1,000 kWh **11.1¢** 500 kWh 11.7¢ 2000 kWh 10.9¢	Cancellation Fee: $20 per month remaining Fact Sheet Terms of Service	Special Terms (844) 840-1066 OR SIGN UP
Southwest Power & Light Company Rating ★★★★★ History	Texas Saver Fixed Rate Autopay E-Plan Fixed Rate 36 Months 16% Renewable	1,000 kWh **11.1¢** 500 kWh 11.9¢ 2000 kWh 10.6¢	Cancellation Fee: $175.00 Fact Sheet Terms of Service	Special Terms (866) 941-7975 OR SIGN UP
Power of Texas No Scorecard Data History	Power of Texas 18 Fixed Rate 18 Months 17% Renewable New Customers	1,000 kWh **11.1¢** 500 kWh 12.2¢ 2000 kWh 10.6¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (888) 500-8348 OR SIGN UP
Frontier Utilities Company Rating ★☆☆☆☆ History	Friends & Family 12 Green Fixed Rate 12 Months 100% Renewable New Customers	1,000 kWh **11.1¢** 500 kWh 11.7¢ 2000 kWh 10.8¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 261-1024 OR SIGN UP
OurEnergy Company Rating ★★★☆☆	OUR FIX GREEN PLAN Fixed Rate 12 Months 100% Renewable New Customers	1,000 kWh **11.1¢** 500 kWh 11.7¢ 2000 kWh 10.8¢	Cancellation Fee: $200 Fact Sheet Terms of Service	Special Terms (888) 545-4687 OR SIGN UP

History

Company	Plan	Price	Fees & Documents	Contact
APG&E Company Rating: 3 of 5 stars History	TrueClassic 5 Fixed Rate 5 Months 6% Renewable New Customers	1,000 kWh **11.1¢** 500 kWh 12.2¢ 2000 kWh 10.5¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 544-4857 OR SIGN UP
entrust ENERGY Company Rating: 2 of 5 stars History	Entrust 18 Fixed Rate 18 Months 17% Renewable	1,000 kWh **11.1¢** 500 kWh 12.2¢ 2000 kWh 10.6¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (800) 871-8100 OR SIGN UP
windrose energy Company Rating: 4 of 5 stars History	Winter Savings Plan Fixed Rate 12 Months 19% Renewable	1,000 kWh **11.2¢** 500 kWh 11.7¢ 2000 kWh 10.9¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (281) 845-2978 OR SIGN UP
Gexa Energy Company Rating: 2 of 5 stars History	Gexa Choice Freedom 12 Fixed Rate 12 Months 6% Renewable New Customers	1,000 kWh **11.2¢** 500 kWh 11.8¢ 2000 kWh 10.9¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (866) 329-4392 OR SIGN UP
YEP energy Company Rating: 5 of 5 stars History	YEP Saver Fixed Autopay E-Plan Fixed Rate 36 Months 16% Renewable	1,000 kWh **11.2¢** 500 kWh 12¢ 2000 kWh 10.7¢	Cancellation Fee: $175.00 Fact Sheet Terms of Service	Special Terms (866) 937-5937 OR SIGN UP
LifeEnergy Company Rating: 1 of 5 stars History	PowerLife 36 ePlan 100% Green Fixed Rate 36 Months 100% Renewable	1,000 kWh **11.2¢** 500 kWh 11.8¢ 2000 kWh 10.9¢	Cancellation Fee: $149.00 Fact Sheet Terms of Service	Special Terms (844) 662-1222 OR SIGN UP
TRIEAGLE Company Rating: 1 of 5 stars History	Eagle 36 Fixed Rate 36 Months 6% Renewable	1,000 kWh **11.3¢** 500 kWh 11.8¢ 2000 kWh 11¢	Cancellation Fee: $20.00 per month left in term Fact Sheet Terms of Service	Special Terms (877) 933-2453 OR SIGN UP
ThinkEnergy by engie Company Rating	THINK SIMPLE 6 Fixed Rate 6 Months 6% Renewable	1,000 kWh **11.3¢** 500 kWh 11.8¢ 2000 kWh 11¢	Cancellation Fee: $45.00 Fact Sheet Terms of Service	Special Terms (800) 481-9805 OR

History

SIGN UP

LifeEnergy Company Rating History	PowerLife 24 ePlan 100% Green Fixed Rate 24 Months 100% Renewable	1,000 kWh 11.3¢ 500 kWh 11.9¢ 2000 kWh 11¢	Cancellation Fee: $149.00 Fact Sheet Terms of Service	Special Terms (844) 662-1222 OR SIGN UP
LibertyPower Company Rating History	TX Wind 36 Fixed Rate 36 Months 100% Renewable	1,000 kWh 11.3¢ 500 kWh 11.9¢ 2000 kWh 11.1¢	Cancellation Fee: $100 IF <12mos, $200 IF =>12mos Fact Sheet Terms of Service	Special Terms (866) 769-3799 OR SIGN UP
Power of Texas No Scorecard Data History	Power of Texas 24 Fixed Rate 24 Months 17% Renewable New Customers	1,000 kWh 11.4¢ 500 kWh 12.4¢ 2000 kWh 10.9¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (888) 500-8348 OR SIGN UP
Power of Texas No Scorecard Data History	Power of Texas Refresh 24 Fixed Rate 24 Months 100% Renewable New Customers	1,000 kWh 11.4¢ 500 kWh 12.5¢ 2000 kWh 10.9¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (888) 500-8348 OR SIGN UP
entrust energy Company Rating History	Entrust 24 Fixed Rate 24 Months 17% Renewable	1,000 kWh 11.4¢ 500 kWh 12.4¢ 2000 kWh 10.9¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (800) 871-8100 OR SIGN UP
Southwest Power & Light Company Rating History	Texas Saver Fixed Rate Autopay E-Plan Fixed Rate 12 Months 16% Renewable	1,000 kWh 11.4¢ 500 kWh 12.2¢ 2000 kWh 10.9¢	Cancellation Fee: $175.00 Fact Sheet Terms of Service	Special Terms (866) 941-7975 OR SIGN UP
entrust energy Company Rating History	Texas Refresh 24 Fixed Rate 24 Months 100% Renewable	1,000 kWh 11.4¢ 500 kWh 12.5¢ 2000 kWh 10.9¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (800) 871-8100 OR SIGN UP
LifeEnergy Company Rating History	PowerLife 12 ePlan 100% Green Fixed Rate 12 Months 100% Renewable	1,000 kWh 11.5¢ 500 kWh 12.1¢ 2000 kWh 11.2¢	Cancellation Fee: $149.00 Fact Sheet Terms of Service	Special Terms (844) 662-1222 OR SIGN UP

Company	Plan	1,000 kWh	500 kWh	2000 kWh	Fees / Documents	Contact
YEP energy Company Rating ★★★★★ History	YEP Saver Fixed Autopay E-Plan Fixed Rate 12 Months 16% Renewable	11.5¢	12.3¢	11¢	Cancellation Fee: $175.00 Fact Sheet Terms of Service	Special Terms (866) 937-5937 OR SIGN UP
LibertyPower Company Rating ★☆☆☆☆ History	TX Wind 24 Fixed Rate 24 Months 100% Renewable	11.6¢	12.1¢	11.3¢	Cancellation Fee: $100 IF <12mos, $200 IF =>12mos Fact Sheet Terms of Service	Special Terms (866) 769-3799 OR SIGN UP
APG&E Company Rating ★★★☆☆ History	TrueClassic 12 Fixed Rate 12 Months 6% Renewable New Customers	11.6¢	12.8¢	11¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 544-4857 OR SIGN UP
cirro ENERGY Company Rating ★★★☆☆ History	Smart Simple Select 6 Fixed Rate 6 Months 11% Renewable New Customers	11.6¢	12.1¢	11.3¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (844) 417-7180 OR SIGN UP
TRIEAGLE Company Rating ★☆☆☆☆ History	Eagle 24 Fixed Rate 24 Months 6% Renewable	11.6¢	12.1¢	11.3¢	Cancellation Fee: $20.00 per month left in term Fact Sheet Terms of Service	Special Terms (877) 933-2453 OR SIGN UP
Direct Energy Company Rating ★★★★☆ History	Veteran and Active Military 24 Fixed Rate 24 Months 16% Renewable New Customers	11.7¢	12.7¢	11.1¢	Cancellation Fee: $135.00 Fact Sheet Terms of Service	Special Terms SIGN UP
MidAmerican Energy Services, LLC Company Rating ★★★★★ History	Fixed Generation Supply Fixed Rate 24 Months 16% Renewable	11.7¢	12.3¢	11.5¢	Cancellation Fee: $20.00 per month left in term Fact Sheet Terms of Service	Special Terms (800) 342-3346 OR SIGN UP
ELIGOENERGY No Scorecard Data History	12 Months Fixed Fixed Rate 12 Months 11% Renewable	11.7¢	12.2¢	11.4¢	Cancellation Fee: $20 per month remaining Fact Sheet Terms of Service	Special Terms (888) 576-9473 OR SIGN UP

Company	Plan	Price	Fees / Documents	Contact
reliant. an NRG company Company Rating ★★★★★ History	Reliant Power On 12 plan Fixed Rate 12 Months 11% Renewable New Customers	1,000 kWh **11.8¢** 500 kWh 12.8¢ 2000 kWh 11.3¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (855) 350-8650 OR SIGN UP
LibertyPower Company Rating ★☆☆☆☆ History	TX Wind 12 Fixed Rate 12 Months 100% Renewable	1,000 kWh **11.8¢** 500 kWh 12.4¢ 2000 kWh 11.5¢	Cancellation Fee: $100.00 Fact Sheet Terms of Service	Special Terms (866) 769-3799 OR SIGN UP
Green Mountain Energy Company Rating ★★★★☆ History	Pollution Free e-Plus 60 Choice Fixed Rate 60 Months 100% Renewable	1,000 kWh **11.9¢** 500 kWh 12.5¢ 2000 kWh 11.7¢	Cancellation Fee: $300.00 Fact Sheet Terms of Service	Special Terms (844) 854-2260 OR SIGN UP
Direct Energy Company Rating ★★★★☆ History	Veteran and Active Military 12 Fixed Rate 12 Months 16% Renewable New Customers	1,000 kWh **11.9¢** 500 kWh 12.9¢ 2000 kWh 11.4¢	Cancellation Fee: $135.00 Fact Sheet Terms of Service	Special Terms SIGN UP
reliant. an NRG company Company Rating ★★★★★ History	Reliant Power On 24 plan Fixed Rate 24 Months 11% Renewable New Customers	1,000 kWh **11.9¢** 500 kWh 12.9¢ 2000 kWh 11.4¢	Cancellation Fee: $295.00 Fact Sheet Terms of Service	Special Terms (855) 350-8650 OR SIGN UP
Champion Energy Services Company Rating ★★★★☆ History	Champ Saver-16 Fixed Rate 16 Months 12% Renewable	1,000 kWh **11.9¢** 500 kWh 12.4¢ 2000 kWh 11.6¢	Cancellation Fee: $250.00 Fact Sheet Terms of Service	Special Terms (877) 653-5090 OR SIGN UP
TriEagle Company Rating ★☆☆☆☆ History	Eagle 12 Fixed Rate 12 Months 6% Renewable	1,000 kWh **12.1¢** 500 kWh 12.6¢ 2000 kWh 11.8¢	Cancellation Fee: $20.00 per month left in term Fact Sheet Terms of Service	Special Terms (877) 933-2453 OR SIGN UP
EligoEnergy No Scorecard Data History	6 Months Fixed Fixed Rate 6 Months 11% Renewable	1,000 kWh **12.2¢** 500 kWh 2000 kWh	Cancellation Fee: $20 per month remaining Fact Sheet	Special Terms (888) 576-9473 OR

			12.7¢ 11.9¢	Terms of Service	SIGN UP
First Choice Power Company Rating ★★★☆☆ History	You Got This 36 Fixed Rate 36 Months 16% Renewable New Customers	1,000 kWh 12.2¢ 500 kWh 2000 kWh 13.2¢ 11.7¢	Cancellation Fee: $135.00 Fact Sheet Terms of Service	Special Terms (888) 676-9883 OR SIGN UP
Champion Energy Services Company Rating ★★★★☆ History	Champ Saver-24 Fixed Rate 24 Months 12% Renewable	1,000 kWh 12.2¢ 500 kWh 2000 kWh 12.7¢ 11.9¢	Cancellation Fee: $250.00 Fact Sheet Terms of Service	Special Terms (877) 653-5090 OR SIGN UP
MidAmerican Energy Services, LLC Company Rating ★★★★★ History	Fixed Generation Supply Fixed Rate 12 Months 16% Renewable	1,000 kWh 12.2¢ 500 kWh 2000 kWh 12.7¢ 11.9¢	Cancellation Fee: $20.00 per month left in term Fact Sheet Terms of Service	Special Terms (800) 342-3346 OR SIGN UP
Trieagle Company Rating ★☆☆☆☆ History	Green Eagle 12 Fixed Rate 12 Months 100% Renewable	1,000 kWh 12.3¢ 500 kWh 2000 kWh 12.8¢ 12¢	Cancellation Fee: $20.00 per month left in term Fact Sheet Terms of Service	Special Terms (877) 933-2453 OR SIGN UP
Champion Energy Services Company Rating ★★★★☆ History	Champ Saver-6 Fixed Rate 6 Months 12% Renewable	1,000 kWh 12.4¢ 500 kWh 2000 kWh 12.9¢ 12.1¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 653-5090 OR SIGN UP
Cirro Energy Company Rating ★★★☆☆ History	Smart Secure 24 Fixed Rate 24 Months 11% Renewable New Customers	1,000 kWh 12.4¢ 500 kWh 2000 kWh 12.4¢ 12.4¢	Cancellation Fee: $200.00 Fact Sheet Terms of Service	Special Terms (844) 417-7180 OR SIGN UP
Payless Power Company Rating ★☆☆☆☆ History	SmarTricity Rate Lock 12 Fixed Rate 12 Months 0% Renewable Prepaid	1,000 kWh 12.5¢ 500 kWh 2000 kWh 12.5¢ 12.5¢	Cancellation Fee: $40.00 Fact Sheet Terms of Service Prepaid Disclosure	Special Terms (855) 781-6967 OR SIGN UP
Champion Energy Services Company Rating	Champ Saver-12 Fixed Rate 12 Months 12% Renewable	1,000 kWh 12.5¢ 500 kWh 2000 kWh	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 653-5090 OR

Company	Plan	Price	Fees & Documents	Sign Up
History		13¢ 12.2¢		SIGN UP
cirro ENERGY Company Rating History	Smart Basic 12 Fixed Rate 12 Months 11% Renewable New Customers	1,000 kWh 12.5¢ 500 kWh 13.1¢ 2000 kWh 12.3¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (844) 417-7180 OR SIGN UP
FIRST CHOICE POWER Company Rating History	You Got This 24 Fixed Rate 24 Months 16% Renewable New Customers	1,000 kWh 12.5¢ 500 kWh 13.5¢ 2000 kWh 12¢	Cancellation Fee: $135.00 Fact Sheet Terms of Service	Special Terms (888) 676-9883 OR SIGN UP
Green Mountain Energy Company Rating History	Pollution Free e-Plus 24 Choice Fixed Rate 24 Months 100% Renewable	1,000 kWh 12.6¢ 500 kWh 13.2¢ 2000 kWh 12.4¢	Cancellation Fee: $200.00 Fact Sheet Terms of Service	Special Terms (844) 854-2260 OR SIGN UP
FIRST CHOICE POWER Company Rating History	You Got This 12 Fixed Rate 12 Months 16% Renewable New Customers	1,000 kWh 12.6¢ 500 kWh 13.6¢ 2000 kWh 12.1¢	Cancellation Fee: $135.00 Fact Sheet Terms of Service	Special Terms (888) 676-9883 OR SIGN UP
Direct Energy Company Rating History	Power on Command 24 Fixed Rate 24 Months 16% Renewable New Customers	1,000 kWh 12.6¢ 500 kWh 13.6¢ 2000 kWh 12.1¢	Cancellation Fee: $135.00 Fact Sheet Terms of Service	Special Terms (877) 697-7560 OR SIGN UP
CHAMPION ENERGY SERVICES Company Rating History	Free Time-12 Fixed Rate 12 Months 12% Renewable Time Of Use	1,000 kWh 12.6¢ 500 kWh 13.1¢ 2000 kWh 12.3¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 653-5090 OR SIGN UP
Direct Energy Company Rating History	Live Brighter 36 Fixed Rate 36 Months 16% Renewable New Customers	1,000 kWh 12.6¢ 500 kWh 13.6¢ 2000 kWh 12.1¢	Cancellation Fee: $135.00 Fact Sheet Terms of Service	Special Terms (877) 697-7560 OR SIGN UP
	Live Brighter 12	1,000 kWh	Cancellation Fee: $135.00	Special Terms

Company	Plan	1,000 kWh	500 kWh	2000 kWh	Details	Contact
Direct Energy Company Rating ★★★★☆ History	Fixed Rate 12 Months 16% Renewable New Customers	12.7¢	13.7¢	12.2¢	Fact Sheet Terms of Service	(877) 697-7560 OR SIGN UP
APG&E Company Rating ★★★☆☆ History	TrueClassic 7 Fixed Rate 7 Months 6% Renewable New Customers	12.7¢	13.8¢	12.1¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 544-4857 OR SIGN UP
Green Mountain Energy Company Rating ★★★★☆ History	Pollution Free e-Plus 12 Choice Fixed Rate 12 Months 100% Renewable	12.9¢	13.5¢	12.7¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (844) 854-2260 OR SIGN UP
spark energy Company Rating ★☆☆☆☆ History	Choice 18 Fixed Rate 18 Months 0% Renewable New Customers	13.1¢	13.6¢	12.8¢	Cancellation Fee: $100 Fact Sheet Terms of Service	Special Terms (877) 346-0861 OR SIGN UP
APG&E Company Rating ★★★☆☆ History	TrueClassic 6 Fixed Rate 6 Months 6% Renewable New Customers	13.2¢	14.3¢	12.6¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 544-4857 OR SIGN UP
pogo energy Company Rating ★★★☆☆ History	100% Clean Energy Plan 4 Fixed Rate 100% Renewable Prepaid	13.3¢	15.3¢	12.2¢	Cancellation Fee: $0.00 Fact Sheet Terms of Service Prepaid Disclosure	Special Terms (888) 764-6669 OR SIGN UP
pennywise power Company Rating ★★★☆☆ History	Wise Buy 7 Fixed Rate 7 Months 11% Renewable New Customers	13.3¢	13.8¢	13¢	Cancellation Fee: $75.00 Fact Sheet Terms of Service	Special Terms (855) 265-9153 OR SIGN UP
cirro ENERGY Company Rating ★★★☆☆ History	Smart Secure 12 Fixed Rate 12 Months 11% Renewable New Customers	13.3¢	13.3¢	13.3¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (844) 417-7180 OR SIGN UP

Company	Plan	Price	Fees & Documents	Contact
cirro ENERGY Company Rating History	Smart Simple Select 12 Fixed Rate 12 Months 11% Renewable New Customers	1,000 kWh 13.4¢ 500 kWh 13.9¢ 2000 kWh 13.1¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (844) 417-7180 OR SIGN UP
just energy Company Rating History	PTC Plan - 24 Fixed Rate 24 Months 11% Renewable New Customers	1,000 kWh 13.7¢ 500 kWh 13.7¢ 2000 kWh 13.7¢	Cancellation Fee: $$175.00 per ESIID Fact Sheet Terms of Service	Special Terms (866) 587-8674 OR SIGN UP
amigo energy Company Rating History	PTC Plan - 24 Fixed Rate 24 Months 11% Renewable New Customers	1,000 kWh 13.7¢ 500 kWh 13.7¢ 2000 kWh 13.7¢	Cancellation Fee: $$175.00 per ESIID Fact Sheet Terms of Service	Special Terms (888) 995-9299 OR SIGN UP
Tara Energy Company Rating History	PTC Plan - 24 Fixed Rate 24 Months 11% Renewable New Customers	1,000 kWh 13.7¢ 500 kWh 13.7¢ 2000 kWh 13.7¢	Cancellation Fee: $$175.00 per ESIID Fact Sheet Terms of Service	Special Terms (866) 438-8272 OR SIGN UP
AMBIT ENERGY Company Rating History	Lone Star Classic 6 Fixed Rate 6 Months 15% Renewable	1,000 kWh 14¢ 500 kWh 15.6¢ 2000 kWh 13.2¢	Cancellation Fee: $100.00 Fact Sheet Terms of Service	Special Terms (877) 282-6248 OR SIGN UP
Infinite Energy Company Rating History	6 month Simple Plan Fixed Rate 6 Months 4% Renewable	1,000 kWh 14.1¢ 500 kWh 14.7¢ 2000 kWh 13.9¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (877) 928-8766 OR SIGN UP
amigo energy Company Rating History	PTC Plan - 12 Fixed Rate 12 Months 11% Renewable New Customers	1,000 kWh 14.2¢ 500 kWh 14.2¢ 2000 kWh 14.2¢	Cancellation Fee: $$175.00 per ESIID Fact Sheet Terms of Service	Special Terms (888) 995-9299 OR SIGN UP
just energy Company Rating	PTC Plan - 12 Fixed Rate 12 Months 11% Renewable	1,000 kWh 14.2¢ 500 kWh 2000 kWh	Cancellation Fee: $$175.00 per ESIID Fact Sheet	Special Terms (866) 587-8674 OR

History	New Customers	14.2¢ 14.2¢	Terms of Service	SIGN UP
Tara Energy Company Rating History	PTC Plan - 12 Fixed Rate 12 Months 11% Renewable New Customers	1,000 kWh 14.2¢ 500 kWh 2000 kWh 14.2¢ 14.2¢	Cancellation Fee: $$175.00 per ESIID Fact Sheet Terms of Service	Special Terms (866) 438-8272 OR SIGN UP
TXU energy Company Rating History	Simple Value 12 Fixed Rate 12 Months 6% Renewable New Customers	1,000 kWh 14.3¢ 500 kWh 2000 kWh 15.8¢ 13.5¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (855) 847-6135 OR SIGN UP
VETERAN ENERGY Company Rating History	Basic 6 Month Fixed Rate 6 Months 4% Renewable	1,000 kWh 14.4¢ 500 kWh 2000 kWh 14.9¢ 14.1¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (855) 856-7613 OR SIGN UP
AMBIT ENERGY Company Rating History	Lone Star Classic 12 Fixed Rate 12 Months 15% Renewable	1,000 kWh 14.4¢ 500 kWh 2000 kWh 15.9¢ 13.6¢	Cancellation Fee: $199.00 Fact Sheet Terms of Service	Special Terms (877) 282-6248 OR SIGN UP
TXU energy Company Rating History	Simple Value 24 Fixed Rate 24 Months 6% Renewable New Customers	1,000 kWh 14.7¢ 500 kWh 2000 kWh 16.2¢ 13.9¢	Cancellation Fee: $295.00 Fact Sheet Terms of Service	Special Terms (855) 847-6135 OR SIGN UP
TXU energy Company Rating History	Solar Advantage 12 Fixed Rate 12 Months 100% Renewable New Customers	1,000 kWh 15.3¢ 500 kWh 2000 kWh 16.8¢ 14.5¢	Cancellation Fee: $150.00 Fact Sheet Terms of Service	Special Terms (855) 847-6135 OR SIGN UP

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Scope of Competition in Electric Markets in Texas

Report to the 86th Legislature

Public Utility Commission of Texas
January 2019

DeAnn T. Walker
Chairman

Arthur C. D'Andrea
Commissioner

Shelly Botkin
Commissioner

John Paul Urban
Executive Director

Greg Abbott
Governor

Public Utility Commission of Texas

January 15, 2019

Honorable Members of the 86th Texas Legislature:

We are pleased to submit the 2019 *Scope of Competition in Electric Markets r*eport, as required by Section 31.003 of the Public Utility Regulatory Act. The Report provides an overview of the current status of electric competition in Texas, and describes other electric industry matters for which the Public Utility Commission of Texas (the Commission) has responsibility under State law. The report concludes with a discussion of recommendations the Legislature may wish to consider.

We look forward to continued collaboration with the Legislature to secure a bright energy future for Texas's residents, businesses, and industries. If you need additional information about the issues addressed in the report or any other Commission issues, please contact us.

Sincerely,

DeAnn T. Walker
Chairman

Arthur C. D'Andrea
Commissioner

Shelly Botkin
Commissioner

2019 Scope of Competition in Electric Markets in Texas

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I. INTRODUCTION

This report examines the status of electric markets in Texas throughout the two years since the submission of the previous *Scope of Competition in Electric Markets in Texas* to the 85th Legislature in 2017. The report identifies trends affecting competition in the wholesale and retail electric markets and Commission activities of notable interest over the last two years, including implementation of legislation, rulemaking activity, significant proceedings, and changes in the competitive ERCOT market. The report concludes with legislative recommendations.

The competitive electric marketplace in Texas continues to support a healthy number of retail electric providers and a wide variety of products to customers, competitive prices in wholesale markets, reliable service, and a diverse mix of generation resources.

Because of the timing of the preparation of this report, the data used to analyze retail and wholesale trends looks at the two-year period from September 1, 2016 through August 31, 2018, including record-setting peak demand in the summer of 2018.

II. STATE OF THE COMPETITIVE MARKET FROM 2017 TO 2018

A. Residential and Small Commercial Customers in Competitive Retail Markets

Texas is approaching the 20th anniversary of the restructuring of the retail electric market in the state. Passed in the 76th Legislative Session, Senate Bill 7 laid the foundation for a restructured electric market that continues to evolve. Since the implementation of customer choice, Texans in the competitive areas of ERCOT have been able to choose electricity products from a wide variety of retail electric providers (REPs), which offer products tailored to residential, commercial, and industrial customers. Nearly all customers have exercised their ability to choose their electricity provider since the market opened.[1]

1. Customer Choice

The Commission guides improvements to and enforces rules of Texas's competitive retail electric market. The number and diversity of REPs competing for customers provides an indicator of the health and the competitiveness of the retail market. Since the publication of the 2017 *Scope of Competition in Electric Markets in Texas* report, the number of REPs and competitive offers in the areas included in the Electric Reliability Council of Texas (ERCOT) has remained stable. As of September 2018, 116 REPs were operating in ERCOT, providing 315 total unique products, 77 of which solely support electricity generated from 100% renewable sources.[2]

Table 1. Number of REPs and Products Serving Residential Customers by Transmission Distribution Utility (TDU) Service Territory

September 2018 and September 2017

TDU Service Territory[3]	Residential Suppliers (Sept. 2018)	Residential Suppliers (Sept. 2017)	Number of Products (Sept. 2018)	Number of Products (Sept. 2017)
AEP Central	48	52	282	355
AEP North	24	49	237	295
CenterPoint	51	55	305	400
Oncor	50	55	311	390
TNMP	42	49	247	320

[1] ERCOT, *Observed Selection of Electric Providers September 2017 – September 2018*, http://ercot.com/content/wcm/key_documents_lists/89277/Observed_Selection_of_Electric_Providers_September_2018.ppt.pptx, October 1, 2018.

[2] Public Utility Commission, www.powertochoose.org, accessed September 1, 2018.

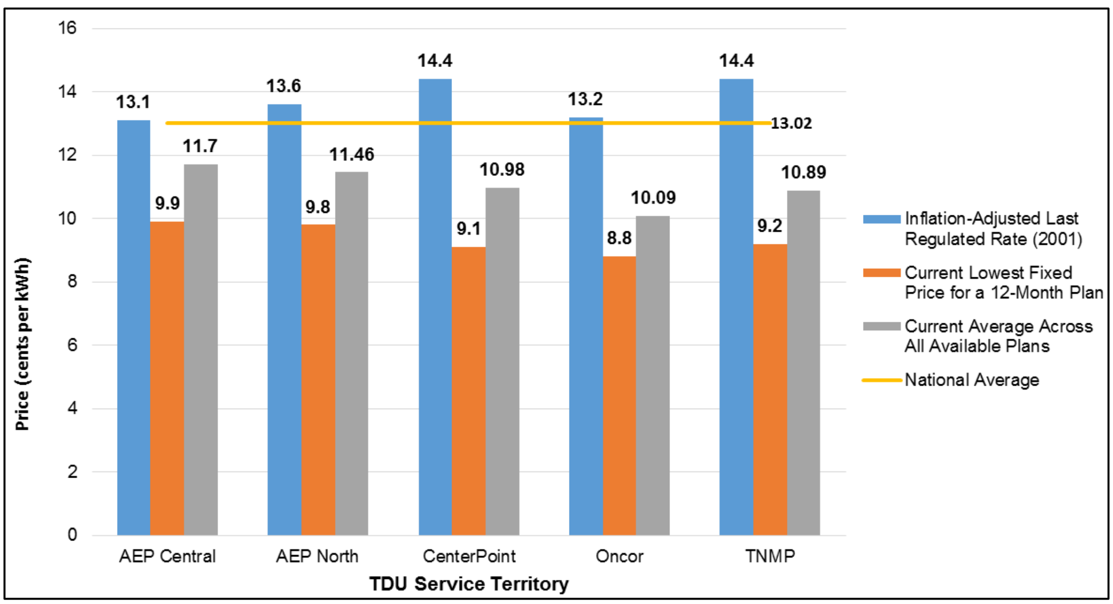
[3] American Electric Power – Texas Central Division ("AEP Central"); American Electric Power – Texas North Division ("AEP North"); CenterPoint Energy Houston Electric ("CenterPoint"); Oncor Electric Delivery Company ("Oncor"); and Texas-New Mexico Power Company ("TNMP").

The matured competitive market offers a variety of products to customers. As of September 2018, plans are available that offer 100% renewable electricity, time-of-use pricing such as free electricity on the weekends, and prepaid plans that allow customers to better budget. Contract terms vary from one month to as long as 60 months.

2. Retail Prices

Together, the REPs in the competitive market serve 6,362,771 residential customers, 1,081,646 commercial customers, and 4,607 industrial customers.[4] Figure 1 compares current offerings to the last inflation-adjusted regulated retail rate. As Figure 1 below demonstrates, rates in the ERCOT competitive market have decreased by 31% since the transition to the competitive market. Rates in the competitive market also remain lower than the national average of 13.02 cents per kWh, as of June 2018 according to the United States Energy Information Agency. The average lowest available residential price across the competitive market was 9.36 cents per kWh in September 2018, and the average price across all plans available in the competitive market in Texas was 10.3 cents per kWh.

Figure 1. Comparison of Currently Available Retail Rates to the National Average and Inflation-Adjusted Last Regulated Rate[5]



[4] ERCOT *Provider of Last Resort Counts,* June 1, 2018. Available at: http://www.ercot.com/content/wcm/key_documents_lists/89277/POLR_Counts_Energy_2018_Reporting.xlsx.

[5] Association of Electric Companies of Texas. Available at: http://www.aect.net/inside-the-charts-prices-available-in-the-competitive-market-today-well-below-the-last-regulated-rate/ and www.powertochoose.org.

3. Customer Education Activities

The Commission has telephone, web-based, and in-person contact with residential and small commercial electric customers. Commission staff provides information about retail electric competition through the Texas Electric Choice campaign and helps customers shop. Commission staff pro-actively participates in public events and responds to customer inquiries through a bilingual call center, the Commission's website, and the Power to Choose shopping website.

a. *Power to Choose Website, Customer Education Campaign, and Call Center*

The Power to Choose website, and its Spanish-language counterpart Poder de Escoger, provide a simple, one-stop shopping portal for Texans who live in an area open to customer choice. Customers can enter a ZIP code and browse through plans offered by the REPs in that area. From September 1, 2016 through August 31, 2018, over a million unique and potential customers visited the Power to Choose and Poder de Escoger websites. Commission staff also promotes the state's electric choice website through social media, as well as by maintaining an active presence at community events, trade shows, and expositions. Table 2 shows the number of visitors to each site.

Table 2. Visitor Website Statistics for September 1, 2016 – August 31, 2018

Unique Visitors	Number
PowerToChoose.org	1,364,686
PoderDeEscoger.org	5,725

The Commission's Customer Protection Division staff speak both English and Spanish. They answer customer calls and provide informational materials comparing electric plans by mail for customers without Internet access. From September 2016 to August 2018, the Customer Protection Division staff handled 6,606 calls from customers requesting assistance with shopping for electric plans.

b. *Educational Literature*

In addition to the educational materials on the Commission's agency and Power to Choose websites, the Commission develops and disseminates brochures and fact sheets by mail and e-mail to community organizations, at public events, and in response to customer requests to the call center. For example, in FY 2017 and FY 2018, agency staff attended and distributed educational materials on electric choice and shopping at community events such as the DFW Family Fair, Earth Day Texas, Women's Expo Houston, Texas Black Expo, the 6 Stones Hurst/Euless/Bedford Back 2 School event, Energy Day Houston, and Round Rock Express, Corpus Christi Hooks, and Midland Rockhounds baseball games. These gatherings offer the agency a critical avenue for reaching diverse communities throughout the state to help ensure the widest engagement with the competitive electric market.

4. Customer Protection

The Commission's rules provide a process for customers to file a complaint with the Commission about electric service. Not every call results in a complaint, and frequently Commission staff is able to provide information that answers a customer's concerns. If the issue cannot be addressed by simply providing information, Commission staff works with the customer and electric service provider to resolve the issue in an informal complaint process. The Commission maintains records of these calls and complaints, and evaluates the complaint statistics as a barometer of a company's behavior and its effect on customers. The Commission staff uses the data to identify company-specific trends, and works with companies to address any issues. The Commission staff also uses the data as a basis for enforcement actions.

The call center receives thousands of electricity-related calls per month in both English and Spanish related to a variety of electric questions such as billing, customer service, and requests for assistance shopping for an electric plan. Historic low temperatures in the winter of 2017 - 2018 may have contributed to the high number of complaints with the ERCOT grid setting multiple new winter peak demand records in January 2018. During the historic cold temperatures in January and February of 2018, the Commission received a total of 1,209 complaints, of which 40% were related to rates and charges, and 23% were related to metering. During the same two-month period a year prior in 2017, the Commission received only 661 complaints. The increase in electricity usage and resulting higher bills prompt more customers to scrutinize their usage and contact the Commission to confirm rates, charges, and metering.

B. Wholesale Market in ERCOT

The Commission engages regularly with ERCOT to oversee market developments and ensure system supply, reliability, security, improved price formation and market outcomes. The Commission also collaborates with the statutorily-required Independent Market Monitor (IMM), as discussed in more detail below, to detect and prevent market manipulation strategies, as well as to identify potential design improvements for the ERCOT wholesale electric market. Changes made as a result of these working relationships have helped improve wholesale market efficiency by creating new opportunities for a variety of generation resources to enter the market and by enhancing wholesale price formation in order to reflect real-time market conditions more accurately.

1. Independent Market Monitor

PURA[6] § 39.1515 requires that the Commission contract with an independent organization to act as the Commission's wholesale electric market monitor. The Commission currently contracts with the statistical and economics consulting firm

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[6] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-58.302 (West 2016 & Supp. 2018), §§ 59.001-66.016 (West 2007 & Supp. 2018) (PURA).

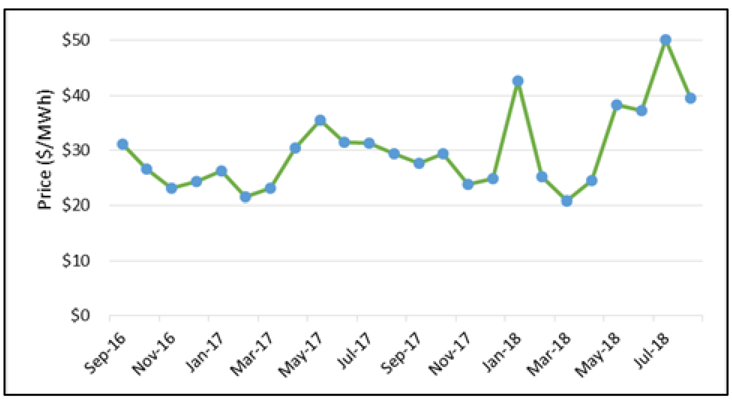
Potomac Economics to serve as its IMM. The IMM submits an annual report on the state of the ERCOT market, which examines whether market power exists and if attempts have been made to exercise it. In the 2017 *State of the Market Report for the ERCOT Electricity Markets* (State of the Market report), which was issued in May 2018, the IMM found that potential economic withholding levels for both the largest suppliers and small suppliers alike in 2017 were extremely low. These results, together with the evaluation of market outcomes presented, led the IMM to conclude that the ERCOT market performed competitively in 2017.

The State of the Market report also includes seven recommendations to improve the efficiency of the wholesale market. Generally, these recommendations relate to improvements to either market operation or price formation. The Commission is currently in the process of studying two of these recommendations, real-time co-optimization and marginal losses.

2. Wholesale Market Prices

Wholesale prices often correlate with prices for natural gas, the fuel used by a large proportion of the region's power plants. The average Houston Ship Channel spot price for natural gas was 19% higher in calendar year 2017 than the average realized in calendar year 2016, increasing from $2.51 per MMBtu in 2016 to $2.98 in 2017. The average price for 2018 through the end of August has risen slightly to $2.99 per MMBtu.[7] The influence of this increase in gas prices can be observed in Figure 2, which shows monthly average wholesale electricity prices. Load-weighted prices are calculated by dividing the price at a load zone by the associated demand. This metric provides a useful proxy for the actual wholesale prices paid by load.[8]

Figure 2. Load-Weighted Average Real-Time Monthly Settlement Point Prices for September 2016 – August 2018[9]



[7] S&P Global Market Intelligence, NYMEX Houston Ship Channel Natural Gas Prices, September 1, 2016 to August 31, 2018 (2018).

[8] Most power in ERCOT is sold through various non-public bilateral arrangements that are designed to hedge daily real-time market price risk.

[9] ERCOT Market Information, http://www.ercot.com/mktinfo/prices, accessed September 1, 2018.

Another significant component of the real-time price of electricity is the cost of transmission congestion. Transmission lines have a finite capacity to deliver electricity safely. If lower cost electricity is available from a given power plant, but the lines needed to deliver it to the customer are not available because the lines are already at maximum capacity, then electricity must be purchased from a different plant at a higher cost. The difference in the prices is the cost of transmission congestion. The cost of transmission congestion reflects the price of serving load and serves as a market signal to both transmission planners and generation market participants of locations where demand exceeds transmission capacity, indicating where additional transmission lines or generation would alleviate the congestion.

Areas of West Texas and Houston have experienced significant amounts of transmission congestion over the past several years. New transmission lines have partially relieved the cost burden in West Texas, but continuing oil and gas production growth in the Permian Basin and Eagle Ford shale areas has resulted in persistent transmission congestion and, as a result, relatively higher zonal prices. High congestion in the Houston area is largely due to planned transmission outages related to the construction of expanded transmission facilities serving this area. Significant portions of these new facilities went into service at the beginning of the summer of 2018 and have already lowered energy prices for customers in the Houston area.

3. Capacity, Demand, and Reserves Report

ERCOT's semi-annual Capacity, Demand, and Reserves report (CDR report) compares electricity generation capacity to estimated demand in the future. The CDR report estimates long-term supply and demand and the associated annual reserve margin (the amount of generation anticipated to be available in excess of forecast demand) for peak summer and winter conditions. While the CDR report is not a forecast of any particular outcome, it provides insight into possible resource adequacy trends. The CDR report estimates possible future outcomes, which vary depending on external variables such as differences in actual versus forecasted load growth, weather assumptions, resource unit retirements, and delays in new generation coming online. Reserve margin estimates taken from the current December 2018 CDR report are shown below in Table 3.

Table 3. December 2018 CDR Report for Peak Summer Conditions for 2019 – 2023

Forecast	2019	2020	2021	2022	2023
Peak Load (MW)	72,674	74,686	76,664	78,295	79,972
Total Capacity (MW)	78,555	82,652	86,016	85,958	85,958
Reserve Margin	**8.1%**	**10.7%**	**12.2%**	**9.8%**	**7.5%**

Because ERCOT operates an energy-only market, the Commission has not established a mandatory reserve margin level. However, the Commission has used a standard of one outage in ten years due to capacity shortage as a benchmark to evaluate the adequacy of the current and projected reserve margin in the CDR report. The reserve margin necessary to satisfy this standard has been calculated to be 13.75%.[10] In 2017, the Commission decided to consider an additional standard, the economically optimal reserve margin (EORM), to evaluate installed capacity.[11] The EORM is an estimate of the reserve margin at which the cost of increasing reliability would exceed the value of a loss of load event. In conjunction with The Brattle Group, ERCOT staff completed a study of the EORM in October 2018. Preliminary results of that study conclude that the EORM for the ERCOT market is 9.0%. ERCOT staff and The Brattle Group have also studied the Market Equilibrium Reserve Margin (the reserve margin that the ERCOT market design is estimated to achieve in the long run) and concluded that the equilibrium reserve is 10.25%. The actual reserve margin at the beginning of the summer of 2018 was 11.0%.

The retirement of a number of older coal-fired generation plants during the winter of 2017-2018 raised concerns that the corresponding lower reserve margin could result in reliability issues in the summer of 2018. While the region set new all-time peak demand records and prices were higher than in previous years, the system operated reliably and efficiently throughout the summer.

The ERCOT system performed well with respect to available system capacity throughout calendar years 2016 and 2017, and the Commission is currently reviewing results from 2018. The Commission continues to devote significant attention to monitoring ERCOT's reserve margin, operational reliability, and developing a wholesale market design that allows customers to continue to receive low-cost and reliable electricity over the long term.

C. Non-ERCOT Utilities: Market Development

Senate Bill 7, the original bill that deregulated Texas electric markets, granted the Commission authority to delay retail competition in areas where deregulation would not result in fair competition and reliable service. Utilities outside of the ERCOT region remain vertically integrated, owning generation, transmission, and distribution assets, as well as selling power to end-use customers. Those utilities include El Paso Electric Company, Southwestern Public Service Company, Southwestern Electric Power Company, and Entergy Texas, Inc. These vertically-integrated utilities are subject to traditional utility regulation, including retail rate setting by the Commission. Customers served by these utilities do not have a choice of provider unless the customer is located in a multiply-certificated area.

The Commission provides policy oversight and makes recommendations to the non-ERCOT portions of the state through the commissioners' participation in state and regional planning groups. The Federal Energy Regulatory Commission (FERC) has

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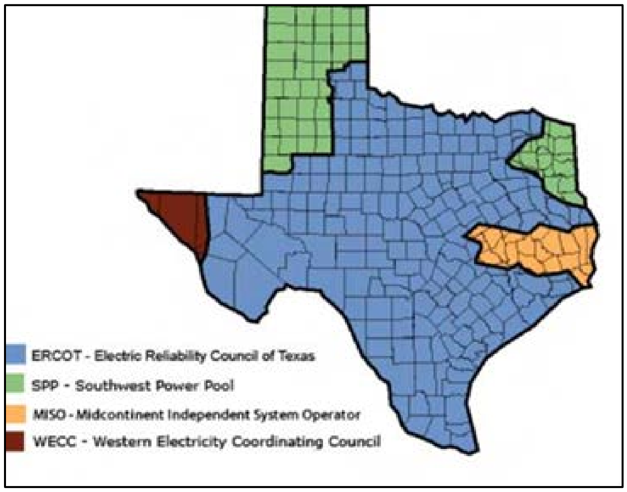
[10] This reserve margin was approved by the ERCOT Board at the November 16, 2010 Board Meeting.

[11] Commissioners directed the study of the Economically Optimal Reserve Margin metric at the September 22, 2016 open meeting, as part of Project No. 42302, *Review of the Reliability Standard in the ERCOT Region*.

regulatory jurisdiction over wholesale power sales and transmission rates outside of ERCOT. The Commission has the authority to retain counsel and consulting experts in order to participate in certain legal proceedings at the FERC and at courts reviewing those FERC proceedings. Figure 3 shows each of the regional transmission organizations' territory in Texas.

Figure 3. Map of Regional Transmission Organizations in Texas



1. Southwest Power Pool

The Southwest Power Pool (SPP) is the regional transmission organization for areas of Northeast Texas and the Texas Panhandle, serving Southwestern Electric Power Company, Southwestern Public Service, several electric cooperatives, and various municipally owned utilities. SPP also includes parts of Arkansas, Iowa, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, South Dakota, Wyoming, and all of Kansas and Oklahoma. The SPP Market Monitoring Unit concluded that the SPP wholesale markets were "workably competitive" in 2017.[12]

Chairman DeAnn T. Walker represents the Commission as a voting member on SPP's Regional State Committee, which consists of the state regulatory agencies in the region. The Regional State Committee meets quarterly and advises SPP on issues such as cost allocation methodologies for transmission upgrades, allocation of Financial Transmission Rights, and the approach used for resource adequacy across the SPP region.

2. Midcontinent Independent System Operator

The Midcontinent Independent System Operator (MISO) is the regional transmission organization that serves all or part of 15 states in the central United States,

[12] *State of the Market 2017*, SPP Marketing Monitoring Unit, at 1, May 2018. Available at: https://www.spp.org/documents/57928/spp_mmu_asom_2017.pdf

one Canadian province, and the portion of eastern Texas served by the vertically integrated utility, Entergy Texas, Inc. MISO is also subject to FERC jurisdiction. The Commission, through outside counsel, has been an active party in recent FERC proceedings, arguing for the right to address generation resource adequacy at the state level, increased regulatory certainty, fair cost allocation across MISO states, and increased market efficiency. The MISO Independent Market Monitor concluded that the MISO wholesale markets were competitive in 2017.[13]

Commissioner Arthur C. D'Andrea represents the Commission as a voting member of the Organization of MISO States (OMS), which coordinates regulatory oversight among the retail regulators in the MISO region and makes recommendations to MISO, FERC, and other entities. Commissioner D'Andrea also represents the Commission as a voting member of the Entergy Regional State Committee, which has certain FERC-approved authority over the Entergy operating companies' cost allocation for transmission projects and addition of transmission projects to the Entergy construction plan.

3. Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) is a regional entity that includes the area surrounding El Paso and extends from Canada to Mexico, including the provinces of Alberta and British Columbia, the northern portion of Baja California, and all or portions of the 14 western states. WECC is the Regional Entity responsible for bulk electric system reliability in the western interconnection and associated compliance monitoring and enforcement. WECC connects electric utilities in the West to operate at a common synchronized frequency, with 38 separate balancing authorities. El Paso Electric Company is the only investor-owned vertically-integrated utility in Texas that is a member of WECC.[14]

[13] *2017 State of the Market Report for the MISO Electricity Markets*, Potomac Economics, June 2018. Available at: https://www.potomaceconomics.com/wp-content/uploads/2018/07/2017-MISO-SOM_Report_6-26_Final.pdf.

[14] El Paso Electric Company's service territory in WECC is not part of a competitive energy market.

III. SIGNIFICANT COMMISSION ACTION FROM 2017 TO 2018

The Commission develops and modifies rules, policies, and procedures for the competitive electric market in Texas. Within the ERCOT region, transmission and distribution utilities remain subject to traditional rate regulation by the Commission. This section provides an overview of the Commission's actions that reflect changes in the scope of competition in electric markets, including rulemaking activities and legislative implementations, taken from calendar year 2016 through 2018.

A. Retail Market

1. Project No. 45625: Rulemaking Related to the Use of Hand-Held Electronic Devices for Retail Customer Enrollment

On February 14, 2017, the Commission adopted an amendment to 16 TAC § 25.474 to allow a REP or aggregator to use a portable electronic device during customer enrollments via door-to-door sales. The amendment provided customer protections while allowing the option of using new technologies for enrollments.

2. Project No. 47343: Amendments to Reflect the Elimination of the System Benefit Fund and Project No. 48337: Rulemaking to Amend 16 TAC § 25.45 to Provide for a Low Income List Administrator Opt-In Process

In May 2018, the Commission opened Project No. 48337 to fulfill the rulemaking requirements of SB 1976 of the 85th Legislature. The bill modified PURA § 17.007 to require the Commission, upon request by a REP, to facilitate a process with the Texas Health and Human Services Commission to develop a low-income customer identification service. A REP can obtain a list of prequalified low-income customers in order to provide targeted customer service, discounts, bill payment assistance, or other methods of assistance. PURA § 17.007 also requires that the requesting REPs finance the cost of the list. In Project No. 48337, the Commission will consider modifications to 16 TAC § 25.45 to develop details for the process by which REPs receive the list. The rule will also define the method by which the Commission approves the allocation of the cost of developing the low-income customer identification service among the REPs that request the service.

3. Project No. 47545: Rulemaking Proceeding to Establish Filing Schedules for Investor-Owned Electric Utilities Operating Solely Inside ERCOT

In April 2018, the Commission adopted new 16 TAC § 25.247, to fulfill the rulemaking requirements of Senate Bill 735 of the 85th Legislature. The rule applies only to investor-owned electric utilities operating solely inside ERCOT, and establishes a schedule that requires those utilities to make periodic filings with the Commission to modify or review transmission cost of service rates. The key provision of the rule establishes a default time period of 48 months between the date of a utility's last Commission order in a comprehensive rate proceeding and the filing date of the company's next comprehensive rate proceeding. The 48-month period may be extended under certain limited circumstances specified in the rule.

In November 2018, the Commission amended the rule to adopt scheduling requirements for the filing of rate updates by non-investor-owned utility (non-IOU) companies, municipally owned utilities, and electric cooperatives that provide wholesale transmission service in ERCOT. A non-IOU company with a wholesale transmission cost of service equal to or greater than one percent of the total amount of ERCOT transmission costs must file an application for a rate update at least every 48 months. A non-IOU company with a wholesale transmission cost of service less than one percent of the total ERCOT transmission costs must file for a rate update at least every 96 months. During an initial 24-month transition period, all non-IOU companies that have not had a recent rate change must file for an initial (transitional) rate update prior to beginning the scheduled periodic filing requirements.

4. Senate Bill 559: Required No Commission Action

The 85th Legislature passed SB 559, which amended Section 182.022(a) of the Tax Code by clarifying that miscellaneous gross receipts taxes are imposed on each utility company making sales to ultimate customers within a city or town having a population of more than 1,000 regardless of the company's physical location. The bill did not require any Commission rulemaking activities or change Commission ratemaking treatments.

5. Senate Bill 1002: Required No Commission Action

The 85th Legislature passed SB 1002, which addressed recent Accounting Standards Updates issued by the Financial Accounting Standards Board (FASB). These updates adopted changes in the presentation of retirement benefits costs to allow for greater transparency and easier analysis by the financial community. The updated language reflects the FASB changes related to the presentation of pension-related costs and did not require any Commission rulemaking activities or change Commission ratemaking practices.

6. Docket No. 47416: Advanced Meter Deployment in Entergy

Senate Bill 1145, enacted by the 85th Texas Legislature, added PURA § 39.452(k) to address the deployment of advanced metering and meter information networks by Entergy Texas, Inc. (Entergy). In December 2017, the Commission approved Entergy's application for a deployment plan for advanced meters in Docket No. 47416.[15] Deployment of the advanced meter communication network began in September 2018. Deployment of approximately 475,000 advanced meters at customer premises is scheduled to begin in 2019 and be completed by 2021. Entergy's deployment plan includes an educational component to introduce customers to advanced meters and familiarize them with the various features and benefits enabled by advanced meters. The plan also includes a provision for customers who decline to have an advanced meter installed at their

[15] *Application of Entergy Texas, Inc. for Approval of Advanced Metering System (AMS) Deployment Plan, AMS Surcharge, and Non-Standard Metering Service Fees*, Docket No. 47416 (December 14, 2017).

premises. Additionally, the final Commission order approving Entergy's deployment plan required the company to initiate a proceeding to address whether and to what extent the company will participate in Smart Meter Texas. On October 9, 2018, Entergy initiated a proceeding, Docket No. 48745, *Compliance Filing of Entergy Texas, Inc*, which will address: (1) whether and to what extent Entergy will participate in Smart Meter Texas; (2) what changes, if any, should be made to Entergy's web-based customer interface; and (3) whether and to what extent Entergy should provide a process for a customer to authorize third-party direct access to customer advanced metering data.[16]

7. Smart Meter Texas

In the ERCOT competitive market, the transmission and distribution utilities jointly own and operate a web portal known as Smart Meter Texas, which allows residential and small commercial customers with advanced meters access to electric consumption data. PURA § 39.107(b) states that "All meter data, including all data generated, provided or otherwise made available, by advanced meters and meter information networks, shall belong to a customer," and that "a customer may authorize its data to be provided to one or more REPs under rules and charges established by the commission." In May 2018, the Commission approved new parameters related to accessing that data as part of Docket No. 47472.[17] The new parameters are expected to improve the function of Smart Meter Texas, reduce costs, and streamline the process that allows customers to grant a competitive service provider access to their data for home energy management and other programs.

8. Docket No. 45414: Sharyland Utilities Legal Transfer of Assets and Effect on Rates

In December 2015, the Commission ordered Sharyland Utilities to file a comprehensive base rate case by April 30, 2016, due to a significant number of complaints regarding high electricity bills.[18] The Commission staff's report filed in Project No. 44592 found that Sharyland rates for its Cap Rock service territory were two to three times higher than those of other transmission and distribution utilities in Texas due to its small size and low customer density.[19] In the pendency of its 2016 rate case, Sharyland agreed to sell its distribution assets to Oncor Electric Delivery Company in exchange for certain Oncor transmission assets. In March 2017, Oncor also filed a comprehensive base rate case.[20] Because Sharyland did not have a historical test year operating as a transmission-only utility, the Sharyland rate case was dismissed on the condition that Sharyland file a new

[16] *Compliance filing of Entergy Texas, Inc. Relating to Participation in Smart Meter Texas and Changes to its Advanced Metering System*, Docket No. 48745 (pending).

[17] *Commission Staff's Petition to Determine Requirements for Smart Meter Texas*, Docket No. 47472 (Jul. 12, 2018).

[18] *Review of the Rates of Sharyland Utilities, L.P., Establishment of Rates for Sharyland Distribution and Transmission Services, LLC., and Request for Grant of a Certificate of Convenience and Necessity and Transfer of Certificate Rights*, Docket No. 45414 (Sept. 29, 2017).

[19] *Relating to a Project Regarding Sharyland Utility Complaints*, Project No. 44592 (Sept. 8, 2015).

[20] *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 46957 (Oct. 13, 2017).

base rate case in 2020 with a historical test year ending December 31, 2019. Oncor's base rate proceeding was settled, and rates were established for Oncor, including the new customers formerly served by Sharyland.

As shown in Table 4, the individual rate decreases for Sharyland's residential customers ranged from 31% to 84% following the transfer. The amount charged for a typical 1,000 kWh monthly bill decreased by 60%. Similar levels of rate reductions for non-residential customers also occurred. Sharyland's former retail customers transitioned from paying among the highest distribution rates in the state to among the lowest.

Table 4. Effect of Sharyland Distribution Transfer on Residential Rates[21]

Residential Rates			
	Sharyland (Cap Rock) Sept. 1, 2017	**Oncor Mar. 1, 2018**	**Percentage Change**
Customer Charge (per month)	$5.69	$0.89	(84%)
Metering Charge (per month)	$4.31	$2.60	(40%)
Transmission Charge (per kWh)	$0.017564	$0.012056	(31%)
Distribution Charge (per kWh)	$0.062669	$0.021141	(66%)
Typical Residential Bill Impact of Transmission and Distribution Costs			
	Sharyland (Cap Rock) Sept. 1, 2017	**Oncor Mar. 1, 2018**	**Percentage Change**
Monthly Bill (1,000 kWh)	$93.26	$37.67	(60%)

9. Sempra Energy's Acquisition of Oncor

Since the 85th Legislative Session, there were two separate applications to purchase Oncor, the largest transmission and distribution utility in Texas. Oncor's former parent company, Energy Future Holdings (EFH), was in bankruptcy proceedings and still owned an interest in Oncor. EFH was required by the bankruptcy court to obtain Commission approval to proceed with any sale of its Oncor subsidiary. Ultimately, one offer was withdrawn, and the Commission approved the second offer and associated conditions of the purchase.

In October 2016, NextEra Energy filed a joint application with Oncor seeking approval from the Commission for NextEra to purchase Oncor. In March 2017, the

[21] This table shows the impact of the Sharyland to Oncor transfer on a residential customer's transmission and distribution portion of their bill; this does not represent a typical final bill as it does not include energy costs.

Commission indicated that it would require several conditions to approve the transaction: a specific organizational structure, including an independent board; an Oncor credit profile separate from NextEra's; and certain customer protections for Oncor's ratepayers, specifically, assurances to hold ratepayers harmless from risks associated with the transfer. NextEra was unwilling to accept those conditions, and the Commission denied approval of the transaction.

In October 2017, Sempra Energy filed a joint application with Oncor seeking approval from the Commission for Sempra Energy to purchase Oncor. In March 2018, the Commission approved a unanimous settlement agreement containing numerous regulatory commitments—generally referred to as "ring-fencing" provisions—that would continue to protect the integrity of the utility as well as Oncor's ratepayers. The Commission's conditions included an Oncor board independent of Sempra Energy, a requirement that Oncor's credit profile was independent of Sempra Energy, and that Oncor's ratepayers be held harmless from risks associated with the transaction.

10. Effect of the Tax Cuts and Jobs Act of 2017 on Rates

On December 22, 2017, Congress signed into law the Tax Cuts and Jobs Act. Several provisions of this legislation significantly affect electric utilities, most conspicuously through the reduction in the maximum corporate income tax rate from 35% to 21%. In January 2018, the Commission opened Project No. 47945 in response to this federal tax legislation to address its impacts on the rates of regulated utilities in Texas.[22]

In February 2018, the Commission exercised its authority under PURA § 14.151 and issued an accounting order in Project No. 47945 that directed regulated utilities and Commission staff to work together on a case-by-case basis to determine the appropriate mechanism to incorporate the new lower federal income tax amount into the rates paid by customers. The order instructed utilities to preserve any changes in federal income tax expense charged by utilities until rates can be changed by recording as a regulatory liability: (1) the difference between revenues collected under existing rates and the revenues that would have been collected had those rates been set using the revised, lower income tax rates and (2) the balance of any excess accumulated deferred federal income taxes (ADFIT) resulting from the decrease in the tax rate.

The Commission approved final orders with provisions similar to those discussed above for three electric utilities with base rate orders dated either just prior to or just after enactment of the Tax Cuts and Jobs Act. As instructed by the Commission, other regulated electric utilities have utilized various available alternative rate mechanisms, such as interim transmission and distribution cost recovery filings or credit tariff riders, to take the first step of reflecting the impact of the lower federal income tax expense in rates charged to customers. Two utilities had previously planned to initiate full base rate proceedings in the spring of 2018 and those companies incorporated the impacts of the Tax Cuts and Jobs Act into those filings. As of the date of this report, the Commission has approved Texas

[22] *Proceeding to Investigate and Address the Effects of the Tax Cuts and Jobs Act of 2017 on the Rates of Texas Investor-Owned Utility Companies*, Project No. 47945 (Aug. 30, 2018).

electric rates approximately $333 million lower than they would have been absent the change in federal income tax expense.

Reflecting the change in income tax expense is the first step in the process of reflecting the lower tax rate in the bills of electric customers. The return of excess ADFIT is another significant impact of the Tax Cuts and Jobs Act. ADFIT is collected from ratepayers at the higher 35% tax rate, but is now owed to the federal government at the lower 21% rate. The calculation of excess ADFIT is complicated by the normalization provisions of the Internal Revenue Code. Some electric utilities have already reflected the return of excess ADFIT through the alternative rate mechanisms discussed above. However, the majority of electric utilities will address the issue in future base rate proceedings. Not all impacts of the Tax Cuts and Jobs Act have been identified to date. The Commission will address such impacts as they become known and quantifiable.

The Commission does not have rate jurisdiction over power generators and REPs within ERCOT and thus has no ability to require reductions in federal income tax expense to be flowed through to ratepayers. However, the Commission expects that the forces of competition will encourage these entities to flow these reductions to the customer and reduce prices.

11. Hurricane Harvey Storm Costs

Hurricane Harvey, one of the most costly natural disasters in United States history, made landfall near Rockport, Texas on August 25, 2017 as a Category 4 storm. The wind speeds dropped quickly, but the rainfall persisted as the storm slowly moved northeast to Houston. Before Hurricane Harvey exited Texas the following Wednesday, the storm caused widespread flooding. Wind damage to utility facilities was concentrated in the area where Harvey initially made landfall, whereas damage to utility infrastructure because of the flooding was widespread throughout the affected region. The storm ultimately affected the Texas coastline from Corpus Christi to the Louisiana border. The hurricane damaged transmission and distribution infrastructure, flooded substations, and caused widespread power outages and displaced numerous customers. Hurricane Harvey resulted in a peak of 323,320 electric outages at any one time, and damage to electric infrastructure is estimated at approximately $700 million. Four Texas utility companies have requested recovery of costs related to Hurricane Harvey through rate applications: AEP Texas, Entergy Texas, Texas New Mexico Power Company (TNMP), and CenterPoint.

PURA § 36.401 enables an electric utility to obtain timely recovery of storm reconstruction costs and to use securitization financing to recover those costs, which lowers the carrying costs relative to conventional financing methods. On August 7, 2018, AEP Texas filed an application under PURA § 36.401-.405 to begin the process of securitizing Hurricane Harvey storm costs.[23] The system restoration costs presented in its case total $415,166,903, which includes costs incurred through April 30, 2018.

[23] *Application of AEP Texas Inc. for Determination of System Restoration Costs,* Docket No. 48577 (Aug. 7, 2018) (pending).

Entergy Texas is requesting recovery of $20.5 million in Hurricane Harvey reconstruction costs though its base rate proceeding filed on May 15, 2018.[24] TNMP is requesting recovery of $6.6 million in Hurricane Harvey reconstruction costs through its base rate proceeding filed on May 30, 2018.[25]

CenterPoint incurred and recorded as a regulatory asset $59.2 million of Hurricane Harvey reconstruction costs. CenterPoint has included approximately $23 million in Hurricane Harvey distribution related capital costs in its recent Distribution Cost Recovery Factor application.[26] CenterPoint is preparing to file a comprehensive base rate proceeding in April 2019 in which the company is expected to seek recovery of the remaining reconstruction costs. CenterPoint may seek recovery of the remaining Hurricane Harvey reconstruction costs as part of its base rate proceeding, during which the prudence, reasonableness, and necessity of all reconstruction costs will be determined.

12. Power to Choose

The Power to Choose website allows REPs to display retail electric offers on a Commission-run website to aid customers living in an area open to customer choice to choose a retail electric plan. In response to the Commission's direction at its June 28, 2018 open meeting, Commission staff identified a number of opportunities to increase transparency in offers and improve the customer's shopping experience.

After reviewing these issues, the Commission directed staff to include a search filter that allows customers to exclude pricing plans that include minimum usage fees and plans that charge a different price per kWh depending on the total amount of kWh used. The Commission also directed staff to limit the number of plans of any one given type (fixed, variable, and indexed) that a REP may post on the website to encourage REPs to offer a variety of meaningfully different plans and also to display offers from more REPs on the first page of search results. Commission staff also developed instructional material for the website that focuses on helping customers use the website to better choose the right plan.

The Commission also directed each REP to develop a Spanish-language version of each offer it places on www.powertochoose.org for the Commission-managed Spanish-language site www.poderdeescoger.org. The Commission continues to monitor each site to ensure the same plans are available.

[24] *Entergy Texas Inc.'s Statement of Intent and Application for Authority to Change Rates*, Docket No. 48371 (May 15, 2018) (pending).

[25] *Application of Texas-New Mexico Power Company for Authority to Change Rates,* Docket No. 48401 (May 30, 2018) (pending).

[26] *Application of CenterPoint Energy Houston Electric, LLC for Approval to Amend Its Distribution Cost Recovery Factor*, Docket No. 48226, (Apr. 5, 2018).

13. Docket No. 46368: Application of AEP Texas North Company for Regulatory Approvals Related to the Installation of Utility-Scale Battery Facilities

In Docket No. 46368, which was initiated in September 2016, AEP requested that the Commission declare that AEP's proposed installation of two utility-scale lithium-ion batteries complies with Texas law and that the batteries would be considered distribution assets eligible for inclusion in distribution cost of service rates. AEP proposed installing each battery for two specific technical problems that could be addressed by a utility-scale battery. One design would provide a source of electric energy to serve retail customers when AEP's transmission facilities could not deliver electricity to those customers. The other battery was intended to provide a source of electric energy to prevent exceedances of the rated capacity of AEP's distribution facilities. The cost of the facilities would be included within the company's distribution rates. AEP proposed that the cost of the energy used to charge the two batteries be passed on to all ERCOT customers through unaccounted-for-energy (UFE) charges.

The Commission determined that the case did not provide sufficient information to allow the Commission to make the declarations sought by AEP with respect to the proposed battery installations. Further, the Commission deemed it imprudent to make any declarations in the docket because any such declaration could limit unnecessarily the future use of energy-storage devices in ERCOT. Ultimately, the Commission dismissed the proceeding and directed Commission staff to open a project in which the necessary policy issues could be addressed. Project No. 48023, *Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service*, was initiated in February 2018 and is currently pending at the Commission.

B. ERCOT Wholesale Market

1. Operating Reserves Demand Curve

The Operating Reserve Demand Curve (ORDC), implemented at the Commission's direction in June 2014, improves price formation by allowing wholesale prices to reflect more fully the value of operating reserves during resource scarcity. The ORDC assigns an economic value to the amount of operating reserves, which is the amount of excess generating capacity available to maintain reliability. In 2018, the Commission directed ERCOT to remove capacity that ERCOT procures through out-of-market actions from the ORDC calculation. Removing out-of-market actions ensures price formation for market-based decisions is not impeded when reserves are scarce. The Commission continues to evaluate the ORDC to ensure its contribution to price formation appropriately reflects the costs of meeting demand and the underlying needs of the system, and results in market-based offers sufficient to meet system demand and ensure reliability.

2. Wholesale Market Design Initiatives

The Commission continues to consider any potential improvements to the market design and its rules that could yield additional price formation efficiencies, reduce the impact of out-of-market actions on market-based offers, and provide opportunities for entry of new technology, while maintaining reliability. The Commission is currently evaluating various proposals that may improve the market design. One such initiative is real-time co-optimization, which may allow for more efficient dispatch of existing generation capacity across the entire ERCOT resource fleet. The Commission is also considering whether to incorporate marginal transmission losses into the real-time dispatch model. The farther the distance that electricity must travel from generation to load, the greater the loss of electricity over transmission lines. Accounting for marginal losses may incentivize generators to locate closer to load and may result in changes to energy prices based on location of the load relative to generation resources. The Commission has opened two projects to evaluate these concepts.[27]

3. Review of ERCOT Market Performance in Summer 2018

The retirement of a number of older coal-fired generation plants during the winter of 2017-2018 raised concerns that the corresponding lower resulting reserve margin (the margin by which generation capacity exceeds the anticipated peak consumption by customers – the peak demand) could result in reliability issues in the summer of 2018. While the region set new all-time peak demand records and prices were higher than in previous years, the system operated reliably and efficiently throughout the summer.

In August 2018, the Commission opened a project to review ERCOT market performance in the summer of 2018.[28] In this project, the Commission solicited comments from market participants to assist in evaluating the market performance with respect to retail mass transitions, market participant credit, grid readiness, and wholesale price formation. In 2018, the ERCOT system broke the August 2016 all-time system-wide peak demand record of 71,093 MW twice in July: on July 18, ERCOT hit a system-wide peak demand of 72,192 MW and July 19, ERCOT once again set a new all-time system-wide peak demand of 73,308 MW. Table 5 shows the ERCOT peak demand growth since 2011.

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[27] *Review of the Inclusion of Marginal Losses in Security-Constrained Economic Dispatch*, Project No. 48539 (pending) and *Review of Real-Time Co-optimization in the ERCOT Market*, Project No. 48540 (pending).

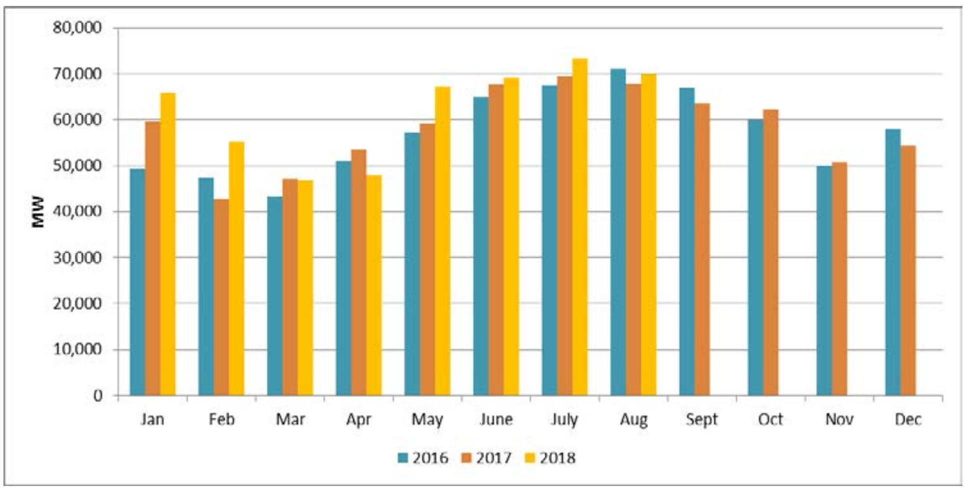
[28] *Review of Summer 2018 ERCOT Market Performance*, Project No. 48551 (pending).

Table 5. ERCOT Peak Demand Growth for 2012 – 2018

Year	ERCOT Peak Demand (MW)	Percentage Change from Prior Year
2011	68,379	-
2012	66,548	(2.78%)
2013	67,245	1.05%
2014	66,454	(1.18%)
2015	69,877	5.15%
2016	71,093	1.74%
2017	68,028	(4.31%)
2018	73,308	7.776%

Figure 4 shows the hourly peak load in ERCOT for each month from January 2016 to August 2018.

Figure 4. Monthly Peak Demand in ERCOT for January 2016 – August 2018



4. Project No. 45078: Rulemaking Related to Distributed Generation Interconnection Agreements

Distributed generation generally refers to small-scale electricity generation such as rooftop solar panels or windmills that are close to the end user. In December 2016, in Project No. 45078, the Commission adopted changes to the agreement form in the standard utility tariff for interconnection of distributed generation.[29] This interconnection agreement is technical in nature, providing for specifications and parameters for interconnecting a customer's distributed generation facility with a utility's distribution system. The adopted

[29] *Rulemaking Related to Distributed Generation Interconnection Agreement*, Project No. 45078 (December 19, 2016).

amendments accommodate changes in the distributed generation market, recognizing that end use customers may authorize third parties that may have more technical expertise and knowledge to enter into the interconnection agreement with the utility on behalf of the end-use customer. The adopted amendments clarify for the end-use customer that the Commission does not regulate the relationship between the end-use customer and any entity that the customer may authorize to enter into the agreement on their behalf unless that entity is already regulated by the Commission. The amendments also allow the end-use customer the flexibility to select an arrangement that best suits individual needs.

5. Project No. 45927: Rulemaking Regarding Emergency Response Service

Beginning in June 2016, the Commission considered amendments to the rules governing ERCOT Emergency Response Service. The proposed changes considered whether ERCOT should be authorized to deploy Emergency Response Service to forestall load curtailment due to local transmission emergencies, and whether current Emergency Response Service providers should be released from their contracts to allow participation in alternative services markets, such as Must-Run Alternative and Reliability Must-Run Service. After considering comments from interested parties, the Commission declined to adopt the proposed changes related to deployment for local transmission emergencies, but adopted changes to 16 TAC §25.507 to permit Emergency Response Service participants to be released from their contracts in order to participate in Must-Run Alternative services.[30]

6. Project No. 46369: Reliability Must-Run Service in ERCOT

In 2017, the Commission amended 16 TAC §25.502 to lengthen the advanced notice to ERCOT that a generation resource owner must provide of its intent to suspend operations. This change permits ERCOT 60 additional days to request and evaluate market-based offers to replace any capacity that may be necessary to maintain reliability, rather than taking an out-of-market action, such as requiring the retiring unit to stay online. In addition, the Commission changed its rules to allow resources that participate in a voluntary interruptible load response program to submit market-based offers for this capacity replacement.[31]

7. Load Transfers Between Regions

Four utilities have requested to transfer load to or from the ERCOT region: Lubbock Power and Light, Rayburn Country Electric Cooperative, East Texas Electric Cooperative, and Lyntegar Electric Cooperative.

On September 1, 2017, Lubbock filed an application in Docket No. 47576 seeking approval from the Commission to transfer 470 MW of its load from SPP into ERCOT by June 2021, citing lower rates for the utility’s customers, congestion reduction, production

[30] *Rulemaking Regarding Emergency Response Service*, Project No. 45927 (Mar. 30, 2017).

[31] *Rulemaking Relating to Reliability Must-Run Service*, Project No. 46369 (Sept. 29, 2017).

cost savings, and operational benefits. In March 2018, the Commission approved, with modifications, an unopposed stipulation between the parties that resolved all of the pending issues in the proceeding.[32] The settlement requires Lubbock to pay $22 million annually for five years to ERCOT wholesale transmission customers through a monthly credit rider, and a one-time payment of $24 million to Southwestern Public Service Company upon disconnection from SPP. Lubbock also agreed that it would not disconnect the transferred load from ERCOT in the future without prior approval from the Commission. Although Lubbock is not required to enter retail competition, the stipulation represented Lubbock's intention to study doing so. The remaining 170 MW of Lubbock's load will remain in SPP.

In August 2018 the Commission also approved Lyntegar Electric Cooperative's application to build a transmission line, which resulted in the transfer of five megawatts of load in west Texas from ERCOT into SPP as part of a CCN to serve a new transmission level customer.[33]

Two other electric cooperatives have requested to transfer load into ERCOT. Rayburn Country Electric Cooperative, in northeast Texas, has requested to transfer 96 MW of load from SPP into ERCOT by 2020; the request is pending in Docket No. 48400.[34] East Texas Electric Cooperative, also located in northeast Texas, has requested to transfer 35 MW of load from SPP into ERCOT by 2018; the request is pending in Docket No. 47898.[35]

Because the majority of the issues raised in the Lubbock case were settled, issues related to future transfers, such as which entity should bear the cost, remain to be answered in future cases. In response to these recent requests, the Commission opened Project No. 48249, *Rulemaking Regarding Load Transfer between Power Regions*, to address the process for future requests to transfer load into or out of ERCOT.[36]

8. Southern Cross Transmission

In August 2016, the Commission opened Project No. 46304 and ordered ERCOT to complete twelve directives regarding market participant issues, operational considerations, and emergency procedures in order to facilitate the interconnection of the

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[32] *Application of the City of Lubbock through Lubbock Power and Light for Authority to Connect a Portion of its System with the Electric Reliability Council of Texas,* Docket No. 47576 (Mar. 15, 2018).

[33] *Application of Lyntegar Electric Cooperative, Inc. to Amend a Certificate of Convenience and Necessity for the Welch 115-kV Transmission Line Project in Gains and Dawson Counties*, Docket No. 47838 (Aug. 30, 2018).

[34] *Joint Application of Rayburn Country Electric Cooperative, Inc. and Lone Star Transmission LLC to Transfer Load to ERCOT, for Sale of Transmission Facilities, and Transfer of Certificate Rights in Henderson and Zandt Counties,* Project No. 48400 (pending).

[35] *Petition of East Texas Electric Cooperative, Inc. for Authority to Transfer 35 Megawatts of Load into the Electric Reliability Council of Texas,* Docket No. 47898 (pending).

[36] *Rulemaking Regarding Load Transfer Between Power Regions,* Project No. 48249 (pending).

Southern Cross Transmission Direct Current Tie (DC Tie).[37] In September 2016, the Commission approved a transmission line to interconnect the Southern Cross Transmission DC Tie to the ERCOT grid in Docket No. 45624. The Commission's order on rehearing identified operational, emergency, and market implementation issues that needed resolution to implement the order. [38] The procedures developed under these directives will set the standards for the Southern Cross Transmission DC Tie as well as any future similar projects. Currently, ERCOT is working within its stakeholder groups to resolve the issues identified in the twelve directives and is submitting regular updates to the Commission regarding its progress.

C. Oversight and Enforcement Actions

The Commission enforces statutes, rules, and orders to protect customers, the electric markets, and the reliability of the electric grid, and to promote fair competition. The Commission's enforcement efforts in the electric industry focus on violations of PURA, the Commission's rules, and ERCOT protocols.

During the period from September 1, 2016 through August 31, 2018, the Commission assessed $5,735,900 in penalties against electric market participants. These penalties are remitted to the state's general revenue fund. Table 6 summarizes electric industry notices of violations since September 2016 by each market sector. During this time period, Commission staff opened 312 investigations for the electric industry and closed 276 investigations.

Table 6. Notices of Violations

Violation Type	Total Penalty Amount
Retail Market Violations	$3,632,600
Service Quality Violations	$1,152,300
Wholesale Market Violations	$951,000
TOTAL	**$5,735,900**

In addition to the imposition of administrative penalties, the Commission uses other mechanisms in exercising its enforcement duties, including revoking a company's certificate to operate. In addition, some companies may be required to relinquish a certificate as part of a settlement after enforcement action has concluded. Table 7 provides the number of certificates revoked or relinquished.

[37] *Oversight Proceeding Regarding ERCOT Matters Arising Out of Docket No. 45624 (Application of the City of Garland to Amend a Certificate of Convenience of Necessity for the Rusk to Panola Double-Circuit 345-kV Transmission Line in Rusk and Panola Counties)*, Project No. 46304 (pending).

[38] *Application of the City of Garland, Texas, for a Certificate of Convenience and Necessity for the Proposed Rusk to Panola Double-Circuit 345-kV Transmission Line in Rusk and Panola Counties, Texas*, Docket No. 45624 (May 23, 2017).

Table 7. Certificates Revoked or Relinquished

Type	Number
Certificates Revoked	0
Certificates Relinquished as Part of Settlement	0
Certificate Relinquished Voluntarily	8

The Oversight and Enforcement Division also issues warning letters to companies in the electric market when it determines that a violation occurred, but given the circumstances surrounding the violation and other mitigating concerns, no administrative penalty is warranted. During the period from September 1, 2016 to August 31, 2018, the Oversight and Enforcement Division issued 203 warning letters. Table 8 details the warning letters issued by the agency since September 1, 2016.

Table 8. Warning Letters

Warning Letter Type	Number
Retail Market Warning Letter	39
Service Quality Warning Letter	1
Wholesale Market Warning Letter	163
TOTAL	**203**

Finally, the Commission generally seeks to reimburse money directly to customers when appropriate. From September 1, 2016 to August 31, 2018, the Commission ordered the reimbursement of $1,661,692 to Texas electric customers.

In addition to its enforcement activities, the Commission also enters into voluntary mitigation plans with companies owning generation that request one through a contested case proceeding pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e). A voluntary mitigation plan provides a safe harbor against allegations of market manipulation. Generators with less than 5% of installed capacity cannot exercise market power under PURA. The generators with installed generation capacity above the threshold have the ability to request that the Commission approve certain bidding practices. Currently, Calpine and NRG have voluntary mitigation plans. Luminant's voluntary mitigation plan was terminated during the recent merger proceeding.[39] The Commission entered into one voluntary mitigation plan in 2017[40]; however, Exelon's installed capacity is now lower than 5%, so its voluntary mitigation plan was terminated.

[39] *Application of Luminant Power Generation LLC, Big Brown Power Company LLC, Comanche Peak Power Company LLC, La Frontera Holdings, LLC, Oak Grove Management Company LLC, And Sandow Power Company Under Section § 39.158 Of The Public Utility Regulatory Act*, Docket No. 47801 (April 2, 2018).

[40] *Request for Approval of a Voluntary Mitigation Plan for Exelon Generation Company, LLC*, Docket No. 47378 (Aug. 31, 2017).

IV. LEGISLATIVE RECOMMENDATIONS

1. Outside Counsel for Proceedings before Regional Transmission Organizations

Regional Transmission Organizations (RTOs) manage the power grid across wide regions of the United States. Most of Texas is inside the ERCOT region; however, there are significant portions of East Texas and the Panhandle that are in the Midcontinent Independent System Operator and the Southwest Power Pool. Issues arise in these RTOs that have significant impact on Texas ratepayers, such as how transmission infrastructure costs will be shared. These proceedings tend to be lengthy and complicated, requiring specialized legal and consulting services.

Texas Utilities Code § 39.4525 currently authorizes the Commission to use outside consultants, auditors, engineers, or attorneys to represent the Commission in proceedings before the Federal Energy Regulatory Commission. This provision has been an important tool for the Commission to respond to complex matters in the federal arena to enable it to protect the public interest in Texas. The Commission recommends that the Legislature expand the language in this statute to include the ability to hire outside assistance for proceedings before the RTOs to provide those same protections to Texas ratepayers in those areas.

2. Default Violations

Under Section 15.024(d) of the Texas Utilities Code, if a person that the Commission issues a Notice of Violation against does not respond to the Notice of Violation within twenty days, then the Commission considers the person to be in default of the Notice of Violation. Section 15.024(f) requires the Executive Director of the Commission to set a hearing at the State Office of Administrative Hearings (SOAH) even though the person has been non-responsive to the Notice of Violation. After the SOAH hearing, the violation is then decided by the Commission. The Commission proposes that the Legislature consider amending Section 15.024(f) to remove the requirement for an administrative hearing before proceeding to the Commission in situations in which a person has failed to respond to the Notice of Violation. This change would allow these default violations to move more quickly through the process; thus, providing a faster resolution and saving resources for both the Commission and SOAH. The proposed change is also consistent with the Texas Water Code; therefore, the change would align telecommunications and electric proceedings with the Commission's process in water utility proceedings.

3. Registration of Retail Electric Brokers

The Commission currently has the authority to certify retail electric providers and register electric aggregators. However, there are additional businesses that help customers navigate the marketplace to find a retail electric plan. Retail electric brokers connect buyers with sellers of electricity. While not necessary for every customer, some customers use brokers and are willing to pay for this service. Many non-residential electric customers use brokers as an alternative to developing in-house expertise to negotiate a retail electric contract. These can be commercial and industrial business owners, but also includes churches, schools, and other community organizations.

Some non-residential customers have the desire and the ability to enter into more sophisticated contracts for retail power. This increase in complexity allows non-residential customers to achieve lower rates, but can also expose them to more financial risk. For residential customers, retail electric brokers often use the "concierge" business model, in which the customer authorizes the retail electric broker to make electricity contract decisions on his behalf. This requires the concierge broker to maintain customer-specific information related to the customer's energy usage and payment information. For all types of service, the customer depends on the retail electric broker's energy expertise. When a retail electric broker offers bad advice, it is the final customer who ultimately pays the price.

The Commission regulates many participants in the retail electric market and has a suite of customer protection rules, including requirements that those participants demonstrate industry expertise and financial stability. Electric aggregators perform many of the same functions as retail electric brokers and are required to register with the Commission under section 39.353 of the Texas Utilities Code. The Commission does not regulate retail electric brokers, and there are currently no customer protection or business requirements specifically for individuals or companies acting as brokers. There is no recourse for customers beyond civil litigation and fraud statutes.

The Commission recommends that the Legislature require retail electric brokers to register with the Commission in a manner similar to retail electric aggregators to ensure that customers who use a retail electric broker have adequate consumer protections.

4. Electric Industry Security

The security and safety of electric utility assets has always been a prime concern for utility operators. Without secure infrastructure, utilities cannot meet their obligations to provide electric service and cannot meet their fiduciary obligations to their shareholders. As such, utilities have invested substantially, including physical, financial, and intellectual resources, toward ensuring the safety of their assets. Much of this investment is on prominent display when utilities respond to and recover from natural disasters. However, utilities are also protecting infrastructure in numerous ways not evident to the public and need to be careful not to disseminate information about the grid's potential vulnerabilities.

Utilities' efforts to secure their information resources against malicious actors have continued to evolve since the introduction of computer technology. Cybersecurity is a challenging field for a regulatory agency such as the Commission, which typically sets specific rules for utilities to follow. Because of the rapidly evolving nature of the threat, prescriptive regulation has limited effectiveness in combatting cybersecurity threats. In addition, a focus on compliance to regulation may draw resources away from effective responses that are not part of the regulations. The Commission can bring value in a facilitation role to ensure continued public confidence in the safety and reliability of electric service and to respond to legislative concerns. For that reason, the Commission has brought on additional staff to collaborate with utilities on their cybersecurity efforts.

The Commission recommends that the Legislature establish a collaborative cybersecurity outreach program that would bring additional resources to bear, without impeding work already being done by utilities. This program would include regular meetings with utilities to identify best practices and emerging threats, coordination of workforce training and security exercises, and related research.

5. Review of Power Generation Mergers and Acquisitions

Over the last few years, the Commission has begun receiving more applications for review of power generation company mergers and acquisitions, growing from five such applications in 2015 to 26 in 2018. Furthermore, the applications are not filed at a steady pace over time, but tend to arrive late in the year. These merger and acquisition transactions may be put on hold pending Commission review, causing regulatory uncertainty and impeding business. Two sections of the Texas Utilities Code are relevant to the review of these applications. In the course of processing these applications, the Commission has noted that opportunities may exist to harmonize and clarify these two sections, improving the speed and efficiency of such transactions and reducing regulatory burden.

Section 39.158 requires the Commission to review mergers and acquisitions of entities if the newly merged companies will "offer for sale" more than one percent of the "total electricity for sale" in the state. The Commission is further required by Section 39.158 to approve the merger or acquisition, unless the new company exceeds a 20% installed generation capacity limit set by Section 39.154. The review required by Section 39.158 serves as a threshold to determine whether review for compliance under Section 39.154 is necessary. While the two sections use similar language, the phrasing is not identical.

First, the phrase "total electricity for sale" is not defined in the statute but, because Section 39.158 functions as a trigger for review under Section 39.154, may be inferred to mean installed generation capacity. The Legislature may wish to clarify that the two phrases are intended to be synonymous.

Texas Utilities Code Section 39.154 also specifies that the prohibition on ownership of more than 20% of the installed generation capacity is applicable only in a power region open to customer choice. This provision was intended to prevent a power generation company from having the oligopoly power to influence electricity prices on its own. For power regions that have not instituted customer choice, Commission oversight of the rate-regulated utilities suffices to protect retail customers. The Legislature may wish to clarify that the review under Section 39.158 applies only in a power region open to customer choice.

Finally, the Legislature should consider whether the one percent threshold for review of mergers may be overly stringent. At a one percent threshold, numerous transactions are required to undergo regulatory review despite the negligible likelihood of breaching the 20% limit, which delays these transactions unnecessarily. Therefore, the Commission recommends increasing the threshold for review of mergers and acquisitions of power generation companies from one percent to 10% of installed generation capacity. The Commission does not recommend changing the limit that prevents one company from owning more than 20% of the installed generation capacity.

6. Use of Battery Storage in ERCOT

Since the unbundling of the electric market in ERCOT into retail, generation, and transmission and distribution businesses, new technologies have developed that the Commission believes pose new questions for the Legislature's consideration. Specifically, the ownership and deployment of electricity from battery storage devices has emerged as an issue that would benefit from legislative clarity.

Transmission and distribution utilities

AEP Texas, a TDU operating in ERCOT, brought this issue to the Commission in the form of a request to install utility-scale batteries to address reliability issues in two sparsely populated areas in its distribution system. The Commission dismissed the docket on the grounds that there was insufficient information for a decision. To gather additional information, the Commission opened a project to evaluate more broadly the possibility of an electric utility owning and operating an energy storage device. In this project, the Commission has received extensive, sharply differing comments on whether PURA currently allows a TDU to own or operate an energy storage device.

Texas Utilities Code Section 35.152 provides that electric energy storage that is "intended to be used to sell energy or ancillary services at wholesale" are generation assets, and the owner or operator is a power generation company. However, section 31.002(10) defines a power generation company as a person that generates electricity that is intended to be sold at wholesale, does not own a transmission and distribution facility, and does not have a certificated service area. Finally, Section 39.105 states that a TDU "may not sell electricity or otherwise participate in the market for electricity except for the purpose of buying electricity to serve its own needs." For a TDU that owns and operates a storage device on its system, an argument can be made that the TDU does not "intend" to sell power at wholesale or participate in the market for electricity. Rather, the device is intended to support reliability. Others argue the opposite.

A number of options exist for the ownership and operation of energy storage devices by TDUs. Options include the following: prohibiting a TDU's involvement with an energy storage device other than to provide transmission and distribution service to it; allowing a TDU to contract with a power generation company for reliability service from an energy storage device; limiting a TDU's ownership and operation of an energy storage device only to limited, specified circumstances such as to address a reliability issue in a sparsely populated area in its distribution system; and allowing a TDU to own and operate an energy storage device in circumstances where the TDU's ownership and operation of the device would provide the lowest cost transmission and distribution service. The Legislature may consider whether further direction is warranted regarding the ownership and operation of energy storage devices by TDUs.

Electric cooperatives and municipally owned utilities

A related, but distinct, ownership issue exists for electric cooperatives and municipally owned utilities. As previously mentioned, Texas Utilities Code Section 31.002(10) defines "power generation company" using the term "person" to describe the entity being defined. However, the definition of "person" in Texas Utilities Code Section 11.003(14) excludes electric cooperatives and municipally owned utilities. Further, both electric cooperatives and municipally owned utilities can, and do, own transmission and distribution facilities and have certificated service areas in this state.

Texas Utilities Code sections 35.151 and 35.152 require the "owners or operators" of electric energy storage equipment (i.e. batteries) to register as a power generation company. However, electric cooperatives and municipally owned utilities cannot qualify as a "power generation company" as defined by Section 11.003(14). Therefore, it could be inferred that they are not permitted to own or operate a battery without bringing into question their status as a municipally owned utility or electric cooperative.

The Legislature could provide clarity with a statutory exemption for electric cooperatives and municipally owned utilities in Texas Utilities Code sections 35.151 and 35.152 to allow them to own or operate batteries without registering as a power generation company.

7. Recovery of Costs of Advanced Meter Deployment in All Non-ERCOT Areas of the State

The Commission recommends that utilities regulated under PURA Subchapters K and L, electing to deploy advanced meters and metering information networks, be allowed to recover the reasonable and necessary costs of advanced meter deployment. Senate Bill 1145 enacted in 2017 paved the way for Entergy's advanced meter deployment plan. Legislation allowing for cost recovery would expand the benefits of grid modernization to the utility customers in the remainder of the State.

Appendix A – Acronyms and Abbreviations

AEP	American Electric Power
AEP Central	American Electric Power – Texas Central Division
AEP North	American Electric Power – Texas North Division
ADFIT	Accumulated Deferred Federal Income Tax
CenterPoint	CenterPoint Energy Houston Electric, LLC
Commission	Public Utility Commission of Texas
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Committee
IMM	ERCOT Independent Market Monitor
kWh	Kilowatt-hour
MISO	Midwest Independent System Operator
MMBtu	One Million British Thermal Unit (BTU)
MW	Megawatt
MWh	Megawatt-hour
NextEra	NextEra Energy
OMS	Organization of Miso States
Oncor	Electric Delivery Company
ORDC	Operating Reserves Demand Curve
PURA	Public Utility Regulatory Act
REP	Retail Electric Provider
Sempra	Sempra Energy
Sharyland	SharylandUtilities, L.P.
SPP	Southwest Power Pool
TDU	Transmission and Distribution Utility
TNMP	Texas-New Mexico Power Company
WECC	Western Electricity Coordinating Council

FINANCIAL IMPACT OF QUESTION 3

FINANCIAL IMPACT – CANNOT BE DETERMINED

OVERVIEW

Question 3 proposes to amend Article 1 of the *Nevada Constitution* by adding a new section requiring the Nevada Legislature to provide by law for an open, competitive retail electric energy market no later than July 1, 2023. To ensure that protections are established that entitle customers to safe, reliable, and competitively priced electricity, the law must also include, but is not limited to, provisions that reduce costs to customers, protect against service disconnections and unfair practices, and prohibit the grant of monopolies and exclusive franchises for the generation of electricity.

FINANCIAL IMPACT OF QUESTION 3

If approved by the voters at the 2016 and 2018 General Elections, Question 3 will require the Legislature and Governor to approve legislation creating an open, competitive retail electric energy market between the effective date (November 27, 2018) and July 1, 2023. The Fiscal Analysis Division cannot predict when the Legislature and Governor will enact legislation that complies with the Initiative, nor can it predict how the constitutional provisions proposed within the Initiative will be implemented or which state or local government agencies will be tasked with implementing and administering any laws relating to an open, competitive retail electric energy market. Thus, the financial impact relating to the administration of the Initiative by potentially affected state and local government entities cannot be determined with any reasonable degree of certainty.

Under current law, state and local governments, including school districts, may receive revenue from taxes and fees imposed upon certain public utilities operating within the jurisdiction of that government entity, based on the gross revenue or net profits received by the public utility within that jurisdiction. The Fiscal Analysis Division cannot determine what effect, if any, the open, competitive retail electric energy market created by the Legislature and Governor may have on the consumption of electricity in Nevada, the price of electricity that is sold by these public utilities, or the gross revenue or net profits received by these public utilities. Thus, the potential effect, if any, upon revenue received by those government entities cannot be determined with any reasonable degree of certainty.

Additionally, because the Fiscal Analysis Division cannot predict whether enactment of Question 3 will result in any specific changes in the price of electricity or the consumption of electricity by state and local government entities, the potential expenditure effects on those government entities cannot be determined with any reasonable degree of certainty.

Prepared by the Fiscal Analysis Division of the Legislative Counsel Bureau – August 12, 2016

The Governor's Committee on Energy Choice

Report of Findings and Recommendations to the Governor

July 1, 2018

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EXECUTIVE SUMMARY

At the General Election on November 8, 2016, Nevada's voters approved Ballot Question 3, the Energy Choice Initiative ("ECI"). ECI is a proposed amendment to the Nevada Constitution that would require that, "Not later than July 1, 2023, the Legislature shall provide by law for provisions…to establish an open, competitive, retail electric energy market," and that,"[e]lectricity markets be open and competitive so that all electricity customers are afforded meaningful choices among different providers, and that economic and regulatory burdens be minimized in order to promote competition and choice in the electric energy market." The proposed amendment would effectively require Nevada to transition from its current structure in which its primary electric utility is vertically integrated, to a new system in which electricity providers compete in a restructured, competition-based marketplace. In order for ECI to become law, Nevada's voters must approve the proposed constitutional amendment a second time at the 2018 General Election.

Following initial voter approval of ECI, Governor Brian Sandoval announced during his January 2017 State of the State Address a plan to "Create by Executive Order the Governor's Committee on Energy Choice [to] help prepare us for the complicated changes that lay ahead if Nevadans approve [ECI]." The Governor signed Executive Order 2017-03, establishing the Governor's Committee on Energy Choice, on February 9, 2017, three days after the start of the 2017 Regular Legislative Session. Executive Order 2017-03 required the Committee to "[i]dentify the legal, policy, and procedural issues that need to be resolved, and to offer suggestions and proposals for legislative, regulatory, and executive actions that need to be taken for the effective and efficient implementation of [ECI]." This Executive Order was amended shortly after the conclusion of the legislative session to require the Committee to additionally study whether ECI's proposed constitutional amendment would have an effect on specific renewable energy policy proposals, namely renewable portfolio standards and the development of community solar gardens.

The Energy Choice Committee was initially comprised of 25 members representing a broad coalition of community stakeholders and perspectives, including state legislators, executive agency directors, commercial electricity customers, private sector industry representatives, state regulators and consumer advocacy representatives, conservation group representatives, organized labor representatives, and representatives from Nevada's rural electric co-operatives. The Committee first met on April 26, 2017, and concluded its work on June 18, 2018. Committee Chairman Mark Hutchison organized the Committee into five Technical Working Groups to engage in particularized studies of specific issues relating to ECI and the restructuring of electricity markets. Between April of 2017 and June of 2018, the Committee and its working groups met more than 30 times and heard from dozens of policy experts from Nevada and from around the nation. These meetings were held subject to

Nevada's Open Meeting Law, and there was significant public engagement and participation throughout the Committee's work. Public comment submitted to the Committee has been included in Appendix C. This report constitutes the findings and policy recommendations adopted by the Committee as a result of this extensive deliberative process.

Some of the prominent issues that are implicated by the potential passage of ECI were outlined in Executive Order 2017-03. In order to thoroughly examine these issues, the Committee was organized into five Technical Working Groups comprised of five committee members each. The working groups were assigned specific topics relating to the issues contained in the Executive Order, as follows: Technical Working Group on Open Energy Market Design and Policy; Technical Working Group on Consumer Protection; Technical Working Group on Innovation, Technology, and Renewable Industry Development; Technical Working Group on Generation, Transmission, and Delivery; and Technical Working Group on Ratepayer and Investor Economic Impacts. Each working group conducted public meetings, heard presentations related to their assigned topics and issues, and subsequently presented a report and recommendations for approval by the full Committee.

In September of 2017, the Committee voted to request that the Public Utilities Commission of Nevada (PUCN) open an investigatory docket to examine specific issues related to ECI. In particular, the Committee requested the docket be opened to ensure that a robust and transparent study was conducted regarding technical issues requiring extensive expertise and experience in energy and electricity market regulation. The Committee requested that the PUCN open the docket based on the agency's ability to devote the necessary resources and technical expertise that a full study of these issues would require. The PUCN subsequently opened docket #17-10001 to study the issues requested by the Committee pertaining to ECI, and in April of 2018, issued a final report of findings after unanimously approving the report. The PUCN's *Energy Choice Initiative Final Report* was then presented to the Committee in May.

While the PUCN conducted its public workshops and investigation, the Committee's Technical Working Groups (TWGs) also held public meetings during which presentations were offered by technical and policy experts and other stakeholders. Each working group ultimately adopted a set of recommendations based on the information they received, and those recommendations were then presented to the full Committee. The Committee unanimously approved all of the recommendations that were presented by the technical working groups dealing with their respective assigned topics.

The TWG on Open Energy Market Design proposed four recommendations. The TWG recommended that Nevada join an existing Independent Systems Operator (ISO) with an already existing wholesale market located in close proximity to the State, presumably the California ISO (CAISO). The TWG also recommended that any contract or arrangement with CAISO or another neighboring ISO should ensure that Nevada retains its own authority with regard to certain key aspects of regulating the wholesale market, including retention of popular programs like energy efficiency and net metering. With regard to a retail market structure, the TWG recommended that the Governor and State Legislature form a joint committee to further examine options for a retail market, inclusive of a provider of last resort (POLR) and net metering. The TWG also recommended that the PUCN be empowered to establish POLRs for back-up electric service in each area of the State open to competition.

The TWG on Innovation, Technology, and Renewable Energy proposed five recommendations addressing the potential impacts of a restructured energy market on currently existing renewable energy programs, including renewable portfolio standards, community solar programs, and net metering. The TWG recommended that policymakers implement ECI in a manner that conditions market participation on alignment with Nevada's existing policy goals with regard to renewable energy technology development. The TWG further recommended that any competitive retail market policies adopted to implement ECI should be consistent with programs that advance the use of renewable energy and clean technology. Finally, the TWG recommended the creation and funding of pilot projects to develop renewable energy technology that may provide meaningful choice for Nevadans, that policies be considered that promote regulatory flexibility for offering incentives for "smart" energy technology, and that all proposed policies for implementing ECI be evaluated in consideration of positioning Nevada as a net exporter of energy.

The TWG on Generation, Transmission, and Delivery proposed three recommendations addressing issues related to resource adequacy and planning reserves, reliability "must-run" units, and expanding export/import transmission capacity. The TWG recommended, assuming an organized wholesale market is established and functioning prior to opening a competitive retail market, that the PUCN continue to establish planning reserve margin requirements and ensure compliance with the wholesale market operators' resource adequacy requirements through the existing integrated resource planning process until a competitive retail market is established. Once a competitive retail market is established, Nevada should continue to establish planning reserve margin requirements but the existing integrated resource planning process will need to be replaced with a process that ensures retail providers secure adequate resources. In addition, the TWG recommended that NV Energy, as the incumbent utility provider, identify "must-run" generation units (a unit that ensures grid reliability under certain circumstances such as transmission outage), and identify the costs for eliminating the conditions necessitating "must-run" status for these units. The TWG recommended that these costs be recovered at the ratepayer level. Finally, the TWG recommended further study of transmission import and export capacity to determine whether additional expansion is required in order to join a wholesale market such as CAISO.

The TWG on Consumer Protection proposed fifteen policy recommendations. These recommendations addressed the need for effective and comprehensive consumer education efforts, particularly for small business and residential customers. Additionally, the Consumer Protection TWG offered recommendations for ensuring that customers are able to make accurate comparisons of essential terms of service among potential providers, as well as recommendations for protecting customer data and privacy, updating Nevada's unfair and deceptive trade practices statutes, and discouraging excessive costs. The TWG's recommendations also addressed the need to update Nevada's Consumer Bill of Rights and specified particular unfair marketing practices that may need to be regulated or prohibited in a competitive energy market.

The TWG on Investor and Consumer Economic Impacts approved a single recommendation: that the State Legislature commission further investigation into stranded assets and transition costs as soon as practicable, should ECI be approved in November. The Economic Impacts TWG concluded that issues related to stranded assets and divestiture implicate questions that are among the most challenging to address. Based upon the information presented to the TWG, as well as prior studies conducted by the Nevada Legislative Counsel Bureau(LCB) and the April 2018 PUCN Investigatory Report, the Economic Impacts TWG recommended that the State Legislature commission further study of the stranded assets, transition costs, and divestiture issues.

On May 9, 2018, the Committee voted to approve all recommendations presented by each of the technical working groups. During its final meeting on June 18, 2018, the Committee approved the TWG on Investor Impacts report and recommendation, and unanimously approved this final report of findings and recommendations to be transmitted to the Governor.

This report provides a summary of the information presented to the Committee and the TWGs, and discusses in detail the Committee's findings and policy recommendations for potential legislative, executive, and regulatory action that may be required if ECI is approved at the November 2018 General Election. In the event that Nevada's voters choose to amend the Nevada Constitution and adopt ECI, requiring a transition to a restructured electricity market, policymakers will be confronted with important decisions regarding consumer protection, the selection of an organized wholesale market, the appropriate steps and processes for divesting incumbent utility providers of generation assets, and the impacts of a new competitive electricity market on the development of renewable energy infrastructure, to name a few. This report is not a discussion of the merits or advisability of ECI and neither encourages nor discourages passage of the initiative. It is intended to provide policymakers with an initial framework that will help to formulate a successful transition plan and facilitate future policy discussions surrounding the implementation of ECI, should the initiative be approved.

COMMITTEE ON ENERGY CHOICE POLICY RECOMMENDATIONS

If ECI is approved by Nevada voters at the 2018 General Election, the Committee on Energy Choice recommends the following:

Open Energy Markets Design

1. WHOLESALE MARKET RECOMMENDATION: Successful implementation of a restructured energy market for Nevada should include, but not be limited to, joining or contracting with an existing Independent Systems Operator (ISO), with a deep, liquid, and robust market, located in close geographic proximity to the State of Nevada, and already integrated with Nevada and neighboring western states.
2. WHOLESALE MARKET RECOMMENDATION: Nevada's interstate contract with the neighboring ISO shall retain Nevada's ability to control Nevada's own fuel mix, retain popular demand-side programs – like energy efficiency and net metering – and provide future governors and legislators with the legislative flexibility and power to make further changes to ensure consumer protection.
3. RETAIL MARKET RECOMMENDATION: The Governor and the Legislature should create a joint committee to address specific legislative and/or regulatory actions needed for a competitive retail electricity market inclusive of providers of last resort and net metering. The newly-created committee should be administratively housed in the PUCN and have dedicated PUCN staff to assist the committee with legislative recommendations no later than July 31, 2020.
4. PROVIDER OF LAST RESORT (POLR) RECOMMENDATION: Successful implementation of a restructured energy market for Nevada should include, but not be limited to, ensuring the PUCN has the necessary power to establish POLRs for back-up electricity service in each area of Nevada open to competition. The policy of POLR service shall serve as a necessary safety net for customers whose chosen retail energy provider is unable to offer or continue electricity service. The POLR service should be intended as temporary service, and used only under rare circumstances. These circumstances should be defined by state law no later than the conclusion of the 2021 Legislative Session.

Investor and Ratepayer Economic Impacts

1. The Legislature should, as soon as practicable, commission further study and investigation of the issues implicated by divestiture, particularly calculating, allocating, and recovering stranded asset costs and other transition costs, including but not limited to costs arising from impacts to incumbent utilities, the workforce, and other aspects of implementing a restructured market.

Innovation, Technology, and Renewable Energy

1. The Committee encourages the Governor, Legislature, and regulatory agencies and organizations to implement the Energy Choice Initiative in a manner that conditions market participation on retail offerings that align with Nevada's existing goals for renewable energy, energy efficiency and technology, and that do not harm Nevada's current programs, statutes, and regulations, including but not limited to, renewable energy requirements, energy efficiency, subsidized services for low-income customers, net metering as set out in A.B. 405 (2017), and storage.
2. The Committee encourages the Governor and the Legislature to adopt competitive retail market policies that do not impede progress and innovation in current and future technologies, and to develop and promote innovative policies and programs that advance the use of renewable energy and clean technology.
3. The Committee encourages the Governor and the Legislature to consider the creation or funding of incubators or pilot projects for innovative technologies that may provide meaningful choice for Nevadans.
4. The Committee encourages the Governor and the Legislature to consider policies that promote regulatory flexibility for incentives and renewable energy programs that offer pilot programs to integrate "smart" energy technologies that support distributed generation, storage, and other clean energy advances, including policies that could promote transportation innovation such as green fleets and the use of electric vehicles for storage and distributed generation, and to revisit the topic of community solar gardens during the 2019 Legislative Session.
5. The Committee encourages the Governor and the Legislature to evaluate all proposed policies and programs in consideration of positioning Nevada to be a net exporter of energy.

Generation, Transmission, and Delivery

1. The PUCN should continue to address resource adequacy and planning reserve requirements through the existing Integrated Resource Planning process until an organized, open, competitive market is established by the Legislature.
2. NV Energy should identify "must-run" generation units and provide multiple options to eliminate the condition(s) giving rise to the must-run status along with the estimated cost and timeframe for implementation of each option provided. Construction costs should be recovered through ratepayers.
3. Transmission import and export capacity will need to be studied to see if additional expansion is necessary to join a wholesale market such as CAISO or Southwest Power Pool (SPP).

Consumer Protection

1. The Nevada Legislature, in collaboration with the PUCN and stakeholders, should amend the Consumer Bill of Rights to address issues related to Energy Choice, ensuring adequate protections exist to safeguard against the complaints and issues that have arisen in other restructured markets. In amending Nevada's Consumer Bill of Rights, other similar statutes in restructured markets should serve as model legislation.
2. Customer education initiatives should include explanations of the fundamental components of restructuring, in multiple languages, to ensure that non-English speaking customers are equipped with the information and tools necessary to participate in a restructured market and are not penalized by the switch to a restructured market.
3. Customer education initiatives should clearly explain potential impacts on prices, consumer protections, and low-income programs under a restructured market.
4. Customer education initiatives should clearly explain customer risks, rights, and responsibilities.
5. Customer education initiatives should leverage the ability of community organizations in developing messaging and executing education strategies for low-income, elderly, non-English speaking, rural, small business, and other communities and constituencies who may require particularized educational assistance that is uniquely tailored to their needs.
6. The Legislature should examine strategies to ensure that comprehensive customer education initiatives are appropriately funded.
7. The Legislature and/or PUCN should consider adopting a model Terms of Service Disclosure Form which all retail energy providers must use in order to participate in the restructured market.
8. The model Terms of Service Disclosure Form should require standardized methods of disclosure of essential terms such as price, contract length, additional fees, dispute, complaint, and collections practices, and the like.
9. The Legislature should examine NRS 603A to identify any provisions which may need to be amended to ensure that security of personal customer information is maintained in a restructured, competitive energy marketplace and set directive policy for the oversight of rules for managing data privacy and data exchanges with regard to ratepayer data.
10. The Legislature, in collaboration with the PUCN and stakeholders, should follow the examples of other states and require a notification of "switching" from retail providers to customers, as a way to identify and stop "slamming" and "cramming" practices. Without such notification, customers may not be aware their provider was switched.
11. Third-party retail marketers should be prohibited, as in other states that have had problems with such entities inadequately informing or misleading customers, which contributed to the "slamming/cramming" problem, particularly where compensation for third-party marketers is based on

"sign-ups." Third-party marketers can also make it difficult to deal with complaints/problems as they are not an actual provider, meaning that liability and remedies issues can become more complicated. Third-party marketers may also "disappear," rendering regulatory oversight of unfair behavior difficult.

12. Nevada should consider prohibiting door-to-door sales and/or telephonic solicitation, as these are often used by third-party marketers, creating problems related to misleading or misinforming customers, high-pressure sales tactics, "slamming/cramming," and the like.
13. The Legislature should examine both NRS 598 and NRS 598A to identify any provisions of the State's Unfair Trade Practices Act and Deceptive Trade Practices Act which may need to be amended to ensure that retail market participants do not engage in unfair or deceptive trade practices, and that adequate penalties are in effect for participants who do engage in such practices.
14. Variable rate contracts should be prohibited as they create enormous confusion for customers and can easily lead to problematic contracts for customers who then end up paying more.
15. The Legislature, in collaboration with the PUCN and stakeholders, should consider capping fees, especially related to enrollment, and prohibit disenrollment fees, as residential ratepayers may end up paying excessive fees for lower rate contracts in the hopes such contracts may save them money. Disenrollment fees have been used in other states as a means of preventing customers from switching to lower-cost providers or their preferred choice.

HISTORICAL BACKGROUND OF ELECTRICITY MARKET RESTRUCTURING IN THE U.S. AND NEVADA

Up until the late 20th century, electricity service in the United States was provided by electric utilities that had been granted exclusive franchises for specific service areas. Under this regulatory structure, an electric utility was granted an exclusive franchise by the state to provide service at rates that were then regulated at the state level by a utility commission.[1] When Congress passed the Federal Power Act in 1935, regulatory authority over electric service was divided between the federal government and the states, with the federal government responsible for regulating the interstate transmission of electricity and the wholesale purchase and delivery of electricity, while states retained authority to regulate retail sales of electricity within their respective states. Under this system of regulation, commonly referred to as the "regulatory compact," public interests in reliability and affordability with regard to electricity service were balanced with ensuring a reasonable return on investment for the electric utility, including the recovery of costs deemed to be "prudent and reasonable." The utility was most often "vertically integrated," meaning that the generation, transmission, and distribution of electric power were all performed by the same entity.[2] Nevada currently retains the "vertically integrated" model, as explained by the Public Utilities Commission of Nevada (PUCN).[3] Further elaborating on "what the current retail electric service looks like in Nevada," the PUCN defined "vertically integrated" as referring to "a utility that owns all levels of the supply chain: generation, transmission, and distribution," further explaining that in Nevada, "a utility is given a monopoly over electric service in a specific area," and "the utility's obligation to serve demand in a defined service territory at regulated rates comes with the monopoly."[4]

During the 1990s, a number of states began efforts to modify or restructure the traditional system of regulating vertically integrated electric utilities, and transitioned from the "regulatory compact" model to market-based, competitive models. A number of factors contributed to this regulatory shift. Among these factors were the lessons from deregulation of other national industries, including the airline, trucking, railroad, and telecommunications industries. Other factors, both political[5] and economic, including high retail electricity rates, low natural gas prices, and the development of new technologies with the potential for reducing electricity prices

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[1] For a more detailed discussion of the history of the electric industry in the United States, see generally Nevada Legislative Counsel Bureau, Bulletin No. 97-11, *Competition in the Generation, Sale, and Transmission of Electric Energy* at 3-12 (1997).
[2] Jeff Lien, U.S. Department of Justice Economic Analysis Group Antitrust Division, *Electricity Restructuring: What has Worked, What has Not, and What is Next* at 2 (2008).
[3] See *PUCN Energy 101: Presentation to the Governor's Committee on Energy Choice*, Presentation by PUCN to the Governor's Committee on Energy Choice at 6-7 (April 26, 2017).
[4] Id. See also, generally, Committee Meeting Minutes and Public Comments at 4 (April 26, 2017).
[5] Matthew H. Brown & Richard P. Sedano, Nat'l Council on Elec. Policy, *A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future* at vii (2003).

additionally contributed to the transition away from the traditional model.[6] By the middle of the decade, a movement toward restructuring electricity markets had generated momentum around the country: "[b]y 1995, a majority of state legislatures recognized that electric industry restructuring was a political issue that they would soon have to face. The forces advocating for change were strong. They included large customers looking for lower prices, power marketers looking for business opportunities, and in some cases, electric utilities hoping for higher earnings."[7] By 2001, nearly half the states in the nation, including Nevada, had enacted legislation to implement restructured, competitive power markets.[8]

Policy developments at the federal level also contributed to the movement toward restructuring electricity markets, especially with regard to the establishment of a regulatory framework governing wholesale electricity markets and ensuring reliability of the nation's bulk power system. In particular, passage of the Public Utility Regulatory Policies Act (PURPA) in 1978, the Energy Policy Act (EPAct) in 1992, and Orders 888 and 2000 issued by the Federal Energy Regulatory Commission (FERC) provided a regulatory framework for the movement toward more competition in electricity markets. In its *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*, the Electric Energy Market Task Force established by the EPAct described PURPA and EPAct as examples of federal "steps to facilitate competition in the electric power industry to overcome perceived shortcomings of traditional cost-based regulation," concluding that federal policies "have sought to strengthen competition but continue to rely on a combination of competition and regulation."[9]

While the features of each individual state's restructuring efforts were distinct, reflecting unique circumstances, needs, and the priorities of individual states, common aspects, challenges and general approaches to restructuring efforts were also evident. The history of state efforts to restructure energy markets shows that inherent in any shift from the traditional regulatory model to a competitive system are common issues to be addressed and questions to answer. These commonalities stem from shared experiences in transitioning from the same original regulatory model. As noted above, the most common model under the traditional regulatory scheme for electricity markets involved the "vertically integrated" utility, a single provider performing generation, transmission, and distribution services. The transition away from this common model in nearly every state required that the incumbent utility separate the generation function from its transmission and distribution functions in order to allow other providers to compete in the market.[10] In addition, most state efforts to restructure their electricity markets and move from a regulated monopoly system to a competitive market involved a transition

[6] Matthew H. Brown, Nat'l Conf. of St. Legislators, *Restructuring in Retrospect* (2001).
[7] Matthew H. Brown & Richard P. Sedano, Nat'l Council on Elec. Policy, *A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future* at 6 (2003).
[8] Id. at 25.
[9] The U.S. Department of Justice, Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy* at 2 (2006).
[10] Jeff Lien, U.S. Department of Justice Economic Analysis Group Antitrust Division, *Electricity Restructuring: What has worked, What has Not, and What is Next* at 7 (2008).

period, often requiring mechanisms to stabilize rates and market features to mitigate uncertainties associated with implementing the new system. Moreover, every state that has implemented a restructured market has confronted other cost-related issues associated with how to manage this transition period, and states have implemented varying policies to that end.[11] Other common issues related to restructuring include, as noted, divesting the incumbent utility of generation assets, managing the transition period, allocating and recovering transition costs, ensuring protections for consumers, and establishing default electric service or a provider of last resort (POLR). It is worth noting that to date, states that have implemented restructured markets have done so through policy changes at the legislative and administrative levels.[12] No state has implemented competitive electricity marketplaces or policies associated with restructured markets through a constitutional amendment.[13] If ECI's proposed constitutional amendment is approved, Nevada would be the first state in the nation to provide for a competitive marketplace in its constitution.

As noted above, the State of Nevada was one of many states to explore electricity market restructuring during the 1990s. A brief discussion of Nevada's experience illustrates both the common features of state-led transitions to competitive markets as well as the concerns that led to a general halt of state-led transitions to competitive markets.[14] In 1995, the Nevada State Legislature approved A.C.R. 49, noting the "nation-wide trend toward competition" and affirming that it was in "the best interests of the residents of the State of Nevada to explore the effects of competition in the generation, sale, and transmission of electric energy so as to assess the economic consequences and opportunities associated with such competition." A.C.R. 49 directed the Legislative Commission to, "Conduct an interim study of the competition in generation, sale, and transmission of electrical energy."[15] Among the issues to be included in this interim study were "quantification and recovery of stranded investments…pricing of transmission and distribution services…unbundling costs and services…commerce clause constraints…the continuing obligations of a utility to serve customers…development and use of renewable resources," and other issues common to most states that were attempting to restructure their electricity markets at the time.

The report by the Legislative Commission that was required by A.C.R. 49 included a discussion of both advantages and disadvantages of market restructuring. The report noted that proponents at the time claimed restructuring would "increase customer choice by giving large and small customers access to multiple suppliers at

[11] Matthew H. Brown & Richard P. Sedano, Nat'l Council on Elec. Policy, *A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future* at 32 (2003) ("Most states recognized from the outset that they could not expect retail power markets to take off quickly, and that some transition period would be necessary to phase in competition").
[12] See generally the U.S. Department of Justice, Electric Energy Market Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy*. "State Retail Competition Profiles" at 137 (2006).
[13] Committee Meeting Minutes for *NCSL Presentation to CEC* at 5 (March 7, 2018).
[14] See generally *Historic Overview: Nevada Deregulation in the 1990's.* Presentation by PUCN to the Governor's Committee on Energy Choice (Nov. 7, 2017).
[15] A.C.R. 49 (NV Legislative Session 1995).

a lower costs," while opponents at the time maintained that "restructuring will shift costs to small consumers who cannot effectively contract for alternative sources."[16] The 90-page report ultimately included a single recommendation to the 1997 State Legislature: "The subcommittee recommends that the 1997 Legislature appoint a six-member interim study subcommittee to conduct further investigation into all aspects of restructuring the electric industry."[17] During the 1997 legislative session, the State Legislature passed A.B. 366, which was, as the PUCN noted, the "foundational piece of the restructuring legislature," requiring that "retail access should commence no later than December 31, 1999" while allowing the PUCN the discretion to postpone restructuring.[18]

In August of 1997, the PUCN opened investigative docket #97-8001 which examined issues related to retail competition, and ultimately delayed Nevada's restructuring efforts. Governor Kenny Guinn would later delay Nevada's restructuring efforts even further. As the PUCN explained, "Governor Kenny Guinn announced the delay of opening the electricity market in Nevada until no later than September 1, 2001," and appointed a "bipartisan panel to develop a long-term strategy and report its findings." The panel recommended that "only large commercial customers be allowed to participate in retail choice until electricity market prices stabilized in the west."[19] By spring of 2001, Nevada's restructuring efforts were indefinitely halted through the passage of A.B. 369 and A.B. 661, which returned electric utilities to vertically-integrated, regulated utilities under the traditional scheme.[20]

Two somewhat related developments during 2000 and 2001 are typically cited as the reasons behind some states abandoning their efforts to restructure electricity markets.[21] During the summer of 2000, an energy crisis gripped the western region of the United States leading to large-scale blackouts and significant electricity price increases. In addition, the Enron scandal, which broke during the fall of 2001, drew national attention to abuses of the deregulated energy marketplace by bad actors and spurred political backlash that also contributed to a general halt in market restructuring.[22] In its 2006 *Report to Congress*, the federal Electric Energy Market Task Force asserted that, "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

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[16] Nevada Legislative Counsel Bureau, Bulletin No. 97-11, *Competition in the Generation, Sale, and Transmission of Electric Energy* at 16-17 (1997).
[17] Id. at 58.
[18] AB 366 (NV Legislative Session 1997).
[19] See generally *Historic Overview: Nevada Deregulation in the 1990's.* Presentation by PUCN to the Governor's Committee on Energy Choice at p. 22 (Nov. 7, 2017).
[20] Id. at 23.
[21] See generally Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report*, Investigatory Docket No. 17-10001 at 16-18 (April 2018).
[22] Amy Abel, et al. Congressional Research Service. *Electric Utility Restructuring: Maintaining Bulk System Reliability* at 3 (February 2005). ("The collapse of Enron is another indicator to some that restructuring of the electric utility industry could result in a loss of reliability. Enron's bankruptcy did not result in blackouts anywhere in the United States; however, some of Enron's trading practices in California may have contributed to blackouts during that state's energy crisis").

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."[23]

The experiences of states that have continued operating under a restructured electricity market have been mixed, and evaluations of the perceived successes or shortcomings of restructuring efforts are inconclusive. In general, there is some consensus that in states that have implemented restructured markets, the benefits of competition have been most obvious within the wholesale markets and affect large-scale industrial consumers, while competition at the retail level has not significantly benefited small-scale and residential consumers.[24] As reported to Congress by the federal Electric Energy Market Task Force, "[i]n most profiled states (Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, and Texas), 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 services often is limited."[25] Another study concludes, "[t]here is substantial evidence that significant efficiencies have been achieved by market restructuring, especially through improved incentives for plant-level operating efficiencies and improved mechanisms for eliciting gains from trade in wholesale trading. However, not all potential benefits of restructuring have been realized, and there is a possibility of further development of market designs."[26] Yet another report concludes, "[s]everal years into the experiment with retail and wholesale competition, it is hard to make solid conclusions…the experiences resulting from state and federal policies have led to the following results: (1) Retail competition has not, for the most part, provided a significant, direct benefit to any but the largest customers…(2) Wholesale competition has led to economic benefits, but both state and federal government officials have a significant role to play in making wholesale markets work better…(3) To a large extent, the major goals of wholesale and retail competition are still elusive."[27] Thus, it is not clear that restructured electricity markets have been conclusively beneficial for all customer classes in the states that have continued to operate under competitive regimes.

Pennsylvania's experience with a restructured electricity market illustrates the potential benefits of switching to a competitive regime and the successes of restructured markets in Pennsylvania are discussed in *A Case Study of Electric Competition Results in Pennsylvania.*[28] The study discusses the various benefits of

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[23] The U.S. Department of Justice, Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy* at 27 (2006).
[24] See *NCSL Presentation to CEC* (March 7, 2018) at 16.
[25] The U.S. Department of Justice, Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy* at 91 (2006).
[26] Jeff Lien, U.S. Department of Justice Economic Analysis Group Antitrust Division, *Electricity Restructuring: What has Worked, What has Not, and What is Next* at 2-3 (2008).
[27] Matthew H. Brown & Richard P. Sedano, Nat'l Council on Elec. Policy, *A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future* at vii (2003).
[28] Christina Simeone & John Hangar, *A Case Study on Electric Competition Results in Pennsylvania: Real Benefits and Important Choices Ahead*, Kleinman Center for Energy (October 28, 2016).

restructured electricity markets in Pennsylvania at both the wholesale and retail levels, and estimates that residential customers obtaining service from a default provider in the competitive market continue to benefit from restructuring. The study asserts that residential customers in Pennsylvania had "the potential to enjoy significant savings as a result of restructuring via the utility-offered default service retail product," because restructuring "required the Pennsylvania Electric Distribution Companies to procure energy and related service from competitive wholesale markets rather than from cost-of-service regulation."[29] With regard to benefits specifically for residential customers, the study concludes that "the switch to competitive procurement for default service has delivered potential savings for residential customers in the amount of over $68 million per month in 2016, or over $818 million for the 2016 year."[30]

On the other hand, the experience in Massachusetts indicates that consumers, particularly residential customers, in restructured electricity markets may be more vulnerable to higher electricity costs than they would be in a non-competitive market. In March of this year, the Massachusetts Attorney General's Office released a two-year study entitled, *Are Consumers Benefitting from Competition? An Analysis of the Individual Residential Electric Supply Market In Massachusetts*, concluding 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."[31] The study also concluded that residents in traditionally underserved communities paid higher rates to competitive suppliers, including "communities with low median incomes, communities with high percentages of households receiving subsidized low-income rates, communities with high percentages of minority households, and communities with high percentages of households with limited English proficiency."[32] Finally, the study asserts that "individual residential customers have suffered large financial losses in the competitive supply market," and recommends that "legislators in Massachusetts consider eliminating the electric supply market for individual residential consumers."[33]

While there is no clear consensus as to the extent to which competitive electricity markets or traditional regulated markets are more or less beneficial to all classes of consumers, it is clear there is vastly more information available on this subject today than was available twenty years ago when Nevada first considered implementing a competitive electricity market. The general history of electricity markets restructuring and the varying conclusions and experiences from states that have implemented restructured electricity markets illustrate that the prospect of transitioning from a regulated electricity market presents significant questions in a number of critical areas. In order for Nevada to successfully transition from the traditional cost-of-service, "vertically integrated" regulated

[29] Id.at 33.
[30] Id.
[31] Susan M. Baldwin, Massachusetts Attorney General's Office, *Are Consumers Benefiting from Competition? An Analysis of the Individual Residential Electric Supply Market in Massachusetts* at viii (March 2018).
[32] Id. at x.
[33] Id.

model to a competitive market system, sound policy decisions must be made regarding wholesale and retail market structure and design, ensuring protections for consumers, calculating and recovering the costs associated with utility divestiture, maintaining renewable energy programs, ensuring electric service reliability, and other important components of electricity generation, transmission, and supply. These issues were examined in great detail by the Committee with direct input from a number of states that have experience in restructuring electricity markets, including Pennsylvania, Massachusetts, Texas, Illinois, California, and others. The following sections of this report summarize the experiences and associated information on restructuring as presented to the Committee.

This Committee was tasked by the Governor with identifying the "legal, policy, and procedural issues that need to be resolved, and to offer suggestions and proposals for legislative, regulatory, and executive actions that need to be taken for the effective and efficient implementation of [ECI]."[34] In carrying out this directive, the Committee has solicited input from a number of other states with experience implementing competitive electricity markets. The experiences of other states, along with the lessons learned over the course of the history of electric markets restructuring, should inform any revived effort by Nevada to replace a regulated cost-of-service system with a competition-based electricity market. These lessons and experiences should guide any potential decision-making process in Nevada so that the successes in market restructuring can be replicated where possible, and the failures can be avoided.

[34] Exec. Order No. 2017-03, *Order Establishing the Governor's Committee on Energy Choice*, Sec. 8 (February 9th, 2017).

OPEN ENERGY MARKET DESIGN SUMMARY OF FINDINGS

The Technical Working Group on Open Energy Market Design and Policy was tasked with examining issues related to the structure and design for both wholesale and retail markets should ECI successfully pass again in November 2018. The TWG was also tasked with studying issues and solutions surrounding Provider of Last Resort (POLR) services. Representatives from seven organizations provided presentations to the TWG. Additionally, each member of the TWG participated in the full Committee on Energy Choice, which was also presented with information pertaining to retail and wholesale market structure.

Wholesale Market Structure

Currently, Nevada's electricity is delivered through vertical integration where the utility is responsible for, and maintains control over, all three levels of power delivery: generation, transmission, and distribution.[35] If approved, ECI would require the Nevada State Legislature to establish an open and competitive energy market. ECI does not specifically require the Legislature to establish an organized wholesale market structure for Nevada;[36] however, discussions, presentations, and the experiences of other states have shown that doing so would be sensible and the plausible first step to establishing the open energy market mandated by ECI.[37] Each state that has deregulated has either established its own organized wholesale market or joined an existing one.[38] These markets are managed by operators known technically as Independent Service Operators (ISOs) or Regional Transmission Organizations (RTOs) which are set up independently of the market participants to ensure the daily functioning, reliability and planning aspects of market operations.[39] Nine market operators currently exist within North America, seven of which are located within the United States, six of which are regulated by FERC, and one of which, Texas, is regulated exclusively by its state regulatory agency (Electric Reliability Council of Texas, or ERCOT).[40]

During TWG meetings and meetings of the full Committee, two primary options were considered for Nevada in choosing an organized wholesale market: creating a Nevada-only wholesale market or joining an existing ISO or RTO. Relative pros and cons emerged from each, depending upon which factors were prioritized.

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35 See *PUCN Energy 101: Presentation to the Governor's Committee on Energy Choice,* Presentation by PUCN to the Governor's Committee on Energy Choice at 6 (April 26, 2017).
36 See generally *The Energy Choice Initiative*, Ballot Initiative Petition (February 3, 2016).
37 Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report*, Investigatory Docket No. 17-10001 at 68 (April 2018).
38 Id., Matt Griffin & Josh Weber, *Energy Choice: A New Energy Policy for Nevada*, Energy Choice Initiative Presentation to the Governor's Committee on Energy Choice at 6 (April 26, 2017).
39 See generally John Orr, *Retail Market Potential: Moving from Vertical Integration to Retail Choice*, Constellation's Presentation to the Governor's Committee on Energy Choice (July 11, 2017).
40 Stacy Crowley, *California ISO: Regional and National Marketplace Presentation*, Presentation by CAISO to the Governor's Committee on Energy Choice at 3 (April 26, 2017).

Creating a Nevada-Only Independent System Operator

Factors influencing the creation of a Nevada-only ISO include, namely, cost, governance, and time. Speakers to the Committee and TWG presented estimates of the costs to establish a Nevada-only ISO to be anywhere from $100 million – $500 million.[41] Although it would also require FERC approval, a Nevada-only ISO would allow the state much greater flexibility in governance issues and structure within the creation of regulatory and legislative designs.[42] Notwithstanding, issues were raised regarding the size of a Nevada-only market relative to other ISOs/RTOs and its ability to provide the same level of load and fuel diversity to suppliers and end-use consumers for potentially greater competition and lower pricing. Furthermore, the timeline for implementing and ultimately ensuring a robust Nevada wholesale market comes to fruition could run past the 2023 ECI deadline.[43] Finally, the aforementioned factors would be compounded if Nevada chooses to allow the expansion of a Nevada-only ISO to other interested western states.

Joining an Existing Independent System Operator or Regional Transmission Organization

As with creating a Nevada-only ISO, the same factors of cost, governance, and time were discussed. The added issue of geographic proximity was also noted during discussions of the Committee and TWG in deliberations on joining an existing ISO or RTO. Due to the lack of close proximity of many of the existing ISOs or RTOs throughout the United States, along with the lack of adequate physical connectivity, many of the ISOs/RTOs were ruled out as realistic or viable options. States with close physical proximity to Nevada were seen as most realistic. For example, due to its location and established market, California's ISO (CAISO) emerged as a practical existing ISO/RTO for Nevada to join during discussions of the TWG and Committee as a whole.[44] At the outset, estimates provided that the costs of Nevada joining CAISO would likely be lower than those of establishing a Nevada-only market.[45] Timing for transitioning Nevada to CAISO would depend on how quickly governance decisions were determined, in addition to the time required for FERC approval and time to transition operations

[41] Steve Berberich, *California ISO,* Presentation by CAISO to the Technical Working Group on Open Energy Markey Design & Policy at 9 (July 10, 2017),*See also* Meeting Minutes and Public Comments at 4 (July 11, 2017), and Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report,* Investigatory Docket No. 17-10001 at 79 (April 2018).
[42] Id.
[43] Carl Monroe & Bruce Rew, Southwest Power Pool, *SPP Wholesale Markets and Retail Markets,* Presentation to the Governor's Committee of Energy at 14 (Aug. 8, 2017), Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report*, Investigatory Docket No. 17-10001 at 79 (April 2018), Lauren Rosenblatt, NVEnergy, *Energy Market Policy,* Presentation to the Governor's Committee of Energy at 11 (July 11, 2017).
[44] Meeting Minutes and Public Comments at 5 (July 10, 2017), Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report,* Investigatory Docket No. 17-10001 at 77 and appendix 1240-1 (April 2018), Lauren Rosenblatt, NVEnergy, *Energy Market Policy,* Presentation to the Governor's Committee of Energy at 11 (July 11, 2017). Presenters and data provided to the Committee and Working Group generally discussed California's Energy Imbalance Market (EIM). Currently, Nevada Rural Electric Association and NV Energy fully participate in California EIM. However, if ECI is adopted, Nevada may need to become a full participant in an ISO.
[45] Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report*, Investigatory Docket No. 17-10001 at appendix 2469 (April 2018) (California ISO provided the following estimates: an initial cost of $250,000 to fund a study regarding Nevada joining CAISO, an upfront cost of $500,000 for Nevada to join, plus any additional costs that may be required to transition technology. Ongoing annual maintenance fees were estimated to be approximately $21-27 million).

and technology. In joining CAISO, data was provided that established an estimated timeline of two years for initial integration and up to another year and a half for system simulation.[46] The primary disadvantages of joining CAISO were identified as issues surrounding governance and ensuring Nevada had an opportunity to advocate for its own interests. Currently, CAISO is governed by a Board selected by California's Governor and confirmed by its Legislature.[47] During TWG discussions, CAISO stated its willingness to support Nevada's decision to join; however, any decision regarding Nevada joining the market would require action by the California Legislature.[48] Thus, in determining its final recommendation on Wholesale Markets, the TWG adopted recommendations that focused on the successful implementation of a restructured energy market by way of joining or contracting with an existing ISO within close proximity to the State. Specifically, the TWG recommended that Nevada should retain its authority with regard to certain key aspects of regulating the wholesale market, including retention of popular programs like energy efficiency and net metering, while working with an outside entity.

Retail Market Structure

A retail market is a market in which energy is sold directly to an end user, whether the end customer is residential, commercial or an industrial consumer.[49] A retail energy market as contemplated by ECI is one in which end users are able to freely choose the retail electric provider from which they purchase their electricity.[50] Unlike wholesale markets, which are governed by FERC, retail markets are governed by the laws and regulations of the state in which the sale occurs. Various factors have the ability to influence the success of a competitive retail market and were discussed in depth during meetings of the full Committee and the TWG. These issues include: (1) How to address the integration of energy co-ops, municipal aggregators, and public utility districts; (2) Determining which entity will serve consumers if they do not make a decision to switch (default service provider); (3) What licensing and regulatory requirements will exist for retail energy providers; (4) How best to execute an effective consumer education campaign; (5) How best to effectively exchange data upon customer switching and other practical decision points; and (6) How and by whom will customers be serviced and billed.[51]

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[46] Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report*, Investigatory Docket No. 17-10001 at 78 (April 2018).
[47] Meeting Minutes and Public Comments at 6 (May 10, 2017).
[48] Meeting Minutes and Public Comments at 5 (July 10, 2017) (At time of drafting, the California Legislature was considering Assembly Bill 813, which would allow for a western regional transmission organization through the expansion and reorganization of CAISO).
[49] Lauren Rosenblatt, NVEnergy, *Energy Market Policy*, Presentation to the Governor's Committee of Energy at 2 (July 11, 2017).
[50] See generally Matt Griffin & Josh Weber, *Energy Choice: A New Energy Policy for Nevada*, Energy Choice Initiative Presentation to the Governor's Committee on Energy Choice at 4-8 (April 26, 2017).
[51] John Hanger, Former Sec. of Panning & Policy and Pennsylvania PUC Commissioner, Comments to the Governor's Committee on Energy Choice at 2-7 (May 10, 2017), Craig. G. Goodman, National Energy Marketers Association, Presentation to the Governor's Committee on Energy Choice at 11 (February 7, 2018).

States that have previously introduced competitive retail markets have addressed the foregoing in an assortment of ways, taking into account their own state's resources, structure and needs, and the goals of the restructured market. Given the intricacies and variables associated with each factor, any decisions on retail market structure will be left to the Nevada Legislature and Nevada's regulatory bodies to determine. Accordingly, with the potential passage of ECI, many of the critical components and the information required to select an appropriate retail market structure remain unknown. Consequently, the TWG proposed that the Governor and the Legislature should create a Joint Committee to address the particular legislative and regulatory actions necessary for a competitive retail electricity market that includes providers of last resort and net-metering programs.

Provider of Last Resort (POLR) Services

In addition to examining options for wholesale and retail market structures, the Open Market TWG was tasked with determining options for Nevada's POLR services. In each restructured retail market, a POLR serves as an energy customer's reliable fallback when their own retailer is no longer able to provide service. Different states establish providers of last resort services in a variety of ways. For example, potential options include soliciting bids from suppliers, assigning or designating a supplier as the POLR, or requiring the incumbent utility or an affiliate to provide POLR services.[52] In consideration of these different options, the Open Markets TWG approved, and the full Committee unanimously adopted, a recommendation for the State of Nevada which would set up the necessary power providers and entities to support this transition in order to protect consumers. The TWG recommended that the PUCN be empowered with the authority to establish POLRs for back-up electricity service, specifying that POLR provisions should be implemented no later than the conclusion of the 2021 Legislative Session.

[52] *Historic Overview: Nevada Deregulation in the 1990's.* Presentation by PUCN to the Governor's Committee on Energy Choice at 13 (Nov. 7, 2017), Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report*, Investigatory Docket No. 17-10001 at 804 (April 2018).

INVESTOR AND RATEPAYER ECONOMIC IMPACTS SUMMARY OF FINDINGS

The long history of electricity market restructuring and the experiences of the states that have adopted competitive markets demonstrate that the transition from a vertically integrated, cost-of-service model to a competition-based marketplace raises questions regarding potential economic impacts to participants in the marketplace. A thorough study of market restructuring must examine these potential economic impacts. Executive Order 2017-03 directed the Committee to specifically address, "[p]reventing ratepayers and investors from possible economic losses associated with stranded investments."[53] Accordingly, the Committee organized a Technical Working Group on Consumer and Investor Economic Impacts to study the issues associated with stranded assets and transition costs. These issues included a potential transitional structure and rate structure to recover costs of transition and stranded costs, the extent and timing of divestiture of supply assets, a process for divesting utilities of supply assets, the appropriate processes for calculating and recovering stranded costs or benefits, plans to mitigate potential impacts to the workforce, and other issues pertaining to the cost to transition from a regulated system to one based on competition.[54]

The experiences of other states that have implemented electricity market restructuring consistently demonstrate that divestiture of incumbent utility assets, "stranded asset" costs and other transition costs are among the most challenging issues associated with market restructuring. Information provided to the TWG, as well as published scholarship on the issue and prior research conducted in Nevada, all generally support the conclusion that identifying, allocating, calculating, and ultimately recovering stranded costs associated with divestiture has historically presented significant challenges to states exploring the possibility of market restructuring.

For example, when Texas began its restructuring process after the passage of Senate Bill 7, addressing "stranded assets" issues was one of the chief concerns associated with implementing a restructured, competitive energy marketplace: "[t]he largest problem threatening the smooth transition from a regulatory market to a competitive market is stranded cost recovery. Every state that has deregulated the electric utility industry has grappled with this issue…it is therefore of extreme importance to determine who pays for stranded costs, how stranded costs are calculated, and how stranded costs are collected."[55] When Illinois began its process to implement a restructured market in 1996, the Illinois Legislature established a Technical Advisory Group (TAG) similar to the Committee's Economic Impacts TWG, with a fact-finding role and a directive to develop legislative

[53] Exec. Order No. 2017-03. *Order Establishing the Governor's Committee on Energy Choice*, Sec. 10(D) (February 9th, 2017).
[54] See *TWG Workstream Assignments Document* (July 11, 2017) Appendix A-13.
[55] Natalie Scott, *Implementation of Senate Bill 7: The Implication of Stranded Costs Recovery for Residential Electric Utility Consumers*, 52 Baylor L. Rev. 237, 247 (Winter 2002).

proposals for implementing a restructured market.[56] The Illinois TAG issued a report indicating general agreement on the recovery of at least some of the utilities' stranded costs, but "unfortunately, although not unexpectedly, was not able to achieve consensus on any particular plan."[57]

The Federal Energy Regulatory Commission (FERC), in its landmark Order 888, which helped to pave the way for the restructuring of wholesale markets, concluded, "[t]he most critical transition issue that arises as a result of [FERC]'s actions in this rulemaking is how to deal with the uneconomic sunk costs that utilities prudently incurred under an industry regime that rested on a regulatory framework and a set of expectations that are being fundamentally altered."[58] Emphasizing the difficulties that arise with regard to stranded costs issues, the Congressional Budget Office in 1998 stated, "[d]etermining the correct figure for stranded costs, deciding how much of them to compensate, and figuring out how that compensation should be paid are difficult issues, which are slowing progress toward restructuring in many states."[59]

There is a significant body of published scholarship and research surrounding state approaches to stranded costs. One notable published summary of the issue highlights the difficulties associated with stranded assets policy, and touches on general approaches states have taken with regard to stranded costs:

> Because of their magnitude, stranded costs creat[e] a great deal of political tension. The arguments [come] down to fairness and equity compared to economic efficiency…In general, states allowed utilities to recover all or some significant portion of their stranded costs and gave utility commissions guidance as to how to decide what was or was not recoverable…Almost every state legislature chose a definition of stranded costs that referred to costs that were legitimate, net, verifiable, and unmitigated. Utility commissions were left to decide on the exact definitions of those terms.[60]

In Nevada, similar conclusions have been reached regarding the challenges that are inherent in identifying, allocating, and calculating stranded costs. In 1997, the Nevada Legislative Counsel Bureau (LCB), in Bulletin 97-11, thoroughly examined the issue of electric markets restructuring, including the specific issues of stranded costs, as required by A.C.R. 49.[61] The LCB's report concluded, "[t]he issue of stranded costs is one of the most important topics in restructuring." Despite the importance of the issue, however, the report concluded that there was no

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[56] Ruth K. Kretschner & Robert Garcia, *Recovering Stranded Costs: Not "If", but "How."*, 135 No. 2 Pub. Util. Fort. 34 (January, 1997).
[57] Id.
[58] *Transmission Access Policy Study Group v. F.E.R.C*., 225 F.3d 667, 683 (D.C. Cir. 2000).
[59] Gail Cohen, Congressional Budget Office, *Electric Utilities: Deregulation and Stranded Costs* at 26-27 (1998).
[60] Matthew H. Brown & Richard P. Sedano, Nat'l Council on Elec. Policy, *A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future* at 30 (2003).
[61] Nevada Legislative Counsel Bureau, Bulletin No. 97-11, *Competition in the Generation, Sale, and Transmission of Electric Energy* at (1997).

ultimate consensus reached on how to appropriately address stranded costs, as “there were diametrically opposed recommendations about recovery of these costs.”[62] Notably, the sole recommendation from the LCB’s report was for the 1997 Legislature to “[a]ppoint a six-member interim study subcommittee to conduct further investigation into all aspects of restructuring the electric industry.”

Most recently, in its *Final Report on the Energy Choice Initiative*, the PUCN concluded that, “[p]erhaps the most important topic related to potential costs of implementing the Energy Choice Initiative is the issue of divestiture of utility assets and liabilities.”[63] The PUCN’s report discusses in detail the “spectrum of views regarding divestiture, including whether any of Nevada’s public utilities would have to divest of their generation assets and/or long-term power purchase agreements,” and notes that analyzing and quantifying stranded costs is made difficult because such analysis is “not a linear conversation” and by the fact that “market conditions regarding the costs of generating, transmitting, and delivering electricity are constantly changing.”[64]

The PUCN’s final report on ECI identifies a general range in costs associated with stranded assets: “[t]he cost estimates related to divestiture that the PUCN Workshop Proceeding participants presented ranged from…zero dollars…up to approximately 7 billion dollars,” noting that “no participant attempted to monetarily quantify the benefits.” The report estimates a total cost of approximately $4.074 billion, inclusive of regulatory and stranded asset costs. [65]

Information presented to the Committee’s Economic Impacts TWG should assist in quantifying, identifying, and calculating costs that may be incurred by the state’s largest incumbent utility should a competitive market be adopted.[66] Mr. Kevin Geraghty, representing NV Energy, presented an overview of the utility’s major assets, including generation assets and the utility’s power purchase agreements (PPAs). Mr. Geraghty also discussed potential transition costs (establishing a POLR, creating a customer switching mechanism, and creating a new FERC-approved tariff for transmission operations), potential stranded costs, costs associated with maintaining public policy initiatives, and other costs associated with taxes and fees that NV Energy currently pays but may not pay in a restructured market (estimated at $232.6 million). Testimony to the TWG also referenced the divestiture process in New Hampshire and recommended consulting New Hampshire’s approach as one option for Nevada.

Other information submitted by various stakeholders in Nevada may also inform identifying potential economic impacts under a restructured market. The Deseret Power Electric Cooperative presented an overview of

[62] Id. at 52.
[63] See generally Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report*, Investigatory Docket No. 17-10001 at 39-40 (April 2018).
[64] Id. at 51.
[65] Id. at 50, 66.
[66] See Kevin Geraghty, NV Energy presentation, at slides 13, 14, 18 (June 21, 2017).

Deseret Power's operations and generating assets, and discussed specifically its Mt. Wheeler service area, as well as a comparison of utility structures and residential rates. This testimony concluded with the assumptions that if ECI is approved and (1) There is no cost shifting or subsidizing of stranded costs; (2) All utilities and ratepayers are subject to equal stranded costs, and (3) NV Energy's stranded costs total approximately $7.4 billion, then there could be a 30% increase to the energy component of Deseret Power's rates.[67] The Nevada Rural Electric Association (NREA), pointed out in its presentation that Nevadans for Clean Energy Choices, proponents of ECI, have conceded that if the initiative passes, implementation "[m]ay include economic and orderly divestiture of generation and limits on corporate affiliates serving as Retail Energy Providers."[68] NREA's presentation also identified transition costs for NREA owner-members in a competitive market to include Alternative Power Providers' profit margin (10-15%), unspecified transmission and retail wheeling costs, NREA's existing PPA divestiture/liquidation costs ($1 billion+), and other miscellaneous costs.[69] Finally, the Colorado River Commission of Nevada (CRC) pointed out that "ECI has raised questions regarding Nevada's ability to continue to benefit from low-cost, renewable federal hydropower" and regarding the "viability of CRC's long-term hydropower contracts."[70] This testimony also included an assertion by CRC representatives that it is not believed CRC would have any stranded assets should ECI be approved.

In short, the questions that arise with regard to divestiture of assets and liabilities, quantifying stranded costs and transition costs, and ultimately the question on how to recover those costs, are difficult questions to answer. Consensus on the best approach is not arrived at easily. The TWG included as part of its record of deliberations, three pieces of legislation enacted as part of restructuring efforts in California, Ohio, and Texas as reference materials for the Nevada Legislature to consider in future deliberations related to divestiture, stranded assets, and transition costs issues. The Committee recommends that the Legislature commission further investigation into this issue as soon as reasonably practicable if ECI is approved by voters.

[67] Clay MacArthur, Deseret Power Electric Cooperative presentation, *Nevada Energy Choice Initiative*, Presentation to TWG Joint Meeting at 10 (Aug. 17, 2017).
[68] Richard "Hank" James, Nevada Rural Electric Association Presentation to TWG Joint Meeting at 10 (Aug. 17, 2017).
[69] Id. at 18.
[70] Jayne Harkins, P.E., Colorado River Commission of Nevada Presentation, *Presentation to the Committee on Energy Choice*, Presentation to TWG Joint Meeting at 19 (Aug. 17, 2017).

INNOVATION, TECHNOLOGY AND RENEWABLE ENERGY SUMMARY OF FINDINGS

Executive Order 2017-03 directed the Committee to address the issue of "[p]romoting innovation and development in Nevada's renewable energy industries."[71] The amended version of this Executive Order directed the Committee to study the additional issues of "[i]ncreasing Nevada's renewable portfolio standards" and "allowing community solar gardens to begin operating in Nevada."[72] The Committee's Technical Working Group on Innovation, Technology, and Renewable Energy was tasked with examining how electricity market restructuring may interact with and/or impact (1) energy efficiency programs, (2) demand-side management programs, (3) renewable portfolio standards (RPS), (4) electric vehicles, (5) aggregation programs including community solar, (6) incentives for other technologies of interest, (7) net metering, and (8) energy storage technology. Representatives from nine organizations presented to the TWG, providing members with information on a wide range of topics and from a variety of perspectives. The TWG presented key findings related to the potential impacts of a restructured energy market on currently-existing renewable energy programs, on restructured markets and RPS, the implications of a restructured market regarding community solar programs, energy storage, and net metering, and Nevada's ability to be a net energy exporter. The TWG presented five recommendations, each of which the Committee unanimously adopted without revision.

Renewable Portfolio Standards

An RPS is designed to increase renewable electricity production by requiring that a certain percentage of electricity sold to retail customers originates from a renewable source.[73] In 2001, the Nevada Legislature established an RPS that went into effect in 2005, setting minimum renewable requirements that increase over time.[74] Under current law, by 2025, electricity generated from renewable sources must constitute 25% of electricity sales. Presentations to the TWG discussed RPS and some focused, in particular, on the RPS in states with competitive markets. Amanda Levin from Natural Resources Defense Council discussed RPS generally and the interaction of RPS and retail choice. Maria Robinson from Advanced Energy Economy also discussed RPS in restructured states. Anthony Star from the Illinois Power Agency outlined the RPS in Illinois, and Pat Egan from NV Energy discussed NV Energy's compliance with Nevada's current RPS.

In a restructured, competitive electricity market with retail choice, consumers should be able to select an electricity supply product from a range of options. Consumers that value renewable energy may continue to

[71] Exec. Order 2017-03, *Order Establishing the Governor's Committee on Energy Choice.* Sec. 10(E). (Feb. 9th, 2017).
[72] Exec. Order 2017-10, *Order Amending Executive Order 2017-03*. Sec. 1(a) and (b). (June 16th, 2017).
[73] U.S. Energy Information Administration, *Today in Energy*, https://www.eia.gov/todayinenergy/detail.php?id=4850 (last visited June 12, 2018).
[74] NRS 704.7821.

choose to purchase a product that is partially or entirely renewable (as discussed further below). But, without an RPS, other consumers—because of preferences, cost, insufficient information, or a lack of renewable options—will purchase non-renewable products. Because retail choice allows consumers to choose their own supply, there is no guarantee that, absent state policy, the share of renewables will continue to grow if ECI is approved.

The Committee recommends implementing ECI in alignment with Nevada's existing renewable energy goals to ensure that retail choice policies are consistent with Nevada's policies on RPS and renewable energy objectives. Evidence from other states demonstrates such a goal can be achieved. For instance, according to the U.S. Energy Information Administration (EIA) data, California, a state with a competition-based market, generated 37% of its electricity from renewable sources in 2016, and Illinois, which is also deregulated, has a 25% RPS goal by 2025.[75] Additional information on this topic was provided by Amanda Levin representing Natural Resources Defense Council, who delineated the RPS standards in fourteen states with retail choice.[76] So long as Nevada maintains its current RPS, it will meet its 25% renewable goal by 2025.

If voters approve ECI and Nevada maintains its RPS requirements, the Governor, Legislature, and state regulatory agencies will have a number of issues to consider, including credit qualification, the impact of joining an ISO on the price of credits, which entities are responsible for securing credits, retail supplier marketing, and issues regarding POLR compliance.

States that have both deregulated markets and an RPS typically require either suppliers, utilities, or agencies to demonstrate RPS compliance by securing renewable energy credits similar to the portfolio energy credits (PEC) used in Nevada today. If ECI is approved and Nevada's RPS remains intact, Nevada will face a number of decisions regarding RPS credits and compliance. First, if Nevada joins CAISO or another balancing authority, it may decide to deem all renewable generators within the balancing authority, including those that are located outside of Nevada, eligible for PECs. Consumers may benefit from such a policy change because suppliers would gain access to additional credits, some of which may be comparatively cheap, lowering compliance costs without forfeiting environmental benefits. On the other hand, the policy change may reduce payments to existing renewable energy generators in Nevada and instead subsidize out-of-state renewable projects with ratepayer funds that previously encouraged development in Nevada.

Nevada policymakers should also bear in mind that joining CAISO may impact the price of PECs and, as a result, the compliance cost associated with meeting the state's RPS goals. California's RPS is divided into "content

[75] U.S. Energy Information Administration, *Electricity: Detailed State Data*, https://www.eia.gov/electricity/data/state/ (last visited June 12, 2018).
[76] See Amanda Levin, Natural Resources Defense Council, *Renewable Standards: Clean Energy Development & Other Impacts*. Presentation to TWG at 14-15 (August 17, 2017).

categories." If Nevada joins CAISO, renewable energy generation in Nevada may fall within California's balancing authority and, depending on California's renewable procurement rules, the content category for which Nevada's renewable generation projects qualify may change. This could potentially increase the value of the associated credits.[77] In theory, this could benefit renewable energy generation in Nevada by increasing revenues to generators but, at the same time, increase RPS compliance costs borne by ratepayers. If compliance costs are expected to rise significantly, as a result of this change or any other factors, Nevada may consider establishing an alternative compliance structure in which credits can be purchased for a set price, such as allowed in Massachusetts. The revenues can fund additional renewable energy development, energy efficiency improvements, or any other activities deemed appropriate by the Governor, Legislature, and state regulators.

If Nevada joins or creates an ISO, the entity or entities responsible for securing credits and the process by which obligations are calculated and credits are secured may change. Options include requiring suppliers or utilities to procure credits, or contracting for credits through a power agency[78]. In Massachusetts, for instance, suppliers are required to secure credits. Utilities provide the Department of Energy Resources (DOER) with each supplier's load. The DOER communicates that information to each supplier and the supplier then purchases RECs to satisfy compliance requirements based on the information provided by DOER.[79] Nevada may consider soliciting input from the balancing authority it joins or creates, utilities, suppliers, and other stakeholders to determine the best policy for the state.

Today, NV Energy customers can choose to go beyond the state-mandated RPS by selecting NV Energy's GreenEnergy Rider. The optional product is supplied partially or entirely with renewable energy, above and beyond what is required by the RPS. If ECI is approved, Nevada may consider requiring all suppliers to offer a product similar to the GreenEnergy Rider that is either partially or entirely renewable. It is important that any such policy explicitly define which credits are eligible to satisfy the stated commitment. Furthermore, Nevada can consider implementing rules regarding products advertised as "green" and go beyond the RPS. These products may be backed by out-of-state RECs that, unbeknownst to customers, may not result in incremental renewable supply. Nevada could consider requiring suppliers to differentiate between different types of renewable products so customers understand the products that are offered.

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[77] California Public Utilities Commission, *33% RPS Procurement Rules,* http://www.cpuc.ca.gov/RPS_Procurement_Rules_33/ (last visited June 13, 2018).

[78] The Illinois Power Agency (IPA) is an exemplar. It undertakes procurement of energy to meet the load requirements of "eligible retail customers", including procurement to meet RPS targets of utilities. IPA also manages Illinois' alternative energy suppliers' compliance payments and renewable energy credit purchases to meet their RPS obligations. See Anthony Star, Illinois Power Agency, *Overview of the Illinois Power Agency and Changes to the Illinois Renewable Portfolio Standard,* slides 3-4 (October 10, 2017 presentation).

[79] Executive Office of Energy & Environmental Affairs, Department of Energy Resources for the Commonwealth of Massachusetts, *Renewable & Alternative Energy Portfolio Standards Guideline,*https://www.mass.gov/files/documents/2016/08/vu/rps-compliance-basis-guideline.pdf (last visited June 13, 2018).

If Nevada elects to mandate a POLR, it must decide whether or not that supply will comply with the RPS and, if so, whether or not the requirement should go beyond the RPS. In a number of states, the standard POLR product meets the RPS requirement but consumers can opt-in to a POLR product that exceeds RPS requirements.[80]

Customer-sited Renewable Energy, Energy Efficiency, and Demand-side Management Programs

In an effort to lower customers' energy bills and mitigate the electricity sector's impact on the environment, Nevada subsidizes (1) customer-sited renewable energy generation,[81] (2) investments in energy efficiency,[82] and (3) participation in demand-side management programs.[83] These policies are all customer-focused, encouraging individuals to change the way in which they consume electricity. Customer-sited renewable energy generation (e.g., rooftop solar) has the potential to provide customers with cheaper, cleaner electricity than that from the grid. Investments in energy efficiency (e.g., insulation and appliance upgrades) also reduce the amount of electricity that customers purchase from the grid, which lowers customers' energy bills and mitigates the environmental impacts of consumption. Demand-side management programs typically use financial incentives to encourage customers to shift their electricity consumption during periods of peak system demand—when the cost of producing electricity is the highest—to off-peak periods.[84]For instance, payments from a utility or capacity market auction may incentivize customers to participate in a demand-response (DR) program, which allows a grid manager to curb customers' consumption during periods of peak demand. In theory, all three of these programs reduce not only the costs to customers who choose to participate, but total system costs as well, savings which are passed onto all consumers, including non-participants.

Many of the presentations to the TWG discussed these topics. Amanda Levin from NRDC briefly discussed using market-based incentives to encourage investment in both customer-sited renewable generation and energy efficiency. Maria Robinson from Advanced Energy Economy explained that the PUC may "open up new dockets to explore how to incorporate DER [distributed energy resources] into the grid" if Nevada moves from a cost-of-service model to market-based rates. Phil Pettingill representing CAISO discussed the potential for DER

[80] DPU Electric Power Division, Government of Massachusetts, *Basic Service Information and Rates*, https://www.mass.gov/service-details/basic-service-information-and-rates (last visited June 12, 2018), Public Utilities Commission & Division of Public Utilities and Carriers, State of Rhode Island, http://www.ripuc.org/utilityinfo/electric/narrelecschedule.html (last visited June 12, 2018), Pennsylvania Public Utility Commission, *Renewable Energy*, http://www.papowerswitch.com/ways-to-save-energy/renewable-energy-resources (last visited on June 12, 2018).

[81] See generally, Pat Egan, NV Energy, *Energy Efficiency*, *Renewable Energy & Public Policy Customer Programs*, Presentation to the TWG on Innovation, Technology, and Renewable Industries at 7 (October 10, 2017).

[82] Id.

[83] Nev. Admin. Code §704.934 (2017) (Preparation Contents and Submissions of Demand Side Plan; Annual Analyses Regarding Programs for Energy Efficiency and Conservation).

[84] U.S. Energy Information Administration, *Electricity: Electric Utility Demand Side Management*, https://www.eia.gov/electricity/data/eia861/dsm/ (last visited June 12, 2018).

aggregations to participate in wholesale markets as allowed in California since 2015. Pat Egan from NV Energy outlined both the utility's demand-side management programs, including residential air conditioning replacement, smart thermostats, and commercial demand response controls, and its customer-sited renewable energy subsidy program. Jason Burwen from the Energy Storage Association discussed the potential for and value of energy storage, and advocated for allowing storage to compete in deregulated markets on an equal footing with other resources. Chris Neme from the Energy Futures Group discussed the value of energy efficiency, the importance of having a state energy efficiency policy, and the entities that can administer an energy efficiency program in a deregulated market.

Evidence from around the country demonstrates that transitioning to a deregulated market does not necessarily, in and of itself, advance or hinder these customer-focused programs. Other factors, including geography, state policy, the cost of electricity, and political climate, are more important in determining the extent to which customers invest in distributed generation and energy efficiency and participate in demand-response programs. For instance, many of the states with the more successful electric sector energy efficiency programs have competitive markets, including Rhode Island, Massachusetts, and Connecticut.[85] But, a number of fully or partially-regulated states are well-ranked too, including Vermont, Arizona, and Oregon. Similarly, according to EIA data, both regulated and deregulated states rank highest in the country in terms of capacity of small-scale solar installations, the vast majority of which are customer-sited.[86] Hawaii and Vermont, two states that are at least partially regulated, rank first and second in the country, and other restructured states, including Massachusetts and New Jersey, fall within the top five.[87]

One of the Committee's central recommendations to the Governor and Legislature is that these customer-focused programs remain unharmed. Evidence from around the country demonstrates that Nevada can continue to successfully implement these programs in a competitive environment, but only if the programs are funded and administered. In transitioning to a competitive electricity market, one of the biggest challenges facing the state may be determining which entities will be responsible for administering these programs.

[85] Weston Berg et. al., American Council for an Energy-Efficient Economy, *The 2017 State Energy Scorecard: Report U1710* at 22-23 (September 2017). (According to the American Council for an Energy Efficient Economy's 2016 annual state-by-state energy efficiency ranking. All states were ranked based on their success with energy efficiency programs in the electricity sector in 2016, focusing specifically on savings as a percentage of retail sales).
[86] U.S. Energy Information Administration, *Electricity: Form EIA-861M (formerly EIA-826) Detailed Data*, https://www.eia.gov/electricity/data/eia861m/ (last visited June 12, 2018), U.S. Energy Information Administration, *Electricity: State Electricity Profiles*, https://www.eia.gov/electricity/state/ (last visited June 12, 2018) (calculation of the percentage of installed capacity within each that the EIA considers "small PV").
[87] Vermont Official State Website, Department of Public Service, *Electric: Vermont Electric Utilities*, http://publicservice.vermont.gov/electric (last visited June 12, 2018).

For instance, there are three entities, broadly speaking, that could administer Nevada's energy efficiency program: utilities, suppliers, and third-party entities. According to Chris Neme, utilities and third-party entities are the most promising options. Utilities serve all customers, have an existing relationship with customers, and have access to customer data. On the downside, energy efficiency is not necessarily part of a utility's core business and, as a regulated monopoly, may not have an incentive to innovate, though that can be mitigated with correctly-aligned financial incentives. And, because Nevada could decouple electricity sales from utility revenues, the utility would have no perverse incentive to keep consumption high. On the other hand, an independent third-party would also serve all customers, have a singular focus, and innovate in the face of competition, though it would not have an existing relationship with customers or access to customer data initially. Customer-sited renewable energy and demand-side management programs can continue to be successful in a deregulated environment so long as Nevada directs an entity to administer the programs and maintains a funding mechanism for them.

The Committee also recommends that the Governor and Legislature ensure that low-income customers continue to have subsidized access to these services, that Nevada avoid adopting policies that impede technological progress, and that the state consider incubators and pilot projects for innovative technologies, and encourage the adoption of "smart" technologies that support distributed generation, storage, and clean energy. So long as there are funding sources and entities to administer these programs, these objectives are achievable under a restructured electricity marketplace.

Net Metering and Community Solar

Net-metering programs encourage the deployment of customer-sited distributed generation through a different channel. Rather than receive an initial payment for installing distributive generation (DG), customers accumulate credits for each unit of electricity produced. Those credits are used to offset the customer's utility bill and, if credits exceed consumption, some programs allow customers to receive a cash payment. Currently, Nevada has a net metering program. Credits are worth a percentage of the total retail rate of electricity, and the value of these credits decreases over time, from 95% to 75% of the retail rate as more capacity is installed.

Community solar programs take net metering a step further. They are jointly shared by multiple parties, each of which receives credits on their electricity bill for their share of the power that is generated. Community solar allows those who would not typically be able to invest in DG, like renters, condo owners, and those with insufficient financial means to participate in a DG program. Today, community solar programs are not legislatively authorized in Nevada.

Marta Tomic from Vote Solar discussed the benefits of community solar and community solar in restructured markets. Pat Egan from NV Energy discussed NV Energy's net metering program and Assembly Bill 405 (passed in 2017), which changed net metering in Nevada. Justin Barnes from EQ Research, LLC discussed how retail choice interacts with net metering, including the importance of clear net metering guidelines, and suggested that Nevada retain as much of its current net metering structure as possible if ECI is approved. The Committee recommends that the Nevada Legislature revisit the community solar and net metering questions during the 2019 Legislative Session.

Electric Vehicles

Transitioning to an electric-based vehicle fleet would bolster Nevada's energy independence, reduce the State's exposure to global energy markets, potentially reduce energy costs, and mitigate environmental impacts. In recent years, the cost of electric vehicles has fallen and the number of available vehicle options has climbed. The TWG examined how a transition to a competitive market may impact the burgeoning electric vehicle market and heard Pat Egan from NV Energy discuss electric vehicles in Nevada and NV Energy's electric vehicle program.

Nevada has implemented a number of policies to encourage electric vehicle adoption. For instance, Senate Bill 145 provided funding for EV infrastructure development.[88] The legislation was driven in part by the fact that, according to a number of studies, Nevada is well-positioned for EV growth. The Committee recommends encouraging the Governor, Legislature, and regulatory agencies and organizations to implement ECI in alignment with Nevada's existing renewable energy, energy efficiency and technology goals. Therefore, energy market deregulation should be implemented in a manner that does not interfere with the development of the electric vehicle market.

If electric vehicle uptake is high, additional generation capacity may be necessary to serve the new load unless consumers charge their vehicles during off-peak periods. NV Energy's time-of-use rate aims to solve that problem by charging customers lower rates during off-peak period and higher rates during on-peak periods.[89] In a restructured market, suppliers may not offer a similar time-varying-rate (TVR) product or, if they do, they may not advertise it well. Therefore, the legislature may consider ways in which it can encourage or mandate suppliers to provide at least one TVR product to customers with an EV. Similarly, if a POLR is established, the Nevada Legislature may also consider mandating that electric vehicle customers using the POLR take a TVR.

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[88] See S.B. 145 (2017). *An Act relating to energy…Creating the Electric Vehicle Infrastructure Demonstration Program.*
[89] Pat Egan, NV Energy, *Energy Efficiency, Renewable Energy & Public Policy Customer Programs*, Presentation to the Technical Working Group on Innovation, Technology, and Renewable Industries at 34 (October 10, 2017).

Storage

Energy storage technologies capture energy for use at a later time. Storage is a valuable service because it allows operators to capture energy during off-peak periods, when the demand for and price of electricity are relatively low, and redeploy that energy during high demand, which results in higher priced periods. In the past, pumped-storage was generally considered to be the only financially-viable form of grid-scale storage. More recently, other technologies, including lithium ion, lead acid, and other battery types have become more affordable. In an effort to encourage the deployment of energy storage on the grid, in 2017, Nevada added storage to the list of technologies eligible for subsidies under NRS 701B. Senate Bill 145 explicitly allocated $10 million to storage.

Two of the presentations to the TWG, from Pat Egan and Jason Burwen, addressed energy storage. Pat Egan from NV Energy discussed storage legislation in Nevada. Jason Burwen from the Energy Storage Association gave an overview of storage technology, discussed its benefits and the barriers to deployment, and argued for competition in grid planning and procurements, and that storage should be compensated for its full value and be afforded fair and equal access to the grid. The Committee recommends that the Governor and Legislature adopt competitive retail market policies that do not impede progress and innovation of current in future technologies, including energy storage technologies.

GENERATION, TRANSMISSION, AND DELIVERY SUMMARY OF FINDINGS

Executive Order 2017-03 directed the Committee to address "[t]he need to amend laws governing the generation, transmission, purchase, and delivery of electricity to all Nevadans."[90] Accordingly, the Technical Working Group on Generation, Transmission, and Delivery was formed and assigned a number of issues pertaining to this topic of electricity markets restructuring. The TWG was tasked with examining infrastructure and other needs to support imports, exports, and renewable energy development, resource adequacy and system planning, policies that will enable Nevada to become a net energy exporter, federal and state land issues associated with transmission and generation development, and other questions pertaining to ISO/RTO governance and alignment with Nevada's energy goals and policies.[91] In examining these issues, the TWG met four times and heard from a number of interested stakeholders, ultimately adopting three recommendations that were approved by the Committee based upon the information presented to the TWG.

Generation, transmission, and delivery (or distribution) are the terms generally used to describe the three major components of the process of supplying electricity to customers. Generation is the process of producing electricity from coal, natural gas, solar, geothermal, wind, or other sources of energy, while transmission refers to high-voltage transportation to load centers, and distribution refers to lower-voltage delivery to end-use customers.[92] More specifically, the PUCN defined "transmission" as "the act or process of transporting energy in bulk," and "distribution" as "the system of wires, switches, and transformers that serve neighborhoods and businesses, typically lower than 69,000 volts."[93] The TWG received information from a variety of Nevada-based participants on the issues of how ECI might affect generation, transmission, and delivery.

Resource Adequacy and Planning Reserves

Resource adequacy requirements are governed by the North American Electric Reliability Corporation (NERC).[94] As one study explains, "[a] power system has adequate resources if its supply-and-demand-side resources reliably exceed its loads…[resource adequacy] generally refers to a planning timeframe under which

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[90] Exec. Order 2017-03. *Order Establishing the Governor's Committee on Energy Choice*. Sec 10(A). (Feb. 9th, 2017).
[91] See *TWG Workstream Assignments Document* (July 11, 2017) Appendix A-13.
[92] Garrett Weir, Hayley Williamson, Nevada Public Utilities Commission. *Energy 101: Presentation to the Energy Choice Committee* at 6-7 (April 26, 2017).
[93] Id. at 8.
[94] Amy Abel, et al., Congressional Research Service. *Electric Utility Restructuring: Maintaining Bulk System Reliability*. ("Reliability of the electric grid has been defined by NERC in terms of two functional aspects. These include: 'Adequacy' and 'Security'.") at 3 (February, 2005).

resources' total nameplate capacity must exceed annual peak load by a specified planning reserve margin."[95] The study further explains that the structure of the wholesale market plays a critical role in determining resource adequacy outcomes, "particularly the manner in which resource investors are compensated."[96] Implementation of ECI will require resource adequacy, including required reserves, to exist within the wholesale market region to support market restructuring (i.e. there must be ample generation in the wholesale market area to meet expected loads in the market region served in order to foster competitive wholesale pricing of that generation). If Nevada elects to join an existing organized wholesale market such as the California Independent System Operator (CAISO) or the Southwest Power Pool (SPP), the wholesale market region is that of the organized wholesale market. If Nevada elects to create its own organized wholesale market, the wholesale market region is that of Nevada.

Currently, resource adequacy requirements are being met in the CAISO balancing area.[97] Installed generation capacity is reported at 71,740 Megawatts (MW). Nevada native load peak of 7,961 MW occurred in 2016 (native load is only that of NV Energy affiliates and does not include balancing area loads of rural Nevada utilities, municipal utilities, and NRS 704B customers) and would add approximately 11% (excluding reserves) to the CAISO resource requirement. CAISO has processes in place to ensure resource adequacy and would presumably require Nevada electric providers to fund or acquire additional generation capacity to satisfy resource adequacy requirements for their load.

Resource adequacy requirements are being met for the SPP balancing area as well.[98] Installed generation capacity is reported at 50,622 MW. Nevada native load peak of 7,961 MW occurred in 2016 (native load is only that of NV Energy affiliates and does not include balancing area loads of rural Nevada utilities) and would add approximately 16% to the SPP resource requirement. As with CAISO, SPP also has processes in place to ensure resource adequacy and would presumably require Nevada electric providers to fund or acquire additional generation capacity to satisfy resource adequacy requirements for their load.

Building new generation requires several years to plan, permit, finance and construct. Development of new baseload or intermediate generation resources within Nevada may not be possible within the available time frame. Buildout of new peaking or utility scale renewable resources may be possible in the time frame available. The decision as to what organized wholesale market Nevada will participate in must be made several years in

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95 Matthew J. Morey, et al. *Retail Choice in Electricity: What Have We Learned in 20 Years?* Electric Markets Research Foundation at 51 (Feb. 11, 2016).
96 Id.
97 Stacy Crowley, California ISO, *Regional and National Marketplace Presentation*, Presentation to the Governor's Committee on Energy Choice (April 26, 2017).
98 Carl Monroe & Bruce Rew, Southwest Power Pool, *SPP Wholesale Markets and Retail Markets,* Presentation to the TWG on Open Markets (August 8, 2017).

advance of the effective date for ECI, in order to provide time for the organized wholesale market to prepare for and adjust its resource mix for Nevada, or for Nevada to construct additional generation should Nevada elect to create its own organized wholesale market.

Resource adequacy issues in Nevada will be further exacerbated by generation units or purchased power agreements that are not marketable for various reasons including contract terms, cost of generation or age of generating units. NV Energy currently has approximately 6,011 MW of owned generation and 2,930.5 MW in purchased power agreements (including pre-commercial agreements).[99] The two primary electric energy trading hubs[100] available for Nevada markets are currently COB and Mead. The trading hubs serve as a proxy to current competitive wholesale markets in the region. Generation assets held by NV Energy with busbar[101] costs above these trading hub prices or purchased power agreements (PPAs) may be difficult to liquidate and will further add to Nevada's resource adequacy issues in the short term. Current pricing at Mead follows in the below table. Of the 61 PPAs identified by NV Energy, all but the Kingston, Mill Creek, Newmont, TMWRF, Techren 2, Hoover, Stillwater PV, NPC_SPCC, and Techren 1 PPAs have pricing in excess of the Mead trading prices.

MEAD

Quote Date 10/13/2017

Forward Month	On Peak (6x16)	Wrap	7X24
Nov-17	$28.207	$23.281	$26.014
Dec-17	$29.105	$25.079	$27.244
Jan-18	$29.406	$26.852	$28.280
Feb-18	$28.939	$25.659	$27.533
Mar-18	$26.944	$23.139	$25.352
Apr-18	$25.268	$20.382	$23.096
May-18	$25.878	$21.455	$23.928
Jun-18	$35.404	$25.712	$31.312
Jul-18	$43.476	$25.919	$35.359
Aug-18	$42.315	$26.075	$35.505
Sep-18	$32.133	$23.894	$28.288
Oct-18	$28.801	$25.005	$27.209
Nov-18	$27.060	$23.228	$25.354

[99] Kevin Geraghty, NV Energy, Presentation to the Technical Working Group on Economic Impacts (June 21, 2017).
[100] See Southwest Power Pool, *Glossary of Terms*, https://www.spp.org/glossary/ (Accessed June 19, 2018).
[101] See Public Power Council, *Glossary of Northwest Electricity Industry Terms*, https://www.ppcpdx.org/industry-info/glossary/#B (Accessed June 19, 2018).

Of the generation assets owned by NV Energy, its two coal resources, Navajo Generating Station (255 MW) and North Valmy Generating Station (261 MW), are slated for retirement before or near the effective date of Energy Choice. These retirements will further add to the resource adequacy issues in the short term. Other units which were constructed prior to 1980 and may be difficult to market such as Tracy Unit 3 (1974, 108 MW), Fort Churchill Units 1 and 2 (assuming must run conditions eliminated) (1968, 226 MW), and Clark Unit 4 (1973, 54 MW).

In addition to other factors, resource adequacy is affected by planning reserves. The concept of planning reserve margins is described by NERC as "…designed to measure the amount of generation capacity available to meet expected demand in the 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."[102] Reserves are intended to ensure sufficient generation resources are available to meet real-time operating requirements and to avoid the possibility that a load loss occurs no more frequently than one day in 10 years, commonly referred to as the "1-in-10 resource adequacy standard." Reserve margins directly affect reliability of the electric grid and cost of electric service. Reserve margins are established as a percentage of net customer requirements for NV Energy's native load and are 12% for NV Energy's customers in southern Nevada and 15% for NV Energy customers in northern Nevada. These reserve margins amount to 941 MW of generation in the year 2020, again the equivalent of two large baseload/intermediate generating plants.

Studies need to be completed to determine the adequacy of reserve requirements for Nevada. These studies need to be probabilistic in nature and take into consideration numerous factors including intra-Nevada transmission constraints, transmission import and export limits, and organized wholesale market structure. Under a restructured electricity market should ECI be approved, the regulated utility will no longer be responsible for generation development but will continue to be responsible for the development of transmission and distribution facilities to deliver electricity to consumers within its designated service area. Thus, reserve margins should be appropriate for Nevada-specific circumstances. With regard to resource adequacy, the TWG recommended, assuming an organized wholesale market is established and functioning prior to opening a competitive retail market, that the PUCN continue to establish planning reserve margin requirements and ensure compliance with the wholesale market operators' resource adequacy requirements through the existing integrated resource planning process until a competitive retail market is established. Once a competitive retail market is established, Nevada should continue to establish planning reserve margin requirements but the existing integrated resource planning process will need to be replaced with a process that ensures retail providers secure adequate resources.

[102] See https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx (Accessed June 12, 2018)

Reliability "Must-Run" Units

"Must-run" generation units are those generation units that must operate to provide for electric grid reliability under certain conditions. By definition a must run generation unit has no competition; it is the only unit that can be operated to meet/eliminate the condition giving rise to the must-run status (e.g. transmission capacity overloads and transmission outages). NV Energy has identified several must-run generation stations which, if sold without addressing the must-run condition, could result in anti-competitive behavior by the owners of such stations. These stations include Fort Churchill Generating Station, North Valmy Generating Station, Clark Generating Station and Clark Mountain Generating Station. Anti-competitive pricing by owners of must-run generation units can be eliminated by pricing controls enacted by the organized wholesale market, or by elimination of the must-run conditions through transmission system modification, load shedding or peak clipping that allow competition to occur.

Expanding Export/Import Transmission Capacity

Some of the advantages of joining an organized wholesale market include: (a) participating in economies of scale relating to generation development; (b) taking advantage of load diversity amongst market participants; (c) minimizing overall quantities of reserves held in the market region; and (d) making available the natural resources of various areas (solar, wind, geothermal) to all participants of the organized wholesale market. Realizing these benefits will require sufficient transmission import and export capabilities from Nevada to the overall region served by the wholesale market. The transmission system serving Nevada is electrically connected to all of its surrounding states. However, greatest connectivity from an import/export capacity perspective exists with California and Arizona.[103] This connectivity could support the deployment of the CAISO organized wholesale market into Nevada; however, development of a Nevada only or deployment of an SPP organized wholesale market could also occur with the adoption of interchange policies between adjacent organized wholesale markets as common in organized wholesale markets serving Midwest, East and Northeast regions of the country.

Currently, transmission import and export capabilities into Nevada are less than NV Energy's existing native load. Southern Nevada import limits are reported at 5,331 MW and northern Nevada import limits are reported at 1,000 MW. Increasing transmission import and export limitations is currently a multi-year process involving numerous stakeholders including interconnected transmission owners, regional transmission operators, the Western Electricity Coordinating Council, public utility regulatory bodies, local planning commissions, federal land

[103] Shahzad Lateef & Marc Reyes, NV Energy, *Generation, Transmission, and Delivery,* Presentation to the Innovation TWG (November 7, 2017).

management agencies, land owners, environmental groups, and citizen groups. Until import and export limitations are increased, Nevada based generation serving NV Energy native load is required.

Transmission planning in Nevada currently occurs in a vertically integrated utility environment in which one organization forecasts load requirements and plans the generation and transmission to meet that requirement. Once approved by the regulatory body, the utility proceeds with development efforts. As pointed out by Pat Woods in his presentation on May 10, 2017, one of the critical components to ensure success of competitive wholesale markets (and by extension ultimately retail markets) is that the region covered by the market must have “robust” transmission infrastructure.

The current process used in Nevada to plan generation and transmission resources is the Integrated Resource Planning (IRP) process. This process is required under both state statutory and administrative code provisions. Under the IRP process, NV Energy files an energy supply plan annually and an IRR every three years with the Nevada Public Utility Commission. Much of this process may no longer be applicable to NV Energy in a retail choice environment as they would not serve this function. Using the IRP process, NV Energy historically has built the least-cost transmission option to meet local needs. In a competitive environment transmission must be planned proactively as “highways” to benefit the region covered by the organized wholesale market. This broader approach to transmission planning allows loads to be served and renewable generation options to be developed.

Should ECI be approved, responsibility for planning transmission to support local needs and to eliminate must-run generation units may still fall to the utility. Furthermore, under a restructured market system, responsibility for planning transmission to support increases in Nevada import and export capabilities may need to be assigned the regional transmission operator and the organized wholesale market. Additionally, implementing ECI may require that the responsibility to plan transmission to support development of localized wind, solar and geothermal resources be delegated to an existing or new state agency.

In a vertically-integrated utility model transmission study costs under the existing integrated resource planning process are borne by electric utility rate payers. Therefore, transmission study cost responsibility pursuant to ECI will need to be addressed. Currently, transmission development is funded by the regulated utility’s investors who earn a rate of return on that investment once a project is approved by the PUCN. Transmission development in a restructured market may occur in a variety of formats including transmission companies, existing utilities, and state funded projects.

One concept used by SPP to allocate the cost of its high voltage lines is identified as the "highway/byway" methodology. Under this concept cost responsibility is allocated based on voltage as follows:

Voltage	Region Pays	Local Zone Pays
300 kV and above	100%	0%
Above 100 kV and below 300 kV	33%	67%
100 kV and below	0%	100%

Texas instituted a program called the Competitive Renewable Energy Zones (CREZ) transmission development. Under CREZ, the Electric Reliability Council of Texas (ERCOT) identified areas of the state best suited for wind development. The Public Utility Commission of Texas then selected those areas as CREZ. ERCOT developed transmission plans to transfer future wind energy from CREZ to loads. A joint venture called Electric Transmission Texas (ETT) was formed to by several companies to construct approved transmission projects. Once a transmission project is constructed the ETT receives a return on its investment through transmission revenues collected by ERCOT. Use of the CREZ process resulted in the development of 18,500 MW of generation in Texas. Texas produces more wind power than any other state. Wind energy accounts for 12.63% of the energy generated in Texas.

Supporting transmission investments under a restructured market system can pose a significant challenge, given the multiple parties and jurisdictional issues involved. As the U.S. Department of Justice Antitrust Division has reported, "[m]arket participants with conflicting interests continue to have a say in the transmission planning process, and it can be very difficult to create governance and cost-allocation structures that allow conflicting interests to unify into decisions that will be efficient for the whole. Furthermore, the siting of any large transmission projects can be subject to the regulatory authority of numerous states, and local opposition can be fierce."[104] Nevertheless, provisions of the Energy Policy Act of 2005 that allow FERC to directly permit transmission projects when state approval is delayed, as well as the growing need for inter-regional transmission capacity are factors that should support investments in transmission capacity.[105]

[104] Jeff Lien, U.S. Department of Justice Economic Analysis Group Antitrust Division, *Electricity Restructuring: What has Worked, What has Not, and What is Next* at 10 (2008).
[105] Id. at 11 ("The need for inter-regional transmission capacity is greater now that we have market structures in place to effectively utilize the transmission system").

CONSUMER PROTECTION SUMMARY OF FINDINGS

A number of prominent industries in the United States that began under regulated, non-competitive regimes were subsequently restructured or deregulated and now operate in competitive markets. The airline, banking, mineral, telecommunications, and other industries, for example, began under "tightly regulated" market structures but have, over time, become less regulated.[106] As these industries have undergone restructuring, policies have been adopted to ensure that consumers are protected from bad actors in less regulated competitive markets. As has been the case with these industries that have deregulated, the restructuring of electricity markets also implicates consumer protection issues, and information provided to the Committee should help to guide potential decision-making to ensure consumers are adequately protected under a restructured market in Nevada.

The Committee endeavored to address consumer protections issues under a broad theme of protecting customers from undue rate increases and fraudulent practices.[107] Specific issues related to this area included licensing, market behavior and transactional rules, customer education on the marketplace and their rights, customer complaint and dispute resolution, oversight and rules for managing data privacy and data exchange, low-income customer assistance, and other customer protection policy issues. It is clear from both Nevada's past experience with the prospect of restructuring as well as from contemporary proponents and opponents of restructuring alike, that there is general agreement regarding the need for mechanisms to protect consumers in a competitive electricity marketplace. The Committee's Technical Working Group on Consumer Protection presented five key findings pertaining to consumer protection issues, specifically relating to consumer education, comparison of terms of service among competing providers, protecting customer data and privacy, modernizing Nevada's unfair and deceptive trade practices acts, and minimizing excessive costs. The TWG presented fifteen recommendations related to these areas, each of which the full Committee adopted unanimously without revision.

In 1997, when Nevada first examined the prospect of adopting a competition-based electricity market, consumer protection policies were considered by the Legislative Subcommittee to Study Competition in the Generation, Sale, and Transmission of Electric Energy, as reported by the LCB's *Bulletin 97-11*: "[o]bservers suggested that suppliers of retail power should be licensed and subject to relevant consumer protection laws…proponents indicated that in a competitive environment, consumers need more education and protection against deceptive trade practices and less assistance in the area of economic regulation."[108] More recently, the PUCN affirmed a general consensus that introducing competition in Nevada's electricity marketplace presents new

[106] See generally, David B. Spence, *Can Law Manage Competitive Energy Markets?* 93 Cornell L. Rev. 765, (May 2008).
[107] See generally, *Technical Advisory Committee Workstream Issues Assigned by Chairman* and Committee Meeting Minutes, (July 11, 2017).
[108] Nevada Legislative Counsel Bureau, Bulletin No. 97-11, *Competition in the Generation, Sale, and Transmission of Electric Energy* at 50 (1997).

issues to be resolved in order to protect electricity customers: "[t]he participants are in agreement that a transition from a bundled service monopoly model to a competitive retail market requires a new set of consumer protection measures. The participants also agree that one of the best ways to safeguard customers and to implement a competitive market is through customer education."[109]

Successful Implementation of the Energy Choice Initiative Will Depend on Effective and Comprehensive Efforts to Educate and Inform Customers, Particularly Residential and Small Business Customers

Proponents of market restructuring agree that protecting consumers in a competition-based marketplace is essential in order for a competitive market to function successfully, and that consumer education in particular is a necessary component of consumer protection. According to the National Energy Marketers Association (NEMA), an organization supportive of competitive electricity markets, "[o]ne of the most effective means of protecting consumer[s] is providing them with the choice to do business with whom they want, and to purchase what they want, when they want it, and not to force them to business with any one entity."[110] Illustrating its recognition of the need for consumer protection policies in competitive electricity markets, NEMA has "implemented practical, straightforward and sensible safeguards to protect the consumer," and NEMA members "affirm their commitment to adhere to the principles set forth in NEMA's *Consumer Bill of Rights,"* as well as a "zero tolerance policy for any fraudulent, illegal, or unethical conduct of any employee or agent."[111] NEMA's *Consumer Bill of Rights* recognizes specifically the consumer's right to be provided access to "education on energy, energy conservation, and technology available to help control energy costs."[112] Indeed, consumer education appears to be one of the most accepted consumer protection policies in the context of electricity markets restructuring. In a report commissioned by the United States Agency for International Development, Office of Energy, Environment and Technology, "public education" is included as one of the goals that, "at a minimum, consumer protections policies should foster."[113] And in its report *Retail Electric Competition: A Blueprint for Consumer Protection*, the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy concluded that, "a comprehensive public education program should maximize public participation in the implementation of retail competition, minimize customer confusion about the changes being undertaken, and equip *all* customers with the means to participate effectively in the competitive electric market."[114] Thus, there appears to be broad consensus that

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[109] Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report*, Investigatory Docket No. 17-10001 at 104 (April 2018).
[110] National Energy Marketers Association, *National Marketing Standards of Conduct* at 2 (2013). See also, Technical Working Group on Consumer Protection Meeting Minutes and Public Comment (Aug. 23, 2017).
[111] National Energy Marketers Association, *National Marketing Standards of Conduct* at 2 (2013).
[112] National Energy Marketers Association Presentation, *Consumer Bill of Rights*, Item 9 (Aug. 23, 2017).
[113] U.S. Agency for International Development, The Regulatory Assistance Project, *Best Practices Guide: Implementing Power Sector Reform* at 63 (2000).
[114] U.S. Dept. of Energy, Office of Energy Efficient and Renewable Energy, *Retail Competition: A Blueprint for Consumer Protection* at 17 (Oct. 1998).

consumer protection policies, particularly comprehensive consumer education initiatives, are necessary for a competitive electricity market to function successfully.

The particular emphasis that is placed on consumer education in the context of restructuring electricity markets reflects another general point of agreement, which is that residential consumers appear to be more vulnerable and less likely to participate in a competitive market than other industrial or large commercial consumers. Consumer education initiatives are cited as one component of consumer protection policies that can help to ensure all classes of consumers are able to participate in a competitive market. Presentations to the TWG, as well as a number of published studies show that residential customers in restructured markets are overall less likely to select competitive electricity providers while larger and industrial consumers more readily switch to competitive suppliers, and this disparity can be linked to education efforts or the lack thereof. According to West Virginia's Consumer Advocate Office, there is a direct link between the levels of residential consumer participation in a competitive market and the education efforts that are tailored to residential customers.[115] In its presentation to the TWG, the West Virginia Consumer Advocate's Office asserted that, "[i]n most restructured states, the great majority of industrial and large commercial customers will switch to alternative retail generation suppliers, while the majority of residential customers will most likely remain with or return to some type of default service (if available)."[116] This general lack of participation, moreover, can be traced to the quality of education efforts geared toward residential customers. According to the West Virginia Consumer Advocate's Office, "[c]ustomer education is essential," and "the worse customer education is, the more customers will be on default service."[117] Acknowledging that "[t]hose consumers most in need of protection are the small commercial, agricultural, and household/residential customers" due to their "general level of sophistication and their relative economic circumstances," the U.S. Agency for International Development concludes that "[p]erhaps the most effective means of consumer protection is that of public education."[118]

The unique needs of small and residential customers in restructured electricity markets are further reflected by the fact that these classes of consumers generally do not participate in the competitive electricity market to the same degree as industrial consumers when given the choice and opportunity to do so. As the National Council on Electricity Policy observes, "[t]he results of [restructuring] laws have shown that, for the most part, competition in the form of distinct choices of electric suppliers has been slow to come to the smallest of consumers, while the larger consumers have received more attention from marketers and generally been able to take advantage of the

[115] Jackie Roberts, West Virginia Consumer Advocate Presentation to the Consumer Protection TWG, *Electric Restructuring in Nevada: Protecting Consumer* (Aug. 23, 2017).
[116] Id. at 10.
[117] Id. at 26.
[118] U.S. Agency for International Development (USAID), The Regulatory Assistance Project, *Best Practices Guide: Implementing Power Sector Reform* at 65-66 (2000).

competitive market."[119] Another study supports the finding that, in general, larger commercial customers are better able to take advantage of competitive markets: "A far larger proportion of commercial and industrial customers have switched to alternative providers throughout the United States than have small commercial and residential customers. This indicates that these customers were receiving enough savings by shopping for power to make it worth their time and effort to make the switch."[120]

More recently, a 2008 study by the U.S. Department of Justice Antitrust Division concluded that "[i]n electricity markets, customer choice programs have been slow to develop, particularly at the residential level…where the transaction costs associated with comparing multiple complicated pricing offers might be significant compared to potential cost savings." [121] The study further acknowledges that "[i]n most states, the vast majority of residential customers rely on the default service and there is little switching to alternative retailers." [122]

The disparity in participation rates among small and residential customers as compared with larger customers illustrates that these classes of electricity consumers occupy distinct positions in a competitive market. This distinction further amplifies the need for effective consumer protection policies, particularly with regard to consumer education initiatives for small and residential customers, which can encourage residential and other small electricity consumers to fully participate in a competitive market and help ensure that the benefits of competition are not reserved for larger commercial and industrial consumers. As the State of Nevada Bureau of Consumer Protection presented to the Committee, "[c]ustomer education is critical to energy choice," and "consumers will need to be educated about the competitive market," in order for the restructured market to function.[123]

In Order for Customers to Make Informed Choices in a Competitive Electricity Market, they Must be Able to Make Accurate Comparisons of Essential Terms of Service among Various Providers

In order for customers to make informed decisions when selecting energy service providers under a restructured market, customers must have access to fair, transparent, and accurate disclosures of essential terms of service, such as pricing, contract duration, environmental impacts, and other important terms of service. Enforceable standards will ensure providers are disclosing such terms of service will be critical in making sure customers are able to make "apple-to-apple" comparisons when choosing their electricity provider under a

[119] Matthew H. Brown & Richard P. Sedano, Nat'l Council on Elec. Policy, *A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future* at 25 (2003).
[120] Matthew H. Brown, Nat'l Conf. of St. Legislators, *Restructuring in Retrospect* at 25 (2001).
[121] Jeff Lien, U.S. Department of Justice Economic Analysis Group Antitrust Division, *Electricity Restructuring: What has worked, what has not, and what is next* at 12 (2008).
[122] Id. at 13.
[123] State of Nevada, Bureau of Consumer Protection Presentation to the Consumer Protection TWG, *Consumer Protection: Protections from Undue Rate Increases and Fraudulent Practices* at 45-46 (Oct. 18, 2017).

restructured market. The Nevada Bureau of Consumer Protection (BCP) stated during testimony to the Committee that transparency with regard to the contract information provided to customers is essential to "allow consumers to compare costs, contracts, variable rates, etc."[124]

As an example of how fair and accurate comparisons can be encouraged at the regulator level, the Nevada BCP highlighted the messaging adopted by the Public Utilities Commission of Ohio (PUCO) which emphasizes disclosure in customer selection of providers: "[w]ith the PUCO's innovative tool, the differences between supplier plans, costs, and contract terms are always right in front of you."[125]

Ensuring accuracy and fairness in disclosing essential terms of service has been identified as an important component of market restructuring since at least 1996, when the National Association of Regulatory Utility Commissioners (NARUC) urged states adopting retail electricity markets to "include enforceable standards of disclosure and labeling that would allow retail consumers to easily compare the price, price variability, resource mix, and environmental characteristics of their electricity purchases."[126]

Proponents of competitive electricity markets agree that it is necessary for customers to be able to make accurate comparisons of essential terms of service offered by retail providers. The National Energy Marketers Association's "Consumer Bill of Rights" includes as items 2 and 3, the customer's right to "[a]ccurate price and usage information, from both the utility and competitive energy supplier, that is expressed in simple and straightforward terms," and the right to "[t]erms and conditions written in plain language that set forth contractual obligations for both the consumer and energy supplier." Testimony provided to the Committee from representatives of AARP indicates that accurate price and terms of service information and disclosure is of particular importance for elderly consumers and other vulnerable classes of customers.[127]

Successful Implementation of the Energy Choice Initiative Should ensure that Excessive Costs do not Prohibit Customers from Exercising the Right to Choose a Retail Provider

As stated to the TWG, the right to choose an energy provider under a restructured energy marketplace "is not an end unto itself."[128] That is, customers' ability to participate in a competitive retail energy market must be

[124] Id.
[125] Id. at 50.
[126] U.S. Dept. of Energy, Office of Energy Efficient and Renewable Energy, *Retail Competition: A Blueprint for Consumer Protection* at 20 (Oct. 1998).
[127] Bill Malcolm, AARP Presentation to the Consumer Protection TWG, *Retail Choice and Residential Customers* at 14-16 (Feb. 8, 2018).
[128] Jackie Roberts, West Virginia Consumer Advocate Presentation to the Consumer Protection TWG, *Electric Restructuring in Nevada: Protecting Consumers* at 20 (Aug. 23, 2017).

coupled with the ability to choose service providers that offer reliable service at reasonable prices. Customers must be able to evaluate and choose providers based upon the value of the service offered. Accordingly, steps should be taken to discourage excessive costs or costs that effectively prohibit a customer from fully exercising the right to choose a provider based upon the value of the service offered. In light of the potential for stranded asset costs and other costs associated with transitioning from Nevada's current system to a competitive market, these considerations related to excessive or prohibitive costs are all the more pressing.[129]

A Competitive Energy Marketplace Must Ensure the Protection of Confidential Customer Data and Maintain Respect for Customer Privacy

Implementation of ECI will implicate new issues related to protecting customer data, respecting customer privacy, and maintaining confidentiality of records. Such information is particularly valuable in a competitive marketplace in which service providers must attract customers in order to participate in the market and account for marketing to customers as a cost of doing business. Given that studies indicate the costs of marketing to residential customers are generally higher than the costs of marketing to non-residential customers, the value of customer data and personal information is all the more clear.[130] In 1997, the Nevada LCB's report on competitive electricity markets observed that, "[a] major concern in a more competitive environment is access to customer information. To compete equally, marketers need access to consumer purchasing data. However, such access raises questions about proprietary rights to information as well as customer privacy."[131] There must be adequate protections for customers to ensure that their reasonable expectation of privacy and confidentiality is protected, and to prohibit the abuse or misuse of private customer data.

According to the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, "[s]tates must strike a balance between the need for fair dealings in the use and access to customer information to enable development of a competitive market and customers' reasonable expectation that personal billing and payment information will remain private."[132] The importance of protecting customer privacy was emphasized by the Nevada BCP in its testimony to the Committee, which included a slide dedicated to discussing the need for "oversight of and rules for managing data privacy and data exchange."[133] The PUCN, in its report on ECI, echoes the conclusion that, "Nevada will need to strike a balance between customer privacy and business expediency," in

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[129] Id.
[130] See Matthew H. Brown, Nat'l Conf. of St. Legislators, *Restructuring in Retrospect* at 16 (2001) ("Indications are that the cost of securing individual residential customers is high…since most individual residential customers do not use a great deal of electricity, the returns on the [marketing] investment in securing each customer are small.").
[131] Nevada Legislative Counsel Bureau, Bulletin No. 97-11, *Competition in the Generation, Sale, and Transmission of Electric Energy* at 53 (1997).
[132] U.S. Dept. of Energy, Office of Energy Efficient and Renewable Energy, *Retail Competition: A Blueprint for Consumer Protection* at 33-34 (Oct. 1998). Available at: https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/26116.pdf
[133] State of Nevada, Bureau of Consumer Protection Presentation to the Consumer Protection TWG, *Consumer Protection: Protections from Undue Rate Increases and Fraudulent Practices* at 58-59 (Oct. 18, 2017).

order to implement ECI if it is approved.[134] A balanced approach to protecting customer data in a competitive electricity marketplace was also supported in testimony by the Office of the West Virginia Consumer Advocate. During its presentation to the TWG, the Office stated that, "the balance between customer privacy and facilitating retail choice will have to be struck in a manner that adheres to constitutional principles, protects customer safety and identity, and is accepted by those whose private data is being released."[135] There is strong consensus, then, that data protection and security with regard to customer privacy are important components of protecting energy consumers in a competitive energy market.

Successful Implementation of the Energy Choice Initiative May Require Amending Nevada's Deceptive Trade Practices and/or Unfair Trade Practices Acts that Respond to and Reflect Changes Attendant to a Competitive Electricity Marketplace

Nevada, along with many other states, has adopted a statute that mirrors federal law prohibiting "unfair methods of competition and unfair or deceptive acts or practices in or affecting commerce."[136] Nevada has enacted both an Unfair Trade Practices Act[137] and a separate Deceptive Trade Practices Act.[138] Nevada's deceptive trade practices statute addresses a wide range of topics, including pyramid schemes,[139] door-to-door sales,[140] grant-writing services[141] and telecommunication services.[142] One common practice addressed in Nevada's deceptive trade practices statute is the practice known as "slamming," whereby a customer's service provider changes without the customer's permission.[143] "Slamming" was a prevalent practice among providers in the telecommunications sector after it was restructured, and is potentially a concern for a restructured energy market. According to the Attorney General's Office Bureau of Consumer Protection, so-called "slamming" is among the commonly-reported complaints by customers in restructured markets, along with "billing issues, unexpected or hidden fees, inadequate or false information, high-pressure sales tactics, telemarketing," and others.[144] "Slamming" is one example illustrating that some potential practices specific to retail energy providers in a competitive market, similar to telecommunications service providers, may potentially need to be addressed in Nevada's deceptive trade practices statute should Nevada adopt a competitive electricity marketplace. The Nevada BCP presented testimony

[134] Public Utilities Commission of Nevada, *Energy Choice Initiative Final Report*, Investigatory Docket No. 17-10001 at 100 (April 2018).
[135] Jackie Roberts, West Virginia Consumer Advocate Presentation to the Consumer Protection TWG, *Electric Restructuring in Nevada: Protecting Consumer* at 20(Aug. 23, 2017).
[136] See generally 15 U.S.C. § 45(a)(1) (2012), Nev. Rev. Stat. §§598.0903-9694 (2017).
[137] Nev. Rev. Stat. §598(A) (2017).
[138] Nev. Rev. Stat. §598 (2017).
[139] Nev. Rev. Stat. §598.100 (2017).
[140] Nev. Rev. Stat. §598.140 (2017).
[141] Nev. Rev. Stat. §598.535 (2017).
[142] Nev. Rev. Stat. §598.968 (2017).
[143] Nev. Rev. Stat. §598.969 (2017).
[144] State of Nevada, Bureau of Consumer Protection Presentation to the Consumer Protection TWG, *Consumer Protection: Protections from Undue Rate Increases and Fraudulent Practices* at 40-41 (Oct. 18, 2017).

discussing common customer complaints in competitive electricity markets, and highlighted the need for effective monitoring and oversight of market participants and providers.[145]

[145] Id. at 39-41.

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Appendix A: Presentations & Material Provided to the Energy Choice Committee*

Available Online at http://energy.nv.gov/Programs/TaskForces/2017/EnergyChoice/

A-1: February 9, 2017 - Executive Order 2017-03, Order Establishing the Governor's Committee on Energy Choice
A-2: April 26, 2017 - California ISO 1 Presentation to the Committee
A-3: April 26, 2017 - California ISO 2 Presentation to the Committee
A-4: April 26, 2017 - Assignments to the Technical Working Groups by Lt. Governor Mark Hutchison
A-5: April 26, 2017 - Energy Choice Initiative: Nevadans for Energy Choice Presentation to the Committee
A-6: April 26, 2017 - NV Energy: Federal Energy Regulatory Commission Oversight
A-7: April 26, 2017 - Public Utilities Commission of Nevada (PUCN): Energy 101
A-8: April 28, 2017 - PUCN Request for Additional Rate Information
A-9: April 28, 2017 - PUCN Follow-up Request for Additional Rate Information
A-10: May 10, 2017 - California Public Utilities Commission: Customer and Retail Choice in California
A-11: May 10, 2017 - Pennsylvania Public Utilities Commission: Comment of John Hanger
A-12: May 10, 2017 - Pat Wood, Principal of Wood3 Resources: Implementing Electricity Consumer Choice in Nevada
A-13: June 16, 2017 - Executive Order 2017-10, Order Amending Executive Order 2017-03
A-14: July 11, 2017 - Constellation: Retail Market Potential, Moving from Vertical Integration to Retail Choice
A-15: July 11, 2017 - NV Energy: Nevada's Wholesale Energy Market
A-16: July 11, 2017 - Technical Working Group Workstream Issues Assigned by Chairman
A-17: September 13, 2017 - Energy Choice Committee Request for an Investigatory Docket
A-18: September 13, 2017 - Monitoring Analytics: Market Monitoring in PJM
A-19: September 13, 2017 - NV Energy: Energy Choice and Considerations for Resource Adequacy
A-20: October 30, 2017 - Newspaper Form: Notice of Energy Choice Initiative Investigation
A-21: November 7, 2017 - Analysis Group: Electric Customer Choice & Renewable Energy: Insights from Other States
A-22: November 7, 2017 - PUCN: Historical Overview: Nevada Deregulation 1990's
A-23: November 7, 2017 - PUCN: Historical Overview: Nevada Deregulation 1990's Presentation Materials
A-24: November 7, 2017 - Walmart: Overview of Walmart's Commitment to Renewable Energy, Energy Supply, and Experience in other Competitive States
A-25: November 15, 2017 - Letter to the Committee and the Technical Working Groups
A-26: March 7, 2018 - National Conference of State Legislatures: Energy Choice: State Policy Considerations
A-27: April 30, 2018 - PUCN: Energy Choice Initiative Final Report: Investigatory Docket No. 17-10001

* Every effort has been made to include all materials that were provided to the Committee and Technical Working Groups. As of the publication of this report, all materials are also available to be accessed online at http://energy.nv.gov/Programs/TaskForces/2017/EnergyChoice/

Appendix B: Presentations & Material Provided to the Technical Working Groups

Available Online at http://energy.nv.gov/Programs/TaskForces/2017/EnergyChoice/

TWG on Consumer Protection: Protecting Against Undue Rate Increases and Fraudulent Practices

B-1: August 23, 2017 - West Virginia Consumer Advocates: Electric Restructuring in Nevada: Protecting Customers
B-2: August 23, 2017 - National Energy Marketers Association: Consumer Bill of Rights
B-3: August 23, 2017 - National Energy Marketers Association: National Standards of Conduct
B-4: October 18, 2017 - State of Nevada: Bureau of Consumer Protection Presentation
B-5: February 7, 2018 - Temporary Appointment to the TWG
B-6: February 8, 2018 - AARP: Retail Choice and Residential Customers
B-7: March 23, 2018 - Recommendations for Consumer Protection Workgroup by AARP Nevada
B-8: March 23, 2018 - U.S Department of Energy Retail Electric Competition: A Blueprint for Consumer Protection
B-9: April 20, 2018 - Office of the Attorney General: Consumer Protection Issues for Residential Customers in a Restructured Electricity Market
B-10: April 20, 2018 - Susan M. Baldwin, Discussion of Massachusetts Report
B-11: April 20, 2018 - Temporary Appointment to the TWG

TWG on Generation, Transmission and Delivery

B-12: November 7, 2017 - NV Energy Generation, Transmission, and Delivery Presentation
B-13: December 12, 2017 - GridLiance Presentation to the TWG
B-14: December 12, 2017 - TriSage Consulting, Nevada Energy Assistance Corporation: Transmission Initiative Routing Study Then and Now
B-15: January 12, 2018 - California ISO, Transmission Planning at the ISO & Overview of Generation-Related Transmission

TWG on Energy Consumer and Investor Impact: Divesting Asserts and Investments

B-16: June 21, 2017 - NV Energy Presentation
B-17: August 17, 2017* - Colorado River Commission of Nevada, Presentation to the Committee on Energy Choice
B-18: August 17, 2017* - Department of Energy, Bonneville Power Administration
B-19: August 17, 2017* - Desert Power Electric Cooperative, Nevada Energy Choice Initiative
B-20: August 17, 2017* - Nevada Rural Electric Association Presentation
B-21: October 17, 2017 - NV Energy, Impacts of Energy Choice on Long Term Agreements
B-22: February 6, 2018 - IBEW Local 396 and 1245, Wage Rates, Annual Salary and Benefits for Impacted Workers at NV Energy
B-23: February 6, 2018 - NV Energy, NV Energy Workforce Impacts of Question 3
B-24: May 30, 2018 - Reference Legislation: California 1996 Legislative Service, Chapter 854
B-25: May 30, 2018 - Reference Legislation: Ohio Revised Code Section 4928.31-4928.40
B-26: May 30, 2018 - Reference Legislation: Texas Legislature Section 39.251
*This meeting was a joint meeting of TWG on Economic Impacts and the TWG on Generation, Transmission, and Delivery

TWG on Innovation, Technology, and Renewable Energy

B-27: August 9, 2017 - NRDC, Renewable Standards: Clean Energy Development & Other Impacts
B-28: August 9, 2017 - AEE Presentation, RPS in Restructured States
B-29: October 10, 2017 - California ISO, Grid Infrastructure and Distributed Energy Resources
B-30: October 10, 2017 - Illinois Power Agency, Overview of the Illinois Power Agency and Changes to the Illinois Renewable Portfolio Standard
B-31: October 10, 2017 - NV Energy, Energy Efficiency, Renewable Energy & Public Policy Customer Program
B-32: December 5, 2017 - Vote Solar Presentation
B-33: December 5, 2017 - Energy Storage Association: Considerations for Nevada
B-34: January 23, 2018 - EQ Research, LLC, Retail Choice and Net Metering: Issues and Considerations
B-35: January 23, 2018 - Nevada Rural Electric Association Presentation
B-36: February 6, 2018 - Energy Futures Group, Capturing Nevada's Efficiency Potential in a Competitive Retail Electricity Market

TWG on Open Energy Market Design and Policy: Commercial and Residential

B-37: July 10, 2017 - California ISO Presentation to the TWG
B-38: July 10, 2017 - Mothership Energy Group, Nevada Open Energy Market Design and Policy
B-39: August 8, 2017 - Valley Electric Association Presentation to the Working Group
B-40: August 8, 2017 - Southwest Power Pool, Wholesale Markets and Retail Markets
B-41: August 8, 2017 - Nevada Rural Electric Association Presentation
B-42: August 8, 2017 - Southwest Power Pool Presentation
B-43: February 7, 2018 - Southern Nevada Homebuilders Association: Ensuring Consistency and Affordability for New Homes in a Restructured Energy Market
B-44: February 7, 2018 - National Energy Marketers Association, Benefits of Electricity Choice
B-45: February 7, 2018 - National Energy Marketers Association Presentation to the TWG
B-46: February 7, 2018 - National Energy Marketers Association, Average Price of Electricity (annual)

Appendix C: Meeting Minutes & Public Comment Material

Available Online at http://energy.nv.gov/Programs/TaskForces/2017/EnergyChoice/

C-1: Meeting Minutes April 26, 2017 - Committee on Energy Choice
C-2: Meeting Minutes May 10, 2017 - Committee on Energy Choice
C-3: Meeting Minutes June 21, 2017 - Energy Consumer & Investor Impact TWG
C-4: Meeting Minutes June 21, 2017 - Innovation, Technology, & Renewable Energy TWG
C-5: Meeting Minutes July 10, 2017 - Open Market Design & Policy: Commercial and Residential TWG
C-6: Meeting Minutes July 11, 2017 - Committee on Energy Choice
C-7: Public Comment July 11, 2017 - Sierra Club Toiyabe Chapter: Letter to the Committee on Energy Choice
C-8: Meeting Minutes August 8, 2017 - Open Energy Market Design & Policy TWG
C-9: Meeting Minutes August 9, 2017 - Innovation, Technology, & Renewable Energy TWG
C-10: Meeting Minutes August 17, 2017 - Joint Meeting of the TWG on Generation, Transmission and Delivery, and TWG on Energy Consumer and Investor Economic Impact
C-11: Meeting Minutes August 23, 2017 - Consumer Protection TWG
C-12: Meeting Minutes September 13, 2017 - Committee on Energy Choice
C-13: Meeting Minutes October 10, 2017 - Innovation, Technology, & Renewable Energy TWG
C-14: Meeting Minutes October 17, 2017 - Energy Consumer & Investor Impacts TWG
C-15: Meeting Minutes October 18, 2017 - Consumer Protections: Protecting against Undue Rate Increases and Fraudulent Practices TWG
C-16: Meeting Minutes November 7, 2017 - Committee on Energy Choice
C-17: Meeting Minutes November 7, 2017 - Generation, Transmission & Delivery TWG
C-18: Meeting Minutes December 5, 2017 - Open Energy Markey Design & Policy: Commercial and Residential TWG
C-19: Meeting Minutes December 5, 2017 - Innovation, Technology, & Renewable Energy TWG
C-20: Meeting Minutes December 6, 2017 - Energy Consumer & Investor Impact: Divesting Assets & Investments TWG
C-21: Meeting Minutes December 12, 2017 - Generation, Transmission, and Delivery TWG
C-22: Meeting Minutes January 12, 2018 - Generation, Transmission, and Delivery TWG
C-23: Meeting Minutes January 23, 2018 - Innovation, Technology, & Renewable Energy TWG
C-24: Meeting Minutes February 6, 2018 - Energy Consumer and Investor Economic Impacts TWG
C-25: Meeting Minutes February 6, 2018 - Innovation, Technology, & Renewable Energy TWG
C-26: Meeting Minutes February 7, 2018 - Open Energy Market Design & Policy: Commercial & Residential
C-27: Public Comment February 7, 2018 - Solar Energy Industries Association, Renewable Energy Policies and Electric Competition
C-28: Meeting Minutes February 8, 2018 - Consumer Protection TWG
C-29: Meeting Minutes March 7, 2018 - Committee on Energy Choice
C-30: Public Comment March 7, 2018 - Nevada RTO Options: Letter to the Committee on Energy Choice
C-30: Public Comment March 21, 2018 - White Pine County Board of County Commissioners: Letter to the Committee on Energy Choice
C-31: Meeting Minutes March 23, 2018 - Consumer Protection TWG
C-32: Meeting Minutes April 19, 2018 - Open Energy Market Design and Policy TWG
C-33: Meeting Minutes April 20, 2018 - Consumer Protection TWG
C-34: Public Comment April 27, 2018 - Motion for Leave to Submit Reply Comments of Nevadans for Affordable Clean Energy
C-35: Meeting Minutes May 9, 2018 - Committee on Energy Choice
C-36: Public Comment May 9, 2018 - Garrett Group Presentation, Nevada Stranded Cost/Benefit Analysis
C-37: Public Comment May 9, 2018 - Garrett Group Reply Materials
C-38: Meeting Minutes May 30, 2018 - Energy Consumer & Investor Economic Impact TWG
C-39: Meeting Minutes June 18, 2018 - Committee on Energy Choice Final Meeting
C-40: Public Comment June 18, 2018 - Status of Full and Partial Retail Energy Choice, the Brattle Group
C-41: Public Comment June 18, 2018 - Copper Development Association, Inc.

THE ENERGY CHOICE INITIATIVE

Explanation: Language in ***bolded italics*** is to be added to the constitution by this amendment.

The People of the State of Nevada do enact as follows:

Section 1: Article 1 of the Nevada Constitution is hereby amended by adding thereto a new section to read as follows:

1. Declaration of Policy:
The People of the State of Nevada declare that it is the policy of this State that electricity markets be open and competitive so that all electricity customers are afforded meaningful choices among different providers, and that economic and regulatory burdens be minimized in order to promote competition and choices in the electric energy market. This Act shall be liberally construed to achieve this purpose.

2. Rights of Electric Energy Purchasers:
Effective upon the dates set forth in subsection 3, every person, business, association of persons or businesses, state agency, political subdivision of the State of Nevada, or any other entity in Nevada has the right to choose the provider of its electric utility service, including but not limited to, selecting providers from a competitive retail electric market, or by producing electricity for themselves or in association with others, and shall not be forced to purchase energy from one provider. Nothing herein shall be construed as limiting such persons' or entities' rights to sell, trade or otherwise dispose of electricity.

3. Implementation
(a) Not later than July 1, 2023, the Legislature shall provide by law for provisions consistent with this Act to establish an open, competitive retail electric energy market, to ensure that protections are established that entitle customers to safe, reliable, and competitively priced electricity, including, but not limited to, provisions that reduce costs to customers, protect against service disconnections and unfair practices, and prohibit the grant of monopolies and exclusive franchises for the generation of electricity. The Legislature need not provide for the deregulation of transmission or distribution of electricity in order to establish a competitive market consistent with this Act.

(b) Upon enactment of any law by the Legislature pursuant to this Act before July 1, 2023, and not later than that date, any laws, regulations, regulatory orders or other provisions which conflict with this Act will be void. However, the Legislature may enact legislation consistent with this act that provides for an open electric energy market in part or in whole before July 1, 2023.

(c) Nothing herein shall be construed to invalidate Nevada's public policies on renewable energy, energy efficiency and environmental protection or limit the Legislature's ability to impose such policies on participants in a competitive electricity market.

4. Severability:
Should any part of this Act be declared invalid, or the application thereof to any person, thing or circumstance is held invalid, such invalidity shall not affect the remaining provisions or application of this Act which can be given effect without the invalid provision or application, and to this end the provisions of this Act are declared to be severable. This subsection shall be construed broadly to preserve and effectuate the declared purpose of this Act.

RECEIVED
FEB 03 2016
SECRETARY OF STATE
ELECTIONS DIVISION

DESCRIPTION OF EFFECT

Subject to limited exceptions, Nevada law authorizes a single utility to provide electric service to customers in each electric service territory in the state. The utility is owned by investors and provides service to Nevadans under a legal monopoly. As such, most electricity customers are required to purchase their electricity from a single provider, and the customers cannot purchase electricity from any other entity.

This petition prohibits a legalized monopoly for electric utility generation and gives Nevada electric utility customers the right to choose their service provider from an open retail market based upon price, reliability, and other important factors. This includes the right for these persons, businesses, associations, and other entities, whether on their own or in conjunction with others, to produce their own electricity from renewable energy sources or other sources, and to sell that electricity on the open market.

This petition directs the Legislature to enact laws providing for the establishment of an open, competitive electricity market by not later than July 1, 2023. It also directs the Legislature to set standards for safety, reliability, use of renewable resources, and protections for customers, but does not set or secure any certain price or rate structure.

County of ____________________ **(Only registered voters of this county may sign below)**
Petition District:________________ **(Only registered voters of this petition district may sign below)**

			This space for Office Use Only
1	PRINT YOUR NAME (first, initial, last)	RESIDENCE ADDRESS ONLY	
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AFFIDAVIT OF CIRCULATOR

(To be signed by circulator in the presence of a notary public)

STATE OF NEVADA)
)
County of ____________)

I, ______________________________________, (print name), being first duly sworn under penalty of perjury, depose and say: (1) that I reside at ____ (print street, city and state); (2) that I am 18 years of age or older; (3) that I personally circulated this document; (4) that all signatures were affixed in my presence; (5) that the number of signatures affixed thereon is ________; and (6) that each person who signed had an opportunity before signing to read the full text of the act or resolution on which the initiative or referendum is demanded.

____
Signature of Circulator

Subscribed and sworn to or affirmed before me this

____ day of ______________, 2016, by________________________.

____
Notary Public

NCSL
NATIONAL CONFERENCE *of* STATE LEGISLATURES

The Forum for America's Ideas

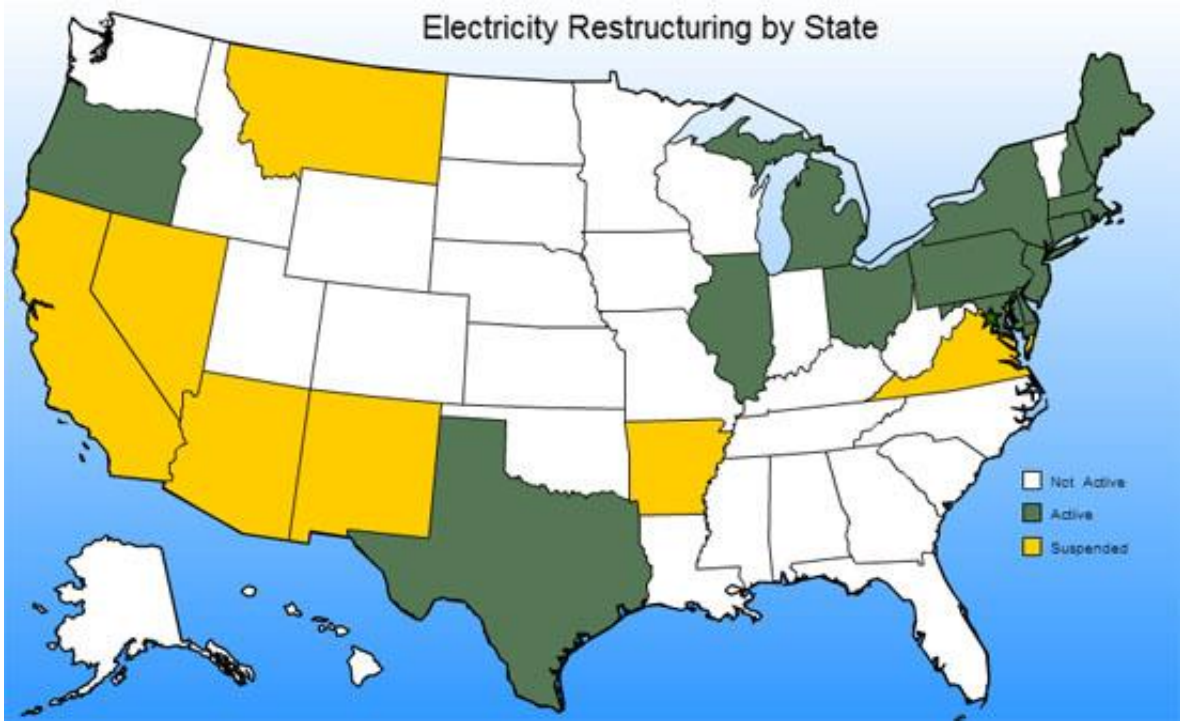
Energy Choice: State Policy Considerations

Governor's Committee on Energy Choice

March 7, 2018

Glen Andersen
NCSL Energy Program Director

Status of Retail Choice



Source: Energy Information Administration

Illinois

- **Customer Choice Act (1997)**
  - Reduced residential rates by approximately 20 percent of 1997 levels and froze them for a decade
  - Retail choice was phased in from 1999 to 2002
- **Amendments between 2006 and 2007**
  - Offered $1 billion in rate relief
  - Created Office of Retail Market Development within the Illinois Commerce Commission
  - Allowed municipal corporate authorities to aggregate residential and small commercial retail electric loads in their jurisdiction and solicit bids for service

Illinois

- **Amendments between 2006 and 2007**
  - Illinois Power Agency Created in 2007
    - Default suppliers (ComEd and Ameren) use the Agency to procure supply on the market. Submit plans to PUC for rate cases.
    - Utility assumed payment collection and provided consolidated billing (line charges and supplier bill), then pays supplier. Alternative suppliers can't turn of service but utility can.
  - Implementation completed around 2012, and suppliers entered the market

Illinois

- Between 56 and 67 percent of residential customers in Ameren zones have alternate suppliers while the rate is 35 percent in ComEd
- 2012-14 alternative suppliers were saving $139, but paying $87 more by 2017

Planning year Ending in May	Annual Savings compared to ComEd's PTC (in million)	Annual Savings inclusive of the PEA Impact (in million)
2012	$17.2	$24.2
2013	$250.8	$257.5
2014	-$40.2	$38.7
2015	-$12.3	-$73.4
2016	-$79.7	-$115.2
2017	-$131.4	-$152.1
Six-year Total	$4.4	-$20.3

Illinois

- By 2013, residential switching reached 25 percent
- By 2015, 70% residential market in ComEd switched, but decreased to 35% by 2017
- Slightly more than half were with municipal aggregators

Residential Customers on Competitive Supply

	May 2012	May 2013	May 2014	May 2015	May 2016	May 2017
Ameren Illinois Rate Zone I:	28,459	147,513	185,251	172,449	180,480	182,073
Ameren Illinois Rate Zone II:	12,752	138,163	140,439	129,211	126,871	127,439
Ameren Illinois Rate Zone III:	47,124	277,229	345,911	308,554	326,904	326,723
ComEd:	406,144	2,312,654	2,356,669	2,126,674	1,434,319	1,244,899
Total:	494,479	2,875,559	3,028,270	2,736,888	2,068,574	1,881,134
Ameren Illinois Rate Zone I:	8.7%	45.2%	63.9%	53.0%	55.6%	56.3%
Ameren Illinois Rate Zone II:	6.8%	73.2%	74.5%	68.5%	67.1%	67.4%
Ameren Illinois Rate Zone III:	8.7%	51.2%	63.9%	56.9%	60.2%	60.1%
ComEd:	11.9%	67.7%	68.5%	61.5%	40.9%	35.2%

Texas

- **Senate Bill 7 (1999)**
  - Designated a Provider of Last Resort (incumbent utility)
  - Requires customers to start with an affiliated retailer – no default service
  - T&D provider still regulated
  - Established an effective date of January 1, 2002
  - Certification process for Retail Electricity Providers
  - Established "Price to Beat" for 2002-2007
    - Prevents incumbent providers from undercutting new entrants' prices
    - Price floor for incumbents

Texas

- **Senate Bill 7**
  - Allowed munis and co-ops to opt into retail choice (just one co-op so far)
  - Mandated Energy Efficiency
    - Implemented by Transmission Distribution Utilities
    - Funded through surcharge on electric bills
    - Reduce customers' energy consumption as well as electric peak demand
    - Legislation sets EM&V requirements and goals
  - In 2016, 109 retail providers were operating in ERCOT, providing 440 total unique products, 97 of which provided 100% renewable sources

Texas

- **Texas Power To Choose Website**
  - Providers will try to game search results and try to create plans that exploit search parameters
  - Electricity facts one pager summarizes offer is required to be posted.
  - Filters minimum usage fees (legislation to ban them failed)
  - Shows providers' complaint records
  - Even with requirements, can be hard to compare plans: i.e. some charge is 1.5 cents per kwh up to 1,000 kwh and 8.8 cents for more than 1,000

Texas

- **Rates**
  - 92% of Residential and 98% of non-residential customers have switched providers since the market opened in 2002
  - Average across all available plans in the competitive market was 9.8 cents per kWh in 2016
  - Fixed and variable rates lower than nationwide average of 13.45 cents

TDU Service Territory[6]	Last Regulated Rate (2001), ¢/kWh[7]	Last Regulated Rate, Adjusted for Inflation	Current Lowest Fixed Price[8]	Percentage Change
AEP Central	9.6	13.1	5.6	–57.25%
AEP North	10.0	13.6	5.0	–63.24%
CenterPoint	10.4	14.1	5.4	–61.7%
Oncor	9.7	13.2	4.5	–65.91%
TNMP	10.6	14.4	5.0	–65.28%

2017 Report to the 85th Texas Legislature: Scope of Competition in Electric Markets in Texas

Pennsylvania

- Electricity Generation Customer Choice and Competition Act (1996)
  - Legislature worked in close collaboration with the PUC in drafting legislation
  - Default Service Provider – regulated and must pass through cost of generation – can't lowball or overcharge
  - Rate caps were removed by 2011, retailers started entering the market in 2010
  - One year pilot phase-in period for 5% of customer base to identify and sort out challenges
- Legislation to require choosing a retail provider failed in 2013 after polar vortex rate spikes

Pennsylvania

- **Key Reforms**
  - Quick Switching – allow customers to quickly switch back to default provider—within 3 days in PA
  - Marketing regulations – required suppliers to verify enrollment through 3rd party to minimize slamming
  - Disclosure regulations – craft rules that help customer navigate new offerings but don't hinder innovation
  - Electronic Data Exchange Working Group – data exchange between utilities and suppliers is key to a functioning market

Pennsylvania

- **Outcomes**
  - Between 1996 and 2011, rate caps were removed in individual utility regions one after another
  - Switching rates from January 2018
    - Residential 33%
    - Commercial 85%
    - Industrial 97%
  - Low Income
    - Support of EE for lower incomes
    - Bills capped to percentage of income
    - 70% of the low income customers who switched from default service paid more (Kleinman Center for Energy Policy - University of PA)

Pennsylvania

- **Rate Impacts**
  - From 2011 to 2014, Commercial and Industrial rates generally lower than default service rates
    - 5 to 56% lower than 1996
  - Residential rate generally higher
    - 2 to 41% lower than in 1996
  - Distribution prices
    - Down for commercial and industrial sector
    - Up for residential sector

https://kleinmanenergy.upenn.edu/paper/electricity-competition

Montana

- Montana Electric Utility Industry Restructuring and Consumer Choice Act (1997)
  - California crisis introduced major volatility into the market
  - Couldn't insulate itself from regional market fluctuations
  - Price caps expired after 2003
- State responded by passing nine bills in 2001
  - Waived taxes and other incentives for new generation in the state
  - Voters rejected major bill to save the industry in a 2002 referendum, which ended restructuring efforts
- Reregulated in 2007 with the Electric Utility Reintegration Act

Rate Impacts in Other States

- The **Maine** Public Utilities Commission found that, from 2014 to 2016, competitive electricity provider customers paid $77.7 million more than what they would have paid for standard offer service

- In January 2013, **New York**'s attorney general found that 91.5 percent of upstate low-income consumers who'd switched were paying higher rates than if they'd stuck with the default provider utility

	Weighted Average Prices ($/kWh)				
Calendar Year	CEP	SOS	Percent Difference	Number of Customers with CEPs	Difference in Charges at CEP vs. SOS Price ($)
2016	$0.1011	$0.0649	55.8%	117,544	$28,739,752
2015	$0.1077	$0.0671	60.5%	136,139	$37,897,764
2014	$0.0834	$0.0744	12.0%	163,679	$11,032,570
TOTAL					**$77,670,086**

Issue to Consider

- **Providing an accurate, informative, and fair presentation of offers; setting parameters**
  - Ensuring customers can easily distinguish differences in cost, services and benefits
  - Balance tension between distorting market and provide enough information, but not too much
  - Requirements for all electricity companies to advertise their plans with the same pricing details (kwh charges plus T&D)
  - Minimum usage rates discourage conservation, hurt low-income consumers and increase T&D costs; effect energy efficiency
  - Address minimum fees, low intro rates, early termination charges, contract length, and other details
  - PA website requires all disclosures and 1 page contract summary while new rulemaking addresses introductory pricing

Issue to Consider

- **Switching**
  - Ensure customers receive clear signals when switching
    - In Texas, ERCOT sends postcard notice before switching
    - In Pennsylvania, third party verification of switching
  - Provide significant penalties for slamming and cramming
  - Set switch hold policy

- **Reporting**
  - Biennial report to legislature in TX: Scope of Competition in Electric Markets
  - No reporting required in PA
  - Legislative reports required in IL

Conclusion

"Restructuring of the electric utility industry is not for the impatient, the weak-kneed, or the fainthearted."

- Montana Electrical Utility Industry Restructuring Transition Advisory Committee Report to the Governor and Legislature, December 2002.

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Additional Resources

NCSL Energy and Environment Database

NCSL Energy Program

Did Residential Electricity Rates Fall After Retail Competition?

A Dynamic Panel Analysis

Mine Yücel and Adam Swadley

Research Department

Working Paper 1105

Federal Reserve Bank of Dallas

Did Residential Electricity Rates Fall After Retail Competition?*

A Dynamic Panel Analysis

May 2011

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Federal Reserve Bank of Dallas

Abstract: A key selling point for the restructuring of electricity markets was the promise of lower prices, that competition among independent power suppliers would lower electricity prices to retail customers. There is not much consensus in earlier studies on the effects of electricity deregulation, particularly for residential customers. Part of the reason for not finding a consistent link with deregulation and lower prices was that the removal of the transitional price caps led to higher prices. In addition, the timing of the removal of price caps coincided with rising fuel prices, which were passed on to consumers in a competitive market. Using a dynamic panel model, we analyze the effect of participation rates, fuel costs, market size, a rate cap and a switch to competition for 16 states and the District of Columbia. We find that an increase in participation rates, price controls, a larger market, and high shares of hydro in electricity generation lower retail prices, while increases in natural gas and coal prices increase rates. The effects of a competitive retail electricity market are mixed across states, but generally appear to lower prices in states with high participation and raise prices in states that have little customer participation.

*The views expressed are those of the authors and are not necessarily those of the Federal Reserve Bank of Dallas or the Federal Reserve System. The authors thank Anil Kumar for helpful comments, as well as seminar participants at Rice University for helpful comments on an earlier draft.

Did Residential Rates Fall After Retail Competition? A Dynamic Panel Analysis

I. Introduction

Electricity market restructuring has received significant attention in the energy economics literature, particularly in the mid-2000s after many states restructured their electricity markets and offered retail choice. A key selling point for the restructuring of electricity markets was the promise of lower retail electric prices, that competition among independent power suppliers to lure customers from the incumbent utility company's default or "standard offer" service would lower prices to retail customers.

There is no consensus among earlier studies on how restructuring affected retail prices. Zarnikau and Whitworth (2006), Rose (2004) and Joskow (2006) note that large commercial and industrial customers have realized some cost-saving benefits from competition, while Apt (2005) concludes that competition has not lowered electricity rates for industrial users. Joskow (2006) finds retail competition lowers both residential and industrial electricity prices, but attributes the price decline to non-market artifacts of restructuring legislation and regulated default service rather than competitive forces. In a study focusing on the residential market in Texas, Zarnikau and Whitworth (2006) show that electricity rates rose faster in areas of the state that were open to retail competition than in areas that were not.

It is important to note that the timing of many of these earlier studies of electricity restructuring was such that many of the states offering retail choice to residential customers had regulated default service, transitional pricing mechanisms, or other price controls in place. These temporary price controls varied across states, but their common purpose was to protect consumers and power generators from price volatility in the transition to a competitive market. As Joskow (2006) notes, there is an inseparability of the effects of these price controls from those of increased competition, resulting in overstated benefits of retail competition. Further, as Axelrod, et.al. (2006) point out, the expiration of these price controls led to sharp rate increases as price controls were removed and market forces took over. Another factor in the rise of retail price was that the expiration of many of these price controls was followed by periods of fuel cost increases. Together, these factors contributed significantly to higher electric rates and led many to conclude that competition at the wholesale and retail levels had resulted in higher electric rates (Axelrod, DeRamus, and Cain, 2006). In a more recent paper, Kang and Zarnikau (2009) show that retail prices declined in Texas after the removal of price caps.

The Electric Reliability Council of Texas (ERCOT) market presents an especially interesting case for study and a baseline for comparison given its wide regard as the most successful retail market in North America (Adib and Zarnikau, 2006). The ERCOT market has been successful in attracting a large number of providers offering choice to customers of all sizes. The ERCOT market also leads all other states with 50.6% of residential customers choosing a competitive retail electric provider (CREP)[1]. In this paper, we use panel data to study 16 states and the District of Columbia that started retail competition in the late 90s and early 2000s, and have mainly completed their restructuring and ended their transitional prices. Among these states, only California and Virginia have suspended retail competition for residential customers. Given that transitional pricing ended several years ago in most of these states, we have several years of data to study the effects of retail competition. We contribute to the literature in a couple of ways. We estimate the effects of retail competition and transitional pricing on residential electric rates, using Texas as a baseline and estimating separate effects of these policies for individual states in our panel where possible. The second major contribution of

[1] As of May 2010. Percent of eligible ERCOT area residential customers who have chosen a competitive retail electric provider.

this paper is to estimate the effect of increased residential customer participation in a competitive markets on residential electric rates. The analysis is conducted using a dynamic panel model, where cost drivers and participation are allowed to affect residential electric rates with a lag. We find that an increase in participation rates, price controls, a larger market, and high shares of hydro in electricity generation lower retail prices, while increases in natural gas and coal prices increase rates. The effect of moving to a competitive retail electricity market is mixed across states, but generally appears to lower prices in states with high participation and raise prices in states that have little customer participation.

II. Data and Model

Our goal is to develop a model of electricity prices for residential customers that takes advantage of differences both within and across states that have or have had retail competition in their electricity markets. We are interested in examining differences in the effects of retail competition programs and transitional pricing schemes across states. Earlier studies (eg, Joskow 2006) do a panel data analysis of a similar flavor but do not attempt to single out differences across states. Further, earlier studies fail to separate the effects of retail competition from temporary effects of transitional price controls and level of participation by residential customers. We develop a dynamic panel model that accounts for the aforementioned issues.

The data employed in our analysis is a monthly panel of 16 states and the District of Columbia. The states analyzed are CA, CT, DC, DE ,IL, MA, MD, ME, MI, NH, NJ, NY, OH, PA, RI,TX and VA. Table 1 shows these states and the start and completion of their restructuring.   The panel contains 3,247 observations and covers a period from January 1990 to May 2010. The data are primarily from the U.S. Energy Information Administration (EIA) and state Public Utility Commissions. The dependent variable is seasonally adjusted average real price per kilowatt-hour (kWh) for residential customers. As a key independent variable, we include the percent of eligible residential customers who have chosen a competitive provider in each state to capture the level of market participation by residential customers. The model allows participation by residential customers and various control variables to affect residential electric rates at a lag of up to six months. We choose the six month lag length as suggested by the Energy Information Administration (EIA, 2007), because fuel costs would take around six months to be reflected in customer rates. We use this lag length as a base for our model and assume that other cost drivers would take an equal or lesser amount of time to be reflected in customer rates.

To control for input costs of electric generating facilities that might be passed on to customers, we include the real average cost of coal for electricity generation and the real average cost of natural gas for electricity generation. We also include controls for each state's percentage of generation from nuclear and hydro sources. The total number of megawatt hours sold in each state is included to control for market size, and the deviation from normal heating and cooling degree days is included to capture weather-related demand spikes. We include dummy variables to capture months when each state is open to electric competition for residential customers[2], and months when each state had some sort of price control or transitional pricing (rate cap, rate freeze, etc.) in addition to retail competition. Finally, we include a lag of seasonally adjusted average real price per kilowatt-hour (kWh) for residential customers in an effort to proxy for unknown omitted variables that affect prices historically. This lagged dependent variable may also partially pick up fixed pricing schemes offered to customers.

[2] While many states had "pilot" periods where some portion of residential customers were able to choose their electric provider, the retail competition dummy variable is set =1 only when retail competition is open to ALL residential customers. The exception here is Texas, where we make the simplifying assumption that all residential customers are eligible to choose their provider. In fact, only about 85% of the Texas residential market is open to competition.

Estimation

The baseline model to be estimated is of the form:

$$\Delta y_{it}=(\Delta \mathbf{x}_{i,t-k})'\boldsymbol{\beta}+\delta(\Delta y_{i,t-1})+\mathbf{f}_{it}'\boldsymbol{\gamma}+\Delta\boldsymbol{\varepsilon}_{it} \qquad (1)$$

where **x** is a vector of control variables at lags $k \in K=\{0,1,2,3,4,5,6\}$ believed to influence residential electric rates:

$PARTICIPATION_{i,t-k}$	Percent of residential electric customers in state *i* choosing a competitive retail electric provider at time *t-k*
$LNTOTALSALESMWH_{i,t-k}$	Log of total megawatt hours sold in state *i* at time *t-k*
$LNCOALPRICEELECGEN_{i,t-k}$	Log of real national average cost of coal for electricity generation at time *t-k*
$LNGASPRICELECGEN_{i,t-k}$	Log of real national average cost of natural gas for electricity generation at time *t-k*
$PCNTHYDRO_{i,t-k}$	Percent of electric generation from hydro in state *i* at time *t-k*
$PCNTNUCLEAR_{i,t-k}$	Percent of electric generation from nuclear in state *i* at time *t-k*
$CDDEV_{i,t-k}$	Deviation from normal number of cooling degree days in state *i* at time *t-k*
$HDDEV_{i,t-k}$	Deviation from normal number of heating degree days in state *i* at time *t-k*

and **f** is a vector of dummy variables:

$RETAILCOMP_{it}$	=1 if state *i* was open to residential retail electric competition at time *t*; =0 otherwise
$RATECAP_{it}$	=1 if state *i* had a transitional price control or rate cap in place at time *t*; =0 otherwise
$RETAILCOMP_{it}*STATE_i$	Interaction of $STATE_i$ with $RETAILCOMP_{it}$, defined above [3]
$RATECAP_{it}*STATE_i$	Interaction of $STATE_i$ with $RATECAP_{it}$, defined above

$\boldsymbol{\varepsilon}_{it}$ is a state specific heteroskedastic error term, and β, δ, and γ are parameters to be estimated.

[3] This allows for estimation of a state-specific coefficient for *RETAILCOMP* that is used to determine the effects of retail competition in that state particular state. The *RATECAP* and the state dummy variable interaction serves an analogous purpose. Texas is the omitted state dummy and serves as the baseline for comparison.

We first-difference all continuous variables to remove fixed effects that maybe present while also addressing nonstationarity of the individual time series. Dummy variables controlling for retail competition and transitional pricing schemes enter the model in levels. We adopt the level form of the dummy variables to capture effects on residential electricity rates over the time they are in place rather through a one-time impact[4].

The introduction of a lagged dependent variable as a regressor in the framework of a usual first-differences model results in inconsistent estimates because of correlation between $\Delta y_{i,t-1}$ and $\Delta\varepsilon_{it}$, through the shared term ε_{it-1}. Several techniques have been suggested to handle such situations. Anderson and Hsiao (1982) suggest using an instrumental variables approach to estimate a first-differenced equation, where the lagged dependent variable regressor ($\Delta y_{i,t-1}$) is instrumented using either $\Delta y_{i,t-2}$ or $y_{i,t-2}$. Arellano (1989) finds efficiency in the approach of using the level variable as an instrument in lieu of lagged differences, and Arellano and Bond (1991) examine one-step and two-step GMM estimators that essentially expand on the work of Anderson-Hsiao (1982) and Holtz-Eakin, Newey, and Rosen (1988). The Arellano-Bond (1991) approach considers additional lags of the dependent variable as instruments, thus improving efficiency by taking advantage of the additional moment conditions. Kiviet (1995) proposes the usual least squares dummy variable approach and develops a bias correction that he finds to be more efficient than GMM estimates.

We face an additional complication in choosing an appropriate estimation technique because we have a long panel, i.e., a long time dimension (large T) and few cross sections (small N) while all of the aforementioned solutions assume large N and small T. Judson and Owen (1999) address this very topic, conducting a Monte Carlo study to examine the properties of

[4] This is a simplifying assumption. Idiosyncrasies across states will result in price controls and retail competition affecting prices over varied time periods.

these estimators in our situation and that usually faced by macroeconomists. Judson and Owen (1999) conclude that even with a fairly long time series, the asymptotic bias should not be ignored, although they do find improvement in all estimators as the time dimension of the panel increases. The suggested method for the longest timeframe considered with an unbalanced panel is the usual least squares dummy variable fixed effects estimator (Judson and Owen, 1999). This is consistent with the findings of Nickell (1981) and the suggestion of Roodman (2006). We also consider Judson and Owen's (1999) suggestion of Arellano-Bond one-step GMM estimation as a second best choice. Because Arellano-Bond estimation is an instrumental variables approach, it has the added advantage of allowing us to test for and address, if necessary, potentially endogenous variables in the model such as *PARTICIPATION*.

Due to the possibility of endogeneity of the *PARTICIPATION* variable, as well as to mitigate any concerns of inconsistency or concerns of spurious correlation resulting from nonstationarity of individual time series, we settle on Arellano-Bond one-step difference GMM estimation. A difference-in-Sargan test suggests that in fact, the *PARTICIPATION* variable is not endogenous in this data and therefore does not need to be instrumented. We believe this finding is plausible given the length of the time series employed and that in this particular data set, well over half of the years in the set contain *PARTICIPATION* values of zero yet some price fluctuation still occurred. We proceed in our analysis operating under this assumption.

Because the time dimension of our panel is large, we must be aware of the issue of instrument proliferation resulting from Arellano-Bond estimation on data with a large time dimension. Using the default Arellano-Bond approach in panels with long time dimensions, the number of instruments grows rapidly and causes overfitting of the endogenous variables (Cameron and Trivedi, 2010; Roodman, 2006). Roodman (2009) suggests two solutions to this problem. The first is limiting the number of lags to be used as instruments to fewer than all available lags as is the default of Arellano-Bond. This results in what Judson and Owen (1999) call a "restricted GMM" estimator, which they find to be computationally less-taxing but without significant loss of effectiveness. Additionally, Roodman (2009) suggests "collapsing" the instrument matrix. This involves horizontally collapsing the usual instrument matrix containing an instrument for every lag available at each time period (a matrix that is quadratic in T) to a simplified instrument matrix that only adds columns or instruments when additional lags are used as instruments. The moment conditions associated with the usual instrument matrix imply the moment conditions associated with the collapsed instrument matrix, however, some efficiency is lost simply because there are fewer moment conditions to satisfy.

We employ both of Roodman's (2009) suggestions for reducing the instrument count. Keeping with a goal of a few, strong instruments we choose to limit our set of instruments to two lags of the dependent variable; specifically, instruments for $\Delta y_{i,t-1}$ are $y_{i,t-2}$, $y_{i,t-3}$. This allows efficiency gains over the just-identified case while still keeping the size of the instrument matrix under control. Estimation with three lags as instruments results in no observable efficiency gains, and more than three lags cannot be confirmed as valid instruments[5]. As a check of robustness and to increase the model's flexibility, we also consider an analogous model with the addition of year time dummies.

We estimate both models with the intention of examining contemporaneous and lagged effects. The contemporaneous effect is determined from the coefficient at lag 0. To determine lagged effects of our control variables, we perform hypothesis testing on sums of lagged coefficients. This allows us to determine the number of months over which the variable has a lagged impact on residential electricity rates.

[5] As suggested by the Arellano-Bond test for AR(2) in first differences when more than three lags are used as instruments.

III. Results

The results from the estimation are generally consistent with our expectations. Tables 3a and 3b show results from the baseline model. An increase in participation rates takes some time to be reflected in lower electricity prices. Although the contemporaneous effect of the participation rate on retail prices is positive and significant, the lagged effects of increased participation are negative, significant, and larger in magnitude than the contemporaneous effect. A 10 percentage point increase in participation initially raises the price by 2.9 percent but then lowers the price by 4.3 percent, with the full effect taking around 6 months to be reflected in prices. The positive coefficient estimate on the contemporaneous effect of increased participation matches Kang and Zarnikau's (2009) results. A higher participation rate implies that a larger group of residential customers are switching to competitive retail electricity providers (CREPs), increasing the share supplied by competitive retailers, and eventually lowering the overall residential price of electricity. The magnitude of the coefficient may seem small, but it is similar to estimates by Kang and Zarnikau (2009) for Texas. As Chart 1 shows, the participation rate does not start rising for some states until the states are well into restructuring, and really takes off after price controls are removed. In the case of Texas, participation rises nearly linearly from the start of retail competition, suggesting a transitional pricing scheme that encouraged competition early on. These differences illustrate the idiosyncrasies of state transitional pricing schemes that provide different incentives for customers to switch providers, and for competitive providers to serve residential customers in a given market. These differences and findings are further discussed below. For many states, participation rates are still quite low, but our findings suggest that higher participation rates lead to lower retail prices.

The contemporaneous effect of a change in total megawatt hours sold in a state is a statistically significant decline in retail prices. Lagged effects are positive but statistically insignificant. If we think of the MWh variable as a measure of the size of the total electricity market, then the larger the market, the more suppliers it can support, leading to more competition and lower prices. A larger market may also result in lower prices because of economies of scale in electricity generation.

As would be expected, increases in the prices of fuels used to generate electricity have an overall positive effect on retail prices. The effects of the rise in fuel prices come in with a lag, as neither coal nor natural gas prices used in electricity generation have a significant contemporaneous effect on retail electricity prices. A rise in natural gas prices has a significant effect on electricity prices with a lag of two months, reflecting the time required for increased fuel costs to be passed to consumers. As seen in Table 3a, a 10 percent increase in the price of natural gas leads to a statistically significant 0.2 percent increase in the price of electricity at the end of two months. To put this in perspective, if an average customer used 1000 KWh per month, a 10 percent increase in natural gas prices would imply a small $3.29 increase in the customer's annual electricity bill, assuming the panel mean rate of 13.7 cents/KWh. In the first half of our sample, natural gas prices to electricity generators were relatively stable, averaging around $2.50 per year. Furthermore, electricity rates in the vast majority of states were still under regulation and less sensitive to short run volatility in fuel prices. However, in the second half, as restructuring got under way in the 2000s, natural gas prices were very volatile (Chart 2), with prices ranging from $4 to $12. As rate caps ended, consumers who had switched to competitive providers and who were in states which depended on natural gas for a majority of their generation, such as Massachusetts, Maine, New York, and Texas probably saw their retail prices go up substantially as natural gas prices remained high. However, our finding of a relatively small effect of natural gas prices on monthly retail rates is consistent with Bushnell and Mansur's (2005) finding that monthly retail rates do not capture much of the volatility of natural gas prices. Moreover, most generators buy their natural gas with longer contracts, rather than on the spot market, dampening the pass-through of short-term gas price volatility.

Similarly, an increase in the price of coal has a positive and significant effect for all lags. A10 percent increase in the price of coal results in increases in retail electricity prices ranging from 2.1 percent in the first month to 2.9 percent through the sixth month. This effect is much larger than the effect of gas prices; however, coal prices have been much less volatile over the sample period.

For states that used either hydro or nuclear as the energy source for electricity generation, an increased share of hydro generation lowers retail prices while an increased share of nuclear generation has no significant effect on retail prices because all nuclear coefficients are all insignificant. No state in our panel has hydro as their main source of generation, but California, New York, and Maine all have a sizable hydro share. Nuclear is the main source of energy for Connecticut's electricity generation, while Illinois has 48 percent, New York has 31 percent and Pennsylvania has a 35 percent share of nuclear in their power generation. Comparing our results to Joskow (2006), we find that signs on our contemporaneous coefficients (which are insignificant) are opposite of Joskow's but that our lagged effects match the sign of Joskow's results. Two points are worth noting here. First, Joskow (2006) uses annual rather than monthly data. Second, because we are dealing with monthly data we are primarily interested in the lagged effects of these variables since changes in generation costs take some number of months to be reflected in customer rates. Thus, it seems plausible that signs on our lagged values using monthly data would more closely match Joskow's (2006) contemporaneous values using annual data.

We would expect deviations from normal heating and cooling degree days to have a positive effect on retail prices. The signs of the coefficients of these variables are mixed, but all were insignificant, adding no explanatory power to the estimation. One possible explanation for these results could be that the effect of these variables is being picked up by the electricity usage variable.

Table 3a also shows the state effects of retail competition and transitional pricing (the *RETAILCOMP* and *RATECAP* variables) on retail prices. The separate state dummy variables for *RETAILCOMP* and *RATECAP* are useful for two reasons. First, states have had varied levels of success in their restructuring efforts. Second, it is likely that the timing of effects from different retail competition setups and price controls was quite different. For instance, one state may have seen the full effect as soon as a price control was put in place while a different state may have seen more gradual price effects. The coefficients on the *RETAILCOMP* and *RATECAP* dummies are interpreted as the monthly growth of residential electricity rates when retail competition and/or a price control is in place. These coefficients are best interpreted if annualized. Annualizing the coefficient -.0034 for *RETAILCOMP* suggests that, holding all else equal, having a competitive retail market in Texas caused the average residential electric bill to decline at approximately a 4.0 percent annual rate over the sample period.

Our results suggest that state effects of competitive markets and transitional pricing are somewhat mixed. For Texas, Connecticut, Maine, and Pennsylvania, moving to a competitive retail market lowers retail prices. Texas, Connecticut, and Pennsylvania have relatively high participation rates, and Pennsylvania still had some price controls in place over our sample period. Although the participation rate for Maine is low in Table 1, Maine's restructuring initiatives differ from many other states and a very high percentage of Maine customers essentially get their power through a competitive market. The incentive for Mainers to choose a competitive retail provider is limited because Maine's standard offer service generation is already procured through a competitive bidding process. This keeps prices low and eliminates both the incentive for residential customers to choose a different provider and for competitive retail providers to serve residential customers in that market. The coefficient for Maine is negative and statistically significant suggesting that Maine's unique style of competition, although not dependent on individual customers, may also be effective in lowering retail prices.

For the remaining states, the switch to retail competition did not necessarily lower retail prices. For CA, DE, IL, MD, MI, NJ, and DC, having a competitive market actually appears to have raised rates while MA and NY have statistically insignificant coefficients, implying no change in retail prices in these states. It is possible that the participation rate, which starts rising after transitional pricing is eliminated, is picking up much of the effect of restructuring, as would be expected if price decreases are driven by competitive forces. The significant (and largely positive) coefficients on retail competition in states with relatively low participation suggest that higher rates of participation in the retail market are necessary to successfully lower residential electric rates.

Looking at the effects of price controls on state retail prices, the results for all states except for Massachusetts are significant. For Texas, price controls increased retail prices, a finding that agrees with Kang and Zarnikau (2009). This is likely a function of the design of the "price-to-beat" in Texas, which was held relatively high to encourage competitive providers to enter the market and to encourage customer switching to competitive retailers. For the rest of the states, rate caps had a significant effect in lowering retail electricity prices.

As a check of robustness and for added model flexibility, we estimated an additional model, adding time dummies to the baseline model. Tables 4a, 4b, and 4c show that the basic results do not change when time dummies are added. Both the participation and total megawatt hours variables become more significant and their coefficients increase slightly. Most notably, the coefficients on retail competition in MI and NJ lose significance, while the coefficients on retail competition for MA and NY become negative, implying a fall in retail prices with competition, although the coefficients remain insignificant. The addition of time dummies has almost no effect on the *RATECAP* variables, with the exception of the price control variable becoming significant for MA. The time dummies themselves are insignificant 16 out of the 20 years (table 4c). Interestingly, the coefficients for the time dummies are mostly positive in the first half of the sample period and negative in the latter half. Although these coefficients are not statistically significant, the negative signs suggest some overall downward movement of retail prices over the period. This could suggest that the time dummies in these periods are picking up, to some degree, the effects of national level wholesale deregulation initiatives around this time, as well as newly restructured wholesale markets overseen by regional transmission operators and independent system operators.

IV. Discussion

The recent expiration of transitional price controls in many states' competitive electricity markets has provided us with a data set that allows us to shed light on whether a truly competitive retail market lowers rates for residential customers. Our results strongly suggest that if such a market is designed correctly, residential customers may benefit from competition among electricity providers. Although the level of benefit may vary, evidence also suggests that there is no single correct way to implement a successful competitive retail market, as demonstrated by the successes of states with very different approaches (Maine and Texas, for example).

Our results show that none of the retail electricity market designs yield instant price reductions for customers. States that held prices artificially low during the transition to a competitive market may have seen lower prices initially; however, the long-run effect of artificially depressed prices is a misallocation of resources and an inefficient electricity market. Consumers have no incentive to switch to an alternative electricity provider and providers have no incentive to enter the market to serve residential customers. A successfully designed market must provide profit opportunities for providers as well as incentives for consumers to switch providers. Although this may result in higher-than-desired rates initially, in the long-run intensified competition is more to likely yield *sustainable* lower rates. An alternative seemingly-successful approach is to procure standard-offer electricity services through a competitive bidding process, as in Maine. This approach does not have the dependence on retail customers' participation, but still has the potential to yield some level of benefit resulting from competition.

Beyond simply reducing electricity rates, a competitive retail market holds the potential to achieve other policy goals through the workings of the marketplace. If increased generation from alternative fuels is a policy goal and there are consumers demanding electricity from alternate fuels, a competitive retail market can match these customers with their suppliers. As Roe et.al. (2001) note, an increased willingness to pay for electricity generated from renewable fuels suggests that a competitive retail market may be one step in achieving renewable energy goals.

It is also important to consider the impacts of new smart grid technologies and alternative rate structures on competitive retail electricity markets. Our results show that in the current environment, a robust competitive retail electricity market can offer lower average monthly electricity rates. As new technologies increase customer price awareness, rate structures such as time-of-use and real time pricing—pricing that more closely reflects fluctuations in the wholesale market—offer the potential for greater pricing transparency and even greater average monthly savings. However, in this environment retail electricity providers are no longer competing with an advertised monthly rate and may offer a wider variety of more complex rate plans. Such an environment would obviously benefit customers who have high demand elasticities or who have the highest demand during off-peak hours. Overall reductions in state-level average monthly prices, as we show in this paper, are less clear. This is an area for future research as smart grid technologies become more widespread in mature competitive markets.

V. Conclusion

The restructuring of U.S. electricity markets has received a great deal of attention in the energy economics literature, particularly in the mid 2000s as many states experimented with retail competition. Earlier studies on the effects of restructuring initiatives have failed to reach a consensus, particularly as these initiatives apply to residential customers. Previous efforts to study this topic were complicated by an inseparability of the effects of temporary transitional pricing schemes from the true effects of a competitive market. With several years of data following the expiration of many of these temporary pricing schemes, we revisit this issue using an econometric approach unique to this literature. Increasing participation in the competitive market appears to be a crucial element in reducing residential electric rates, while price reductions detected by earlier studies were likely driven by price controls rather than competitive forces. With the exception of Maine's somewhat unique bid-for-generation setup, states that have failed to provide the proper market incentives for residential customers to switch to a competitive provider and for firms to provide electricity to residential customers have been less successful in reducing residential electric rates. Our findings suggest that with a market design that encourages adequate participation, a competitive retail electricity market can benefit residential customers.

Status of Electric Market Restructuring as of September 2010

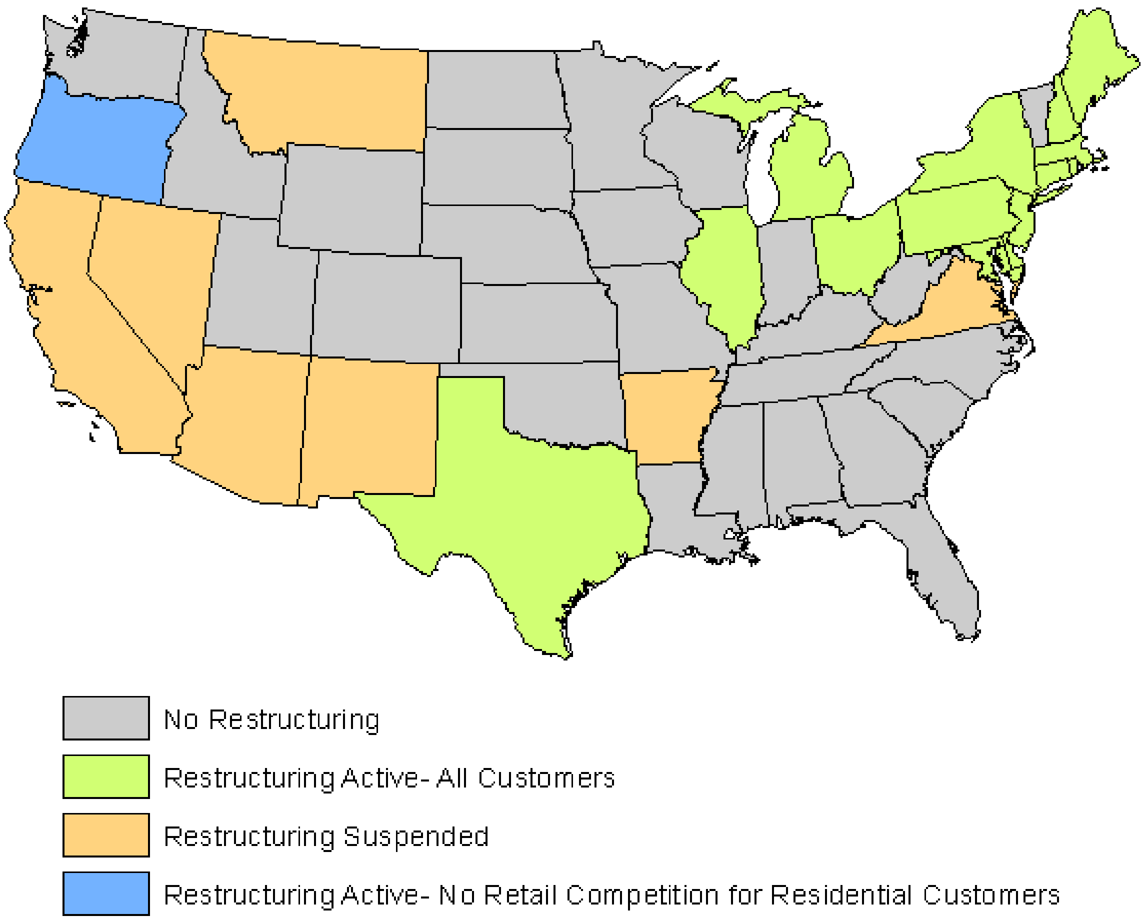


Table 1. State Electricity Restructuring

State	Main Energy Source	Participation Rate	Retail Comp Begin	Rate Cap Begin	Rate Cap End
CA	Gas	0.6%	Deregulation Suspended September 2001		
CT	Nuclear	24.6%	July 2000	July 2000	January 2007
DC	Petroleum	3.4%	January 2001	January 2001	February 2007
DE	Coal	2.6%	October 2000	October 2000	May 2006
IL	Coal	0.01%	May 2002	August 1998	January 2007
MA	Gas	12.3%	March 1998	March 1998	March 2005
MD	Coal	6.7%	July 2000	July 2000	June 2006
ME	Gas	2.6%	March 2000	N/A	N/A
MI	Coal	0.0%	January 2002	January 2002	January 2006
NH	Nuclear	N/A	July 1998	July 1998	May 2006
NJ	Nuclear	0.5%	June 1999	June 1999	August 2003
NY	Gas	17.9%	May 1999	May 1999	August2001
OH	Coal	22%	January 2001	January 2001	---
PA	Coal	11.3%	January 2000	January 2000	January 2011
RI	Gas	N/A	July 1998	January 1998	January 2004
TX	Gas	50.6%	January 2002	January 2002	January 2007
VA	Coal	N/A	Deregulation Suspended April 2007		

Table 2. State Electricity Generation by Source: 2008

	State	CA	CT	DE	IL	MA	MD	ME	MI
	Net Gen (GWh)	207,984	30,409	7,523	199,500	42,505	47,360	17,094	114,989
Percent From	**Coal**	0.6	14.4	70.0	48.4	25.0	57.5	2.1	60.7
	Petroleum	1.2	1.7	2.9	0.1	5.0	0.9	3.1	0.4
	Gas	60.3	26.5	18.4	2.1	50.6	3.9	43.2	8.4
	Nuclear	6.8	50.8	-	47.7	13.8	31.0	-	27.4
	Hydro	15.8	1.8	-	0.1	2.7	4.2	26.1	1.2
	Other Renewables	9.1	2.4	2.2	1.5	3.0	1.3	23.7	2.3

	State	NH	NJ	NY	OH	PA	RI	TX	VA	DC
	Net Gen (GWh)	10,977	63,674	140,322	153,412	222,351	7,387	404,788	72,679	72.3
Percen From	**Coal**	15.1	14.2	13.7	85.2	52.9	-	36.3	43.7	-
	Petroleum	0.6	0.5	2.7	0.9	0.4	0.4	0.3	1.6	100.0
	Gas	30.9	32.6	31.3	1.6	8.4	97.4	47.7	12.8	-
	Nuclear	40.9	50.6	30.8	11.4	35.4	-	10.1	38.4	-
	Hydro	7.1	-	19.0	0.3	1.1	0.1	0.3	1.4	-
	Other Renewables	5.1	1.4	2.4	0.4	1.3	2.1	4.4	3.7	-

Table 3a. Baseline Model Estimation Results[6]

Baseline Model Dependent Variable: lnsarprice	Contemporaneous Effect	Lagged Effects (Sum of lags)					
		1-6	1-5	1-4	1-3	1-2	Lag 1
lnsarprice	-	-	-	-	-	-	0.1158
	-	-	-	-	-	-	(0.0730)
participation	0.2959**	-0.4480**	-0.0275	-0.2254**	-0.2287	0.0260	-0.0472
	(0.1142)	(0.1874)	(0.0803)	(0.1000)	(0.2049)	(0.1012)	(0.1294)
lntotalsalesmwh	-0.1255*	0.0777	0.0507	0.0474	0.0266	0.0268	0.0377
	(0.0648)	(0.1102)	(0.1029)	(0.0914)	(0.0633)	(0.0366)	(0.0325)
lncoalpriceelecgen	-0.0027	0.2930***	0.2562***	0.3083***	0.3124**	0.1434**	0.2101***
	(0.0934)	(0.0723)	(0.0968)	(0.1170)	(0.1224)	(0.0613)	(0.0511)
lngaspriceelecgen	-0.0102	0.0154	0.0145	0.0111	-0.0039	0.0207**	-0.0051
	(0.0081)	(0.0167)	(0.0138)	(0.0112)	(0.0098)	(0.0084)	(0.0071)
pcnthydro	0.0057	0.0051	-0.0061	-0.0015	-0.0340***	-0.0298***	0.0011
	(0.0140)	(0.0355)	(0.0195)	(0.0239)	(0.0104)	(0.0106)	(0.0095)
pcntnuclear	-0.0056	0.0069	0.0059	0.0099	0.0067	0.0039	0.0043
	(0.0096)	(0.0251)	(0.0195)	(0.0169)	(0.0107)	(0.0090)	(0.0067)
cddev	0.000020	-0.000058	-0.000007	-0.000018	0.000005	0.000020	0.000014
	(0.000034)	(0.000118)	(0.000105)	(0.000081)	(0.000057)	(0.000029)	(0.000033)
hddev	-0.00002	-0.000019	-0.000012	-0.000013	-0.000027	-0.000026	-0.000016
	(0.00001)	(0.000045)	(0.000039)	(0.000031)	(0.000027)	(0.000018)	(0.000015)
Wald chi-square (80 d.f.): 547.72	Prob > Chi2 0.000	Arellano-Bond test for AR(2) in first differences: z=1.34	Prob > z 0.180	Sargan test of overidentifying restrictions: Chi2(1)=1.02			Prob > Chi2 0.313

*** significant at 1%; ** significant at 5%; * significant at 10%

Values in parentheses below coefficients are robust standard errors.

[6] Coefficients for PARTICIPATION, PCNTHYDRO, and PCNTNUCLEAR have been multiplied by 100 to allow for an interpretation analogous to the logged variables. For example, the results for the sum of lags 1-6 of the PARTICPATION variable should be read “a 1 percent increase in PARTICIPATION results in a -0.4557 percent decrease in the dependent variable”.

Table 3b. Baseline Model Estimation Results: Continued

Baseline Model Dependent Variable: lnsarprice	Contemporaneous Effect
retailcomp (TX)	-0.0034***
	(0.0011)
retailcomp+CAretailcomp	0.0173***
	(0.0034)
retailcomp+CTretailcomp	-0.0028*
	(0.0015)
retailcomp+DEretailcomp	0.0185***
	(0.0042)
retailcomp+ILretailcomp	0.0034***
	(0.0003)
retailcomp+MEretailcomp	-0.0029***
	(0.0004)
retailcomp+MDretailcomp	0.0058***
	(0.0008)
retailcomp+MAretailcomp	0.0002
	(0.0007)
retailcomp+MIretailcomp	0.0040***
	(0.0005)
retailcomp+NJretailcomp	0.0013**
	(0.0005)
retailcomp+NYretailcomp	0.0002
	(0.0006)
retailcomp+PAretailcomp	-0.0087***
	(0.0009)
retailcomp+DCretailcomp	0.0043***
	(0.0006)

*** significant at 1%; ** significant at 5%;
* significant at 10%
Values in parentheses below coefficients are robust standard errors.

Baseline Model Dependent Variable: lnsarprice	Contemporaneous Effect
ratecap (TX)	0.0087***
	(0.0011)
ratecap+CAratecap	-0.0155***
	(0.0037)
ratecap+DEratecap	-0.0164***
	(0.0044)
ratecap+ILratecap	-0.0063***
	(0.0006)
ratecap+MDratecap	-0.0070***
	(0.0011)
ratecap+MAratecap	0.0002
	(0.0007)
ratecap+MIratecap	-0.0056***
	(0.0009)
ratecap+NYratecap	-0.0073***
	(0.0014)
ratecap+RIratecap	-0.0169***
	(0.0026)
ratecap+DCratecap	-0.0022***
	(0.0007)

*** significant at 1%; ** significant at 5%;
* significant at 10%
Values in parentheses below coefficients are robust standard errors.

Table 4a. Estimation Results with Year Time Dummies Included

Baseline Model w/ Time Dummies Dependent Variable: lnsarprice	Contemporaneous Effect	Lagged Effects (Sum of lags) 1-6	1-5	1-4	1-3	1-2	Lag 1
lnsarprice	-	-	-	-	-	-	0.1284*
	-	-	-	-	-	-	(0.0699)
participation	0.3216***	-0.3803***	0.0232	-0.1760*	-0.2005	0.0428	-0.0357
	(0.0916)	(0.1406)	(0.1192)	(0.0912)	(0.1794)	(0.1075)	(0.1440)
lntotalsalesmwh	-0.1280**	0.0634	0.0375	0.0364	0.0173	0.0203	0.0353
	(0.0651)	(0.1162)	(0.1091)	(0.0962)	(0.0661)	(0.0368)	(0.0314)
lncoalpriceelecgen	0.0375	0.4736***	0.3768**	0.3973***	0.3752***	0.1852***	0.2312***
	(0.1024)	(0.1500)	(0.1495)	(0.1269)	(0.1286)	(0.0672)	(0.0520)
lngaspriceelecgen	-0.0042	0.0191	0.0215	0.0166	0.0015	0.0245***	-0.0039
	(0.0082)	(0.0158)	(0.0136)	(0.0105)	(0.0081)	(0.0085)	(0.0069)
pcnthydro	0.0056	0.0061	-0.0051	-0.0009	-0.0333***	-0.0298***	0.0003
	(0.0139)	(0.0370)	(0.0211)	(0.0248)	(0.0117)	(0.0113)	(0.0098)
pcntnuclear	-0.0051	0.0089	0.0076	0.0112	0.0077	0.0046	0.0046
	(0.0095)	(0.0254)	(0.0197)	(0.0173)	(0.0113)	(0.0093)	(0.0070)
cddev	0.000019	-0.000043	0.000006	-0.000008	0.000013	0.000026	0.000016
	(0.000033)	(0.000128)	(0.000114)	(0.000090)	(0.000065)	(0.000033)	(0.000033)
hddev	-0.000022*	-0.000033	-0.000023	-0.000022	-0.000035	-0.000031*	-0.000020
	(0.000013)	(0.000048)	(0.000042)	(0.000033)	(0.000028)	(0.000018)	(0.000015)
Wald chi-square (100 d.f.): 401.35	Prob > Chi2 0.000	Arellano-Bond test for AR(2) in first differences: z=1.59	Prob > z 0.111	Sargan test of overidentifying restrictions: Chi2(1)=1.43			Prob > Chi2 0.231

*** significant at 1%; ** significant at 5%; * significant at 10%
Values in parentheses below coefficients are robust standard errors.

Table 4b. Estimation Results with Year Time Dummies Included: Continued

Baseline Model **w/ Time Dummies** Dependent Variable: lnsarprice	Contemporaneous Effect
retailcomp (TX)	-0.0042**
	(0.0018)
retailcomp+CAretailcomp	0.0185***
	(0.0035)
retailcomp+CTretailcomp	-0.0031*
	(0.0017)
retailcomp+DEretailcomp	0.0161***
	(0.0047)
retailcomp+ILretailcomp	0.0024*
	(0.0014)
retailcomp+MEretailcomp	-0.0034**
	(0.0013)
retailcomp+MDretailcomp	0.0043**
	(0.0020)
retailcomp+MAretailcomp	-0.0013
	(0.0014)
retailcomp+MIretailcomp	0.0022
	0.0019
retailcomp+NJretailcomp	0.0018
	(0.0014)
retailcomp+NYretailcomp	-0.0011
	(0.0017)
retailcomp+PAretailcomp	-0.0078***
	(0.0016)
retailcomp+DCretailcomp	0.0037**
	(0.0016)

*** significant at 1%; ** significant at 5%;
* significant at 10%
Values in parentheses below coefficients are robust standard errors.

Baseline Model **w/ Time Dummies** Dependent Variable: lnsarprice	Contemporaneous Effect
ratecap (TX)	0.0074***
	(0.0008)
ratecap+CAratecap	-0.0163***
	(0.0033)
ratecap+DEratecap	-0.0138***
	(0.0045)
ratecap+ILratecap	-0.0057***
	(0.0008)
ratecap+MDratecap	-0.0053***
	(0.0017)
ratecap+MAratecap	0.0028***
	(0.0009)
ratecap+MIratecap	-0.0031*
	(0.0017)
ratecap+NYratecap	-0.0044**
	(0.0021)
ratecap+RIratecap	-0.0145***
	(0.0025)
ratecap+DCratecap	-0.0023**
	(0.0010)

*** significant at 1%; ** significant at 5%;
* significant at 10%
Values in parentheses below coefficients are robust standard errors.

Table 4c. Estimation Results with Year Time Dummies Included: Time Dummies

Time Dummies	Contemporaneous Effect	Time Dummies	Contemporaneous Effect
1991	0.0044***	2001	-0.0004
	(0.0010)		(0.0025)
1992	0.0008	2002	-0.0014
	(0.0010)		(0.0013)
1993	0.0021*	2003	-0.0009
	(0.0011)		(0.0018)
1994	0.0018**	2004	-0.0029
	(0.0008)		(0.0021)
1995	0.0020	2005	-0.0011
	(0.0013)		(0.0032)
1996	-0.0001	2006	0.0050
	(0.0011)		(0.0036)
1997	-0.0023*	2007	0.0040
	(0.0012)		(0.0030)
1998	-0.0023	2008	-0.0027
	(0.0012)		0.0039
1999	-0.0012	2009	-0.0022
	(0.0018)		(0.0017)
2000	0.0015	2010	-0.0016
	(0.0016)		(0.0026)

*** significant at 1%; ** significant at 5%; * significant at 10%
Values in parentheses below coefficients are robust standard errors.

Chart 1
Participation Rates of Residential Customers

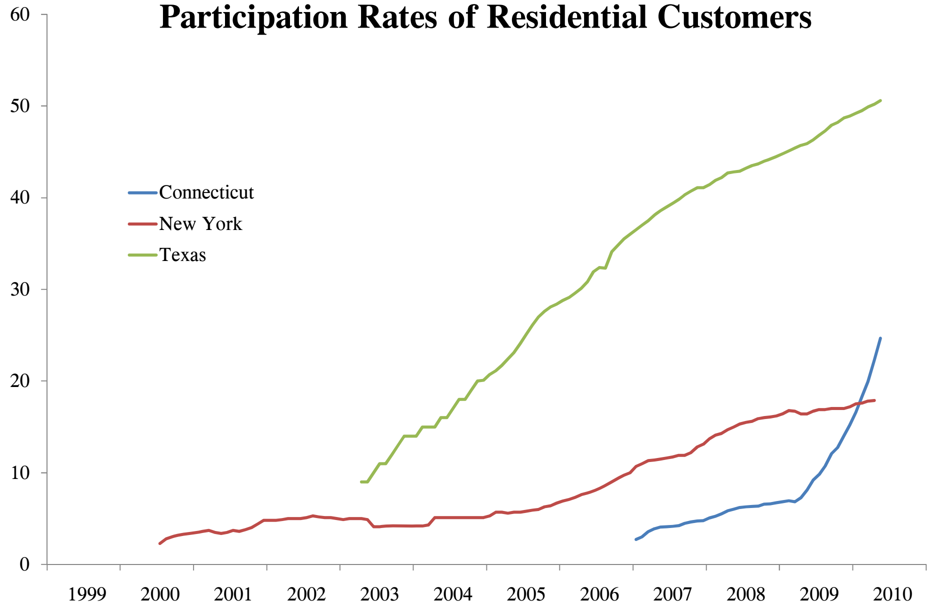
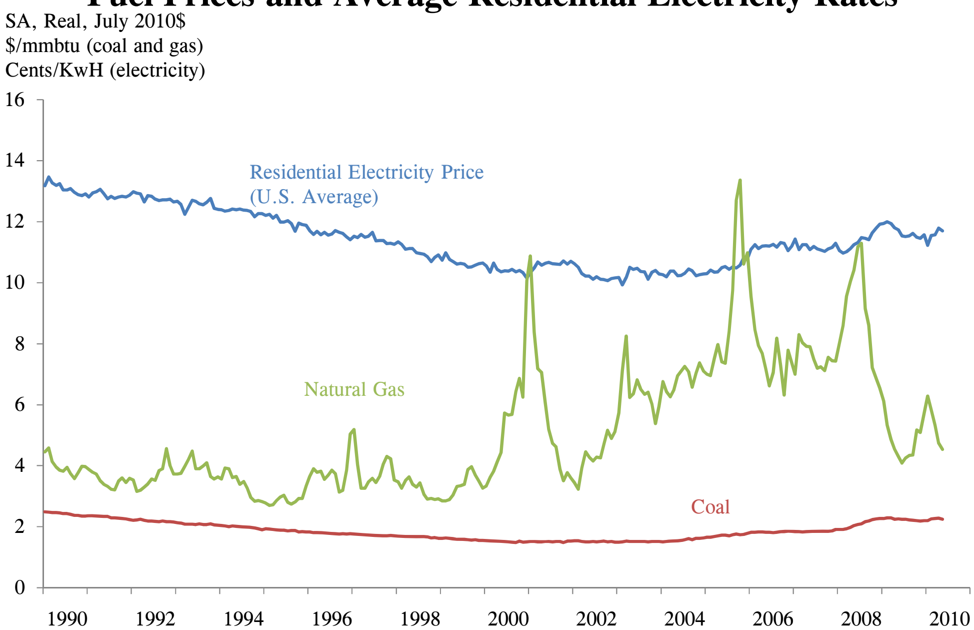


Chart 2
Fuel Prices and Average Residential Electricity Rates



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An Econometric Assessment of Electricity Demand in the United States Using Utility-specific Panel Data and the Impact of Retail Competition on Prices

Agustin J. Ros

Executive Summary

The electricity sector has undergone fundamental changes in the past half century including major technological advances in generation supply and the development and growth of wholesale and retail competition. In this paper I use utility-specific panel data covering 72 electricity distribution companies from 1972 to 2009 to econometrically estimate structural demand and reduced-form price models for residential, commercial and industrial customers. The use of utility-specific panel data covering a diverse set of electricity distribution companies throughout the United States and for close to a 40-year period is a significant contribution to the economics literature on electricity demand and pricing and permits for the estimation of econometric models that control for important unobservable utility-specific factors. Another contribution to the literature on electricity pricing in this paper is that I control for utility-specific total factor productivity ("TFP"), the absence of which would result in biased and inconsistent parameter estimates in the reduced-form electricity pricing models.

I find that the own price elasticity of demand varies between -0.40 to -0.61 for residential customers, between -0.33 to -0.77 for commercial customers and is approximately -0.60 for industrial customers. While static models work well for residential demand dynamic models are more appropriate for the larger customer classes who require more time to adjust consumption. I find that the income elasticity of demand varies between 0.34 to 0.41 (for residential demand), 0.43 to 0.79 (for commercial demand) and 1.3 to 4.6 (for industrial demand). These findings on

the own-price elasticity of demand for the different customer classes add to the literature on the topic and can be used as inputs into different types of electricity and energy studies such as tariff and demand response studies.

Regarding the reduced-form price equations I find consistently that TFP is a significant determinant of electricity prices with a 1% increase in TFP resulting in electricity price declines ranging between 0.05% to 0.30%, depending on the model used and the customer class analyzed. I find that retail competition has provided benefits to consumers. For residential customers I find that based upon the econometric evidence the mean total impact of competition during the period 1998-2009 was approximately -4.2% (simple average of the results from different models: -4.1%, -2.02%, -2.40%, -5.3% and -7.2%) but the effect was declining over the period and eventually turning positive in 2007. For commercial customers I find that based upon the econometric evidence the mean total impact of competition during the period 1998-2009 was approximately -8.45% (simple average of: -9.6%, -6.27%, -5.6%, -9.8% and -11.0%) with the impact being fairly constant during the period. For industrial customers I find that based upon the econometric evidence the mean total impact of competition during the period 1998-2009 was approximately -11.62% (simple average of -14.98%, -9.83%, -8.50%, -11.35% and -13.42%) with the effect generally increasing over time. These results thus indicate that continued market liberalization of retail electricity markets in the United States is expected to lead to increased consumer benefits with greater benefits expected for the larger customer classes.

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Retail Competition in electricity markets

Christophe Defeuilley

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Retail competition in electricity markets.

Christophe Defeuilley[1]

Abstract : The introduction of competition into retail electricity supply gave rise to great expectations. However, to date its performance has proven less than stellar, owing primarily to the theoretical concepts underpinning this reform, which draw heavily on the Austrian school. Neither consumers' decision processes nor this sector's technical paradigm were adequately accounted for, leading to an uncorrect estimation of the expected impact of opening to competition. Short- and medium-term prospects for the evolution of retail markets must be reconsidered from the perspective of greater stability : not a generalization of competition, but rather a persistent segmentation between active and inactive clients ; not a large and rapid diffusion of radical innovations in commercialisation, with the potential for undermining the incumbents' positions.

[1] LARSEN and EDF R&D. The views expressed herein are strictly those of the author and do not necessarily represent those of EDF. This work benefited from input and comments from Raphaël Boroumand, Dominique Finon, Matthieu Mollard, Fabienne Salaun and two anonymous referees, whom I thank.

1. Introduction

The opening to competition into retail electricity supply gives the opportunity to residential consumers to choose their own supplier. This measure, first tested in Norway, then in Britain, was applied in all countries of the European Union, in some U.S. states, in Australia, and in New Zealand. It constitutes one of the major features of the reforms in the electricity sector. The removal of price controls and other regulatory constraints should have enabled to set the market‘s price formation process into action. The introduction of competition should have increased consumers’ choices, reduce the barriers to entry and thereby encourage innovation and lessen prices.

However, the current situation of retail electricity markets reveals that the expected results did not always materialize. To date, the proportion of active consumers is rather limited in many countries, new entrants experienced difficulties to compete against the incumbent companies, few salient innovations have been successfully introduced. Is it the effect of remaining barriers to entry that stymied the full manifestation of retail competition ? It ought to be stressed that in the large majority of cases market prices co-exist with regulated tariffs. Remaining end-user price regulation is one of the factors which hinders equal access of all suppliers to customers and impedes retail market competition from developing (ERGEG, 2007). But in other cases, end-user price controls and other regulatory constraints have been suppressed (NAO, 2008). These measures have obviously given an impetus to the competition in retail (high switiching rates, pressure on prices), but with some important limitations. What should we conclude ? This article suggests that the effects of the introduction of competition in the retail electricity supply have been uncorrectly estimated.

This misestimation is due to the partial relevancy of the economic arguments providing their rationale. The introduction of competition was largely inspired by ideas originating from the Austrian school [1]. This approach left its mark on the electricity sector thanks to the intermediating work of M. Beesley and S. Littlechild, two Austrian scholars who were also intimately associated with the design of the reforms (Helm D., 2003)[2].

With its emphasis on analyzing competition as an *entrepreneurial driven process*, the Austrian School conveys a vision of the market that lacks behavioral and technical depth. As a consequence, it neglects to account for two main phenomena that reduced the impacts from introducing competition in the retail electricity supply : cognitive bias affecting consumer’s decisions to switch, technological paradigm reducing innovation opportunities in commercialization.

[1] While we don’t want to trivialize the profound differences that exist among economists belonging to the Austrian School, and the notable developments it has experienced between the initial work of Carl Menger (1871) and today, we here present a simplified version of the key Austrian conceptions of the nature of competitive process.

[2] This influence is stressed by S. Littlechild himself: “[Kirzner] writings in this area [nature of competition and entrepreneurship] were influential in the development of my own thinking about privatization, competition and regulation of the utilities. Subsequently, the regulation of the Bristish electricity industry reflected his and other Austrian ideas” (Liitlechild S., 2002a).

This paper is organized as follows. After presenting the arguments advanced by the Austrian school to support the opening to competition (Section 2), then sketching the state of electricity retail markets (Section 3), we analyse the factors that explain the discrepancy between the current reality and expectations as they were initially formulated (Section 4). Several concluding remarks follow, underscoring the importance of rethinking the prospects for the evolution of retail markets (Section 5).

2. Theoretical background

The introduction of competition was not an obvious decision to make. Two of the main traditional functions of retailers, largely elude electricity suppliers. In the first place, intermediation - the organization of the transmission and distribution of goods from producers (generators) to consumers - falls outside of their control. Indeed, electricity transmission is technically constrained (the virtual impossibility of storing it, the need to maintain and modulate voltage levels) as well as economically (the natural monopoly character of transmission and distribution grids). Therefore, grid operators (TSO, DSO), not suppliers, manage the organization of intermediation.

In the second place, for a good as homogeneous as electricity, opportunities for transformation and marketing (presentation and packaging, bundling, co-branding) are limited. This is the reason why retailing represents only a small percentage of total electricity bills. These distinctive features generate three effects that mitigate the likely impacts of the introduction of competition.

- The potential demand for an electricity supplier to meet is limited by low revenues generated by the retailing activity.

- Since the intermediation role was historically assumed by the incumbent generating and/or distribution companies, the retail market must be created *ex nihilo*. Consumers, having long-standing relationship with their incumbent company, cannot exercise their freedom of choice without supporting switching costs. It may be costly to change supplier. These switching costs can be decomposed into three broad types : search costs (identifying suppliers, comparing their offers), learning costs (relations with the new supplier) and transaction costs (contracting, negotiating). All of these costs are in part attributable to the fact that each consumer makes a specific investment when entering into a relationship with a supplier. He or she is learning to use the product or the service, is becoming familiar with the menu of contracts its supplier may propose, the rewards it may offer for repeated purchases, etc. A consumer having learnt to use a product or a service delivered by a company, has therefore a strong incentive to continue to buy from that company. Products that are *ex ante* homogenous become, after the purchase of one of them, *ex post* heterogeneous (Klemperer P., 1987). For instance, in the electricity retail market, consumers are familiar with the service supplied by the incumbent company, have a long-standing experience of the quality of service delivered, know approximately the average bill they have to pay. The creation, but also the breach of a client-supplier relationship generates switching costs which can be considered as barriers to entry. These barriers to entry are making consumers less prone to switch even when the new entrant offer is beating the incumbent price (the price elasticity of consumer's demand is weak).

- The homogeneity of the product makes it difficult to offer any differentiation. The potential to create value-added services is therefore limited [1].

Limited potential demand, switching costs involving the creation of barriers to entry, and little room left for product differentiation : the retail electricity market does not provide sound profit opportunities for new entrants.

In this context, is it really valuable to open retail markets to competition ? The potential benefits for consumers may be negligible and there is a risk of incurring additional costs (marketing, advertising and promotion expenses). Especially if the consumers are not adequately protected from exploitation by new entrants trying to take advantage of the confusion and the poor information misleading consumer's choices. Would it not be better to seek out other solutions allowing retail consumers to really benefit from electricity competition, as it is notably advocated by P. Joskow (2000) and other leading energy economists (Littlechild S., 2003) ? As P. Joskow suggests, the incumbent company could provide a basic electricity service (BES) allowing residential consumers to buy directly from the wholesale market at the spot price. Retail consumers could therefore benefit from wholesale competition while being protected from the drawbacks of retail competition (exploitation by the suppliers). It would also suppress the wasteful marketing and advertising costs that could increase final prices. Alternative suppliers could still enter the market and will succeed to generate sound positive profits if they are able to bring value-added services to consumers "over and above" what can be realized through direct purchasing at wholesale through the incumbent company. The benefit will be double : to protect consumers from supporting additional costs (the basic electricity service would be used by consumers as a hedge and a benchmark to help comparison with competing offers) while incite new entrants to enhance consumer services (Joskow P., 2000).

In spite of these doubts, the European Union, Norway, and other OECD countries have chosen to introduce retail electricity competition for the domestic consumers[2]. This choice was largely inspired by "Austrian" concepts regarding the nature of competitive mechanisms and its allegedly positive outcomes.

In the Austrian approach of market process, economic agents are facing not only risk, but also radical uncertainty and sheer ignorance (Kirzner I., 1997a). Their decisions have to be made in ever-changing market circumstances. Technological possibilities, tastes, products, costs and demands are neither "given" and constant, nor known to all market participants. Therefore, as long as useful economic information remains undiscovered or poorly disseminated, market imperfections created by artificial barriers to entry, exercise of market power, productive or allocative inefficiency may be experienced, creating excessive profit opportunities.

[1] The two first arguments are less relevant to industrial clients.

[2] An analytical and well-documented comparison of the social net value of the different organizational forms of retail electricity supply (full competition, BES option, strong regulatory constraints on price formation, etc.) is outside of the scope of this paper. See for instance Littlechild S. (2003) for an extended discussion about the costs and benefits associated with the BES option. Our purpose is to cast some light upon the current situation in the European retail markets and their prospects of evolution in the near future.

In these circumstances, economic agents, spurred by these profit opportunities, will seek to discover more efficient ways to produce and to meet consumers' requirements, better technologies to use, new organizational forms to adopt, etc. Anomalies or disequilibria in prices, illustrating market imperfections, provide the incentive for their elimination by economic agents discovering information, developing innovative processes and adopting new technologies (Thomsen E., 1992). Market participants tend to learn from their successes and mistakes in their attempts to adopt better courses of action. In consequence, over time there is a tendency for dissemination of efficient technologies, organizational forms and most wanted goods and services. As a result of learning and competition by rival firms, disequilibrium prices tend to be replaced by prices reflecting efficient costs of production.

These economic agents, gaining advantage of the opportunities provided by new knowledge and ideas that are not fully exploited by incumbent companies, are termed by the Austrian School "entrepreneurs". Entrepreneurs (simple company founder, manager of small, family-owned firms) are distinguished from other agents by their behaviors : they are innovative, flexible, dynamic, risk-taking and creative. Their "alertness", their "judgment" in business decision-making allow them to discover new opportunities, and to envision new ways of using assets to produce goods and services (Kirzner I., 1997b ; Endres A., Woods C., 2006 ; Foss N., Klein P., 2004). The Austrian approach assigns a pivotal role to entrepreneurship. Entrepreurial discovery is seen as gradually but systematically pushing back the boundaries of sheer ignorance. For the Austrian School, competition is thus considered as a « discovery procedure » (Hayek F. 1945, 1968) driven by an entrepreneurial and learning process.

Applied to the retail electricity supply, this approach of competition as an *entrepreneurial driven process*, should provided the following social benefits (Littlechild S., 2000).

- **Reducing market imperfections.** Entrepreneurs entering in the retail market will seek to reduce costs at all stages of the supply chain. They are expected to expose the true costs of commercialising electricity (previously aggregated into the costs of generation and transmission) and to reduce market imperfections by entering in geographical zones or niches in which the incumbent company gain extra-normal profit. These market imperfections exacerbate the inertia of consumers, increase market segmentation and create price anomalies (Waddams-Price C., 2004). Reduction of market imperfections should benefit to all consumers. In a competitive market, those consumers who become engaged in the market process will force suppliers to become more efficient, with the benefits being passed on to all consumers, even those who are not actively engaged (NAO, 2008).
- **Discovering new products or price/service quality combination** that best meet consumer's needs. Retail suppliers are expected to provide an enhanced array of retail service products, risk management (hedging), and new opportunities for service quality differentiation to better match individual consumer preferences. The discovery of valued and hitherto "unappreciated attribute" of an existing product constitutes an economic improvement from the customer's perspective (Littlechild S., 2002a).
- **Stimulating the alertness of consumers** to the availability of better offers than those proposed by the incumbent. Retail suppliers alert consumers to the existence and potential merits of alternative offers. They can provide accurate information about prices of these alternatives. They help consumers

to become active participants in the market process. Once active, consumers could better evaluate what was on the offer and what would best suit them. They could follow more accurately market evolutions, learn from their past experiences and make better informed choices.

- **Stimulating competition in generation.** A vibrant retail electricity market will ensure that wholesale power markets operate efficiently. Producers will be incited to make efficient investment choices and entry will be easier in wholesale generation markets. Retailers can not only stimulate better prices responsiveness from consumers but also encourage the development of forward contracts, which can reduce the incentives for generators to withhold supply capacity and increase liquidity (Littlechild S. 2000).

The introduction of competition in the retail electric supply should provide the products that consumers really want, reduce the barriers to entry, encourage innovation, reduce prices, and stimulate competition in generation. From this perspective, the consequences of the introduction of competition in the retail electricity supply could go far beyond the reduction of commercialisation costs supported by consumers. Therefore, the solution advocated by P. Joskow - price regulation designed to ensure that wholesale prices are passed on to final customers - cannot replicate the entire effects of the competition process and yield the same results. The Austrian view of competition as a discovery process involves that no one can predict the new services that a new entrant might profitably provide (Littlechild S., 2002b).

S. Littlechild stressed the importance of entry of small, newly created companies, in order to stimulate competition in the retail electricity market and to impede incumbent companies to increase prices, to put aside innovation and to enjoy a comfortable life at the expense of residential consumers (Littlechild S., 2005). This statement can be interpreted as an illustration of the driving role assigned by the Austrian School to entrepreneurship in the competitive process.

3. Retail electricity markets : current situation

Has the opening of the electricity retail market triggered an influx of new entrants stimulating innovative processes, challenging the incumbents and ensuring a renewal of supply ? In order to obtain a first picture of the development of competition in the retail markets, the following indicators are examined : the consumers’ switching , the evolution of consumers’ mobility, the switching costs (as a proxy of barriers to entry), the number of electricity retailers (new entrants) and the innovations which successfully passed the market test (see also NERA, 2007).

3.1. General picture : still barriers to mobility

This first indicator to be considered is the percentage of customers who are active on the market, i.e. who exercise their freedom of choice. This can be measured by adding several groups of consumers : those who have changed supplier (expressing a switching rate), those who renegotiated their contract with the incumbent (but without switching), and those who made inquiries and compared the different suppliers, but then stayed over. Unfortunately, a part of these active consumers fall into categories that are partially or totally non-observable. Essentially, those are the ones who do not end up switching supplier (Loomis D., Malm E., 1999). It is therefore difficult to obtain a precise estimate of the percentage of active clients on electricity retail markets[1]. Given the available information, the rate of active consumers in retail markets is approximated by the rate of switchers[2].

Table 1. Switching rates since the opening of retail markets

European Countries	Year of opening of retail markets	Switching rates
Great Britain	1999	47%
Sweden	1999	32%
Norway	1997	28%
Spain	2003	7%
Finland	1998	11%
Belgium	2003	12%**
Netherlands	2004	15%
Germany	1998	7%
France	2004*	6%
Denmark	2003	2%

Other countries / states	Year of opening of retail markets	Switching rates
Victoria (Aus.)	2002	45%
Texas (USA)	2002	36%
South Australia (Aus.)	2003	34%
New-York (USA)	1999	11%
Ohio (USA)	2001	8%
Massachussetts (USA)	1998	7%
Pennsylvania (USA)	1997	3%
Connecticut (USA)	2000	2%
Maine (USA)	2000	1%

2006 data, except for Sweden and Finland (2005). * Non residential (open as of July 2007) : small I&C consmers ** Flanders exclusively. Sources : national regulators, KEMA, Alliance for retail choice, PUCO, Pennsylvania and Maine Public Adovcate Offices, NERA, Cap Gemini, RWE, Joskow P. (2006).

The incumbents' shares lie between 85 and 95 per cent in most European countries[3]. Globally, customers are not very disposed to change supplier, and the incumbents are not challenged by competition from new entrants (see below). In Italy, Denmark, France, Germany, the Netherlands, and Belgium, switching rates remain below 10 per cent. They are slightly above 10 per cent in Finland and Spain. Only three countries exhibit net switching rates exceeding 20 per cent : Great Britain, Sweden and Norway. In Great Britain, by the end of 2006, 47 per cent of customers had left their electric incumbent company since the opening to competition in 1999 (OFGEM, 2007).

[1] To our knowledge, only two European countries, Norway and Sweden, provide information on the rate at which clients renegotiate with their incumbent company : 5 per cent for the former, 18 per cent for the latter (Nordreg, 2005).

[2] We here refer to net switching, i.e., the (cumulative) percentage of clients having left the incumbent company since the opening of the market. This is below the gross rate of switching, which captures all movements : customers having changed supplier several times or having returned to the incumbent.

[3] Conversely, businesses frequently opt for an alternative supplier : their market share fluctuates between 35 and 50 percent, depending on the country.

In the US, only ten or so states have opened their retail market to competition (essentially on the east coast and in Texas) : they represent around 56 million eligible consumers. On this total, 12% (roughly 6,7 million) have left their historical supplier by th end of 2006. This mean hides strong disparities. Most of consumers who have exercised their freedom of choice are from Texas and the state of New York. (see tab.1). Results from other states that have opened their retail market are not evidential in terms of switching (see also Joskow P., 2006).

To encourage retail's competitition, Texas implemented a price control on historical suppliers. They had to offer a standard rate for their consumers, or a "Price to Beat", set by the Public Utility Commission[1]. This Price to Beat remainedin effect for five years (unitil January 2007), but the incumbent companies could begin to offer a rate lower than the "price to beat" within their respective distribution service areas after three years or until 40% of residential and small business customers are served by alternative providers. This rate was designed to give customers of the incumbent companies a discount (a six-percent rate reduction at the start of competition), and allow alternative suppliers and new entrants the opportunity to offer lower rates and to gain market shares (Adib P, Zarniakau J., 2006). More than 70 firms have entered the market. The number of offers has been multiplied and switching rates reached almost 40% (PUCT, 2007). The dynamic of this retail's competition in Texas has been fostered by regulated prices' levels which favour new entrants[2].

This is also the case in several Australian States (South Australia, Victoria), where incumbent companies are required to offer electricity at standing regulated prices (NERA, 2007). These tariffs are set to allow competition to develop (Menezes F., 2005). This regulation leads to high switching rates (34% in South Australia, 45% in Victoria) and encourage new companies to enter in the retail markets[3].

In Europe and the US, markets with low switching rates are often suffering from several hindrances : regulated tariffs below market prices or switching barriers of various kinds (ERGEG, 2007). The conditions for competition are not always met because price controls have not been removed or because the regulators haven't taken appropriate action to help consumers to take advantage of competition, for example, by ensuring that consumers can switch easily between suppliers (duration, complexity, execution and costs of the switching and cancellation procedures). In order to empower consumers to make the right decisions, information about suppliers and their offers needs to be easily accessible, trustworthy and comparable (NAO, 2008 ; ERGEG, 2008). In many countries, these conditions are not met and switching barriers remain high (ERGEG, 2007). But numerous countries, notably in Europe, are now taking appropriate measures to improve the situation and to foster competitive dynamic in retail.

[1] Price to beat is a variable price which is dependent on the cost of fuel used to generate electricity (mostly natural gas), which can be adjusted twice a year.

[2] Since 2007, in a context of high wholesale prices, Texan newspapers echoed about the difficulties encountered by several new entrants obliged to cease their business because they failed to meet their financial obligations to the Texas power grid or indicated that they could not do so (see for instance, The Star Telegram, June 16, 2008 ; The Dallas Morning News, June 5, 2008).

[3] As in Texas, these regulated tariffs are set to provide a transition to full retail competition. Their phasing-out has begun at the end of 2007 (NERA, 2007).

3.2.The exceptions : Great-Britain,Sweden and Norway

Three european countries exhibit switching rates above 25% while having removed all major regulatory controls (including regulated tariffs) : Great-Britain, Sweden and Norway. Despite high switching rates and pressure on prices for at least a part of the consumers, competition in these retail markets is not perfoming as it was expected.

Switching dynamics. At a first glance, we may consider that initial low switching rates are the consequences of the relative novelty of the opening to competition. The first years yields weak results owing to the inexperience of clients, the potential need for strategic adjustments by new entrants, and possible flaws in the regulatory rules. From this perspective, switching rates should rise over time with the dismantling of barriers to mobility that impede competition and the development of learning effects. However, this is not what we observe.

In Great Britain, the evolution of the electricity retail market can be divided in two periods : 1999–2001 and 2002–2006. During the first period, nearly 32 per cent of consumers (or 8.5 million) chose to leave their incumbent, representing a mean of 240 000 departures per month. This flood tapered off as of 2002, as 3.6 million consumers opted for an alternative supplier between the beginning of 2002 and the end of 2006, corresponding to 60 000 monthly departures, on average (OFGEM, 2007). The pace of switching fell to a quarter of its former value.

In Sweden, the evolution of net switching rates does not appear to have followed the same trajectory. The number of clients leaving their incumbent was between 150 000 and 300 000 annually on average between 2000 and 2006 (i.e. between 3 and 6 per cent of all residential consumers), but the pattern of annual fluctuation does not describe any falling or rising trend during this period (Littlechild S., 2006). The situation is similar in Norway, where no clear-cut trend stands out - years characterized by the greatest activity being followed by more stable years. Globally, the switching rate in Norway is lower than in Sweden, with an annual mean of 2 to 3 per cent of departures during the period 1997–2006[1]. The dynamics of retail markets are not identical from one country to the next and switching rates do not automatically grow over time.

Switching costs are not decreasing. Competition should lead to a downward trend in switching costs, owing to the efforts undertaken by new entrants to discover the most profitable market segments, to penetrate them and to challenge the incumbent company's position. Switching costs should also decrease as a consequence of the intensification of learning effects that allow consumers to reduce the risks and uncertainty associated with their decision[2].

This reduction of barriers to mobility that impede many consumers to choose an alternative supplier should have two main effects. First, the number of active consumers should grow while the competitive game is intensifying. Second, the prices set by the various suppliers (new entrants as well as the incumbent

[1] Sources: Statistics Sweden, www.scb.se; Norwegian Water Resources and Energy Directorate, www.nve.no.

[2] Accumulated experience, better information and knowledge of how to compare between suppliers, how to switch rapidly and adequately.

company) should gradually convergence towards the cost of entry[1]. However, once again, this is not what we observe.

In Great Britain, where consumers are switching the most repeatedly, prices are not converging. The difference between the average price offered by the incumbent and the mean offer from the best alternative supplier has not declined significantly since 2000: It continues to fall within a spread ranging from 12 to 17 per cent (OFGEM, 2007)[2]. This is also the case in Norway. Incumbent companies' prices may exceed the best available offers by 10-15 percent (Von der Fehr N-H., Vegard Hansen P., 2008).

This result suggests that two distinct retail markets can be observed : an "active market", bringing together consumers who have already switched supplier at least once, and an "inactive market", involving consumers who remain loyal to their incumbent. The active consumers, those who are participating in the market are in position to benefit from a vibrant competition. In this market segment there is a variety of suppliers and prices are closely related to costs. Competing suppliers cannot set prices below the average price without loosing market shares. This is not the case in the inactive segment. The inactive consumers are paying prices that exceed costs by non-negligible amounts (Von der Fehr N-H., Vegard Hansen P., 2008 ; OFGEM, 2007).

This market segmentation allows retail suppliers to implement strategies of price discrimination based on geographical location. Retail suppliers set a cheaper basket of prices for their active consumers (i.e. consumers living outside supplier's historical geographic zone) than for those who are inactive (i.e. living in their historical zone). They can also offer a set of different contracts, the first ones being only available to their local consumers' base, the other ones for consumers in other regions.

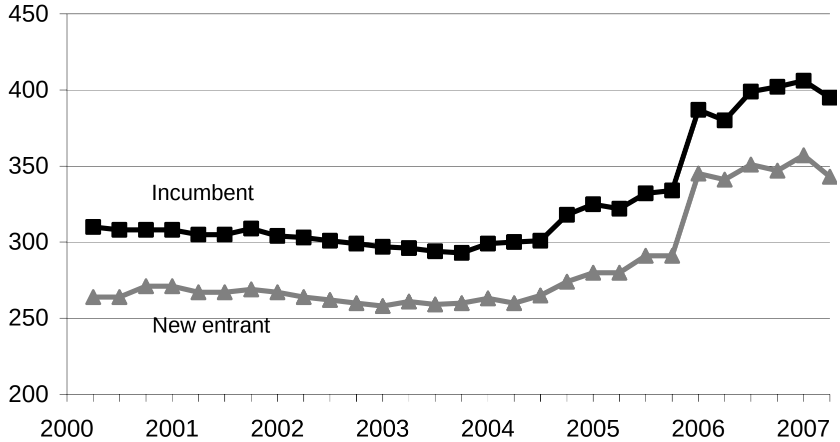
Active and inactive segments do not react in the same way to price signals. In Great Britain, as in Norway and Sweden, mobility within the "active market" accelerated during periods of prices spikes (especially in 2006 for the former and during the winter of 2002–2003 and also in 2006 for the two latter). The overall movements within the active market increase or remain at high levels, consumers who have already switched, switched again, choosing another new entrant or going back to the incumbent company.

Active consumers seem to be very sensitive to the evolution of price. On the contrary, inactive consumers do not respond to price signals. In these three countries, the pace of consumers' loss of the incumbents do not accelerate during the prices spikes episodes. Sticky consumers remain loyal, information conveyed by price is not sufficient to stimulate them to exercice their freedom of choice. This inertia leaves the door open for the incumbent (who benefit from a sticky customer base) to maintain higher prices on a portion of its clientele.

[1] Since electricity is a homogenous good, we assume that significant qualitative differences in the nature of the good or the forms of commercialization cannot explain this price spread.

[2] In an econometric analysis based on a paneldata containing detailed information about electricity supply prices over the period 1999 to 2006 in the UK, Giulietti M. *et al.* (2007) show that prices are remaining dispersed among suppliers. They conclude that there are still significant potential benefits to consumers from searching alternative suppliers.

Fig. 1. Price differential between incumbent and best offer in GB



Comparison of the mean bill from an incumbent and the best mean alternative offer from a new entrant. In pounds sterling. Source : OFGEM, 2007

The setback of new entrants. In most countries, the opening to competition was followed by a two-fold inflow. First, newly created independent companies (start-ups) entered in the electric retail market, experimenting a new business model. They focused their activities on retail supply (branding, consumer relationships, value-added services), trying to take advantage of a low-cost, reactive and flexible organisational structure. Second, incumbent companies originated from other industrial sector (gas) or from other geographical zones (regions, countries) expanded into the domestic electricity market, competing with their regional or national counterparts. The first category of new entrants failed to succeed in their efforts to attract a significant number of consumers and to validate the relevance of their business model[1].

Even at their peak in 1999–2001, these low-cost companies were unable to attract more than approximately 500 000 consumers in the United Kingdom, or about 2 per cent of the market (Littlechild S., 2005). In other countries, the result was even less impressive. With few exceptions, they were unable to survive and run into difficulties. They either bankrupted or were acquired by the electricity or gas incumbents. In Norway, the attempt made by Statoil, the major Norwegian oil and gas producer, to enter in the electric retail market, was unsucessful. Many other companies share the same experience and exit the market. Two independent suppliers, which both succeeded in building up a considerable customer base, were acquired by incumbent companies (Von der Fehr N-H., Vegard Hansen P., 2008). In the most active retail markets, the bulk of the competition is now driven by new “incumbent” entrants (gas or regional electric utilities).

In Great Britain, the gas incumbent has been the major entrant into the retail electricity market. Low-cost new entrants are primarily constrained by economic and financial factors. The low rate of entry in the most vibrant European retail markets (Great-Britain, Norway and Sweden) is not the consequence of

[1] Except in Texas and Australian States (South Australia, Victoria). As indicated below, incumbent companies are required to offer electricity at standing regulated prices. These prices are sufficiently high to allow competition to develop and encourage alternative suppliers to enter in the retail market.

institutional or regulatory barriers, energy regulators have taken steps to remove the most relevant ones. Without physical and financial adequate hedging, these firms were exposed to the evolution of wholesale purchase costs and faced huge risks, endangering their profitability. Relying on wholesale markets via either spot purchases or longer-term contrats is not an accurate risk management strategy for new entrants in retail. Up-stream integration in generation continues to be a strong mean of risk diversification and permits to reduce the volatility of their earnings (Chao H-P. *et al.*, 2008). This is why the few surviving independent low-cost firms are now adopting strategies of upstream integration.

Reproducible innovations. The first years following the opening to competition saw a great deal of experimentation, mainly done by new entrants. These innovations offered a potential for redefining the frontiers of the market by initiating a convergence with other activities. New channels of retail supply (sales over the Internet) and joint offers (dual fuel, sales of energy associated with telephony or Internet access) were developed and commercialised. These experiments, though ambitious, did not pass the market test.

Since 2000–2001, the innovations that appear to have become truly entrenched are more limited in scope : the combined sale of electricity and gas (dual fuel), the enlargement of menus of contracts (duration, payment type, origin of the electricity including clean energy products, pricing options) and the development of some value-added services (demand monitoring, advice, energy efficiency options), using new technologies, such as web-based auditing and energy management software (Littlechild S. 2006 ; OFGEM, 2007, NAO, 2008)[1]. These innovations certainly expand consumers' choices, provide consumers new and innovative tools to manage and monitor their demand and foster competition between electric retail suppliers (NERA, 2008). Nevertheless, they neither do involve a broad redefinition of retail market attributes nor challenge incumbents' business models by disqualifying their offers both technically and commercially. These new products, tools and contracts, are easily reproductible from a supplier to another one and may be quickly disseminated among all market participants. They seem unable to give a clear-cut and long-lasting competitive advantage to an innovative new entrant in the retail market. To date, this new entrant is not in position to create, what J. Schumpeter coined a temporary monopoly position, from which he will gain overprofit and exploit his competitive advantage at the expense of the incumbent companies.

4. Why this discrepancy ? Two analytical insights

The current situation of retail electricity markets reveals that the expected outcomes did not always occur. Two elements, which were supposed to drive the entrepreneurial competitive process, seem to have been overstated : firstly, the ability of consumers to make appropriate choices and, secondly, the nature of innovative processes.

[1] To date, the primary innovation in Great Britain has been the introduction of dual fuel (OFGEM, 2007). Fixed price contrats, online, green tariffs and free energy monitor have also been introduced recently (NAO, 2008) In Scandinavia, innovations are essentially related to contract durations and prices. In Sweden, fixed-price contracts for one to three years and variable-price contracts, in Norway, fixed-price contracts for one year or more and contracts indexed on the spot price (Nordreg, 2005).

4. 1. Information, decision and choice

As previously noted, the discovery of information should lead to a progressive elimination of price anomalies and to convergence of prices towards the marginal cost. However, we observe that price differences between suppliers persist on electricity markets, even years after the introduction of competition. The Austrian approach implicitly assumes that consumers make fully rational decisions and choose the supplier that best meet their preferences. They respond perfectly (or, at the least, satisfactorily) to the incentives and information transmitted by price signals.

Research in the field of behavioural economics cast some doubt on that assumption (Rabin M., 1998 ; Kahneman D., 2003). In many cases, consumers' decisions do not react adequately to price-signals. Their decisions can be affected by various biases that act as a wedge between the choices they should make to maximize utility and the choices they actually do make.

The decision-marking processes prove less simple than they appear (McFadden D., 1986). They arise from the preferences expressed by consumers and the decision protocols they use to make their choice. These preferences, in turn, depend on general values (degree of altruism, moral attitudes) and perceptions of the gains from switching. These perceptions, in turn, are constructed from several elements. In the first place, they draw upon each consumer's past experiences and memory, especially as they relate to similar choices (for example, switching in another sector : banking, insurance, telephony).

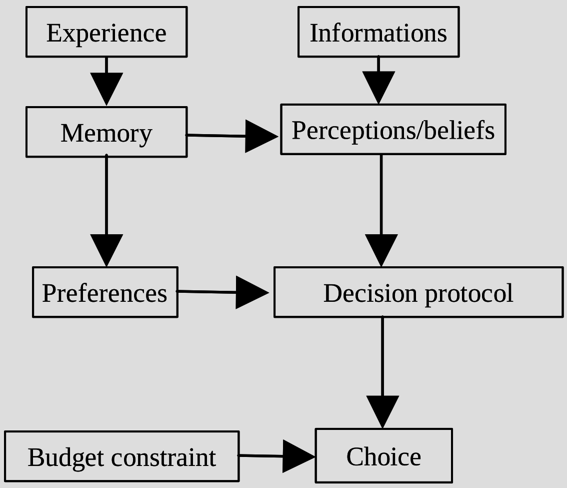
Second, they spring from information available on the type of choice and on the attributes of the good or service (number of competing offers, degree of comparability of the products, quality of the deliverable). Thus, the manner in which consumers perceive their participation in market transactions affects their decision of whether or not to exercise their choice (McFadden D., 2001).

This is not only a matter of risk aversion. Decision biases are not solely attributable to consumers risk perception, but also to inappropriate decision protocols, which may yield anomalies. Laboratory experiments have allowed several types of these anomalies to be identified. Preferences can be affected by the framing of decision problems (i.e. alternative descriptions of the same problem can lead to alternative choices). Decisions can be made on the basis of truncated or misinterpreted information and on the basis of a selective memory (imperfections in remembering facts). Economic agents can also exhibit a "status quo bias", because they tend to value more a good they own. They would demand a considerably higher price for a product that they own than they would be prepared to pay for it (this bias is also coined the "endowment effect" or "loss aversion") (Rabin M., 1998; Kahneman D. et al., 1991).

Economic agents may find choice overwhelming, and "routinely use procrastination, precommitments, habit, imitation, social norms, defaults, and superstitions to avoid confronting choice. [Agents] pass up trading opportunities, particularly in unfamiliar situations" (McFadden D., 2006) because they consider that choice is a stressful experience. They can also be influenced in their decision-making process by the context and by their social environment, and by unconscious thought mechanisms (Wolozin H., Wolozin B., 2007).

Last but not least, it should also be noted that learning effects do not always reduce or eliminate these anomalies. On one hand, this is because routines of choice are often well-established,. On the other hand, this may be because a consumer, confronted with new information discrediting the validity of a choice, may tend to be inattentive to it, minimize its extent or simply ignore it. Such "anchoring" phenomenon may lead economic agents to misread the new information as an additional support for their initial choice (Rabin M., 1998).

Fig. 2. Choice processes



Source: McFadden D., 2006

Consumers' risk perceptions biases in decision processes may curb their incentives to switch supplier or lead them to make inappropriate choices. C. Wilson and C. Waddams-Price (2007) analyse the results of two surveys, conducted in 2000 and 2005 (the latter made by the authors), on consumer's choices on the British electricity retail market. They show that British consumers having switched for a new electricity supplier only appropriate between 37 and 44 per cent of the average maximum gains available. A mere 14 to 18 per cent of clients select the cheapest supplier, while 25 to 31 switched to a more expensive supplier[1]. As C. Wilson and C. Waddams-Price (2007) pointed out, "the extent to which consumers' choices appear inaccurate is puzzling"[2]. The two surveys also reveal that accumulated experience is not much help for appropriating the potential gains offered by mobility. Customers having switched for a new gas supplier prior to select a new electricity provider do not fare much better.

[1] Maximum gains available refers to the change in surplus that would have been realized by a switcher has he switched to the cheapest alternative supplier.

[2] It does not seem that is result is a consequence of measurement errors or methodological bias. See C. Wilson and C. Waddams-Price (2007) for a detailed explanation. In a more recent paper, Tina Chang Y. and Waddams-Price C. (2008) made a more precise statement about the determinants of consumers' choices. "While a model of utility maximisation provides some explanation of consumers' market activity, the influence of expected gains and time involved is relatively small. Many other factors, in particular the confidence with which consumers hold their estimates of gains and costs, are important influences. And much remains unexplained, suggesting that consumers both maximise utility and display *behavioural* characteristics in deciding whether to search for better deals and switch providers".

Table 2. Choices on the British electricity market. Results of two surveys

	Survey 2005	Survey 2000
Survey population	2027	3417
Total number of switchers	310	523
Number of switchers (sample)	154	318
Average max. gains available (£ per year)	49.04	43.02
Average actual gains made (£ per year)	17.9	19.4
Average actual gains / average max. gains	37%	44%
Proportion of switchers with perfect gains	18%	14%
Proportion of switchers with negative gains	31%	25%

Source: Wilson C., Waddams-Price C., 2007

Consumer's choices are not always judicious, even when they can appropriate net gains when choosing to switch. The consumers seem not to always respond adequately. Even if competitive suppliers behave in a way that reduces barriers to mobility, it is possible that consumers will not fully respond. Their decisions are partly conditioned by their perceptions of the risks they are running and by the choice protocols they use. Risk-averse agents, who persist in a routine of immutable choice, or who assign a status quo premium, can remain inactive even when it is in their interest to switch (NAO, 2008).

Are retail electricity markets different from other retail markets like mobile and fixed phone, credit cards, insurance, bank, regarding consumer's choices ? It is beyond the scope of this paper to undertake a genuine comparison with other sectors, but a superficial look may suggest that bias in consumer's behaviors are a common feature in a vast number of markets (see Della Vigna S., 2008 for a recent survey). Electricity retail market is therefore not an exception.

Taking into consideration some of these key features of decision-making processes can be useful to understand the current situation of the electricity retail market.

- Improving the quality and dissemination of information is not, in and of itself, sufficient to multiply the number of active clients, reduce switching costs, and stimulate a vibrant competition in retail. A price shock that is well reported by the media (such as in Norway and Sweden during the winter of 2002–2003 and in Great Britain in 2006), though it may provide an incentive for clients who are already active to switch again, have not triggered a mass migration among inactive customers.

- Learning effects have an unequivocal impact on customers' mobility. Several cases can be experienced. Over time, some clients who are already active improve the efficiency of their decision-making process, stay informed, explore the market, and react to price changes. Risk aversion, which was weak at the beginning, declines, learning effects reduce their switching costs. But, other active clients, having chosen poorly, appropriate negative gains from their switch, or encountered difficulties while switching, are disappointed and decided to renounce to exercise their freedom of choice. Risk aversion, which was weak at the beginning, increases. There are also cases of inactive customers who are reassured in their decision not to switch by the dynamic and reactive nature of the market, rendering the decision making process more uncertain (Giulietti M. et al., 2005). They impute a higher premium to the status quo. Their risk aversion, which was strong at the beginning, increases over time with the growing number of competitors and with the development of complex, non linear tariff options [1].

One can argue that consumers interpret new information that becomes available to them in a way that confirms their initial perception. Active clients will consider that a fluctuating market, characterized by frequent price changes, provides a continuous stream of new opportunities, while inactive clients will consider this very same instability as a sign of increased complexity and a greater risk of mistakes. Thus, both groups of consumers find that this information bears their choice out. This type of reaction does not foster market liquidity. It is more liable to progressively reinforce the market segmentation and lock in the positions taken by various categories of clients (active vs. inactive).

4.2. Innovation, technological opportunities and learning effects

Innovation is supposed to be the second driver of competition. It should provide an incentive to invest in R&D programmes, to implement new production processes, and to develop new goods and services. However, to date, the introduction of competition in the electricity retail supply have not led suppliers to successfully develop innovations which enable them to challenge the incumbents' positions. The postulates of the Austrian school suggesting that competition fosters innovative processes has to be reconsidered [2].

Competition is not the only driver of innovation. Other factors, like technological patterns and learning effects, are entering into consideration to explain the origins, the nature and the path of innovative processes. Technological opportunities are not identical across sectors. The sectoral knowledge base (and particularly its proximity to the technological frontier) underpins firm's innovative activities in each sector and affects the potential for technological improvements in each domain of activity (Dosi G., 1988). Moreover, innovative processes depend on learning mechanisms that the firms themselves implement through practice and use. These learning mechanisms explain the cumulative aspect of many innovative processes.

The sectoral differences between the organization of innovative processes may be summarized as follow. In sectors characterised by few technological and scientific opportunities, but high appropriability and cumulativeness at the firm level, the innovative processes are supported by large established firms. These sectors exhibit a stable core of large firms accumulating technological knowledge and capabilities and a low rate of innovative entry. On the contrary, in sectors characterized by high technological opportunities, but low appropriablitity and low cumulativeness at the firm level, the innovative processes are supported by entrepreneurs and new entrants. High technological opportunities allow for the continuous entry of new innovators. Sectoral characterisation of innovative

[1] This risk aversion can be artificially exacerbated by some retailers which may increase the difficulties faced by consumers to evaluate and to compare the alternative offers. The limited capacity of consumers to choose efficiently between suppliers can be an additional barrier to mobility and reduce their willingness to switch.

[2] Following Schumpeter, we are assigning here a key role to new entrants in the innovative processes. This is implicitly recognized by S. Littlechild (2005) as a reason to introduce competition into electricity retail supply (in particular, when he emphasizes the central role played by new entrants as vectors of the development and penetration of innovations).

patterns changes over time. A rather stable organization characterized by incumbents may be displaced by a more turbulent one with the entry of new firms using new technologies in case of major technological, knowledge or market discontinuities (Breschi et al., 2000 ; Malerba F., 2002).

The electricity supply sector is a steering example of a stable industry, organised around large incumbent companies implementing cumulative innovation processes. The reasons are twofold.

First, technological change in this industry is largely cumulative. Technical choices in electric generation and transmission exhibit a high degree of interdependency and complementarity (in terms of technological choice, dimensioning, location of infrastructure and equipment) and carried out strong externalities. These interdependencies tend to steer technical progress and innovation efforts in one main direction, i.e. the design and operation of centralized generation units whose energy yield is rising and whose long-term marginal costs are declining, served by grids with increasing capacity. Electricity retail is part and parcel of this coherent and stable technical system organized around large generation units and interconnected grids displaying scale economies. Nevertheless, it has to be mentioned that, for several years, R&D efforts have been targeted at the development of decentralized means of production, mass storage solutions, and an in-depth redefinition of the role and the functioning of the grids – through the integration of technologies from power electronics and intelligent metering systems, as well as the management of information and communications (Jamasb T. et al., 2006 ; EU, 2006). But, considering the lifespan of the current equipment and infrastructures and the strong complementarities binding them, the penetration of one or several groundbreaking technologies would be very incremental, even with a short time to market.

Second, innovative processes in the electricity sector are largely propelled by equipment suppliers rather than by the electrical utilities themselves (Jacquier-Roux V., Bourgeois B., 2002).

Beset by the lack of technological and scientific opportunities that can be exploited in the short term and by a dependence on equipment suppliers, electrical firms often focus on accumulative innovative processes, involving learning by using routines and frequent interactions with equipment suppliers. Consequently, large companies tend to adopt new technologies earlier than smaller utilities or new entrants. Large companies are less averse to risk of earlier adoption (their portfolio of generation units reduce the impact of a bad technological choice on their overall profitability). They are able to benefit from economies of scale. Moreover they can benefit from internal engineering, design and maintenance staffs capable of adopting new technologies (Joskow P., Rose N., 1990). New entrants, conversely, may have an incentive to adopt proven technologies (Jamasb T., Pollitt M., 2005).

In this context, retail competition cannot be, by itself, the main driving force of the innovative processes which are taking place in the electricity sector. On one hand, new entrants in the electricity market are not the main vector of innovation. On the other hand, the suppliers are not in a position to make technical choices independently from those made upstream by the producers and the grid operators. Suppliers are largely constrained in their choices by the overall architecture of the electricity system. Regardless of their talent and imagination, it seems rather difficult for the entrepreneurs striving to enter the retail market to ignore these limitations.

Nonetheless, electricity retail supply may experience the emergence of innovative processes that are partially dissociated from the technological paradigm within which it is embedded. Indeed, innovation in services - of which retail supply is one - involves other issues : mobilizing competencies and know-how, interacting with customers, solving specific problems, etc. In services, innovative processes are characterized as mechanisms combining improved techniques and competencies (Gallouj F., Weinstein O., 1997). New entrants can innovate by recombining the competencies and techniques used for supplying electricity to residential consumers. This can be done by importing generic or specific techniques having been implemented in other sectors (information technologies, customer management), by incorporating new services (advice, services, demand-side management), or by defining new standards of usage and pricing devices. New entrants in electricity retail supply have a limited capacity to spur radical innovative processes.

To sum up, one can consider that innovation in retail supply is largely dependant of the current technological paradigm of the electricity sector. In the longer term, if the electric technological paradigm evolves towards a greater integration of decentralized generating units, associated with a grid relying on information and communications technologies, opportunities for innovations in commercialization could expand considerably (differentiating the product electricity, dynamic demand management, associated services)[1].

5. Conclusion

In this paper we have tried to understand why the introduction of retail competition did not yield the expected results. We shed some light on the limitations of the Austrian analysis of competition as an *entrepreneurial driven process*. Two issues were inadequately accounted for. First, the complexity of the determinants of choice (perceptions and decision protocols), which may explain why so many consumers remain inactive even when they have a clear-cut interest to switch. Second, the technological paradigm in the electricity sector, which limits new entrants' potential for developing radical innovations. This is not to say that end-user price controls and other regulatory constraints do not play an important role to impede the development of a vibrant retail market. But even in markets where the main barriers to entry have been suppressed, the magnitude of the retail competition have to be re-evaluated.

Short- and medium-term prospects for the evolution of retail markets must be reconsidered from the perspective of greater stability. 1) Not a generalization of competition, but rather a persistent segmentation between active and inactive clients leading to the co-existence of two market segments : a dynamic one, in which price competition is permanent and consumers respond to price-signals, and a more stagnant one, in which price competition is weak and consumers

[1] Smart metering is an example. Advanced Metering Infrastructure (AMI) can play a role in promoting innovation in product offerings. “AMI could provide a platform through which retailers can offer a variety of services based on time of use, pre-payment, direct load control (e.g., thermostat control, A/C cycling), demand response programs“ (NERA, 2008). AMI may be a catalyst to develop retail competition by giving new and more proactive roles to consumers, which can take new responsabilities for their energy monotoring and consumption choices.

inertia is strong. This “brand loyalty” gives a market power to the incumbent over its consumers and implies that a firm’s market share determines its profit. In this perspective, it is difficult to evaluate if retail competition leads to an improvement in the overall efficiency of the electricity market. Retail competition create new opportunities for the active consumers and force suppliers to become more efficient. But for the consumers which are unable or unwilling to be active, it is not obvious that the opening of retail electricity markets was a gain. 2) In the short-term, new entrants in retail will face difficulties to offer radical innovative services undermining the incumbents’ positions and paving the way for an enhancement of retail service products and for a sharp reduction of end-user prices.

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Market Restructuring, Competition and the Efficiency of Electricity Generation: Plant-level Evidence from the United States 1996 to 2006

J. Dean Craig and Scott J. Savage***

This paper examines the effects of market restructuring initiatives that introduced competition into the United States electricity industry on the thermal efficiency of electricity generation. An empirical model is estimated on annual data for over 950 plants from 1996 to 2006. Model estimates show that access to wholesale electricity markets and retail choice together increased the efficiency of investor-owned plants by about nine percent and that these gains stem from organizational and technological changes within the plant. Although not directly targeted by restructuring initiatives, similar efficiency gains are also found for municipality-owned plants. This result suggests that the potential benefits from competition have spilled over to public electricity generation.

Keywords: Competition, Efficiency, Electricity generation

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1. INTRODUCTION

Electricity is a fundamental input for almost all economic activity. By reducing the retail prices faced by consumers, and the emission of carbon dioxide during production, the efficient generation of electricity has substantial potential to increase societal welfare. This paper examines empirically the effects on the

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thermal efficiency of generation plants from state market restructuring initiatives that introduced wholesale and retail competition into the United States (U.S.) electricity industry. Thermal efficiency is measured by the heat rate, the number of British Thermal Units (BTUs) of fuel used to generate a kilowatt hour (kWh) of electricity.

The electricity industry is comprised of generation, transmission and distribution. Until recently, U.S. electricity was typically supplied by vertically-integrated utilities with a monopoly in their local geographical area. These utilities were either privately owned by shareholders ("investor-owned utilities", "IOUs") or publically owned by cooperatives, municipalities, state and federal governments. The Federal Energy Regulatory Commission (FERC) regulated wholesale sales and the transmission of electricity in interstate commerce while state Public Utility Commissions (PUCs) oversaw generation, retail sales and intrastate transmission and distribution. FERC and the PUCs typically employed cost-based regulation whereby wholesale and retail prices were set to cover the utilities' costs of production plus a "fair" return on investment. Some states have also experimented with incentive regulations that made the utility the residual claimant to their cost-reducing effort and innovation.[1]

Market restructuring commenced with the passing of the Federal Energy Policy Act of 1992 and FERC Order No. 888 in 1996 which permitted non-utilities to enter wholesale markets and placed greater emphasis on market-determined prices for IOUs.[2] Individual states responded by considering the unbundling of generation, transmission and distribution so that multiple generators could compete with one another over the supply of electricity to retailers. This wholesale competition would ultimately take place in various centralized state or regional markets operated by seven regional transmission organizations or independent system operators (hereafter "RTOs").[3] Several states also considered initiatives that would directly relate retail prices to wholesale markets. These included the abolishment of cost-based rate regulation and the introduction of retail competition that allowed end consumers to buy their electricity from two or more retailers ("retail choice"). By removing restrictions on revenue and exposing plants to competitive wholesale and retail forces, market restructuring was expected to increase the incentives for managers to increase plant efficiency in order to decrease costs.

Several papers study the efficiency of investor-owned plants in states transitioning towards competition. Using data from coal and natural gas fueled

1. For example, heat-rate programs set price conditional on the firm-level average heat rate. Individual utilities with a relatively low heat rate were able to retain the incremental profits from being more efficient. To see a specific example see http://www.resourceinsight.com/work/naruc_pbr_97.pdf which describes in detail performance-based regulations tied directly to the heat rate for San Diego Gas and Electric.

2. Non-utilities are firms that generate, buy and/or sell electricity but are not involved in transmission.

3. See Table 1 for a description of RTO member states.

plants from 1981 to 1996; Knittel (2002) finds that heat-rate programs increased efficiency by about two percent. Hiebert (2002) estimates a stochastic frontier cost model for 633 fossil-fueled plants from 1988 to 1997. He finds that the mean efficiency of coal plants increased by about 50 percent in states preparing for retail competition. Fabrizio et al. (2007) estimate input demand functions for 769 fossil fueled plants from 1981 to 1999. They show that the labor and non-fuel expenses of plants in states that passed market restructuring legislation were about three to five percent lower than similar plants in states that did not pass legislation. Moreover, the implementation of retail choice provided incremental reductions in labor and non-fuel expenses of about three to 17 percent. Using data from 73 nuclear plants from 1992 to 1998, Zhang (2007) shows that the passing of market restructuring legislation was associated with a reduction in fuel, operating, and maintenance costs by eleven to 23 percent.[4]

This paper uses variation in the timing of market restructuring initiatives across states from 1996 to 2006 to measure the effects of competition on the efficiency of investor- and municipality-owned generation plants.[5] We develop a unique and comprehensive annual data set of over 950 coal, natural gas, and petroleum fueled generation plants, representing six different types of generation technology. We use these data to make three contributions to the literature. First, because we study the entire population of states that implemented wholesale market reforms and retail choice, we are able to estimate the efficiency effects for states with access to wholesale electricity markets *only* ("partial competition") versus states with *both* access to wholesale electricity markets *and* with retail choice ("full competition").[6] Second, because our sample includes plants that are owned by municipalities and cooperatives, we also test if the efficiency gains from restructuring have spilled over to non-restructured, publically-owned generation. Third, by measuring efficiency with the heat rate we are able to directly convert any fuel reductions from market restructuring into environmental benefits, as measured by the associated decrease in carbon dioxide emissions.

Our results show no significant correlation between partial competition and thermal efficiency. However, thermal efficiency is roughly nine percent higher

4. Several papers study the price effects from restructuring. Kleit and Tecrell (2001) use data from 78 gas plants in 1996 to estimate cost savings from restructuring of up to 13 percent. Joskow (2006) finds that restructuring of wholesale and retail markets leads to lower retail prices. Taber et al. (2006) investigate residential, industrial, and commercial prices and find that restructuring did not lower electricity rates. Blumsack et al. (2008) find that states with restructuring have higher price-cost markups. Kwoka (2008) reviews the recent literature and summarizes the methodological problems associated with measuring the price effects from restructuring. In a related literature, Sanyal and Ghosh (2010) find that deregulation does not increase upstream innovation.

5. For the purpose of this study, we use "municipality-owned utilities" to describe plants that are publically owned by municipalities or cooperatives.

6. Table 1 shows there are 17 states in our sample where at least ten percent of consumers within the state can buy their electricity from two or more retailers. Only seven states actually implemented retail choice in Fabrizio et al.'s (2007) sample; four in 1998 and three in 1999. Four states implemented retail choice in Zhang's (2007) sample.

for both investor-and municipality-owned plants located in states with full competition than comparable plants in states without. These results are interesting because they imply that access to wholesale electricity markets and retail choice together are important for realizing the most efficient gains from electricity generation. Moreover, competition became less popular following the price increases and blackouts in California in 2000 and 2001, and many states decided to delay or suspend restructuring. Such decisions may not have been economically rational. All other things held constant, our results imply that market restructuring initiatives that lead to a more fully competitive marketplace are associated with significant benefits corresponding to a 30 to 50 million ton decrease in carbon dioxide emissions during the sample period. The public power sector has also opposed restructuring (Kwoka, 2008). Our results suggest that the efficiency gains from restructuring may have spilled over to the non-restructured, public power sector. This implies that restructuring is good for consumers and society, but maybe not so good for public power executives who have to work more efficiently.

The paper is organized as follows. Section 2 describes the competition-efficiency hypothesis in the context of U.S. electricity generation and outlines the empirical model used to test the hypothesis. The data are described in Section 3. Section 4 presents the empirical results and Section 5 uses the results to calculate the potential reduction in carbon dioxide emissions due to market restructuring. Section 6 concludes.

2. EMPIRICAL MODEL

2.1 Market Restructuring and Competition

An important question facing state regulators considering market restructuring is the extent to which the production and distribution of electricity should be opened up to competition. California was the first state to pass independent market restructuring legislation in 1996 that introduced competition into wholesale and retail markets during 1998. Column one of Table 1 shows that another 36 states followed California's lead by also permitting their utilities to trade in market places for wholesale electricity, operated by several regional or state RTOs.[7] Column two shows the seven RTOs that operate the wholesale electricity market places. Of the 37 states that permitted wholesale electricity trading, column three shows that 17 states also implemented retail choice, with wholesale market reforms typically preceding retail reforms. The remaining 20 states preferred to restrict reforms to the wholesale level, at least until experience resolved some of the market uncertainties and justified the additional move to retail competition. Note that following California's electricity crises in 2000 and 2001,

7. The District of Columbia (D.C.) is included and will be counted as a state hereafter.

Table 1: States with Competition 1996–2006

	Access to wholesale markets ("partial competition")		Retail choice	Access to wholesale markets and retail choice ("full competition")
State	Year	RTO	Year	Year
Arkansas	2004	MISO, SPP		
California	1998	California ISO	1998	1998
Connecticut	1997	ISO-NE*	2000	2000
Delaware	1997	PJM*	2001	2001
Illinois	2002	PJM, MISO*	1999	2002
Indiana	2002	PJM,MISO*		
Iowa	2002	MISO		
Kansas	2004	SPP		
Kentucky	2002	PJM*		
Louisiana	2004	SPP		
Maine	1997	ISO-NE*	2000	2000
Maryland	1997	PJM*	2000	2000
Massachusetts	1997	ISO-NE*	1998	1998
Michigan	2002	PJM,MISO*	2001	2002
Minnesota	2002	MISO		
Mississippi	2004	SPP		
Missouri	2002	MISO, SPP		
Montana	2002	MISO		
Nebraska	2004	SPP		
New Hampshire	1997	ISO-NE*	1998	1998
New Jersey	1997	PJM*	1999	1999
New Mexico	2004	SPP		
New York	1999	NYISO*	1998	1999
North Carolina	2002	PJM*		
North Dakota	2002	MISO		
Ohio	2002	PJM, MISO*	2001	2002
Oklahoma	2004	SPP		
Pennsylvania	1997	PJM, MISO*	1999	1999
Rhode Island	1997	ISO-NE*	1998	1998
South Dakota	2002	MISO		

(continued)

Table 1: States with Competition 1996–2006 *(continued)*

	Access to wholesale markets ("partial competition")		Retail choice	Access to wholesale markets and retail choice ("full competition")
State	Year	RTO	Year	Year
Tennessee	1997	PJM*		
Texas	1997	ERCOT, SPP	2002	2002
Vermont	1997	ISO-NE*		
Virginia	2002	PJM*	2002	2002
West Virginia	2002	PJM*		
Wisconsin	2002	MISO		
D.C.	2002	PJM*	2001	2002

NOTES: California suspended retail restructuring in 2001. Virginia suspended retail market restructuring in 2007. The EIA currently lists Oregon as having retail choice but this occurred after 2006. Retail choice is the year when at least ten percent of consumers within the state could buy their electricity from two or more retailers. * Indicates that the state is part of a wholesale market that allows for capacity trading. MISO stands for Midwest Independent Transmission System Operator. PJM stands for Pennsylvania-New Jersey-Maryland Interconnection. California ISO stands for California Independent System Operator. ISO-NE stands for Independent System Operator New England. SPP stands for Southwest Power Pool Electric Energy Network. NYISO stands for New York Independent System Operator. ERCOT stands for Electric Reliability Council of Texas.
SOURCES: EIA, FERC, NARUC (2009); NEAAP (2009); State PUC web sites.

Arizona, California, Nevada, and Oregon suspended part or all of their restructuring activities, as did Arkansas and Virginia in 2003 and 2007, respectively.[8] Note also that columns one and four highlight the state and time differences in the implementation of wholesale and retail market reforms that permit empirical testing of the separate efficiency effects from partial competition (i.e., access to wholesale electricity markets) versus full competition (i.e., access to wholesale electricity markets *and* retail choice).

2.2 Competition-efficiency Hypothesis

About 90 percent of U.S. electricity was generated by steam-cycle technology in 2006 (Energy Information Administration (EIA), 2009). Coal, natural gas, nuclear fission or petroleum was used to heat a water boiler with the steam from the boiler rotating a turbine that generates electricity. For coal-, natural gas-, and petroleum-fired plants, fuel comprises about 80 percent of total variable costs. All other things being equal, plants with a relatively lower heat rate, or higher

8. Oregon subsequently lifted its suspension of retail choice after 2006.

thermal efficiency, have a lower fuel cost for producing a single unit of output and, potentially, higher profits.

When operating in wholesale market bid systems, firms can submit bids to the spot market that indicate the prices and supply from their generation plants. The ranking of bids from lowest to highest price determines the electricity dispatch order and the market wholesale price, which is the price bid from the marginal plant (Fabrizio et al., 2007). Plants with low variable costs are placed higher in the dispatch ranking and can earn higher expected profits through relatively larger price-cost margins and by increasing their likelihood of supply. Plants with high variable costs face the prospect of short-run losses and ultimately potential exit from the market place. As such, managers of investor-owned plants in states with wholesale market restructuring are subject to entry, exit, and competitive pricing. This gives them a strong incentive to decrease operating costs by reducing their plant's heat rate. They can achieve this by implementing industry best practice maintenance and operational procedures, downsizing, upgrading to higher quality fuel, and/or by introducing new technologies that improve boiler efficiency.[9] The effects from market restructuring can also spill over to non-restructured, publically-owned utilities. For example, municipality-owned utilities may improve their efficiency through the exchange of knowledge with investor-owned utilities or in response to latent threats of restructuring and the associated competition.

Prima facie, one could expect trading in wholesale electricity market places to provide sufficient competitive pressures (as described above) to encourage more efficient electricity generation. However, without the corresponding implementation of retail market restructuring, the buyers of electricity in the newly formed wholesale markets are predominantly distribution companies that have been divested from the previously vertically-integrated incumbent utilities. Because historical practices in procurement, distribution and marketing are likely ingrained in these distribution companies, their behavior may be unresponsive to the changes in electricity trading conditions. Under this scenario, relatively inefficient generation plants would still be able to sell their electricity in wholesale markets for a profitable price and, as such, face weaker incentives to reduce their plant's heat rate. If such behavior occurs, there could be no observable impact on measures of plant efficiency from wholesale market reforms only.

With both wholesale and retail competition, customers may purchase their electricity either directly from the wholesale market or from one of several new competing retail or marketing companies. Innovative new retail entrants that are successful in building end-user (retail) market share, and in procuring their electricity at lower costs, will grow and comprise an increasing share of the low-cost plant's revenue base (Bohi and Palmer, 1996). Under these market conditions,

9. For example, improved sensor technology within the boiler maintains the ideal mixture of oxygen and carbon monoxide so that the optimal heat is obtained from the given fuel source. This means less fuel is needed to spin a turbine (Vesel et al., 2007).

relatively higher-cost plants will have incentive to become more efficient in order to be placed higher in the dispatch ranking in wholesale markets and to sell more electricity. As such, actual or potential retail competition from market restructuring may be sufficient to encourage generating plants to become more efficient. Ultimately, the efficiency effects from partial competition versus full competition remain an empirical question and are the focus of the remainder of this paper.

2.3 Model Specification

Market restructuring can be measured in several different ways: (a) plant access to wholesale electricity market places through an RTO; (b) the date at which formal hearings on restructuring began; (c) the date at which restructuring legislation was enacted; (d) the implementation date for retail choice under that legislation; and (e) complementary aspects of restructuring, such as access to wholesale markets that permit capacity trading, the mandatory divestiture of generating assets and the type of rate regulation (Fabrizio et al., 2007; Zhang, 2007; Kwoka, 2008; Craig, 2009; and Davis and Wolfram, 2011). In this paper, we construct our primary independent variables of interest with information on plant access to wholesale electricity market places, and with a new measure of retail choice that replaces the date of implementation with the date when at least ten percent of customers within the state have a choice between two or more retailers of electricity.

These measures allow us to make two contributions to the literature. First, because most states implemented wholesale reforms first, we construct two variables that capture the phasing in of restructuring initiatives through time and the associated increase in the intensity of competition. Specifically, *PCOMP* is partial competition, which equals one when the plant is located in a state where utilities have access to wholesale electricity market places through an RTO, and zero otherwise.[10] *FCOMP* is full competition, which equals one when the plant is located in a state where utilities have access to wholesale electricity market places and at least ten percent of customers have a choice between two or more retailers of electricity, and zero otherwise. Because *FCOMP* measures the incremental gains in efficiency from retail choice beyond access to wholesale electricity markets, the estimated coefficients on *PCOMP* and *FCOMP* provide the basis for testing whether wholesale market reforms are a sufficient condition for restructuring.

Previous studies use the date of implementation of retail choice to measure the start of retail competition. However, because it reflects the removal of a significant barrier to entry and not actual entry, the date of implementation mea-

10. To be clear, we are not confusing electricity market restructuring with the presence of an RTO. Instead, we are using the timing of wholesale and retail reforms by the states to test whether the presence of an RTO, as measured by *PCOMP*, is sufficient for maximizing the efficiency gains from restructuring.

sures actual and potential competition.[11] Ideally, firm specific market share data are needed to measure actual competition in retail markets, but these data are not publically available. Nevertheless, our second contribution to the literature improves upon the date of implementation by employing information on the number of customers within each state that have a choice between two or more retailers of electricity. In order to provide a better measure of actual competition, we then measure retail competition with the date at which ten percent of customers within the state had retail choice. Moreover, for a robustness check, we consider an alternative measure for retail competition where retail choice is permitted to vary from zero to 100 percent of residential customers.[12]

We test the competition-efficiency hypothesis with an empirical model that compares the efficiency of generation plants located in states with competition to the efficiency of similar plants in states without.[13] Estimates of these effects are consistent when restructuring is randomly assigned between states. However, as noted by Grogger (2003) and Zhang (2007), policy endogeneity can arise when unobserved time varying state factors affect the timing of electricity market restructuring. For example, when changes in unobserved management practices, resulting in lower (higher) production costs, are positively associated with changes in competition, the coefficient estimates for competition will be biased downwards (upwards). One way to minimize this bias is to use state-specific time trends to decompose from the error term the unobserved state-time components that may be correlated with both efficiency and the market restructuring variables.

The baseline model specification for plant $i = 1, \ldots, n$ in state $s = 1, \ldots, S$ at year $t = 1, \ldots, T$ is:

$$\log EFF_{ist} = \alpha PCOMP_{st} + \beta FCOMP_{st} + W_{is}\delta + X_{ist}\gamma + TREND_{st}\tau + v_s + \eta_t + \varepsilon_{ist} \quad (1)$$

11. Actual competition refers to firm responses to actual entry by new competitors and is typically measured by new entrant's market share or by market concentration. Potential competition refers to plant responses to expected entry and is typically measured by the removal of barriers to entry. By comparing plants in states that implemented restructuring reforms to plants in states that did not, this paper is important to economists and policymakers considering the implementation of restructuring or the lifting of any current suspensions. As such, at this initial stage of the restructuring process, it is not as important where the efficiency gains come from but that they exist and have economic and statistical significance.

12. In Section 4.1 below we also perform a sensitivity analysis that considers three complementary measures of restructuring: access to wholesale markets that permit capacity trading; the mandatory divestiture of generating assets; and the presence of performance based rate regulation.

13. It would be ideal to also work with cost data. While we have some information on firm costs, these are not complete across the sample, and are often interpolated from the characteristics of similar plants. This makes estimation of a stochastic cost frontier problematic. However, we were able to perform frontier estimation with heat rate data from IOUs and a parsimonious model specification with fewer controls. The estimated coefficient on *PCOMP*, $\alpha = -0.009$, is not significantly different from zero, while the estimated coefficient on *FCOMP*, $\beta = -0.120$, is significant at the one percent level. These results, not reported in the paper, are qualitatively similar to those from our baseline specification reported in Table 4.

where EFF is thermal efficiency, W is a vector of time-invariant plant characteristics, X is a vector of time-varying plant characteristics, $TREND$ is a vector of state-specific time trends that control for unobserved state effects that vary through time, the υs are unobserved state fixed effects, the ηs are unobserved time fixed effects and ε is an error.[14]

The parameters of interest $\partial \log EFF/\partial PCOMP = \alpha$ and $\partial \log EFF/\partial FCOMP = \beta$ indicate the percentage differences in efficiency due to partial and full competition, respectively. If the null hypothesis that $\alpha = \beta = 0$ cannot be rejected, this implies that we cannot reject the null hypothesis that market structuring does not affect efficiency. A finding of $\alpha < \beta = 0$ supports the hypothesis that the competitive forces from wholesale markets are sufficient to lower the heat rate and increase thermal efficiency. A finding of $\beta < \alpha = 0$ supports the hypothesis that the competitive forces from both wholesale and retail markets together are required to lower the heat rate and increase thermal efficiency.

An issue we must address when estimating equation (1) concerns attrition bias. Because efficiency is observed for a non-random sample of plants that survive the sample period, it is possible that the estimates of α and β measure the effects from exit by less efficient firms. That is, output moves from "high cost" to "low cost" plants during the sample period and the total inputs required to produce a given level of electricity output decreases (Olley and Pakes, 1996; Disney et al., 2003; Syverson, 2004). We address this potential bias with Heckman and Lee's two-step estimation procedure that estimates the effects on efficiency from market restructuring given the observed, surviving plant was a relatively more efficient generator of electricity to begin with.

For the first-step selection equation, we define the new dependent variable $SURVIVE$, which equals one when the plant survived throughout the sample period and zero when the plant exited the sample and/or reported no observations for continuous years during the sample period. The plant's decision to remain in the market is based on their expected profits:

$$\pi^*_{ist} = Z_{ist}\phi + \varphi FC_{ist} + u_{ist} \qquad (2)$$

where $Z = [PCOMP, FCOMP, W, X, TREND]$, FC is a vector of variables that approximate the fixed costs of electricity generation and u is an error. Although expected profits are not observable to the researcher, it is possible to observe

14. It is also possible to account for the potential bias from non-random assignment of retail market restructuring with instrumental variable (IV) estimation. For instruments, we follow Craig (2009) and use a vector of state-time level variables that approximate interest group pressures and the preferences of policy makers to explain the state legislatures' decision to restructure electricity markets. IV estimates of the efficiency equation, not reported, are similar to those presented in Section 4. Specifically, the IV estimate of the effect of full competition on thermal efficiency is slightly more negative, with a larger standard error, and marginally insignificant for the IOU sample. For municipality-owned plants the coefficient estimate on full competition is more negative, with a larger standard error, and also marginally insignificant.

when the plant provides electricity, with $SURVIVE_{ist} = 1$ if $\pi^*_{ist} > 0$ and $SURVIVE_{ist} = 0$ if $\pi^*_{ist} \leq 0$. The probability that the plant is a survivor is:

$$Prob(\pi^*_{ist} > 0) = Prob(u_{ist} < Z_{ist}\phi + \varphi FC_{ist}) = F(Z_{ist}\phi + \varphi FC_{ist}) \qquad (3)$$

where $F(\cdot)$ is the standard normal distribution function. In the second step, the efficiency for the surviving plants is:

$$\log EFF_{ist} = \alpha PCOMP_{st} + \beta FCOMP_{st} + W_{is}\delta$$
$$+ X_{ist}\gamma + TREND_{st}\tau + \sigma_u \lambda_{ist} + \nu_s + \eta_t + \varepsilon_{ist} \qquad (4)$$

where $\lambda_{ist} = -f(Z_{ist}\hat{\phi} + \hat{\varphi}FC_{ist})/F(Z_{ist}\hat{\phi} + \hat{\varphi}FC_{ist})$ is the inverse mills ratio (*MILLS*), $f(\cdot)$ is the standard normal density function and σ_μ is the covariance between the errors u and ε. By conditioning on λ, equation (4) controls for unobserved selection effects that might otherwise bias the relationship between efficiency and market restructuring. This allows us to assess the extent to which the efficiency gains from market restructuring are driven by changes to production within the plant, or by market selection effects where the inefficient plants exited the market during the sample period.

3. DATA

3.1 Sample

We follow the industry standard and define a plant as a facility that contains prime movers, electric generators, and auxiliary equipment for converting mechanical, and chemical energy into electricity. A prime mover is the engine, turbine, water wheel or similar machine that drives an electric generator or a device that converts energy to electricity directly. Ideally, we would prefer to measure production from the individual generating units within each plant but these data are not publicly available.

Annual data on location, ownership structure and production for 977 steam-cycle plants were sourced from Ventyx Energy.[15] The data are from 1996 to 2006 and represent plants in all 50 states and D.C.; 717 plants are investor owned and 260 are municipality owned. The sample plants are fired by coal, natural gas and/or petroleum and accounted for about 48 percent of total U.S. net generation by all energy sources in 2006, and about 67 percent of total U.S. net generation by coal, natural gas and petroleum (Ventyx Energy, 2007; EIA, 2009).[16]

15. Ventyx Energy (formerly Global Energy Decisions) gathers data from FERC and other reporting services, and packages these data to private and government entities.

16. Total U.S. net generation includes electricity generated by all energy sources; coal, petroleum, natural gas, other gases, nuclear, hydroelectric, other renewables, and by type of producer; electric utilities, independent power producers, electric power, commercial and industrial (EIA, 2009).

Table 2: State Characteristics 1996–2006

	All states	States with partial competition	States with full competition	States with no competition
Variable	Mean	Mean	Mean	Mean
Net generation (1000 MWh)	1,360.8	1,392.9	1,234.8	1,612.6
Area (miles^2)	92,760	62,294	98,519	127,983
Population (millions)	11.1	4.3	17.0	7.7
Population per mile^2	215.1	78.6	342.5	128.5
Median household income ($)	43,269	40,170	45,476	42,948
Republican PUC	0.58	0.41	0.66	0.68
Number of states	51	20	17	14

NOTES: Republican PUC equals one when the majority of state's PUC commissioners are Republican. Partial competition is when a majority of states power producers have access to some form of wholesale market, full competition is when a majority of the states power producers have access to some form of wholesale market, and at least 10 percent of customers have access to their choice of retail provider.
SOURCES: EIA, NARUC (1995, 2001), U.S. Census Bureau (2009), Ventyx Energy (2007).

We merged our plant data with information on the timing of the implementation of market restructuring initiatives across states obtained from the EIA, FERC, the National Energy Affordability and Accessibility Project (NEAAP, 2009), individual RTO websites, and state PUC web sites. Table 2 presents selected characteristics for states with partial competition, full competition, and no competition during the sample period. States with full competition produce less total electricity, have larger populations, greater population densities and higher median income than states with either partial or no competition. States with partial competition have Democrat dominated PUCs, while states with no competition or full competition have Republican dominated PUCs.

3.2 Variables and Summary Statistics

The unit of observation is plant $i = 1, \ldots, n$ in state $s = 1, \ldots, S$ at year $t = 1, \ldots, T$. The outcome variable of interest is thermal efficiency, or, the net heat rate (*EFF*). This is the number of BTUs of fuel used to generate a kWh of electricity that is sent from the generation plant to the grid.[17] The important in-

17. Plant production can be measured in terms of gross generation and net generation. Gross generation comprises all the electricity supplied to the grid, the electricity used by the plant to run equipment, provide lighting, etc. and in some cases, the electricity supplied to a complementary production process, such as steel manufacturing. See Joskow and Schmalensee (1987) for a study of

dependent variables of interest are partial competition (*PCOMP*) and full competition (*FCOMP*).[18] Table 3 provides a detailed description of *EFF*, *PCOMP*, *FCOMP* and all the other variables used in the empirical analysis and their sources.

In order to measure *PCOMP* and *FCOMP* we first identified which states permitted wholesale and retail competition, respectively, and in what years. To determine wholesale competition we visited the FERC website to find out the year that the RTO was founded and the corresponding member states. We then verified this information by checking the individual RTO websites or other online sources, such as press releases and State PUC websites, to see if all states were included on the date indicated by FERC or if states were added at a later date. For example, the website http://www.ferc.gov/market-oversight/mkt-electric/pjm.asp indicated that Pennsylvania is a member of the Pennsylvania-New Jersey-Maryland Interconnection (PJM), an RTO ". . . that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia." Complementary information from PJM's website at http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx indicated that Pennsylvania companies first became part of the PJM in 1927 but that the PJM officially became an RTO in 1997. As such, we measure the year that Pennsylvania implemented wholesale restructuring as 1997 (See column two, row 28 of Table 1). Maine provides another example. The FERC website indicates that Maine has Independent System Operator New England (ISO-NE) membership and that ISO-NE became an RTO in 1997. Corresponding information from the ISO-NE website at http://www.iso-ne.com/aboutiso/co_profile/history/index.html shows that six states have been part of ISO-NE dating back to when it was the New England Power Pool (NEPOOL).[19] Because Maine is one of these six states and the ISO-NE was founded in 1997, we measure the year that Maine permitted wholesale competition as 1997 (See column two, row eleven of Table 1).[20] http://www.eia.gov/cneaf/elec-

the determinants of thermal efficiency based on gross generation. Net generation is the electricity supplied to the grid. "Down time" can result in plants having zero or negative generation. For example, the plant may have to source electricity from the grid when management temporarily closes the plant for maintenance, because of poor market conditions and/or to supply a complementary production process.

18. 17 states permitted retail competition in our sample. Eleven states permitted retail competition following the implementation of wholesale competition, and three just prior to implementing wholesale competition. One state, Illinois, permitted retail competition two years before wholesale competition. For a robustness check, we estimated an alternative specification of the efficiency equation in Table 8 of Section 4 with the additional variable *RCOMP* (equals one when ten percent or more of customers have a choice of two or more electricity providers and no wholesale competition, and zero otherwise) to account for the four states with retail competition only for a short period of time. The results are qualitatively similar to those from our baseline specification reported in Table 6.

19. NEPOOL was formed in 1991 by investor- and municipality-owned plants to help organize and coordinate the power grid for the six states that are now members of ISO-NE.

20. For our baseline efficiency equation, we coded $PCOMP = 1$ for Kentucky, Louisiana, Mississippi, New Mexico and Tennessee even though these states have only a small part of their territory served by an RTO. For robustness, we also estimated the efficiency equation with $PCOMP = 0$ for

Table 3: Variable Descriptions

Variable	Description
EFF	Number of BTUs of fuel used to generate a kWh of electricity that is sent from the generation plant to the grid. Source: Ventyx Energy (2007).
PCOMP	One when the plant is located in a state where utilities have access to wholesale electricity market places through an RTO, and zero otherwise. Source: EIA, FERC, NARUC (2009); NEAAP (2009); State PUC web sites.
FCOMP	One when the plant is located in a state where utilities have access to wholesale electricity market places through an RTO and at least ten percent of customers have a choice between two or more retailers of electricity, and zero otherwise. Source: EIA, FERC, NARUC (2009); NEAAP (2009); State PUC web sites.
CAPACITY	Maximum sustainable amount of thousands of MWh of electricity generated per hour. Source: Ventyx Energy (2007).
UNITS	Number of turbines within the plant. Source: Ventyx Energy (2007).
MULTI PLANT	One when the plant is owned by a firm that has acquired more than one plant and brought them under the umbrella of a single corporate entity and zero otherwise. Source: Ventyx Energy (2007).
ZERO OUTPUT	One when the plant had zero net generation of electricity for any month during the year and zero otherwise. Source: Ventyx Energy (2007).
NEG OUTPUT	One when the plant had negative net generation of electricity for any month during the year and zero otherwise. Source: Ventyx Energy (2007).
AGE	t minus the year of initial operation divided by 100. Source: Ventyx Energy (2007).
MULTI PRIME	One when the plant has more than one type of prime mover for generating electricity. Source: Ventyx Energy (2007).
COMB GAS	One when the prime mover is a combined gas plus waste turbine and zero otherwise. Source: Ventyx Energy (2007).
GAS	One when the prime mover is a combustion gas turbine, including jet engine design, and zero otherwise. Source: Ventyx Energy (2007).
PETROL	One when the prime mover is an internal combustion turbine, including diesel and piston design, and zero otherwise. Source: Ventyx Energy (2007).
COAL	One when the prime mover is an integrated coal gasification combined cycle turbine or a condensing steam turbine and zero otherwise. Source: Ventyx Energy (2007).
SURVIVE	One when the plant survived throughout the sample period and zero when the plant exited the sample and/or reported no observations for continuous years during the sample period. Source: Ventyx Energy (2007).

(continued)

Table 3: Variable Descriptions *(continued)*

Variable	Description
FIXED COSTS	Total fixed costs (million $). Source: Ventyx Energy (2007).
PBR	One when the plant was located in a state with current performance based regulation and zero otherwise. Source: Sappington et al. (2001), state PUC web sites (2009) and through personal correspondence with state PUCs (2009)
CAPACITY MARKET	One when the plant is located in a state that is a member of ISO-NE, NYISO or PJM, and zero otherwise. Source: NARUC (2009); NEAAP (2009); State PUC web sites.
YEARS PCOMP	Zero for the year in which utilities in the state first had access to wholesale electricity market places through an RTO, and increasing by one for each additional year that this reform was active. Source: NARUC (2009); NEAAP (2009); State PUC web sites.
YEARS FCOMP	Zero for the year in which utilities in the state first had access to wholesale electricity market places through an RTO and at least ten percent of customers had a choice between two or more retailers of electricity, and increasing by one for each additional year that these reforms were active. Source: NARUC (2009); NEAAP (2009); State PUC web sites.
DIVESTITURE	Percentage of a state's generating assets that had been divested. Source: NARUC (2009); NEAAP (2009); State PUC web sites.
RCOMP	One when ten percent or more of customers have a choice of two or more electricity retailers but utilities in the state had no access to wholesale electricity market places through an RTO, and zero otherwise. Source: EIA, FERC, NARUC (2009); NEAAP (2009); State PUC web sites.
FCOMP_PERCENT	Percentage of residential customers with a choice of two or more electricity retailers in states where utilities have access to wholesale electricity market places through an RTO and customers have a choice between two or more retailers of electricity. Source: EIA, FERC, NARUC (2009); NEAAP (2009); State PUC web sites.

tricity/page/restructuring/restructure_elect.html to find out which states have implemented retail choice. From this website, we then click through to individual states to find out if retail choice is active or suspended, and for additional information to determine when at least ten percent of customers within the state could

these five states. For investor-owned plants, the estimated coefficient on *PCOMP*, $\alpha = -0.041$, is not significantly different from zero, while the estimated coefficient on *FCOMP*, $\beta = -0.097$, is significant at the five percent level. For municipality-owned plants, the estimated coefficient on *PCOMP*, $\alpha = -0.065$, is not significantly different from zero, while the estimated coefficient on *FCOMP*, $\beta = -0.098$, is significant at the five percent level. These results, not reported in the paper, are qualitatively similar to those from our baseline specification reported in Table 6.

choose among alternative retailers of electricity. For example, the EIA website shows that customers in Pennsylvania have retail choice. We then click through to the individual profile for Pennsylvania and observe that in January 1999, retail choice was available to two thirds of their customers. As such, we measure the year that Pennsylvania permitted retail competition as 1999 (See column four, row 28 of Table 1). By following similar steps, we observe that at least ten percent of customers in Maine had retail choice by March, 2000 (See column four, row eleven of Table 1). Given these measurements of wholesale and retail competition, for Pennsylvania we code $PCOMP = 1$ for 1997 through 2006, and zero otherwise, and code $FCOMP = 1$ for 1999 through 2006, and zero otherwise. For Maine, we code $PCOMP = 1$ for 1997 through 2006 and zero otherwise, and code $FCOMP = 1$ for 2000 through 2006, and zero otherwise.

Some states delayed retail competition and eventually suspended it. For example, the EIA lists Arkansas' retail restructuring as suspended and when we click through to the individual state information we observe that Arkansas eventually discontinued competition initiatives in February, 2003. As such, for Arkansas, we code $PCOMP = 1$ for 2004 through 2006, and zero otherwise, and code $FCOMP = 0$ for 1996 through 2006. Similarly, the EIA website also lists Virginia's retail restructuring as suspended. When we click through to the individual state information, we see that over ten percent of customers had retail choice by the end of 2002, but that retail restructuring was suspended in February, 2007. As such we code $PCOMP = 1$ for 2002 through 2006, and zero otherwise, and code $FCOMP = 1$ for 2002 through 2006, and zero otherwise.

The vector of time-invariant plant characteristics, *W*, describes the prime movers used to generate electricity. The vector includes: *COMB GAS* (equals one when the prime mover is a combined gas plus waste turbine and zero otherwise); *GAS* (equals one when the prime mover is a combustion gas turbine, including jet engine design, and zero otherwise); *PETROL* (equals one when the prime mover is an internal combustion turbine, including diesel and piston design, and zero otherwise); and *COAL* (equals one when the prime mover is an integrated coal gasification combined cycle turbine or a condensing steam turbine and zero otherwise). For brevity we collapsed the original six generation technologies described in the data into the aforementioned four indicator variables.[21]

The vector *X* contains time-varying plant characteristics that may affect efficiency. *CAPACITY* (maximum sustainable amount of thousands of MWh of electricity generated per hour by the plant)[22] and *UNITS* (number of turbines within the plant) measure the potential for economies of scale. *MULTI PLANT* (equals one when the plant is owned by a firm that has acquired more than one plant and brought them under the umbrella of a single corporate entity and zero

21. Estimates of equation (1) with the original six technology indicator variables, not reported, are similar to those presented in Section 4.

22. This is calculated during summer months when electricity generation is at a maximum and, as such, is a reasonably good proxy for capital input.

otherwise) measures potential economies of scope. *ZERO OUTPUT* (equals one when the plant had zero net generation of electricity for any month during the year) and *NEG OUTPUT* (equals one when the plant had negative net generation of electricity for any month during the year) control for down time.[23] *AGE* (equals t minus the year of initial operation divided by 100) and AGE^2 control for changes in operating efficiency through time due to plant vintage. Because of coordination problems, efficiency may be lower in plants with several different types of prime movers. As such, *MULTI PRIME* (equals one when the plant has more than one type of prime mover for generating electricity) is included to control for plant heterogeneity.

TREND is a vector of state-specific time trends. For the linear specification of *TREND*, $TREND_{1st}$ is one for state one at 1996, two for state one at 1997,..., eleven for state one at 2006, and zero otherwise. Similarly, $TREND_{2st}$ is one for state two at 1996, two for state two at 1997,..., eleven for state two at 2006, and zero otherwise.

In summary, the gross sample comprises of 8,923 plant-year observations for investor-owned utilities and 3,119 plant-year observations for municipality-owned utilities from 1996 to 2006. Because of missing data due to plant exit or because some firms did not report operating information for certain years, the net sample comprises of 7,454 plant-year observations for investor-owned utilities and 2,416 plant-year observations for municipality-owned utilities.[24] Table 4 presents summary statistics for the investor-owned plants in the net sample. The data show that the average investor-owned plant is about 44 years old, has 3.7 turbines with an overall capacity of about 450 MWh, and uses 142,930 BTUs of fuel to generate a kWh of electricity.[25] About 20 to 30 percent of investor-owned plant-year observations had a month or more in a given year with zero or negative generation respectively, indicating a temporary shutdown. Over 80 percent of the investor-owned plant-year observations are multi-plant observations, which indicate a prevalence of horizontally-integrated firms in U.S. electricity generation. Table 5 presents summary statistics for the municipality-owned plants in the net sample.

4. RESULTS

The empirical model and data are used to examine the effects of market restructuring initiatives that introduced competition into electricity markets on the

23. This effect can run either way. Plant efficiency can increase when downtime is used for maintenance programs. However, efficient plants are often selected for downtime because it is less costly to shut them down and start them up again.

24. The additional observations from the gross sample are used for robustness checks for attrition bias in Section 4.

25. There are 15 observations with values for *EFF* that are below the lowest possible heat rate of 3,412.3 and, as such, violate the first law of thermodynamics. These values are most likely due to reporting or recording error. Estimates of the efficiency equation without these 15 observations, not reported, are similar to those presented in Section 4.

Table 4: Summary Statistics: Investor-owned Plants

Variable	Mean	S.D.	Min	Max
EFF	11910.85	19637.34	165	1133333
PCOMP	0.49	0.47	0	1
FCOMP	0.26	0.44	0	1
CAPACITY	0.45	0.43	0.00	2.60
UNITS	3.67	2.45	1	32
MULTI PLANT	0.87	0.34	0	1
ZERO OUTPUT	0.20	0.40	0	1
NEG OUTPUT	0.32	0.47	0	1
AGE	0.44	0.19	0	1.06
MULTI PRIME	0.48	0.49	0	1
FIXED COSTS	12.71	16.30	–4.43	307

NOTES: Number of observations is 7,454. S.D. is standard deviation.

Table 5: Summary Statistics: Municipality-owned Plants

Variable	Mean	S.D.	Min	Max
EFF	1182.22	6610.43	316.25	96799.60
PCOMP	0.40	0.49	0	1
FCOMP	0.14	0.35	0	1
CAPACITY	0.23	0.28	0.00	1.80
UNITS	3.22	1.97	1	8
MULTI PLANT	0.70	0.46	0	1
ZERO OUTPUT	0.23	0.42	0	1
NEG OUTPUT	0.36	0.48	0	1
AGE	0.38	0.17	0	1.06
MULTI PRIME	0.42	0.49	0	1
FIXED COSTS	7.61	10.91	–0.19	115

NOTES: Number of observations is 2,416. S.D. is standard deviation.

thermal efficiency of generation plants. We estimate the baseline model of the efficiency equation for investor- and municipality-owned plants. We then estimate a selection model that controls for attrition bias, and also re-estimate the efficiency equation for subsamples of natural gas-, petroleum-, and coal-fired plants.

Because our observations represent plants in geographic markets, it is possible that there are shocks or unobservables that are common or correlated across nearby markets. While this does not affect the consistency of our estimator, it does impact the standard error. To address this issue, we allow correlations in the residuals across plants in the same state when computing these standard errors. This is reasonable, for example, if some unobservable characteristics of plant efficiency are determined at the state level.

4.1 Investor-owned Plants

Ordinary Least Squares (OLS) estimates of the efficiency equation for investor-owned plants are presented in Table 6. Column one presents the baseline specification where we regress plant efficiency (log*EFF*) on partial competition (*PCOMP*), full competition (*FCOMP*), the vector of time-invariant plant characteristics (*W*), the vector of time-varying plant characteristics (*X*), state-specific linear time trends, and state and time fixed effects.[26] The model is reasonably well specified; the coefficients on many of the important control variables have plausible signs and magnitudes. The estimated coefficient on *CAPACITY* is negative and is not statistically significant, and the coefficient on $CAPACITY^2$ is positive and again not statistically significant. However, the estimated coefficient on *UNITS* is positive and statistically significant which, holding *CAPACITY* constant indicates that an increase in the number of turbines used within the plant decreases thermal efficiency. Both of the coefficients on *ZERO OUTPUT* and *NEG OUTPUT* are negative and significant, and suggest that down time is used for maintenance programs that increase plant efficiency. The estimated coefficients on *AGE* and AGE^2 indicate that older plants are relatively more efficient which is not altogether surprising given that older plants have, by definition, survived longer because they are relatively good at generating electricity. The estimated coefficient on *MULTI PRIME* is negative and significant. Holding *CAPACITY* and *UNITS* constant, this result indicates that it is more efficient for the plant to have different types of multiple prime movers (*e.g.*, gas, petroleum, coal, *etc.*) rather than the same type of multiple prime movers.

The important parameters of interest in the baseline model, α and β, are both negative, but the estimate of α is not statistically different from zero. The estimated coefficient on *FCOMP*, $\beta = -0.0891$, is significantly different from zero at the five percent level and indicates that market restructuring is associated with an increase in the thermal efficiency of investor-owned plants of about nine percent. The finding of $\alpha = 0$ and $\beta < 0$ supports the hypothesis that it is the com-

26. We follow Ziliak et al. (2000) and Grogger (2003) by estimating the efficiency equation with linear time trends and then with log-linear time trends. For the log-linear specification of *TREND*, $TREND_{1st}$ is log one for state one at 1996, log two for state one at 1997,..., log eleven for state one at 2006, and zero otherwise. Similarly, $TREND_{2st}$ is log one for state two at 1996, log two for state two at 1997,..., log eleven for state two at 2006, and zero otherwise. The Akaike Information Criterion and Bayesian Information Criterion indicate that the inclusion of linear time trends was more appropriate.

Table 6: Estimates of Efficiency Equation

	IOU	IOU	IOU	MUNI	MUNI	MUNI
	Baseline Efficiency Equation	First Step Selection Equation	Second Step Efficiency Equation	Baseline Efficiency Equation	First Step Selection Equation	Second Step Efficiency Equation
PCOMP	−0.0426 [−1.319]	−0.0138 [−0.020]	−0.0380 [−1.07]	−0.0338 [−0.875]	−0.1725 [−1.110]	−0.0316 [−0.750]
FCOMP	−0.0891** [−2.318]	−0.0843** [−2.390]	−0.0948** [−2.33]	−0.0928*** [−2.956]	−0.6870 [−1.330]	−0.0857** [−2.640]
CAPACITY	−0.0693 [−0.944]	5.7877*** [5.200]	−0.1051 [−1.15]	−0.2844 [−1.446]	1.8750 [0.610]	−0.3487** [−2.340]
CAPACITY^2	0.0081 [0.239]	−2.5500 [−5.550]	−2.1700 [0.520]	0.0988 [0.804]	−4.1800 [−1.520]	1.5500 [1.710]
UNITS	0.0120** [2.544]	−.0540** [−2.430]	0.0101** [2.150]	0.0181 [1.341]	−0.0408 [−0.490]	0.0172 [1.13]
MULTI PLANT	−0.0123 [−0.471]	0.5384** [2.53]	−0.0164 [−0.590]	−0.0056 [−0.147]	−0.0859 [−0.350]	−0.0259 [−0.680]
ZERO OUTPUT	−0.1532*** [−4.547]	−0.1766 [−0.93]	−0.1311*** [−4.190]	−0.1573*** [−3.127]	−0.3239 [−0.990]	−0.2020*** [−4.120]
NEG OUTPUT	−0.1899*** [−5.649]	0.0442 [0.020]	−0.2137*** [−6.97]	−0.1984*** [−3.320]	0.6555** [1.97]	−0.1873** [−2.78]
AGE	0.3088 [1.379]	1.4316 [1.300]	0.3474 [1.41]	−0.0558 [−0.249]	−1.8221 [−0.740]	−0.1064 [−0.460]
AGE^2	−0.3324* [−1.876]	−0.5995 [−0.55]	−0.3767* [−1.98]	−0.2160 [−0.761]	1.1670 [0.500]	−0.1721 [−0.580]
MULTI PRIME	−0.0485*** [−2.777]	1.2450*** [4.77]	−0.0667*** [−2.79]	−0.0036 [−0.079]	−0.2938 [−0.960]	−0.0126 [−0.280]

(continued)

Table 6: Estimates of Efficiency Equation *(continued)*

	IOU	IOU	IOU	MUNI	MUNI	MUNI
	Baseline Efficiency Equation	First Step Selection Equation	Second Step Efficiency Equation	Baseline Efficiency Equation	First Step Selection Equation	Second Step Efficiency Equation
MILLS			0.0622 [0.079]			0.0132 [0.180]
FIXED COSTS		1.44 [0.0511]			0.4727*** [4.42]	
FIXED COSTS^2		−0.0003* [−1.650]			−0.0044* [−1.73]	
CONSTANT	11.4327*** [107.522]	−3.9237*** [−5.330]	8.990*** [69.740]	8.9234*** [114.524]	0.4346 [0.580]	8.9596*** [110.430]
$\chi^2(2)$		13.50***			19.67***	
Plant prime mover fixed effects	Yes	Yes	Yes	Yes	Yes	Yes
Year fixed effects	Yes	Yes	Yes	Yes	Yes	Yes
State fixed effects	Yes	Yes	Yes	Yes	Yes	Yes
State-specific linear time trends	Yes	Yes	Yes	Yes	Yes	Yes
Observations	7,454	8,092	6,623	2,416	2,621	1,943
R-squared	0.163		0.168	0.181		0.169
Pseudo R-squared		0.486			0.534	

NOTES. Dependent variable is log*EFF*. *** significant at the 0.01 level;** significant at the 0.05 level; * significant at the 0.1 level; *t* statistics are reported in brackets. Estimates of fixed effects and time trends not reported. χ^2 tests the hypothesis that the estimated coefficients for *FIXED COSTS* and *FIXED COSTS*^{2} in the first-step selection model are jointly equal to zero.

petitive forces from both wholesale and retail markets together that lower the heat rate and increase thermal efficiency.[27,28]

Our gross sample contains 638 additional plant-year observations for investor-owned plants that did not report operating data during the sample period. Because these excluded firms likely exited the market or failed to report operating data because of poor market performance or mergers, the estimates of the effects from competition for the surviving plants in column two of Table 6 may be biased downwards. As a robustness check, we re-estimate the efficiency equation with Heckman and Lee's two-step estimation procedure for the gross sample of 8,092 surviving and exiting plant-year observations. For identification, we use *FIXED COSTS* (total fixed costs of the plant in millions of dollars) and *FIXED COSTS*^{2} as the excluded instruments in the first-step selection equation. All other things being equal, survival should be more likely for larger plants with larger fixed costs (Hall, 1987; Cabral, 1995). However, fixed costs should not directly impact plant efficiency.

Column two and column three of Table 6 present two-step estimates of plant efficiency.[29] We first note in column two that the coefficients on the excluded instruments in the selection equation, *FIXED COSTS* and *FIXED COSTS*^{2}, have the expected signs and are reasonably precisely estimated. A χ^2-test ($\chi^2(2) = 13.50$; Prob $> \chi^2 = 0.00$) rejects the hypothesis that the estimated coefficients for *FIXED COSTS* and *FIXED COSTS*^{2} are jointly equal to zero. All other things being equal, survival into the net sample is more probable for firms with

27. Because most states implemented wholesale competition before retail competition, it is possible that the estimate of β is predominantly measuring more experience with wholesale competition. To investigate this possibility, a new variable *YEARS PCOMP* (i.e., the number of years since the implementation of partial competition) was added to the efficiency equation. The estimated coefficient on *YEARS PCOMP* is not statistically significant from zero, and all other coefficient estimates are qualitatively similar to those reported in Table 6 and Table 7. Similar results are also obtained when *YEARS FCOMP* (i.e., the number of years since the implementation of full competition) was added to the efficiency equation. These results indicate that the average effect of *FCOMP* is the same regardless of the number of years since implementation.

28. For robustness, we also estimated the efficiency equation on the sub sample of states without retail competition and tested the efficiency effects from wholesale competition only. The estimated coefficient on *PCOMP*, $\alpha = -0.0426$, is not significantly different from zero and implies that we cannot reject the null that wholesale competition does not affect thermal efficiency of investor-owned plants. A similar finding is also found for municipality-owned plants where the estimated coefficient on *PCOMP*, $\alpha = -0.0245$, is not significantly different from zero. These results, not reported here, are consistent with the findings from Table 6 that show that access to wholesale markets alone has no significant impact on plant efficiency.

29. We initially estimated the two-step model on the gross sample of 8,923 plants for all states. In the first step, the state indicator variables for Connecticut, Delaware, Kansas, Montana, Rhode Island, South Carolina, Utah, West Virginia, and D.C. predicted success perfectly and were dropped from the probit model, along with their corresponding 831 observations. As such, we estimated the first-step probit model without these states on the smaller sample of 8,092 observations. We then estimate the second-step price efficiency equation on the reduced sample of 6,623 observations for surviving plants and report these results as a test for potential selection bias.

large fixed costs. The estimated coefficient on the selection term, *MILLS*, is not statistically different from zero and suggests there is no problem with attrition bias. Moreover, as expected, the estimated coefficient on *FCOMP* of $\beta = -0.0948$ is similar to the single-equation OLS estimates reported in column one. Overall, the two-step results suggest that efficiency gains from competition stem from internal organizational and technological changes within the plant, and are not due to the attrition of inefficient plants from the sample over time.

We now examine whether the competitive effects from market restructuring are different for plants with different fuel sources.[30] Table 7 reports estimates of efficiency for subsamples of gas, petroleum and coal plants. The estimated coefficient on *FCOMP* for the gas subsample, $\beta = -0.1023$, is reported in column one and is marginally insignificant at the ten percent level. The estimated coefficient on *FCOMP* for the coal subsample, $\beta = -0.0794$, is reported in column three and is significant at the five percent level. These results suggest that the efficiency gains from full competition are most prominent for gas and coal-fired plants.

4.2 Municipality-owned Plants

Policy makers and regulators aimed the competitive initiatives from market restructuring squarely at investor-owned plants. However, it is possible that the efficiency gains from market restructuring indirectly spill over to non-restructured, publically-owned utilities. To test for potential spillover effects, we estimate the efficiency equation for all the municipality-owned plants in our sample. Column four through Column six of Table 6 show that the overall pattern of results is very similar to those for investor-owned plants. All other things held constant, municipality-owned plants in states with both wholesale and retail competition are about nine percent more efficient than plants located in states without full competition. In addition, as shown in column four through column six of Table 7, the efficiency gains from restructuring are also most apparent in municipality-owned, gas- and coal-fired plants.[31]

4.3 Sensitivity Analysis

We conclude this section with some additional analysis that examines the sensitivity of our key findings to several additional or alternative measures of market restructuring. These measures include:

30. Chow tests rejected the equality of the estimated coefficients in the efficiency equation between oil, gas and coal investor-owned plants ($F(116, 7338) = 8.19$; $Prob > F = 0.00$), and for municipality owned plants ($F(116, 2300) = 3.33$; $Prob > F = 0.00$).

31. Because they predicted success perfectly, several state indicators were dropped from the probit model, along with their corresponding 831 observations. As was the case for investor-owned plants, we estimated the first-step probit model without these states on the smaller sample of 2,621 observations. We then estimate the second-step price efficiency equation on the reduced sample of 1,943 observations for surviving plants and report these results as a test for potential selection bias.

Table 7: Efficiency Estimates for Investor-owned and Municipality-owned Gas, Petroleum and Coal Fired Plants

	IOU Efficiency Equation	IOU Efficiency Equation	IOU Efficiency Equation	MUNI Efficiency Equation	MUNI Efficiency Equation	MUNI Efficiency Equation
	Gas	Petroleum	Coal	Gas	Petroleum	Coal
PCOMP	−0.1060 [−1.594]	0.1992 [0.614]	−0.0263 [−1.140]	−0.0991 [−0.992]	−0.6766 [−1.222]	0.0118 [0.421]
FCOMP	−0.1023 [−1.529]	−0.1803 [−0.623]	−0.0794** [−2.470]	−0.1016* [−1.947]	0.6626 [0.971]	−0.0845*** [−3.142]
CAPACITY	−0.0668 [−0.294]	0.3970 [0.833]	−0.1477** [−2.278]	−0.3472 [−0.450]	25.9426 [0.649]	−0.2626 [−1.274]
CAPACITY^2	0.0169 [0.105]	−0.4379 [−1.494]	0.0391 [1.526]	0.6269 [0.683]	−486.3621 [−0.997]	0.0906 [0.681]
UNITS	0.0102 [1.519]	0.0045 [0.066]	0.0167 [1.058]	−0.0145 [−0.495]	0.3019*** [12.332]	0.0280** [2.339]
MULTI PLANT	−0.0200 [−0.365]	0.1403 [0.848]	−0.0260 [−1.198]	0.0597 [0.800]	−0.0865 [−0.811]	−0.0506 [−0.986]
ZERO OUTPUT	−0.1462** [−2.664]	−0.1659 [−1.173]	−0.1037*** [−2.934]	−0.1231 [−1.295]	0.3138 [1.303]	−0.2604*** [−5.162]
NEG OUTPUT	−0.1978*** [−3.574]	−0.0909 [−0.637]	−0.1902*** [−5.537]	−0.1195 [−1.542]	−0.4284 [−1.643]	−0.1853*** [−3.148]
AGE	0.4288 [1.289]	1.2868 [0.838]	0.2494 [0.719]	−0.9054 [−1.341]	−33.9412 [−1.742]	0.2464 [0.583]

(continued)

Table 7: Efficiency Estimates for Investor-owned and Municipality-owned Gas, Petroleum and Coal Fired Plants *(continued)*

	IOU Efficiency Equation	IOU Efficiency Equation	IOU Efficiency Equation	MUNI Efficiency Equation	MUNI Efficiency Equation	MUNI Efficiency Equation
	Gas	Petroleum	Coal	Gas	Petroleum	Coal
AGE^2	−0.2994 [−1.187]	−2.1877* [−2.013]	−0.3280 [−1.081]	0.8409 [1.282]	33.6150 [1.516]	−0.6007 [−1.165]
MULTI PRIME	−0.0741 [−1.526]	0.2121* [1.926]	−0.0590** [−2.666]	0.0358 [0.349]	−0.2351 [−0.862]	−0.0212 [−0.722]
CONSTANT	11.3091*** [60.933]	9.0737*** [5.341]	11.7327*** [167.707]	9.1961*** [48.556]	20.7913*** [4.108]	8.9684*** [123.013]
Plant prime mover fixed effects	Yes	Yes	Yes	Yes	Yes	Yes
Year fixed effects	Yes	Yes	Yes	Yes	Yes	Yes
State fixed effects	Yes	Yes	Yes	Yes	Yes	Yes
State specific linear time trends	Yes	Yes	Yes	Yes	Yes	Yes
Observations	2,748	392	4,314	841	83	1,492
R-squared	0.185	0.344	0.194	0.242	0.711	0.286

Notes: Dependent variable is log*EFF*. *** significant at the 0.01 level;** significant at the 0.05 level; * significant at the 0.1 level; *t* statistics are reported in brackets. Estimates of fixed effects and time trends not reported.

- *CAPACITY MARKET*, which equals one when the plant is located in a state that is a member of ISO-NE, NYISO or PJM and zero otherwise, to control for wholesale markets that permit capacity trading;[32]
- *DIVESTITURE*, which equals the percent of the state's major electricity provider's generating assets that had been divested or sold off, to control for states that required some retailers to divest their generation facilities;[33]
- *PBR*, which equals one when the plant was located in a state with current performance-based regulation and zero otherwise, to control for states that implemented performance based regulations, such as a price cap or profit-sharing agreement, when restructuring electricity markets;
- *RCOMP*, which equals one when ten percent or more of customers have a choice of two or more electricity retailers and no wholesale restructuring, and zero otherwise, to control for states that implemented retail choice prior to wholesale competition; and
- *FCOMP_PERCENT*, which equals the percentage of residential customers in a state with a choice of two or more retailers in states with both wholesale and retail competition and zero otherwise, as alternative to the ten percent threshold.

Because of market imperfections that led to higher prices and blackouts in California during 2000 and 2001, we also estimate the model on the subsample of data that excludes California plants.

Table 8 summarizes the results from the sensitivity analysis for investor- and municipality-owned utilities. Overall, the findings are similar to those reported in Table 6 and Table 7. The estimated coefficient on *PCOMP* ranges from −0.014 to −0.062 across the alternative specifications and is not precisely estimated. In contrast, the estimated coefficient on *FCOMP* ranges from −0.076 to −0.135, is always larger in absolute terms than the estimated coefficient on *PCOMP*, and is more precisely estimated. In summary, all other things held constant, investor- and municipality-owned plants in states with both wholesale and retail competition are about eight to 13 percent more efficient than plants located in states without full competition.

5. ENVIRONMENTAL BENEFITS

The National Archives and Records Association (1998) estimates that the generation, transmission, and distribution of electricity accounts for about 30

32. Capacity markets are markets where generators of electricity can sell their capacity to retail suppliers. The retail suppliers can then claim this capacity when they need it for a set price often times close to the variable cost of producing the electricity.

33. This particular form of restructuring is unlikely to affect IOUs, especially when paired with other restructuring initiatives. However, generating assets that continue to be municipality owned may feel pressure to improve efficiency or they too may be divested.

Table 8: Sensitivity Analysis

Description	Plant Type	R-squared	Partial competition	Full competition
The variable *CAPACITY MARKET* which equals one when the plant is located in a state that is a member of ISO-NE, NYISO or PJM and zero otherwise, to control for wholesale markets that permit capacity trading is added to the efficiency equation.	IOU	0.163	−0.0529 [−1.370]	−0.0908** [−2.349]
The variable *DIVESTITURE* ranging from zero to one indicating the percent of a state's generating assets that had been divested is added to the efficiency equation.	IOU	0.163	−0.0405 [−1.314]	−0.0845** [−2.037]
The variable *PBR* which is one when the plant was located in a state with current performance based regulation and zero otherwise is added to the efficiency equation	IOU	0.163	−0.0531 [−1.340]	−0.0899** [−2.663]
The variable *RCOMP* which is one when ten percent or more of customers have a choice of two or more electricity retailers and no wholesale restructuring, and zero otherwise is added to the efficiency equation	0.163	−0.0547* [−1.748]	−0.1086*** [−3.105]	
The variable *FCOMP_PERCENT* which is the percentage of residential customers with a choice of two or more retailers in states with both wholesale and retail competition and zero otherwise is used in place of *FCOMP*.	IOU	0.163	−0.0481* [−1.858]	−0.1352*** [−4.476]
When California is excluded from the sample.	IOU	0.164	−0.0269 [−0.734]	−0.0837 [−1.650]
The variable *CAPACITY MARKET* which equals one when the plant is located in a state that is a member of ISO-NE, NYISO or PJM and zero otherwise, to control for wholesale markets that permit capacity trading is added to the efficiency equation.	MUNI	0.181	−0.0624* [−1.790]	−0.1062*** [−3.585]

(continued)

Table 8: Sensitivity Analysis *(continued)*

Description	Plant Type	R-squared	Partial competition	Full competition
The variable *DIVESTITURE* ranging from zero to one indicating the percent of a state's generating assets that had been divested is added to the efficiency equation.	MUNI	0.181	−0.0138 [−0.360]	−0.0759*** [−3.966]
The variable *PBR* which is one when the plant was located in a state with current performance based regulation and zero otherwise is added to the efficiency equation	MUNI	0.181	−0.0622* [−1.817]	−0.1072*** [−3.546]
The variable *RCOMP* which is one when ten percent or more of customers have a choice of two or more electricity retailers and no wholesale restructuring, and zero otherwise is added to the efficiency equation	MUNI	0.181	−0.0365 [−0.944]	−0.0998*** [−3.234]
The variable *FCOMP_PERCENT* which is the percentage of residential customers with a choice of two or more retailers in states with both wholesale and retail competition and zero otherwise is used in place of *FCOMP*.	MUNI	0.181	−0.0369 [−0.965]	−0.0976* [−1.819]
When California is excluded from the sample.	MUNI	0.180	−0.0353 [−0.928]	−0.0913 [−1.496]

NOTES: Dependent variable is logEFF. *** significant at the 0.01 level;** significant at the 0.05 level; * significant at the 0.1 level; *t* statistics are reported in brackets. There are 7,454 observations for all IOU specifications except for when California is excluded from the sample when there are 7,162. There are 2,416 observations for all MUNI specifications except for when California is excluded from the sample when there are 2,210.

percent of U.S. annual greenhouse emissions.[34] Because we have a direct estimate of increased thermal efficiency, a natural question arising from our empirical findings above is how much carbon dioxide was abated due to the efficiency gains from electricity market restructuring?

In 2006, 291 of our IOU sample plants were located in states that had restructured electricity markets, producing approximately 524 million MWh of net generation. Applying our estimate of $\beta = -0.0891$ from column one in Table 6 to fuel savings means that enough fuel was saved to generate about 47 million MWh of electricity. The EIA estimates that one MWh of electricity produces 1341 lbs. of carbon dioxide for the average fossil fuel electricity generating plants and 2095 lbs of carbon dioxide for the average coal electricity generating plant.[35] Because most of the efficiency savings in our sample were achieved by plants using coal as their primary input, we will use the coal estimate of pollution as an upper bound, and the fossil fuels number as our lower bound for carbon dioxide emission reductions. Using our estimate of fuel savings equivalent to 47 million MWh translates to 32 to 49 million tons of carbon dioxide abated using our estimates from the EIA study mentioned previously.[36] To translate this to a more tangible savings we use a market value of $11.45 per ton for carbon dioxide under cap and trade to construct a dollar value of the reduction in carbon dioxide from market restructuring.[37] Using this estimate, market restructuring is associated with a reduction in carbon dioxide valued between $361 million and $564 million for 2006.

6. CONCLUSIONS

This paper examined the effects of market restructuring that introduced competition into the United States electricity industry on the thermal efficiency of electricity generation. An empirical model was estimated on annual data for over 950 plants from 1996 to 2006. Model estimates show that both wholesale and retail competition together increased the efficiency of investor-owned plants by about nine percent. These gains stem from organizational and technological changes within the plant, and are not due to the attrition of inefficient firms. Additionally, the gains are most precisely estimated when working with the subset of coal-fired plants indicating much of the efficiency gains come through this subset. Although not directly targeted by restructuring initiatives, we also find similar efficiency effects for municipality-owned plants. This result suggests that the benefits from restructuring have spilled over to public electricity generation.

34. http://clinton4.nara.gov/Initiatives/Climate/electric.html.

35. From a EIA study conducted in 1998–1999. http://www.eia.doe.gov/cneaf/electricity/page/co2_report/co2report.html

36. Davis and Wolfram (2010) find that electricity deregulation and consolidation are associated with an annual decrease of 40 million metric tons of carbon dioxide emissions.

37. International Emissions Trading Association report prepared for the World Bank in May of 2006 http://www.ieta.org/ieta/www/pages/getfile.php?docID = 1667

These results are interesting because they imply that wholesale and retail competition together are important for maximizing efficiency gains in electricity generation. Moreover, market restructuring became less popular following the price increases and black outs in California in 2000 and 2001, and many states decided to delay or suspend restructuring. All other things held constant, our results imply that market restructuring is associated with environmental benefits from the 30 to 50 million ton decrease in carbon dioxide emissions over the sample period. The public power sector has also opposed restructuring (Kwoka, 2008). Our results suggest that the efficiency gains from restructuring may have spilled over to the non-restructured, public power sector. This implies that restructuring is good for consumers and society, but perhaps not so good for public power executives who have to work more efficiently.

Finally, by comparing plants in states that permitted competition to plants in states that did not, this paper is important to economists and policymakers considering the implementation of restructuring initiatives or the lifting of any current suspensions. When competition evolves and more firm-specific data becomes available, future work may want to consider using entrants' market share and/or market concentration to estimate the separate efficiency effects from potential versus actual competition.

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THE U.S. ELECTRICITY INDUSTRY AFTER 20 YEARS OF RESTRUCTURING

Severin Borenstein
James Bushnell

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The U.S. Electricity Industry After 20 Years of Restructuring
Severin Borenstein and James Bushnell
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ABSTRACT

Prior to the 1990s, most electricity customers in the U.S. were served by regulated, vertically-integrated, monopoly utilities that handled electricity generation, transmission, local distribution and billing/collections. Regulators set retail electricity prices to allow the utility to recover its prudently incurred costs, a process known as cost-of-service regulation. During the 1990s, this model was disrupted in many states by "electricity restructuring," a term used to describe legal changes that allowed both non-utility generators to sell electricity to utilities — displacing the utility generation function — and/or "retail service providers" to buy electricity from generators and sell to end-use customers — displacing the utility procurement and billing functions. We review the original economic arguments for electricity restructuring, the potential winners and losers from these changes, and what has actually happened in the subsequent years. We argue that the greatest political motivation for restructuring was rent shifting, not efficiency improvements, and that this explanation is supported by observed waxing and waning of political enthusiasm for electricity reform. While electricity restructuring has brought significant efficiency improvements in generation, it has generally been viewed as a disappointment because the price-reduction promises made by some advocates were based on politically-unsustainable rent transfers. In reality, the electricity rate changes since restructuring have been driven more by exogenous factors — such as generation technology advances and natural gas price fluctuations — than by the effects of restructuring. We argue that a similar dynamic underpins the current political momentum behind distributed generation (primarily rooftop solar PV) which remains costly from a societal viewpoint, but privately economic due to the rent transfers it enables.

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I. Introduction

In the mid-1990s, the great majority of electricity customers in the U.S. were served by an investor-owned, vertically-integrated monopoly utility (IOU) that provided generation, transmission, local distribution and billing/collections.[1] IOUs were closely regulated by state-level public service commissions under "cost-of-service" regulation, in which utilities were effectively guaranteed the recovery of prudently-incurred operating costs plus a regulated return on capital expenditures. In the seven years between 1995 and 2002 a wave of major regulatory reform aimed at introducing competition in various utility functions – known broadly as "electricity restructuring" – transformed the industry.[2] These changes followed closely on the heels of what was seen as the successful economic deregulation of many other industries, including airlines, railroads, telecommunications, gasoline retailing, and the production of oil and natural gas.

At the time, it was widely expected that this transformation would eventually lead the entire industry to a less-regulated and more market-based structure. Yet in the years following 2002 – after the 2000-2001 electricity crisis in California's restructured market – the movement for electricity deregulation encountered a significant backlash. While there was some debate over "rolling back deregulation," public policy after 2002 is more accurately described as a cessation of any further restructuring. For the last decade, the policy focus for the electricity industry has turned elsewhere – mostly towards environmental concerns – and the loud debates from the early 2000s over the merits of restructuring have been reduced to a background murmur.

The central premise of this paper is that views of restructuring in the electricity industry over the last two decades have been driven primarily by pursuit of quasi-rents that have resulted from investments in generation capacity, power purchase agreements, and other strategies whose payoff is revealed over long time periods. These strategies create fluctuations in the relationship between the average cost and marginal cost of producing and delivering electricity to consumers. Average cost is the basis for price setting under regulation, while marginal cost is the basis for pricing in a competitive market. During periods in which these two costs have diverged, consumer and political sentiment has tilted toward whichever regime (regulation or markets) offered the lowest prices at that time.

The relationship between average and marginal cost in the industry is in turn influenced by many factors. Some of these – such as productivity, level of investment, and the choice of type of investment – are influenced by the transitional incentive problems attributed to cost-of-service regulation. Others are influenced by factors largely beyond the control of state utility commissioners. Two critical exogenous trends during this period have been technology innovations adapted from other sectors (such as aircraft engine technology that changed the design of gas turbines and semiconductor innovations that reduced the cost of solar power) and trends in the prices of natural gas, which is generally the fuel setting

[1] More than 75% of end-use electricity was provided by IOUs. Most other customers received electricity from publicly-owned municipal utilities or, in some rural areas, local cooperatives. See Energy Information Administration (1995).

[2] Throughout this paper we use the term "restructuring" to describe the suite of changes that impacted both the organization of electricity firms and the methods by which those firms were regulated.

marginal costs in most electric systems.

Thus, 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. In fact, rates rose in both regulated and deregulated states, and more rapidly in the deregulated ones in the early years of reform. Subsequent studies of retail rates in both groups of states have generally overlooked the key point that exogenous shocks to the industry often dominated the incremental benefits that regulatory reform can provide. There is clear evidence that competition *has* improved efficiency at power plants and improved the coordination of operations across a formerly balkanized power grid. But the impact of gas price movements and new technologies have had a far larger impact.

We argue that many of the same incentive that created political momentum for restructuring 20 years ago are still present in the industry. One way they manifest today is in the increasing focus on "distributed generation," the term generally used for electricity generation that takes place on the customer side of the meter and reduces the customer's retail electricity demand from the utility. While valid economic and technological arguments can be made for and against an expanded role for distributed generation, transfers of quasi-rents play a major role in the policy positions.

In section 2 we review the expectations the drove the push for electricity restructuring in the 1990s and how those beliefs shaped the market-based models for electricity markets in each vertical component of the industry: generation, transmission, distribution and retailing. In section 3, we examine the evidence on what effect restructuring has actually had, as well as the most common confusions that confound electricity restructuring with changes in input costs and other factors. Section 4 looks ahead to the most pressing challenge the industry will face in the coming years, the increasing role of renewable and intermittent energy sources, both from utility-scale generation plants and from much smaller scale distributed generation at households and commercial customers. We conclude in section 5.

II. Theory and Implementation of Electricity Restructuring

One of the challenges for an analysis of electricity restructuring is that there are several competing definitions of what restructuring or deregulation actually is. Outside the United States, a key step in electricity restructuring was the divestiture of the government-owned assets that had comprised a nationalized power sector. In the United States, government ownership was never the dominant form of organization and the exceptions in the U.S. – federally marketed hydro-electric power and municipally-owned generation and distribution companies – have remained largely unchanged during the restructuring era. Technically, wholesale electricity markets are still regulated by the Federal Energy Regulatory Commission (FERC) under the authority granted by the 1938 Federal Power Act. The wave of state-level restructuring did not change this fact, although FERC has applied its authority flexibly by allowing states and regions to set "market-based" rates. Such authority can be revoked, however, so it is inaccurate to label even wholesale markets in fully restructured regions as "deregulated."

In a market-based system for electricity provision, the industry is generally considered as participating in four separate activities: generation of electricity, long-distance transmission over high-voltage lines, voltage step-down (to the 110V common in the U.S. or 220V used in Europe and elsewhere) and local distribution to end users, and retailing (marketing and resale of wholesale power) to end use customers. The last activity includes procurement of power under long-term contracts, rate setting, billing, and collection. The U.S. restructuring process was focused on generation, transmission and retailing. The local distribution lines continued to be considered a natural monopoly that would be subject to either regulation or municipal ownership.

Changes to generation, transmission and retailing were pursued with varying levels of commitment in different parts of the country. Independent oversight and control of the transmission networks was viewed by many as the backbone of restructuring, because transmission was critical to generators accessing a competitive wholesale market into which they could sell and to retailers accessing competitive sellers from which they could buy. Restructuring of generation resembled most closely the deregulation that had taken place in other industries, with free entry of unregulated electricity plants (known as "merchant" generators or independent power producers (IPPs)) that would live or die by their cost of production and the price they could get for their output. Finally, retail restructuring, in the limited areas it has taken hold in the U.S., has allowed non-utility companies to become the wholesale procurement entities for retail customers, offering customers alternative retail pricing structures, though across a rather limited spectrum as we discuss below.

In theory, at least, the three aspects of restructuring were closely intertwined. Without independent oversight of transmission, a merchant electricity plant would be at the mercy of the local transmission owner, which could extract large shares of the quasi-rents available once the plant was built, thereby discouraging entry of competitive generation. Even with transmission access, a merchant generator would be in a very weak position if there were only one retail electricity provider to which it could sell its output. A monopoly retail provider (a distribution utility) could still engage in competitive procurement, but that creates a narrower spectrum for competitive generation and it means that the monopoly retailer is the single determinant of the range of products that might be procured for retail. For instance, the monopoly retailer might not pursue low-carbon sources even if there are many retail customers who would be willing to pay a premium for greener energy. Thus, retail competition potentially makes competitive generation more viable. Likewise, competitive generation is central to the retailer being able to offer better procurement options, different generation sources, or alternative billing mechanisms, which the retailer would likely want to balance with the wholesale contracts it has with producers.

In practice, while pursuit of restructuring in the three activities has been regionally correlated, many areas have developed generation restructuring without retail competition. And independent transmission operators have taken over large swaths of the U.S. grid in which both generation and retail competition varies greatly.

A. Transmission Access Reforms

Transmission restructuring proceeded along two paths, a regulatory path that attempted to impose rules upon vertically-integrated utilities that would promote third party access to their networks, and an institutional path that encouraged the creation of Independent System Operators (ISOs) and later Regional Transmission Organizations (RTOs).[3] FERC attempted through a series of orders during the 1990s and 2000s to force the creation of more transparent online market places for available transmission capacity and to require vertically integrated utilities to provide transmission service to third-party independent power producers. These efforts have achieved at best mixed success.

The more successful path to nondiscriminatory grid access appears to have been the creation of the RTO/ISO. These entities are organized as user-supported non-profit companies and operate essentially as regulated entities overseen by FERC. In the U.S. these transmission companies do not own the transmission assets in their jurisdiction, but rather they control access to those assets by virtue of approving, and in some cases setting, the production schedules of the power plants within their regions, as well as operating real-time balancing markets that adjust supply as needed to maintain network reliability. In each case, the decisions made by the ISOs with regards to generation operations are dominated by a mandate to respect the constraints of the transmission network and other reliability considerations. Unlike the vertically integrated network entities, ISOs have no generation assets or retail consumers, and are therefore credibly impartial as to specific market outcomes as long those outcomes do not threaten reliability.[4]

Initially the RTO/ISO model was largely restricted to markets undertaking the full suite of restructuring steps described in this section. The full and unfettered access of disparate power producers to the available population of electricity customers dictated an institutional structure that would eliminate concerns over vertical barriers. Conversely, jurisdictions that wanted no part of retail competition were equally suspicious of the RTO/ISO structure as an initial step down the slippery slope to full restructuring. Thus, many municipal utilities and some of the largest and strongest integrated utilities, as well as the Federal Marketing Agencies, kept their transmission systems organized along traditional structures in which they directly controlled access and real-time use.

This changed in the latter half of the 2000s. As we discuss below, the pressures to restructure other aspects of utility operations receded in many regions, so joining an RTO/ISO market no longer implied the inevitable dissolution of the traditional utility franchise. At the same time, the benefits of better coordination of operations and lowering of transactions costs within ISOs appear to have been substantial.[5] Figure 1 illustrates the geographic reach of North American ISOs and RTOs as of 2012. Currently, RTOs such as the Midcontinent Independent System Operator, Southwest Power Pool, and PJM each contain several states that never seriously considered restructuring their generation or retail sectors.

The creation and expansion of the RTO/ISO model may be the single most unambiguous success of the restructuring era in the United States. The U.S. has historically suffered

[3]Both types of organizations are tasked by FERC to coordinate investment and operations of regional power grids in a non-discriminatory transparent manner.

[4]Indeed, RTO/ISOs have at times been criticized as being *too* exclusively focused on reliability and not sufficiently concerned with the costs their instructions and mandates place on the customers and generators operating within their systems. It is true that the performance of ISOs is generally measured in terms of the reliability of their systems and the costs of the relatively narrow scope of operations directly housed within ISOs, rather than on the indirect effects their decisions may have on productivity and prices.

[5]See Joskow (2006), Wolak (2011a), and Mansur and White (2012).

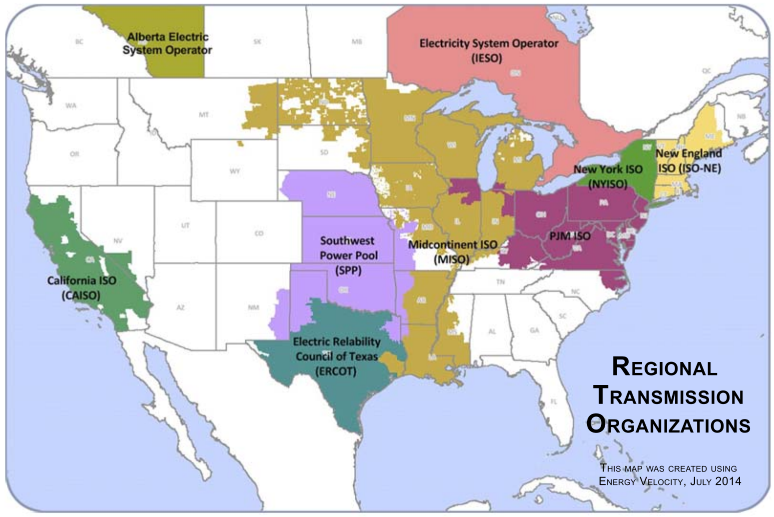

Figure 1. U.S. ISOs and RTOs as of 2012

from a utility system that was highly balkanized relative to most other countries. The evidence suggests that the lack of coordination across utility control areas impeded Pareto-improving trades worth billions of dollars.[6] Although the early momentum for aggregating utility control areas into more regionally managed RTOs was provided by it being seen as a necessary step toward the ultimate goal of deregulating generation and retail, the expansion of the RTO structure has come to be viewed as a valuable legacy of this period even for states that never showed serious interest in these other aspects of restructuring.

B. *Restructuring of Generation Ownership*

The second dimension of restructuring impacted the ownership status and remuneration of generation assets. Large amounts of generation capacity were converted from utility status to independent power producer (non-utility or "merchant") status. Effectively, these assets transitioned from a cost-of -service regulation model, in which they were compensated based upon average production cost, to a market-based pricing model, under which these assets earned a market price for the output they were able to produce.

To the extent one considers the electric sector to be "deregulated," it is due to this fundamental shift in the paradigm for compensating owners of generation. In addition to the divestiture of much of the existing generation fleet previously owned by IOUs in restructured states, an equally dramatic change impacted the investment in new generation. The construction of generation assets was no longer coupled with a guarantee to recover a positive return on those capital costs. In 1997 only 1.6% of U.S. electricity was produced by generation owned by firms classified as Independent Power Producers. That figure rose

[6]See White (1995), Joskow(1997), Kleit and Reitzes (2008), and Mansur and White (2012).

to 25% by 2002 and was just under 35% in 2012. The share of nuclear generation owned by IPPs rose from zero in 1997 to almost 50% in 2012, as utilities sold off their nuclear assets.

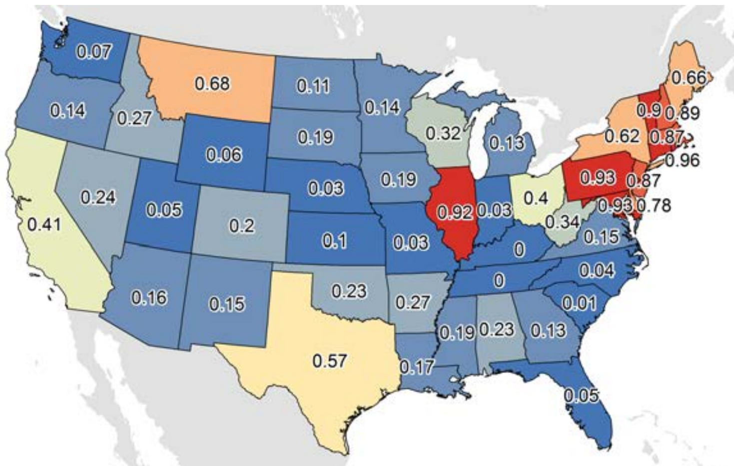

Figure 2. Share of Output from Merchant Generators in 2012

Figure 2 displays the diversity of ownership patterns across the U.S. as of 2012 and illustrates the strong regional pattern of generation restructuring. The Southeast, with its large and regionally powerful IOUs, and much of the Pacific Northwest, with its dominance of federally operated generation and municipal utilities, have largely resisted changes in generation ownership. Importantly these regions also enjoyed amongst the lowest average retail rates in the country in 1997. The Northeast and Illinois have almost fully transitioned to a non-utility form of ownership, while Texas, California and Montana have also seen large shares of IPPs.

As we will discuss below, we consider this dimension of restructuring to be the most economically meaningful in its consequence. This is mainly because the majority of costs still reside in the generation sector and the fact that the most potential variation in costs and prices resides in this sector.

Political attitudes toward the effects of restructuring during the last 20 years have also been dominated by outcomes in the generation sector. These attitudes can largely be captured by comparing average to marginal costs.

In the early 1990s, just prior to the initial years of restructuring, much of the country experienced large generation reserve margins (see Figure 3). Until the last few years (with the rise of intermittent renewable generation), this statistic was a very good proxy for measuring the efficient deployment of capital. Larger reserve margins generally imply installed capacity (and capital) that is underutilized. Lower utilization implies higher average costs as the capital expenditures are spread across a smaller consumer base. Lower utilization rates also often implied that generation with relatively low marginal cost was often available, and marginal, thereby contributing to relatively low regional wholesale prices. Historically low natural gas prices during the 1990s also greatly contributed to low regional wholesale prices.

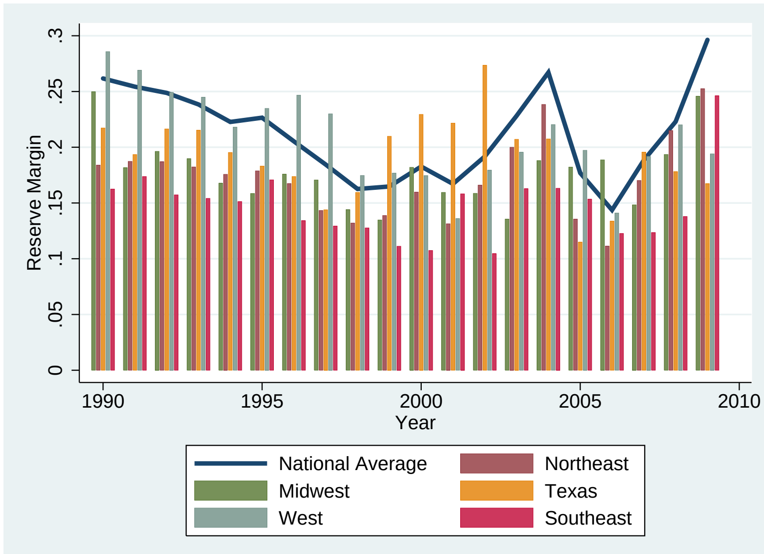

Figure 3. Generation Reserve Margins

The industry during the late 1990s was therefore experiencing very high reserve margins, leading to unusually low marginal costs and unusually high average costs. This is the fundamental source of the pressure for restructuring. While, as discussed above, much of the rhetoric at the time focused on retail deregulation, this needs to be seen from the perspective of customers (often large industrial customers) who saw great opportunity in being able to gain "direct access" to the wholesale market. [7]

Of course, what appeared as a great opportunity for customers conversely created a real threat to utilities who were the residual claimants on generation assets for which the market value in a competitive wholesale market would have been well below the depreciated capital value that remained on the utilities' books at the time of restructuring. This fact was quickly internalized by equity markets. Share prices of the largest utilities in California, Pennsylvania, and New England all experienced sharp declines during the mid-1990s. The concern among holders of utility stocks soon gave way to a period of reflection and negotiation over an acceptable transition from an average-cost to market-based pricing paradigm. The political and regulatory process was forced to confront the uncomfortable fact that much of the consumer appeal of restructuring was rooted not in cost savings and productivity gains, but rather in an opportunity to shift responsibility for paying the sunk costs of what were considered uneconomic "stranded assets." This meant that immediate con-

[7] In Borenstein and Bushnell (2000), we pointed out this tension between efficient economic decision making and incentives for rent shifting.

sumer savings were largely dependent upon an equivalent reduction in returns for utility shareholders. This is an important theme we will return to when we examine the current rhetoric about the "utility of the future."

In the end, utilities in all restructuring states persuaded regulators that the implicit agreement between the regulator and the IOU (commonly refered to as a "regulatory compact") required that the utility be made whole for any lost asset value from restructuring. Nearly all the generation assets with market value below the IOU's remaining book value had been built with the approval, and in some cases mandate, of regulatory commissions,[8] so it was generally concluded that to force restructuring without compensation for stranded assets would violate the regulatory compact. Most state restructuring schemes included a plan for 100% recovery by utilities of any stranded investment and the others aimed at nearly 100% recovery.

The most common mechanism for recovering stranded cost was to allow a transition period in which portions of utility retail prices would be frozen at what were then considered to be above-market rates during a transition period. Utilities would therefore be allowed to apply these excess retail margins to pay down the stranded costs on their divested and retained generation assets. This approach produced devastating consequences for California where the excess retail margins suddenly turned negative and caused the 2000-01 California electricity crisis.[9] In order to avoid conflict between the goals of fostering retail competition and recovery of stranded costs, these *competition transition charges* were generally applied as surcharges to the bills of distribution companies who maintained a monopoly franchise over the wires components of the business. Therefore, somewhat ironically, while the customer impetus that started electricity restructuring was a desire to avoid paying for high average costs during a period when marginal costs were lower, the transition charges largely guaranteed that utilities recovered something close to those costs anyway.

C. Restructuring and Reform of Retail Services

The aspect of restructuring to receive the most rhetorical attention and market hype was the relaxing of the utility monopoly franchise over retailing. Phrases evoking liberty and freedom, such as "customer choice" and "freedom to choose" were rhetorical staples of the restructuring process. There was also much hope that electricity retail competition might spur innovation in retail services in the way that it had for telecommunications. Exactly how this was supposed to be achieved was never clear.[10] Electricity service has proven to be less amenable to the sorts of usage and complementary product innovation that wired

[8] In addition to generation assets operated by utilities, stranded assets in several states included uneconomic long-term contracts with IPPs that were mostly mandated by PUCs under the Public Utilities Regulatory Power Act of 1978. See White (1996).

[9] Through a combination of real scarcity and generator market power (caused in part by high local natural gas prices that followed a pipeline explosion), California wholesale electricity prices skyrocketed in summer 2000 and remained extremely high into May of 2001. Under the competition transition plan, the two largest utilities in the state were not allowed to raise retail rates to reflect the high wholesale prices. One of them, Pacific Gas & Electric, was forced into bankruptcy and the other, Southern California Edison nearly followed. For detailed discussions of these events, see Joskow (2001), Blumstein, Friedman and Green (2002), Borenstein (2002), Wolak (2003b), and Bushnell (2004).

[10] See Joskow's (2000) discussion of the potential for new product innovation under electricity restructuring.

telecom service experienced in the 1980s and 1990s. Perhaps this isn't surprising given that the product is so narrow – just the electricity, not any devices that use it – and so homogeneous. In order to use the grid, electricity must meet exact specifications that make one provider's product indistinguishable from another's. The place where innovation did seem valuable and likely to occur with retail choice was in financial arrangements: price schedules, payment plans, and options to bundle purchases with complementary products.

More concretely, retail restructuring involved giving customers access to new "energy-only" retail providers who produced or acquired wholesale power for sale to end users. The incumbent utility (and the grid operator) maintained a franchise over distribution and transmission related functions. In many cases the incumbent utility was allowed to continue to offer a default "bundled" retail rate for customers who did not switch retailers.[11] Customers who did switch received a bill for "energy-only" service from the third-party retailer they chose, and a separate charge, intended to recover transmission and distribution system investments made by the incumbent utility.

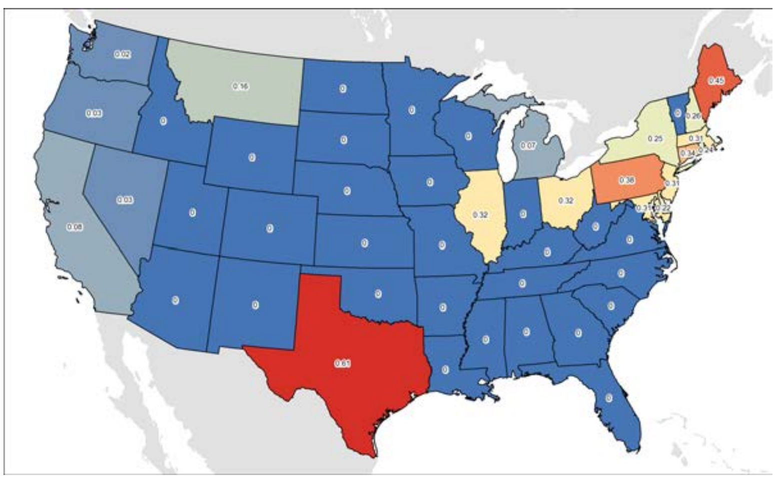

Figure 4. Share of Retail Sales from Retail Power Marketers

The extent to which this transformation has materialized has varied greatly around the U.S. Figure 4 illustrates the fraction of total sales in each state from entities with an ownership classification of 'retail power marketer.'[12] Texas has far outstripped the rest of the country on the retail competition front, with the only other significant activity clustered in the Northeast.

[11]The bundled rate combined energy with the incumbent utility's transmission, distribution and retailing charge. This was sometimes called the "default provider" or "provider of last resort" (or POLR) rate. In some states, the default provider franchisee is selected through auctions overseen by local regulators.

[12]These data are compiled from EIA form 861.

Retail Price Reform. — To understand the potential for efficiency improvements in pricing electricity, it helps to review the inefficiency concerns raised by the typical 1990s electricity retail tariff. Throughout most of the history of electric utilities, retail pricing policy has been driven more by equity than efficiency considerations. Because customers had little alternative to the monopoly utility provider, and the utility was focused on satisfying the terms of cost-of-service regulation more than maximizing profits, there was little initiative to improve the efficiency of pricing. However, with greater competition and demand elasticity – from non-utility energy sources and retail suppliers, and more recently from improved opportunities to generate electricity on the customer side of the meter – the pressure to align prices with marginal costs has grown.

Efficient retail prices should reflect the short-run marginal cost in every hourly (or even shorter) time period at every location on the grid. At the beginning of restructuring, nearly all residential, commercial and industrial customers faced prices that did not vary hour to hour. Furthermore, utilities recovered nearly all of their costs through volumetric charges, including the substantial share of costs that are fixed with respect to a customer's marginal consumption. For most residential customers, the rate was a simple constant price per kilowatt-hour (kWh) consumed, regardless of when the energy was used, set to cover all the utility's costs, variable and fixed.[13]

Setting price equal to short-run time-specific and location-specific marginal cost leads to efficient consumption given the level of investment, but only under a very narrow set of conditions does it exactly cover total costs.[14] In reality, there are almost certainly some costs that scale less than proportionally with the total quantity sold, so efficient marginal pricing would result in a revenue shortfall.

A fixed charge can be used to capture the additional needed revenue. A fixed charge (per month, for instance) is particularly efficient in residential electricity markets because the elasticity of connecting to the grid with respect to the monthly fixed charge is likely near zero over a wide range of charges. Thus, the deadweight loss that could result if some customers chose to consume zero because the fixed charge exceeds their consumer surplus is likely to be small.

For basically the same reason, however, the distributional consequences of a fixed charge are of great concern. Moving from a flat volumetric rate and no fixed charge to a lower flat rate and a fixed charge is very regressive. Borenstein (2011) shows that such a revenue-neutral change to a higher fixed charge and lower volumetric rate would raise the average bills of low-income customers by 69% to 92% of the fixed charge across the three large investor-owned utilities in California. Equity notions often suggest that the fairest allocation of such a revenue requirement would be in proportion to quantity consumed.[15] That approach, however, steers back towards average cost pricing and the inefficiencies that it is known to produce.

The problem of average cost pricing is exacerbated in the electricity industry by the na-

[13]Borenstein and Holland (2007) show that the break-even flat price could be higher or lower than the second-best optimal flat rate, depending on whether peak or off-peak price elasticities are higher.

[14]Under constant returns to scale, optimal pricing covers costs if capacity is also set optimally. If capacity is greater than the optimum level, optimal pricing will generate less revenue than is needed to cover total costs.

[15]Or, if data were available, in proportion to consumer surplus gained by each customer.

ture of the contract between the retail provider and the customer. In nearly all cases, the customer has an option, but not an obligation, to purchase any quantity at the announced price, known in the industry as a "requirements contract." This in itself wouldn't be a destabalizing force if price adjusted quickly,[16] but with long lags between cost changes and price adjustment, this creates an opportunity for buyers to switch between alternative suppliers inefficiently. This is the same phenomenon as described earlier for the state decision to deregulate, but manifest in contemporaneous customer choice among competing sources. The combination of requirements contracts and average-cost retail pricing could create increasing problems if distributed generation ("behind the meter") continues to expand, as we discuss below.

Thus, as restructuring began 20 years ago, retail pricing deviated considerably from the ideal efficient structure. It seemed at least possible that competitive pressure on the existing structure would lead to substantial changes in pricing, and the potential for differentiation among the products retailers sold. The technological and market configuration, however, turned out to leave much less space for pricing innovation than was suggested at the time.

The principle technological constraint was metering: in the 1990s, virtually all residential customers, and most commercial and industrial customers, had meters that recorded only the aggregate amount of electricity that had flowed through them. They did not have the capability to collect information on when the electricity was consumed. This meant that time-varying pricing wasn't feasible without a significant investment in metering. Nor could a retailer necessarily overcome this constraint just by metering its own customers, because the arrangements for billing and payments among retailers and the utility providing distribution services were generally not set up to accommodate time-varying pricing. Instead, in most cases a retailer was deemed responsible for providing power to its customers – either generating it, signing long-term contracts, or buying on the spot market – based on a standard assumed "load shape" (a time-varying pattern of consumption) that was applied to all customers within broad location, customer type, and sometimes size, classes. The assumed load shape was independent of the prices the customer faced, so the retailer had no incentive to charge time-varying prices. With the expansion of smart meters in the late 2000s, the groundwork is now being laid for broader use of time-varying pricing, but the vast majority of residential customers with non-utility retail providers still see no time-variation in the prices they pay. Commercial and industrial customers have experienced a much greater shift towards time-of-use pricing, which entails two or three different pre-set prices that apply at different times of the week. TOU pricing, however, is known to capture a small share of the hourly variation in wholesale electricity prices.[17]

A second way in which retailers might have offered greater differentiation was in reliability, but this too was undermined by the structure of the retail markets that were established. Because the grid operator must always balance supply and demand to avoid service disruptions, the grid operators in these markets procured enough reserves to make sure that the full expected demand could be met. If one retailer did not procure sufficient supplies

[16] In a sense, sellers in any commodity market operate under requirements contracts, at least over a large range of purchase quantity, but they can and do change prices rapidly as market conditions change.

[17] See Borenstein (2005).

to meet its retail demand obligation, the result was not reduced supply to the customers of that retailer – as would occur with nearly any other product. Instead, the grid operator drew on its reserves to make sure all demand was met. The cost of those reserves was spread over all retail quantities whether or not the provider to a particular customer ever caused the grid operator to need those reserves. Reliability was assured by the grid operator and charged to every kWh supplied, so there could be no differentiation on reliability. Alternative arrangements – in which the customer either lost power when its supplier had procured insufficient quantities (which posed technological challenges along the same lines as real-time metering) or the retailer or customer were charged a very high fee for running short of delivered electricity – would have created a significant cost for insufficient supply and likely led to greater product differentiation along these lines, but these weren't widely adopted. The lack of retailer responsibility for reliability also undermines the incentive to implement price-responsive demand, which could be a valuable tool for a retailer in balancing its supply and demand while keeping costs down.

Reliability differentiation also could extend to the ramifications of exit by the retailer. If a retailer exits the market, what cost is borne by its customers? If customers can easily switch to another supplier at a pre-determined rate, then a similar moral hazard problem arises in which a retailer can procure short-term power at spot prices when that price is low, but exit if the spot price rises, leaving the customer to switch to some default rate. If that default rate is a price that reflects average procurement costs over a longer period, then once again the variation in average versus marginal price drives behavior in the market. Enron and some other retail providers in California took this path when prices in the California wholesale market spiked in 2000. In Texas, which has the most extensive retail residential competition (see figure 4), rules have been adjusted so that customers of a retail provider that exits are moved, by default, to a tariff that reflects the contemporaneous marginal cost of procuring power.

III. Electricity Market Performance Since Restructuring Began

Electricity restructuring's most consequential economic changes took place on the wholesale production and marketing sectors of the industry. We therefore begin by discussing the evolution of the industry since 1997 at the wholesale level. As discussed above, formal centralized markets only formed in the parts of the country that embraced the RTO/ISO structure, which were also the areas with the highest prices and for which the average cost exceeded marginal cost by the largest amount.

A. Wholesale Markets

The regions with RTO/ISOs are also the markets for which the best data on wholesale prices are available. Figure 5 summarizes annual average prices from two data sources. For 1998 through 2001 we use data from Bushnell, Mansur and Saravia (2008), which are drawn from ISO websites. For 2001 on, we report data from the Intercontinental Exchange (ICE) for trading hubs in Southern California (SP15), western Pennsylvania (PJM) Massachusetts (ISO-NE) and the Pacific Northwest (Mid C) hubs. The dashed line in figure 5 summarizes the U.S. average city gate natural gas price, taken from the Energy Information Administration.

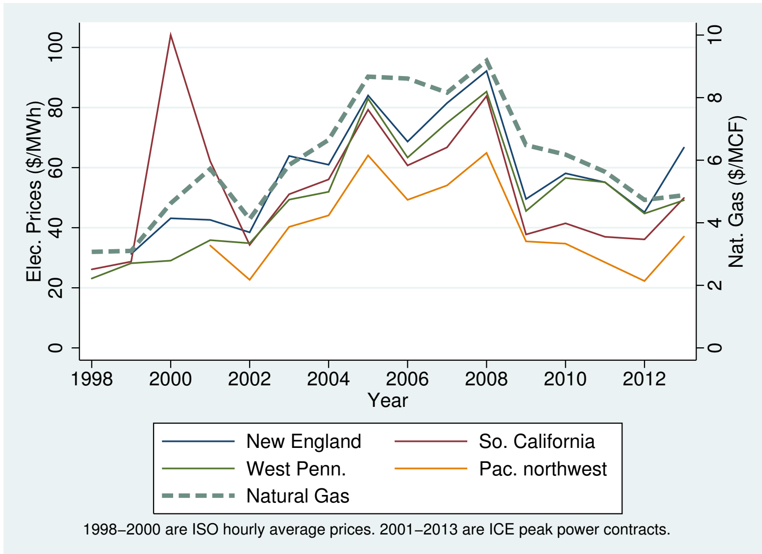

FIGURE 5. WHOLESALE ELECTRICITY AND CITYGATE NATURAL GAS PRICES

Since 1998, two facts are worth noting. First, although somewhat muted by the annual aggregation in the data, the California market stands out as suffering from sustained extremely high price levels during the 2000-2001 period. Both academic research and subsequent regulatory findings have determined that this market suffered from a lack of competition made acute by a combination of tightening capacity and a near total absence of forward contracting.[18] Second, in the other markets wholesale power market prices are dominated by natural gas prices, though somewhat less so in the Pacific Northwest. This is consistent with the general fact that natural gas fired generation units are the marginal source of power in most markets during most times, but the Pacific Northwest is influenced more by the availability of hydro-electric power.

Because gas generation comprises a minority share in most electricity markets, under average-cost based regulation it did not dominate rate making. Prices for deregulated generation, however, are driven by the marginal producer, which is much more commonly gas generation. Thus to a degree that was not appreciated at the time, 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

[18]See Borenstein (2002), Borenstein, Bushnell and Wolak (2002), Joskow and Kahn (2002), Wolak (2003a), Bushnell(2004) and Puller (2007).

regulation.

During 2006 and 2008 the U.S. natural gas price peaked above \$11/MMBTU. The higher gas prices drove up generation costs and power market prices. By this time, the relationship between marginal and average costs of power production had again reversed so that marginal cost-based market prices were higher than the average costs of operating and producing from a mixed generation portfolio. Many of the nuclear and coal-fired power plants in restructured states, which had been considered "stranded" assets in the late 1990s, were by 2007 tremendously profitable due to their low operating costs and the relatively high market prices they earned for their output.

The combination of higher prices and healthy profits earned by power producers in restructured states contributed to a strong dissatisfaction with restructuring in several states.[19] This mood of ex-post regret in restructured states peaked in 2007-2008. States such as Illinois, Maryland and Maine initiated proceedings that were characterized as rolling back deregulation.[20] After 2009, however, with plummeting natural gas prices and increasing reserve margins, momentum for significant changes dissipated.

B. Restructuring and Plant Operations

One aspect of restructuring that has been studied at a micro level has been its impact on the performance and efficiency of power plants. Overall the results point to a positive influence of restructuring on the operations of plants. Unfortunately, while cost data on regulated plants are extensive, there is much less data available on the costs of non-utility generation. Thus, studies of plant-level impacts of restructuring have either focused on its impact on regulated plants or were limited to a focus on the few performance variables that continue to be reported for deregulated plants. Fabrizio, Rose, and Wolfram (2007) compared the performance of regulated plants in states that pursued restructuring (by the Energy Information Administration's definition, which we discuss further below) against regulated plants in states that did not initiate restructuring, and against publicly owned plants in both types of states. They find modest efficiency gains in the restructured states, much of these focused on employment and labor productivity. There is some evidence that the efficiency of fuel consumption, the largest single variable expense in power plants, can be influenced by incentives and skill,[21] but to date the evidence on fuel efficiency at restructured plants has been inconclusive.

The most dramatic documented impact of restructuring on power plant operations has been on the performance of nuclear plants, shown by Davis and Wolfram (2012). Almost half of the nuclear generation plants in the U.S. were divested to non-utility producers since 1998.[22] Davis and Wolfram show that industrywide U.S. nuclear power plants have greatly increased capacity factors since 1998, but relative to their regulated counter-parts, output at the restructured plants increased 10 percent between 1998 and 2010. They estimate this

[19] See Johnston (2007).
[20] See Sharp (2007) and Behr (2009).
[21] See Bushnell and Wolfram (2009)
[22] Since 1998, no new nuclear plants have come online.

additional output has a market value of $2.5 billion dollars annually.[23]

C. Restructuring and Retail Prices

It is useful to begin a review of retail prices under deregulation by examining conditions in 2007, when dissatisfaction with restructuring peaked. In 2007, the New York Times ran a series of articles highlighting the fact that rates had risen faster in restructured states than in regulated ones. The articles cited studies that relied upon average retail price data reported to the Energy Information Administration and essentially performed a difference in difference comparison between restructured and non-restructured states.[24]

A central challenge in studies like this is to identify what constitutes "restructured" in order to assign a state to one category or the other. Many papers have relied upon the Energy Information Administration's definition, which is focused on the status of retail competition. An alternative measure of restructured is based upon the fraction of energy generated in a state that is produced by Independent Power Producers (IPP). Figure 2 illustrates these values for 2012, but we can apply the full panel of values to capture the underlying points of transition in each state.

As one examines recent data on retail rates, it is clear that many of the conditions of 2007 have since dramatically reversed. Table 1 summarizes the average retail rates in states considered "restructured" according to two alternative measures against those that remained under traditional regulation[25] The first measure is the one used in a study by Showalter (2007) for Power in the Public Interest (PPI) that is cited in the NY Times article. This definition excludes from the restructured category states such as Illinois and Pennsylvania which by 2012 have almost all of their energy provided from non-utility sources. As an alternative measure, we assign states to the restructured category if they had more than 40% of their energy provided by non-utility sources in 2012.[26]

From Table 1 one can see that at this level of analysis the definition of restructured makes only a small difference. The time period examined, however, makes an enormous difference as rates in restructured states increased at a pace nearly 50% higher than those in non-restructured states between 1997 and 2007 but have actually declined slightly since 2007. Average rates in states that did not restructure have continued to increase since 2007, though at a slightly lower pace than between 1998-2007. Overall there is almost no difference in the change in average rates for the two groups over the full sample from 1998-2012.

Figure 6 illustrates the annual levels of rates in restructured and non-restructured states using our generation-based definition, along with the national average city gate natural gas

[23]Hausman (2014) concludes that the gains in utilization were not accompanied by degradation of safety among deregulated plants.

[24]See Showalter (2007) and Tierney (2007).

[25]Retail price data come from the EIA form 861, which report sales and revenues by utility. We examine the average rate across all major rate categories, including residential, industrial and commercial. Several previous studies, including Showalter (2007) and Apt (2005) have focused on rates paid by industrial customers.

[26]The NY Times article lists the restructured states as CA, CT, DC, DE, MA, MD, ME, MI, MT, NH, NJ, NY, RI, and TX. Our generation-based definition puts CA, CT, DE, IL, MA, MD, ME, MT, NH, NJ, OH, PA, NY, RI, TX, and VT into the restructured category.

Table 1—Summary of Retail Price Changes

Definition	Status	Average Retail Price			Percent Change		
		1997	2007	2012	97 to 07	07 to 12	98 to 12
PPI Definition	Not Restructured	5.89	7.44	8.72	0.21	0.15	0.32
	Restructured	8.96	12.53	12.35	0.29	-0.01	0.27
At least 40% IPP in 2012	Not Restructured	5.67	7.23	8.57	0.22	0.16	0.34
	Restructured	8.83	11.99	11.95	0.26	0.00	0.26

price. Restructured states experienced higher rates during the 1990s, a major factor in their election to adopt restructuring. The gap between traditionally regulated and restructured states narrows around 1998, reflecting the impact of legislation that required immediate rate reductions accompany restructuring in several states. Since that time, rates in restructured states more closely follow the trajectory of gas prices up during the early 2000s and back down since then.

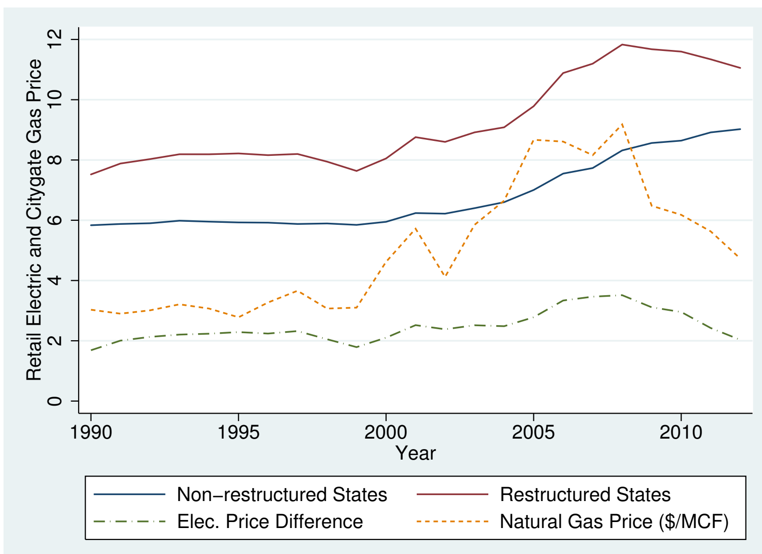

Figure 6. U.S. Average Retail Rates and Natural Gas Prices

To further test this relationship between natural gas prices, restructuring and electricity rates we estimate the following regression on state level annual changes in electricity prices and city-gate natural gas prices.

$$(1) \qquad \Delta Elec_{s,t} = \alpha + \beta_1 FractionIPP_{s,t} + \beta_2 \Delta NGas_{s,t} + \beta_3 FractionIPP_{s,t} * \Delta NG_{s,t},$$

where $\Delta Elec_{st} = ln(Rate_{s,t}) - ln(Rate_{s,t-1})$ and $\Delta NGas_{s,t} = ln(NG\_CityGate_{s,t}) - ln(NG\_CityGate_{s,t-1})$ are the annual changes in log state average electricity rates, and log state average city-gate natural gas prices, respectively. We estimate for 1998 (the change from 1997) to 2012. Table 2 presents the summary statistics for these variables in the years 1997 and 2012.[27] We estimate (1) clustering standard errors at the state level.

Table 2—Summary Statistics of Retail Electric and Natural Gas Prices

Variable	Mean	S.D.	Min	Max
Data for 1997				
Variable	Mean	S.D.	Min	Max
Price	6.72	2.03	3.87	11.66
Fraction IPP	0.03	0.07	0.00	0.46
Nat. Gas	3.54	0.64	2.12	5.18
Data for 2012				
Price	9.70	2.30	6.90	15.54
Fraction IPP	0.35	0.33	0.00	0.99
Nat. Gas	4.90	0.97	3.46	7.73

The results of regression (1) are reported in table 3. As table 1 suggests, restructuring, which we are representing with fraction of energy generation from non-utility sources in that year ($Fraction\_IPP$), has no statistically discernible effect on average changes in rates over the 1997 to 2012 period. The point estimate implies that a state with 100% merchant generation has a 0.6% higher average annual rate increase, but one cannot reject no effect at conventional significance levels. Changes in local natural gas prices, however, do influence rates. The second column of table 3 suggests that a 1% increase in natural gas prices implies a 5% increase in electricity prices on its own. The third column in the table yields greater clarity on the mechanism. When the change in natural gas price is interacted with the $Fraction\_IPP$, the results suggests that the effect of natural gas is much greater in restructured states as the earlier discussion would suggest. The influence of natural gas price on retail rates is estimated to be nearly twice as large in a state with all merchant generation than in a state with none. The effect of natural gas prices in a state with no merchant generation is not statistically significant, while the interacted effect with $Fraction\_IPP$ is highly significant.

We do not intend this to be an exhaustive analysis of the drivers of retail prices.[28] However these data are strongly supportive of the argument that, apart from the California electricity crisis, any harm that electricity restructuring has done to consumers was a side-effect of changes in the price of natural gas. In restructured markets, natural gas generation

[27] Both time series are from the Energy Information Administration. Electricity rates are the "Total Electric Industry" average price across all customer classes, per state, as reported at http://www.eia.gov/electricity/data/state/ and derived from EIA form 861 data. Natural Gas prices are available at http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm, and derived from EIA form 857 data.

[28] Others such as Apt (2005) and Taber, Chapman and Mount (2006) have performed more extensive exercises, but only utilizing data during the early years of restructuring.

Table 3—Analysis of Retail Price Changes

	1	2	3
Pct IPP	0.006	0.007	0.006
	(0.005)	(0.005)	(0.005)
Pct Change in		0.051	0.023
Nat. Gas		(0.016)	(0.016)
ΔNGasxPctIPP		NA	0.018
			(0.005)
N	720	720	720

Dependent variable is change in log annual state-level average electricity rates. Standard Errors are clustered by state.

determines market prices and therefore the remuneration for all the non-utility assets. The more non-utility assets featured in a state's generation mix, the more exposed that state is to the natural gas market.

Simply put, restructuring in the U.S. was in hindsight very poorly timed. Assets that were viewed as stranded in 1998 were sold as white elephants at prices far below what they would have fetched in 2007. Conversely, large customers in the 1990s were motivated by low wholesale prices to push for restructuring, but the switch to market pricing, which increased their exposure to the natural gas market, came just as natural gas price increases starting a long climb up to a peak in 2007. This timing is not coincidental: the same factors that contributed to the low valuation of utility assets in the late 1990s (low wholesale prices) were the ones that made the prospect of restructuring so appealing to customers and policy makers.

D. The Evolution of Retail Price Structures

Unfortunately, data on retail price structures are much less available than data on average retail price levels. Nonetheless, it is clear that there has been gradual movement towards time-varying pricing, primarily for commercial and industrial customers. In the last decade – partially in response to funding from the 2009 American Recovery and Reinvestment Act (ARRA) – many utilities have rolled out so-called "smart meters" to even residential customers. Estimates vary, but by 2013 it is likely that more than 40% of all customers in the U.S. had smart meters.[29]

These meters record total electricity consumption in hourly or shorter periods, and can facilitate much wider use of pricing that changes frequently to reflect real-time supply/demand balance, known as dynamic pricing.[30] So far, such granular and timely pricing has appeared for only a narrow slice of large industrial and commercial customers, but with smart meters

[29] See FERC (2013).
[30] The meters also communicate information to the utility without onsite visit by a meter reader. Savings on meter reading labor have been the largest benefits projected by utility installing smart meters.

now in place, most of the financial cost of dynamic pricing down to even residential customers has been sunk. Still, there remains substantial resistance to dynamic pricing among residential consumers and groups that represent them. Data from a 2012 EIA survey of utilities suggest that only a few percent of customers are on tariffs that have any dynamic pricing component.[31]

Of course, the efficiency gain from dynamic pricing depends on the ability and willingness of customers to respond to those prices. Opponents have generally argued that households won't pay the attention necessary to adjust thermostat settings, washer/dryer use, and other electricity-consuming activities in response to dynamic prices. Simple calculations, such as in Borenstein (2013), show that the financial gain from paying attention to such price fluctuations has been modest. Still, increased penetration of intermittent generation resources (wind and solar) is likely to increase wholesale price volatility and raise the social return to such attention, while automation is likely to continue lowering the cost of the necessary attention.

A very large literature has now developed using randomized control trials, randomized encouragement designs and quasi-experiments to analyze just how much consumers do respond to dynamic pricing. The evidence is fairly consistent that even without automation, customers respond significantly on average, though with a fairly small elasticity, generally estimated to be in the -0.1 to -0.2 range.[32] The research suggests that the larger elasticities result from interventions that include technology to convey information, such as emails, text messages, and in-home electricity usage displays.

The literature on elasticity with automated demand response is much thinner; it is pretty much non-existent in economics outlets. But programmable controllable thermostats – which can permit a person to automate response to a price or other warning signal or allow an authorized third party to do so – have been in use for more than a decade. Industry publications suggest these technologies greatly increase potential demand response.[33]

IV. The Next 20 Years

After a tumultuous period from 1996 to 2005, the regulatory/legal status of electricity restructuring – in generation, transmission, distribution and retailing – has changed little in the last decade. In recent years, however, the continuing evolution in technology and in environmental concerns has disrupted the industry in new ways. These changes are ongoing and are likely to continue for many years.

The greatest change occurring in electricity markets today – and likely going forward for many years – is the increased recognition of environmental costs of electricity generation, most notably (but not exclusively) greenhouse gas emissions. Environmental issues have played a significant role in electricity for decades, but most of the emphasis in past years was on limiting the local air and water pollution from traditional generation sources. Of course, appropriate pricing of the environmental externalities – either through a tax or a

[31] See FERC (2013) and EIA Form 861.
[32] See Jessoe and Rapson (2014), Ito (2014), and Wolak (2011b).
[33] See Faruqui and George (2002).

cap-and-trade program – would be the simplest and most efficient way to incorporate these environmental costs.[34] Currently, most U.S. utilities either pay zero for their greenhouse gas emissions, while a minority pay prices well below the most common estimates of the social cost of those emissions. In that situation, raising marginal retail price above the utility's private marginal cost can be efficient, of course, and it can at the same time reduce the need for fixed charges discussed earlier.

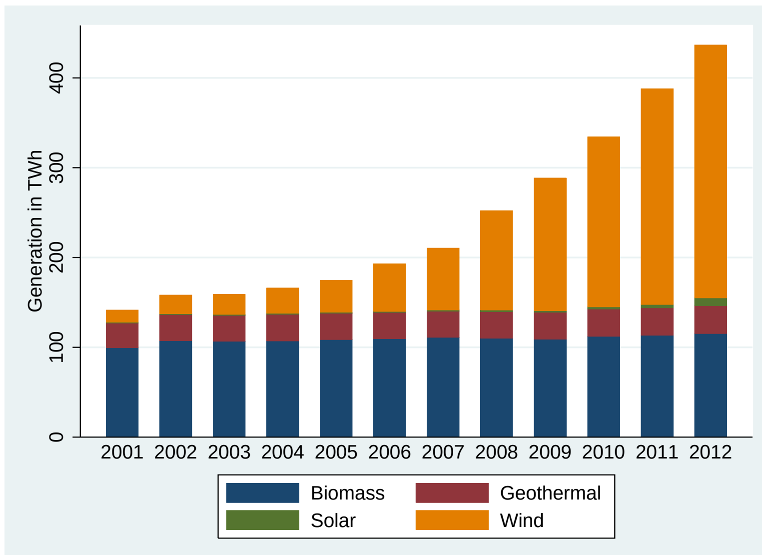

Figure 7. Electricity produced from non-hydro renewable sources (excludes distributed generation)

In the last decade, with growing concern about climate change and with improving technology, environmental stakeholders have turned more and more to goals for increasing generation from renewable sources. While hydro-electric and nuclear generation are by far the largest low-carbon sources in the U.S., wind and solar are growing rapidly, as shown in figure 7.

The growth of wind and solar generation sources raises two issues that are now coming to dominate policy discussions among utilities and policy makers: (1) economic and technical management of intermittent-production resources for which costs are largely sunk before production begins and (2) policy towards distributed generation resources that are on the property of the end user (so-called "behind the meter" generation). The latter is primarily an issue with rooftop solar PV today, but could expand to batteries and other generation or storage devices in the future.

[34] "Appropriate" is a key word here. Simply setting a tax or a quantity cap addresses the issue efficiently only if the tax or quantity limit is set correctly. This is an obvious point, but one that seems to be missed or ignored by many policymakers.

A. Management of Intermittent Generation Resources

Numerous regulatory and legislative initiatives, including President Obama's Clean Power Plan proposed in 2014, are pressuring electricity providers to reduce the greenhouse gas footprint of the power they supply. Many options exist for reducing GHG emissions from electricity, but among the most prevalent today are greater use of wind and solar power. Economic and technical integration of these intermittent renewable generation resources is likely to be one of the principal challenges facing the electricity industry in the next few decades.

The technical challenge stems primarily from the fact that production from these resource occurs intermittently and largely outside the control of the owner – when the wind blows or the sun shines.[35] Because the physics requires that quantities supplied and demanded in an electrical grid must balance at all times for the system to be stable – and because storage is still quite expensive – the intermittency of wind and solar implies that either other flexible supply resources must be available to offset these fluctuations or demand must change in response. Both solutions are technically feasible, though supply-side responses have been the focus of more discussion.

Intermittency problems occur on both short and long timescales. Large fluctuations in electrical generation can occur second by second from solar PV, and minute by minute from wind. On a longer scale, both wind and solar can exhibit many hours of higher or lower production than was forecast even a day in advance.[36] Short scale intermittency is generally localized and idiosyncratic, so a diversity of locations may substantially mitigate the problem, though studies suggest that some additional balancing resources or demand responsiveness will still be necessary at high penetration.[37]

Longer-scale intermittency is likely to be a more formidable problem if wind and solar become a large share of generation capacity. Absent inexpensive electricity storage, days or weeks without much sunshine or wind would create energy supply fluctuations that would be very costly for demand to follow. If the existence of those days requires full or nearly-full capacity coverage from conventional fossil resources, then the full cost of supplying power with high renewables penetration grows significantly.

Further complicating the technical challenge, conventional fossil generation is constrained in how quickly it can "ramp" output up and down to offset large changes in output from renewable resources. In general, the most flexible conventional generation is from gas-fired peaker plants, which are also the least efficient and most expensive. Larger combined-cycle gas turbine plants are somewhat less flexible, but lower cost, and coal and nuclear plants are the least flexible.

A well-know concern is illustrated in what has become known as the "duck chart" shown in figure 8. The duck chart presents the forecast total demand and net demand for the

[35] In reality, these resources can be adjusted downward, just not upward if wind or sun aren't present. Both wind and solar PV are potentially curtailable, but require communication between the grid operator and the resource. Wind turbine blades can be positioned so as not to catch the wind and stop turning. Solar PV curtailment requries a smart inverter that can be told to disconnect the PV system from the grid. The inverters currently on nearly all residential and small commercial systems do not have this capability.

[36] See Joskow (2011) and Schmalensee (2012).

[37] See Mills and Wiser (2010) and Tabone and Callaway (2013).

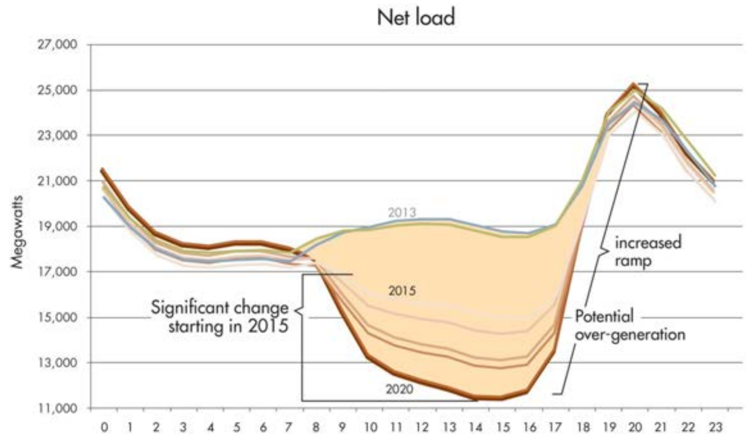

Figure 8. Projected Hourly California Demand and Solar Production (on a sunny, cool March weekday) with Increased Solar Penetration

California electricity grid on a sunny spring day with high penetration of solar PV.[38] The lowest line shows the net demand after subtracting solar PV generation from total electricity consumption with solar penetration projected for 2020. Even if solar generation were perfectly forecastable, the rapid drop in net demand as the sun rises and increase in net demand as the sun sets would be difficult to meet with the current mix of gas-fired generation in California.

The most cost-effective solution proposed by a recent study would be to run more gas-fired plants in the middle of the day and curtail production from solar PV.[39] In other words, the least costly engineering solution at this point may be to forego electricity that has zero marginal cost. It seems quite possible that if retail prices at these times were set at or near zero to reflect this situation, consumers would find innovative ways to use nearly costless electricity, but that requires adoption of high-frequency, time-varying pricing. While such pricing is completely feasible with current smart-meter technology, it has not been widely adopted, as mentioned earlier. In this way, technical challenges to integration overlap a great deal with economic policies.

Further economic challenges arise with the addition of subsidized renewable resources, because they change the economic returns to conventional generation. The most notable change is that because solar and wind generation have near-zero marginal cost they are generally used virtually all the time they are available. This pushes out the supply curve and lowers the market clearing price for electricity, reducing profits for all conventional generation in the market. In the longer run, this worsens the economics of conventional generation and can lead to exit. All of that would be a description of an efficiently operating

[38]This could be seen as a worst case, because a sunny spring day with relatively cool temperatures maximizes afternoon solar PV production while minimizing demand from air conditioning.

[39]See Energy & Environmental Economics (2014).

competitive market if no generation sources were subsidized, all sources paid their full social marginal cost, and electricity prices reflected the social value of marginal production at every point in time. However, renewable generation costs are artificially low due to investment and production subsidies, while conventional generation does not pay for its negative pollution externalities. And wholesale prices do not reflect the value of marginal power at a specific point in time or space; instead, the system operator separately arranges for electricity needed to maintain voltage in specific areas, to offset fluctuation of intermittent resources and for other operational constraints, and to respond to un-forecasted demand volatility. One of the common ways to assure needed capacity does not exit is through capacity payments, which generally pay companies to have generation available regardless of the electricity it is called upon to generate.[40]

B. *Policy towards distributed generation*

Cost reductions in solar PV technologies have also changed the economics of self-generation by end-use customers, known as distributed generation. In California, Hawaii and other sunny locations with high electricity prices, falling PV system costs have combined with substantial federal and state subsidies to make installing solar PV a money saver for some customers. The result has been a booming market in behind-the-meter solar PV. In the U.S., distributed solar PV capacity installation has increased from 400 MW in 2009 to about 1900 MW in 2013, with about half of new installations occurring in California.[41]

This trend has led some observers and utility executives to predict a "death spiral" in which a significant number of customers self-generate much of their electricity, forcing the utility to raise rates for the electricity they still sell in order to cover fixed investments, in turn making solar PV economic for a larger set of customers who then reduce their purchases, leading to a greater revenue shortfall and another rate increase, and restarting the cycle. Ultimately, some argue, the monopoly utility disappears. This scenario has triggered widespread debate – both positive and normative – about the future and viability of the utility. The regulator in New York state has even proposed a complete redesign of utility systems that is focused on customers also being generators.[42]

The social welfare gain from increasing reliance on distributed PV generation, however, is still far from clear. Even the most optimistic cost scenarios suggest that the full social levelized cost of electricity from residential solar PV is likely at least \$0.20/kWh in relatively sunny areas, more than double the full cost of gas-fired generation including a greenhouse gas cost of \$40/ton.[43] Distributed PV generation is eligible for the same tax benefits as large scale solar, a 30% tax credit through the end of 2016 and accelerated depreciation. Borenstein (2015) estimate that the accelerated depreciation amounts to an

[40] See Joskow (2008) for a broad overview of the role of capacity payments.

[41] See Sherwood (2014). These numbers are the sum of residential and non-residential installations that are non-utility scale.

[42] See NYS Department of Public Service (2014).

[43] The \$0.20/kWh figure uses the calculations in Borenstein (2012) and recent system cost figures reported by Barbose, Weaver and Darghouth(2014) to be as low as \$4 per watt of installed capacity. Most estimates of the long-run private cost of gas-fired generation are around \$0.06/kWh and emissions of about 0.0004 tons of GHG per kWh. Valuing the social cost of GHG emissions at \$40/ton yields a full social cost of \$0.076/kWh.

additional effective subsidy of about 15%.[44]

Distributed PV generation also benefits from being compensated at retail prices for the power it produces. Under "net metering," which has been adopted in most of the U.S., customers are credited for all power produced from their PV system by deducting the quantity from the customer's consumption.[45] In reality, calculations by Darghouth, Barbose and Wiser (2013) suggest that less than two-thirds of the power produced by a typical household PV system is consumed onsite – actually reducing the customer's retail demand – but net metering treats all power as demand reduction, thereby crediting it at the retail rate the customer would have paid.[46] If the full benefits that DG solar PV power brings to the market are less than the marginal rate the customer pays, then net metering policies lead to over-compensation of DG solar production. A simple calculation suggests this is very much the case, but the full system benefits are a matter of some dispute.[47] What is clear is that retail electricity rates are set in ways that are not closely tied to long-run marginal cost, so incentivizing DG solar through net metering will conflate solar policy with rate design policy and will have unpredictable effects on the incentive to install residential solar.

Probably the clearest illustration of perverse incentives from net metering policy is in California, where more than half of U.S. residential PV has been installed and where the gap between marginal retail rates and marginal cost may be highest. Most California utilities use increasing-block residential electricity pricing, meaning that the marginal price a customer faces increases in steps as the customer's consumption increases during the billing period. The two largest California utilities, each of which has an average residential retail price around \$0.18/kWh, have four blocks in their residential tariffs with prices from about \$0.12/kWh up to more than \$0.35/kWh on the highest block. Borenstein (2015) reports that a greatly disproportionate share of California households installing PV from 2007 to 2013 had consumption levels that reached into the two highest price tiers. He also finds that installations have been calibrated to eliminate consumption on the highest-price tiers, but not to crowd out the lower-price consumption. Borenstein (2015) estimates that the average bill savings from installing DG solar for customers of these utilities was about 25%-50% greater due to increasing block pricing than it would have been if the utility charged a flat rate equal to their average residential price per kWh. He estimates that the bill savings were more than double what they would have been if the utilities had charged \$0.10/kWh, a rough approximation of social marginal avoided cost.[48]

[44]Actually, the accelerated depreciation benefit is available only if the system is owned by a company, not an individual. This has been a significant factor behind the rapid growth of third-party owned residential systems in which the third-party owner leases the system to the homeowner or, more commonly, sells the electricity from the system to the homeowner. Third-party owners of these systems point out that this model also greatly lowers, or eliminates, the up-front payment the homeowner would otherwise have to make.

[45]See http://dsireusa.org/solar/solarpolicyguide/?id=17 for timely information on U.S. state net metering policies.

[46]This is for a system that generates electricity equal to about 60% of the household's demand. The figure would be even lower for a system that is larger relative to household demand.

[47]See Borenstein (2012) and Cohen and Callaway (2013).

[48]The best estimates of long-run marginal cost from gas-fired generation is about \$0.06/kWh as mentioned earlier, but DG solar PV consumed onsite also avoids the 7%-9% of electricity that is dissipated through line losses as the power flows from generation through transmission and distribution lines to the end user. See Borenstein (2008). Accounting for line losses, the electricity delivered for consumption from conventional generation has a marginal cost

Talk of a "death spiral" and questions of the viability of utilities, however, raises a question that extends far beyond these issues of implicit and explicit subsidies and the value of incremental DG solar generation. Can DG really function without the grid? Without low-cost electricity storage, and tolerance of less reliable electricity at some times (*e.g.,* a week without sunshine), it seems unlikely that most customers will be ready to operate off the grid anytime soon. If the grid is needed, how should it be paid for? The utility pricing model to date has been based on volumetric average cost pricing. Distributed generation at this point looks very much like the push for restructuring discussed in section 2: a comparison of average cost to marginal cost that ignores that the difference is not a real savings, but rather cost shifting. To the extent that a DG solar household has costs greater than or equal to the social marginal cost of grid-supplied electricity, the private savings are offset, or more than offset, by a revenue shortfall at the utility. That shortfall must then be made up by utility shareholders or, more likely, remaining rate payers. In fact, the notion of a death spiral – with rising retail rates as consumption declines – necessarily implies that price is above marginal cost, and an excessive incentive to install DG.

V. Summary

The changes in the electricity industry over the last two decades have been dramatic, but many were not the changes that were anticipated at the beginning of the industry's grand experiment with market-based pricing of generation and retail services. While the revenues for much of the nation's conventional and nuclear generation sources are now based upon market prices rather than production costs, retail pricing for the vast majority of residential customers remains dominated by state regulatory processes.

In the mid-1990s, the strong momentum for restructuring was driven by a large gap between market-based prices – which were based upon marginal cost in competitive markets – and regulated rates – which were based upon average production costs. During this period of relatively large capacity margins and low natural gas prices, market-based pricing appealed to customers and terrified utility shareholders whose assets would become stranded absent other compensation. However, despite the allure of market-based pricing, the reality of the regulatory process, and of case law, dictated that utilities be allowed to recover the bulk of what appeared at the time to be stranded costs.

The great irony of this period is that a half decade after transition arrangements largely compensated utilities for the losses incurred in selling or transferring these assets, the market value of those same assets had fully recovered. By the mid-2000s the relationship between average and marginal cost had largely reversed, and many states expressed a great deal of regret about the decision to restructure. However, since the formerly regulated generation assets were now largely held by private, deregulated firms, there was no clear path to

closer to $0.065/kWh. The timing of power from solar PV also boosts its value, or the cost of alternative sources. Solar PV generation produces more at peak times, so it is replacing power at times when marginal electricity costs are higher. Borenstein (2008) estimates that in real-world grid operation this increases the cost of the alternative power source by an average of 20%, bringing marginal cost of alternative generation to around $0.078/kWh. Inclusion of the cost of GHG emissions raises the cost of alternative generation by $0.015-$0.02 per kWh at a GHG price of $40/ton, bringing the alternative marginal cost to about $0.10.

dramatically "re-regulate" the industry without paying full market value for those assets. Looked at this way, one can view the disappointment with restructuring as being driven by magnificently poor market timing. Utilities sold off their assets at the nadir of their value; then, as natural gas prices climbed throughout the 2000s, those assets became quite valuable under market-based pricing.

Since 2009, this story has largely reversed yet again. Natural gas prices have declined sharply, nearly to the levels seen at the dawn of the restructuring movement. The attention of policymakers has now been consumed by environmental priorities, particularly the implications of coal generation decline and renewable generation growth for costs and greenhouse gas emissions. A surge of subsidized renewable generation, combined with low natural gas prices, has driven wholesale prices steadily lower. As one would expect, in the short run this has benefited consumers in market-based states disproportionately more than those in regulated states.

Going forward, the role of intermittent renewable generation at both the wholesale and distributed level is likely to continue to dominate the economics and policy of the industry. The low wholesale prices that have resulted from expansion of subsidized renewables are not sufficient to cover the total cost of renewable or conventional sources, so the prominence of extra-market sources of revenue – such as above-market contracts and capacity payments – is likely to continue to grow. This will mean that even in the "market" states, the true cost of supply will increasingly diverge from the underlying price of the fundamental commodity, electrical energy.

At the retail level, distributed energy threatens to unravel the economics of retail distribution supply. Again the juxtaposition of average and marginal cost is a driving force here, although the differences are exacerbated by inefficient rate-making and political economy. Current rate-making practices encourage individuals to install distributed generation, such as solar PV, that is privately economic because rates, which include the fixed costs of transmission and distribution, exceed the marginal cost of generated energy by a large margin. The next natural step in the rate-making process will be a move to two-part tariffs that include monthly charges decoupled from the volume of electricity consumed. There is speculation that the cost of storage technologies, perhaps deployed in a joint application such as with electric vehicles, could decline enough that households might bypass the grid completely.[49] Such an outcome would be a giant leap forward in technology, but it could be a step backward in economics if such decisions would again be motivated by an ability to shift sunk costs – this time of grid assets – onto other customers or utility shareholders. Policymakers again have a chance to make economically rational decisions based on true incremental costs. We can only hope that this time they will grab that opportunity.

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[49] See Lacey, 2014

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Powering Progress: Restructuring, Competition, and R&D in the U.S. Electric Utility Industry

Paroma Sanyal and Linda R. Cohen***

This paper investigates the R&D behavior of regulated firms when they transition to a competitive environment. Using data from the US electricity market from 1990-2000, we analyze how competition, institutional changes, and political constraints have contributed to the precipitous decline in R&D expenditure by regulated utilities. We find that firms reduce their R&D significantly at the very early stages of restructuring or even when they expect restructuring to occur. Once the emerging institutional structure becomes clear, R&D spending recovers but is later offset by another decline when restructuring legislation is enacted. In addition, greater competition and the nearing of such competition adversely affects research spending. In aggregate, R&D declines by 78.6 percent after electricity markets are restructured. Firm and state characteristics matter, and a majority of the research is conducted by large generation companies located in pro-research states, especially if they are part of a larger holding company. Such characteristics have a different impact on research spending in the pre- and post-restructured periods.

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"Research and development is our nation's investment in its own future. America's science and technology base may well stand as our most important renewable resource. The overarching public goal of US R&D policy, of which energy R&D is a major component, must be to assure for future generations that our Nation's capacity to shape the future through scientific research and technological innovation is continually being renewed" (US Department of Energy Report).[1]

"In a nutshell, the government that had created this regulated industry was saying, 'We don't want to regulate you anymore. Here's your business. Good luck.' However, the restructuring process initially generated more questions than answers, as the various players in the market tried to understand how the configuration of this industry might need to change." (CEO, TXU)[2]

INTRODUCTION

The two statements above, one by the Department of Energy taskforce and the other by an electric utility CEO, succinctly capture the central ideas on which this paper is based. First, investment in research and development (R&D) activities is fundamental for economic progress (Schmookler, 1966), and energy-related research is especially important. Second, the restructuring of the US power market has created uncertainties about the future business landscape, and electric utilities are trying to adapt as best as they can. This paper analyzes how R&D has fared in this environment. Data shows that, coincident with the movement towards restructuring the electricity industry in the early to mid-1990s, there was a dramatic decline in research activity in this sector in a relatively short period of time. This decline is worrying because it may "result in slowing technology development, sacrificing future prosperity to meet short-term goals, and failing to meet national energy goals" (GAO Report, 1996) and may thus have implications for the future of U.S. energy security. This paper is a step towards understanding how the transition from a regulated to a market regime influences firm R&D behavior.

Four major entities performed R&D in the U.S. electricity sector – the electrical equipment manufacturers (EEMs), such as General Electric[3]; the investor owned utilities; the Department of Energy; and the Electric Power Research Institute (EPRI). This paper focuses on the utilities' R&D expenditure, which fell precipitously between 1993 and 2000.[4]

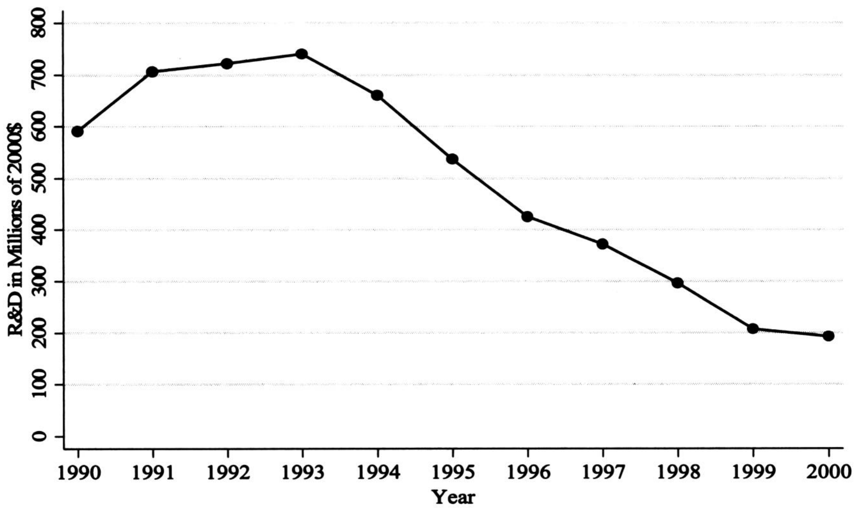
1. Final Report of the Task Force on Strategic Energy Research and Development, Secretary of Energy Advisory Board, U.S. Department of Energy, June 1995.

2. "Leading change: An interview with TXU's CEO (C. John Wilder)" by Warren L. Strickland. The McKinsey Quarterly, 29th March 2007.

3. For a detailed discussion on the structure and organization of research activities in the electric utility sector, please refer to Sanyal (2001).

4. To put this in context, the Energy Policy Act, which started the deregulation process, was passed in 1992. Utilities could probably see that market restructuring would follow in the near future, and since R&D spending is forward looking, they would have begun reducing their expenditures.

Figure 1. Total (Real) R&D for US Electric Utilities, 1990–2000



From its highest level of $741 million (in 2000 dollars) in 1993, R&D expenditure declined to $193 million in 2000 – a drop of nearly 74% (Figure 1).[5] R&D expenditures by the other players declined as well. Collaborative research by EPRI experienced a sharp drop (71 percent) as major utilities[6] slashed contributions. State electricity R&D funding declined by 30 percent between1993 and 1999, and the Department of Energy's funding decreased by 3 percent during the same period.[7] In addition, for EEMs, total R&D as a percent of sales declined as well. To provide a context, we can benchmark these numbers against other industries. In Appendix Figure 1, we provide graphs for the total (real) R&D trends from 1990-2000 for four industrial sectors: drugs, chemicals, machinery, and autos.[8] We find that three out of the four sectors show a steady increase in R&D expenditures over the time period.[9] This illustrates that the changes in the electric utility industry R&D during this period were not due to any general macroeconomic factor but were rather, peculiar to the industry itself. As such, the sharp drop in utilities' R&D expenditure requires further investigation.

5. We use the data that was collected up to the year 2000 since this corresponds to our sample period. Due to the California electricity crisis in 2001, many states stopped the restructuring process and some reversed course. Thus, including data after 2000 would have confounding effects on our results. Fabrizio et. al (2007) limit their sample to 1999 when studying electric utility productivity due to similar concerns.

6. GAO (Appendix II, 1996), Moore (1995)

7. EPRI (1997), GAO (1998)

8. The graphs are based on Compustat data. R&D is in millions of dollars and has been deflated by the producer price index in 2000.

9. The chemical sector shows a slight decline after 1999.

The magnitude and timing of these changes raise questions about the forces behind this decline. Since this drop in R&D was coincident with market restructuring, the obvious factors appear to be the changing institutional and market structures in the power sector. At the outset, however, it is important to ask whether such a decrease is cause for concern. To answer this question, we need to briefly address two related issues. First, what are the technology improvements that have taken place in the electricity industry, and what is the contribution of electric utility research to such progress? Second, how has the composition of R&D spending by utilities changed during restructuring, and should we be concerned?

On the technology front, there have been some major breakthroughs. The first is the rise of distributed generation technologies, such as the combustion turbine, fuel cells, and photovoltaics, which have eliminated the need for large scale power plants. The second is the development of the Integrated Gasification Combined Cycle (IGCC),[10, 11] which is a part of the clean coal technology program and can confer significant environmental and efficiency benefits. The third type of technology relates to renewables, such as wind, geothermal, and biomass energy. The fourth innovation is in the creation of demand side management programs to reduce electricity use by consumers. Although a majority of these technologies are being developed by large electric equipment manufacturers, such as GE, utilities have been playing a large role in testing these technologies and improving them.

As an example, in 1994 Southern California Edison spent approximately $1 million a piece on heat-rate improvement of fossil fuel generation and distributed generation; $8 million on renewable technologies, such as photovoltaics; and another $6 million on demand side management programs, for a total budget of approximately $70 million.[12] In 2000, the company was not involved in any of the above projects, and total R&D expenditure fell to just $1 million. Duke Energy Corporation spent 21 percent of its internal R&D budget on fossil-fuel generation research in 1994, and this declined to 9 percent in 2000. During the same period, their total R&D budget shrank from $18 million to $9 million. Yet another example is the Gulf Power Company, which spent about 40 percent of its internal R&D budget on clean coal technologies in 1994 and reduced this expenditure to zero in 2000. With the vast reduction in these budgets, the equipment manufacturers may have to look elsewhere for testing their technology, and this may adversely impact new technology development.

In addition, utilities spent a sizeable portion of their internal research budgets on public interest environmental R&D projects, such as research on global warming and the effects of electromagnetic fields on health. From the data, we find that for most utilities, the large projects with potential externalities, such as

10. This technology is being developed by two competing consortia: GE (Chevron Texaco)/ Bechtel and Siemens (Conoco Phillips). (http://www.hewm.com/docs/en/regulatory_strategies_new_energy_tech.pdf)

11. This technology converts coal into gas and then removes the impurities from that gas before it is used for electricity generation. This significantly reduces the emissions of sulfur dioxide, mercury, and particulate matter.

12. All dollar figures here are 2000 dollars.

air and environmental quality research, have been replaced by smaller and more targeted research projects, such as hydro basic research projects.[13] Again using Southern California Edison as an example, we find that such R&D expenditures have declined from $11 million to 160,000 dollars, a drop of almost 98 percent. In general, we find that collaborative research and classic "public interest" R&D has led the charge in the overall decline in research spending (Hirsch, 1998; U.S. House of Representatives Testimony, 1998). Since such research does not confer any short-term monetary benefits, one would assume that the equipment manufacturers would not be willing to step in and pick up the slack. The combination of declining federal R&D support and the precipitous drop in utility research expenditures does not bode well for such research. These are important concerns, and analyzing how the restructuring policies have affected utility R&D behavior will help in understanding the relation between market structure and the conduct of R&D.

Considerable theoretical and empirical attention has been focused on the linkages between market structure, innovation, productivity, and R&D[14] for manufacturing firms. However, relatively little attention has been devoted to the behavior of firm R&D when such firms are regulated and have to adapt to a competitive threat. The electricity industry restructuring provides a good opportunity to study this question. The restructuring of the U.S. electricity industry is likely to substantially alter innovation incentives and, consequently, affect the level and composition of R&D. We believe that this study has broader implications for the conduct of R&D in restructured industries and may serve as a good benchmark for other regulated industries in transition. In addition, identifying the factors behind the decline may suggest ways in which such funding decreases can be mitigated.

Our results indicate that restructuring, and consequent changes in market and institutional arrangements, are a significant determinant of the R&D response of utilities. In particular, the expectation of restructuring and the early stages of the restructuring process are associated with a decline in research spending. R&D suffers as the specter of competition draws closer and as the level of competition increases. A part of this decline is reversed when an actual restructuring order has been passed and utilities are fairly certain about the emerging institutional structure. However, this increase is offset by a further decline when states actually implement restructuring legislation. In aggregate, restructuring is responsible for a 78.6 percent decline in electric utility R&D expenditures. In addition, a majority of the research is conducted by large generation companies, especially if they are part of a larger holding company. State preferences also influence the amount of R&D conducted by the utilities, and firm and state characteristics have a different impact on R&D before and after restructuring. The derivation and the implication of these results are analyzed in subsequent sections of the paper.

13. For an extensive discussion, see Sanyal (2007).

14. For a complete discussion on this topic, please refer to Kamien & Schwartz (1975) - "Market Structure & Innovation: A Survey", JEL, 13:1.

This paper is organized into five sections. The first section briefly outlines the restructuring process and the nature and organization of R&D activities in the US power industry. The second section discusses earlier literature that investigates both the R&D model and the incentives to conduct R&D under a regulated versus a market framework. Methodological issues, data sources, and the specifics about the variables used are presented in the third section. The fourth section explains the empirical results, and the last section concludes.

1. BACKGROUND

The Energy Policy Act (EPAct) of 1992 gave impetus to wholesale power competition by creating a new class of power producers called the exempt wholesale generators and by creating open-access transmission grids for wholesale transactions. In 1996, FERC Orders 888 & 889[15] encouraged retail competition for the first time while furthering wholesale competition.[16] These were federal guidelines, and each state interpreted and implemented the Orders in different ways. This led to the emergence of a diverse set of state-specific institutional arrangements that governed utilities and this paved the way for altering the existing regulated monopolies into firms that could successfully navigate the new competitive environment[17] (Blumstein, 1997; Borenstein, & Bushnell, 1997; Bushnell & Stoft, 1995; Hogan, 1997; Joskow, 1989, 1997, 1999; Moyer, 1993; Sloan, 1994; Taylor, 1998; Wolak, 1997).

Despite common federal guidelines, deregulation and restructuring of the industry did not occur as a one-time monolithic change. Instead, the processes involved a complex set of institutional changes that ranged from implementing pricing rules and setting up auction mechanisms for the power market to modifying the policies governing various operational facets of electric utilities. The pace

15. Order 888 – "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities" and Order 889 – "Open-Access Same-Time Information System." For a detailed provision of the orders, please refer to DOE/EIA (1997).

16. The main provision of Order 888 is that utilities that own transmission networks must provide transmission services to other power generators at cost-based, non-discriminatory prices. Provisions were also laid out governing the recovery of stranded costs by utilities. Order 889 required each public utility to participate in an Open Access Same-Time Information System (OASIS) to facilitate wheeling by third parties that did not own transmission capacities. These orders taken together provided impetus to wholesale competition and initiated an effective groundwork to begin retail wheeling whereby retail consumers could shop around for the best rates while purchasing electricity.

17. Currently there are about 3200 electric utilities in the US, of which only about 700 generate power. In the generation sector there are two broad groups – the utilities and the non-utilities. The utilities consist of the five distinct groups: the investor owned utilities (IOUs), federally owned utilities, other public utilities (state, municipal, etc.), co-operatives, and power marketers. The non-utility group is comprised of qualified and non-qualified cogenerators, small power producers, exempt wholesale generators, and non-qualified non-cogenerators. The non-utilities are "privately owned entities that generate power for their own use and/or sale to utilities and others" (DOE/EIA-X037, 2000). The investor owned utilities are the most important category, and they account for 75 percent of power generated in the US.

and nature of restructuring differed considerably from state to state. Most states, however, went through three common stages of restructuring, starting with the initiation of investigations into the deregulation process and ending with the passage of some form of retail competition order. In addition, several other policies, including those that affected the mandated date for retail competition, the percentage of market open to such competition, the guidelines governing the divestiture of assets, default provider rules, and stranded cost recovery, were important as well. All these policies changed not only the operating environment of the utility, but also the very nature of the firm, and hence have implications for the conduct of R&D.

We are interested in studying electric utilities because they were the entities most directly affected by the restructuring process. Historically, the EEMs have conducted most of the R&D and generated a majority of the innovations in this industry.[18] Compared to these EEMs, the R&D levels for utilities were low since the latter could not internalize the benefits of such research. They allocated some of the research dollars to in-house projects, such as those focused on global warming, and the rest of the money was given to external collaborative research agencies, such as EPRI. Within the cohort of utilities, R&D was primarily conducted by big, vertically integrated firms that owned generation, transmission, and distribution. Companies that were solely distribution or transmission companies invested very little in research. In the regulated environment, R&D investment was essentially a risk-free venture for the utilities since such investments could be recouped. With restructuring, the incentives for R&D changed, and appropriability and cost concerns became important. The next section briefly discusses the motives for R&D in the regulated and restructured regimes and frames the observed decline in light of the changed incentives.

2. LITERATURE REVIEW

2.1 General Determinants of R&D

R&D is considered a critical engine of economic and productivity growth (Griliches, 1979, 1986; Griliches and Mairesse, 1984; Nadiri, 1979; Van Reenen, 1997), and there has been substantial research on the drivers of R&D (Cumming and Macintosh, 2000). Two broad hypotheses have emerged from such analysis. Pioneered by Schmookler (1966), the demand-pull hypothesis emphasizes demand side factors, such as consumers' demand for new products, and cost-reductions as primary drivers of R&D. The supply-push hypothesis, on the other hand, (Rosenberg, 1974) holds that supply-side factors, such as differences in the technological environment of the firm and industry concentration, lead to variations in R&D expenditures. Empirical evidence suggests that neither hypothesis alone can explain firm R&D behavior and that both demand and supply aspects

18. See Sanyal & Ghosh (2008) for a detailed analysis of the impact of restructuring on innovation by electric equipment manufacturers, such as General Electric and Westinghouse.

are important (Scherer, 1982; Pakes and Schankerman, 1984; Jaffe, 1986, 1988). Combining the hypotheses, one can point to a common set of factors that are important drivers of R&D spending.

First, a firm's characteristics and organizational structure (Piga and Vivarelli, 2003) are important in explaining its R&D propensity. Firm size seems to be of critical importance, and large firms are more research intensive than small ones (Grabowski, 1968; Lee, 2003). Profitable firms, and those with excess cash, also conduct more R&D (Reynard, 1979; Connolly and Hirschey, 1984). Unionization is an important determinant of R&D, and greater unionization has adverse impact on such spending (Menezes-Filho et. al, 1998). Second, features of the industry within which the firm operates are equally important. Industry concentration, product market competition (Wahlroos and Backstrom, 1982), and exogenous technology accumulation by other firms (Lee, 2003) also explain a firm's R&D behavior. Third, government policies and public R&D support influence a firm's R&D choice. Tax incentives and R&D subsidies can often boost research expenditures (Mansfield and Switzer, 1985; Hall and Van Reenen, 2000). In addition, most studies find that government support has a positive effect on private R&D expenditures (Levin and Reiss, 1984; Lichtenberg, 1984, 1987, 1988; David et. al, 1999). In this paper, we add to this literature by analyzing the R&D behavior of regulated private monopolies, which then undergo restructuring and have to respond to market competition and price-cost pressures.

2.2 R&D Under Regulation

The relation among market structure, R&D, and innovation has been the subject of extensive analysis in the industrial organization literature (Fellner, 1951; Scherer, 1967; Needham, 1975; Kamien and Schwartz, 1975; Levin, 1981; Culbertson, 1985; Cohen and Levin, 1989). Most studies, however, have focused on the incentives of profit-maximizing firms. While there are a few studies that analyze the behavior of regulated firms, their focus is on technology choice rather than R&D decisions. These studies have two main findings. First, regulation appears to have an adverse effect on technological progress and stifles innovation (Petersen, 1975; Magat, 1976; Riorden, 1992; Granderson, 1999). Second, rate of return regulation distorts firms' choice of technology (Smith, 1975; Okuguchi, 1975). In particular, regulated firms choose technology that enhances the non-capital input at the expense of capital inputs, and this input mix differs from that chosen by non-regulated firms (Granderson, 1999).

These papers give us some insight into the incentive structures of regulated firms and their technology choice behavior. However, they do not directly address the R&D decisions by these firms. The analysis of technology choice in these papers is based on Averch-Johnson types of distortion,[19] where the regulated firm goes off its path of equilibrium and chooses a technology that distorts the

19. Rate of return regulation distorts investment incentives and leads to over-capitalization in a regulated industry.

capital-labor ratio in a way that exacerbates the distortion. R&D decisions are different because such expenditures are expensed and not capitalized and therefore have to be analyzed separately from technology investment questions. To the best of our knowledge, the only works that investigate this question are a paper by Wilder and Stansell (1974) and a comment on their paper by Delaney and Honeycutt (1976). The former estimate a simple model based on 1968-1970 electric utility data and find that firm size and profitability are important determinants of R&D. Delaney and Honeycutt (1976) refute the claims made by the above authors and show that their conclusions are sensitive to sample and time-frame choice. Our paper adds a necessary piece to the existing literature by investigating the determinants of R&D expenditure choice by regulated utilities and the changes that occur with restructuring.

The incentive structure of regulated utilities are different from profit-maximizing firms since the former were subject to rate-based regulation, and most major expenditures had to be approved by regulators. For regulated utilities, R&D was done, for the most part, not to gain any competitive advantage but for other political economy reasons. One might argue that under "regulatory lag" conditions, a company might perform R&D in order to improve operating efficiencies, which is consistent with the notion that its incentives are aligned with those of private firms when not subject to rate reviews. But the incentive to perform R&D under these conditions is weak.[20] Electric utilities had franchise monopolies that not only protected their activities from interlopers (obviating the basic Schumpeterian reason for conducting research) but also circumscribed their own business undertakings. Their ability to exploit research results was consequently limited.

Even when formal rate hearings lag company decisions, regulated utilities operate in a shadow of potential regulatory oversight that darkens prospects for R&D. Research is inherently risky, with the risk justified by infrequent but valuable inventions. But if a utility succeeded in producing, for example, a cost-reducing innovation, regulators would likely take notice and redistribute exceptional returns to rate-payers. Our data series does not include years during which utilities allegedly enjoyed regulatory lags, but anecdotal evidence suggests that they did not devote unsupervised surplus to the pursuit of research.[21]

The second reason a regulated utility would have a research program is by order, or anticipated order, of its regulatory commission. In this case, we would expect the program to reflect the preferences of the commissioners. For

20. During the 20th century, electricity technology underwent enormous technological advance, and regulated utilities are credited with providing a stable, forgiving environment ideal for inducing innovation (of at least some types) from electric equipment manufacturers (EEM) and other manufacturing firms. Innovation by EEMs and other firms and the role of regulation in inducing such innovation is clearly an important topic, but an analysis of it is beyond the scope of this paper. See Ishii (2004), and Sanyal and Ghosh (2008) for a related analysis.

21. In contrast, AT&T, while holding down a regulated monopoly on phone service, conducted an extraordinarily successful research program and was among the world's top annual patent recipients. Neither the electric utilities nor, prior to 1990, their research consortium, the Electric Power Research Institute (EPRI), obtained patents on inventions. See Hirsh (1989); Corey (1997).

example, "green" states, such as California, may want their utilities to invest more in environmental projects and increase the overall R&D spending on the firms. The discussion above yields some suggestions about the variables that can be used to model R&D activity in a regulatory regime. In the econometric specification, we use regulator characteristics and state R&D preferences to capture the above influences.

2.3 R&D Under Restructuring

Under restructuring, the incentives will be mostly similar to that of other private profit-maximizing firms. The restructuring process involves significant uncertainties about market structure and conduct, and will thus have a large impact on a firm's research investment decisions, although apriori, its direction is ambiguous. For example, uncertainty over demand conditions may affect the timing of an investment or the choice of technology. If the actual nature of the market is unknown, the real options literature and efficient investment principles dictate a delay in investment (McDonald and Siegel, 1986; Dixit and Pindyck, 1994; Ishii and Yan, 2003; Goorbergh et. al, 2003; Macauley, 2003). This spills over to R&D to the extent that research is conducted in response to demand for technology, or "induced demand" R&D (Newell, Jaffe and Stavins, 1999). Thus, we expect uncertainty to dampen R&D expenditures. In addition, policies that adversely impact firm finances, such as the ability of a firm to recoup its stranded costs, will decrease R&D.

However, there are forces that work in the opposite direction (Kort, 1998). Research activities in a firm increase the firm's ability to absorb the research results of others or to innovate in areas related to, but distinct from, the firm's own research project (Dosi, 1988). Second, R&D can be a hedge. A firm may choose to conduct research on several technology options and thus increase the research budget during the investment delay. The importance of this effect depends on the timing of the resolution of uncertainty and on the research production function. If there are high fixed costs to research (Hall, 2002),[22] the hedging characteristic may dominate the incentive to delay. Third, if a firm delays ordinary investment, it may face fewer budget constraints for other activities. R&D can substitute for investment if it places the firm in a position to invest more rapidly in new technology once the optimal investment strategy is revealed. Last, Schumpeterian analysis predicts that when firms face a relatively elastic demand curve (as in the restructured phase), they may perform more R&D (Reinganum, 1989).[23]

Drawing from the above discussion, the next section formulates the empirical model that analyzes the effect of restructuring policies on R&D expenditures by IOUs, conditional on state and firm characteristics.

22. R&D activities tend to be very stable over time, an effect believed to be due to the high fixed costs of assembling a research staff and the very low value of the staff in any alternate use.

23. The intuition is that a small success – and small price decrease – will secure for the firm a large number of new customers.

3. DATA AND VARIABLE CONSTRUCTION

3.1 Data on R&D Expenditures

The key source of data for this paper is Form 1, which regulated utilities file with the Federal Energy Regulatory Commission (FERC). The Form contains all financial data, such as revenue and sales; generation data, such as the amount of electricity produced from steam, nuclear, and hydro; customer data about the share of sales , the revenue of residential, commercial and industrial customers; and other expense data, such as R&D, wages, and salaries. The primary data on restructuring policies is collected from EIA's (Energy Information Administration) "Status of State Electric Industry Restructuring Activity as of February 2004."[24] Data on the percentage of customers eligible for retail access is obtained from the "Retail Energy Deregulation Index 2000," published by the Center for Advancement of Electricity Markets.

Our main focus is to study how the transition from regulation to competition changes the R&D behavior of firms. To implement this we use data for the period 1990-2000[25] for all major utilities (195 of them). The panel is unbalanced due to missing data, which occur primarily in the early 1990s. Merger of companies also contributes to the unbalanced nature of the panel, although this accounts for less than 1 percent of the missing numbers. In total, there are 1663 observations for the period, and 1291 are associated with positive R&D numbers. These numbers imply that approximately a quarter of the utilities do not conduct any research. From the pre- and post-deregulation statistics presented in Table 1, we observe that the R&D expenditures are significantly different in the two periods. Appendix Figure 2 shows a dramatic decline in R&D for the top 15 R&D performing firms, further supporting the trends in Table 1. The next sections discuss the explanatory variables used in the empirical analysis.

3.2 Regulatory Variables

3.2.1 Restructuring Variables

Over the last decade, the electric utility industry has been in a state of flux. Deregulation, mergers, acquisitions, and divestitures have dramatically changed the landscape of the industry. The sharp decline in electric utility R&D expenditure (by approximately 74 percent) that has accompanied the electricity market restructuring puts the responsibility of this decrease squarely on the regu-

24. This publication outlines the regulatory orders, legislations, and investigative studies that have been undertaken by each state up to the present.

25. Although available, we do not use data after 2000 as there are confounding issues after that year. The California electricity crisis happened in the summer of 2001, and many states, including California, halted the restructuring process. Adding the post-crisis years would make our results difficult to interpret because of the reversals, and no general conclusions about the effect of competition on regulated firm R&D behavior can be drawn.

latory policies. We use several variables to capture these policy changes. First, the major federal law change (FERC Order 888 & 889) that began the restructuring process and market competition is captured by a dummy variable $FERC_{1996}$ that takes the value 1 starting in 1996. However, restructuring was not embodied in any single law change, and each state pursued restructuring in a different way and at a different pace. Thus, any one variable is not adequate to capture the dynamic nature of this change, and we use six variables to characterize these state-level institutional changes.

First, we construct three dummy variables based on the status of restructuring in states.[26] EIA classifies the status of deregulation into four categories: "No Activity," "Investigations Ongoing or Orders and Legislation Pending," "Order Issued for Retail Competition," and "Legislation Enacted to Implement Retail Access." The *deregulation investigation dummy* is 1 if the state has, at the very least, started investigations into the restructuring process or has legislation pending and is 0 otherwise. The *restructuring order dummy* is 1 if a state has issued an order for retail competition and is 0 otherwise. The *legislation enactment dummy* is 1 if the state has passed a legislation to implement retail competition and is 0 otherwise. Table 2a shows the status of restructuring for each state from 1994-2000.[27] From Appendix Figure 3, we observe that states at different levels of restructuring display very different R&D expenditure levels. The states with the lowest levels of restructuring, i.e., ones where investigations are ongoing or orders are pending, suffer the most. High deregulation states where restructuring laws have been passed by the legislature, have low but stable levels of R&D. This foreshadows the fact that it may not be restructuring policies per se, but, rather, the uncertainties associated with the process that adversely affect R&D spending.

In addition to the above dummies, other important restructuring policies that may affect a firm's R&D behavior are those that are concerned with divestiture and stranded cost recovery. In the selection model (Table 5A), we use a *divestiture dummy* that equals 1 if a state encourages or mandates divestiture of generation assets and equals 0 otherwise, and turns on when legislation outlining the divestiture policies adopted by a state, is passed. We hypothesize that if a state encourages divestiture of generation assets, then utilities in those states will stop R&D activity since a majority of R&D resources were invested in generation-related projects.

Last, we use two dummies to capture stranded cost recovery policies. In the selection model we use a *stranded cost mechanism dummy* that takes the value 1 if a state has a stranded cost recovery policy in place. If such a policy exists, then utilities will be confident that they can recover at least a portion of their stranded costs and will not take a financial hit. This should mitigate the R&D expenditure

26. This is based on EIA's publication "Status of State Electric Industry Restructuring Activity as of February 2004."

27. There are two states that had reversal in their deregulation status in 2000. Iowa had started investigations about restructuring in 1996 but stopped the process is 2000. By 1999, Mississippi had restructuring legislation that was pending, but it stopped all activity in 2000

decrease to some extent. To explain the impact of this policy on the level of R&D, we construct a different variable (*stranded cost recovery type*) that captures the permitted level of stranded cost recovery. It is conceivable that a utility located in a state that allows one hundred percent recovery through a wire charge, for example, will decrease its R&D budget by less than a utility located in a state where full recovery is not allowed, or where there is uncertainty about the recovery mechanism. During our sample period, 14 states had taken steps to mandate the level of permitted stranded cost recovery and its composition. We generate an indicator variable that takes the value 0 if there is no recovery mechanism in place, 1 if there is discussion about stranded cost recovery but no concrete step has been taken, 2 if a mechanism is in place but full recovery is not guaranteed and is conditional on certain factors being fulfilled,[28] and 3 if there is opportunity for full recovery of all stranded costs. Both variables are turned on when stranded cost recovery legislation is enacted (Table 2b)

3.2.2 Competition Variables

To characterize the nature of competition in a state, we use the number of months until retail competition begins and the percentage of customers eligible for retail competition. First, the *number of months until retail competition begins* should affect a firm's R&D spending. Two states may have passed a retail access order in the same year, but one may mandate that retail competition should begin ten years from the order date, while the other may mandate that retail competition begin immediately. Presumably, firms will behave differently in the two situations. Apriori, the effect on research spending is not clear and will depend on a firm's perception of uncertainty, and thus we are agnostic about the direction of this variable. One may argue that as retail access moves closer, the firms will cut back on research because the pressure to reduce prices will adversely affect discretionary spending such as R&D. On the other hand, if such research increases efficiency or decreases cost, then such R&D spending should increase as the threat of competition draws closer.

So far, 23 states have set concrete dates for the phasing in of full retail competition. For states that have not set a date, we assume that they have 180 months (or 15 years) until retail competition begins (i.e., at any point in time, their expected start date is 180 months in the future, unless an act regarding retail access is passed). For the states with a specific start date, this variable is constructed as a difference between the mandated start-date (month and year) of retail competition and the current month and year, i.e., it counts the number of months until the actual start of retail access, and becomes zero once retail access is implemented.

28. The recovery may vary by individual utility and depends on its mitigation efforts, divestiture of generation assets, whether just and reasonable stranded costs can be recoverable if appropriate consumer safeguards related to stranded costs are implemented, or if there is an opportunity to recover prudently incurred stranded costs.

Thus, it is bounded below at zero, and bounded above at 180.[29] For a summary of the mandated dates, please refer to Table 2c.

Passing a restructuring order, or even mandating the date for the start of retail competition, may not be sufficient to engender effective competition in the market. For example, a state may be deregulated but may lack firms that will compete in the retail market, or only some customers may be eligible to switch to other power providers (at least at the beginning of the restructuring phase). These conditions would lead to low levels of actual competition. To measure this we use the *percent of customers eligible for retail competition,* i.e., the percentage a utility's of customers who are eligible to choose an alternate provider (Malloy and Mohammad, 2000). This is essential to the development of retail energy competition and its maturation because the greater the percentage of eligible customers, the greater the potential competitive threat to the incumbent utility. This is particularly important as research expenditures are essentially forward looking, and a firm that knows that its entire market will be open to competition a few years down the line may behave very differently from another whose market is fairly protected despite restructuring. Theoretically, the effect of competition on R&D is ambiguous. On one hand, firms may increase their research spending, especially on those projects that directly related to gaining market share or increasing profits. On the other, firms may cut back on R&D if it does not help them gain a competitive advantage. Since R&D was not the core mission of these regulated utilities, we expect the latter effect to dominate, i.e., we expect competition to adversely affect research spending.

3.3 State Characteristics

The move towards restructuring the energy markets was a fairly gradual process. Thus, utilities may have formed a fairly good expectation about the emerging status of restructuring in their home states. Since R&D in a forward looking variable, expectations about future changes in the institutional structure should affect the decision to conduct R&D. We capture this by using a *high electricity price state dummy* that takes the value 1 if the average electricity price per megawatt-hour in the state was greater than the average US price between 1990 and 1996 and takes the value 0 otherwise.[30] The state electricity price is a good predictor of the varied status of electricity reform in different states (Ando Palmer, 1998; Sanyal, 2001). Utilities could have made a fairly good prediction about the possibility of restructuring in their states by looking at these prices since higher-priced states had a greater chance of embarking on a restructuring program in an attempt to decrease these rates. We expect this variable to have a negative impact due to the reasons cited above for the deregulation investigation dummy.

29. Sensitivity analysis shows that the choice of 20 years does not affect the results.

30. We choose 1996 as the cutoff date because this variable loses its information content after that year. States such as California began their restructuring in 1996, and this dummy is no longer a good predictor of restructuring due to endogeneity between electricity prices and restructuring policies.

Implicit regulatory pressure and other state characteristics also influence R&D investment decisions by utilities. We use the voting records of state legislators on green issues as a proxy for *regulator nature*. The League of Conservation Voters (LCV) publishes detailed voting records of state senators and legislators on all environmental legislations brought forward in the Senate and Congress. If legislators reflect the preferences of their constituents, then their voting pattern should convey information about the state. Typically, green states have also been pro-active in areas such as R&D and innovation. Thus, we assume that regulators in green states will be pro-R&D and thus may exert pressure on utilities to increase their research spending. We use a three-year moving average for the LCV score (for legislators) of each state.

The *share of coal generation in the state* also captures state preferences, and is constructed as the ratio of electricity generated from coal divided by the total electricity generated in the state. The effect of this variable on R&D can go in either direction. States that generate most of their electricity from coal are big polluters, and therefore regulators may not have much incentive to push utilities to do more research. On the other hand, since these firms pollute much more than others, regulators may choose to placate environmental action groups by having them conduct more research.[31]

Last, we include a *dummy for high R&D states*. Traditionally, six US states, California, Massachusetts, Michigan, New Jersey, New York, and Pennsylvania, have been considered high R&D states (NSF Science & Technology Report, 1993). These states have a high level of private and state funding for R&D, and it stands to reason that this reflects some preference pattern for investing in research. We hypothesize that utilities in such states will, on average, be more likely to invest more in R&D because of both regulator preferences and a greater availability of monetary and non-monetary R&D support.

3.4 Firm Characteristics

The nature and type of firm also affects both the decision to conduct R&D and the magnitude of the research spending. The yearly operating revenue (2000 dollars) of each company is used as a proxy for *firm size*. We expect size to have a positive impact on both the decision to engage in R&D and its magnitude. Firms need a critical minimum scale to reap benefits from research; therefore, small firms will not conduct R&D. Among the firms that choose to invest in R&D, larger firms have more resources at their disposal than their smaller counterparts and will thus invest more.

31. In other specifications not reported here, we also included state GSP and the share of electric utilities in the state GSP to capture the wealth of a state and the importance of the electricity sector in the state. Neither variables were significant.

3.4.1 Utility Type

We use several variables to characterize the nature of the utility. First, we use two variables that show whether electricity generation is an important part of the utility. In the selection model, we use a *distribution firm dummy* to capture the fact that distribution companies rarely perform any R&D. Only firms that are involved in generation conduct research. This dummy is 1 if the share of generated electricity is less than 75 percent of the total electricity sold by the company[32] and 0 otherwise. When explaining what determines R&D levels, we use the *share of generation in total electricity sales* to capture the fact that a company that generates more power may invest more in R&D since a large portion of such research expenditure was generation related.

Second, we use a fuel based variable to capture generation technology. The *share of fossil fuel* in the generation mix is used to investigate whether dirtier fossil fuel-based plants conduct more research. If it is true that these utilities conduct more research, it may be the case that they perform the research in order to keep regulators happy, or they are particularly interested in developing cleaner technologies. A hydro-electric utility rarely does any research as these are traditionally low-technology operations and are less likely to invest in research than are nuclear or fossil fuel companies. Nuclear utilities also conduct little research.

Third, we use the *share of industrial customers* to characterize a firm's exposure to competition. Utilities serve three distinct types of customers – industrial, commercial, and residential. Even before deregulation, new co-generation technology had made it possible for some large industrial customers to supply their own power. The existence of such bypass opportunities pressured some utilities to offer better rates to these customers. In addition, with retail access, this customer segment would be the first to look for alternative suppliers that could give them cheaper rates. Thus, utilities that serve a greater amount of industrial customers would have greater exposure to competition and may be under pressure to lower their rates. Apriori, the effect on R&D is unclear. Firms may invest more in R&D projects that enhance generation efficiency and decrease costs. However, the opposite may happen as well: utilities may decide to cut back on R&D to save money, thereby reducing costs.

Last, we use a *wholesale market participation* variable to capture whether a utility has been participating in the competitive wholesale market. After the introduction of the1992 EPAct, utilities could buy and sell power for resale, and rates were usually set by the transacting parties.[33] Customers such as municipalities could shop for power, and this greatly increased the risk for utilities, who found themselves in danger of losing these customers to competitors. This may have put

32. For robustness, we have varied the cutoff from 75 to 80, 85, and 90 percent, and this does not make a difference to the results.

33. The rates were nominally required to be set by the Federal Energy Regulatory Commission (FERC), but, in practice, FERC allowed the parties involved to choose the rate.

downward pressure on prices, and concern about the bottom line may decrease R&D participation. Hence, we expect a negative coefficient on this variable.

3.4.2 Organizational Structure

We also control for the organizational structure of the utility. Some utilities belong to large holding companies, and the budget constraints driving their R&D spending will be different from stand-alone utilities. We use two variables to capture this: *holding company dummy* and the *size of the holding company*. In the selection equation, we use the holding company dummy to control for the fact that a utility within a holding company may have access to greater internal resources, and externalities from its research may be better internalized. Thus, such a firm may be more likely to invest in research. In the level regression, we include the size of the holding company, i.e., the number of firms within the holding company structure. We expect utilities belonging to larger holding companies to invest more resources in R&D for the same reasons stated above.

Last, in the selection equation we use a dummy to control for *pending mergers*. This dummy is 1 from the time mergers are announced until the date they are consummated. Utilities with a merger in the horizon face substantial uncertainty about the nature of the emerging firm. The real options literature suggests that in such a scenario, firms will hold back on investment until the dust settles. Therefore, we expect such firms to put a hold on their research activities, at least temporarily. The next section presents the empirical results, and summary statistics for the estimation sample (with and without zero research expenditures) are presented in Table 3.

4. EMPIRICAL SPECIFICATION AND RESULTS

4.1 Did Restructuring Really Affect R&D Spending?

We begin by estimating a simple difference-in-difference model (Bertrand et. al, 2002) to analyze whether restructuring was, indeed, responsible for the significant R&D decline. The equation given below is estimated using the random effects panel data methodology.[34]

$$\begin{aligned} \ln RD_{ijt} &= \alpha + \beta FERC_{1996} + \lambda Treated_{jt} + \theta(FERC_{1996} * \\ &* Treated_{jt}) + \sum_{P=1}^{p} \gamma_P F_{ijt} + \sum_{j=1}^{47} \delta_j S + \sum_{t=1}^{9} \gamma_t T + v_i + \varepsilon_{it-1} \end{aligned} \qquad (1)$$

where: i denotes the firm; j, the state; and t, the year. $\ln RD_{ijt}$ is the log of the firm's real R&D expenditure in a given year, F_{ijt} denotes firm characteristics, S and T denote state and year fixed effects, and $FERC_t$ is the FERC order dummy. The

34. The error can be disaggregated into two components: v_i - the random disturbance that varies by firm but not over time ($v_i \sim N(0, \sigma^2_v)$) and ε_{it} - is the idiosyncratic error component ($\varepsilon_{it} \sim N(0, \sigma^2_\varepsilon)$).

$Treated_{jt}$ dummy takes the value 1 for those states that had a higher than average electricity price before restructuring, i.e., the *high electricity price state dummy* equals 1. We choose this as the treatment group since the primary reason for restructuring was to bring down high electricity prices, and states that had prices higher than the national average were the first targets of restructuring. θ is the difference-in-difference coefficient. Results are presented in Table 4.

We find that after controlling for basic firm and state characteristics, the estimate for θ (the difference-in-difference parameter) is negative (-0.283) and significant at the 5 % level – indicating that restructuring has indeed resulted in a significant decline in R&D spending for these utilities. However, this simple specification fails to capture the various facets of restructuring. After 1996, states differed not only in their pace of deregulation and restructuring but also in terms of effective competition and other market institution variables. Hence, we estimate a richer model in Table 5a and 5b to investigate the impact of these variables. The next section presents the detailed two-step model used to analyze R&D spending by utilities.

4.2 Modeling Research Spending by Utilities

R&D data has some peculiar characteristics that are different from other types of data. Typically, small firms do very little R&D, and this results in a high occurrence of zeros in the R&D data. For the econometrician observing the data from the outside, this presents a unique challenge. One is always faced with the question: What do these zeros represent? Do they represent the decision not to conduct any R&D, or are these just zero dollars spent on R&D? Econometrically, these two situations call for different estimation techniques. Although we can use econometric tests to select one over the other, one should also draw from qualitative evidence about firm conduct. For R&D, we believe that the zeros represent decisions not to conduct any R&D. This assertion is based primarily on the qualitative study of how these firms made R&D decisions. We will test this assumption when estimating the empirical models.

We hypothesize that research expenditure decisions are a two-step process. In the first stage, the firm decides whether it should engage in R&D at all, which depends on its expected future benefits from R&D. Benefits in this case do not imply monetary profits alone, but they may include intangible benefits a firm enjoys by keeping regulators happy. The second-level decision involves determining the optimal amount of R&D expenditure that would maximize the present discounted value of the firm's benefit function, subject to various institutional and revenue constraints. In this context, both unobserved heterogeneity and selection issues are a problem. A number of studies have addressed selection issues and unobserved heterogeneity under conditions of strict exogeneity of explanatory variables (Kyriazidou, 1997; Verbeek and Nijman, 1992) and with endogenous regressors (Vella and Verbeek, 1999; Wooldridge, 2002; Fernandez-Val and Vella, 2007). Using methodology developed in the above studies, we first test whether selection is a concern for our specification.[35] We then use the selection correction outlined in Wooldridge (2002) to estimate our two stage model.

Stage 1: Selection Equation

Each year the firm decides to invest in research (y_{it}) if such investment is associated with positive net benefits. The latent unobserved variable is net benefit stream from such research (y^*_{it}). Thus the decision is modeled as:

$$\begin{aligned} y^*_{it} &= x'_{it}\varphi + u_{it}, \quad \text{where } i = 1, \ldots n \text{ and } t = 1, \ldots\ldots. T_i \\ y_{it} &= 1 \quad \text{if } y^*_{it} > 0, \text{ and 0 otherwise} \end{aligned} \tag{2}$$

where: u_{it} is the error term independent of x_{it}, which represents the vector of covariates and comprises state restructuring characteristics, firm attributes, and regulator characteristics. Although this is a panel specification,[36] both, testing for sample selection and consistent estimation of the two-stage model require that we estimate a cross-section probit equation for each year *t* (Wooldridge, 1995, 2002). We derive the inverse Mills ratio[37] (IMR) for each firm *i* for *t* years and use it to test and correct for sample selection in the second stage.

In Table 5a we show the combined results derived from a pooled probit regression.[38] First, we find that the decision to conduct research depends crucially on the regulatory environment of the state and the nature of the firm. The expectation of deregulation (as proxied by the high electricity price state dummy) has a significant negative impact on the decision to engage in research. This variable may be picking up the effects of uncertainty generated by the expectation of restructuring, and utilities are more likely to disengage themselves from research in such an environment. The legislation enactment dummy is negative and significant as well, implying that as states take the final step towards restructuring, utilities are even less likely to do research (all else constant). Since restructuring is inherently uncertain, utilities may tend to conserve their resources and delay non-essential spending, such as R&D, until the market reaches a stable outcome. Second, stranded cost recovery policies have a significant impact as well. If states have a stranded cost recovery mechanism in place, utilities are more likely to engage in R&D since they are assured of a stable income stream in the future. However, contrary to expectation, having a mandatory divestiture policy does not adversely affect the R&D decision. Third, firms in states that have greener and more pro-

35. The tobit model would be an appropriate model if there was no selection present.

36. Following Chamberlain's approach (1980, 1982), we could have used the panel specification, but it would require certain linearity assumptions that may not be warranted for our specification.

37. The inverse Mill's ratio captures the non-selection hazard and is given by $\phi(x'_{it}\beta)/\Phi(x'_{it}\beta)$, where $\Phi(.)$ and $\Phi(.)$ denote the PDF and CDF of the standard normal distribution respectively.

38 Instead of presenting a table for each year, we run a pooled probit model on the data and present the results for ease of interpretation. The coefficients presented are marginal effects.

active regulators (for example California) are more likely to invest in R&D.

In addition, we find that the size of the firm matters in the R&D decision. Bigger firms with higher operating revenues are more likely to engage in research than smaller firms, supporting the "deep pocket" theory of R&D. Contrary to expectation, a distribution company is as likely to invest in research, all else equal, as a generation company, and a fossil fuel-based utility is not any more likely to engage in research than is a hydro or nuclear firm. Wholesale market participation or pending mergers are not significant determinants of the R&D decision. To summarize, a large utility located in a low-price state with low deregulatory activity, a stranded cost recovery policy, and pro-active regulators has a higher probability of investing in R&D.

Stage 2: Determinants of Positive Total R&D

The second stage is observed, conditional on participation in research activities.[39] Here we investigate the factors that influence the magnitude of R&D spending, given that the utility has decided to engage in research. The dependent variable is log of positive R&D spending (in 2000 dollars) and the estimation equation is given by:

$$\ln RD_{ijt} = \alpha + \beta FERC_{1996} + \sum_{k=1}^{6} \chi_k M_{jt} + \sum_{l=1}^{L} \gamma_l F_{ijt} + \sum_{r=1}^{R} \delta_r S_{jt} + \rho\tilde{\lambda}_{it} + \varepsilon_{jit-1} \tag{3}$$

where: $FERC_{1996}$ is the federal FERC Order dummy; M_{jt} is a vector of institutional variables; F_{ijt} denotes firm specific characteristics, such as size; and S_{jt} are state characteristics (that may vary by year), such as the nature of the regulators.[40] To account for selection effect, we include IMR ($\tilde{\lambda}_{it}$), which is calculated based on the probit equation of the first stage.[41],[42] Following Wooldridge (2002), we estimate the above equation using a pooled OLS model and correct the errors for heterosce-

39. The exclusion restrictions are satisfied because there are 3 variables in the selection model that are excluded from the levels equation and because we believe that these affect only the decision to conduct R&D and the level of expenditure.

40. 'k', 'L' and 'R' denote the number of institutional variables, firm characteristics, and state characteristics in the regression respectively.

41. For calculation of the inverse Mills ratio, see Wooldridge (2002) and Fernandez-Val and Vella (2007).

42. We first test whether selection issues are a problem in our specification. We estimate equation 3 using a fixed effects panel data model that accounts for time-invariant heterogeneity and has robust S.E. We find a significant coefficient on the inverse Mills ratio, indicating the presence of selection. This test was first proposed by Nijman and Verbeek (1992) and later modified by Wooldridge (1995). However, the estimates for the other coefficients are inconsistent, as shown in Wooldridge (2002), and thus results are not presented.

dasticity and for the inclusion of the estimated IMR. We find that the coefficient on the IMR is negative and significant (-0.564), indicating the presence of selection.[43] Hence, instead of a tobit specification, a two-stage model is warranted.

Next, we investigate how various restructuring policies have influenced firm R&D behavior. First, we find that the 1996 FERC Order has a significant negative influence on research spending levels, which drop by almost 46.8 percent.[44] When individual states start investigating how they should proceed with restructuring, it has little impact on R&D. As a state proceeds further along the restructuring path, and passes an order for retail competition, utilities increase their research spending 57.8 percent. However, once legislation for retail access is enacted, there is a further decline in R&D by 30.5 percent. We believe that these results can be interpreted in the light of how uncertainties are resolved at each stage. When the federal FERC orders are announced, firms do not have enough information about which way the issue of restructuring will be resolved in their state or about the emerging market landscape. This makes them cut back on research. Once a restructuring order is passed, however, utilities can be fairly confident that the state will eventually move towards full retail access, and this has a positive effect on R&D and may be a correction to the earlier sharp decline. But this increase is temporary, and once legislation is enacted and utilities realize that competition is going to require cost-cutting measures, research spending drops by another 30.5 percent. In aggregate, we find that, even with the increase in R&D after the restructuring order, R&D spending is far below that of the pre-restructuring level.

To study the overall effect of all the restructuring policies, we compute the marginal effect in Table 7. We find that for the mean firm, research spending decreases by 1.9 million dollars when the FERC Orders are enacted, then increases by 1.5 million dollars when an actual retail access order is passed, and declines by 1.1 million dollars when legislation is enacted. So an average utility decreases spending by 1.5 dollars net, or 48 percent, by the time a state finally enacts restructuring legislation.

In line with earlier predictions, increased competition adversely affects R&D spending, and a 1 percent increase in this variable decreases R&D spending by 0.4 percent. In addition, the coefficient on the months till retail competition is positive and significant, implying that R&D declines as the threat of competition draws near. As the retail competition draws one month closer, R&D spending declines by $7,635, which translates to an annual decline of $94,455, or 3 percent. Contrary to expectation, the level of stranded cost recovery is not a significant factor in explaining the R&D decline. This may be because simply having

43. To capture the time-varying nature of selection, we included the interaction between the IMR and year dummies – however, in all specifications the interactions were insignificant, showing that the selection effect does not vary with time. Thus, the interactions have been dropped from the final model.

44. See Halvorsen, R. and Palmquist, P. (1980), and Kennedy, P. (1981) for interpretation of the dummy variable when the dependent variable is in logarithms. The result developed in these papers show that if b is the estimated coefficient on a dummy variable and V(b) is the estimated variance of b, then an estimate of the percentage impact of the dummy variable on the variable being explained is given by 100 (exp(b - V(b)/2) - 1).

a recovery policy in place is enough to guarantee utilities some safety net, and the type and nature of the recovery level becomes unimportant. To summarize, we find that the impact of the main federal and state restructuring policies is an order of magnitude greater than the subsequent policies, such as ones that affect stranded cost recovery.

The next set of variables relate to the financial health of the company and firm characteristics. The effect of size on R&D is positive and both statistically and economically significant. The elasticity of R&D expenditure with respect to size is 1.04, implying constant returns to scale. Also, as holding company size increases by 1 unit, R&D increases by 0.3 percent. R&D spending also increases as generation becomes a primary activity of the utility because a large portion of the R&D budget was spent on generation-related projects. In addition, firms increase their R&D spending when their share of industrial sales increases. Utilities with a larger share of such customers are at a higher risk of losing them after restructuring and may spend more on cost-reducing and efficiency-enhancing types of R&D to gain an edge over competitors. The nature of fuel used by the utility has little influence on R&D.

Last, we find that state characteristics matter, although regulator nature does not. A utility located in a pro-active state does not conduct more research than one located in a more passive state, conditional on the utility having decided to conduct R&D. An important factor that does influence research spending is whether the state had a higher than average electricity price before it actually undertook any formal restructuring activity. As explained earlier, this variable may be thought of as a proxy for the probability of restructuring in a state, and we find that, on average, utilities located in high electricity price states invest 27 percent less in R&D. Finally, we include a dummy for high R&D states, which is positive and significant. On average, electric utilities spend almost 57 percent more on R&D in these pro-research states. Our model predicts that the combined effect of the expectation of restructuring and the formal policies will decrease R&D expenditures by 78.6 percent (Table 7). This result, in conjunction with the difference-in-difference model, shows that there was, indeed, a regime shift when states began restructuring their electricity markets. Thus, firm and state characteristics may have a differential influence on R&D behavior depending on the regime (pre- or post-restructuring). The next section investigates this in greater detail.

4.3 Post-Restructuring Effect

In addition to the average effects described above, we study whether firms and state characteristics affect R&D differently in the pre- and post-restructuring periods since the rules of the game changed once restructuring legislation was enacted. For example, the importance of being within a large holding company structure may become even more important in the post-restructured period when utilities will face greater uncertainty. Being within a large holding company may mitigate some of this uncertainty and may counter the adverse effect of uncertainty on R&D spending. This analysis will add to our understanding of the factors determining R&D under different institutional assumptions. To the best of our knowledge, there are no papers that have analyzed this, and the current analysis will add a missing piece to the literature. To investigate this, we interact the firm and state characteristics with the restructuring legislation enactment dummy in (4) below ($Dum\_legis{*}F_{ijt}$ and $Dum\_legis{*}S_{jt}$). These interactions illustrate whether the firm and state variables behave the same way before and after restructuring.[45]

$$\ln RD_{ijt} = \alpha + \beta FERC_{1996} + \sum_{k=1}^{6} \chi_k M_{jt} + \sum_{l=1}^{L} \gamma_l F_{ijt} + \sum_{r=1}^{R} \delta_r S_{jt} + \sum_{1=1}^{L} \mu_1 \left(Dum\_legis * F_{ijt} \right) + \sum_{r=1}^{R} \pi_r \left(Dum\_legis * S_{jt} \right) + \rho \tilde{\lambda}_{it} + \varepsilon_{jit-1} \tag{4}$$

In Table 6 we present the results. In this specification, while there are differences in the firm and state characteristics, all market institution variables remain unchanged in sign and significance.[46] First, we find that the size of the holding company matters more in the post-restructured regime. This suggests that the holding company structure may provide a safety net in the restructured regime, allowing firms to take risks and invest in more R&D. In addition, after restructuring, a fossil fuel-based utility conducts more R&D than other types of utilities – a result opposite that of the regulated regime. In addition, the fuel composition of a state matters in the deregulated regime, and utilities located in states with a higher share of coal generation perform more R&D. These latter two findings may reflect the same phenomenon. Traditionally, fossil fuel-based utilities are of an older vintage. They are less efficient and face a greater competitive threat from newer plants when a state restructures. The increase in R&D spending may reflect an increase in cost-reducing and efficiency-enhancing types of R&D in an effort to retain their customers and gain an edge over competitors.

5. CONCLUSION

When an industry transitions from a regulated to a market regime, there is concern about how firms adapt to the changes. Industry structure, firm financial decisions, product offerings, investment, research, and innovation conduct parameters may undergo significant changes. We focus on the R&D behavior of regulated utilities transitioning to a competitive market. Earlier literature has focused

45. The interpretation of the coefficients is as follows: For the pre-restructuring phase, the marginal effects are denoted by the coefficients of the explanatory variables. For the post-restructuring phase, the marginal effects are denoted by coefficient of variable + coefficient of interaction term if the interaction term is significant. Otherwise, the explanatory variable has the same marginal effects in both periods.

46. The combined coefficient for the legislation enactment dummy is -0.263 (significant at 5 percent),when all the significant interactions are taken into account.

primarily on the R&D response of competitive industries. However, focusing on how R&D incentives change when competition is introduced to a hitherto regulated industry can provide valuable insights about the drivers of R&D. This paper does just that. We use the deregulation of the US power industry to analyze how the transition from regulation to competition affects the R&D behavior of firms.

The sharp decline in R&D that coincided with the start of the restructuring process has caused some apprehension amongst industry observers and policymakers. Our research concludes that the concern is justified. We find a dramatic decline in R&D at early stages of the restructuring process. The announcement of the FERC Order about retail wheeling alone leads to a 46.8 percent decline in R&D. In addition, the expectation of deregulation leads to a 27 percent drop in R&D, and greater actual competition and the nearing of such competition adversely affect research spending as well. Once the emerging institutional structure becomes clear, however, and an actual restructuring order is passed, R&D spending increases by 57.8 percent, almost reversing the earlier decline. However, we observe further cutbacks in R&D, by 30.5 percent, once restructuring legislation is enacted and the realities of the competitive environment set in. The fact that research expenditures show a large drop in the early stages of restructuring may be due to the uncertainty associated with the emerging institutional and market processes. The upturn in expenditures when an actual policy is passed may signal that the companies are more confident about the nature of the emerging market structure and are willing to begin investing more resources in their research projects. However, this increase is then offset by a further decline in research expenditures once firms are faced with the reality of a competitive market structure. In total, these policies lead to a 78.6 percent drop in R&D. We also find that there was a regime change when states passed restructuring legislations. Some firm and state characteristics have differential effects in the pre- and post-restructured periods.

In aggregate, our model predicts a permanent drop in R&D expenditures for the electric utility industry due to the restructuring process. From Appendix Figure 4, we observe that the prediction from our model explains the reality quite well. Total R&D expenditures by electric utilities from 2001-2006 show no signs of recovering, and they seem to have stabilized at a much lower level than during the pre-restructuring phase. This paper is a step towards understanding the dynamics of R&D spending when firms transition from a regulated to a market environment. These findings suggest that when the uncertainty is resolved and all the institutional and market mechanisms are in place, R&D spending may recover slightly from its current low level but will not recover to pre-restructuring levels. Overall, the prognosis for research spending by the electric utilities in the restructured era is not optimistic and thus has important implications for the role of the government.

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APPENDIX TABLES

Table 1. R&D Statistics (Estimation Sample)

Real Total R&D (2000 $)

	Entire Sample	**Positive R&D Only**
Obs.	1663	1291
Mean	3,125,240	4,058,789
Median	787,782	1,510,386
Standard Deviation	7,213,986	7,939,385
Minimum	-306,125	368
Maximum	87,000,000	87,000,000
Entire Sample	**Pre-1996**	**Post-1996**
Obs.	935	728
Mean	4,022,568	1,972,766
Median	1,014,766	508,396
Standard Deviation	8,831,271	4,050,817
Minimum	0	-708,550
Maximum	87,000,000	38,300,000

Note: Kruskal-Wallis equality-of-populations rank test rejects null hypothesis of equality for the pre- and post-restructuring R&D statistics.

Table 2(a). Deregulation /Restructuring Orders

Year	Investigations Ongoing or Order Pending	Order Issued for Retail Access	Legislation Enacted to Implement Retail Access
1994	California		
1995	Connecticut, Louisiana, Vermont, Washington	California	
1996	Alabama, Colorado, Connecticut, Hawaii, Iowa, Kansas, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Virginia, Washington	New York, Vermont	California, New Hampshire, Pennsylvania, Rhode Island, Texas
1997	Alabama, Arizona, Arkansas, Colorado, Connecticut, DC, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, North Carolina, North Dakota, Oregon, South Carolina, Tennessee, Virginia, Washington, West Virginia, Wisconsin	Illinois, Maryland, New York, Vermont	California, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, Texas
1998	Alabama, Alaska, Arkansas, Colorado, Delaware, Hawaii, Idaho, Indiana, Iowa, Kansas, Louisiana, Minnesota, Missouri, New Mexico, North Carolina, North Dakota, Oregon, South Carolina, South Dakota, Tennessee, West Virginia	Arizona, DC, Georgia, Illinois, Maryland, Michigan, Mississippi, New Jersey, Vermont, Washington	California, Connecticut, Maine, Massachusetts, Montana, Nevada, New Hampshire, New York, Oklahoma, Pennsylvania, Rhode Island, Texas, Virginia, Wisconsin
1999	Alabama, Alaska, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Missouri, North Carolina, North Dakota, South Carolina, South Dakota, Tennessee	Arkansas, DC, Georgia, Michigan, Minnesota, Mississippi, Vermont, Washington	Arizona, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, West Virginia, Wisconsin
2000	Alabama, Alaska, Colorado, Florida, Hawaii, Idaho, Indiana, Kansas, Kentucky, Louisiana, Missouri, North Carolina, North Dakota, South Dakota, Tennessee	Arkansas, Georgia, South Carolina, Vermont, Washington	Arizona, California, Connecticut, Delaware, DC, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, West Virginia, Wisconsin

Table 2(b). Dates for Stranded Cost Recovery Acts

States with No Date (i.e. No Policy)	Alaska, Colorado, DC, Florida, Hawaii, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Missouri, North Carolina, North Dakota, Oregon, South Dakota, Tennessee, Vermont, Washington, West Virginia, Wisconsin
Year	
1996	Alabama, New Hampshire, New York
1997	Arkansas, California, Idaho, Illinois, Maine, Maryland, Massachusetts, Mississippi, Montana, Nevada, New Jersey, Ohio, Oklahoma, Pennsylvania
1998	Arizona, Connecticut, Delaware, Georgia, Rhode Island, South Carolina, Texas
1999	New Mexico, Virginia
2000	Michigan

Table 2(c). Dates of Effective Retail Competition

State	Restructuring Legislation that introduced competition	Date when the Act was enacted	Date when large customers would get retail access	Date when all customers would get retail access
Arizona	HB 2663	5/1998	1/1/1999	1/2001
Arkansas	-	5/1999	1/1/2002	6/30/2003
California	AB 1890	9/1996	3/1998	3/1998
Connecticut	RB 5005	4/1998	1/2000	7/2000
Delaware	-	8/1999	10/1/1999	10/1/2000
Illinois	HB 362	12/1997	10/1999	5/2002
Maine	LD 1804	5/1997	3/2000	3/2000
Maryland	-	4/1999	7/2000	7/2000
Massachusetts	-	11/1997	3/1/1998	3/1/1998
Michigan	-	3/1999	9/1999	1/1/2002
Montana	SB 390	4/1997	7/1998	7/2002
Nevada	AB 366	7/1997	12/31/1999	12/31/1999
New Hampshire	HB 1392	5/1996	1/1/1998	7/1/1998
New Jersey	-	3/1999	6/1/1999	6/1/1999
New Mexico*	-	9/1997	1/2001	1/2001
New York	-	5/1996	1/1998	1/1998
Ohio	-	6/1999	1/1/2001	1/1/2001
Oklahoma	SB 500	4/1997	7/2002	7/2002
Oregon	-	7/1999	10/1/2001	10/1/2001
Pennsylvania	HB 1509	3/1998	7/1998	1/2000
Rhode Island	-	1/1996	1/1998	1/1998
Texas	-	6/1999	1/2002	1/2002
Virginia	SB 1269	3/1999	1/2002	1/2004

Table 3. Summary Statistics for Regressions

First Stage: ***Sample: All Firms, 1990 – 2000 (1663 obs.)***

	Percentage of Ones			
Dependent Variable:	77.81			
Decision to conduct R&D				
Regressors (Dummies):				
Legislation Enactment Dummy	18.40			
Dummy for High Electricity Price States	42.99			
Stranded Cost Recovery Mechanism Dummy	19.96			
Divestiture Policy Dummy	16.60			
Distribution Company Dummy	19.06			
Pending Merger	11.12			
Regressors (Continuous Variables):	**Mean**	**SD**	**Min**	**Max**
Log (Real Operating Revenues)	20.110	1.555	14.561	23.235
Share of Fossil Fuel in Total Generation	0.708	0.338	0	1
Wholesale Market Participation	0.270	0/357	0	1
Regulator Nature	51.560	28.794	0	99

Second Stage: ***Sample: Firms with Positive R&D only, 1990 – 2000 (1288 obs.)***

	Mean	SD	Min	Max
Dependent Variable:				
Log (Real Total R&D Expenditure – 2000 dollars)	13.745	2.283	2.426	18.281
Real Total R&D Expenditure (2000 dollars)	4,58,789	7,939,385	11.314	87 mill
Regressors (Dummies):	**Percentage of Ones**			
FERC Order Dummy	44.00			
Deregulation Investigation Dummy	37.78			
Restructuring Order Dummy	21.88			
Legislation Enactment Dummy	17.53			
Dummy for High Electricity Price States	39.35			
Dummy for High R&D States	23.17			
Regressors (Continuous Vars.):	**Mean**	**SD**	**Min**	**Max**
% Customers Eligible for Retail Comp.	9.622	28.910	0	100
Months Till Start of Retail Competition	153.235	62.891	0	180
Stranded Cost Recovery Type	0.436	0882	0	3
Log(Real Operating Revenues)	20.554	1.192	17.080	23.235
Holding Company Size	3.431	3.509	0	15
Share of Generation in Total Sales	0.684	0.317	0	1
Share of Fossil Fuel in Total Gen.	0.746	0.288	0	1
Share of Ind. Sales in Total Gen.	0.210	0.117	0	0.925
Regulator Nature	50.542	28.338	0	99
Share of Coal Generation in State	0.501	0.298	0	0.985

Table 4. Difference-in-Difference Model

Dependent Variable is Log (Positive Total R&D Expenditure)

Variable	**Coefficient (S.E.)**
Difference-in-Difference Specification	
FERC Order Dummy (1996)	-1.150 (0.177) ***
Treatment Group	-0.203 (0.236)
FERC Order Dummy* Treatment Group	-0.283 (0.138) **
Firm & State Characteristics	
Log(Real Operating Rev.)	1.233 (0.093) ***
Share of Generation in Total Sales	1.090 (0.272) ***
Share of Fossil Fuel in Total Generation	0.712 (0.325) **
Regression Diagnostics	
σ_u	1.086
σ_e	1.028
Fraction of Variance Due to U_i	0.528
Chi-Square(58)	1112.166
R-Square	0.662
No. of Firms	144
No. of Observations	1294

Note: The estimation equation is given by: The estimation technique is a random effects panel data model with year and state fixed

$$\ln RD_{ijt} = \alpha + \beta FERC_{1996} + \lambda Treated_{jt} + \theta(FERC_{1996} * Treated_{jt}) + \sum_{P=1}^{p} \gamma_p F_{ijt} + \sum_{j=1}^{47} \delta_j S + \sum_{t+1}^{9} \gamma_t T + v_i + \varepsilon_{it-1}$$

effects, and a constant term. Errors are corrected for serial correlation and heteroscedasticity. The panel is unbalanced due to missing observations. Range: 1990-2000. The FERC order dummy takes the value 1 for year>=1996. The treatment group comprises states with electricity prices that were higher than the national average before 1996. '***', '**' & '*' denote significance at the 1 percent, 5 percent and 10 percent level respectively. All regressors are jointly significant.

Table 5a. Stage 1 - Selection Equation
Dependent Variable is a Binary Index Function for Total R&D Expenditure

Variable	Coefficient (S.E.)
Regulatory Variables	
Dummy for High Electricity Price States	-0.132 (0.072) *
Legislation Enactment Dummy	-0.145 (0.063) **
Stranded Cost Recovery Mechanism Dummy	0.084 (0.048) *
Divestiture Policy Dummy	0.017 (0.072)
Regulator Nature	0.002 (0.001) *
Firm Characteristics	
Log (Real Operating Revenues)	0.135 (0.022) ***
Distribution Company Dummy	0.037 (0.054)
Share of Fossil Fuel in Total Generation	0.090 (0.059)
Wholesale Market Participation	-0.053 (0.055)
Pending Merger	-0.104 (0.074)
Constant	-10.750 (1.650) ***
Regression Diagnostics	
Pseudo R-Square	0.320
Wald (Chi-Square, 10)	137.36
Number of Observations	1663

Note: The underlying model is given by:

$y^*_{it} = x'_{it}\beta + u_{it}$, where i = 1,...n and t =1,......T_i
$y_{it} = 1$ if $y^*_{it} > 0$, and 0 otherwise

The unobserved latent variable y^*_{it} is the net benefit stream from investing in R&D. y_{it} is the binary indicator showing that R&D is observed only when the latent variable is positive. The results shown are from a pooled probit estimation of the above specification, and explains a firm's decision to conduct R&D ($y_{it}=1$) or refrain from it ($y_{it}=0$). The coefficients presented are marginal effects (except for the constant term). S.E. are robust and clustered by state. '***', '**' & '*' denote significance at the 1 percent, 5 percent and 10 percent level respectively. All regressors are jointly significant. For deriving the actual inverse Mill's ratio used in the second step estimation, the selection equation is estimated separately for each year in our sample using a probit model following Wooldridge (2002). Range: 1990-2000.

Table 5b. Stage 2 - Levels Equation
Dependent Variable is Log (Positive Total R&D Expenditure)

Variable	Coefficient (S.E.)	Semi-Elasticity/ Elasticity
Regulatory Variables		
FERC Order Dummy	-0.619 (0.151) ***	-46.76
Deregulation Investigation Dummy	0.045 (0.167)	
Restructuring Order Dummy	0.482 (0.228) **	57.78
Legislation Enactment Dummy	-0.343 (0.207) *	-30.50
% Customers Eligible for Retail Comp.	-0.004 (0.002) *	0.402
Months Till Start of Retail Competition	0.003 (0.001) *	0.384
Stranded Cost Recovery Type	0.106 (0.089)	
Firm Characteristics		
Log(Real Operating Revenues)	1.039 (0.072) ***	1.035
Holding Company Size	0.087 (0.013) ***	0.277
Share of Generation in Total Sales	1.177 (0.221) ***	0.764
Share of Fossil Fuel Generation	-0.027 (0.193)	
Share of Ind. Sales in Total Elec. Gen.	2.099 (0.484) ***	0.451
State Characteristics		
Dummy for High Elec. Price States	-0.303 (0.167) *	-27.19
Regulator Nature	-0.0004 (0.002)	
Share of Coal Generation in State	-0.328 (0.199)	
Dummy for High R&D States	0.848 (0.152) ***	57.66
Selection Correction		
Inverse Mills Ratio (IMR)	-0.564 (0.344) *	
Regression Diagnostics		
R-Square	0.573	
No. of Firms	144	
No. of Observations	1291	

Note: The estimation equation is given by (eqn. 3):

$$\ln RD_{ijt} = \alpha + \beta FERC_{1996} + \sum_{k=1}^{6} \chi_k M_{jt} + \sum_{l=1}^{L} \gamma_l F_{ijt} + \sum_{r=1}^{R} \delta_r S_{jt} + \rho\tilde{\lambda}_{it} + \varepsilon_{ijt}$$

We estimate the selection corrected second stage equation using a pooled OLS model as suggested by Wooldridge (2002). S.E.s are robust and clustered by state, and bootstrapped to correct for the inclusion of first stage estimates of the Mills ratio. The panel is unbalanced with minimum observations per group=2 and max=11. Range: 1990-2000. Column 1 reports the coefficients and column 2 reports the semi-elasticities for the significant dummy variables and elasticities for the significant continuous variables. '***', '**' & '*' denotes significance at 1, 5 and 10 percent respectively.

Table 6. Post Restructuring Effect
Dependent Variable is Log (Positive Total R&D Expenditure)

Regulatory Variables	**Coefficients (SE)**
FERC Order Dummy	-0.576 (0.151) ***
Deregulation Investigation Dummy	0.021 (0.170)
Restructuring Order Dummy	0.362 (0.216) *
Legislation Enactment Dummy	-4.217 (2.565) *
Regulatory Variables	
% Customers Eligible for Retail Comp.	0.002 (0.001) *
Months Till Start of Retail Competition	0.003 (0.001) **
Stranded Cost Recovery Type	0.052 (0.089)
Firm Characteristics	
Log(Real Operating Revenues)	1.013 (0.076) ***
Holding Company Size	0.098 (0.014) ***
Share of Generation in Total Sales	1.089 (0.243) ***
Share of Fossil Fuel Generation	-0.390 (0.211) *
Share of Ind. Sales in Total Elec. Gen.	2.270 (0.492) ***
State Characteristics	
Regulator Nature	-0.0004 (0.002)
Share of Coal Generation in State	-0.355 (0.222)
Dummy for High Electricity Price States	-0.294 (0.162) *
Dummy for High R&D States	0.769 (0.156) ***
Post-Restructuring Interactions	
Log(Real Oper. Rev.) * Legis. Enact. Dum.	0.103 (0.130)
Hold. Comp. Size * Legis. Enact. Dum.	0.062 (0.034) *
Sh. of Gen. in Tot. Sales * Legis. Enact. Dum.	0.239 (0.511)
Sh. of Fossil Fuel Gen. * Legis. Enact. Dum.	1.625 (0.516) ***
Sh. of Ind. Sal. in Tot. Elec. Gen. * Leg. Enact. Dum.	-1.802 (1.507)
Regulator Nature * Legis. Enact. Dum.	0.001 (0.004)
Sh. of Coal Gen. in State* Legis. Enact. Dum.	1.226 (0.494) **
Selection Correction	
Inverse Mills Ratio (IMR)	-0.729 (0.364) **
Regression Diagnostics	
No. of Observations	1291
Adjusted R-Square	0.584

Note: The estimation equation is given by (eqn. 4 in text). The interaction terms with *Dum_legis* are

$$\ln RD_{ijt} = \alpha + \beta FERC_{1996} + \sum_{k=1}^{6} \chi_k M_{jt} + \sum_{l=1}^{L} \gamma_l F_{ijt} + \sum_{r=1}^{R} \delta_r S_{jt} + \sum_{l=1}^{L} \mu_l (Dum\_legis{*}F_{ijt}) + \sum_{r=1}^{R} \pi_r (Dum\_legis{*}S_{jt}) + \rho\tilde{\lambda}_{it} + \varepsilon_{jit-1}$$

added to test whether firms behave differently post restructuring. Pre-restructuring - marginal effects are the coefficients of the explanatory variables. Post-restructuring: the marginal effects are: coefficient of variable + coefficient of interaction term if the interaction term is significant. Otherwise the explanatory variable has the same marginal effect pre and post restructuring. The estimation methodology is identical to Column 2 Table 5(B). S.E.s are robust and clustered by state, and bootstrapped to correct for the inclusion of first stage estimates of the Mills ratio. The panel is unbalanced with minimum observations per group=2 and max=11. Range: 1990-2000. '***', '**' & '*' denotes significance at 1, 5 and 10 percent respectively.

Table 7. Marginal Effects

	Coeff. (dlnRD/dx)	Mean R&D (dRD/dx)	Median R&D (dRD/dx)
		Effect on R&D when Continuous Variables Change by 1 unit & Dummies go from 0 to 1	
FERC Order Dummy	-0.619	-1,935,721	-487,938
Restructuring Order Dummy	0.482	1,507,519	380,001
Legislation Enactment Dummy	-0.343	-1,070,634	-269,876
% of Customers Eligible for Retail Comp.	-0.004	-1,336	-337
Months Till Start of Retail Comp.*	0.003	7,871	1,984
High Electricity Price State Dummy	-0.303	-948,312	-239,042
Change in R&D (2000 $)		-2,456,355	-619,176
Change in R&D (%)		-78.6%	

Note: Estimates based on the significant regulatory coefficients from Table 5(B). The estimation equation is given by (eqn. 3 in text):

$$\ln RD_{ijt} = \alpha + \beta FERC_{1996} + \sum_{k=1}^{6} \chi_k M_{jt} + \sum_{l=1}^{L} \gamma_l F_{ijt} + \sum_{r=1}^{R} \delta_r S_{jt} + \rho\tilde{\lambda}_{it} + \varepsilon_{ijt}$$

All quantities are in 2000 dollars. The mean and median R&D expenditures are for the entire sample. Thus these are unconditional effects and take into account both, the decision to conduct R&D and the amount. Mean R&D = $3,125,240 and Median R&D=787,782.

* The dollar figures on this variable are added on as negative numbers in the total since as the retail competition date gets one year closer, R&D declines by that amount.

APPENDIX FIGURES

Figure 1. Total R&D (Real) for Four Industrial Sectors (1990 – 2000)

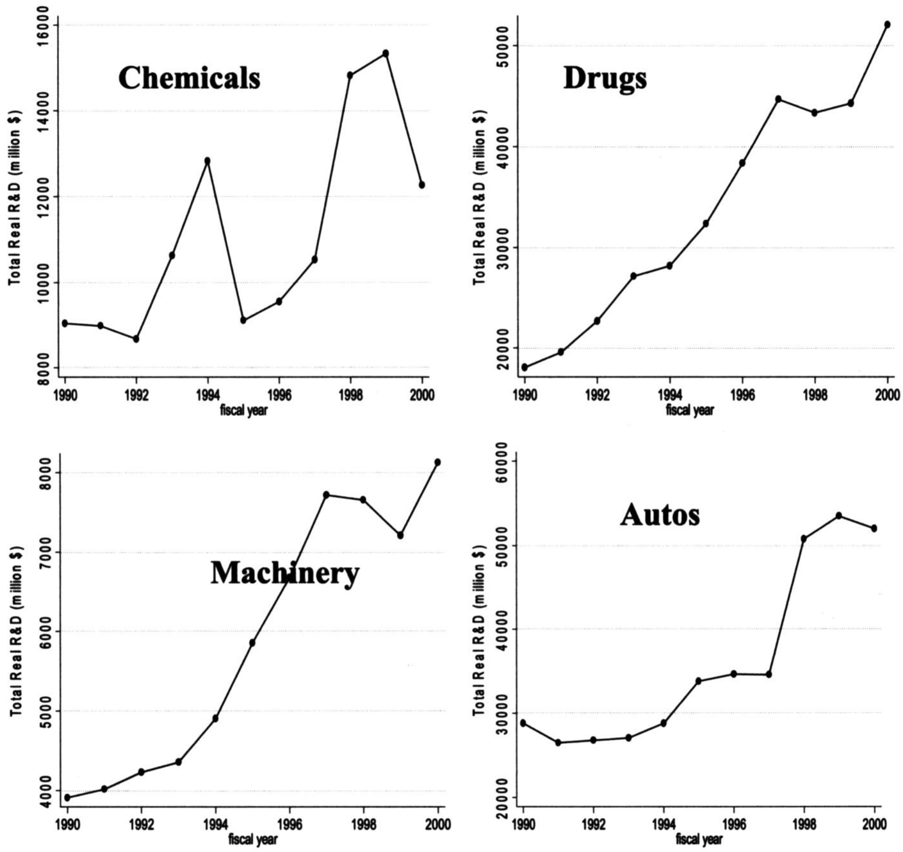


Figure 2. Changing IOU R&D in Fifteen High R&D States

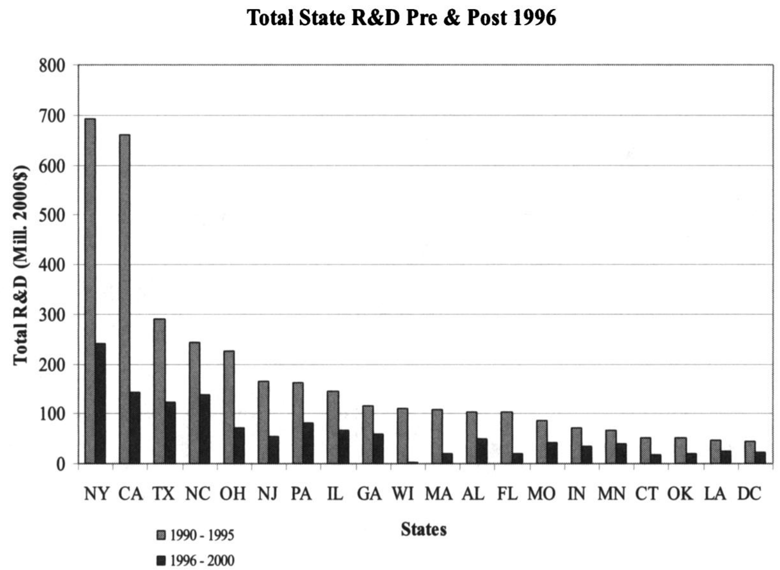


Figure 3. Total (Real) R&D for US Electric Utilities in High Medium & Low Deregulation States, 1990 – 2000

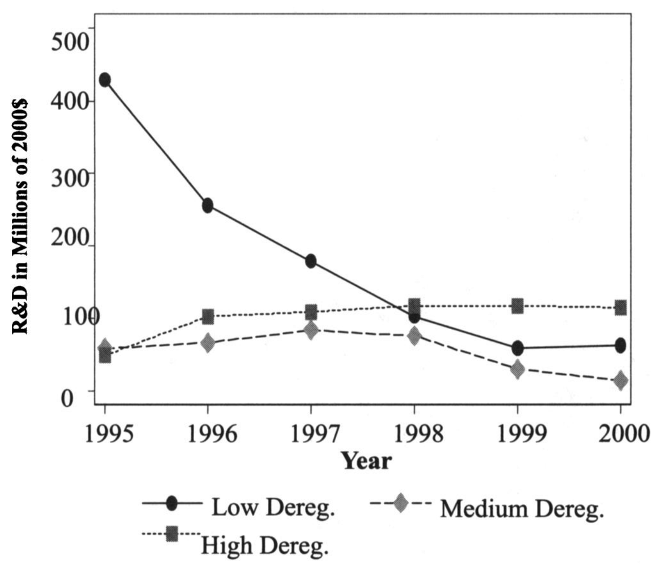
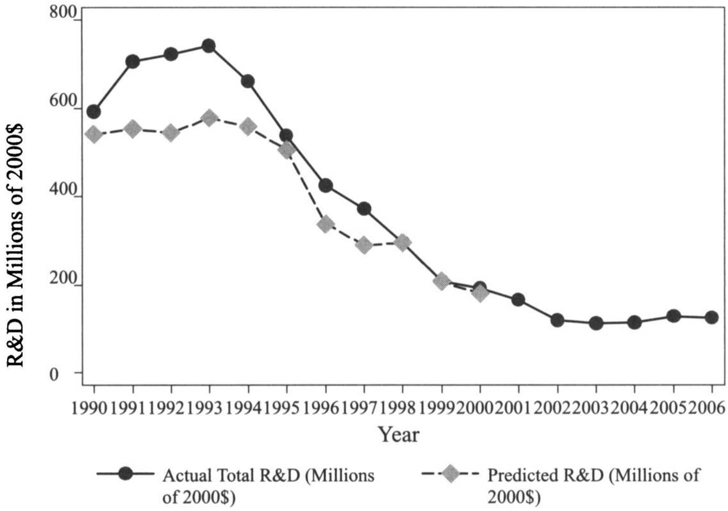


Figure 4. Actual & Predicted R&D, US Electric Utilities 1990-2006



PRODUCT MARKET COMPETITION AND UPSTREAM INNOVATION: EVIDENCE FROM THE U.S. ELECTRICITY MARKET DEREGULATION

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PRODUCT MARKET COMPETITION AND UPSTREAM INNOVATION: EVIDENCE FROM THE U.S. ELECTRICITY MARKET DEREGULATION

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Abstract—This paper studies the innovation response of upstream technology suppliers when their downstream buyers transition from regulation to competition. By modeling the impact of the 1990s U.S. electricity deregulation on patenting, we find that after deregulation, the net competition effect (comprising the pure competition and the escape competition effect) decreased innovation by 18.3% and the appropriation effect increased innovation by 19.6%. Other deregulation factors have led to a 20.6% decline. In aggregate, after deregulation, innovation by the upstream technology suppliers has declined by 19.3%, and upstream innovation quality and generality have declined as well.

I. Introduction

STARTING with Schumpeter (1942), there is a line of research arguing that innovation is best promoted in highly concentrated industries because a monopolist has a stronger incentive and better means to innovate than competitive firms do. The "Darwinian" tradition, however, argues that the most efficient and most innovative firms survive under competition, an argument that has been central to the "creative destruction" literature, formalized by several seminal papers, such as Aghion and Howitt (1992, 1996). In the standard setup of these studies, innovations take place within the firm. Using this as the starting point, researchers study the implications of competition on innovation incentives. However, in the long tradition of the literature on competition and innovation, the innovation response of upstream technology suppliers to changing product market competition faced by downstream technology buyers remains understudied. This paper focuses on the effect of competition on innovation in the context of this vertical upstream-downstream industrial organizational structure and differs from papers that have considered the effect of competition on innovation incentives in a horizontal setup.[1]

To study this question, we use the deregulation of the U.S. electric utility industry and the effect this had on the innovation behavior of electric equipment manufacturers. The technology flow in this industry is from upstream electric equipment manufacturers (EEMs), such as General Electric, responsible for innovating and supplying new technology (such as furnaces and pollution control equipment) to the downstream utilities that do the actual generation, transmission, and distribution of power. Overseen by the Federal Energy Regulatory Commission (FERC) and state regulators, each downstream utility had a service monopoly in a particular geographical region and was subject to cost-of-service regulation that ensured that electricity prices and returns to investment for utilities were stable and not subject to market volatility. In addition, such regulation implied that most costs incurred by utilities (such as investment in new technology) could be passed on to final consumers.

During the early to mid-1990s, this regulation paradigm underwent significant changes that were geared toward competitive electricity markets.[2] In 1992, the passing of the Energy Policy Act (EPAct) gave rise to open-access transmission grids for wholesale transactions and formally introduced wholesale competition, thus subjecting incumbent utilities to price uncertainties and entry pressures.[3] After the introduction of the EPAct, consumers such as municipalities and large industrial customers could shop for power, putting vertically integrated utilities, which had formerly served all of their needs, at the risk of losing them as customers. This led to major changes in the organizational structure of the electricity industry and altered the incentives and optimization decisions of utilities and all the entities that did business with them (see Sanyal & Cohen, 2009, and Cohen & Sanyal, 2007). In particular, the EEMs, which supplied the generators, pollution control technologies, and other equipment to the downstream utilities, were directly affected by this change. Thus, the industrial organization of this sector and the transition of the industry from a regulated to a competitive setup make it ideal for studying innovation behavior in an upstream-downstream setup.

Our investigation is motivated by the observed changes in innovation behavior of EEMs that are coincident with

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[1] See Scherer and Ross (1990) and Gilbert (2006) for surveys on this topic.

[2] For studies on electricity deregulation in the United States, see Blumstein (1997), Borenstein and Bushnell (1999), Borenstein, Bushnell, and Stoft (2000), Joskow (1997, 1999), Wolak (2004), Puller (2007), Sanyal and Cohen (2009), and Cohen and Sanyal (2007).

[3] On the wholesale side, FERC took several steps to ensure increased competition. It required utilities to provide a detailed account of their transmission capacities, it expanded the range of services that the utilities were required to provide to wholesale traders, and it made it clear that approval of application for mergers and the IOUs' ability to charge competitive rates were subject to their filing open access transmission tariffs with comparable service provisions. The competitive threat for utilities comes from the "wholesale" markets where they buy and sell power for resale at retail. Wholesale rates apply to all sales for resale. The Federal Energy Regulatory Commission (FERC) is nominally required to set the rates on a cost-of-service basis; however, in practice, it allows the parties involved to choose them.

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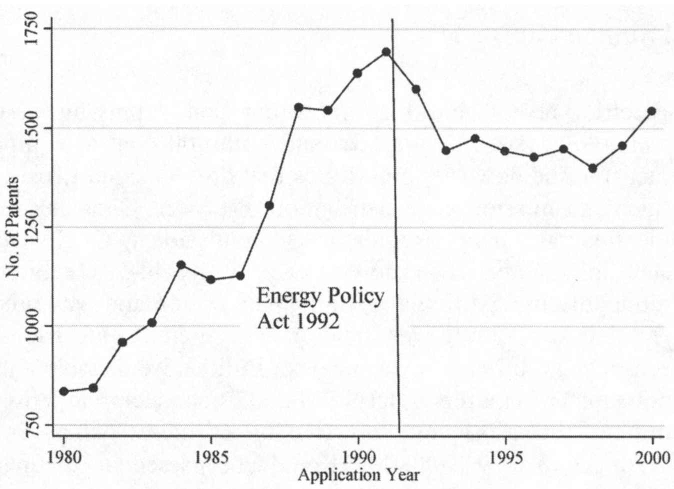
FIGURE 1.—EEM ELECTRIC TECHNOLOGY PATENTS: 1980–2000



deregulation and restructuring activity in the electricity market. As figure 1 illustrates, with the introduction of the competition that was ushered in by the EPAct which was passed in the January 1992, there was a significant drop in the absolute number of electric technology patents granted to EEMs.[4]

This decline is even more puzzling when one observes that this is a period when other technologies boomed. In figures A1 in the appendix, we show that the number of drug and medical patents obtained by corporations (U.S. and non-U.S.) during our sample period increased. This increase is also reflected in other technology classes, such as chemicals and biotech. As a consequence, the share of electric technology patents granted to EEMs declined during this period (see figure A2). This paper explores why EEM innovation declined when other technologies boomed.

Using patents as a metric for innovation, we find that for both the equipment manufacturers and the particular electric equipment patent classes, the amount of innovation declined after the EPAct (1992), which started the deregulation process in the U.S. power industry. Thus, competition in the downstream generation sector adversely affected the innovation behavior of EEMs and, in aggregate, electric technology innovation by EEMs declined by 19.3% after deregulation. In addition, EEM patent quality has been adversely affected, and these patents have become less general since the establishment of the EPAct.

Before proceeding, we briefly review the work that is most closely related to our study. The existing literature has analyzed in considerable detail how the horizontal structure of an industry—the number of firms, in particular—affects incentives for process innovation.[5] Conversely, the literature has devoted much less attention to the corresponding issue of how the vertical structure of an industry affects innovation. A recent strand of the literature considers such vertical structures as they pertain to the impact of vertical integration on innovation incentives.[6] For our purpose, we rule out the possibility of such vertical integration because in the regulated electricity industry, the owners of the upstream and downstream firms had totally different core activities, which prevented such incentives. Another recent paper, on a related theme, is that of Reisinger and Schnitzer (2010). In an upstream-downstream framework with endogenous entry, they show that the downstream conditions dominate overall profitability, while the upstream conditions mainly affect the distribution of profits. Finally, a related literature studies the effect of product market competition on managerial incentives.[7] Aghion, Dewatripont, and Rey (1999) is similar in spirit to that literature, but they consider the effects of competition and the threat of liquidation on innovation and growth in an endogenous growth model. A few years later, Raith (2003) showed that changes in competition affected incentives if these changes lead to higher firm-level output, and Karuna (2007) showed that particular industry characteristics play a major role in influencing incentives.

Our paper adds to the innovation-competition literature in important ways. It empirically models the effect of downstream competition on upstream innovation behavior in situations where the technology buyer and seller are not vertically integrated. This furthers our understanding of how downstream product market competition influences the innovation behavior of upstream technology suppliers. The rest of this paper is organized as follows. Section II briefly discusses the theoretical findings that serve as a backdrop to our empirical results that help in understanding the mechanisms at work. Section III describes the data and empirical methodology, and section IV discusses the results. The last section concludes.

II. Theoretical Underpinnings

Common models of innovation and market structure cannot adequately explain innovation behavior by EEMs since these models focus on a horizontal organization structure where innovation takes place within the firm. In our setup there is a vertical organization structure where innovation is done by upstream equipment manufacturers and bought by downstream utilities. The innovations were bought at an agreed-on price that was determined by the profits generated from the final product. Since the downstream utilities were allowed to maintain a geographic monopoly, the upstream manufacturers and the downstream utilities could

[4] In figure 1 we draw the EPAct line closer to 1991 since the act was passed in January 1992 and the patent total correspond to December of each year. There appears to be an increase in the innovation magnitude of EEMs in 1999 and 2000, although the shares are nowhere near the predereguation levels.

[5] See, for example, Arrow (1962), Loury (1979), and, more recently, Aghion et al. (2005) and Vives (2008) on this.

[6] Chen and Sappington (2010), Choi, Lee, and Stefanadis (2003), Brocas (2003), Buehler, Schmutzler, and Benz (2004), and Buehler, Gartner, and Halbheer (2006) are some papers that delve into such issues.

[7] Schmidt (1997), Hart (1983), Hermalin (1992, 1994), and Scharfstein (1988) are some papers in this vein.

share the monopoly rents thus generated. After the introduction of the EPAct, wholesale competition was made possible in the downstream market. This had two effects. On the one hand, the profitability of the incumbent utilities declined due to increased competition with nonutility generators (often called the independent power producers, IPPs). This affected the innovation incentive and competition in the upstream EEM sector. On the other hand, the entry of these IPPs in the downstream generation market created new customers for the innovation product being sold by upstream EEMs. We explain in detail how these changes influenced upstream innovation.

First, in the presence of competitors (IPPs) in the downstream sector, the pricing of the final goods (electricity price per megawatthour) to consumers would potentially change by becoming more competitive compared to the high regulated rates. This would reduce the profits of the incumbent downstream utilities. This decline in downstream profitability due to competition decreased the buying power of utilities and translated to a lower demand (from incumbent utilities) for upstream innovation. For upstream EEMs, this had a negative impact on the profit generated by selling their innovation to downstream utilities. As predicted by the standard Schumpeterian model, increased competition (in this case, among downstream utilities after restructuring) reduces the monopoly rents that reward successful innovators (in this case, the upstream EEMs), and thus we expect declining downstream profits to dampen upstream innovation.[8] We call this the *pure competition effect*.

The second effect, which may boost innovation incentives as competition increases, is called the *escape competition* by Aghion et al. (2001, 2005).[9] They argue that if incumbent firms are allowed to innovate, then competition may actually increase innovation in certain cases. When there is more competition, innovation incentives depend not so much on postinnovation rents but on the difference between postinnovation and preinnovation rents of incumbent firms.[10] We argue that increased competition may reduce a firm's preinnovation rents by more than it reduces its postinnovation rents: that is, doing nothing may be more costly than investing in more innovation when faced with more competition. Thus, greater competition "may increase the incremental profits from innovating and thereby encourage R&D investments aimed at 'escaping competition'" (Aghion et al., 2001).

We extend their logic in the context of our upstream-downstream setup. In our setup, the downstream incumbent utilities buy innovation from the upstream EEMs. The effect of increased downstream competition would lead to a decline in profits for incumbent utilities and hence reduce their demand for upstream innovation. The upstream EEMs would now have to fight harder to maintain (and or increase) their market share.[11] One potential path is to innovate their way out of competition, or escape competition by increasing innovation and becoming the market leader in certain innovation products. Following Aghion et al.'s (2005) logic, the drive to become the technological leader and maintain or increase market share may drive EEMs to innovate more when faced with shrinking downstream demand (from incumbent utilities).

According to Aghion et al. (2005), which of these two effects dominates depends on the industry structure—whether the industry is leveled (firms are neck-and-neck competitors) or whether it is unleveled (the industry has technological leaders and laggards) and the level of competition in the industry. Their model predicts that the reduction of rents due to competition induces the neck-and-neck competitors to innovate to escape competition, whereas the Schumpeterian effect decreases the innovation incentives for the laggards. If the industry composition is such that it is characterized by a larger share of laggards, increased competition would decrease innovation as the negative Schumpeterian effect (the pure competition effect) would dominate the positive escape competition effect. In the case of the electricity industry, we expect the negative pure competition effect to dominate the positive escape competition effect, leading to a negative net competition effect. A majority of the equipment manufacturers are small, privately owned firms, leading to an unleveled industry structure. In this case, the net effect of competition on innovation should be negative; as downstream profits fall due to competition, upstream innovation should decline as well.

The third effect is an appropriation effect, which is due to the entry of the nonutility generation firms (the IPPs) in the wholesale market.[12] This effect arises because of the downstream-upstream industrial organizational structure particular to our setup. Thus, previous theoretical work on competition and innovations, where innovations occur within the firm, has not considered this effect in their analysis. Two related explanations comprise the aggregate appropriation effect: a bargaining power effect related to the reaction of downstream stream incumbent utilities and a demand-push story based on the reaction of new downstream entrants (the IPPs). We briefly explain these two effects.

[8] See Dasgupta and Stiglitz (1980) and the first generation of Schumpeterian growth models (Aghion and Howitt, 1992, and Caballero and Jaffe, 1993).

[9] We thank the anonymous referee for pointing us in this direction.

[10] According to the authors, this depends on whether the innovation is done by technology laggards or leaders.

[11] The number of upstream EEMs remained fairly unchanged during the sample period. Thus, the incentive to escape competition is not coming from new competitors; rather, existing firms are fighting harder to maintain or gain market share in the context of a shrinking profit scenario.

[12] The Public Utility Regulatory Policy Act (PURPA) (1978) required utilities to purchase power from local nonutility generators at "avoided-cost" prices. This encouraged the growth of independent power producers (IPPs). However, they could not sell their power to wider markets, which limited competition. When the EPAct allowed FERC to issue wheeling orders, the IPPs began competing with the utilities for large customers such as municipalities.

In the regulated regime, when there was a stable core of downstream utilities, the upstream EEMs had little bargaining power in the division of rents since they could not sell their innovations to other competing nonutility downstream firms. With the expansion of IPPs, EEMs could increasingly sell their innovation to these competing firms, and this raised their status quo payoff with the current incumbent firm. The existence of this outside option implied that the price that they received for their innovations from the downstream incumbent firms would probably increase as a result of the increase in bargaining power of the EEMs. In other words, the share from the gains from innovations was higher compared to the regulated regime.

This explanation shows how the EEMs may obtain a bigger share of profits from incumbent firms due to increased bargaining power. In addition to this explanation is a demand-side story that focuses on the new entrants, the IPPs. With an exogenous shift in downstream demand (exogenous from the point of view of the upstream EEMs) due to IPP entry downstream, the size of the pie increases. These IPPs will demand newer kinds of technology, and this demand push will incentivize EEMs to increase their innovation effort, since the upstream EEMs will now be able to capture a larger share of this growing market. Thus, both the bargaining power effect and the demand-push effect originate from downstream IPP entry and will lead to increased innovation by upstream EEMs. Both effects are captured by the aggregate appropriation effect.

From this discussion, we find that there are three possible forces driving the innovation incentives of upstream EEMs: the negative pure competition effect, the positive escape competition effect arising out of competition among the upstream EEMs, and the positive appropriation effect arising out of IPP entry downstream. The structure of the electricity industry is such that the negative pure competition effect will likely dominate the positive escape competition effect, leading to a negative net competition effect: as competition among EEMs increases, innovation would decline. Whether the absolute value of innovations increases or decreases as a result depends on the magnitude of the positive appropriation effect and the negative net competition effect. We now take up this question section.

III. Data

A. Data Sources

Our primary interest is to investigate how downstream competition affects upstream innovation. Using patents as a metric of innovation, we empirically model how the magnitude and nature of innovation by EEMs change from the regulated to the competitive regime. The number of patents, or patent characteristics (such as quality), Y_{it} is modeled as a function of a deregulation dummy, $D_{treatment}$; a dummy, $D_{treated}$, for the group that is being affected by deregulation (electricity patent classes or the EEMs), firm, or patent class characteristics $Char_{it}$; the appropriation effect, A_t, the net competition effect, C_t, and macrocontrols M_t:

$$Y_{it} = (D_{treatment}, D_{treated}, Char_{it}, A_t, C_t, M_t). \qquad (1)$$

Thus, the primary categories of data that this paper relies on are (a) information on patents, (b) variables measuring the appropriation and net competition effects, and (c) firm-level data on financial and other firm characteristics. The patent data are from the National Bureau of Economic Research (NBER) Patent Citations Database. We augment this with the new patent and citation numbers from the recent NBER patent database that contains patents applied for from 1976 to 2006.[13] The data comprise application and grant years, geographical distribution of these patents, technology classifications, number of claims per patent, backward and forward citations (citations to and from a patent),[14] standardized assignee names, and assignee codes that help in tracking assignees across years. In addition, for publicly traded companies, it matches the unique CUSIP identifier from the COMPUSTAT database with assignee numbers.[15]

We then identify the treated group as either electric technology patent classes or firms that can be categorized as EEMs. First, to identify core electricity technology classes, we cross-reference the U.S. Patent Office electricity technology classes with those in which the EEMs patent[16]. This yields 42 electric technology–related patent classes.[17] Second, to classify firms as EEMs, we use the Energy Information Administration's (EIA) form EIA 767, which contains exhaustive data on EEMs, including their names and the type of technology they supply. These manufacturers fall into three main categories: boiler manufacturers, flue gas desulfurization unit manufacturers, and manufacturers of low nitrogen oxide control burners. It is important to note that there is considerable overlap in these groups. In all three categories, 89 EEMs are identified by the EIA. General Electric, Babcock, and Wilcox are some of the larger manufacturers in this group.[18] In order to obtain the patents granted to each EEM, we matched the list mentioned above with the standardized patent assignee names from the 2006 updated NBER database. In a majority of cases, several patent assignee names appear to belong to the same firm. When an EEM is a publicly traded company, such as GE, the match between multiple patent assignees and a parent

[13] This latter data, however, do not contain information on the generality or number of claims.

[14] U.S. citation only. Since the current NBER database has 2006 application-year patents and we use data only to 2000, we are fairly certain that truncation is not a severe problem for the citation numbers. Additionally, the new database has truncation corrected citations that we use in the estimation.

[15] The COMPUSTAT database contains financial data on all publicly traded companies in the United States.

[16] http://www.uspto.gov/web/offices/ac/ido/oeip/taf/stelec.pdf.

[17] Refer to the online appendix, table I, for details.

[18] A detailed list of the equipment manufacturers is provided in the online appendix, table II.

firm is relatively easy to determine. The CUSIP and assignee match from the NBER database allow us to identify all assignees that belong to a single parent. However, not all the subsidiaries of GE, for example, are engaged in electric technology innovation. Therefore, we exclude obvious mismatches, such as the National Broadcasting Corporation. Of the remaining subsidiaries, we cross-reference our list with multiple industry sources, such as Hoovers, industry publications, and the company Web sites, to observe whether the subsidiary is engaged in the electric technology sector. We keep only those subsidiaries that are directly involved in the electricity sector, and the patents granted to these remaining subsidiaries are classified under the firm. However, when the company is not publicly traded and no CUSIP match exists in the NBER database, the match between patent assignee and a parent EEM is not straightforward. Often there are multiple similar assignee names. In such cases, we use the industry sources mentioned above to match the assignee to the EEM identified in the EIA report. After this exercise, if we are still uncertain about the exact match, we retain all the similar assignee names and classify them under one EEM.[19]

From the data we find that of the 89 equipment manufacturers identified by the EIA, approximately 55% patented in the United States during our sample period. In addition, these firms most frequently patented in U.S. patent class 110 (Furnaces).[20] Matching the EEM list to COMPUSTAT leaves us with 15 firms, and we use this information to classify large firms in the sample. For all our samples, if a patent assignee or firm does not patent in a given year, we set the number of patents to 0 in that year.[21] In the estimation, we use two samples: all EEMs and those with atleast one U.S. patent during the period 1980 to 2000. Although the updated NBER patent database comprises grant data to 2006, we restrict our sample to 2000 to avoid truncation issues. When the data were collected in 2007, patent applied for from 2001 to 2006 may not have been granted due to significant grant lags in certain technology areas. Additionally, most patents require a significant number of years to reach their full citation potential (Hall, Adam, & Trajtenberg, 2001). By allowing at least six years from the date of application, we attempt to minimize this problem.

B. *Variable Construction*

Dependent Variables. Our primary dependent variables fall into two categories: measures of patenting activity and citation-based patent characteristics. To measure patenting activity, we construct the percentage of patents and patent counts by patent technology class and patent assignee. When the unit of observation is the patent class, the percentage of patents per class in a given application year is constructed by dividing the number of patents granted in each patent class by all patents granted in the United States for that particular application year.[22] When the patent assignee is the unit observation, our sample is all electric technology classes. Thus, the percentage of patents for each assignee is calculated as the number of electric technology patents granted to that assignee by application year, divided by the total number of granted patents (in all electric technology classes) for that application year. From panel A in table 1, we find that on average, each class has 0.17% of overall patents, with the highest patenting class having 3.3% of all patents. On average, each assignee has 0.001% of patents, with the maximum share being 0.42% within the electric technology category for our sample. Additionally, on average, each assignee has only one patent in our sample, with the highest being 484 patents granted to one assignee for a given application year. When we focus on EEMs in particular, from panel B of table 1, we find that on average, each EEM has 15.7 patents, with the highest-innovating firm holding 590 patents.[23]

Next, we use citation-based measures to construct two main patent characteristics: patent quality and generality. The number of citations received per patent is often used as a measure of patent quality. This form of measurement is based on the idea that patents that make significant contributions will have more citations: a greater number of other patents will cite these patents than those that embody minor innovations (Jaffe, Trajtenberg, & Henderson, 1993; Jaffe, Trajtenberg, & Fogarty, 2000). However, the raw number of citations that a patent receives every year can be misleading. First, there may be significant truncation issues for newer patents since it takes time for a patent to get cited. Second, a patent may receive more citations simply because there are more patents in a given field in the following years, or it may come from a field where it is customary to cite frequently. The problem of truncation is minimized in our context since we have citation data to 2006 and use patents applied for only to 2000. Thus the year 2000 patents have had at least six years to get cited.[24] Additionally, we use the truncation-corrected citations from the updated NBER patent database. To solve the second problem, we purge the truncation-corrected citations of the field effects as suggested by Hall et al. (2001). We then create

[19] As a robustness check we have excluded these companies from the sample, and there is no significant difference to the estimation results.

[20] Placement of an original patent into class 110 requires the following minimum structure or steps for operating such structure: (a) means or a step to either convey or support solid combustible material during combustion, (b) means or a step to supply either directly or indirectly a noncombustible fluid to the solid combustible material, and (c) means or a step to enclose or control the combustion reaction.

[21] Web appendix table III provides the matched list of EEMs, assignee numbers, and CUSIPs.

[22] For robustness, we have constructed alternative patent share measures, where the numerator is number of patents granted in each patent class and the denominator is USPTO patents granted to all corporations or granted to U.S. corporations.

[23] The reason the maximum number varies when we the count by assignee and by firm is that there are multiple assignee numbers under one firm.

[24] See Hall et al. (2001) for a discussion of the distribution of citations over time.

TABLE 1.—SUMMARY STATISTICS FOR TABLES 2 TO 4

A. Statistics for Tables 2 and 4	Sample: All Patent Classes (Table 2)				
	Observations	Mean	S.D.	Minimum	Maximum
Dependent variable					
Percentage of patents per patent class	12,012	0.148	0.258	0	3.347
Number of patents per patent class	12,012	156.137	319.697	0	5,062
Regressors: Dummy variables	Observations	Zeros	Ones		
EPAct dummy (lag two years)	12,012	8580	3432		
Dummy for electric equipment patent classes	12,012	11130	882		
	Observations	Mean	S.D.	Minimum	Maximum
Regressors: continuous variables (lag two years)					
Other patent stock[a]	12,012	14354.22	4780.03	7648	24,411
Own patent stock	12,012	639.98	1195.90	0	19,220.93
Quality stock	12,012	9947.61	23697.23	0	426,819.8
Mean adjusted generality	12,012	1.013	0.927	0	30.262
Mean adjusted claims	12,012	0.661	0.519	0	10.533
Sample: Electric Equipment Patent Classes (Tables 2 and 4)					
	Observations	Mean	S.D.	Minimum	Maximum
Dependent Variables					
Percent age of patents per assignee (Dependent variable table 2)	41,929	0.001	0.014	0	0.418
Number of patents per assignee (Dependent variable table 2)	41,929	1.101	15.129	0	484
Average (adjusted) quality (Dependent variable table 4)	41,929	1.074	5.636	0	297.70
Aggregate (adjusted) quality (Dependent variable table 4)	41,929	1.276	18.480	0	629.76
Average (adjusted) generality (Dependent variable table 4)	41,929	0.110	0.482	0	6.676
Dummy variables	Observations	Zeros	Ones		
EPAct dummy (lag two years)	41,929	30,991	10,938		
Dummy for EEMs	41,929	38,594	3,335		
	Observations	Mean	S.D.	Minimum	Maximum
Continuous variables (lag two years)					
Other patent stock[a]	41,929	59,431.1	30,832.8	38	415,685.8
Own patent stock	41,929	4.717	68.656	0	2,191.206
Quality stock	41,929	69.694	1,068.30	0	35,517.77
Mean adjusted generality	41,929	0.119	0.501	0	7.788
Mean adjusted claims	41,929	0.081	0.343	0	7.342
Variables Common to Both Sample					
	Observations	Mean	S.D.	Minimum	Maximum
Number of boilers (CAAA)	41,929	529.348	794.045	0	2000
U.S. total R&D stock (billions of $2000) (lag two years)	41,929	592.147	170.159	381.565	970.85
GDP (billions of $2000) (lag two years)	41,929	6,518.487	1,309.21	4,540.9	9,066.9
Statistics for Table 3					
Sample: All Electric Equipment Manufacturers					
	Observations	Mean	S.D.	Minimum	Maximum
Dependent Variables					
Number of patents	1,743	16.321	66.297	0	590
Dummy variables	Observations	Zeros	Ones		
EPAct dummy (lag two years)	1,743	1,245	498		
Dummy Low NOx Burner/ Desulfurization unit Product	1,743	357	1,386		
Large EEM dummy	1,743	1,260	483		
Dummy for large U.S. firms	1,743	548	1,195		
	Observations	Mean	S.D.	Minimum	Maximum
Continuous variables					
Other firms's electric technology patent stock[a]	1,743	67,760.89	45,542.91	1,611.26	415,685.8
Mean adjusted quality stock (lag two years)	1,743	968.366	4,308.10	0	34,530.9
Mean adjusted generality (lag two years)	1,743	0.287	0.679	0	4.141
Mean adjusted claims (lag two years)	1,743	0.196	0.476	0	4.403
Sample: Electric Equipment Manufacturers that Have At Least One U.S. Patent					
	Observations	Mean	S.D.	Minimum	Maximum
Dependent variable					
Number of patents	945	30.103	87.724	0	590
Dummy variables	Observations	Zeros	Ones		
EPAct dummy (lag two years)	945	675	270		
Dum. Low NOx Burner/ Desulfurization unit product	945	189	756		
Large EEM dummy	945	567	378		
Dummy for large U.S. firms	945	212	733		
	Observations	Mean	S.D.	Minimum	Maximum
Continuous variables					
Other firms's electric technology patent stock[a]	945	67,439.06	56,189	1,611.26	415,685.8
Mean adjusted quality stock (two years)	945	1,785.92	5,726.04	0	34,530.9
Mean adjusted generality (lag two years)	945	0.527	0.848	0	4.141
Mean adjusted claims (lag two years)	945	0.358	0.596	0	4.403

TABLE 1.—(CONTINUED)

	Both Samples				
Total competition and appropriation effect (lag two years)					
Utility ROA (competition effect)	1,743	0.117	0.007	0.104	0.130
Share of nonutility generation (lag two years)(appropriation effect)	1,743	0.042	0.044	0.001	0.111
	Observations	Mean	Post-EPAct	Observations	Mean
Pre-EPAct					
Utility ROA (Percentage)	1,079	12.04		664	10.30
Percentage of nonutility generation	1,079	2.31		664	11.24
	Observations	Mean	S.D.	Minimum	Maximum
Macrovariables					
Number of boilers (CAAA)	1,743	579.762	813.651	0	2,000
Energy R&D Stock (lag two year)	1,743	4.257	1.185	1.769	6.176
GDP (Billions of 2000$) (Lag two years)	1,743	6,696.848	1,229.623	5,015	9,066.9

[a]Calculation of this patent stock is based on patents in all other classes or patents granted to all other assignees ($j,\ldots,n$) in the patent technology classes assignee i patents in (all within the sample of electric equipment technology patent classes).

demeaned average and total citation measures, and citation stocks by patent class and year and by firm and year.[25]

We use the generality measure developed by Trajtenberg, Jaffe, and Henderson (1997) to investigate whether firms are investing in specific innovations. This measure is also based on citations received by individual patents. Generality implies that patents from a variety of other classes cite this particular patent, that is, it has a significant impact on a wide variety of fields.[26] With deregulation and the associated uncertainties facing the firms, we expect EEMs to produce more targeted and less general patents.

Variables capturing the effects of deregulation. To implement the empirical model, we first need to identify deregulation dummies, electricity technology classes, and the EEMs that supplied technology to downstream utilities. The deregulation dummy is 1 after the passage of the EPAct in 1992.[27] We use a two-year lag of this dummy in our empirical specification, that is, we assume that the deregulation affects the innovation behavior of EEMs with a two-year lag.[28] In the literature there is no clear theoretical or empirical finding that allows us to pick a particular lag structure. We use a two-year lag to allow the firms to adjust to the new regulatory scenario. R&D is usually a long-term strategy developed by a firm, and it may not be possible to instantaneously change this in response to a policy change; thus, the lag reflects this gradual response.[29] Next we construct dummies that identify the electricity patent classes and the EEMs. The EEM dummy is 1 if the company was identified as an EEM on form EIA 767.[30] The electricity patent class dummy is 1 if it is an electricity-related patent class and there is EEM patenting activity in that class.[31]

The theoretically identifiable channels through which downstream competition may affect upstream innovation behavior are the pure competition effect, the escape competition effect, and the appropriation effect. In the empirical model, both the (negative) pure competition and the (positive) escape competition effect are subsumed in the net competition effect variable, which captures the profits of the utilities in the pre- and post- restructuring periods. We use the average profit (return on assets) of all downstream utilities to characterize this effect. Falling downstream profits will reduce the demand for new technology, and since profits were shared between the upstream and downstream, declining downstream profits imply declining upstream profits from innovation and thus reduced innovation incentives (pure competition effect). However, such a reduction in profits may spur upstream firms to innovate more (escape competition effect) if this allows them to capture a larger share of the declining profits. Thus the downstream utility profits give us a net effect of both of these forces.

The appropriation effect measures the impact of new downstream entry, and hence increased upstream bargaining power and increased demand, on EEM innovation. Ideally, we want to obtain the number of entrants to the generation sector in each year and their generation capacity. However, these data are difficult to obtain, so we use the share of generation by nonutilities as a proxy for new IPP entry.

Innovation inputs. We use several past patent characteristics to capture the innovation landscape of a firm or patent class. First, to capture aggregate knowledge stock, we construct the lagged patent stock of other patent classes or firms (other patent stock) to capture any spillover effects that may exist.[32] When the unit of observation is the patent

[25] We use the declining balance formula outlined in Hall, Jaffe, & Trajtenberg (2005) to create the citation stocks and use a 15% depreciation rate.

[26] Generality $= 1 - \sum_{j=1}^{J} \left(\frac{n_{ij}}{n_i}\right)^2$, where n_i is the number of forward citations to a patent and n_{ij} is the number of citations received from patents in class j. A detailed discussion about this variable can be found in Hall et al. (2001).

[27] Deregulation dummy = 1 if year >1992 (1993 and after).

[28] Later in the paper, we provide robustness checks for various lags.

[29] A paper that investigates the efficiency effects on deregulation (Fabrizio, Rose, & Wolfram, 2007) does not use any lags for the deregulation dummy since they study labor and capital efficiency of utilities, metrics that can be changed on a shorter term compared to innovation of the upstream firms, which are one step removed from the deregulation process.

[30] The EEM dummy is 1 for all the firms listed in the Web appendix, table II.

[31] The electricity patent class dummy is 1 for all the classes listed in the Web appendix, table I.

[32] We use the declining balance formula outlined in Hall et al. (2005) to create the citation stocks and use a 15% depreciation rate to create the stock of innovation inputs.

class, this variable captures the patenting activity in all other classes. When the unit of observation is the assignee or firm in the electric equipment classes, this stock is calculated based on the number of patents obtained by other assignees or firms $(j,\ldots,n)$ in the patent classes that assignee or firm i patents within the electric technology classes. This variable captures the innovation activity of the firm's competitors and shows whether there is a positive or negative spillover when competitors increase their patenting activity.

Second, we use the firm's own patent characteristics from the past to capture the idea that past patents serve as knowledge inputs for current patents. We construct a lagged own quality stock using past citation stocks to indicate the quality of innovation inputs that the firm can build on. For example, if a firm has had a very high-quality patent portfolio in the past, it has a better base of knowledge to build on than another firm with low-quality patents. Therefore, the former will have more inventions than the latter. We also use a lagged average generality measure to indicate the range of past innovation. A firm with more general patents can draw from a broader base of knowledge and may stave off diminishing returns to innovation longer than a firm that patents within a very narrow range of technologies. Thus, we argue that a firm with a higher generality score should produce more patents than another with a very narrow and specific patent portfolio.

The average number of claims is used as a proxy for patent breadth (Guellec, van Pottelsberghe de la Potterie, & van Zeebroeck, 2006): the more claims a patent makes, the more things it claims to do, giving it a bigger breadth. The effect of this variable on patents in unclear. If past patents have greater breadth, then numerous potential applications may have already been covered, and this phenomenon may lead to a lower number of current patents. Conversely, if breadth serves as a proxy for quality, we may find the reverse effect. When we use the patent characteristics as the dependent variables, we include the lagged own firm patent stock as an additional control.[33] To create this stock, we consider only the past electric equipment technology patents for each firm. We hypothesize that a firm that has a high electric technology patent stock also has a greater number of inputs at its disposal and is therefore more likely to come up with higher-quality and more general inventions.

Firm characteristics. When we restrict our estimation sample to EEMs, we are able to construct several firm-level variables to account for the nature of the firm. The summary statistics for these variables are presented in panel B of table 1. EEMs produce three main types of products: boiler manufacturers, flue gas desulfurization manufacturers, and low nitrogen-oxide control burners. We construct two dummies based on the type of products. The multiproduct firm dummy is value 1 if an EEM produces more than one type of product. It is possible that such a firm will produce a greater number of innovations since its activities span a greater product space.

In addition, we also include a separate dummy for EEMs that produce burners or desulfurization units. The Clean Air Act Amendments (CAAA) of 1990 targeted older-generation plants in need of updating their pollution control technologies. The two primary technologies that could be adopted to meet the CAAA requirements were low nitrogen oxide (NOx) burners and desulfurization units. Thus, this dummy captures the effect the CAAA may have had on these specific EEMs. In addition, we create a large EEM dummy that captures whether the EEM is publicly traded in the United States. This variable serves as a proxy for firm size and R&D because we lack data for these variables. Finally, we include a U.S. firm dummy that captures whether the EEM is headquartered in the United States, since our sample includes both domestic and foreign EEMS.

Macroenvironment. In all specifications, we include three main macrocontrols: the number of boilers affected by the CAAAs, a measure of R&D, and GDP. The CAAA forced utilities to undertake pollution control measures, and thus it is conceivable that as more boilers have to be in compliance, demand for new technology will increase. We hypothesize that this increased downstream demand will have a positive effect on upstream innovation. This data are from the EIA Clean Air Act Database. The GDP variable captures the overall health of the economy and controls for macrofluctuations; it is obtained from the Bureau of Economic Analysis. The R&D variables are obtained from the National Science Foundation data on science and technology indicators and from the EIA. We use two alternate measures of R&D depending on the sample: the total R&D expenditure stock in the United States to capture the overall research spending in the economy and the total energy R&D expenditure (federal and company) to capture any spillovers that may occur between an EEM's innovation and overall energy R&D. All dollar figures are in real terms (2000 dollars), and all time-varying explanatory variables are lagged by two years.[34]

IV. Empirical Methodology and Results

A. Deregulation and Electricity Innovation

We begin by estimating a simple difference-in-difference model in table 2 to test whether the regime change after deregulation had a significant impact on the innovation behavior of the upstream EEMs. This ensures that deregulation was indeed responsible for the decline in the quantity

[33] Own firm patent stocks include only patents in the electricity classes that are assigned to the firm. Since we argue that past patent stocks serve as inputs to current innovation, only electricity patents are included.

[34] We lag the variables by two years to allay concerns about endogeneity issues. Later in the paper (table 3B), we present a sensitivity analysis for different lags of the deregulation dummy.

TABLE 2.—PATENTING IN ELECTRIC TECHNOLOGY AFTER RESTRUCTURING

	All Patent Classes		Electric Technology Classes	
Sample (All Firms) Dependent Variable	Percentage of Patents per Patent Class (1)	Number of Patents per Patent Class (2)	Percentage of Patents per Assignee (3)	Number of Patents per Assignee (4)
EPAct dummy (lag two years)	−0.055***	0.065***	0.0001	0.139*
	(0.013)	(0.021)	(0.0001)	(0.083)
Electric equipment patent class Dummy	0.137***	0.904***		
	(0.034)	(0.058)		
EPAct dummy(Lag two years) × Electric Equipment Patent Class Dummy	−0.080***	−0.082**		
	(0.015)	(0.040)		
EEM Dummy			0.005**	0.506***
			(0.002)	(0.086)
EPAct Dummy(Lag two years) × EEM Dummy			−0.004**	−0.407**
			(0.0017)	(0.164)
Innovation inputs (lag two years)				
Other Class/Firm Patent Stock[a]	−0.0001***	0.00002**	0.0000001	−0.00001***
	(0.00002)	(0.00001)	(0.00000002)	(0.000001)
Own Patent Quality Stock (Adjusted)	0.00001***	0.00001***	0.00001***	0.0001***
	(0.000001)	(0.0000002)	(0.000001)	(0.00001)
Mean (Adjusted) Generality	0.003	0.185***	0.001***	0.319***
	(0.004)	(0.009)	(0.0004)	(0.022)
Mean (Adjusted) Number of Claims	0.055***	0.436***	0.001***	0.323***
	(0.007)	(0.018)	(0.0002)	(0.029)
Macroenvironment				
Number of Clean Air Act Affected Boilers	0.0001***	−0.00002	0.0000001*	−0.00003
	(0.00002)	(0.00002)	(0.00000007)	(0.0001)
EEM Dummy × Number of Clean Air Act Affected Boilers	−0.0001***	−0.00004*	−0.000002**	−0.0002**
	(0.00002)	(0.00002)	(0.000001)	(0.0001)
Total R&D Stock (Billions of $2000) (Lag two years)	0.001***	0.004***	−0.000006**	0.002***
	(0.0004)	(0.0003)	(0.000002)	(0.0008)
GDP (Billions of 2000$) (Lag two years)	0.0001***	0.0001	0.0000003*	0.0003
	(0.00004)	(0.0001)	(0.000002)	(0.0002)
Relevant statistics				
Observations	12,012	12,012	41,929	41,929
Number of patent classes/assignee	572	572	1,823	1,823
R^2	0.703		0.645	
Chi square	2,340.52	11,301.15	1,965.90	1,784.18

Columns 1 and 3: Random effects panel data model with standard errors clustered by patent class or patent assignee. Columns 2 and 4: Random effects panel negative binomial model. For columns 1 and 2, the sample consists of all patents given to corporations, the unit of observation is the patent class, and the treated groups are the electric equipment patent classes. For columns 3 and 4, the sample consists of electric equipment patents given to EEMs and a random sample of 2,000 firms, the unit of observation is the patent assignee, and the treated groups are the EEMs (electric equipment manufacturers). All specifications contain a time trend and a constant. The sample is from 1980 to 2000. Standard errors are in parentheses. Significant at *10%, **5%, and ***1%.

[a]Calculation of this patent stock is based on patents in all other classes (columns 1 and 2) and patents granted to all other assignees ($j,\ldots,n$) in the patent technology classes assignee i patents (columns 3 and 4).

and quality of innovation in the electric equipment manufacturing sector and that this was not just a secular downward trend that had little to do with the deregulation policies:

$$Y_{it} = \alpha + \beta D_{treatment} + \phi D_{treated} + \theta(D_{treament} * D_{treated}) + \phi t + \sum_{J=1}^{j} \theta_J Z_{it}^j + v_i + \varepsilon_{it}. \quad (2)$$

In equation (2), Y_{it} is the number of patents or the percentage of patents for a given patent class or firm in a given application year, t is a time trend, and Z^j are other control variables.[35] $D_{treatment}$ is the deregulation dummy (lagged by two years), and $D_{treated}$ captures the treated group, which is either electric equipment patent classes (compared to all other patent classes) or the EEMs (compared to the control group, which is a random sample of 2000 firms, selected for tractability, that patent in the electric equipment classes but are not EEMs).[36] The difference-in-difference coefficient is θ.

If deregulation was responsible for a significant negative impact on the innovation behavior of electric equipment producers, we expect θ to have a negative sign. For table 2, columns 1 and 3, when the dependent variable is in percentages, we use a random effect GLS model with robust and clustered standard errors.[37] However, even if we observe a decline in the percentage of electricity patents, we cannot fully conclude that deregulation has a negative impact on the electric technology innovation. An alternate explanation

[35] Percentage of patents per patent class = (Number of patents granted in a patent class i in year t/Total number of utility patents granted by the USPTO)×100. The year refers to application year. Percentage of patents per assignee = (Number of electric equipment patents granted to an assignee in year t/Total number of electric equipment patents granted by the USPTO) ×100. The year refers to application year.

[36] When the unit of observation is the patent class, the sample is all patent classes. When the unit of observation is the assignee, the sample is electric equipment patent classes.

[37] See "How Much Should We Trust Differences-in-Differences Estimates?" Marianne Bertrand, Esther Duflo and Sendhil Mullainathan; *Quarterly Journal of Economics*, 119 (2004), 249–275 for an extensive discussion.

could be the case that EPAct has not had an absolute negative effect, but rather that electricity innovation is growing more slowly compared to other technologies. Thus, the percentages of electric technology innovation are declining. To investigate whether deregulation has actually decreased the absolute number of patented innovations by EEMs, we use number of patents in a patent class or by assignee in columns 2 and 4. Since the dependent variable is in counts, we use a random effects negative binomial model to estimate these two specifications.

From table 2, the interaction term between the treated group and the treatment dummy is the coefficient of interest. As outlined earlier, a negative and significant coefficient implies that deregulation has adversely affected the outcome being studied. In columns 1 and 2, the sample consists of patents granted to corporations in all patent classes between 1980 and 2000, and the dependent variables are the percentage and number of patents granted in each patent class in a given year.[38] The treated groups are the electric equipment patent classes. First, we find that the difference-in-difference coefficients (−0.08) are negative and significant in both columns, implying that the introduction of competition in the power sector has had an adverse impact on both, the percentage and level of patenting in the electric equipment technologies compared to other technologies.[39] Second, electric equipment classes have a higher number of patents when compared to nonelectric equipment classes, holding all else constant. Third, the post-1992 period has seen a decline in the percentage of patents assigned to all classes (column 1) while the absolute number of patents has increased (column 2).[40] The 1990s was a decade of prolific growth in new technologies (giving rise to increasing number of new patent classes) and vigorous innovation in existing areas. This is reflected in the fact that the absolute number of patents went up in each patent class, while the share of each patent class in total patents declined. Based on these results, one can be fairly certain that the decrease in patenting for electricity patent classes that occurs after 1992 is because of deregulation rather than increases in patenting in nonelectricity classes.[41]

We find the same patterns from columns 3 and 4 where we test whether the EEMs were adversely affected compared to other groups within the electric equipment patent classes.[42] To create the control group, we draw a random sample of 2,000 firms from non-EEM assignees that patent in the electric equipment classes.[43] As before there are three coefficients of interest: (a) the effect of EPAct on electric equipment patents in general, (b) average EEM versus non-EEM patenting activity in the electric technology classes, and (c) the interaction between the two, that is, how EEM electric technology patenting activity changed after EPAct. We expect a significant interaction term since the EEMs should be more affected after deregulation compared to other entities that innovate in the electric equipment area. This is because the utilities, the primary clientele of the EEMs, were directly influenced by deregulation and experienced significant changes in their competitive landscape and profitability.

As before, the difference-in-difference coefficient (the interaction term) shows the effect of the treatment (the passage of EPAct in 1992) on the treated (the EEMs in this case). This interaction coefficient is negative and significant in both columns, implying that electric technology patenting by EEMs declined in both percentage and absolute terms following the 1992 EPAct. When we calculate the aggregate effect, we find that EEMs experience a 24.4% decline (based on column 4) in patenting compared to non-EEMs. We also find that all else equal, the passage of the EPAct has had no impact on the percentage of patents in electric equipment classes (column 3) while the number of electric equipment patents granted to EEMs increased after 1992 (column 4). Also, the percentage and numbers of EEM patents are higher when compared to other assignees in the electric equipment technology classes. Before investigating the channels through which such declines occurred, we briefly discuss how the other variables affected patenting.

We control for measures of input quality in these regressions. Previous patents are often used as inputs in current patents, and the properties of past knowledge will influence the amount of innovation that is generated today (Popp, 2002, 2006). First, we control for the stock of patent quality in past years in a given class.[44] A priori, it is difficult to anticipate the direction of impact. One could argue that better-quality inputs may increase current innovation. However, the reverse may be true as well: if a technology class or firm already has patents of very high quality, the patent space may be crowded, and it may be difficult to come up with patentable innovations. From table 2, we find support for the former hypothesis. We find that an increase in past patent quality stock increases both the percentage and number of patents for each class or assignee.

Additionally, a firm's innovation may be influenced by that of its competitors. As discussed earlier, we use the past patent stock of other patent classes to measure this and find mixed results. From columns 1 and 2, we find that as the

[38] All counts are by application year—out of all the patents applied for in year t, the number granted.

[39] We find that deregulation was responsible for a 0.5% decline (based on column 2) in patenting for the 42 electric technology classes.

[40] This is the effect when the total impact is not taken into account, that is, we do not take into account the negative interaction terms between the EPAct dummy and the electric equipment class dummy.

[41] If the decline was a result of increased patenting in other classes, then the difference-in-difference coefficient for the level equation (column 2) would not be negative and significant.

[42] The unit of observation is the patent assignee, and the sample comprises the electric equipment patent classes.

[43] Two thousand firms were selected for reasons of tractability.

[44] We lag the patent class characteristics by two years since these are used as measures of past knowledge and input quality, and since the diffusion of knowledge is not instantaneous, current patents would build on patents that had been granted a couple of years earlier. However, our main results are not sensitive to the choice of lags. Results provided on request.

patent stock of other technology classes increases, the percentage of patents for an individual class falls, while the absolute number increases. The positive effect may imply positive spillovers and some form of unobservable innovative capacity increase effect. The negative effect on the percentage (column 1) may imply that although there are positive spillovers, there are diminishing returns to these spillovers. At the assignee level, we find that in electric technology classes, own firm innovation is adversely affected (column 4) as innovation by competitors increases.

We also control for the generality and breadth of the past patent portfolio and find that these positively influence current innovation activities. Higher average generality implies that patents in this class influence knowledge in a wide range of fields, so it may be easier to build on these patents and come up with patentable inventions in such a fertile field. The number of claims, which measures the breadth of the class, also has a positive impact on patenting, implying that greater patent breadth in the past encourages current innovation.

We also find that as the number of boilers affected by the Clean Air Act Amendments (CAAA) increases, it encourages innovation in general. However, electric technology classes and EEMs show decreased innovation after CAAA. This result is counterintuitive since the CAAA should have increased innovation by these groups. There could be several alternative explanations for this finding. First, instead of picking up the effect of the CAAA, this result could reflect the effect of further restructuring activity around 1996, when the second phase of boilers had to be brought under compliance. Another possible explanation is that firms had already done the research in earlier years in anticipation of the passage of the CAAA, an argument supported by Taylor, Rubin, and Hounshell (2003). Finally, on average, lagged R&D stock and income levels have a positive impact on innovation.

B. Channels of Influence

Next, we focus solely on the EEMs and estimate a richer model that incorporates the appropriation and net competition effects, and illustrates the channels through which downstream deregulation affected upstream innovation. Our sample consists of all EEMs, and we estimate the effect of deregulation on the innovation activity of these firms by focusing on the number of patents granted to each EEM.[45] Since these patent counts are nonnegative integer numbers, we cannot use the usual least squares approach.[46] In addition, these counts have a disproportionate number of zeros since many of the smaller EEMs do not patent every year and some EEMs never patent during our sample period.[47] The data-generating process for the zero outcomes may be qualitatively different from the process that generates the positive outcomes. Therefore, we model such data using a zero-modified negative binomial specification.[48] The log-likelihood function for the model has two distinct parts—one that models the zero outcomes and another that is used for the positive counts.

In the first stage, the zero outcomes are modeled as a binary probability model (logit specification in our case) that describes the probability of observing a zero or positive outcome. It is shown by equation (3):

$$\Pr ob(Z = 1|X) = \frac{e^{x'\beta}}{1 + e^{x'\beta}}, \tag{3}$$

where Z is the dependent variable and is either 1 or 0 depending on whether the EEM has at least one patent in the given application year. The vector explanatory variables (X) include lagged patent stock, lagged average quality of past patent portfolio, a dummy denoting whether the EEM is a large firm, a dummy for multiproduct firm, a dummy denoting a U.S. or foreign firm, lagged-energy R&D expenditure and GDP in the United States (in real $2000), and year fixed effects.[49]

The patent counts are then modeled using a negative binomial function with robust standard errors that are clustered by firm while factoring in the probabilities from the first stage.[50] This specification is given by

$$\begin{aligned} Y_{it} = \alpha + \beta D_{treatment} + \chi A_t + \delta C_t + \phi_i(D_{treatment} \times A_t) \\ + \varphi_i(D_{treatment} \times C_t) + \sum_{P=1}^{p} \gamma_P Char_{it} \\ + \sum_{M=1}^{2} \delta_M Macro_t + \varepsilon_{it}, \end{aligned} \tag{4}$$

where Y_{it}, the number of granted patents for each EEM in a given application year t, is regressed on the deregulation dummy ($D_{treatment}$), the appropriation and net competition effects (A_t and C_t respectively), and two interaction terms.[51] The appropriation effect, as explained earlier, arises due to the greater bargaining power of EEMs and a demand push effect, both of which originate from downstream IPP entry,

[45] Table 1b in the online appendix provides a list of these companies along with their assignee codes (from the NBER database) and patenting rank.

[46] Using OLS will yield some negative predicted values. But since the dependent variable is nonnegative, the predicted values should also be nonnegative for all explanatory variables. If all values of the dependent variable were strictly positive, we could have used a log transformation. However, since some of the values are 0, we prefer using a count data model.

[47] About 55% of the dependent variable has zero value.

[48] See Greene (2002) for a discussion of the model.

[49] From the estimation results, we find that EEMs that have more past patents and better-quality past patents are more likely to innovate in the current period. Being in a multiproduct firm or large firm increases the likelihood of getting a patent; however, the coefficients are not significant. U.S. firms are less likely to patent. R&D and GDP have negligible impact.

[50] Exclusion restrictions for the model imply that there must be at least one variable that is included in the logit model that is not included in the negative binomial part. The multiproduct firm dummy and the lagged patent stock serve as exclusion restrictions.

[51] The net competition effect subsumes the pure competition and the escape competition effects that are discussed in section 2.

which is measured by the share of generation by nonutilities. The net competition effect variable captures the effect of downstream competition on upstream innovation (through changing the competitive conditions upstream due to downstream restructuring) and is measured by the average profit (return on assets) of all downstream utilities. The interaction terms between the treatment dummy and the appropriation and net competition effects show how these latter variables affect innovation behavior after deregulation. $Char_{it}$ denote a set of firm-specific controls, such as patent characteristics for each EEM, capturing the quality of previous knowledge that the firm can build on and the type of firm (boiler manufacturers, flue gas desulfurization manufacturers, low nitrogen oxide control burners, or a combination). $Macro_t$ denotes the macro controls.

In table 3, panel A, columns 1a and 1b, the sample consists of all EEMs, regardless of whether they have a patent. In columns 2a and 2b, we restrict the sample to EEMs that have at least one patent during our sample period, 1980–2000. Columns 1a and 2a report the semielasticities for each term, and columns 1b and 2b report the aggregate elasticities (or semielasticities for dummy variables) after taking into account the interaction terms. The results are similar in sign and significance across the two samples, and we discuss the results in columns 1a and b.

First, we find that after factoring in the direction and magnitude of the appropriation and net competition interactions, deregulation alone has led to a 20.6% decline in patenting by EEMs. A possible reason could be that the downstream utilities could not use a cost pass-through after deregulation. During the regulated era, utilities could pass on most costs to the final customers through the regulated rates. However, after deregulation, with fluctuating market-based wholesale electricity rates and mostly fixed retail rates, the utilities could not pass all costs to the customers. This dramatically reduced their own R&D budget and changed their technology buying behavior, quite apart from the direct effect of competition and declining profits. Additionally, rate-of-return regulation distorted investment incentives and resulted in Averch-Johnson types of distortion, where the regulated firm went off its path of equilibrium and chose a technology that led to overcapitalization (Granderson, 1999; Smith, 1975; Okuguchi, 1975). The lifting of the regulation may have corrected this distortion and reduced capital equipment investments by utilities. These effects in turn had an adverse influence on upstream innovation behavior.

We also find that both the appropriation effect and the net competition effects are significant after the passage of the EPAct but not before it. Before the EPAct, the regulated electric industry did not behave like a profit maximizer, so the adoption of new technology was not governed by cost-minimization concerns. Thus, the net competition effect is not important in explaining upstream innovation in the regulated era. After deregulation, this effect determines in part the innovation response of EEMs. This is a combination of two opposing effects: the pure competition effect that predicts a decline in innovation incentives and an opposing escape competition effect that points to an increase in innovation incentives with increasing competition. Our results show that for our sample period, the pure competition effect swamps the escape competition effect, leading to a decrease in innovation. We find that a 1% decline in downstream profits decreases upstream innovation by approximately 9.18% post-EPAct (net competition effect). From table 1, panel B, we observe that for our sample period, profits declined on average by 2% after deregulation. Thus, the net competition effect is responsible for an 18.3% decrease in innovation.

The appropriation effect, which captures how the status quo payoff of EEMs before and after restructuring affects innovation, is not significant before the EPAct. This is expected because prior to 1992, there were very few new generating companies that were entering the downstream generation market. This changed in a significant way after restructuring, and keeping with the predictions from the theoretical literature, we find that the innovation increases when EEMs have greater outside opportunities to sell their product as new companies enter the downstream market. Empirically, we find that a 1% increase in the appropriation effect, as captured by the nonutility generation share, increases innovation by approximately 2.2% following the introduction of the EPAct. From panel B of table 1, we observe that for our sample period, nonutility generation share increased on average by 8.9% after deregulation. Thus, the appropriation effect is responsible for a 19.6% increase in innovation.

In addition, we find that external spillovers and the quality of innovation inputs matter (Popp, 2002, 2006). An increase in innovation by other EEMs had a positive spillover effect, and a 1% increase in electric equipment patenting by other firms increased a firm's innovation by 0.68%.[52] Additionally, companies whose past patent portfolios were more general also showed an increase in current patenting. The breadth or quality of the past patent portfolio did not affect current innovation. To account for the effect of the CAAA of 1990, we included the interaction of the number of boilers affected by the CAAA each year and the dummy for firms that produced the low NOx burners and desulfurization units. Consistent with earlier literature (Popp, 2003), we find that the CAAA had a positive impact

[52] While this is a fairly large spillover effect, we believe there are two possible reasons for this: a true push toward more innovation and a strategic response. Both can be traced to the industrial structure of the EEM industry. First, since this is an industry with a limited number of players that mostly concentrate on a handful of major technologies, innovation by competitors necessitates a strong response from every firm wishing to maintain its market position. A second reason for observing this strong response could be strategic patenting by firms. Following the line of reasoning laid out in the literature on strategic patenting (Bessen, 2004) and patent thickets (Shapiro, 2000), one may argue that if a competitor is increasing patenting in an oligopoly setting, other firms may take out a greater number of patents around their own core innovations to protect them from infringement by others and to use them as bargaining tools in cross-licensing purposes.

TABLE 3.—CHANNELS OF INFLUENCE

A. Base Case

Dependent Variable Number of Patents for Each EEM	1a Semielasticity[b]	1b Elasticity[c]	2a Semielasticity[b]	2b Elasticity[c]
EPAct Dummy (Lag two years)	−13.613**	−20.595**	−12.205**	−18.514***
	(6.323)	(6.591)	(6.090)	(6.380)
Net Competition Effect (Lag two years)	−11.211		−8.979	
	(11.620)		(11.126)	
Appropriation Effect (Lag two years)	2.526		2.020	
	(4.049)		(3.901)	
EPAct Dummy (Lag two years) × Net Competition Effect (Lag two years)	78.456*	9.182***	70.716*	8.276***
	(46.499)	(0.343)	(44.331)	(0.327)
EPAct Dummy (Lag two years) × Appropriation Dummy (Lag two years)	52.520***	2.200***	46.950***	1.967***
	(13.980)	(0.610)	(14.153)	(0.618)
Innovation Inputs (Lag two years)				
Other Firms' Electric Technology Patent Stock [a]	0.00001*	0.680*	0.00001*	0.627*
	(0.000006)	(0.403)	(0.000006)	(0.313)
Own Firm's Electric Technology Patent Quality Stock	0.00006		0.00007	
	(0.00004)		(0.00005)	
Mean (Adjusted) Generality for Own Firm's Electric Technology Patents	1.679***	0.482***	1.634***	0.861***
	(0.342)	(0.098)	(0.349)	(0.184)
Mean (Adjusted) Number of Claims for Own Firm's Electric Technology Patents	−0.201		−0.265	
	(0.429)		(0.364)	
Firm Characteristics				
Dummy for Low NO_x Burner and Desulfurization Unit Producers	0.017		0.023	
	(0.489)		(0.490)	
Number of CAAA Affected Boilers	0.00001		0.00003	
	(0.0002)		(0.0002)	
Dummy for Low NO_x & Desulf. × Number of CAAA Affected Boilers	0.0004**	0.014**	0.0004**	0.008**
	(0.0002)	(0.008)	(0.0002)	(0.004)
Large EEM Dummy	0.662		0.809	
	(0.850)		(0.844)	
Large EEM Dummy × EPAct Dummy (Lag two years)	−0.309		−0.371	
	(0.878)		(0.876)	
Dummy for U.S. Firms	−1.303*	−1.303*	−1.381*	−1.381*
	(0.746)	(0.746)	(0.780)	(0.780)
Macroenvironment				
Energy R&D Stock (billions of $2000) (Lag two years)	0.066		0.086	
	(0.084)		(0.089)	
GDP (Billions of $2000) (Lag two years)	0.0002		0.0003	
	(0.0004)		(0.0004)	
Observations (Number of firms)	1743 (83)		945 (45)	
Chi square	822.26		1,085.54	

B. Robustness to Lags: Dependent Variable: Number of Patents for Each EEM

Lags of EPAct Dummy	1 No Lag	2 One Year	3 Three Years
EPAct Dummy	−13.032**	−14.201**	−17.146
	(6.204)	(6.082)	(11.970)
Net Competition Effect	−8.102	−11.813	−7.867
	(13.083)	(13.653)	(12.132)
Appropriation Effect	4.689	2.794	−14.139
	(3.915)	(3.662)	(24.617)
EPAct Dummy × Net Competition Effect	74.645*	82.097*	67.257*
	(45.176)	(44.530)	(42.248)
EPAct Dummy × Appropriation Dummy	43.524***	53.917***	56.404**
	(14.137)	(12.306)	(31.183)
Innovation Inputs (Lag two years)			
Other Firms' Electric Technology Patent Stock [a]	0.00001*	0.00001*	0.00001*
	(0.000006)	(0.000006)	(0.000006)
Own Firm's Electric Technology Patent Quality Stock	0.00006	0.00006	0.0001*
	(0.00004)	(0.00004)	(0.00004)
Mean (Adjusted) Generality for Own Firm's Electric Technology Patents	1.686***	1.687***	1.631***
	(0.333)	(0.339)	(0.356)
Mean (Adjusted) Number of Claims for Own Firm's Electric Technology Patents	−0.224	−0.196	−0.164
	(0.416)	(0.446)	(0.410)

TABLE 3.—(CONTINUED)

Firm Characteristics			
Dummy for Low NOx Burner and Desulfurization Unit Producers	−0.030	0.021	0.003
	(0.499)	(0.496)	(0.493)
Number of CAAA Affected Boilers	−0.000001	−0.00001	0.003
	(0.0002)	(0.0002)	(0.004)
Dummy for Low NOx and Desulfurization × Number of CAAA Affected Boilers	0.001***	0.001***	0.0004***
	(0.0002)	(0.0002)	(0.0002)
Large EEM Dummy	0.503	0.642	0.787
	(0.845)	(0.859)	(0.893)
Large EEM Dummy × EPAct Dummy (Lag two years)	0.039	−0.229	−0.691
	(0.695)	(0.750)	(1.016)
Dummy for U.S. firms	−1.189*	−1.274*	−1.439*
	(0.693)	(0.693)	(0.814)
Macroenvironment			
Energy R&D stock (billions of $2000) (Lag two years)	−0.082	−0.070	0.026
	(0.088)	(0.086)	(0.088)
GDP (billions of $2000) (lag two years)	−0.001	0.0002	0.00002
	(0.001)	(0.001)	(0.001)
Observations (number of firms)	1,743 (83)	1,743 (83)	1,743 (83)
Chi square	822.26	777.99	823.12

Note to part A: Zero-inflated negative binomial model (inflation model: logit). Contains a constant and a time trend. Sample: 1980–2000. Columns 1a and 1b: all EEMs; columns 2a and 2b: EEMs that have at least one patent during the sample period. Robust and clustered (by firm) standard errors are in parentheses. Significant at *10%, **5%, and ***1% respectively.

[a]Stock based on the number of patents obtained by other firms ($j,\ldots,n$) in the patent classes that firm i patents in.

[b]Columns 1a and 2a (semielasticities): $d(\ln y)/dx$.

[c]Columns 1b and 2b: elasticities for significant variables. EPAct dummy(Columns 1b and 2b): aggregate semielasticities calculated taking into account the direction and magnitude of the interaction terms.

Note to part B: Zero-inflated negative binomial model (inflation model: logit). Specification is the same as table 3A and contains a constant and a time trend. Range: 1980–2000. Robust and clustered (by firm) standard errors are in parentheses. Significant at *10%, **5%, and ***1%.

[a]This stock is calculated based on the number of patents obtained by other firms ($j,\ldots,n$) in the patent classes that firm i patents in. Columns 1–3 show results for the specification when the EPAct dummy, and the net competition and appropriation variables are used as contemporaneous variables, with one- and two-year lags.

on innovation for these particular EEMs. Finally, we find that the size of the EEM has no impact on patenting, while U.S.-based EEMs appear to be less innovative than their foreign counterparts.[53] The R&D and GDP variables are not significant in any specification.

In the results discussed above (table 3, panel A), we lagged the deregulation dummy by two years. We assume that this is the time it takes to adjust a firm's innovation strategy to reflect the new market conditions, especially since the EPAct was the first deregulation policy instituted in the U.S. electricity market and firms would have little prior experience in negotiating the new market structure. However, since theory does not provide us with a concrete answer about the length of time it takes such market deregulation to affect upstream innovation, we provide in panel B of table 3, sensitivity analysis to different lags of the deregulation dummy. From columns 1 and 2, we find that using the deregulation status for the current year (column 1) or using a one-year lag (column 2) provides results that are very similar to those presented in table 3, panel A. However, the results in column 3 are somewhat different. The EPAct dummy does not influence upstream innovation when it is lagged by three years, suggesting that its influence decays over time. The coefficients for the appropriation and net competition effects are still significant and of the same sign, although the magnitude is smaller.

[53] While interpreting this result, it is important to remember that this may be the result of a selection effect. Non-U.S. firms that patent in the United States would probably be the top innovators in their countries, while for domestic firms, even the least innovative may still apply for a U.S. patent due to low entry barriers.

C. *Patent Characteristics*

Guided by the discussion from the theoretical literature, so far we have focused solely on the magnitude of innovations. However, we believe that studying the effect of regulatory changes on patent characteristics is an important empirical question, since patent numbers do not allow us to draw conclusions about the changing nature of innovation. With the introduction of competition in the downstream power sector, EEMs may face greater pressure to shorten their innovation cycle, and this would adversely affect both the quality and generality of their innovations. They would build on narrow previous knowledge and not explore other fields. This may lead to a decline in the average quality, and generality would also decline since these patents would embody very narrow technology. In addition, the effect of deregulation may be the same for two firms in terms of patent numbers, but one may suffer a greater or lesser quality decline or may have a less general technology portfolio after deregulation.[54] To capture these changes in quality and generality, we use the difference-in-difference model outlined in equation (2).

[54] For example, firm A has 25 patents with an average of ten citations per patent before deregulation. The firm has 15 patents, each with an average of five citations, after deregulation. Firm B also has 25 patents before deregulation and 15 patents after. However, it has five citations per patent on average prederegulation and three citations per patent on average after deregulation. If we focus solely on the number of patents, the effect of deregulation is the same for both firms. Clearly, this is not the case. Before deregulation firm A is producing innovations of greater quality than firm B. However, after deregulation, firm A suffers a greater quality decline than does firm B.

We use two metrics to measure patent quality, the average and the aggregate adjusted quality of a firm's patent portfolio, since neither one alone may be sufficient to capture true innovation quality.[55] In an environment where EEMs are getting fewer patents than in previous years, total citations to a firm's portfolio of patents may fall simply because the number of patents obtained by the EEM is declining or because there are fewer citing patents in the electric technology class. Thus, a decline in total number of citations may not be a true indicator of quality decline. Mean quality, however, may be a better metric. This would fall if and only if the rate of decline in citations is greater than the rate of decline in the number of patents. Hence, we use both measures to assess the effect of deregulation on the patent quality of EEMs.

Quality, as explained earlier, is measured by the number of backward citations (a count variable) received by a patent But to make these citation counts a true measure of patent quality and make them comparable across technologies and time, we purge these of technology and year effects, that is, demean these using patent field and year fixed effects. Additionally, we use the means and stocks of these variables (by firm). These two modifications turn the count variable into a continuous variable The adjusted generality measure is a continuous variable for the same reason. When measured in levels, all of the above variables are bounded by 0 on the lower end of the distribution. Hence, a panel tobit model that accounts for the truncation would be appropriate. However, this does not allow one to correct errors for clustering and heteroskedasticity. Therefore, we use a random effects GLS model with clustered and robust standard errors when estimating the average quality and generality specifications.[56] We have conducted several robustness checks using a random effect tobit model and a censored normal, and the results are stable across all specifications. For the aggregate quality equation, there is a strong autocorrelation component in the data, and correcting the errors for AR(1) is necessary; hence, we use a linear AR(1) panel data model in this case.

Results are presented in table 4 where the sample consists of electric equipment patent classes only. The unit of observation is the patent assignee, the treated groups are the EEMs (electric equipment manufacturers), and the control group is a random sample of 2,000 firms that patent in the electric equipment classes but are not EEMs.[57] The dependent variables are the average (adjusted) quality, aggregate (adjusted) quality, and average (adjusted) generality by patent assignee. We find that the difference-in-difference coefficient is strongly negative and significant for all three columns, implying that both quality and patent generality declined sharply after 1992. Thus, after deregulation, patents generated by EEMs became less general and of lower quality, alluding to the fact that equipment manufacturers may be concentrating on a narrow set of innovations.[58]

There may be alternative explanations for these findings, however. One possible explanation is that of declining productivity. Focusing on energy patents from 1974 to 1980, Popp (2002) shows that the productivity of new innovations tends to decline over time, and thus newer innovations add less to the existing knowledge stock than old ones. This leads to a decline in the quality of knowledge stocks, and in turn such diminishing returns affect future patent quality. Following this line of reasoning, it can be argued that for EEMs, there were diminishing returns to innovation for the electric equipment classes that manifest themselves around the same time as EPAct took effect, and hence the observed decline in quality and generality. However, such a decline would have been more gradual for the entire electric technology class than that observed in the data. Additionally, the comparison with the random sample of firms who also patent in the electric equipment class but suffer no such decline concurrent with the passage of the EPAct may imply that at least part of this decline was due to deregulation.

We also find that past patent stock has a positive effect on the quality and generality of current patents: firms that have a bigger portfolio of past patents tend to produce better quality and more general patents in the current period (columns 1–3), while there is a negative externality as other competitor's increase their innovation activity (columns 1 and 3). The breadth of the patent portfolio also has a positive impact on both average quality and average generality. In addition, firms with more general and broader past patent portfolios have greater average quality. Also firms with better-quality past patents produce more general innovation, and firms whose innovation spans a greater technological area tend to produce more quality patents.

Our control for the CAAA is negative and significant, implying that after the CAAA, aggregate patent quality and generality have suffered. In addition, in column 2, the interaction between the EEM dummy and the CAAA term is negative and significant, implying that aggregate EEM patent quality suffered after CAAA. However, we do not believe that this is the effect of the CAAA. Rather, this may be the effect of the accelerated deregulation policies pursued by states after 1996 that coincided with the second compliance phase of the CAAA. The effects of the aggregate R&D stock and GDP are mixed. The main finding of table 4 is the decline in patent quality and generality after 1992.

[55] Average adjusted quality is measured by the mean number of citations (purged of year and field effects) that each firm or assignee receives. Aggregate adjusted quality is the total number of citations (purged of year and field effects) that each firm or assignee receives. When we purge the citations of year and field effects, this in essence controls for technology and year fixed effects.

[56] The error can be disaggregated into two components: v_i, the random disturbance that varies by firm but not over time ($v_i \sim N(0, \sigma_v^2)$), and ε_{it}, is the idiosyncratic error component ($\varepsilon_{it} \sim N(0, \sigma_\varepsilon^2)$).

[57] We selected a random sample of 2,000 firms for tractability.

[58] However, on average, EEM patent quality and generality are higher than other patents in the electric technology category.

TABLE 4.—PATENT CHARACTERISTICS

Sample (by Patent Assignee) Dependent Variable	Electricity Patent Classes Average (Adjusted) Quality (1)	Aggregate (Adjusted) Quality (2)	Average (Adjusted) Generality (3)
EPAct Dummy (lag two years)	0.009	0.171*	−0.004
	(0.014)	(0.095)	(0.014)
EEM Dummy	0.044**	2.165***	0.076***
	(0.019)	(0.413)	(0.024)
EPAct Dummy (Lag two years) × EEM Dummy	−0.095***	−0.875***	−0.139**
	(0.032)	(0.314)	(0.050)
Innovation inputs (lag two years)			
Other Firm's Electric Technology Patent Stock [a]	−0.000003***	0.00003***	−0.00001***
	(0.000001)	(0.000004)	(0.000001)
Own Firm's Electric Technology Patent Stock	0.001***	0.213***	0.002***
	(0.0001)	(0.001)	(0.0005)
Own Firm's Electric Technology Patent Quality Stock (Adjusted)			−0.0001*
			(0.00004)
Mean (Adjusted) Generality for Own Firm's Electric Technology Patents	0.035***	0.0004	
	(0.010)	(0.040)	
Mean (Adjusted) number of Claims for Own Firm's Electric Technology Patents	0.112***	0.116**	0.204***
	(0.019)	(0.060)	(0.021)
Macroenvironment			
Number of Clean Air Act Affected Boilers	0.00001	−0.0001*	−0.00002**
	(0.00001)	(0.00006)	(0.00001)
EEM Dummy × Number of Clean Air Act Affected Boilers	0.00001	−0.0004**	0.00001
	(0.00002)	(0.0002)	(0.00003)
R&D Stock (Billions of $2000) (Lag two years)	−0.0002	−0.0006	−0.0003**
	(0.0001)	(0.001)	(0.0001)
GDP (Billions of 2000$) (Lag two years)	−0.00001	−0.0005***	−0.00001
	(0.00002)	(0.0002)	(0.00002)
Relevant statistics			
Observations	41,929	41,929	41,929
Number of assignees	1,823	1,823	1,823
R^2	0.435	0.861	0.730
Wald statistic (chi square)	299.54	2,916.11	559.14

In columns 1 and 3, estimation is done using a random effects GLS model with robust and clustered standard errors. In column 2, we use a random effects AR(1) panel data model. Average quality is measured by the average number of citations (adjusted for year and field effects) received by an assignee in each year. The aggregate quality is measured by the total number of citations (adjusted for year and field effects) received by the assignee in a given year. Aggregate quality stock is calculated by a declining balance formula using unadjusted citations. All specifications contain a year trend and a constant. The sample consists of electric equipment patents given to EEMs and a random sample of 2,000 firms, the unit of observation is the patent assignee, and the treated groups are the EEMs (electric equipment manufacturers). The sample is from 1980–2000. Coefficients are marginal effects. Significant at *10%, **5%, and ***1%.

[a]This stock is calculated based on the number of patents obtained by other assignees ($j,\ldots,n$) in the patent classes that assignee i patents in.

V. Conclusion

Deregulation has dramatically changed the landscape of the U.S. electric utility industry by introducing competition in the generation sector. Product market competition from nonutilities (such as the independent power producers) has made utilities more conscious of their bottom line. This shift has had an effect on their technology buying behavior, which in turn has affected the innovation behavior of the electric equipment manufacturers. This paper models the effect of such downstream competition on upstream innovation behavior in situations where the technology buyer and seller are not vertically integrated.

The theoretical literature proposes three opposing effects of deregulation: the pure competition, escape competition, and the appropriation effect. The pure competition effect measures the difference in marginal profits of each downstream firm due to the upstream innovation. Postderegulation, the value added (to utilities) due to new technology adoption decreases because of the competition that utilities face. This decline in value added decreases the demand for new technology, which in turn has a negative effect on the innovation incentive for the upstream firms. However, the escape competition effect is positive and is driven by the effect of competition on pre- and postinnovation profits. This effect spurs firms to innovate more in order to gain advantage over their competitors, that is, to escape competition. In the empirical model, these two effects are subsumed in the net competition effect, which is measured by the average profit of the downstream utilities. In addition, the appropriation effect has a positive effect on innovation. Increased participation of nonutilities in the wholesale market increases the EEM customer base, thus increasing their status quo bargaining power and the price for their innovations and positively affecting innovation. The relative strength of these effects determines the overall effect of downstream product market competition on upstream innovation.

The empirical results show that for the electricity industry, deregulating the downstream sector has adversely affected the innovation behavior of EEMs during our sample period. First, using difference-in-difference models, we show that restructuring the power sector has had an adverse impact on patenting in the electric equipment patent classes when compared with other patent classes. In addition, patenting by EEMs declined after the passage of the EPAct when compared to other firms in the electric equipment technology sector. Next, we model the channels through which such a decline may have occurred. We find that deregulation alone has led to a 20.6% decline in patenting by EEMs. We also find that both the appropriation effect and the net competition effect are significant after the introduction of the EPAct but not before. Following the passage of the EPAct, the total competition effect has led to an 18.3% decline in innovation that has been offset by an increase of 19.6% due to the appropriation effect.

In addition, the innovation environment of a firm matters, and the quality, breadth, and generality of past innovation inputs positively influence current patenting. The CAAA has had a positive impact on innovation for firms that manufacture low NOx burners and gas desulfurization units, and large firms have higher patents. We take the empirical model further by investigating the impact of deregulation on innovation characteristics. The introduction of downstream competition has degraded the quality of upstream innovation and has made it more specific and less general.

This paper contributes to the innovation competition literature by developing an empirical framework that models upstream innovation behavior as a function of downstream competitive forces. The results have implications for all industries with a similar organizational structure and may help in furthering our understanding of innovation incentives in complex markets. In addition, by modeling both the magnitude and attributes of innovation, it provides a comprehensive account of the innovation response of upstream technology–producing firms when their downstream buyers are subject to product market competition.

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APPENDIX

FIGURE 1A.—PATENTS OBTAINED BY FIRMS IN DRUGS AND MEDICAL CLASSES

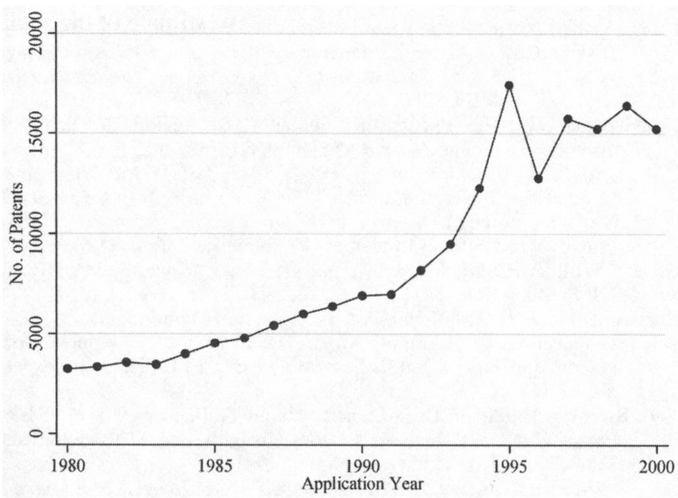
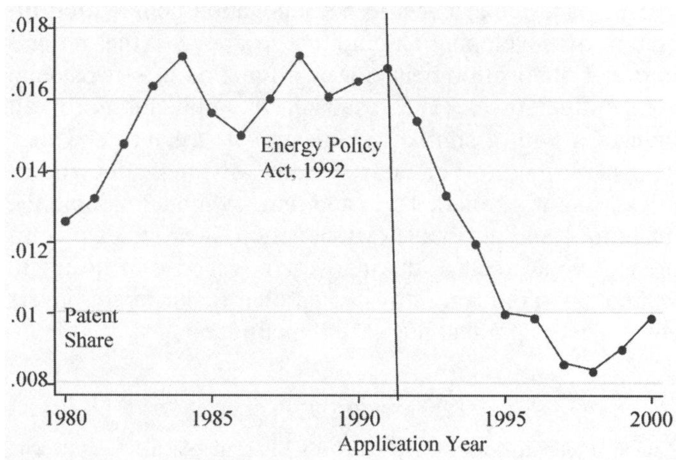


FIGURE 1B.—SHARE OF EEM ELECTRIC TECHNOLOGY PATENTS IN TOTAL USPTO PATENTS, 1980–2000



Lessons Learned from Electricity Market Liberalization

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Lessons Learned From Electricity Market Liberalization

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This paper discusses the lessons learned from electricity sector liberalization over the last 20 years. The attributes of reform models that have exhibited good performance attributes are identified, drawing on empirical analysis of market structure, behavior and performance in many countries. Wholesale and retail market competition and network regulation performance evidence are discussed. Technical, economic, and political challenges to improving the efficiency of what continue to be partial liberalization programs in many countries are considered.

1. INTRODUCTION

It has been almost 25 years since Richard Schmalensee and I published *Markets for Power* (1983), almost 20 years since the UK began to design its innovative and comprehensive electricity sector privatization, restructuring for competition, and regulatory reform program Henney (2004)), over 15 years since Green and Newbery (1992) published their simulation analysis of market power in the deregulated wholesale electricity markets in England and Wales under alternative market structures, 10 years since Newbery and Pollitt (1997) published their social cost-benefit analysis of the privatization and restructuring program in the UK, and 7 years since the California electricity crisis and the collapse of Enron. Several additional countries (or portions of countries) have followed the UK's lead and introduced comprehensive electricity sector reform programs and, at least in theory, comprehensive electricity sector liberalization principles now apply to all

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This paper is based on Joskow 2006c. I recommend highly the book where this paper appears. I am grateful for comments from Richard Green and two anonymous referees.

EU countries.[1] Many other countries have introduced less comprehensive liberalization reform programs. Still others have resisted or slowed down reforms or succeeded in defeating them completely. The U.S. has never enacted a mandatory comprehensive federal restructuring and competition law, leaving the most significant reform decisions to the states. As a result, many U.S. states have introduced only limited liberalization reforms in wholesale markets without fundamental electricity sector restructuring and politicians in several U.S. states that introduced comprehensive reforms prior to 2001 are now calling for "re-regulation."

During the last 25 years most developed countries have also gone through reasonably comprehensive privatization, restructuring and deregulation programs in sectors that were previously regulated monopolies and/or state-owned: airlines, trucking, telecommunications, natural gas (in the U.S., Canada and the UK anyway), mail and package delivery services, railroads, and other sectors. While these reforms have not always proceeded without controversy or led to precisely the results predicted, the general trend of public policy has continued to support liberalization and to move forward with additional liberalization reforms in sectors that were once dominated by regulated legal monopolies. These reforms are generally widely accepted and "re-regulation" of these sectors is not high on the policy agenda. Electricity sector liberalization (and natural gas sector liberalization in much of Europe) seems to be different from the trends in these other industries. In many countries electricity sector reforms are incomplete, either moving forward slowly with considerable resistance or moving backward, despite the success of these reforms in the UK, the Nordic countries, Argentina (before its macroeconomic collapse), Chile, Texas, portions of Australia and other countries and regions. Why is electricity sector liberalization so difficult and subject to so much opposition? Are there lessons to be learned from the diverse experiences in countries around the world in the last two decades to support renewed liberalization efforts in electricity sectors?

This paper develops the lessons learned from roughly two decades of experience with electricity sector liberalization.

2. BACKGROUND

Electricity sectors almost everywhere on earth evolved with (primarily) vertically integrated geographic monopolies that were either state-owned or privately-owned and subject to price and entry regulation as natural monopolies. The primary components of electricity supply --- generation, transmission, distribution, and retail supply --- were integrated within individual electric utilities. These firms in turn had de facto exclusive franchises to supply electricity to residential,

1. It is sometimes argued that Chile is the first country to liberalize its electricity sector. While Chile did introduce a number of privatization, restructuring and competition reforms beginning in the early 1980s, it did not and has not created a real wholesale market for electricity and for many years the major generating company, distribution company and transmission company were under common ownership. See Joskow (2000b).

commercial and industrial retail consumers within a defined geographic area. The performance of these regulated monopolies varied widely across countries. Sector performance in developed countries was generally much better (Joskow 1997) than in developing countries (World Bank 1994, Bacon and Besant-Jones 2001, Besant-Jones 1993), but high operating costs, construction cost overruns on new facilities, high retail prices, and falling costs of production from new facilities driven by low prices for natural gas and the development of more efficient generating technologies (e.g. CCGT), stimulated pressures for changes that would reduce electricity costs and retail prices (Joskow 1998, 2000a).

The overriding reform goal has been to create new institutional arrangements for the electricity sector that provide long-term benefits to society and to ensure that an appropriate share of these benefits are conveyed to consumers through prices that reflect the efficient economic cost of supplying electricity and service quality attributes that reflect consumer valuations. The benefits are to be realized by relying on competitive wholesale markets for power to provide better incentives for controlling construction and operating costs of new and existing generating capacity, to encourage innovation in power supply technologies, to provide incentives for network operators to provide appropriate levels of service quality, and to shift the risks of technology choice, construction cost and operating "mistakes" to suppliers and away from consumers. Retail competition, or "third party access" is supposed to allow consumers to choose the retail power supplier offering the price/service quality combination that best meet their needs and to allow competing generators and intermediaries to offer these services to consumers. Competing retail suppliers were also expected to provide an enhanced array of retail service products, risk management, demand management, and new opportunities for service quality differentiation to better match individual consumer preferences.

It has also been widely recognized that significant portions of the total costs of electricity supply – distribution and transmission – would continue to be regulated as legal monopolies. Accordingly, reforms to traditional regulatory arrangements governing the distribution and transmission networks have generally been viewed as an important complement to the introduction of wholesale and retail competition to supply consumer energy needs. Privatization of distribution and transmission companies combined with the application of Performance Based Regulation (PBR) imposes hard budget constraints on regulated network firms and provides better incentives for them to reduce costs and improve service quality (Beesley and Littlechild 1989, Joskow 2006b, Jamasb and Pollitt 2007). In addition, the efficiency of competitive wholesale and retail markets depends on a well functioning supporting transmission and distribution network infrastructure.

3. THE STANDARD LIBERALIZATION PRESCRIPTION

While a number of variations are potentially available (Hunt 2002, Joskow 2000a, 2005a), it is my view that the "textbook" architecture of desirable features for restructuring, regulatory reform and the development of competitive markets for power involves several key components:

a. Privatization of state-owned electricity monopolies to create hard budget constraints and high-powered incentives for performance improvements and to make it more difficult for the state to use these enterprises to pursue costly political agendas.[2]
b. Vertical separation of potentially competitive segments (e.g. generation, marketing and retail supply) from segments that will continue to be regulated (distribution, transmission, system operations) either structurally (through divestiture) or functionally (with internal "Chinese" walls or "ring fencing" separating affiliates within the same corporation). These changes are thought to be necessary to guard against cross-subsidization of competitive businesses from regulated businesses and discriminatory policies affecting access to distribution and transmission networks upon which all competitive suppliers depend.
c. Horizontal restructuring of the generation segment, to create an adequate number of competing generators to mitigate market power and to ensure that wholesale markets are reasonably competitive.
d. Horizontal integration of transmission facilities and network operations to encompass the geographic expanse of "natural" wholesale markets and the designation of a single *independent* system operator to manage the operation of the network, to schedule generation to meet demand and to maintain the physical parameters of the network (frequency, voltage, stability), and to guide investments in transmission infrastructure to meet reliability and economic standards.
e. The creation of voluntary public wholesale spot energy and operating reserve market institutions to support requirements for real time balancing of supply and demand for electric energy, to allocate scarce network transmission capacity, to respond quickly and effectively to unplanned outages of transmission or generating facilities consistent with the need to maintain network voltage, frequency and stability parameters within narrow limits, and to facilitate economical trading opportunities among suppliers and between buyers and sellers.
f. The development of active "demand-side" institutions that allow consumers to react to variations in wholesale market prices and fully

2. The Nordic countries have had a reasonably successful reform experience without full privatization (Amundsen, Bergman and von der Fehr 2006, Bye and Hope 2006). However, the Nordic model still must face the issue of attracting investment in new generating capacity based on market incentives rather than direct or indirect government mandates or subsidies (Nordic Competition Authorities 2007).

integrate demand side responses to energy prices and reliability criteria into wholesale and retail markets.

g. The application of regulatory rules and supporting network institutions to promote efficient access to the transmission network by wholesale buyers and sellers in order to facilitate efficient competitive production and exchange. This includes mechanisms efficiently to allocate scarce transmission capacity among competing network users, and to provide for efficient siting and interconnection of new generating facilities.
h. The unbundling of retail tariffs to separate prices for retail power supplies and associated customer services to be supplied competitively from the regulated "delivery" charges for using distribution and transmission networks that would continue (primarily) to be provided by regulated monopolies
i. Where policymakers have determined that retail competition will not be available (e.g. for domestic and small commercial customers), distribution companies or alternative designated suppliers would have the responsibility to supply these customers by purchasing power in competitive wholesale markets or, if they choose, to build their own generating facilities to provide power supplies. However, in the latter case the associated charges for power would be subject to wholesale market-based regulatory benchmarks, primarily competitive procurement processes.
j. The creation of independent regulatory agencies with good information about the costs, service quality and comparative performance of the firms supplying regulated network services, the authority to enforce regulatory requirements, and an expert staff to use this information and authority to regulate effectively the prices charged by distribution and transmission companies and the terms and conditions of access to these networks by wholesale and retail suppliers of power, are also an important but underappreciated component of successful reforms.
k. Transition mechanisms must be put in place to move from the old system to the new system. These mechanisms should be compatible with the development of well functioning competitive markets.

4. LESSONS LEARNED FROM INTERNATIONAL EXPERIENCE

There have been few comprehensive "social cost-benefit" assessments of the effects of electricity restructuring in specific countries. Newbery and Pollitt's (1997) analysis of the welfare consequences of reforms in the UK is an exception, though it covers a period that precedes the significant reduction in generation concentration in the late 1990s and the introduction of wholesale market institutions (NETA) to replace the pool (Newbery 1998) in 2001. Wholesale markets in

England and Wales appear to have become much more competitive since the late 1990s, increasing efficiency and conveying more of the benefits of liberalization to consumers (Newbery 2006). There has been much more work on individual segments of the liberalized electricity sectors in a number of countries (e.g. labor productivity in generation and distribution; integration of wholesale markets; investment in generation) as well as many "fragments of evidence" associated with specific aspects of performance in particular segments of the sector (Sioshansi and Pfaffenberger 2006).

One of the challenges that must be confronted in doing a performance assessment of electricity sector liberalization is to choose a suitable *counterfactual* benchmark for comparison purposes. That is, we need to measure various performance metrics and compare them with what these metrics *would have been* if the reforms had not been made at all or if they had been made differently, not comparisons with some abstract ideal.

There are various approaches to examining the effects of liberalization reforms (Joskow 2006c): (a) "before and after" studies using time series data; (b) inter-country and inter-state comparisons where liberalization institutions vary from country to country or state to state; (c) structural simulation approaches. All three of these approaches can provide useful insights into the effects of policy reforms on various performance indicia. However, in each case it is important to adopt what Oliver Williamson (1985) refers to as a comparative governance approach to the evaluation of the performance of alternative institutional arrangements for any industry. It has two components: (a) performance assessments must recognize that observed performance should be compared with performance under a clearly defined alternative set of institutional arrangements and (b) "ideal" textbook performance that we associate, for example, with perfectly competitive markets, is never achievable in reality. Policymakers should be looking for the best that they can do in an imperfect world.

In light of the historical experience to date I now turn to a baker's dozen of lessons learned:

1. *Electricity sector reforms have significant potential benefits but also carry the risk of significant potential costs if the reforms are implemented incompletely or incorrectly:* I believe that it is fair to say that when electricity restructuring and competition programs are designed and implemented well, electricity sector performance, in terms of operating costs, physical network losses, generator availability, theft of service, availability of service, investment, price levels and structures, service quality and other performance variables, can be expected to improve significantly compared to either the typical state-owned or private regulated vertically integrated monopoly. Note that this conclusion is not inconsistent with a finding that there are some regulated vertically integrated monopolies that perform quite well and that, in such cases, the kinds of comprehensive reforms reflected in the textbook model might have little positive effect on performance. Rather, it is a statement about what expectations policymakers, faced with imperfect and asymmetric information about the performance of the regulated sector,

should have in the typical cases. Nor is it a statement that retail electricity prices will always fall in nominal terms as a result of liberalization. In some countries regulated prices were inefficiently low, discouraging investment and wasteful consumption. Liberalization should lead to higher prices and better incentives. Moreover, any analysis of price effects must take account of all exogenous cost drivers, especially fuel costs. Specifically, comparing electricity prices in a regime where natural gas prices are \$2/MCF to a regime where natural gas prices are \$8/MCF without controlling for the effects of changes in natural gas prices on wholesale electricity prices will lead to meaningless results (Joskow 2006a, Harvey, McConihe and Pope 2006).

However, the experience in many countries makes it fairly clear that successful implementation of liberalization reforms is not easy and that there is a risk that costly performance problems may emerge when the transformation is implemented incompletely or incorrectly. California is the textbook case of reforms gone bad, though it is not at all clear that the right lessons have been learned from that experience. Wholesale markets with good performance attributes have been slow to emerge in some countries. Even in England and Wales, major changes were made in the design of the wholesale market in 2001 when NETA replaced the Pool. The promised benefits of retail competition for residential and small industrial customers have been slow to emerge in many countries. The mobilization of adequate investment to expand generation, transmission and distribution capacity has been a (real or imagined) problem in many of the countries that have implemented reforms. These "transition" problems can be minimized by getting the reforms right at the outset.

2. *The textbook model of restructuring, regulatory reform and market design is a sound guide for successful reform:* The use of the phrase "deregulation" to characterize the attributes of the most successful electricity sector reform programs is misleading. This is not the trucking industry and the traditional industry structure based on vertically integrated regulated monopolies is not conducive to simple "deregulation" without supporting structural, regulatory and market design reforms (Joskow and Schmalensee 1983). Restructuring, regulatory reform, wholesale and retail market design, *and* deregulation of competitive wholesale and retail segments go together. The most successful reform programs have followed the "textbook model" outlined earlier reasonably closely: privatization of state-owned enterprises, vertical and horizontal restructuring to facilitate competition and mitigate potential self-dealing and cross-subsidization problems, PBR regulation applied to the regulated transmission and distribution segments, good wholesale market designs that facilitate efficient competition among existing generators, competitive entry of new generators, and retail competition, at least for industrial customers.

In my view, the gold standard for electricity sector reform is England and Wales (Green and Newbery 1992, Newbery and Pollitt 1997, Green 2005b, Newbery 2006). The reforms followed the basic architecture of the textbook model and have led to significant performance improvements in many dimensions.

This is not to say that everything worked perfectly. Clearly, the decision to create only three generating companies out of the state-owned CEGB, two of which set the clearing price in the wholesale market in almost all hours, led to significant market power problems that persisted for several years (Wolfram 1999, Sweeting 2007). Not only were wholesale prices too high, but there was probably an inefficiently high level of entry of new gas-fired CCGTs during the 1990s attracted by high margins. Congestion on the transmission network made some generators "must run," creating additional "locational" market power problems. However, a combination of entry of new generators, divestitures of existing generating plants by incumbent suppliers, and transmission investments has made the wholesale market structurally more competitive over time. Price-cost margins eventually fell dramatically and there is a lively debate about whether it was the reduction in seller concentration or the introduction of the New Electricity Trading Arrangements (NETA) to replace the Pool that is the cause of the reduction in market power observed in the last few years (Evans and Green 2005).

Putting generation market power issues aside, there is a lot of evidence that the high-powered incentives created by competitive wholesale electricity networks lead to lower generator operating costs and improved availability (Newbery and Pollitt 1997, Fabrazio, Rose and Wolfram 2007, Bushnell and Wolfram 2005, ISO New England 2005).

Privatization and the application of high-powered regulatory mechanisms to distribution and transmission have led to improvements in labor productivity and service quality in electric distribution systems in England and Wales as well (Domah and Pollitt 2001, Jamasb and Pollitt 2007). The application of incentive regulation mechanisms to the independent transmission company also led to a dramatic reduction in the costs of managing network congestion and the costs of balancing the system and maintaining network reliability. During the 1990s there was substantial entry of new generating capacity, largely replacing existing generating capacity (that eventually retired), rather than to meet a need for new capacity to meet growing peak demand. The retail competition program in England and Wales has been reasonably successful, though there continue to be debates about whether the benefits of extending retail competition to domestic (residential) customers was worth the costs (Newbery 2006, Green and McDaniel 1998 and Salies and Waddams Price 2004).

England and Wales is not the only country that has followed the textbook model. Argentina followed most features of the basic textbook model and, prior to the country's macroeconomic collapse, currency crisis, and rejection of contractual and regulatory commitments in 2002, experienced excellent performance. Argentina experienced significant improvements in the performance of the existing fleet of generating plants, significant investment in new generating capacity, and improvements in productivity and a reduction in losses (physical and due to thefts of service) on the distribution networks (Dyner, Arango and Larson 2006, Pollitt 2004a, Rudnick and Zolezzi 2001, Bacon and Besant-Jones 2001, Estache and Rodriguez-Pardina 1998). Unlike the case in England and Wales, Argentina made a serious effort at the outset to create a generation sector that was structurally competitive and there is little if any evidence of market power in the wholesale market there. These improvements in performance indicia were realized despite (or perhaps partially because of) the fact that Argentina did not have a real unregulated spot market for electricity. Following the model established in Chile, Argentina's so-called spot market was structured as a security-constrained marginal cost based (i.e. not bid-based) power pool in which the clearing price is determined mechanically by the marginal cost of the generator that clears the market in an efficient cost-based merit order dispatch. This mechanism effectively caps prices in the spot market at very low levels (about $150/MWh during the 1990s) under scarcity conditions. However, the spot market revenues are supplemented by revenues from a capacity payment mechanism to support generation investment.

Texas also took a comprehensive approach to restructuring, regulatory reform and market design that followed many of the basic attributes of the textbook model (Adib and Zarnikau 2006). However, rather than adopting a pool-based wholesale market as in the UK and Argentina, Texas took an approach to wholesale market design that relied as much on bilateral contracts and as little on organized public markets operated by the ISO as possible – more like NETA in the UK. Texas also endeavored to implement structural remedies (i.e. generation divestiture) to respond to concerns about market power. However, transmission network congestion management and associated market power issues have been significant issues in Texas. Rather than introducing capacity payments, Texas has also increased the price cap in the balancing markets for energy and ancillary services. Texas adopted an approach to retail competition that is similar to that adopted in the UK, except retail competition was opened to all classes of customers from the beginning. At least in terms of switching behavior, Texas has the most successful retail competition program in the U.S., especially for smaller customers (Adib and Zarnikau 2006).

New Zealand (Bertram 2006), portions of Australia (Moran (2006)) and the Nordic countries (Amundsen, Bergman and von der Fehr (2006), Bye and Hope (2006), Nordic Competition Authorities (2007)), Ontario, and Brazil adopted many of the key components of the textbook model and have had reasonably successful reform programs, though retail competition opportunities vary between these countries. Australia, the Nordic countries, Ontario, Australia and Brazil have proceeded with their reforms without fully privatizing the generation segment of the sector. The continued mix of public and private generating companies raises some interesting issues both for short run market performance and longer run investment incentives. Investments by public sector firms in new generating capacity based on considerations other than market incentives, direct or indirect subsidies can easily undermine private sector incentives to make investments in new generating capacity without similar support payments. This is a serious issue in all of the markets with mixed public-private generation sectors.

Chile is often identified as the first country to adopt the textbook electricity sector reform model (Raineri (2006). While I believe that the Chilean reforms have led to large efficiency improvements compared to what proceeded them, and that there is much to be proud of in the reforms that were made there beginning in the 1980s, the Chilean system has involved less restructuring, less competition and more regulation than first meets the eye (Joskow 2000b, Joskow 2006c). Whatever the success that the Chilean reforms achieved, they are not *primarily* the result of vibrant unregulated competitive wholesale or retail markets for electricity or real vertical and horizontal restructuring. Privatization, incentive regulation, a simulated competitive spot market, contractual obligations placed on distribution companies, and free entry by incumbent suppliers in response largely to administratively determined generation prices have all contributed to the performance improvements.

In the late 1990s, California and many of the Northeastern U.S. states appear to have adopted many of the components of the textbook model as well. Yet California is often put forward as the textbook case of "deregulation" gone bad. The California restructuring and competition program (but not the T&D regulatory framework) were heavily influenced by the earlier reforms in England and Wales. The initial reform proposals contained in the so-called "blue book" included many of the features of the reform program in England and Wales. And, although disputes about wholesale and retail market design led eventually to a reform program that departed from several aspects of the textbook model, it still retained many of its basic features.

Many explanations have been advanced to explain what happened in California. One set of interpretations of what transpired and why can be found in Sweeney (2006). My views, written at about the time the crisis was winding down and before the Enron and other marketers tapes were released, can be found in Joskow (2001). The most frequent popular explanation is that there was a shortage of generating capacity in California and that this shortage was a result of poor investment incentives inherent in California's wholesale market design. This is not an accurate characterization of what actually happened. There was little investment in generating capacity anywhere in the U.S. during the time period when the California reforms were being designed and implemented (1994-98). This is because there was excess capacity in most regions of the U.S. during the early 1990s. Uncertainties about the future path of structuring, regulatory and competitive reforms that began to be discussed seriously at this time was also a deterrent to potential investors waiting until the rules of the game were specified more clearly. Indeed at the time of the crisis there was a long queue of developers that had applied for permits to build new generating plants in California after the market opened in April 1998. It is unrealistic to expect that even under the best of circumstances any significant amount of new generating capacity could have come out of the construction pipeline in two years. Moreover, California is a summer peaking system. The biggest problems, in terms of high prices, operating reserve emergencies and rolling blackouts did not occur until the winter of 2000-2001. The problem was not that there was inadequate physical generating capacity in place, but rather that a large fraction of the existing generating capacity was not available to generate electricity. This has led to debates about whether the generating capacity was being consciously withheld from the market (fake sick leave) to drive up prices or that the generating equipment broke down (real sick leave).

It is true that California's wholesale market would have been stressed due to tight capacity during the second half of 2000 even if there had been no market power problems. Demand was unusually high throughout the Western Interconnection, natural gas prices and NO_x permit prices rose significantly. However, even after taking account of these factors it is hard to explain what happened during the second half of 2000 only as the result of the interplay of supply and demand in a competitive market. The "shortage" of generating capacity may perhaps be explained by older plants breaking down and by their owners' reluctance to supply when it became unclear about January 2001 whether or not they would be paid. However, there is also abundant evidence that some suppliers exploited opportunities to engage in strategic behavior to jack up market prices. At least in the summer of 2000, some generators were taking advantage of a tight supply situation to exercise market power (Borenstein, Bushnell and Wolak (2002), Joskow and Kahn (2002)). The tapes of the conversations of traders for Enron and other companies that subsequently were released make it clear that they saw and took advantage of opportunities to withhold supplies and increase market prices during the crisis.

In my view, if California had implemented similar transition arrangements to those implemented in the Northeast, in particular if the California utilities had more completely hedged their retail supply obligations with forward contracts and had the opportunity to recover from retail customers reasonable costs of the power they purchased in wholesale markets, there would have been no California electricity crisis. This is not to say that deficiencies in the design of California's wholesale markets would not have led to inefficiencies that would have driven up wholesale power costs to some degree. Rather, there would not have been a sudden financial collapse and California would have had time to improve its wholesale market and transmission institutions as in the Northeast. Instead, California responded to the crisis with costly long-term contracts negotiated by the state, long term procurement obligations, a freeze on retail competition, and a strange mix of regulatory obligations and competitive markets that does not bode well for the future (Sweeney 2006).

3. Departing significantly from the textbook model of restructuring, competitive market institutions and regulatory reform is likely to lead to performance problems.

The reforms in much of continental Europe (Spain and the Netherlands being the primary exceptions), in Japan, and in large portions of the U.S. have not followed the textbook liberalization model (Joskow 2006a, Haas et. al. 2006). The alternatives have been partial liberalization or simply continuing with the basic model of regulated vertically integrated monopoly. The initial focus of the EU reforms was on "market opening" for retail customers rather than comprehensive reforms. That is, the focus was on retail competition. This approach ignores the fact that "market opening" alone will not lead to meaningful retail competition in the absence of appropriate wholesale market and network access and pricing institutions. Retail customers may be given the freedom to shop around for their power needs, but unless they can obtain delivery services on reasonable terms and conditions and there is a well functioning competitive wholesale market where they or their agents can shop, there will be no meaningful opportunity to take advantage of this freedom.

I view the slow pace of development of the development of transparent wholesale, efficient congestion management institutions, and retail competition in many of the countries in continental Europe as being largely attributable to their failure to restructure vertically and horizontally and to create the necessary network access, pricing and wholesale market institutions to create a robust wholesale market (Haas et. al. 2006). Germany provides a good example of how retail competition without restructuring and the creation of competitive market and supporting regulatory institutions leads to performance problems (Brunekreeft and Bauknecht 2006). The German electric power system continues to be dominated by vertically integrated utilities with interests in generation, transmission and distribution. They control the operation of the transmission networks, which are operated as separate control and balancing areas rather than as a single balancing area as in other European countries. There is no independent system operator. Generation ownership is fairly concentrated. Until recently, there was no regulator to determine network costs and prices or to enforce unbundling rules necessary to support retail and wholesale competition. Japan has implemented only very modest structural reforms (Goto and Yajima 2006) and transparent PBR regulatory institutions for distribution and transmission networks have not been introduced. It appears that the development of robust wholesale and retail markets and a network regulatory system with good performance attributes will be a slow process in Japan indeed.

Whether it is by design or accident, however, the EU's focus on market opening for retail consumers has now led it to look more closely at supporting reforms upstream at the wholesale and transmission levels as time has passed. The EU is now considering requiring the creation of independent system operators and transmission entities, relying either on ownership separation or on functional separation or ring fencing. Germany has been forced to create a regulator to regulate (at least) network charges and unbundling protocols. While the EU and other pan-European institutions have focused on transmission facilities that connect individual member countries, rather than getting involved in intra-country market design or competition issues, system operators are increasingly realizing that efficient use of interconnector capacity requires some compatibility between intra-country wholesale market designs and coordination between them. Accordingly, the EU and members countries are now moving back upstream to implement a variety of structural and institutional reforms that would have, ideally, been done first rather than last.

Another example is Brazil. The reforms in Brazil proceeded without a comprehensive reform blueprint and the blueprint developed for them by a large consulting firm was not implemented (Lizardo and Araujo 2006). The progress of the reform program was further overwhelmed by a water shortage in a system that is heavily dependent on hydroelectricity. This would have led to problems under any circumstances. These problems were probably worse because of the incomplete implementation of the reforms and were blamed unfairly on the reforms themselves.

4. *Transparent organized spot energy and ancillary services markets should be integrated with the allocation of scarce transmission capacity.* The most efficient design of spot wholesale energy markets continues to be a subject of dispute among interest groups and independent experts (Joskow 2005a, Hunt 2002, Stoft 2002, Green 2005a). Should the market be built around a pool or rely on bilateral contracts? Should there be locational pricing of energy and operating reserves? How should scarce transmission capacity be allocated? Should transmission rights be physical or financial (Hogan 1992, Joskow and Tirole 2000, Gilbert, Neuhoff and Newbery 2004)?

While there is some room for flexibility, and some of the disputes reflect the self-serving arguments of interest groups that expect to benefit from inefficient markets, I believe that the experience to date supports the desirability of several basic wholesale market design features. These basic design features include the creation of *voluntary* transparent organized spot markets for energy and ancillary services (day-ahead and real time balancing) that accommodate bilateral contracts and self-scheduling of generation if suppliers choose to take this approach; locational pricing of energy reflecting the marginal cost of congestion and losses at each location; the integration of spot wholesale markets for energy with the efficient allocation of scarce transmission capacity; auctioning of (physical or financial) transmission rights that are simultaneously feasible under alternative system conditions to hedge congestion, serve as a basis for incentives for good performance by system operators and transmission owners, and partially to support new transmission investment[3] (Joskow and Tirole 2000); an active demand side that can respond to spot market price signals (Borenstein, Jaske and Rosenfeld 2002). These are the attributes of the PJM markets, as well as those in New England, New York and the Midwest ISO in the U.S. (Joskow 2006a). California is proposing to implement a similar "nodal price" market design, though its implementation has been delayed until 2008 and Texas is considering doing so as well. While markets without transparent locational pricing can work reasonably well (e.g. NETA in the UK), they are more likely to run into problems (as in California, Texas, Alberta and Ontario) without locational pricing based on the integration of wholesale electricity markets and the allocation of scarce transmission capacity.

3. The allocation of transmission rights can, however, affect the incentives of firms to exercise market power and this should be taken into account in the design of rights allocation mechanisms and restrictions on the entities that can purchase these rights (Joskow and Tirole (2000), Gilbert, Neuhoff and Newbery (2004)).

5. Market power is a significant potential problem in electricity markets, but the cure can be worse than the disease. Try to deal with potential market power structurally ex ante rather than ex post. The potential for market power to be a particularly severe potential problem in electricity markets was recognized many years ago (Joskow and Schmalensee 1983, Chapter 12) and was reinforced as the reforms in the UK were implemented in 1990 (Green and Newbery 1992) and those in California in 1998 (Borenstein and Bushnell 1999). Generator market power arises as a consequence of transmission constraints that limit the geographic expanse of competition, generation ownership concentration within constrained import areas, the non-storability of electricity, and the very low elasticity of demand for electricity (Joskow 1997), Borenstein 2002). Generator market power was a serious problem for several years following the launch of the privatization, restructuring and competition program in the UK (Wolfram 1999, Sweeting 2007). Concerns about market power in the U.S. were reinforced by the events in California in 2000-2001 (Borenstein, Bushnell and Wolak 2002, Joskow and Kahn 2002) where market power and the exploitation of market design imperfections contributed to the explosion in wholesale prices beginning in June 2000. Market power issues of various kinds have been identified in many other electricity markets, including New Zealand, Chile, Columbia, PJM, Texas, Alberta, Brazil and some areas of continental Europe. The problems can be attributed to the interactions between the attributes of electricity networks noted above, too few competing generating companies, wholesale market design flaws, vertical integration between transmission and generation that creates the incentive and opportunity for exclusionary behavior, excessive reliance on spot markets rather than forward contracts, and limited diffusion of real time prices and associated communications and control technology that facilitates the participation of demand in wholesale spot markets.

Clearly, market power is an issue that must be taken seriously since electricity markets have attributes that are conducive to exercising market power (Borenstein 2000). No market design will work well if there are not an adequate number of competitive suppliers of generation service, adequate demand side responsiveness, or the market power of dominant firms has not been mitigated in some way (i.e. with regulated forward contracts). As a result, market power mitigation strategies have become an important component of wholesale market reforms in many countries. In the U.S., FERC market monitoring and market power mitigation protocols have been a central component of all of its reform initiatives. All of the ISOs in the U.S. have market monitoring units, wholesale price caps have been implemented and special bidding and mitigation restrictions have been placed on generators located in small geographic load pockets. The Energy Policy Act of 2005 expanded FERC's authority to penalize suppliers identified as engaging in "market manipulation" in natural gas and wholesale electricity markets and FERC's rules for implementing this authority have been codified in Order 670 issued in January 2006[4] and a related Order 674. FERC has used that authority in

4. http://www.ferc.gov/legal/maj-ord-reg/land-docs/order670.asp

two recent cases involving alleged market manipulation in natural gas markets.[5] These market monitoring and mitigation protocols appear to have been reasonably successful in mitigating the ability of suppliers to exercise significant market power in these situations as well. On the other hand, these market power mitigation programs may be too aggressive, constraining prices from rising to competitive levels when demand is high, capacity is fully utilized, and competitive market prices should reflect scarcity values that exceed the price caps in place. Thus, these efforts to mitigate market power in the short run may create adverse generation investment incentives in the long run (Joskow and Tirole 2007), a subject to which I shall return presently.

6. Good transmission and distribution network regulatory institutions are important but sometimes neglected components of the reform process. It is important to remember that the textbook model includes the development and application of a well-designed regulatory framework to govern the distribution and transmission networks that will continue to be subject to government regulation of prices, costs, service quality, access rules, and investment programs. These "residual" regulated segments of the electricity sector often represent a significant fraction of the total retail price for services paid for by consumers (prices for competitive plus regulated services). Moreover, the performance of the regulated segments can have important effects on the performance of the competitive segments since the regulated segments provide the infrastructure platform upon which the competitive segments rely (e.g. the electric transmission and distribution networks). Accordingly, the welfare consequences of electricity sector restructuring and competition reforms depend on the performance of both the competitive and the regulated segments of these industries.

Regulatory reform focused on applying PBR mechanisms was a central feature of the liberalization program in the UK and the regulatory institutions and mechanisms that have evolved there also represent the gold standard of effective incentive or performance-based network regulation (Beesley and Littlechild 1989, Joskow 2006b). Privatization and the application of high-powered regulatory mechanisms have led to improvements in labor productivity and service quality in electric distribution systems in England and Wales, Argentina, Chile, Brazil, Peru, New Zealand and other countries (Newbery and Pollitt 1997, Domah and Pollitt 2001, Rudnick and Zolezzi 2001, Bacon and Besant-Jones 2001, Estache and Rodriguez-Pardina 1998, Pollitt 2004, Jamasb and Pollitt 2007). Sectors experiencing physical distribution losses due to poor maintenance and antiquated equipment, as well as resulting from thefts of electric service, have generally experienced significant reductions in both types of losses when appropriate incentive regulation mechanisms have been introduced. Penetration rates for the availability of electricity to the population have increased in those countries where service was not already universally available and queues for connections have been short-

5. http://www.ferc.gov/EventCalendar/Files/20070726084254-IN06-3-002.pdf; http://www.ferc.gov/EventCalendar/Files/20070726084235-IN07-26-000.pdf

ened. Distribution and transmission network outages have declined. Improved performance of regulated distribution (and sometimes transmission) systems has accompanied privatization and the application of high-powered PBR mechanisms almost everywhere it has been tried.

It is also now widely recognized that cost reduction efforts by network owners could lead to a deterioration of service quality --- increases in network outages, delays in service restoration, delays answering telephone inquiries. Accordingly, well-designed regulatory programs include performance-based regulatory mechanisms that apply to various dimensions of service quality (Joskow 2006b, Jamasb and Pollitt 2007, Yu, Jamasb and Pollitt 2007). These mechanisms reward or penalize network companies based on their performance against pre-specified service quality benchmarks.

One issue that comes up naturally when distribution networks are privatized involves the valuation of distribution assets and how these decisions can affect the prices paid by consumers for distribution service. The typical approach has been to carry forward the existing depreciated book value of historical investments in transmission and distribution into the new regime so that the base level of distribution and transmission charges associated with the recovery of capital-related charges does not change as a consequence of the transition. Incremental investments are then accounted for more or less as they were under the old regime (as in the U.S. and Canada) or economic/inflation accounting methods and approximations to economic depreciation are applied (as in the UK).

Bertram and Twaddle (2005) examine this issue in the case of New Zealand. In New Zealand, however, a decision was made to "write up" the value of distribution assets to reflect a specific measure of their (higher) replacement cost and to use these higher valuations to set the base level of network prices. This valuation method led to higher prices and higher price-cost margins for distribution network owners. The argument for adopting this valuation approach was that this would allow prices to rise to their efficient level and provide consumers with appropriate price signals. The arguments against this revaluation were that (a) it would lead to significant price increases and unfairly burden consumers, (b) nonlinear pricing could be used to restore the correct price incentives on the margin, and (c) it created windfall profits for distribution network owners and undermine support for restructuring and competition.

However, and though they do not emphasize it, the empirical results reported in Bertram and Twaddle (2005) also demonstrate that *operating costs* incurred by distribution companies in New Zealand fell very significantly during the same period of time. These cost reductions appear to reflect both the consolidation of small distribution companies through mergers and the incentives for cost reduction provided by a high-powered incentive scheme. Empirical analysis of distribution system productivity in Australia (Moran 2006) also shows significant productivity improvements as well, without any apparent deterioration in network reliability.

Effective regulation of networks does not occur by accident. It requires good regulatory institutions. Regulatory institutions that are independent, are well staffed and have access to necessary information about costs, prices, and service quality continue to be an important linchpin of successful electricity reform programs. Inadequate attention has been paid to created good regulatory institutions in many countries. Germany and New Zealand's initial decisions to proceed with a liberalization initiative without any sector regulator at all, relying instead on negotiated prices and the constraints of competition law, were clearly a mistake.

7. *Creating a well functioning transmission investment framework is important but continues to be a significant challenge in many countries.* As wholesale markets have developed, congestion on the transmission network has not only increased but is increasingly recognized as a significant constraint on the development of efficient competitive wholesale markets for power. In many countries, states, provinces and regions that have liberalized their electricity sectors, investment in transmission capacity, especially interregional transmission capacity, has not kept pace with the expansion in demand, generating capacity, or the volume of wholesale trade. In Europe and the United States there has been almost no investment in interregional transmission capacity since the early 1990s. Inadequate transmission investment is identified as a problem in Brazil and in Chile as well. Texas (ERCOT) appears to have responded to intra-regional transmission congestion with new investment, but ERCOT is still effectively disconnected from the rest of North America (Joskow 2006d).

In addition to the effects of transmission congestion on wholesale power prices and the associated social costs of congestion, a congested transmission network makes it more challenging to achieve efficient wholesale market performance. Transmission congestion and related reliability constraints create load pockets, reducing effective competition among generators and leading policymakers to impose imperfect market power mitigation rules that create other distortions. Congestion makes it more challenging for system operators to maintain reliability using standard market mechanisms, leading them to pay specific generators significant sums to stay in the market rather than retire and to rely more on out-of-market actions calls that depress market prices received by other suppliers.

In the UK and Argentina (Newbery 2006, Joskow 2006b, Jamasb and Pollitt 2007), the restructuring process included a comprehensive set of institutions and regulatory mechanisms to govern transmission operating cost and reliability, the allocation of scarce transmission capacity and approvals of transmission investment programs, as an integral aspect of the reform process. In many other countries, the regulatory framework governing transmission operation and investment was not given too much attention and allowed to evolve along with the markets. Stimulating performance improvements in the operation of transmission networks and, especially, attracting adequate investment to reduce congestion and to increase the geographic expanse of competition to reduce market power and the associated need to regulate wholesale markets to mitigate it, has been a challenge. The transmission systems that have exhibited the best performance are organized with a single independent transmission company that spans a large geographic area, and integrates system dispatch, congestion management, network maintenance and investment under PBR regulation (e.g. NGC in England and Wales). Fragmented transmission ownership, separation of system operations from transmission maintenance and investment, and poorly designed incentive regulation mechanisms reduce performance (Joskow 2005b). Relying primarily on market-based "merchant transmission" investment, that is where new transmission investments must be fully supported by congestion rents (the difference in locational prices times the capacity of a new link) is likely to lead to inefficient investment in transmission capacity (Joskow and Tirole 2005a).

8. *System reliability, "supply security," and "resource adequacy" are of great concern to policymakers in almost every country. Even relatively short blackouts carry high political (if not economic) costs. The jury is still out on whether and how competitive power markets can stimulate levels of investment in new generating capacity in the right places at the right times consistent with political preferences for reliability.* Many policymakers are increasingly expressing concerns about "supply security," "resource adequacy," and the reliability of their electricity sectors, though there is no evidence that reliability has deteriorated in liberalized markets. It is also not always very clear precisely what phrases like "supply security" and "resource adequacy" actually mean. An excellent conceptual discussion of different dimensions of supply security can be found in Amundsen, Bergman and von der Fehr (2006). One dimension of supply security relates to the operating reliability of the network as measured by involuntary losses of power --- non-price rationing or controlled rolling blackouts-- given the existing stock of capital on the network. Customers may experience blackouts due to failures on the distribution system, the transmission system, or due to inadequate generating capacity and price sensitive/interruptible demand to balance supply and demand in real time consistent with maintaining the physical integrity of the network. Failure to keep the system in balance can lead to cascading uncontrolled blackouts and network collapses affecting large regions (as occurred in the U.S. and Italy in 2003).

There is also a longer run concept of "resource adequacy" that reflects the adequacy of investments in distribution, transmission and generating capacity. Over time, investment in additional capacity should be made as long as the incremental value of the investments exceeds the incremental cost of the investment. If too little investment is made, costs and prices, including the costs associated with non-price rationing of demand and network collapses as discussed above, will be too high. Thus, long run concepts of supply security or resource adequacy are related to short run concepts of supply security or network reliability. I have already discussed network investment issues and will turn now to issues associated with investment in new generating capacity.

Creating appropriate investment incentives for new generating capacity is perceived to be a growing problem in many countries. At first blush, this concern may be surprising since the early experience with reforms during the 1990s suggested that competitive wholesale markets could and would mobilize adequate (or more than adequate) investment in new generating capacity. Substantial amounts of capital were mobilized during the late 1990s to support construction of new efficient generating capacity in many countries that have implemented reforms. In the U.S., over 220,000 MW of new generating capacity went into service between 1999 and 2006, most of it merchant capacity, an increase of about 30% in total U.S. generating capacity (Joskow 2005b) over ten years. About 40% of the stock of generating plants in service in England and Wales was replaced with modern efficient combined-cycle gas turbine (CCGT) technology between 1990 and 2002 as old coal-burning generators have been closed and expensive dirty coal plants have been displaced by cheaper and cleaner CCGT capacity. Many other countries implementing reforms during the 1990s, including Argentina, Chile and Australia, also attracted significant investment new generating capacity (Jamasb 2002) after the reforms were initiated.

So, why are policymakers so concerned about security of supply today? First, we should recognize that liberalization has evolved in much of Europe during a period when there was significant excess generating capacity, Spain and Italy being the major exceptions. Even in the UK, the quantity of generating capacity in service today is not much greater than it was in 1990, with most of the investment in generating capacity during the 1990s being stimulated by opportunities to replace the inefficient stock of old generators that the state-owned CEGB kept in service to maximize consumption of expensive British coal, long term contracts entered into by retail suppliers early in the UK's liberalization program, and the high prices available in the wholesale market, influenced by the exercise of market power as already discussed. Second, the environment for financing new generating investments has changed dramatically in the last few years as a result of financial problems faced by merchant trading and generating companies in Europe, the U.S. and Latin America, as well as macroeconomic and political instability in Latin America and Asia (Joskow 2005a, Jamasb 2002, De Araujo 2001). Third, policymakers perceive that private sector commitments to build new generating capacity are inadequate to meet growing demand later in this decade consistent with traditional reliability criteria (e.g. North American Reliability Corporation (2007), Nordic Competition Authorities (2007)).

Table 1. Generating Capacity Additions in the U.S.

YEAR	NEW CAPACITY (MW)
1997	4,000
1998	6,500
1999	10,500
2000	23,500
2001	48,000
2002	55,000
2003	50,000
2004	20,000
2005	15,000
2006	11,000

Source: U.S. Energy Information Administration, *Monthly Energy Review*, various issues.

Let's look at the U.S. experience. (See Table 1) After peaking at 55,000 MW of new capacity entering service in the U.S. 2002, only 11,000 MW of new generating capacity entered service in 2006, most of which was built either for municipal utilities that have not been subject to restructuring and competition reforms or wind and other renewable electricity generation projects that benefit from special subsidies and contractual arrangements. Concerns about future incentives for investment in additional generating capacity have been expressed in many other countries. In some cases, state-owned entities have stepped in to contract for additional generating capacity (e.g. Chile, Brazil, New Zealand, Ontario, California) to mitigate resource adequacy concerns. The actions by state-owned entities to support investment in new generating capacity may have salutary short run effects, but these actions are likely to discourage private investment in the longer run. Programs designed to stimulate investments in renewable generation (mostly wind) with special tax subsidies, contractual benefits, or mandatory purchase obligations, further complicate the investment picture for "ordinary" generating plants.

What is the problem? Potential private investors in new generating capacity are looking for stable market rules and longer term contractual commitments before they will commit capital for new generating facilities. Continuous market redesign, regulatory actions that limit wholesale market prices, system operators' "reliability" actions that depress market prices, and other market and regulatory imperfections are being pointed to as deterrents to private investors in unregulated generating plants. Financing investments in peaking capacity, which rely heavily on wholesale market prices creating "rents" to support fixed investment costs in a relatively small number of hours, is especially problematic. Analyses done of regional markets in the U.S. make it fairly clear that "energy-only" markets do not produce adequate revenues to attract investment in generating capacity consistent with the reliability standards that are still applicable to them and have now become mandatory (Joskow 2006a and 2007, Cramton and Stoft 2006).

A number of countries are considering imposing resource adequacy, forward contracting obligations, or providing capacity payments to generators to overcome imperfections in wholesale and retail markets in order to restore incentives for investments in generating capacity and demand response capabilities consistent with traditional reliability levels (Joskow 2006a, 2007, California Public Utility Commission 2005, Cramton and Stoft 2006). The organized markets in the U.S., Chile, Spain, Argentina, and Columbia have such obligations. These policies are and will continue to attract considerable attention, analysis and debate as they should.

9. *Retail market design and the terms and conditions of default service provided by incumbents have important implications for the success of retail competition programs*. The designs of retail competition programs vary widely from country to country and even within countries where reforms have been driven by states and provinces. All countries that have adopted market liberalization reforms allow large customers to buy power competitively at the outset of their restruc-

turing programs. In some countries, retail competition remains available only to such large customers. Residential and small commercial customers then continue to buy power from their local distribution companies which in turn procure their power in competitive markets and pass along the associated costs in the prices charged to these groups of retail consumers. Other countries have gradually expanded retail competition opportunities to customer classes that consume smaller amounts of power, with the long run goal of opening up the retail market to all customers. In this case, the distribution company (or a retail affiliate) buys power in the wholesale market and passes along the associated costs to the remaining retail customers during a transition period. Finally, retail competition is sometimes (e.g. in the states in the U.S. that have adopted retail competition programs) made available to all customers at the outset of the reforms program. However, since customers, especially smaller customers, do not switch instantly to competitive suppliers, some type of regulated "default service" must be provided to them, typically by their local distribution company or a retail affiliate. Thus, in all cases, there is some period of time during which a significant fraction of retail consumers continue to be served under some type of regulated default service tariff.

The terms and conditions of retail default service can have significant effects on the ability of competitive retailers to attract customers. In the U.S. (Tschamler 2006) and some other countries (e.g. Spain, France), default service prices or tariffs have been used to support a number of objectives other than promoting a robust retail market. These include commitments that retail customers will receive an immediate and sustained price reduction of some magnitude, stranded cost recovery considerations, income redistribution goals, and consumer protection goals. As a result, default service prices have sometimes been set at levels below the wholesale cost of power, or wholesale prices have risen over time, closing or reversing the gap between default prices and wholesale market prices. Under these circumstances it is impossible for a competitive retailer profitably to offer services that can attract customers away from default service. If as a matter of policy regulators want to protect customers from high market prices by giving them access to regulated tariffs fixed at prices below market then retail competition will never be successful. Such policies may also signal a lack of faith and commitment by policymakers in retail competition.

The experience in Pennsylvania (a state that is part of the PJM wholesale market) provides a good example of the effects of mixing regulated default pricing with retail competition. Different default service prices were set for each utility in Pennsylvania, reflecting historical regulated costs of generation service and stranded cost recovery settlements. The prices were fixed in 2000 for a term of up to ten years (varying from company to company), with some adjustments for fuel and other input price changes. The regulated default service prices are now starting to expire, most recently for Penn Power starting in 2007. Customers who do not choose an ESP are supplied from power purchased in the wholesale market and must pay the associated purchased power costs upon which the distribution company earns no additional profit.

Figure 1 provides time series data on the fraction of residential customers which switched to a competitive retailer for each utility in Pennsylvania. Figure 2 provides the same data for industrial customers. There is both wide variation in the initial fraction of customers who switched to competitive retail suppliers and significant evidence of their switching back and forth between regulated default service and regulated services. The inter-utility variations must be attributable to differences in regulated default service prices since there is no inherent reason why customers in (say) Pittsburgh should be more likely to shop for alternatives than are customers in (say) Philadelphia. By July 2005 nearly all residential customers had returned to regulated default service and a large fraction of the industrial customers who initially opted for competitive service had also returned to default service. This is attributable to rising nominal wholesale prices in PJM which have reduced or eliminated the "headroom" between the regulated default service price and the wholesale market price for power. However, for Duquesne and now Penn Power, large industrial customers have moved relatively quickly into the competitive retail market when the regulated transition default service prices expired and their default service prices then increased to reflect wholesale market condition. The huge rapid shift of Penn Power's industrial customers to ESPs in 2007 after the regulated default service rates come into effect is especially impressive. In the U.S., the biggest problem faced by competitive retailers is "competition" from default service, a service for which the incumbents typically make no profit either.

The general pattern of retail switching behavior in most countries is that large industrial customers are more likely to switch and to do so more quickly than smaller industrial and commercial customers. Residential customers switch more slowly and are more likely to remain with the incumbent, especially when the incumbent must offer a regulated default price that is at or below the wholesale market price of power. This phenomenon can by illustrated with the experience in Massachusetts. All customers were given access to competitive retail suppliers in April 1998. However, most customers continued to be eligible for regulated "standard offer service whose prices gradually fell further and further below wholesale market prices. During 2005 the availability of regulated "standard offer" service began to end and distribution companies began to buy default service supplies by taking supply bids with durations of 6 months to two years. Prices for default service from the local distribution company then rose to reflect the costs they incurred to procure power competitively in the wholesale market. Since 2005, the movement to competitive retail suppliers has accelerated, with almost all supplies to large industrial customers provided by competitive suppliers and 50% of demand overall supplied by competitive ESPs.

Figure 1. Pennsylvania Direct Access Load: Residential (%)

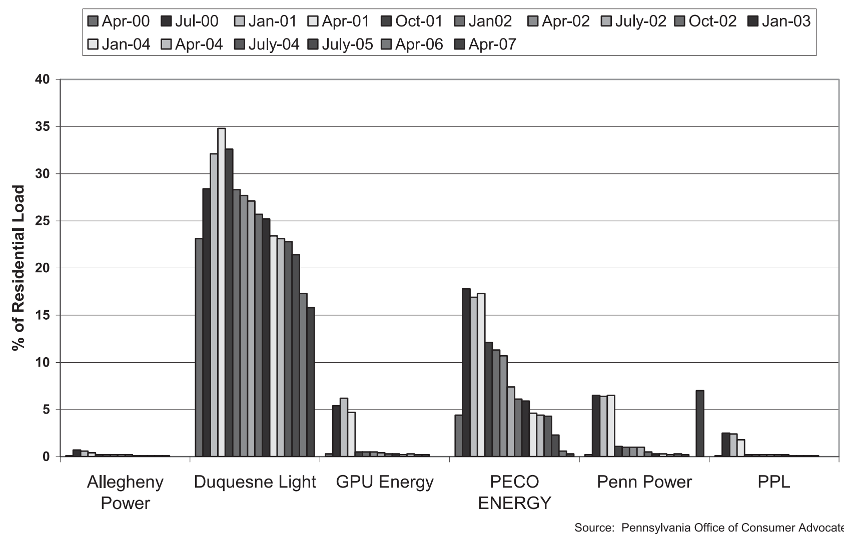


Figure 2. Pennsylvania Direct Access Load: Industrial (%)

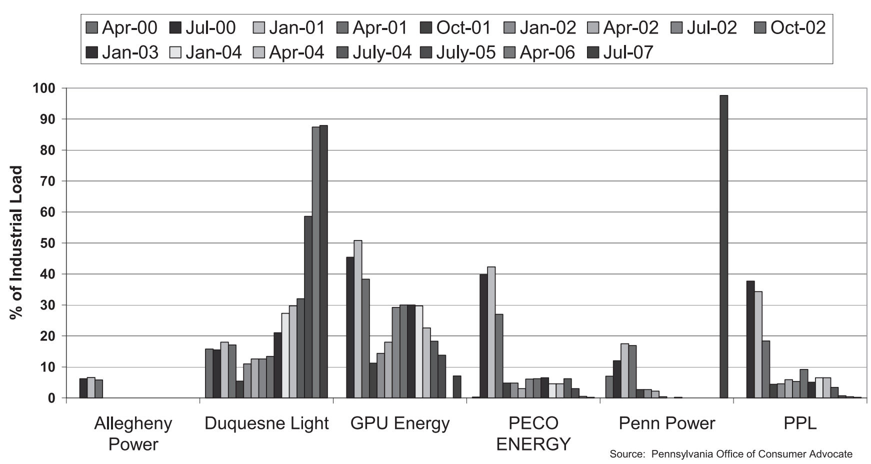


Table 2. Retail Competition in Massachusetts

	2002 and 2007	
Type	*Competitive Retail Supply (%)*	
	April 2002	*June 2007*
Residential	0.8%	10.3%
Small Commercial	7.2	31.6
Large Commercial	15.7	47.3
Large Industrial	42.2	85.9

Retail competition starts in April 1998. Regulated Default service ends 2005.

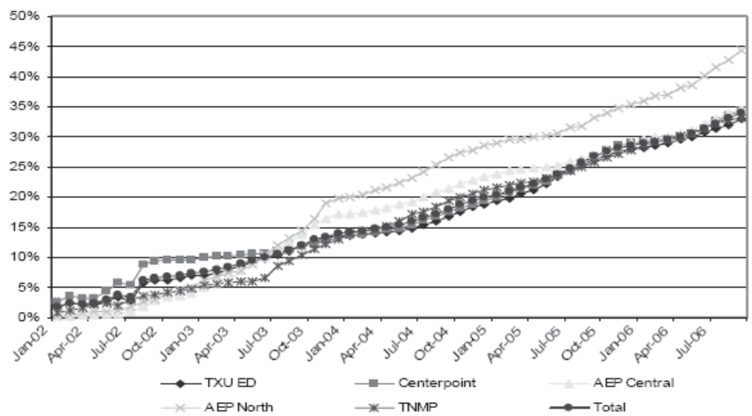
Source: Massachusetts Department of Energy Resources

The Massachusetts experience also indicates that for residential (domestic) customers, even if the regulated default service price is equal to the comparable competitive wholesale market value of the power supplied, retail suppliers need a significant additional margin both to induce sticky retail customers to switch suppliers and to cover their retail supply costs. This margin has turned out to be much larger than anticipated when retail competition was first introduced. In particular, the retail supply costs for the mass market (residential and small commercial) are much higher than many retailers had anticipated. Billing, customer service, bad debt, advertising and promotion costs add up quickly. Accordingly, the default service price may have to be significantly higher than the comparable wholesale market price to induce much customer switching.

The retail competition framework applied in Texas did exactly this. The "price to beat," the default service price in Texas, was set at a level well above the competitive wholesale price for power and was adjusted for changes in natural gas prices; natural gas fired generation sets the wholesale market price in Texas in a large fraction of the hours of the year and wholesale market prices move very closely with natural gas prices (Public Utility Commission of Texas 2007). This framework provided incentives to retail customers and retail suppliers to participate in the competitive retail market. And the consistent increase in the fraction of retail customers who have switched reflects this framework's attributes.

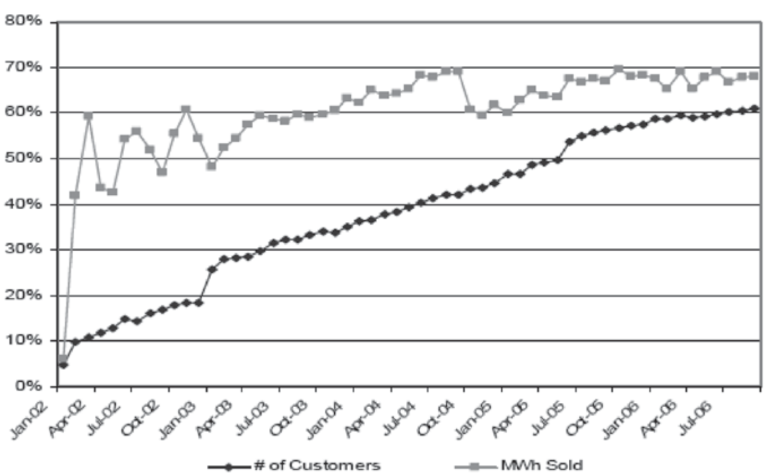
There has been relatively little systematic analysis of the effects of competition reforms on electricity prices --- are they higher or lower than they would have been under the previous regime? This kind of "but for" analysis has been complicated significantly by the dramatic increase in natural gas prices and the resulting increase in electricity prices, especially in regions where the wholesale electricity market clears on natural gas-fired generation during many hours of the year. Newbery and Pollitt (1997) find that there were overall social gains from restructuring, but that a large share of these gains were captured by suppliers. The fall in wholesale margins around the time that NETA was introduced in the UK suggests that this balance has changed. Joskow (2006a) and Harvey, McConihe

Figure 3. Share of Residential Customers Switching to Competitive Supplier



Source: Public Utility Commission of Texas (2007)

Figure 4. Share of Large Industrial Customers Switching to Competitive Retail Suppliers



Source: Public Utility Commission of Texas 2007 and Pope (2006) find that through 2004, retail prices were lower in states that adopted restructuring programs than they would have otherwise been, though the impact of the availability of regulated default service is a more important factor than retail competition during this period. It is fairly clear, however, that the dramatic and unexpected increase in natural gas prices has had a large impact on wholesale electricity prices in some areas. This had led to higher retail prices (in the short run) than would have been the case if electricity consumers had continued to receive the benefit of "rolled in" pricing of pre-existing regulated coal-fired and nuclear plants whose economic value increased dramatically as natural gas prices increased. Basically, these customers are seeing prices below the efficient market clearing level due to continuing regulation.

During the early 1990s, the gap between the regulated cost of generation service (high) and the wholesale market value of generation service (lower) fostered political support for electricity restructuring in many areas. Now that the gap has reversed in these areas, due primarily to large unexpected increases in wholesale electricity prices driven by higher natural gas prices, it has become a deterrent to deregulation of wholesale and retail prices.

This experience naturally leads to the final issue. Is retail competition worth the trouble compared to a regime where the distribution company procures power competitively and resells it at cost to residential and small commercial customers? Unfortunately, there is little if any good empirical analysis available to evaluate this question rigorously, though there is no shortage of strong ideological views. Looking at switching rates alone isn't very informative as an index of the welfare consequences of retail competition. The presumption has been that retail competition is a good thing to offer larger customers, where transactions costs are low, opportunities to offer risk management and demand management products are greater, and customers are expected to be able to shop intelligently. There are also benefits for the development of competitive wholesale market resulting from having more buyers active on the demand side, reducing monopsony problems that might emerge if distributors were the only buyers. Moreover, if the alternative is competitive procurement by the distribution company, regulators must become involved in determining procurement rules, including the attributes of the contracts that will be put out for bids. Industrial customers and their agents should be in a better position to express their risk preferences than are regulators. (See Littlechild (2003) for these and other arguments in support of retail competition.) And indeed, where default prices have been allowed to float to reflect spot wholesale market prices (including capacity prices), large customers appear to migrate fairly quickly to the market and to sign contracts that hedge price volatility from one to three years into the future.

It is far from obvious to me, however, that residential and small commercial customers have or will benefit much, if at all, from retail competition compared to a regime where their local distribution company purchased power for their needs by putting together a portfolio of short term forward contracts (from days to several years) acquired in wholesale markets (Joskow (2000a, 2000b) and

Littlechild 2003 for a different view)) and passing along the associated costs in the prices charged to residential and small commercial customers. Indeed, New Jersey has used the so-called Basic Generation Service (BGS) auction process quite effectively to buy power competitively for residential and small commercial customers and to resell it to default service customers. There is little evidence that residential customers are getting any significant value added services from retail suppliers aside from some billing options and choices between contracts which set the prices for different durations (e.g. one vs. two years). Retail competition with load profiling leads to some inefficiencies (Joskow and Tirole 2006). There is evidence that there are significant costs associated with implementing a retail competition program for residential consumers (Green and McDaniel 1998) and that they may make poor shopping decisions (Salies and Waddams Price 2004).

If policymakers are committed to fostering retail competition for residential and small commercial customers, despite the possibility that retail prices will rise in the short run due to increased transactions costs, switching costs and market power, the frameworks adopted by the UK, Texas, and the Nordic countries is likely to be the most successful in stimulating retail shopping and the development of a viable retail supply sector. If they are not committed to retail competition for smaller customers then they must devise an alternative credible competitive power procurement regime (like the New Jersey BGS) auction that conveys market wholesale market prices in retail prices and also provides good incentives for investment.

10. *Vertical integration between retail supply and generation is likely to be an efficient response to imperfections in wholesale markets. It may also create market power problems. Thus, policymakers must confront a tradeoff*: In several countries with active retail competition programs there appears to be a growing movement to an industry structure where competitive retail suppliers acquire generating capacity to meet a significant fraction of their retail commitments. This trend is likely to reflect an efficient response to relatively high transaction costs associated with real wholesale power markets in practice (Coase 1937, Williamson 1975, Carlton 1979, Joskow 2005d). There is no inherent competition problem with vertical integration of this type as long as there are a sufficient number of vertically integrated suppliers that continue to compete in the market. However, if there is significant market power in the upstream or downstream markets, vertical integration could lead to a further reduction in competition by increasing the operating or entry costs of rival retail suppliers (Ordover, Salop and Saloner 1990, Riordan 1998). Bertram (2006) suggests that in New Zealand the intensity of competition declined significantly as retail suppliers became vertically integrated while Moran (2006) suggests that in Australia vertical integration did not lead to market power problems. See also Bushnell, Mansur and Saravia (2007) and Mansur (2007). Thus, there may be a tradeoff between increases in efficiency and increases in market power.

11. *Expanding demand response in spot wholesale energy markets needs more attention.* In markets for most goods and services, when demand grows and

supply capacity constraints are reached, prices rise to ration demand to match the capacity available to provide supplies to the market. In electricity markets, however, as generating capacity constraints are reached, relatively little demand can be rationing by short term price movements and, instead, must by rationed with rolling blackouts. This reflects both the limited use of real time pricing and the system operator's need to adjust demand very quickly at specific locations. The possibility of broader uncontrolled cascading blackouts and regional network collapses further exacerbates this problem and necessarily leads to regulatory requirements specifying operating reserves, operating reserve deficiency criteria and associated administrative actions by system operators to balance the system to meet voltage, stability and frequency requirements in an effort to avoid cascading blackouts (Joskow and Tirole 2007). In addition, retail competition has more attractive welfare properties if the real time consumption of retail consumers can be measured instead of relying on load profiling (Joskow and Tirole 2006). The challenges faced by network operators to maintain system reliability and avoid non-price rationing of demand would be reduced if additional demand-side response instruments were at their disposal. These instruments include the ability to rely on demand response by more customers who can see and respond to rapid changes in market prices and expanded use of price-contingent priority rationing contracts (Chao and Wilson 1987).

As a general matter, too little demand side response has been developed to date in most countries. The demand response instruments that are available are poorly integrated with spot markets and are likely to have the effect of depressing prices inefficiently. Moreover, the prices that are paid for demand response or the prices that can be avoided by responding to price signals are too low compared to the cost of carrying generating capacity reserves to meet planning reserve margins in some cases. Improving demand response should be given higher priority in wholesale market design.

12. *Electricity sector reform appears to be a continuing process of improvement, but a process of continuing reform of the reforms has both potential benefits and potential costs.* It is quite clear from recent historical experience that none of the reform programs got it all right out of the box. Initial reform programs are followed by additional reforms, some major and some minor, to respond to performance problems that emerge in practice or lessons learned about best practices from other countries. On the one hand, reforms that are needed to fix major performance problems certainly should be considered carefully. On the other hand, a process of ongoing reforms that have significant and uncertain future financial impacts on market participants is not likely to create a framework that is conducive to investment in long-lived assets whose value is subject to policy reform risks. Policy reforms may also be used opportunistically to respond to political pressures that arise under market conditions when investors properly expected that they would achieve high returns, effectively truncating the upper end of the return distribution and leading investors to require higher expected returns from other states of nature than would otherwise be the case.

The search for perfection can be the enemy of the good. Policymakers need to make sure that the benefits of any additional reforms exceed their short run and long run costs, in particular those related to investment incentives. And if there are to be reforms of the reforms it is desirable to package them together so that there can be one reform of the reforms rather than a continuing stream of them. Finally, if policymakers are serious about competitive markets for power they will have to rethink the long tradition of relying on taxation by regulation of the electric power industry to implement policies in ways that hides the associated costs from taxpayers.

13. *A strong political commitment to reform is important.* Implementing a good electricity sector liberalization program is a technical, institutional and political challenge. Almost everywhere, some unanticipated (at least by the policymakers) problems emerged that required major or minor refinements to the original reform program. In some cases (e.g. UK, New Zealand, Alberta, Australia, Texas) the reforms were consistent with the continuing development of competitive markets and in other cases they were not (e.g. California, Ontario, Brazil). It appears that reforms that have strong pro-competition political support are more likely to respond to problems by identifying market or institutional imperfections and trying to fix them in ways that are consistent with the continued successful evolution of competitive wholesale and retail markets. They are also likely to be willing to live with some imperfections, recognizing that no market is perfect and that the cures can be worse than the disease. Where the commitment to competitive electricity markets is weak, when problems emerge policymakers are more likely to seek what appear to be quick fixes that undermine continued evolution of competitive markets or just cut and run from the competitive market agenda. If the commitment to competition is not strong in the first place, of course, the reforms are likely to be timid and have little effect on the status quo anyway, Japan and many U.S. states being the prime examples.

5. CONCLUSION

Structural, regulatory and market reforms have been applied to electricity sectors in many countries around the world. Significant performance improvements have been observed in some of these countries as a result of these reforms, especially in countries where the performance of state-owned monopolies was especially poor. Privatization combined with the applications of good PBR mechanisms to regulated distribution companies has generally yielded significant cost reductions without reducing service quality. Wholesale markets have also stimulated improved performance from existing generators and helped to mobilize significant investments in new generating capacity in several countries.

We must recognize, however, that creating well functioning competitive wholesale and retail markets for electricity is very challenging both technically and politically. The California electricity crisis, electricity crises in Brazil, Chile, Ontario, and elsewhere, scandals involving energy trading companies like Enron, the failure of poorly designed reforms in countries such as Brazil, macroeconomic problems undermining investments in generally well designed systems as in Argentina, increases in wholesale electricity prices driven by unexpected increases in natural gas prices and (in Europe) the price of CO_2 emissions permits, have certainly made policymakers more cautious (but not necessarily more thoughtful) about electricity sector reforms.

However, these problems and challenges do not imply that restructuring, regulatory reform, and promoting the development of competitive wholesale and retail markets for power, are ill-advised. The problems that have emerged are now much better understood and solutions to many of them are at hand. The primary question is whether governments properly can choose between competing solutions and have the political will to resist interest group pressures and pursue reforms that will lead to more efficient markets and better performance of the network platforms upon which competition depends.

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Tab 5

Presentations

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

DATE: February 11, 2019

Florida law charges the Financial Impact Estimating Conference (FIEC) with the responsibility to prepare a financial impact statement to the public regarding the probable financial impact of any amendment proposed by a citizens' initiative. *See, § 5, Art. XI, Fla. Const. and § 100.371, Fla. Stat.* Citizens for Energy Choices, the sponsor of the initiative entitled, "Right to Competitive Energy Market for Customers of Investor-Owned Utilities; Allowing Energy Choice" (Energy Choice Amendment), intends this memorandum to provide the FIEC with information for its consideration as it undertakes this legal obligation. To put the Energy Choice Amendment in context, this memorandum describes, generally, the types of electric utilities currently operating in Florida, the different structures for retail electricity markets, the existing retail electricity market structure in Florida, the purpose of the Energy Choice Amendment, and how a change in Florida's retail electricity market might impact state and local government revenues and costs.

Florida Electric Utilities

Generally, an electric utility is a power company that generates, transmits, and distributes electricity for sale to customers. Not all electric utilities necessarily perform all three functions. The following describes the types of electric utilities that have operated in Florida:

- **Investor-Owned Utilities (IOUs)** are for-profit companies owned by their shareholders. The Florida Public Service Commission ("FPSC") grants IOUs the license to operate in specific areas of the State under certain terms and conditions through enforcement of various territorial agreements among the utilities. Their interstate generation, transmission, and power sales are regulated by the Federal Energy Regulatory Commission and their distribution system and retail sales are regulated by the FPSC. IOUs that generate and transmit electricity are also subject to Florida's environmental and facilities siting laws. An IOU like Florida Power and Light Company performs all three functions of an electric utility. It generates, transmits and distributes electricity for sale to its customers. Florida Public Utility Company, by contrast, is a "transmission and distribution" company. It purchases wholesale power from another utility and transmits and distributes it for sale to its retail customers.

- **Public Power Utilities (also known as "Municipal Utilities")** are not-for-profit utilities owned by cities or counties or their affiliated authorities, or by independent special districts.[1] Municipal utilities are generally not regulated by FERC, and their rates and service are not regulated by the FPSC, but they are subject to limited FPSC jurisdiction relating to enforcement of monopoly service territories, coordination of the interconnected electric grid, and whether they structure their rates in a reasonable and non-discriminatory manner. Like IOUs, municipal utilities that generate and transmit power are subject to Florida's environmental and facilities siting regulations.

- **Cooperatives (Co-Ops)** are not-for-profit entities owned by their members. They must have democratic governance and operate at cost. Members vote for representatives to the co-op's Board of Directors who oversee operations. Any revenue in excess of costs must be returned to members. Co-ops also tend to serve in rural areas that were not historically served by other utilities. State regulation of Co-Ops is similar to that of municipal utilities.

- **Independent Power Producers**, sometimes called non-utility generators, are privately-owned businesses that own and operate their own generation assets and sell power to other utilities.

U.S. Retail Electricity Markets

According to the *United States Electricity Industry Primer*, published by the U.S. Department of Energy (Attached as Appendix "A"):

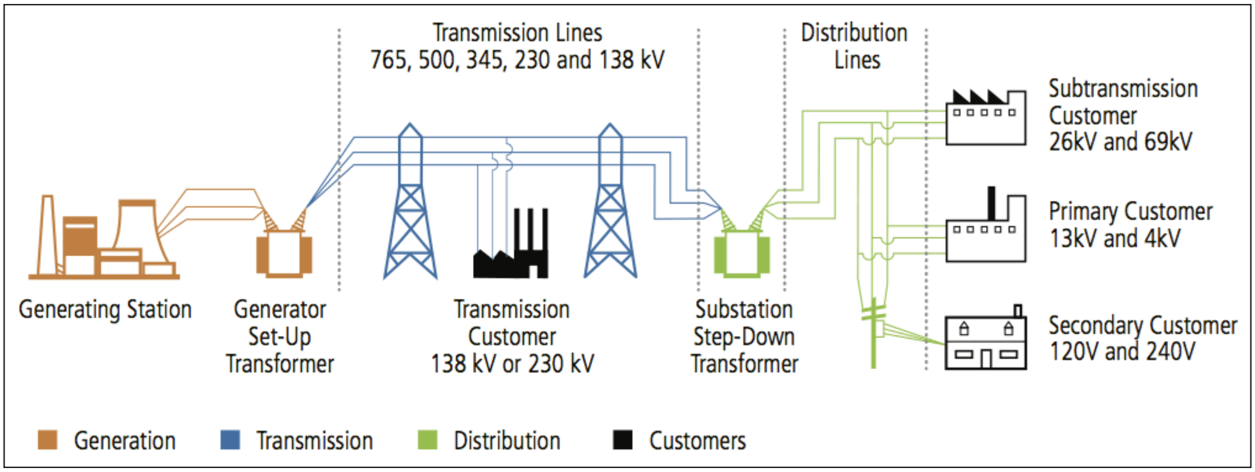
[1] The FPSC has determined that the Reedy Creek Improvement District is a municipal utility for regulatory purposes. RCID is an independent special district established by special act of the Florida Legislature.

The retail market involves the sale of electricity from an electricity provider to an end-user. The end-user could be a large industrial facility, small business, or individual household. In every State, regardless of whether there is retail competition or not, the electricity supply for end-users is obtained either through the competitive wholesale market, or from utility-owned rate-based generation, or a combination of the two. All States regulate rates for the delivery of electricity to end users (customers) through distribution wires and related systems. In States where there is full retail competition[2], "retail choice", customers may choose between their current utility supplier and other competitive suppliers for the generation portion of their electric service. Competitive retail suppliers provide a variety of service plans that give consumers and businesses options for electricity purchases. The price the end-user pays, or the retail price, may not reflect the real-time pricing of wholesale market pricing. Retail prices may be an average of annual costs or some other mechanism to determine end-user prices.[3]

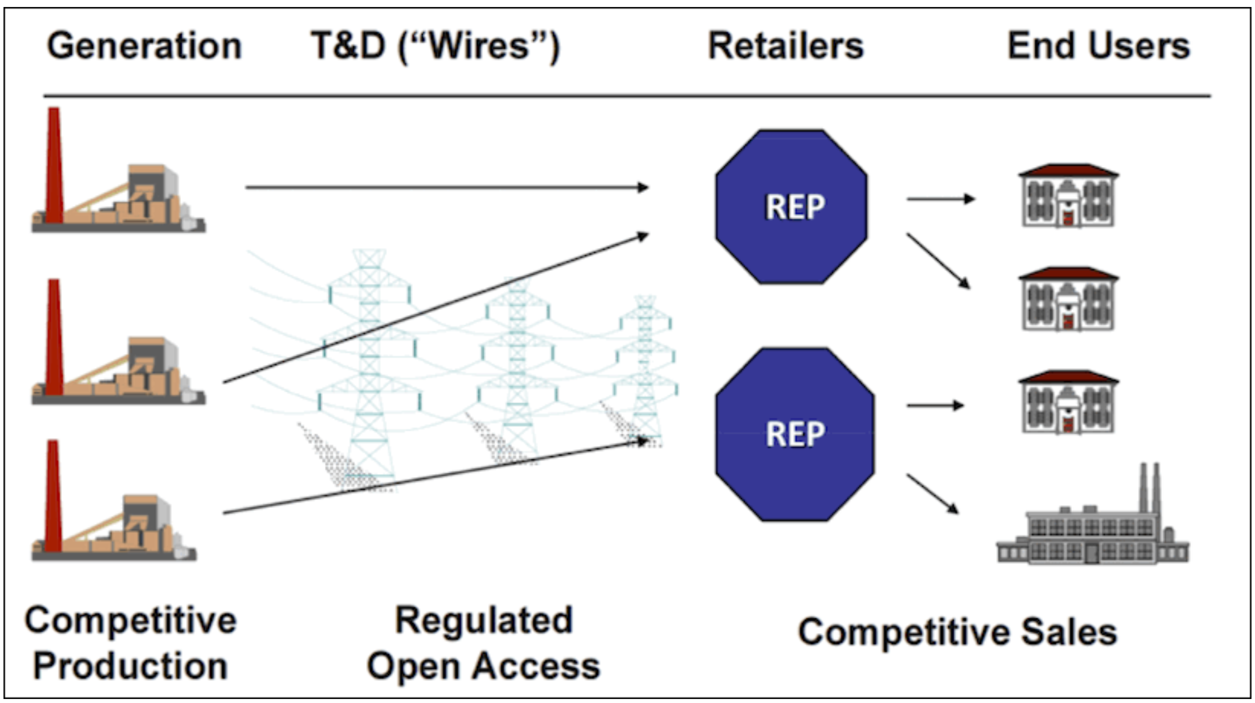
For investor-owned utilities, the regulation of retail markets falls under the jurisdiction of states. State regulatory commissions, which are often called the State "Public Utility Commission" or "Public Service Commission," regulate a utility's costs and rate of return. Municipally- and cooperatively- owned utilities may be subject to some State regulation but in general, self-regulate their costs. As non-profit entities, municipally- and cooperatively- owned electric utilities do not earn a return on capital invested.[4] In retail choice States, the commissions can require competitive suppliers to be licensed and subject to some regulation before they are allowed to service customers. In States without retail competition, commissions regulate the expenditures of investor-owned utilities and set an authorized rate of return on capital invested. In these States, where utilities are vertically integrated, utilities may construct, own and operate power plants and the costs are reflected in retail prices.

The following figure illustrates a rate-regulated monopoly market. In this market structure, one monopoly company owns generation assets, transmission & distribution facilities, and provides merchant functions.

[2] Comment (not in original): The use of the clause "In states where there is full retail competition" gives the erroneous impression that several states have retail electricity markets that are structured to enable full retail competition. Currently, "full retail competition" exists only in Texas.
[3] Comment (not in original): Rarely, if ever, are retail prices set based on an average of annual real-time pricing. Rather, retail suppliers may base pricing on long-term contracts with specific generators, financial hedges, and other mechanisms.
[4] Comment (not in original): While municipal utilities do not earn an authorized rate of return on invested capital, rates are often established to generate sufficient revenues to fund non-utility public needs.



The figure below depicts the competitive retail market established in Texas. In this fully restructured competitive market, power generating companies compete in a wholesale marketplace, while separate retailers perform the merchant functions competing in the retail market, providing a wider range of merchant and value-added functions. Rate-regulated transmission and distribution companies own and operate the open access system of poles and wires.



In Texas, the Texas Public Utilities Commission regulates T&D utilities, certifies participants, is responsible for the siting of generation and transmission projects, ensures customer protections, and provides the authority to mitigate market power. The Electric

Reliability Council of Texas (ERCOT), one of Texas' two reliability entities, is the Independent System Operator (ISO) and acts as the wholesale market clearing house, acts as the agent for the exchange of electronic communications between market participants, and maintains the market protocols to ensure reliability, market operations, and the like. ERCOT continually monitors the market to ensure that there is no market manipulation or other threats to reliability. Texas' other reliability entity, the Texas Reliability Entity, is one of the eight NERC regional entities, and independently monitors the wholesale market.

An April 17, 2012, slide presentation entitled "History of Electric Deregulation in ERCOT" from the Texas Public Utilities Commission, attached as Appendix "B", provides additional information on ERCOT and Texas' move to retail competition.

Florida's Retail Electricity Market

As in other states with a traditional market structure, electric utilities in Florida are responsible for the production, transmission, and distribution of electricity, as well as the merchant functions such as metering, customer service, and billing of the electric energy sold to homes and businesses. This complete package of electric services has been termed "bundled retail service" or "integrated utility service."

In Florida, a total of 57 electric utilities currently provide bundled retail service to end-use customers in their service areas. The FPSC fully regulates the rates and services of 5 IOUs: Florida Power & Light Company; Duke Energy Florida; Florida Public Utilities Company; Gulf Power Company; and Tampa Electric Company.[5] Together, these five IOUs provide more than 75 percent of all electricity sold to retail customers in Florida. The remainder is provided by 35 municipal electric utilities and 17 rural electric cooperatives.

Florida has two reliability entities: the Florida Reliability Coordinating Council (FRCC) covering peninsular Florida, and the Southeastern Electric Reliability Council (SERC) covering a part of the western panhandle. These North American Electric Reliability Corporation (NERC) reliability entities implement and enforce reliability standards to maintain stability of the bulk power system within their areas, similar to how the Texas Reliability Entity does for Texas. However, unlike ERCOT in Texas, neither of Florida's reliability entities serve as an ISO or as a Regional Transmission Organization, and do not act as wholesale market monitors or facilitators.

[5] In January, NextEra Energy, Inc., parent to Florida Power & Light Company, announced that it had purchased the assets of Gulf Power Company.

The Energy Choice Amendment

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

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

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

FULL TEXT OF PROPOSED AMENDMENT:
(a) POLICY DECLARATION. It is the policy of the State of Florida that its wholesale and retail electricity markets be fully competitive so that electricity customers are afforded meaningful choices among a wide variety of competing electricity providers.
(b) RIGHTS OF ELECTRICITY CUSTOMERS. Effective upon the dates and subject to the conditions and exceptions set forth in subsections (c), (d), and (e), every person or entity that receives electricity service from an investor-owned electric utility (referred to in this section as "electricity customers") has the right to choose their electricity provider, including, but not limited to, selecting from multiple providers in competitive wholesale and retail electricity markets, or by producing electricity themselves or in association with others, and shall not be forced to purchase electricity from one provider. Except as specifically provided for below, nothing in this section shall be construed to limit the right of electricity customers to buy, sell, trade, or dispose of electricity.
(c) IMPLEMENTATION. By June 1, 2023, the Legislature shall adopt complete and comprehensive legislation to implement this section in a manner fully consistent with its broad purposes and stated terms, which shall take effect no later than June 1, 2025, and which shall:
(1) implement language that entitles electricity customers to purchase competitively priced electricity, including but not

limited to provisions that are designed to (i) limit the activity of investor-owned electric utilities to the construction, operation, and repair of electrical transmission and distribution systems, (ii) promote competition in the generation and retail sale of electricity through various means, including the limitation of market power, (iii) protect against unwarranted service disconnections, unauthorized changes in electric service, and deceptive or unfair practices, (iv) prohibit any granting of either monopolies or exclusive franchises for the generation and sale of electricity, and (v) establish an independent market monitor to ensure the competitiveness of the wholesale and retail electric markets.
(2) Upon enactment of any law by the Legislature pursuant to this section, all statutes, regulations, or orders which conflict with this section shall be void.
(d) EXCEPTIONS. Nothing in this section shall be construed to affect the existing rights or duties of electric cooperatives, municipally-owned electric utilities, or their customers and owners in any way, except that electric cooperatives and municipally-owned electric utilities may freely participate in the competitive wholesale electricity market and may choose, at their discretion, to participate in the competitive retail electricity market. Nothing in this section shall be construed to invalidate this State's public policies on renewable energy, energy efficiency, and environmental protection, or to limit the Legislature's ability to impose such policies on participants in competitive electricity markets. Nothing in this section shall be construed to limit or expand the existing authority of this State or any of its political subdivisions to levy and collect taxes, assessments, charges, or fees related to electricity service.
(e) EXECUTION. If the Legislature does not adopt complete and comprehensive legislation to implement this section in a manner fully consistent with its broad purposes and stated terms by June 1, 2023, then any Florida citizen shall have standing to seek judicial relief to compel the Legislature to comply with its constitutional duty to enact such legislation under this section.

Purpose and Effect of the Constitutional Amendment

The Energy Choice Amendment’s purpose is to change a significant portion of Florida’s retail electricity market from a traditional vertically integrated monopoly framework to a competitive framework, so that a customer of Florida’s investor-owned utilities is empowered to choose their preferred electricity provider from several competing alternatives, or to produce electricity for themselves or in association with others. The

Energy Choice Amendment requires the Legislature to implement this directive within specified parameters by a date certain, and enables the citizens, through judicial action, to compel the Legislature to undertake its responsibility. Municipally owned and cooperative electric utilities are exempted from retail competition, unless they opt-in.

The Energy Choice Amendment's policy declaration is intended to enshrine the main goal of the initiative into state policy – competitive choice for individual customers. The operative portion of the Energy Choice Amendment conveys an individual right to buy, sell, trade, or otherwise dispose of electricity – whether by self-generation, or by purchase from competing electricity suppliers – for all customers of investor-owned utilities. The words "wholesale" and "retail" are both used and are intended to ensure that freedom of choice in electricity is guaranteed to all buyers of all types in all stages of the market, and the use of the word "competitive" is intended to reinforce that Floridians currently served by investor-owned utilities are entitled to more than just a modicum of choices – they are entitled to real competition. Exceptions to the application of the Amendment are made for municipal utilities and electric cooperatives.

The Energy Choice Amendment makes a clear carve-out for municipal utilities and electric cooperatives. Nothing in the Amendment is intended to change them or their operations in any way, except that it would allow them to participate in competitive markets as they see fit. The carve-out follows the Texas example, and recognizes the democratic governance and ownership that these types of utilities have. Additionally, the municipal-cooperative carve-out will allow municipal utilities and electric cooperatives to unbundle at their own pace, and at their own discretion. Even if they don't participate in the competitive retail market, municipal utilities and co-ops can benefit from improved wholesale market conditions under the Energy Choice Amendment as competition throughout the state drives down wholesale electricity prices.

Because of the complexity involved in implementing full electricity restructuring, the initiative delegates the lion's share of specifics to the Florida Legislature – the Energy Choice Amendment's implementation language is meant to direct Legislative implementation toward competition and away from monopoly. The Amendment grants the Legislature three years to enact comprehensive legislation, and provides an additional two years before such legislation takes effect, allowing stakeholders a period of transition to the new regulatory environment.

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.

By limiting the activity of incumbent IOUs to an electricity transmission and distribution business, the Energy Choice Amendment prevents IOUs from generating electricity, thereby significantly reducing incumbent monopoly power and paving the way for competition. The limitation restricts IOUs to their natural monopoly function of maintaining and operating the electricity grid, and is a key element in the success of Texas in reducing end-user prices following its market restructuring efforts. Properly implemented, this limitation would require Florida's existing IOU's to functionally unbundle their current operations by transferring their power generation and retail sales functions to separate business entities subject to market power limitations established by the Legislature. Under such a market structure, an incumbent IOU's transmission and distribution unit would earn revenue by charging system users for use of the transmission and distribution system to transport electricity from power generators to end users[6]. Power generators would generate revenue by selling electricity at wholesale to certified retail providers. Retail providers would generate revenue by charging customers for the electricity they receive and by providing value-added services.

The Amendment's requirement that implementing legislation limit an IOU's market power ensures that the legislation is designed to prevent any future market participants from becoming too powerful. This provision of the Energy Choice Amendment is primarily aimed at future IOU affiliates, but will apply equally to any entities which might be able to use their market power to dampen competition for electricity customers. While the requirement mandates that the Legislature promote competition and limit abuses of market power, specifics of how these ends are accomplished are left to the Legislature.

Additional requirements for implementing legislation address customer protection, prevention of monopolies or exclusive retail service franchises, and market monitoring to ensure that the new retail electricity market is functioning competitively.

Effect on State and Local Revenues and Costs

The Energy Choice Amendment's intent is to establish a competitive retail electricity market in Florida structured similarly to the competitive market established in Texas, but leaves to the Legislature significant freedom in implementation. The means chosen by the Legislature to implement the Amendment are likely to determine whether, and the degree to which, the retail price of electricity decreases as a result of the Amendment's adoption. State and local government revenue sources that would be

[6] The rates charged for transmission and distribution would continue to be regulated by the PSC, as monopoly utility charges should be.

affected are tied to electric utility revenues, and are therefore directly affected by the retail price of electricity.

Moreover, the unbundling of the functional elements of the utility business required by the Amendment may require the Legislature and local governments to revise how various utility-related taxes and fees are applied and administered. It is impossible to predict how the Legislature and local governments might approach such a task. As a result, the impact of the Energy Choice Amendment on state and local government revenues is currently unknown and speculative.

With regard to costs of the State and local government as a purchaser of electricity from affected utilities, it would be speculative to predict the Legislature's policy choices that may result in changes to retail electricity prices, or to predict future purchasing decisions of the State and local governments.

With regard to implementation costs to state and local governments, the wide range of alternatives open to the Legislature in establishing an entity to monitor and facilitate wholesale and retail markets is speculative and unknown.

LIST OF APPENDICES

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APPENDIX A

July 2015

United States Electricity Industry Primer

Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy

DOE/OE-0017

ACKNOWLEDGMENTS

This report was prepared by the Office of Electricity Delivery and Energy Reliability under the direction of Patricia Hoffman, Assistant Secretary, and Devon Streit, Deputy Assistant Secretary.

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1 INDUSTRY OVERVIEW

The electric power industry is the backbone of America's economic sectors, generating the energy that empowers its people and businesses in global commerce. Transportation, water, emergency services, telecommunications, and manufacturing represent only a few of the power grid's critical downstream dependencies. Reliance on the electric grid is a key interdependency (and vulnerability) amongst all *Critical Infrastructure and Key Resource* (CIKR) sectors, plus supporting infrastructures, making grid reliability and resilience a fundamental need for national safety and security.

The United States has one of the world's most reliable, affordable, and increasingly clean electric systems, but it faces significant vulnerabilities with respect to physical threats from severe weather, terrorist attacks, and cyber threats. The popular transition to *smart*, data-driven technologies aims to increase power grid efficiency and engage customer reliability roles, but has been introduced at an unprecedented rate relative to the history of the industry, and injects uncertainty into grid operations, traditional regulatory structures, and utility business models—which have been successful over the past century and a half.

Electric power was first generated, sold, and distributed to urban customers in the 1870s and 1880s. Similar to modern-day *distributed generation*, electricity was generated locally in small power plants and distributed via direct current (DC) circuits, as opposed to the alternating current (AC) generation, transmission, and distribution systems used today. As with modern-day operations, several voltage levels were distributed depending upon the customer's needs.

As demand for power spread geographically over time, DC power systems struggled to expand due to high costs of construction and operation. A more robust, cost-efficient system was needed to generate, transmit, and distribute power over long distances to other urban and rural areas. Toward the end of the 19th century, the industry entered a transition with construction of the first large AC generation station at Niagara Falls—which marked the first technology capable of inducing AC power to be transmitted over long-distance circuits. The construction of larger AC power stations became the commercially-viable solution for the development of a robust, national power grid, and eventually outpaced modular DC power systems.

Today, the U.S. electricity sector is influenced by a variety of new forces that have the potential to affect future management and operation of the grid. Current drivers include the growing use of less expensive natural gas for power generation, the retirement of coal and fuel oil generation for carbon reduction, uncertainty in the long-term role for nuclear generation, rapid deployment of intermittent renewable energy technologies, evolution of load types and reduced load growth, severe weather, and growing jurisdictional interactions at Federal, State, and local levels.

The private sector, States, and Federal Government all play crucial roles in ensuring that electricity infrastructure is reliable, resilient, and secure. This document will provide a baseline for understanding important topics in each division of the electric power supply chain; examine vulnerabilities to the grid; discuss regulatory and ownership structures; and offer context for causes of power outages and response efforts during emergencies.

2 ELECTRICITY BASICS

Most Americans understand that electricity is sent from a power plant over power lines, but cannot describe specifically how it is generated or how its properties are manipulated in order to be delivered to customers. Electrical energy, including electrical potential, or circuit voltage, is actually neither created nor destroyed, but transformed from mechanical work at a power generating station. This occurs through electromagnetic induction, a process that was discovered by Michael Faraday in 1831. Faraday found that current and voltage in a circuit were spontaneously induced in the presence of a changing magnetic field. Modern electric generators utilize turbine engines to spin or rotate magnets around coils of conductive wiring to induce alternating currents and voltages capable of performing work over time, which is also known as power.

Electrical power is the instantaneous flow of electrical charges, or currents, which serve as the means to perform work. Currents are driven by an electromotive force, or voltage, which represents the driving potential for performing work. Contemplate the water wheel analogy: in the old days, waterwheels provided mechanical power from the potential energy in a flowing body of water, the river, or current in this case. In this imaginary circuit, the pressure of the flowing water drives the waterwheel; the fluid itself provides the weight, or force, used to perform mechanical work on the wheel. Together, mechanical power is generated from the repetitive forces exerted on the drive shaft from the rotating wheel. In an electric circuit, power is equal to the product of the voltage and current, or $P = IV$.

Figure 1: Basic Electricity Definitions

Basic Electricity Definitions

- **Current, *I*:** the flow rate of charge; measured in Amperes, *A*
- **Voltage, *V*:** the electromotive force, or electrical pressure applied to electrons, forcing flow of charge through the circuit, or path; measured in Volts, *V*
- **Energy, *E*:** stored work; measured in Joules, *J*
- **Power, *P*:** the rate at which energy changes form or location. It is the work performed, or energy conversion, in a unit of time; measured in Watts = Joules/second, *W*

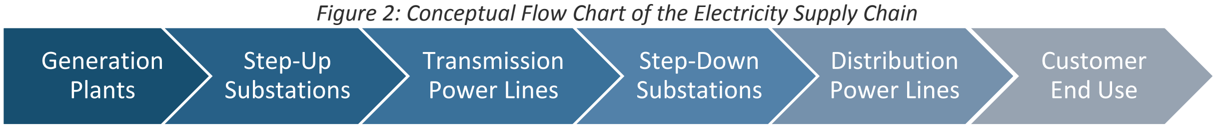
Source: U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability

Electrical power flow is instantaneous and finite. Commercially viable storage options do not currently exist. The flow of electricity is governed by electromagnetic properties of the materials that make up the electric grid. Circuits are constructed to establish a path for power to flow, and flow can be controlled in a system using protective elements such as fuses, breakers, relays, and capacitors. The following sections will dive deeper into the processes for delivering electricity, explore the regulatory and private entities that operate the grid and ensure its reliability, and examine vulnerabilities and response efforts that take place during energy emergencies.

3 Electricity Supply Chain

The structure of electricity delivery can be categorized into three functions: generation, transmission, and distribution, all of which are linked through key assets known as substations. Even though power infrastructure is highly redundant and resilient, customer outages do occur as a result of system disruptions.

Figure 2: Conceptual Flow Chart of the Electricity Supply Chain



3.1 Generation

Number, Capacity, and Fuel Mix

In 2014 there were 19,023 individual, commercial generators at 6,997 operational power plants in the United States. A power plant can have one or more generators, and some generators have the ability to use more than one type of fuel. Power supply in the United States is generated from a diverse fuel mix. In 2014, fossil fuels like coal, natural gas, and petroleum liquids accounted for 67 percent of U.S. electricity generation and 89 percent of installed capacity.

Figure 3: U.S. Power Generation by Fuel Type in 2014

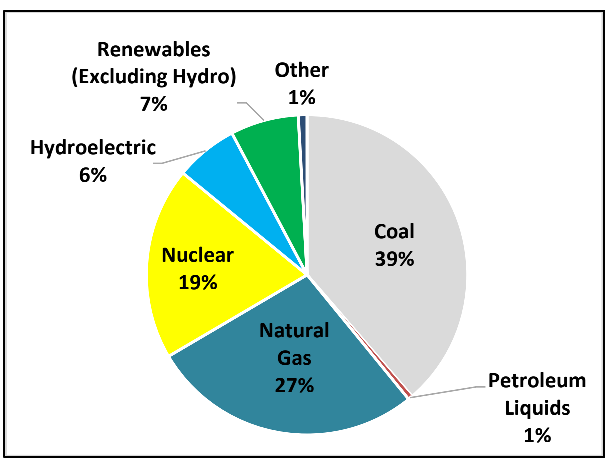
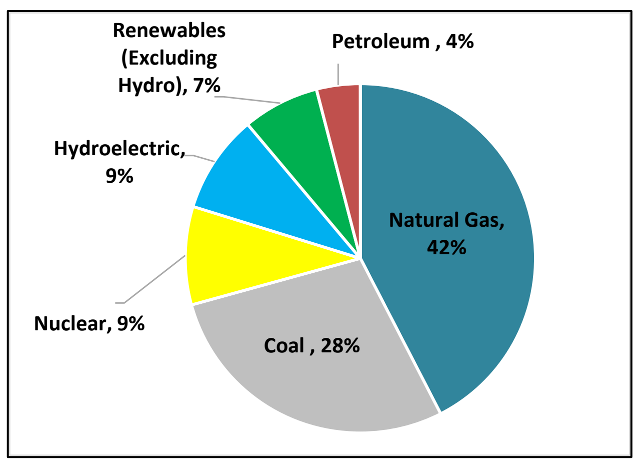


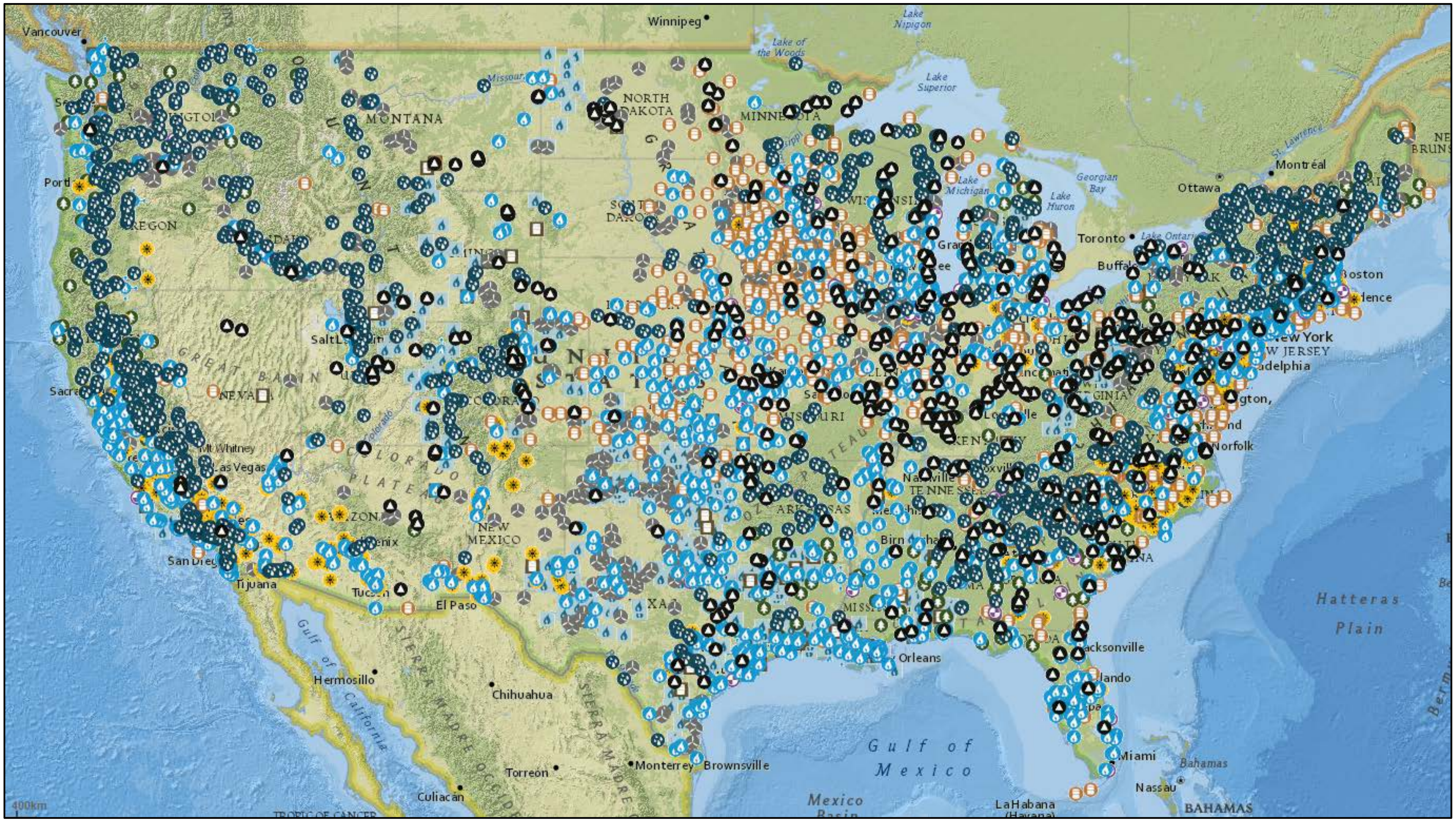
Figure 4: U.S. Generation Capacity in 2013



Sources: U.S. Department of Energy, Energy Information Administration (EIA)

Generation capacity also varies by State and can be dependent upon the availability of the fuel resource. Coal and gas power plants are more common in the Midwest and Southeast whereas the West Coast is dependent upon high-capacity hydroelectric power as well as gas-fired power plants. Power generation fuels also have a supply chain of their own. Coal, natural gas, uranium, and oil must all be extracted, processed into useable fuels, and delivered to the generation facility. Vast infrastructure networks of railroads, pipelines, waterways, highways, and processing plants support the delivery of these resources to generating facilities, and many rely on electric power to operate.

Figure 5: Geographic Distribution of U.S. Power Plants (More than 1 Megawatt)



Source: U.S. Department of Energy, Energy Information Administration (EIA)
Energy Mapping Tool
Data: http://www.eia.gov/maps/layer_info-m.cfm

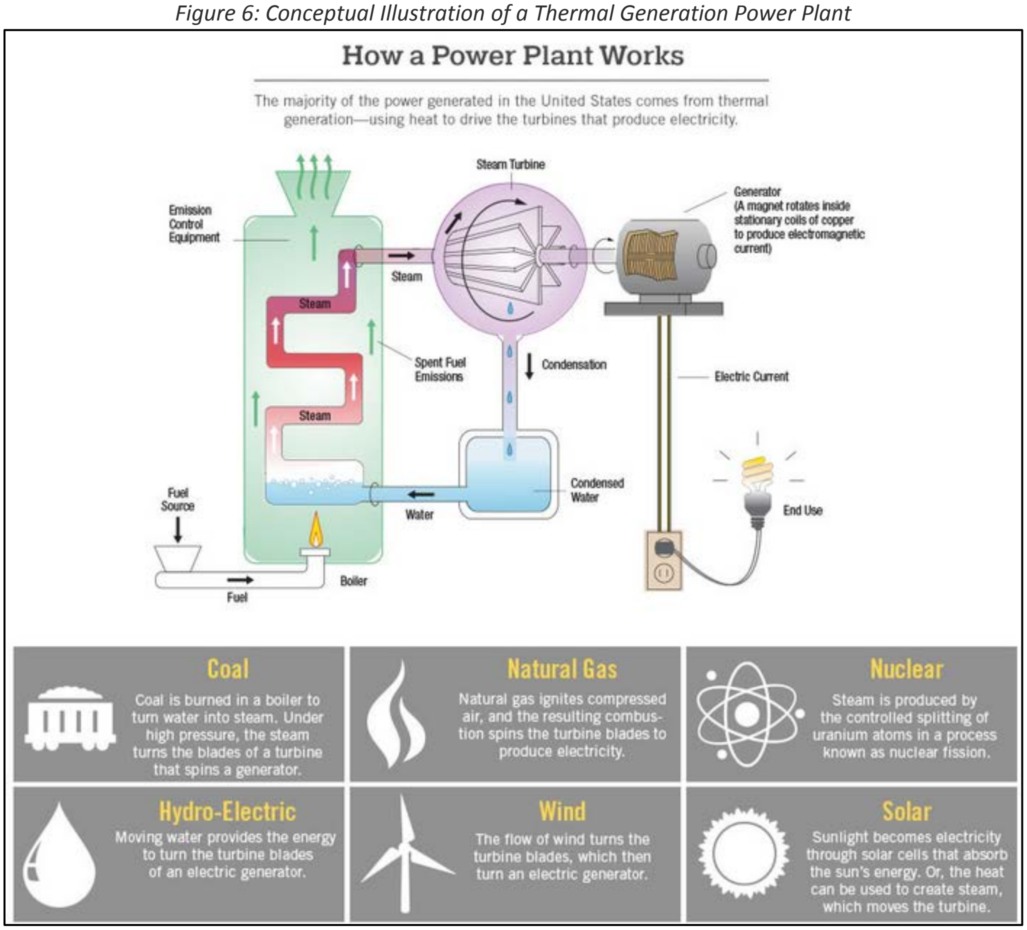
Coal Power Plant
Hydroelectric Power Plant
Natural Gas Power Plant
Nuclear Power Plant
Petroleum Power Plant
Solar Power Plant
Wind Power Plant
Wood Power Plant

How Does a Power Plant Work?

Electricity is a secondary power source harvested from the mechanical work that is exerted *from* a turbine *to* a coupled, rotary magnet that spins around copper coils within a generator. The purpose of the primary fuel's energy is to create mechanical power that can be transformed into electrical power. In the case of a three-phase AC generator, there are three windings that the magnets rotate around to induce three separate AC currents. The induced currents drive an electromotive force, and together produce power from the power plant. For more insight on alternating current and three-phase generators, refer to Appendix B.

The majority of turbine generators used are thermally driven by steam. In thermal generation, fuel is combusted to produce steam from which mechanical work is extracted as it releases energy through high-pressure condensation in a turbine. Coal, gas, nuclear, and petroleum power plants all utilize thermal power generation in combustion turbines. Sometimes these facilities also utilize waste heat to drive an additional turbine to increase the plant's thermal efficiency, known as combined cycle facilities. Thermally-reliant power plants are characterized by their thermal efficiency factor which compares the amount of energy produced to the amount that was consumed in the process. These factors typically range from 0.45 – 0.60, which becomes incorporated in the design of the plant.

Figure 6: Conceptual Illustration of a Thermal Generation Power Plant

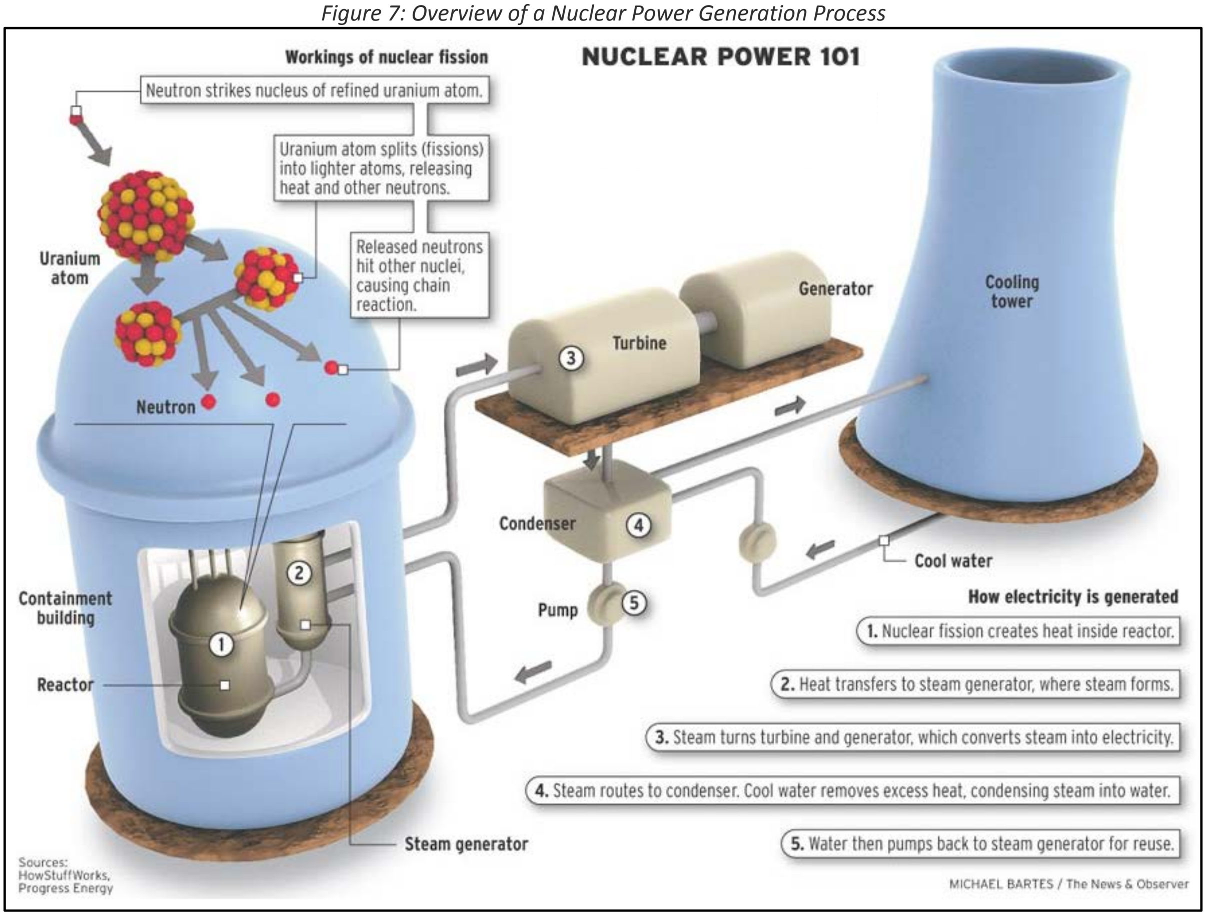


Source: Edison Electric Institute (EEI)

Nuclear Power Plants

Nuclear power plants are also thermally driven; however, the heating requirement for steam is not fossil-fuel reliant, but rather heated from the controlled splitting of uranium atoms in a process known as nuclear fission. As of January 2015, there were 99 operating commercial nuclear reactors at 61 nuclear power plants in the United States. The Fort Calhoun plant in Nebraska has one reactor with the smallest summer generating capacity of 502 megawatts (MW). The Palo Verde plant in Arizona has three reactors with the largest combined summer generating capacity of about 3,937 MW. For cost and technical reasons, nuclear power plants are generally used more intensively than coal or natural gas units. In 2014, 19 percent of national power output came from nuclear plants; however, national nuclear generation capacity was only 11 percent.

Figure 7: Overview of a Nuclear Power Generation Process



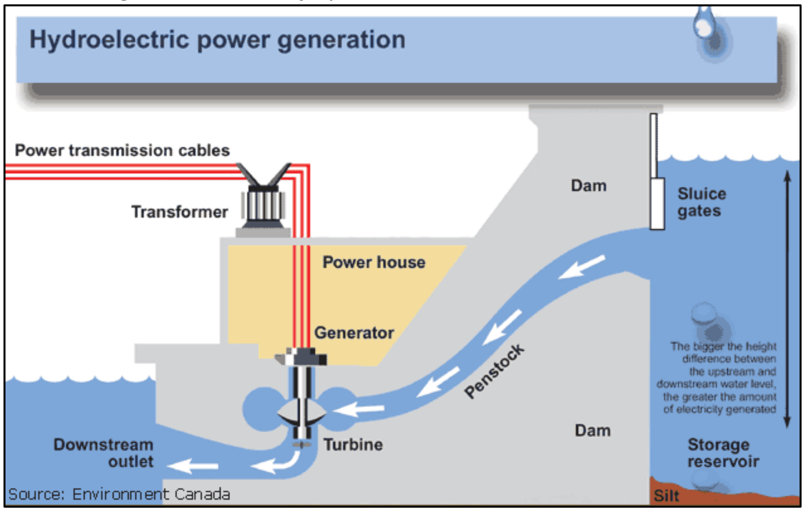
Sources: How Stuff Works / Progress Energy

Start up and shut down procedures for nuclear reactors are very lengthy as a result of the large magnitudes of energy involved in a nuclear reaction as well as the precautionary measures required when dealing with highly toxic sources of radiation. In an outage scenario, a nuclear power plant would either enter a “hot” or “cold” shutdown depending on the location of the problem. If the issue has impacted downstream units independent of the reactor (generator), the plant’s reactor may remain online in a hot condition, which is more favorable for efficiently restarting the plant. Cold shutdowns are executed if a problem has been detected within the reactor or to replace depleted fuel rods.

Other Power Plants

Hydroelectric power plants transform potential energy in an elevated storage reservoir using gravity and fluid dynamics to drive turbine shafts. Hydro plants also supply pumped storage in which the facility consumes pumping power to recharge the reservoir during non-peak, low-price hours, so that a larger supply is available at peak hours and prices.

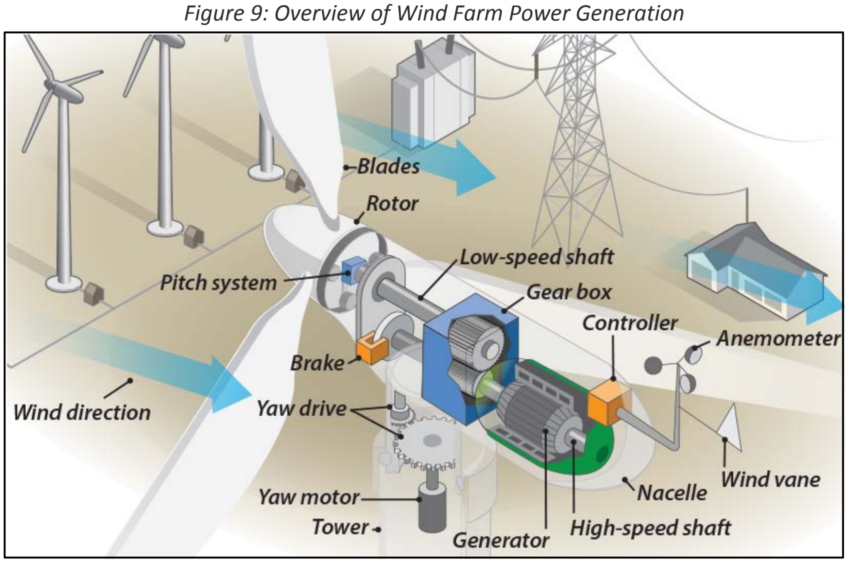
Figure 8: Overview of Hydroelectric Power Generation Process



Source: Environment Canada

Similarly, wind power utilizes natural wind currents to generate mechanical work. Solar photovoltaic technology[1] can convert radiation from the sun, as well as heat absorption into electrical current.

Figure 9: Overview of Wind Farm Power Generation



Source: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy

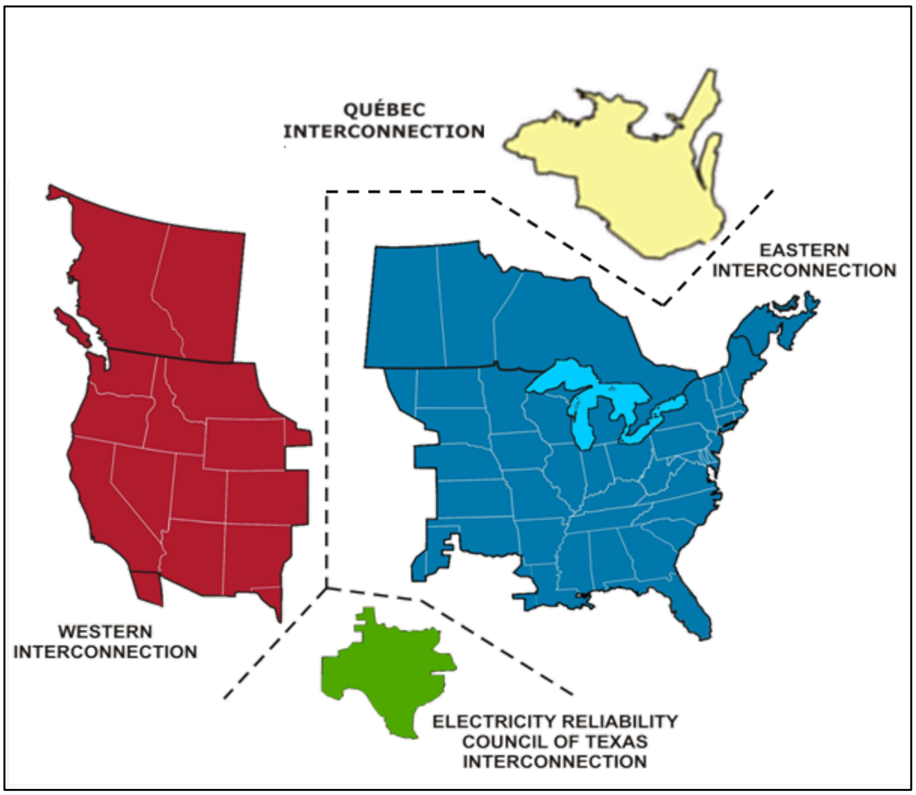
[1] Photovoltaic solar cells absorb light photons that positively ionize semiconductor materials to create free electric charges.

3.2 Transmission and the Grid

The Grid

The combined transmission and distribution network is known as the "power grid" or simply "the grid." North America's bulk power system actually comprises of four distinct power grids, also called interconnections. The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from the Great Plains to the Eastern Seaboard. The Western Interconnection includes the western one-third of the continental United States, the Canadian provinces of Alberta and British Columbia, and a portion of Baja California Norte in Mexico. The Texas Interconnection comprises most of the State of Texas, and the Canadian province of Quebec is the fourth North American interconnection. The grid systems in Hawaii and Alaska are not connected to the grids in the lower 48 states.

Figure 10: Map of Four North American Power Grid Interconnections



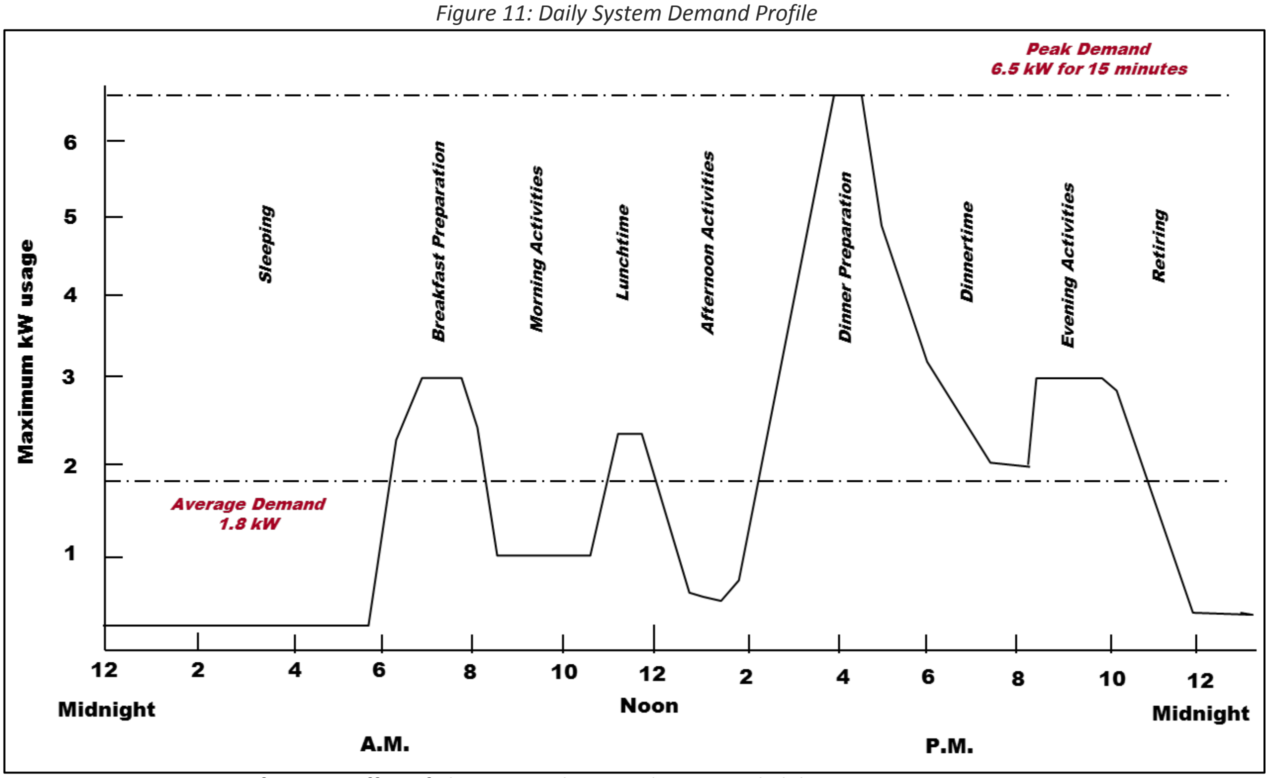
Source: North American Electric Reliability Corporation

Interconnections are zones in which utilities are electrically tied together during normal system conditions. Each interconnection operates independently of one another with the exception of a few direct current (DC) conversion links in between. Interconnections strive to operate at a synchronized average frequency of 60 Hertz, but can fall out of phase for a number of reasons. DC converter substations enable the synchronized transfer of power across interconnections regardless of the operating frequency as DC power is non-phase dependent. There are few converter substations in the United States.

Sending Power to the Grid

Power demand fluctuates throughout the day and across regions with varying population densities because utility-scale electricity storage does not exist. To keep the power grid balanced at all times, generation operators must dispatch enough power required to supply demand. Power dispatch is coordinated by the plant operator and a transmission system operator making communications critical at generation facilities. Figure 11 shows an example of a demand curve as it might occur over the course of a single day and is indicative to the level of human activity. Demand rises from off-peak hours in the early morning, approaching shoulder peaks during the work and school day. Priority peak occurs in the evening hours where peak load is reached. Because demand is hardly constant, generation must adjust accordingly. Base-loading power plants operate in off-peak hours to satisfy the minimum or base demands whereas peaking power plants gradually come online and provide power as demand approaches shoulder and peak loads. In order to rapidly accommodate fluctuating demand, natural gas-fired plants, which have faster start up times but typically higher fuel costs, are activated gradually for peaking demands. Coal and nuclear plants, which can take up to 12 or more hours to start, are most effective at satisfying base-load demands.

Figure 11: Daily System Demand Profile



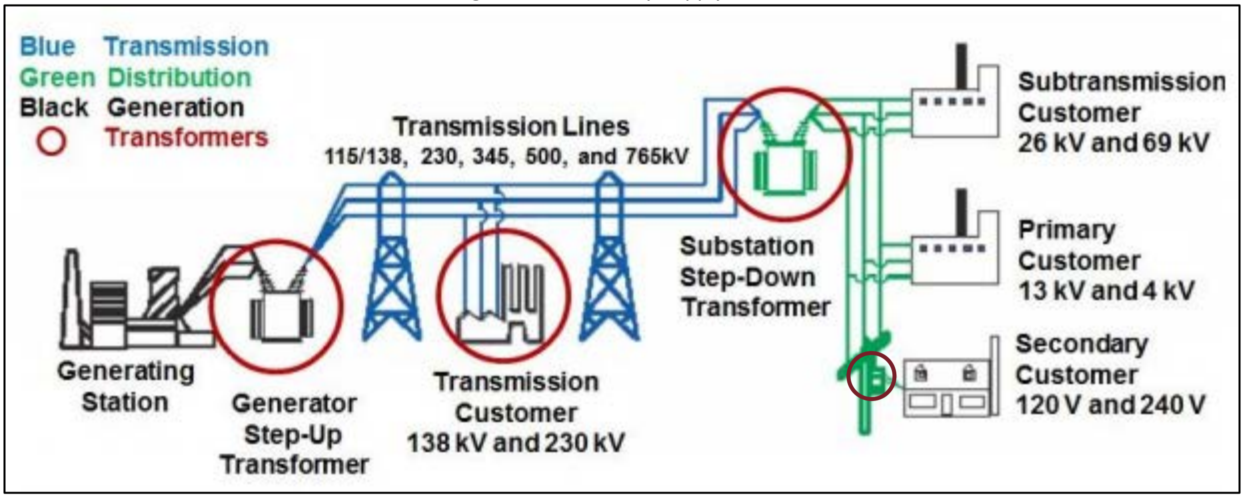
Source: U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability

Step-Up Transformers

Electricity is generally produced at 5 to 34.5 kilovolts (kV) and distributed at 15 to 34.5 kV, but transmitted at 69 to 765 kV. Because power plants are generally distant from demand centers, at constant power output, electricity cannot be transmitted over sizeable distances without meeting significant resistance and power loss; hence, a large driving force to efficiently transfer energy over long distances is required.

At a constant power rate, voltage and current are also proportional, meaning that an increase in voltage results from a reduction in current flow; thus, power plants utilize "step-up" transformers to drastically increase power generation voltage to the transmission system level. Transformers play several key roles in the supply chain, and are very technically complex. Facilities that house the equipment and conversion infrastructure are referred to as substations. The functionality and variations of substations and transformers will be addressed in more depth in subsequent sections.

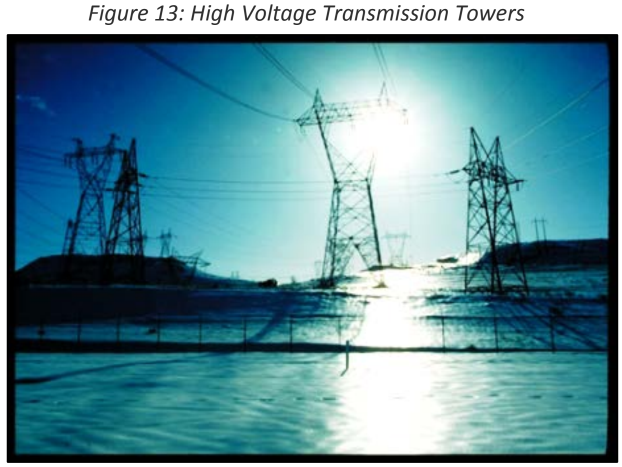
Figure 12: Electricity Supply Chain



Source: U.S. Federal Energy Regulatory Commission and U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability

Transmission

Figure 13: High Voltage Transmission Towers



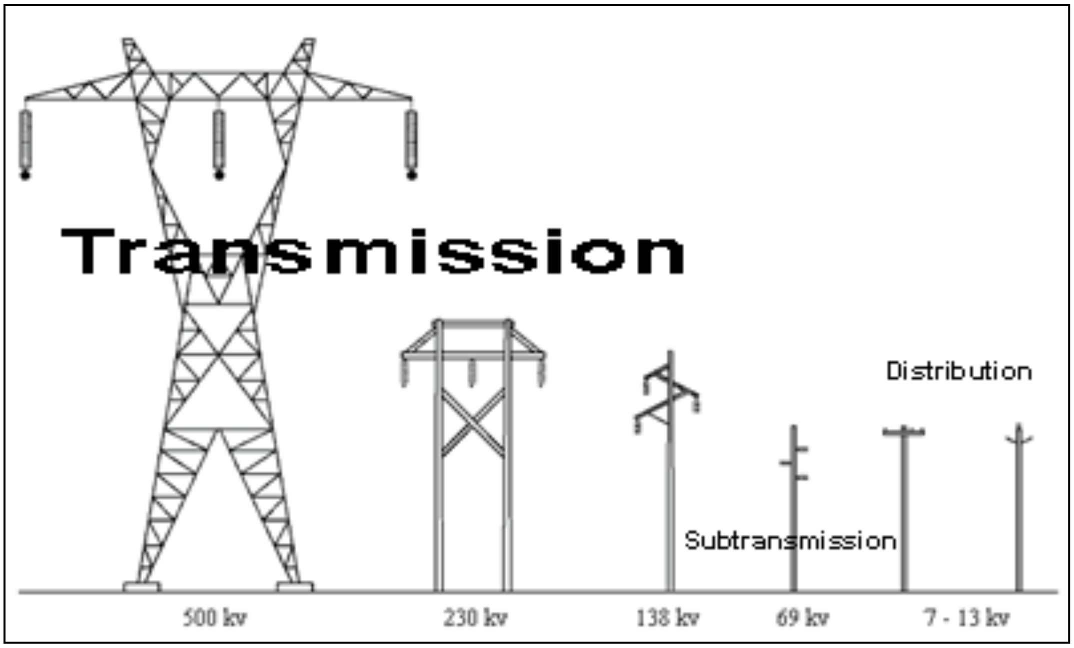
Source: U.S. Department of Energy

The United States' bulk electric system consists of more than 360,000 miles of transmission lines, including approximately 180,000 miles of high-voltage lines, connecting to about 7,000 power plants[2]. Power transmission lines facilitate the bulk transfer of electricity from a generating station to a local distribution network. These networks are designed to transport energy over long distances with minimal power losses which is made possible by boosting voltages at specific points along the electricity supply chain. The components of transmission lines consist of structural frames, conductor lines, cables, transformers, circuit breakers, switches, and substations. Transmission systems are generally administered on a regional basis by a regional transmission organization (RTO) or an independent system operator (ISO) which will be discussed in the Markets and Ownership Structures section.

[2] Source: North American Electric Reliability Corporation Electricity Supply & Demand Database, http://www.nerc.com/page.php?cid=4|38

Transmission lines that interconnect with each other to connect various regions and demand centers become transmission networks, and are distinct from local distribution lines. Typical transmission lines operate at 765, 500, 345, 230, and 138 kV; higher voltage classes require larger support structures and span lengths as shown in the following figure. Note how each structure has three line connections. A single-circuit transmission line consists of three conducting lines, one line for each phase in three-phase AC circuits.

Figure 14: Structural Variations of Transmission Towers



Source: U.S. Department of Labor, OSHA

Reactive Power in Transmission

Reactive power flow is required to stabilize electricity transfer from generating stations to load centers. The reactive power is the component of the apparent power that assists in maintaining voltage across transmission systems. Transmission voltage is stabilized by supplying the system with reactive power from generating stations and static capacitors built into transmission lines. Sources for reactive power must be located in close proximity to demand centers as flows are subject to significant resistance over transmission distance, and are consumed at load centers and on highly-utilized transmission lines. As transmission capacity utilization increases, more reactive power is consumed; thus, more is required to maintain system voltage. When the reactive power supply is limited, increased utilization will cause a voltage drop along the line. If reactive supply is not provided at the end of the line, the voltage could fall precipitously. At the point of voltage collapse, transmission systems can no longer transfer electric power from distant generation to energy users in load centers. Low-system voltage and reactive power flows were two contributing factors in the 2003 cascading Northeast blackout that affected 50 million people. For more information on reactive power, refer to Appendix B.

Substations

Substations not only provide crucial links for generation but also serve as key nodes for linking transmission and distribution networks to end-use customers. While a substation can provide a number of distinct system functions, most utilize transformers to adjust voltage along the supply chain. A substation may be designed initially for the purpose of bulk power transmission, but may also incorporate an additional transformer to distribute power locally at a lower voltage. Power lines are classified by their operational voltage levels, and transmission lines are designed to handle the higher voltage ranges in the following table. Transformer equipment at substations facilitate energy transfer over networks that operate at varying voltage levels.

Figure 15: Transmission Voltage Classes

Power Line Classification	Voltage Range [kV]	Purpose
Ultra High Voltage (UHV)	> 765	High Voltage Transmission > 765 kV
Extra High Voltage (EHV)	345, 500, 765	High Voltage Transmission
High Voltage (HV)	115, 138, 161, 230	
Medium Voltage (MV)	34, 46, 69	Subtransmission
Low Voltage (LV)	< 34	Distribution for residential or small commercial customers, and utilities

Source: U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability

A substation generally contains transformers, protective equipment (relays and circuit breakers), switches for controlling high-voltage connections, electronic instrumentation to monitor system performance and record data, and fire-fighting equipment in the event of an emergency. Some important functions that are carried out at substations are voltage control, monitoring the flow of electricity, monitoring reactive power flow, reactive power compensation, and improving power factors.

Listed below are frequently used terms for several types of substations in the bulk power system, along with a description and the function for each:

- **"Step-Up Substation":** Links a generation plant to the transmission system
  - Because AC power plants typically generate voltages below 35 kV, generator transformers provide the voltage "step-up" so that bulk power can be transmitted over long distances. Higher transmission voltage is analogous to increased pressure to deliver product through a pipeline. Generator substations are normally housed within the power plant, and act like a switch from the power plant to the grid.
- **"High Voltage Substation":** Connects high voltage transmission systems
  - Since high voltage transmission networks are highly redundant and facilitate power flow between systems of varying high-voltage levels, interconnecting transformers at transmission substations adjust voltages to network-specific levels.
- **"Step-Down Substation":** Connects a high-voltage transmission system to a sub-transmission system
  - For shorter power transmission distances from the main high-voltage transmission network, it can be economic to transmit on a subtransmission network at a voltage level in between standard transmission and distribution voltages. Larger substation transformers are more expensive to manufacture and operate.

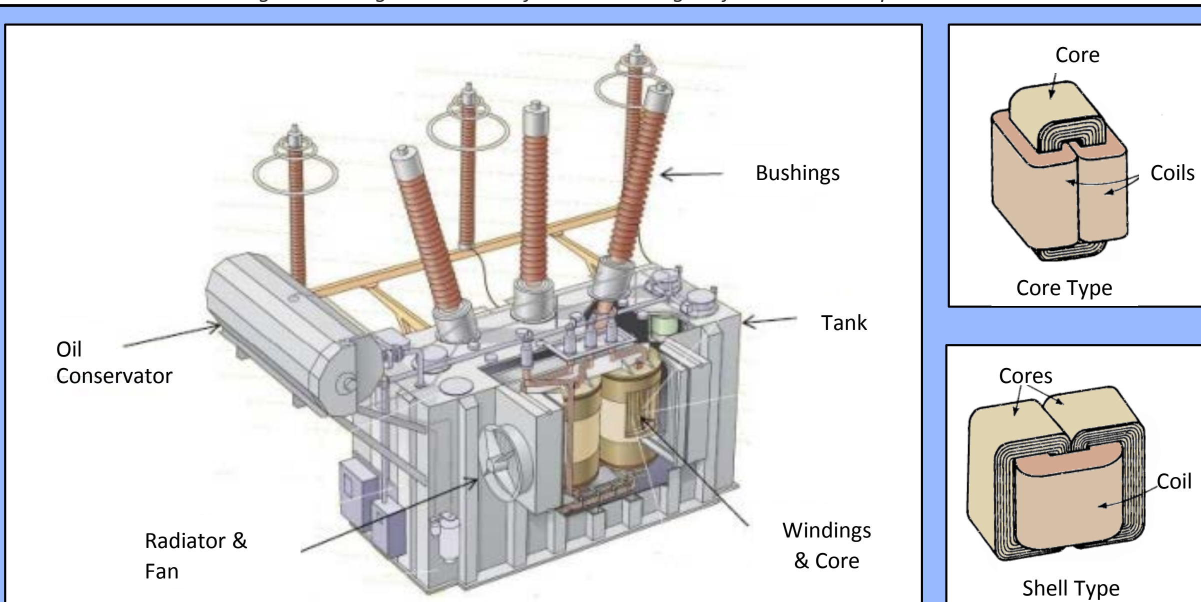
- **"Distribution Substation":** Connects transmission or subtransmission network to medium voltage distribution networks.
    - Once power has reached a load center, a "step-down" distribution substation reduces voltage to medium ranges for major distribution networks.
- **"Distribution Transformer":** Connects the medium voltage distribution system to end use customers
    - Because the voltage in major distribution lines is medium range, smaller, modular distribution transformers step voltage down to low utilization levels required by neighborhoods and commercial centers. Smaller distribution transformers are the cylindrical devices mounted on local distribution lines or mounted on a concrete pad in a neighborhood. Underground local distribution transformers are also common. These are typically not referred to as "substation" because they are modular and lack most of the equipment found in a large, high voltage substation.
- **"Converter Substation":** Connects non-synchronous AC transmission networks through high voltage direct current transmission (HVDC), or connects a HVDC transmission line to an AC transmission network.
    - High-voltage direct current substations are used to link AC power grids that are not operating at the same frequencies. The four major North American power grid interconnections, which will be discussed subsequently, are connected via HVDC transmission lines and substations. HVDC substations are also used to link HVDC transmission lines that are sometimes more economical than AC transmission over significantly long distances, or in the case of a submarine transmission system.
- **"Switching Substation":** Acts as a circuit breaker in transmission and distribution networks
    - These are the substations meant for switching purposes only and do not have transformer equipment. Switching substations are meant for disconnecting and connecting a part of the network and facilitating maintenance work.

Transformers

Transformers are critical equipment in delivering electricity to customers, but many are located in isolated areas and are vulnerable to weather events, acts of terrorism, and sabotage. The loss of transformers at substations represents a significant concern for energy security in the electricity supply chain due to shortages in inventory and manufacturing materials, increased global demand in grid-developing countries, and limited domestic manufacturing capabilities. Substations are highly specific to the systems they serve, which also limits the interchangeability of transformers. Replacing a transformer is associated with a long delivery lead time as they are generally difficult to transport due to their size and weight, and larger more sophisticated models are manufactured abroad. Failure of even a single unit could result in temporary service interruption.

Although power transformers come in a wide variety of sizes and configurations, they consist of two main components: the core; made of high-permeability, grain-oriented, silicon electrical steel, layered in pieces; and windings; made of copper conductors wound around the core, providing electrical input and output. Two basic configurations of core and windings exist, the core form and the shell form. In the usual shell-type power transformer, both primary and secondary windings are on one leg and are surrounded by the core; whereas, in a core-type power transformer, cylindrical windings cover the core legs. Shell form transformers typically use more electrical steel for the core and are more resilient to short-circuit in the transmission systems and are frequently used in industrial applications. The core and windings are contained in a rectangular, mechanical frame known as the tank. Other parts include bushings, which connect to transmission lines, as well as tap changers, power cable connectors, gas-operated relays, thermometers, relief devices, dehydrating breathers, oil level indicators, and other controls.

Figure 16: Large Power Transformer Detailing Major Internal Components



Component	Function
Core	Provides a path for magnetic flux.
Primary Winding	Receives electricity from the AC source.
Secondary Winding	Receives electricity from the primary winding and delivers it to the load.
Tank	Provides enclosure and protects internal components from dirt, moisture, and mechanical damage.
Radiator and Fan	Provides air flow and cooling system for internal equipment to regulate operational temperatures.
Oil Conservator	Provides sufficient storage for insulation oil which can increase in volume at high temperatures.
Bushings	Insulation device to allow safe connection of transmission wires into the tank enclosure of the transformer.

Sources: ABB and http://www.vias.org/matsch_capmag/img/matsch_caps_magnetics-787.png

Transformers and their components are unique due to their specificity in design and application, the availability of required materials and associated costs, and the timeline required for complete implementation. The startup of any large power transformer takes around 2 years and requires contract procurement, design, manufacturing, testing, delivery, and installation as illustrated in Figure 17. It is important to recognize that in the real world, delays in any of the steps could result in significant lengthening of the initial estimated lead time.

Figure 17: 2011 Large Power Transformer Procurement Process and Estimated Optimal Lead Time

Source: U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability

Pricewise, transformer labor costs and material prices vary by manufacturer, by market condition, and by location of the manufacturing facility. In 2010, the approximate cost of a large power transformer with a megavolt-ampere MVA[3] rating between 75 MVA and 500 MVA was estimated to range from $2 to $7.5 million in the United States; however, estimates were "Free on Board" factory costs, exclusive of transportation, installation, and other associated expenses, which generally add 25 to 30 percent to the total cost. Figure 18 shows characteristics and estimated costs for larger power transformers based upon 2011 data.

Figure 18: Estimated Characteristics of Large Power Transformers in 2011

Voltage Rating (Primary-Secondary)	Capability MVA Rating	Approximate Price ($)	Approximate Weight & Dimensions
Transmission Transformer			
Three Phase			
230–115kV	300	$2,000,000	170 tons (340,000 lb) 21ft W–27ft L–25ft H
345–138kV	500	$4,000,000	335 tons (670,000 lb) 45ft W–25ft L–30ft H
765–138kV	750	$7,500,000	410 tons (820,000 lb) 56ft W–40ft L–45ft H
Single Phase			
765–345kV	500	$4,500,000	235 tons (470,000 lb) 40ft W–30ft L–40ft H
Generator Step-Up Transformer			
Three Phase			
115–13.8kV	75	$1,000,000	110 tons (220,000 lb) 16ft W–25ft L–20ft H
345—13.8kV	300	$2,500,000	185 tons (370,000 lb) 21ft W–40ft L–27ft H
Single Phase			
345–22kV	300	$3,000,000	225 tons (450,000 lb) 35ft W–20ft L–30ft H
765–26kV	500	$5,000,000	325 tons (650,000 lb) 33ft W–25ft L–40ft H

Source: U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability

[3] MVA, or megavolt-ampere represent the power rating, or range required to support voltage ratings of various transformers.

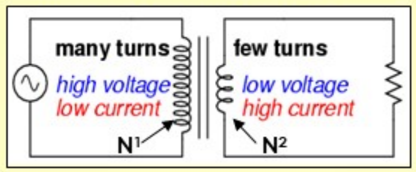
Fact Box

Substation Transformers

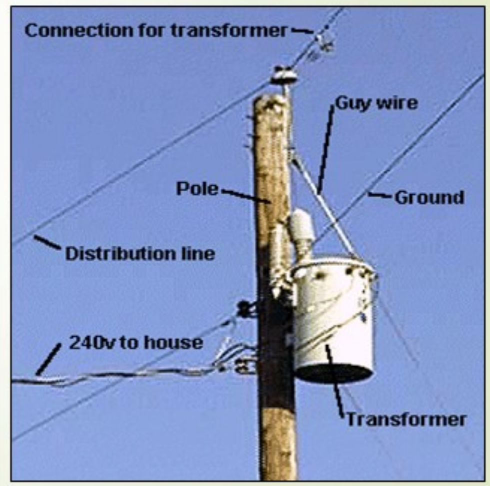
U.S. Department of Energy
Office of Electricity Delivery
and Energy Reliability

- Transformers harness electromagnetic properties of electrical energy to convert voltage levels in the transmission system, enabling safe, efficient delivery of electricity
- Consists of two conductive coils arranged so that the magnetic field of one coil influences the other
- Voltage conversion factor known as the "turns" ratio: the number of turns in the primary coil (N^1) to the number of turns in the secondary coil (N^2)

Step Down Circuit Diagram



Turns Ratio: $N^1 > N^2$ for a Step-Down Transformer. Voltage reduction proportional to the factor of N^2/N^1 .



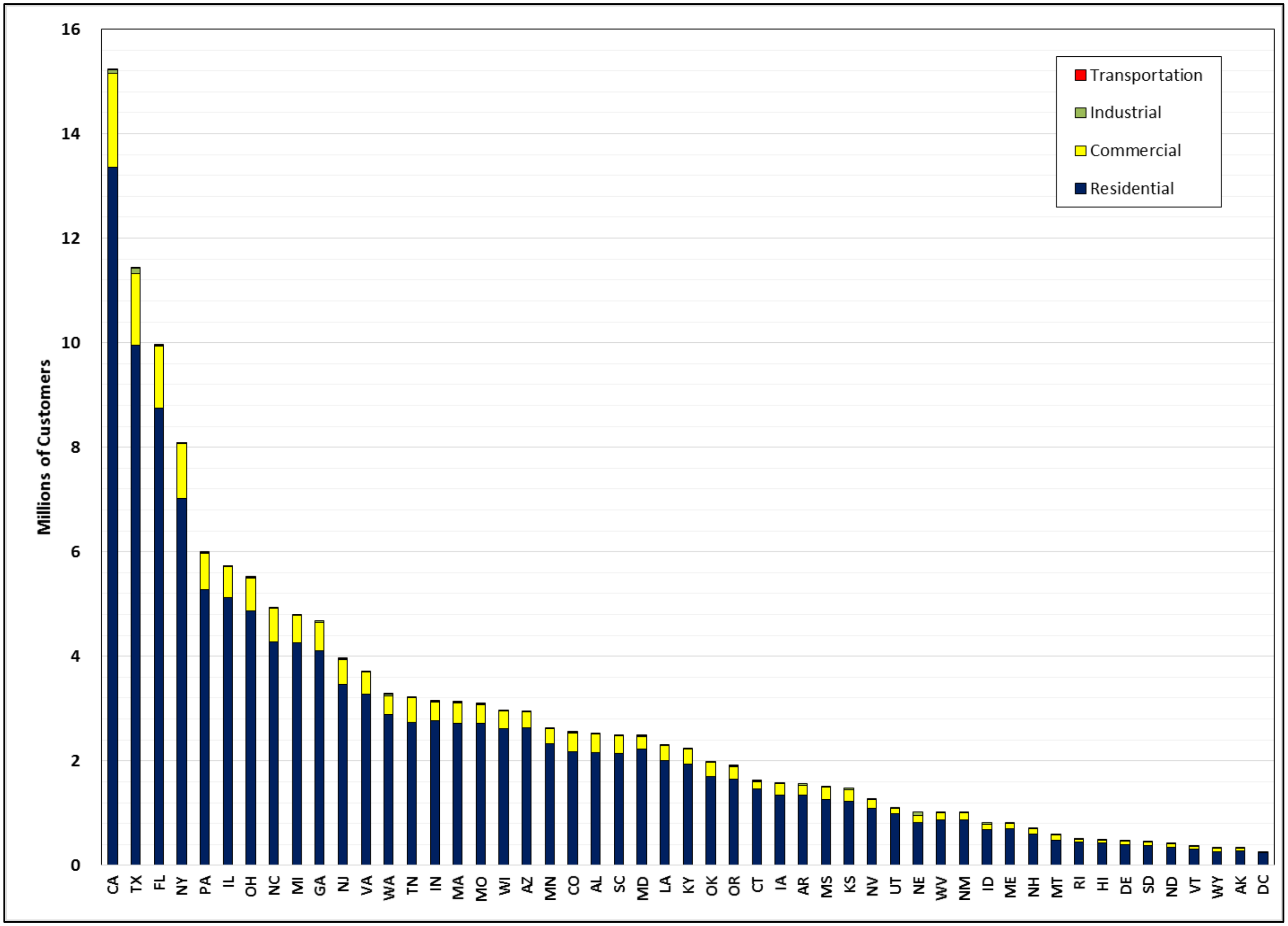
(Above) This distribution transformer's job is to reduce the 4,160 distribution voltage down to the 240 utilization voltage normal for household electrical service.

<u>Supply Chain Vulnerabilies</u>

- Many substations are located in isolated areas and are vulnerable to damage
- Limited interchangeability due to differing specifications
- Long delivery lead times; large models are difficult to transport
- Some only manufactured abroad.

Sources: U.S. Department of Labor, OSHA; http://www.miningmayhem.com/2009/05/transformer-into-river.html; and http://www.ibiblio.org/kuphaldt/electricCircuits/AC/AC_9.html

Figure 19: State-Level Distribution of Electric Customers in 2013

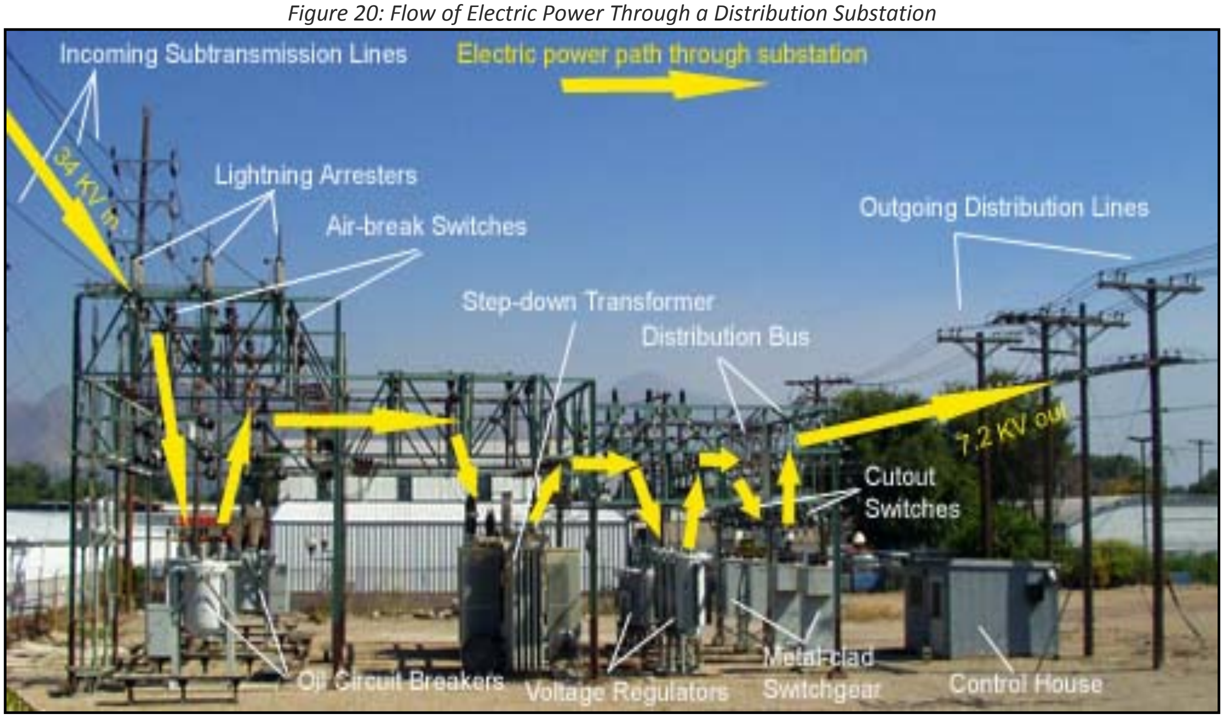


Source: U.S. Energy Information Administration, EIA

3.3 DISTRIBUTION

The power distribution system is the final stage in the delivery of electric power, carrying electricity out of the transmission system to individual customers. Distribution systems can link directly into high-voltage transmission networks, or be fed by subtransmission networks. Distribution substations reduce high voltages to medium-range voltages and route low voltages over distribution power lines to commercial and residential customers.

Figure 20: Flow of Electric Power Through a Distribution Substation



Source: U.S. Department of Labor, OSHA

The figure above illustrates the flow of electricity through a distribution substation. The incoming 34 kV subtransmission lines first pass through a series of protective equipment before entering the transformer. Lightning arresters are designed to attract power surges from lightning strikes safely to ground, away from the voltage reduction equipment. Switches, circuit breakers, and voltage regulators assist in controlling and routing high voltage connections through the transformer to the distribution bus where the outgoing distribution lines connect to the substation. Although not shown above, substations can have multiple transformers and distribution buses to route power through multiple low-voltage networks. The substation above reduces transmission voltage from 34 kV to the 7.2 kV distribution level. Primary distribution circuits, also known as express feeders or distribution main feeders, carry medium-range voltage to additional distribution transformers that are located in closer proximity to load areas. Distribution transformers are the cylindrical devices mounted on local power lines or on a concrete pad in a neighborhood. Underground local distribution transformers are also common. Distribution transformers further reduce the voltage to utilization levels and feed power to secondary circuits where residential and commercial customers receive power off a service drop through a metering socket.

Figure 21: Diagram of Transmission and Distribution Networks

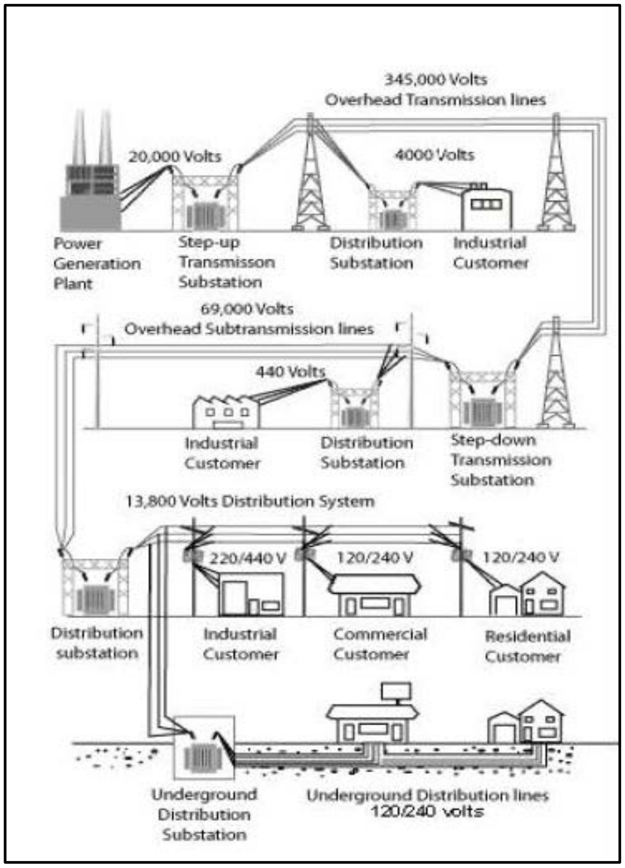
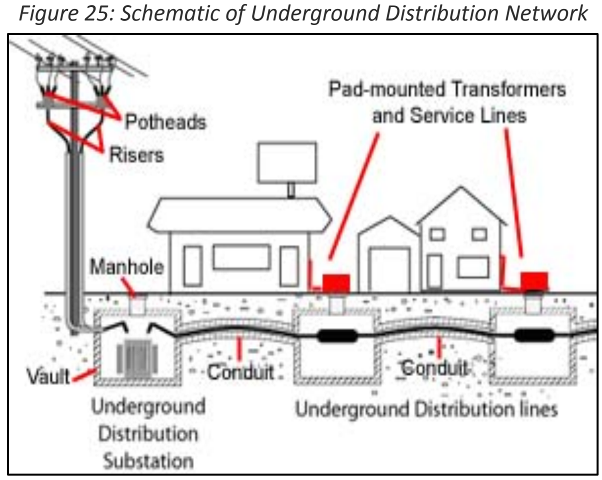


Figure 22: Service Drop for an Industrial Facility

Figure 23: Household Service Line Drop from Distribution Line

Figure 24: Pad-Mounted Distribution Transformer

Figure 25: Schematic of Underground Distribution Network

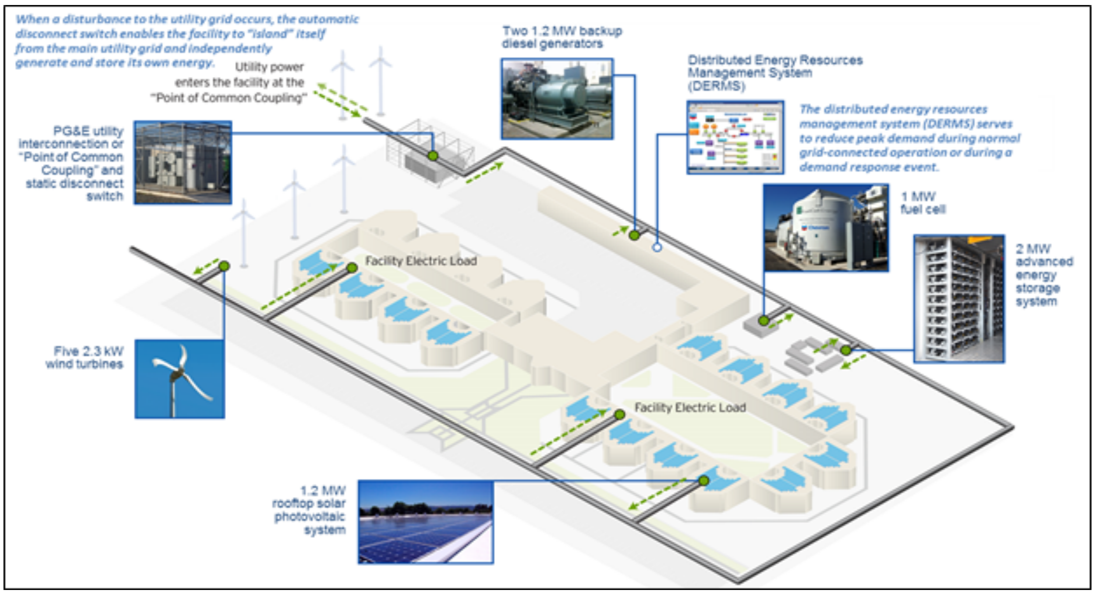


Sources for Above Figures: U.S. Department of Labor, OSHA

Distributed Energy Resources

Unlike power generation plants that require an interconnection to the transmission network, distributed energy resources position modular generation capacity downstream from the transmission network, allowing generation flexibility and supplemental power supplies located closer to load centers. A group of localized distributed generation is known as a microgrid and can function independently of the power grid in the event of an outage.

Figure 26: Commercial Microgrid Application at Santa Rita Jail in California



Source: County of Alameda, California; http://www.acgov.org/pdf/SRJMicrogrid.pdf

The commercial microgrid demonstration project shown in Figure 26 illustrates a viable approach to utilize and integrate renewable and clean distributed energy resources to accommodate local loads. The objectives of this project were to reduce the peak load of utility-supplied power and to provide energy surety to 100 percent of the jail's load. The entire 12 kV distribution system downstream from Pacific Gas and Electric Company's (PG&E) interconnection will be kept energized in the event of a utility outage. In the event of a microgrid failure, the existing emergency backup generation system will be used to provide the second layer of outage protection, in conjunction with the established load shedding criteria.

4 Markets and Ownership Structures

4.1 Overview

Before discussing various markets within the U.S. electricity sector, it is important to define some of the major players and regions that make up the industry. The first few sections that follow will provide an overview of major regulatory bodies, regional organizations, and utilities and their ownership structures. Later in this section, the various markets within the electric industry will be described.

4.2 FERC

The Federal Energy Regulatory Commission (FERC) is an independent agency within the U.S. Department of Energy that regulates the interstate transmission of electricity (as well as natural gas and oil) within the United States. FERC also regulates natural gas and hydropower projects. Within the electricity sector, FERC:

- Regulates the transmission and wholesale sales of electricity in interstate commerce.
- Reviews certain mergers and acquisitions and corporate transactions by electricity companies.
- Reviews the siting application for electric transmission projects under limited circumstance.
- Licenses and inspects private, municipal, and State hydroelectric projects.
- Protects the reliability of the high voltage interstate transmission system through mandatory reliability standards.
- Monitors and investigates energy markets.
- Enforces FERC regulatory requirements through imposition of civil penalties and other means.
- Oversees environmental matters related to hydroelectricity projects.
- Administers accounting and financial reporting regulations and conduct of regulated companies.

The Energy Policy Act of 2005 expanded FERC's authority to enforce regulations concerning the reliable availability of energy resources. FERC is entrusted with assisting consumers in obtaining reliable, efficient, and sustainable energy services at a reasonable cost through appropriate regulatory and market means by: (1) ensuring that rates, terms and conditions are just, reasonable and not unduly discriminatory or preferential; (2) promoting the development of safe, reliable and efficient energy infrastructure that serves the public interest; and (3) achieving organizational excellence by utilizing resources effectively, adequately equipping FERC employees for success, and executing responsive and transparent processes that strengthen public trust.

To maintain FERC's independence as a regulatory agency capable of providing fair and unbiased decisions, neither the President of the United States nor Congress reviews the decisions of FERC. FERC decisions are only reviewable by the Federal courts.

It is important to note that FERC does not regulate retail electricity sales to retail customers, approve the construction of electric generation assets, regulate the activities of nuclear power plants, assess reliability problems related to distribution facilities, or monitor utility vegetation control residential areas.

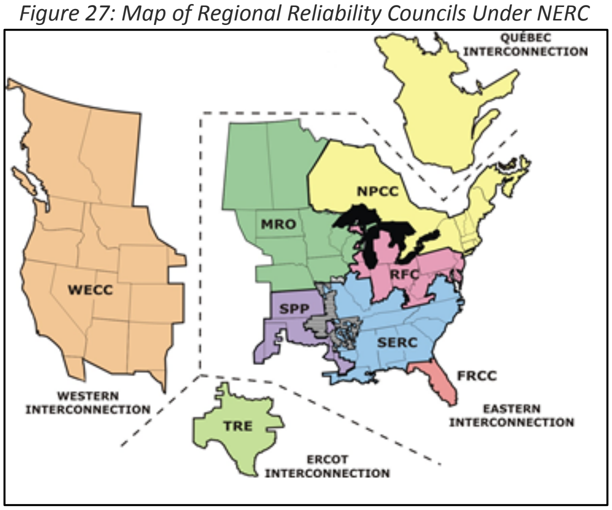
4.3 NERC

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose objective is to ensure the reliability of the bulk power system in North America. In 2006, FERC designated NERC as the government's electrical reliability organization (ERO), thereby granting NERC the power to oversee and regulate the electrical market according to certain reliability standards. Although NERC is the organization that audits power companies and levies fines for non-compliance, the authority behind NERC's decisions comes from FERC. Several of NERC's responsibilities include:

- Developing and enforcing reliability standards
- Annually assessing seasonal and long-term reliability
- Monitoring the bulk power system through system awareness
- Educating, training, and certifying industry personnel.

NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico made up of regional reliability coordinators. NERC has jurisdiction over electric users, owners, and operators of the bulk power system. In the United States, FERC oversees the operations of NERC as an ERO.

Figure 27: Map of Regional Reliability Councils Under NERC



Source: NERC

4.4 ISOs/RTOs

Within the three main interconnections in the United States lie regional entities called regional transmission organizations (RTOs) and independent system operators (ISOs). The formation of ISOs and RTOs comes at the direction or recommendation of the Federal Energy Regulatory Commission (FERC). The role of ISOs and RTOs are similar and may be confusing. Comparable to an RTO, ISOs either do not meet the minimum requirements specified by FERC to hold the designation of RTO or have not petitioned FERC for that status. In short, an ISO operates the region's electricity grid, administers the region's wholesale electricity markets, and provides reliability planning for the region's bulk electricity system. RTO's perform the same functions as the ISOs, but have greater responsibility for the transmission network as established by the FERC. The RTOs coordinate, control, and monitor the operation of the electric power system within their territory. They also monitor the operation of the region's transmission network by providing fair transmission access. ISOs/RTOs engage in regional planning to make sure the needs of the system are met with the appropriate infrastructure. Before ISOs/RTOs were developed, individual utilities were responsible for coordinating and developing transmission plans. Utilities in areas where there is no RTO or ISO continue to serve this function. As can be seen from the map below, there are large sections of the United States, particularly in the Southeast and the West, where there is no ISO or RTO. Electric utilities in these areas, however, are still subject to the same rules under FERC. The Electric Reliability Council of Texas (ERCOT) does not fall under interstate FERC authorities over interstate transmission and wholesale markets, but is still subject to NERC oversight and FERC regulation for reliability.

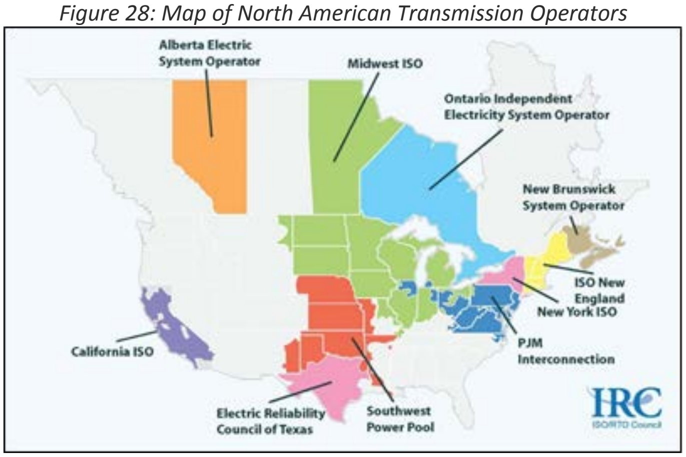
There are currently seven ISOs within North America[4]:

- CAISO—California ISO
- NYISO—New York ISO
- ERCOT—Electric Reliability Council of Texas; also a Regional Reliability Council
- MISO—Midcontinent Independent System Operator
- ISO-NE—ISO New England
- AESO—Alberta Electric System Operator
- IESO—Independent Electricity System Operator

There are currently 4 RTOs within North America[5]:

- PJM—PJM Interconnection
- MISO—Midcontinent Independent System Operator; also an RTO
- SPP—Southwest Power Pool; also a Regional Reliability Council
- ISONE—ISO New England; also an RTO

Figure 28: Map of North American Transmission Operators



Source: IRC ISO/RTO Council

[4] http://www.ferc.gov/industries/electric/indus-act/rto.asp
[5] http://www.ferc.gov/industries/electric/indus-act/rto.asp

4.5 State Regulatory Agencies

The role of State regulatory bodies in the electricity sector can vary significantly by State. There are numerous State agencies that regulate the electric industry. The list below describes the function of each as they are related to electricity.

1. **State Public Service Commission:** Names of these entities can vary by State, such as Public Utilities Commission or Corporation Commission. State commissions regulate what are fair and reasonable rates for electric service under their jurisdiction. Commissions adopt and enforce regulations that protect the public's safety and interests, study the economic and environmental impact of utility operations, ensure the safe and reliable service of electricity to customers, and in some cases, mediate disputes between the utility and its customers. Commissions are also charged with electric system reliability. They oversee utility plans for vegetation management, facility inspections, and maintenance of assets.
2. **State Department of Environmental Protection:** Names of these entities can also vary by State. Some States have a Department of Environmental Quality, which serves a similar purpose. The basic role of these organizations is to regulate the State's air, land, and water resources. These departments provide air permits for the construction of pollutant emitting assets, ensure public safety by cleaning contaminated sites, and monitor emissions by companies.

4.6 Utilities

A utility is a power company that generates, transmits, and distributes electricity for sale to customers. Not all utilities, however, must provide all three functions. There are more than 3,200 electric utilities in the United States, serving over 145 million customers.[6] The following section describes the various types of electric utilities in the Nation:

- **Investor-Owned Utilities (IOUs)** are for-profit companies owned by their shareholders. These utilities may have service territories in one or more States. State commissions will grant IOUs the license to operate in specific areas of the State under certain terms and conditions. Their interstate generation, transmission, and power sales are regulated by FERC and their distribution system and retail sales are regulated by State commissions.
- **Public Power Utilities (also known as "Municipals" or "Munis")** are not-for-profit utilities owned by cities and counties. City-owned utilities are referred to as municipal utilities (munis). Universities and military bases can own and operate their own utilities. These are generally not regulated by FERC or by States, but by their own local government.
- **Cooperatives (Co-Ops)** are not-for-profit entities owned by their members. They must have democratic governance and operate at cost. Members vote for representatives to the co-op's Board of Directors who oversee operations. Any revenue in excess of costs must be returned to members. Co-ops also tend to serve in rural areas that were not historically served by other utilities.

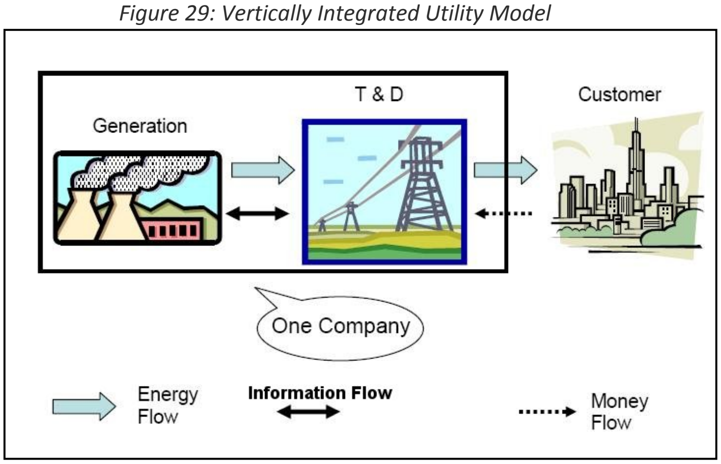
[6] Energy Information Administration Forms EIA-861

- **Federal Power Programs** include the Bonneville Power Administration (BPA), the Tennessee Valley Authority (TVA), the Southeastern Power Administration (SWPA), the Southeastern Power Administration (SEPA), and the Western Area Power Administration (WAPA). These wholesale-only entities provide a range of electric service functions to other utilities (mostly to munis) for distribution to end users. TVA is an independent, Government-owned corporation, but should not be confused with BPA and WAPA, also known as Power Marketing Administrations (PMAs). BPA and TVA own both generation and transmission facilities. WAPA is a transmission-only utility providing power from Federal hydroelectric facilities in the West to other retail utilities. PMAs are explained in more detail in the fact box on the next page.
- **Independent Power Producers**, or sometimes called a non-utility generator, are privately-owned businesses that own and operate their own generation assets and sell power to other utilities or directly to end users.

Vertically Integrated Utility Model

The sale and delivery of electricity can occur in two ways: the traditional, regulated, vertically integrated model and a more competitive approach that uses electricity as a tradable commodity. In a vertically integrated model, utilities are responsible for generation, transmission, and distribution of electricity in a specific geographical area. They may own all or have shares in power plants and transmission lines, or purchase power through contracts with other electricity producers. The price the customer pays in a vertical model is based on costs to serve over a period of time. These costs are monitored by State regulatory commissions and are adjusted in rate cases. The following diagram provides an overview of how a vertically integrated model is structured.

Figure 29: Vertically Integrated Utility Model



Source: National Programme on Technology Enhanced Learning

4.7 WHOLESALE ELECTRICITY MARKETS

Electricity can also be bought and sold in what is known as a wholesale market. The wholesale electricity market is where producers of electricity offer their electricity output to load serving entities (LSEs) and power marketers who sell to LSEs and other marketers. With the exception of ERCOT, sales of wholesale power are regulated by FERC. ISOs and RTOs administer wholesale power markets. They dispatch the system in accordance with their respective market rules employing some form of economic dispatch algorithm, and can provide market monitoring oversite. Both ISOs and RTOs provide open access to transmission and to ancillary services such as reserves and voltage support.

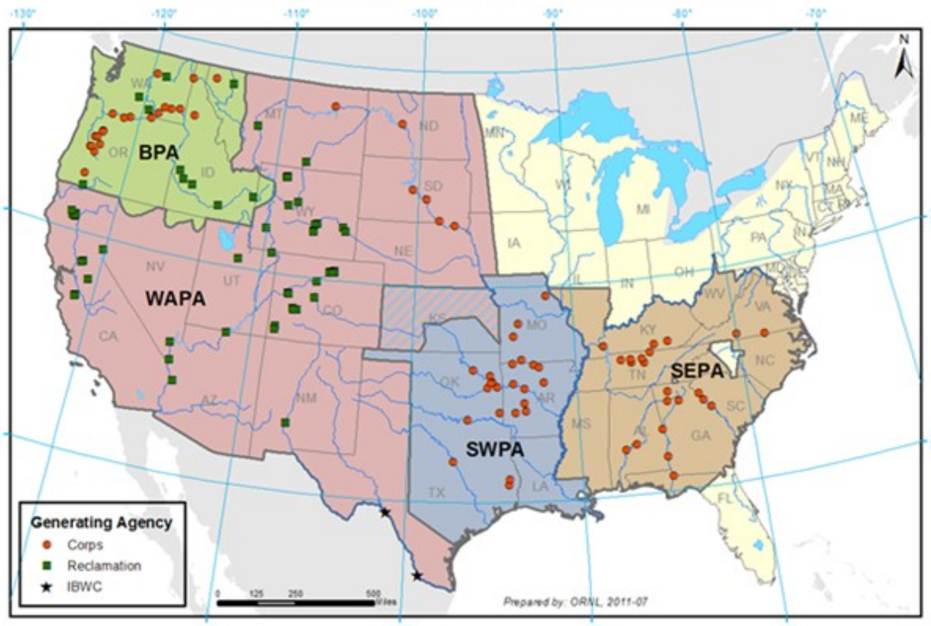
Fact Box

Power Market Administrations

**U.S. Department of Energy
Office of Electricity Delivery
and Energy Reliability**

- Four federal Power Marketing Administrations (PMAs) operate electric systems and sell the electrical output of federally owned and operated hydroelectric dams in 33 states. The Bonneville Power Administration (BPA), the Western Area Power Administration (WAPA), the Southeastern Power Administration (SEPA), and the Southwestern Power Administration (SWPA) marketed 42% of the nation's hydroelectricity in 2012, representing 7% of total generation in the United States. There is minor overlap in territories, but generally, the territories are self-contained. The U.S. Army Corp of Engineers and the Department of Interior's Bureau of Reclamation also own and operate hydroelectric facilities within these regions.
- The purpose of a PMA is to market wholesale power. In most cases, PMAs do not own their own electric generation plants. They market the electricity that is generated by plants and acts as a balancing authority (ensures electricity supply matches electricity demand at all times).
- PMAs also have a role in the transmission system as both transmission owners and operators, however SEPA does not own any transmission assets.

Federal Power Marketing Administration territories and facilities



Source: EIA

BPA – Owns and operates three-quarters of the high voltage transmission system in its territory. BPA also owns the Columbia Nuclear Generating Station in Washington.

WAPA – Service area composed of a 15-state region with more than 17,000 circuit miles of transmission systems that carry electricity from 56 hydropower plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. WAPA also markets power from the Hoover Dam, the nation's sixth largest hydroelectric plant in the U.S. located on the Colorado River.

SWPA – Markets hydroelectric power from 24 U.S. Army Corps of Engineers dams.

SEPA - Markets hydroelectric power from 23 U.S. Army Corps of Engineers water projects.

4.8 Retail Electricity Markets

The retail market involves the sale of electricity from an electricity provider to an end-user. The end-user could be a large industrial facility, small business, or individual household. In every State, regardless of whether there is retail competition or not, the electricity supply for end-users is obtained either through the competitive wholesale market, or from utility-owned rate-based generation, or a combination of the two. All States regulate rates for the delivery of electricity to end users (customers) through distribution wires and related systems. In States where there is full retail competition, "retail choice", customers may choose between their current utility supplier and other competitive suppliers for the generation portion of their electric service. Competitive retail suppliers provide a variety of service plans that give consumers and businesses options for electricity purchases. The price the end-user pays, or the retail price, may not reflect the real-time pricing of wholesale market pricing. Retail prices may be an average of annual costs or some other mechanism to determine end-user prices.

For investor-owned utilities, the regulation of retail markets falls under the jurisdiction of states. State regulatory commissions, which are often called the State "Public Utility Commission" or "Public Service Commission," regulate a utility's costs and rate of return. Municipally- and cooperatively-owned utilities may be subject to some State regulation but in general, self-regulate their costs. As non-profit entities, municipally- and cooperatively-owned do not earn a return on capital invested. In retail choice States, the commissions can require competitive suppliers to be licensed and subject to some regulation before they are allowed to service customers. In States without retail competition, commissions regulate the expenditures of investor-owned utilities and set an authorized rate of return on capital invested. In these States, where utilities are vertically integrated, utilities may construct, own and operate power plants and the costs are reflected in retail prices.

4.9 Capacity Markets

To meet Federal and State reliability requirements, grid operators must ensure that load serving entities have enough resources to meet expected demand plus a "reserve margin," that provides for a cushion during unexpected spikes in demand or potential loss of a supply or transmission resource. Reserve margins help operators maintain the reliability of the system. Capacity markets in RTO/ISO regions are typically set up to ensure that there are sufficient resources available to serve load plus reserves at some point in the future, typically from one month to several years out in time. Capacity markets may use auctions to lock in prices for electric capacity from generation resources well before they are actually needed (3 years in some markets). Capacity markets can also be marketplaces for demand response in which customers reduce their demand when called upon to do so in exchange for capacity payments similar to what generators receive. Prices vary by location and timing of capacity commitments and typically not by size or fuel type. ISO New England, PJM, MISO and NYISO operate capacity markets, while other ISOs do not currently have capacity markets.

5 Power Outages and Restoration

When disaster strikes, utilities mobilize crews to restore power to their customers as quickly as possible. The process begins well before storms are even on the radar. Utilities are prepared for all kinds of storms and situations, which requires planning for standard operating procedures and procuring resources to meet a wide variety of challenges. The following sections discuss the vulnerabilities of the power sector, preparation for events, and restoration efforts.

5.1 Power Sector Vulnerabilities

The power sector is vulnerable to various disruptive events that require preparation for mitigating impacts and restoring service in a timely fashion. The following is a list of risks that the sector is susceptible to:

1. **Weather-Related:** Outages due to weather events such as hurricanes, tropical storms, tornadoes, snow and ice storms, and flooding. Outages due to weather are the most common type of disruptive events.
2. **Cyberterrorism:** Hackers from around the world can attack areas within the U.S. power grid, shutting off power to millions. While there have been no known cases of cyberterrorism affecting the U.S. grid and causing power outages, utilities and agencies across the country are well aware of the potential risks associated with cyberterrorism.
3. **Theft and Physical attacks:** Electric assets are sometimes targets of theft and physical attacks by individuals or groups. Recently, a California substation was attacked, resulting in the shutdown of numerous giant transformers that supplied power to an extensive commercial and industrial customer base.
4. **Man-Made Accidents:** Vehicle crashes, software-related glitches, and other human errors can also result in power outages. Examples include, civilian vehicles crashing into utility poles or utility employees accidentally tripping wires while conducting routine maintenance.
5. **Supply/Demand:** A supply and demand imbalance within a given area can produce power failures. This could result from a sudden surge in demand due to extreme temperatures or unplanned power plant outages. In April 2006, parts of Middle and South Texas faced rolling blackouts due to high excess demand from high temperatures. In February 2011, 50 power plants tripped offline, causing rolling blackouts in North and Central Texas.
6. **Other Natural Events:** Wildfires, earthquakes, and animals can interfere with electrical equipment. In August 2014, an earthquake in Napa County, California left more than 70,000 customers without power.

The 2003 Northeast blackout is an example of a complex large-scale outage event that was caused by multiple factors. The Fact Box on the next page provides details and a timeline of events leading up to the historic blackout that left 50 million people without power in the Northeastern United States and Canada.

Fact Box

2003 Northeast Blackout

U.S. Department of Energy
Office of Electricity Delivery
and Energy Reliability

- The most devastating blackout to hit the U.S. power industrial complex occurred on August 14, 2003, leaving close to 50 million people across the Great Lakes Region without power, some for up to two weeks
- A number of system factors primed the region for a cascading failure: deferred vegetation management, faulty alarm equipment, inexperienced operators, and lack of communication and situational awareness amongst supply chain operators
- Loss of generation across the region imposed heavy congestion and reactive power demands on the Ohio transmission system. The line-tripping domino effect placed increased stress on northwest generation in Michigan, further disconnecting the region from the rest of the grid. With lack of western generation support, the current reversed spreading outages northeast through Pennsylvania, and into New York and Ontario

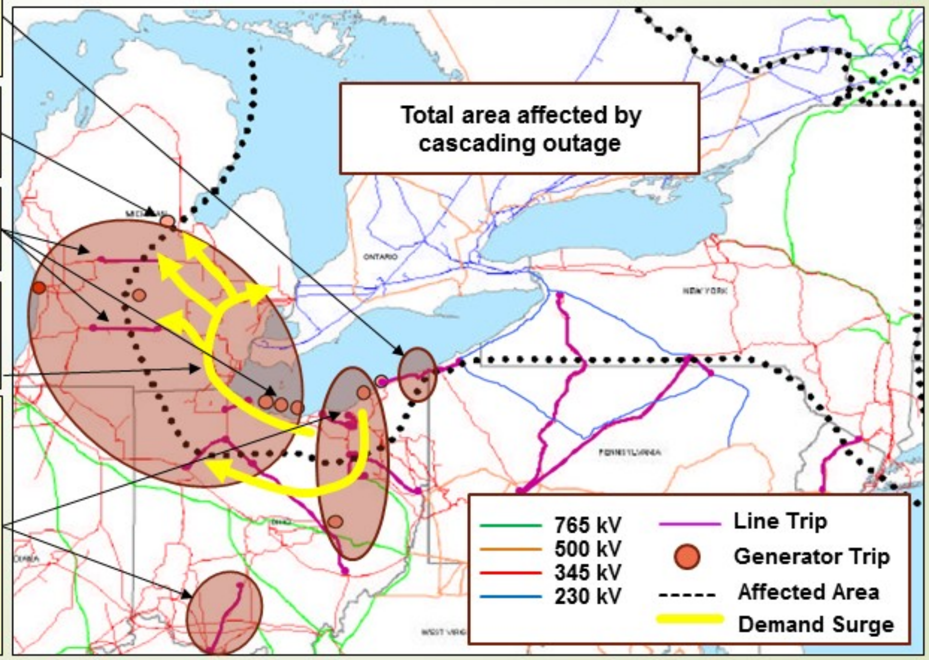
4:10:38 PM – Surge that had been flowing northwest suddenly reverses flow, tripping the Ohio-Pennsylvania line and sending the cascade across Pennsylvania, New York, and Ontario

4:10:37 PM – Significant generation trip imposes depressed system voltages across Michigan

4:10:04 PM – 20 generation units trip along Lake Eerie, surging power flows and tripping Michigan's East-West 345kV lines.

4:09 PM – Cleveland-Akron surge triggers collapse of 345 kV Ohio system; Northern Ohio and Detroit loads forced power demands north on Eastern Michigan.

12:05 – 4:06PM – Unplanned generator trips, alarm notification failures, and miscommunication between plant and system operators leads to voltage and reactive power abnormalities ultimately causing low system voltage and significant line sagging. Three 345kV lines trip from vegetation contact triggering high electricity flows over lower level 138kV lines and 600 MW of sudden load shedding in the Cleveland-Akron area.



Sources: U.S./Canada Power Outage Task Force, August 2013 Outage Sequence of Events: Initial Blackout Timeline, September 12, 2003.
U.S./Canada Power Outage Task Force, Final Report on the August 2013, 2003 Blackout: Causes and Recommendations, April 2004.

5.2 Black Start

The 2003 blackout was so widespread and severe that black start procedures were required to bootstrap the affected electric grid. A "black start" is the process of restoring a power unit(s) to operation without relying on external electric power from the transmission network. Typically, a plant coming online requires electricity for startup units and control equipment. When the entire grid is down, plants have no external sources of power to restart, and thus rely on dedicated black start diesel generators.

Different types of plants can perform black start functions; nuclear and hydro units are typically used due to their large capacity size and backup power capabilities. During a black start, the system operator will designate a "cranking path," which determines the order for units to start up in different parts of the system in order to gradually restore the grid to operation. In order to maintain readiness, designated plants are frequently required to test their black start capabilities.

5.3 General Preparedness

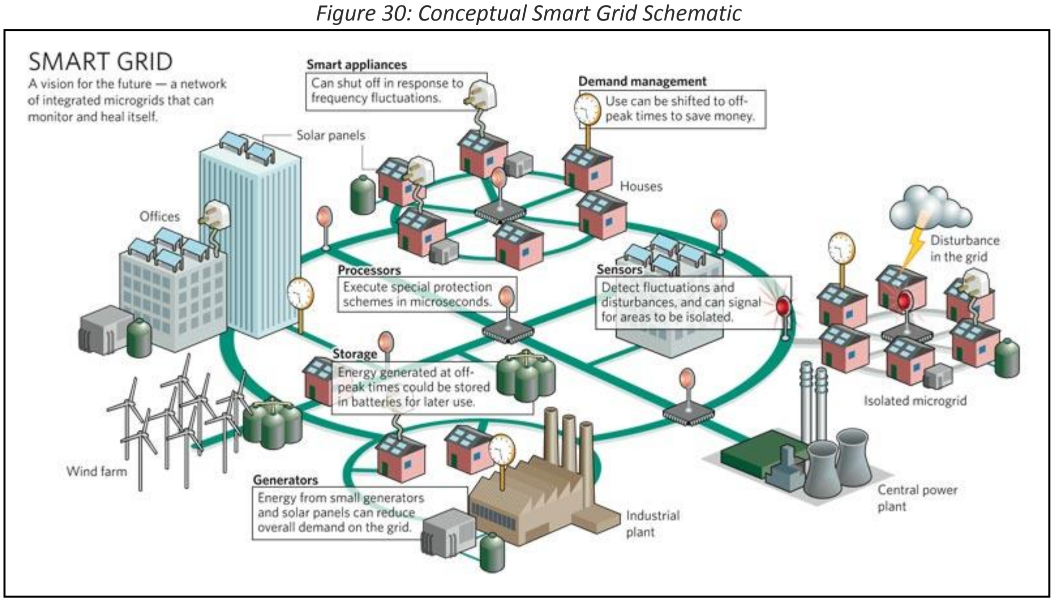
Year-round, utilities prepare for all sorts of scenarios ranging from small thunderstorms, winter snow and ice storms, hurricanes, inadequate reserves of generation, lack of fuel stocks, accidents, thefts, sabotage, and cyber-attacks. The following describes some activities utilities engage in, particularly during business-as-usual conditions, to better prepare for events.

- **Exercises:** Utilities often engage in regularly timed exercises and drills to prepare for various scenarios. These drills prepare employees and crews for what to expect during live disasters.
- **Hardening:** This is a general term to describe the physical changes to a utility's infrastructure to make it less susceptible to storm damage. Hardening can increase the durability and reliability of transmission and distribution assets, as well as generators. Undergrounding, or burying transmission and distribution lines underground, where appropriate, is one type of hardening. Undergrounding can protect lines from above-the-ground events such as storms, accidents, and even physical attacks. Underground lines, however, are expensive, more susceptible to flooding damage, and they are more difficult to repair when problems do occur. Utilities can also harden their infrastructure by modifying design elements of their assets. This includes elevating certain infrastructure like substations or designing electricity poles that are able to withstand high winds.
- **N-1 Contingency Planning:** Utilities ensure that they are able to maintain service if one or more system elements goes offline. Elements are referred to as transformers, generators, transmission and distribution lines, and other assets that are involved with the supply of electricity. In a system of "n" total elements, an "n-1" event is referred to as an event where one element or multiple *linked* (electrically or physically) elements go offline. A single element going offline is the most common—for example, when one transmission line goes out of service. The remaining operating transmission lines must be able to pick up the shut line's load and maintain reliable service. There may be cases in which a single element goes offline and others follow it. For example, when a single tower that operates two transmission lines is offline, the two lines will be subsequently unavailable. This is still referred to as an "n-1" contingency because one

element was initially out of service and two additional linked elements were unavailable as a result.

- **Vegetation Management:** Vegetation management involves the removal or trimming of trees, bushes, and other greenery that may be too close to electric infrastructure so as to potentially damage equipment during storms. There are many rules that regulate how a utility conducts vegetation management. First, a utility is required by Federal reliability standards (FERC) to maintain a certain clearance amount for service reliability and safety purposes. These apply to transmission facilities. Distribution lines that connect to local homes and business are generally governed by State utility commissions and local agencies. To maintain reliability, utilities are given a right-of-way to manage vegetation on private property. Utilities with rights-of-way on Federal lands have additional maintenance requirements from Federal land management agencies.
- **Smart Grid and Microgrid:** The development of smart grid is a form of hardening that is slowly being implemented by utilities across the country. Smart grid allows utilities to quickly identify outage areas, and use crews and resources more efficiently. Utilities can save time by avoiding having to send out personnel just to identify a problem area. A microgrid is a less common form hardening, yet still effective. A microgrid is essentially an isolated "island" of electricity generation, transmission, and distribution. Microgrids are able to disconnect from the grid and operate independently for an extended period of time. These technologies are more common in large complexes like military bases, but are gaining widespread support and development across industry and government.

Figure 30: Conceptual Smart Grid Schematic



Source: U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability

- **Inspections/Maintenance:** Utilities regularly inspect their facilities to make note of any wear and tear and any required repairs or upgrades.

- **Resiliency:** Resiliency is the ability of a utility to quickly recover from severe damage to its assets. While it may not be a preventative measure, it is important because a resilient utility can continue to operate after sustaining damage or rapidly return to normal operations. One such measure of resiliency is having a sufficient crew size with the proper training. Similarly, utilities also have a well-maintained stock of backup supplies, such as poles, lines, transformers, and backup generators. Enhanced communication and planning can serve as a great measure for resiliency. Utilities can use mobile command centers that are able to expedite response efforts. Mobile command centers can enable satellite and cellular communications and video monitoring to help coordinators allocate crews and resources to where they are needed.
- **Mutual Assistance:** Large-scale outage events affecting tens of thousands and even hundreds of thousands of customers can make the restoration process even more difficult for utilities that are affected. During such events, utility crews must make repairs at numerous damage locations and often require the assistance of outside help to expedite power restoration. This outside help comes from neighboring and regional utilities that have entered into an agreement prior to an outage event taking place. Typically, other utilities supply the affected utility with labor, materials, and specialized expertise to aid in the restoration effort. Resources could include crews that specialize in vegetation management, repairing lines, or other potential needs during an outage event. It is important to note that mutual assistance is voluntary and not-for-profit. A group of investor-owned utilities within a specific geographic area (intrastate or interstate groups are common) that have formed such agreements are called Regional Mutual Assistance Groups (RMAGs). RMAGs are crucial for resource mobilization and logistics. A Fact Box detailing RMAGs and their role in Superstorm Sandy is shown on the next page. Similarly, municipally owned and cooperatively owned utilities have also established mutual assistance contracts and plans to enact during disasters, but on much smaller scales compared to RMAGs.

5.4 Prestorm Preparation

When a storm is announced, utilities assess the situation based on the storm's forecasted path and strength. The list below provides some key items utilities must address when a storm is approaching. It is important to note that these are not necessarily done in the same order by all utilities, and most utilities have emergency restoration plans that are designed in advance and exercised regularly.

1. **Appoint Coordinator(s):** Utilities appoint a lead or leads for various functions (e.g., live wires down, restoration, vegetation management, overall communications). This may even be done during the business-as-usual period.
2. **Identifying Plan for Response to Priority 1 Calls:** Priority 1 calls refer to situations where there is an immediate threat to life or major property loss. This type of communication enables utilities and their crews to prioritize situations where damaged infrastructure threatens public safety, as well as prioritize the restoration of hospitals and other emergency services.
3. **Reviewing Critical Facility List:** This involves reassessing the critical asset list and ranking assets for restoration priority.

4. **Communications Plan:** Utilities have plans to communicate with local, State, Federal officials, local emergency responders, and members of mutual assistant groups. Utilities also maintain open communication channels with customers to inform them of safety measures, impact assessments, and restoration estimates. This may also be done during business-as-usual conditions.
5. **Identify Resources:** Utilities identify resources that are available to respond to an emergency. This includes crews, backup generators, mutual assistance, and Federal and State financial aid.

5.5 Restoration Process

When heavy storms are in the forecast, utilities begin to mobilize crews and other restoration resources. Mobile command centers are dispatched to impact areas and provide a central hub for communication and coordination for restoration efforts. Crews and equipment are also organized and pre-positioned, and mutual assistance is called upon if a storm is projected to have significant impacts. Once a storm has passed, utilities execute the following basic procedures for restoring power:

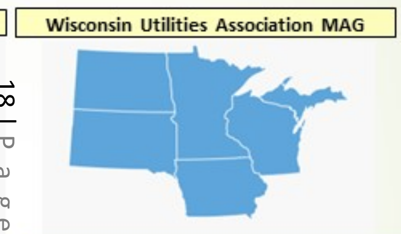
1. **Damage Assessment of Assets:** Utilities conduct a damage assessment of lines and substations. Damage assessment is done by sending out crews to inspect the service area. Utilities that have advanced smart grid technology can save time by having already identified areas that have suffered outages. Customers may also contribute to damage assessments by calling in and reporting major outages or broken lines that pose a threat to their safety. The assessment allows the utility to direct its crews and other resources to areas where they are needed the most.
2. **Eliminating Hazardous Situations:** Repairs are made to downed live wires or potentially life-threatening situations. Live damaged wires and substations are shut to prevent harm.
3. **Power Plants:** After a damage assessment, if power plants have been damaged and shut, these are usually the first to get restored as they are the electricity source.
4. **Large Transmission Lines and Substations:** Utilities then focus on large transmission lines that carry high-voltage electricity to the distribution system from generation stations or other transmission infrastructure. Lines such as these must be repaired first along with any damaged substations as they can supply power to thousands of customers.
5. **Restoring Power to Critical Infrastructure:** Power is restored to public health and safety facilities, such as hospitals, police, and fire stations.
6. **Distribution Lines and Substations:** Repairs are done to distribution substations and their respective main feeder lines, which link smaller scale customers such as neighborhoods and businesses.
7. **Individual Homes:** Power is restored to individual homes and small businesses.

Fact Box

Regional Mutual Assistance Group

U.S. Department of Energy
Office of Electricity Delivery
and Energy Reliability

- When a group of utilities within a region form a mutual assistance network, it is called a Regional Mutual Assistance Group, or RMAG. The RMAG structure is primarily used by IOUs, whereas municipal and co-op utilities have their own distinguished mutual assistance processes. RMAGs are important in that they promote safety of employees and customers, improve communication and the relationship between utilities, mitigate the risks and costs of member utilities during major events, promote the sharing of best practices, and enable a consistent and unified response to emergency events.
- Various groups can also have overlapping members, particularly when unique resources are required for certain areas. Super-storm Sandy highlighted the need for a more expansive mutual assistance program, one that goes beyond a regional scope to one that is able to respond to national response events (NREs). Following the storm, coordination began on a national level, which spanned over multiple RMAGs, as well as enhanced coordination with federal and state agencies. Several RMAGs in the Northeast combined to form the North Atlantic Mutual Assistance Group (NAMA).



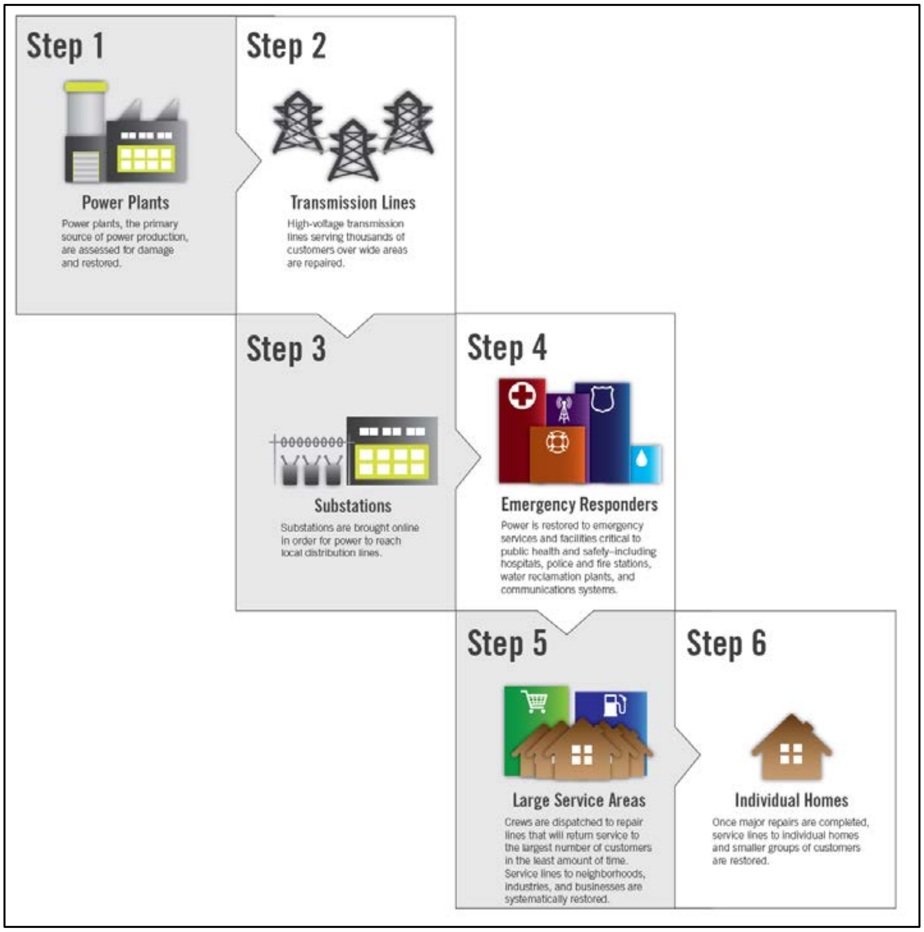
Source: Outage Central

Superstorm Sandy

- 67,000 mutual assistance personnel from 80 utilities joined the restoration efforts including line-workers, support and logistics personnel, engineers, vegetation management, safety personnel, and customer service representatives
- Within two weeks, power was restored to 99 percent of customers who could receive power.
- Three PMAs, BPA, WAPA and SWPA brought in 235 staff and roughly 200 pieces of equipment for restoration. This marked the first time WAPA and SWPA engaged in mutual aid with investor-owned utilities as part of DOE's ESF-12 response. The Department of Defense helped airlift equipment from PMA facilities.
- Utilities, such as Con Edison, received resources from as far as Canada and California.

The following diagram by EEI summarizes the process:

Figure 31: Typical Power Restoration Process



Source: EEI

Often times, power restoration is not as straightforward as going through a checklist of items. For example, utilities may not restore power to certain areas or individual homes that have suffered massive damage because they deem it unsafe to do so. In such instances, property owners must hire their own electrical inspector to assess the damage and then make the necessary repairs. This was the case after Superstorm Sandy when significant damage to property delayed restoration efforts for weeks.

Timing is also very important when it comes to storm preparations. For hurricanes and tropical storms, utilities typically have more than a week to plan. This allows them ample time to mobilize their own crews as well as have additional resources on standby should they be required for extensive damage and outages. In many cases, utilities regularly conduct exercises and drills to prepare their employees for emergencies. Some severe thunderstorms, on the other hand, provide very little advance warning.

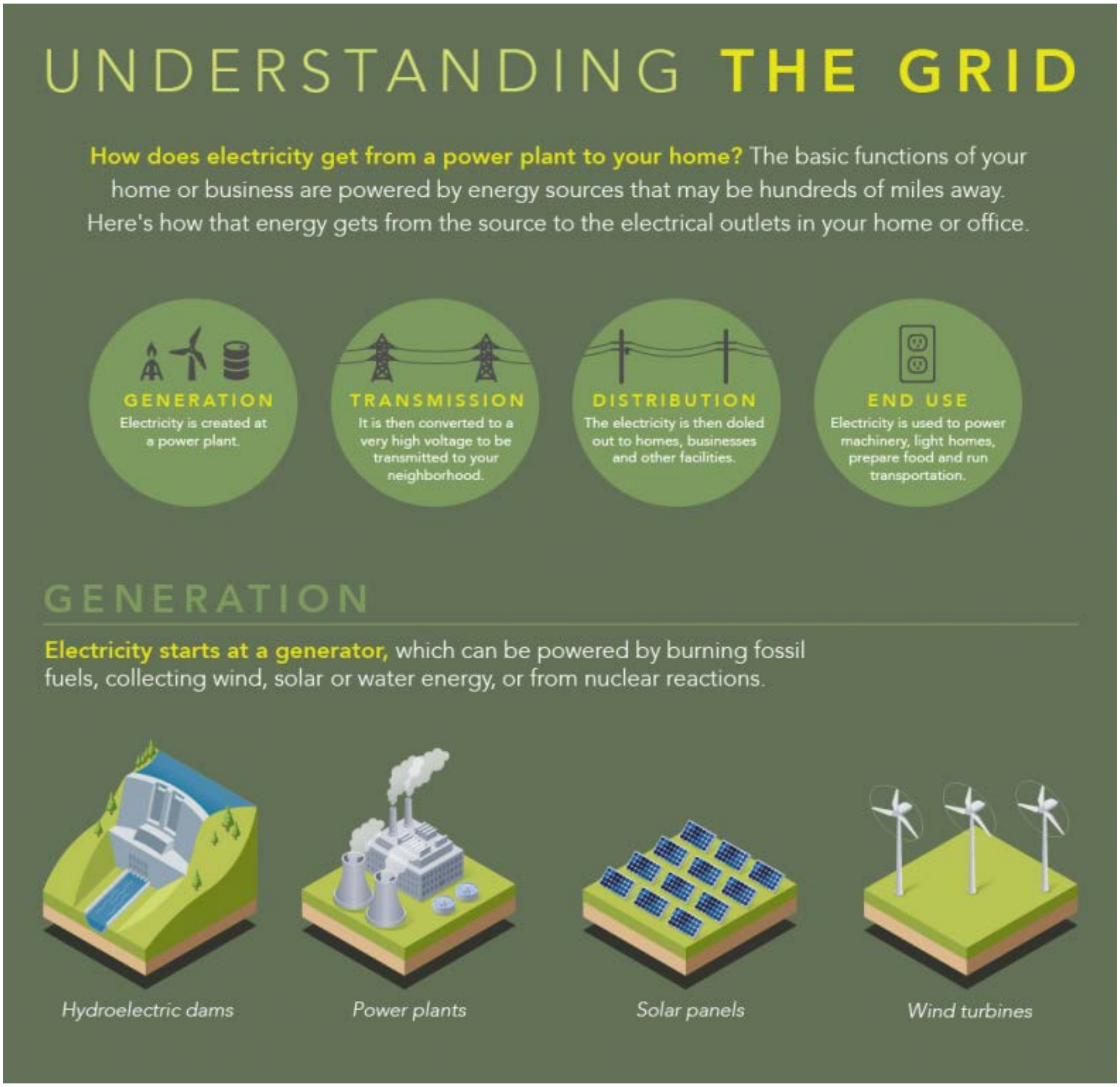
5.6 Interdependencies

Interdependency, in the general sense, is mutual dependence between entities. In the energy industry, interdependencies across various sectors, particularly in oil, gas and electric, can further complicate power restoration. The production and delivery of oil and gas heavily depends on the supply of power. The production of electricity requires the steady supply of fuels such as natural gas, coal, and oil. Furthermore, petroleum product pipelines and terminals around major hubs, petroleum product pipelines to big cities, natural gas lines to communities, and gas stations depend on a reliable supply of electricity. Water treatment facilities, pumping stations, and communication systems also rely heavily on electricity supply. Superstorm Sandy, once again, provides a case study of how interdependencies work and the problems that could arise when the power goes out. The storm shut down a substation in Manhattan, which cut power to 200,000 customers. Many of these customers were unable to receive water in their high-rise apartments because of pumping stations being shut. Superstorm Sandy also shut power to many gasoline stations throughout the Northeast. This left tens of thousands of motorists without the ability to refuel their tanks. Situations in which gasoline stations are closed can be made worse when emergency response vehicles are also scrambling to refuel. In June 2014, the U.S. Department of Energy established the first Federal regional refined petroleum product reserve called the Northeast Gasoline Supply Reserve. The Reserve holds one million barrels of gasoline and serves as a buffer for fuel supply for several days in the event of a massive storm. In addition, in October 2014, New York established a Strategic Fuel Reserve to help ensure that gasoline and diesel fuels are available to emergency responders.

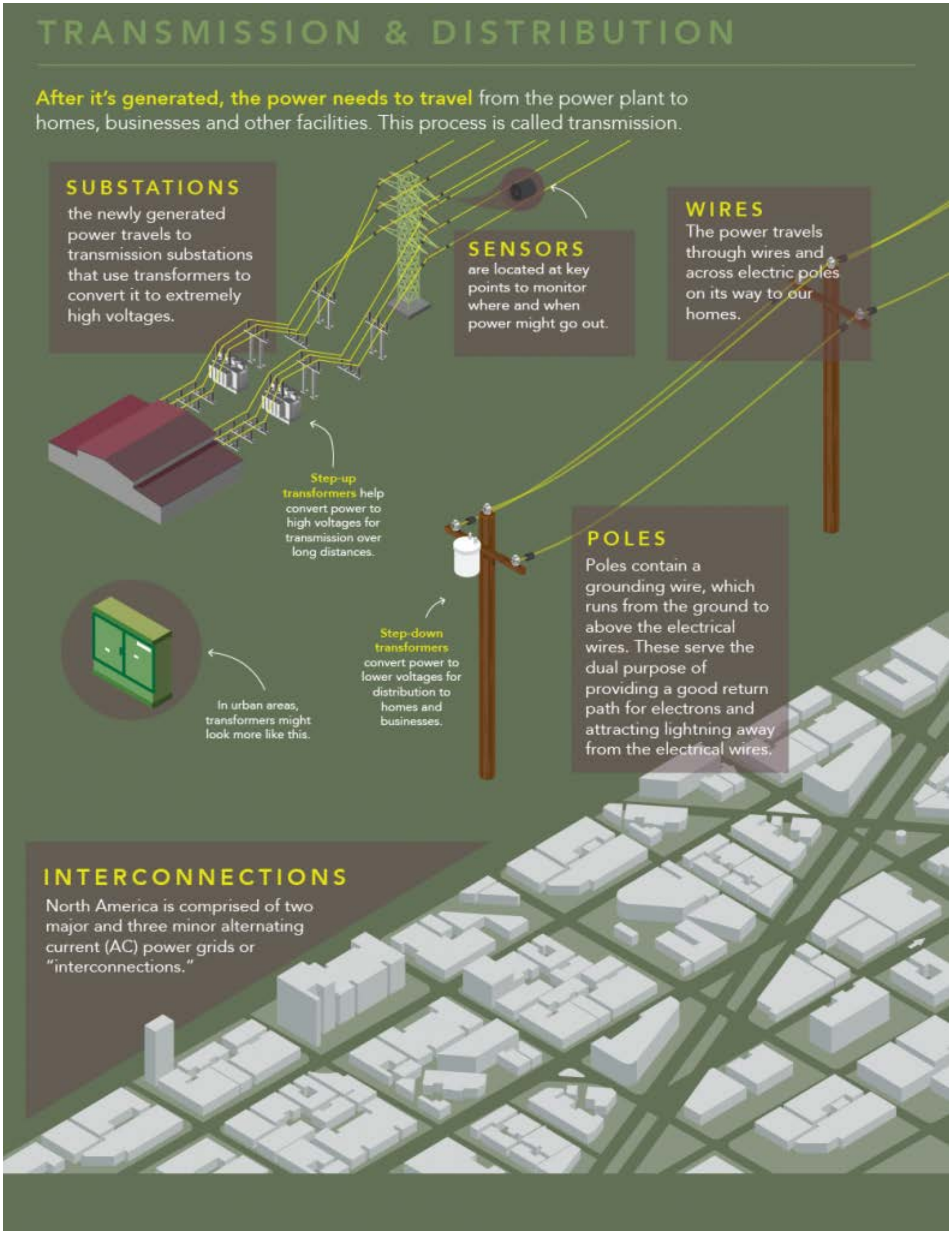
5.7 Conclusions

This document aims to provide a baseline for understanding industrial sectors of the electric power supply chain, discuss vulnerabilities to the electric grid, discuss regulatory and ownership structures, and provide context for causes of power outages and response efforts during emergencies. Several appendices further conceptualize the supply chain, explore the physics behind electrical circuits, address reliability standards, and relevant legislation. Last, a glossary of commonly used industry terms is provided to conclude the document.

APPENDIX A: UNDERSTANDING THE GRID[7]



[7] http://energy.gov/articles/infographic-understanding-grid


TRANSMISSION & DISTRIBUTION
After it's generated, the power needs to travel from the power plant to homes, businesses and other facilities. This process is called transmission.
SUBSTATIONS
the newly generated power travels to transmission substations that use transformers to convert it to extremely high voltages.
SENSORS
are located at key points to monitor where and when power might go out.
WIRES
The power travels through wires and across electric poles on its way to our homes.
Step-up transformers help convert power to high voltages for transmission over long distances.
POLES
Poles contain a grounding wire, which runs from the ground to above the electrical wires. These serve the dual purpose of providing a good return path for electrons and attracting lightning away from the electrical wires.
Step-down transformers convert power to lower voltages for distribution to homes and businesses.
In urban areas, transformers might look more like this.
INTERCONNECTIONS
North America is comprised of two major and three minor alternating current (AC) power grids or "interconnections."

END USE

Once distributed, **electricity is used to keep food cold, rooms lit and computers charged.**

ELECTRIC VEHICLES

HOMES

COMMERCIAL AREAS

INDUSTRIAL AREAS

Did you know? In 2012, the average American home used more electricity for space cooling than lighting, refrigeration or heating.

GRID INNOVATIONS

The grid is currently undergoing a major evolution with new technologies enabling shorter power outages, clean energy and energy efficiency options and providing a platform for innovative consumer services and products.

MICROGRIDS

Microgrids help distribute power, but can also disconnect from the larger grid and function as an electrical island in case there's a disruption on the grid.

ENERGY STORAGE

Energy storage technology helps integrate renewable energy into our power grid by managing the electricity supply: storing excess energy and distributing it as needed.

SMART METERS

Smart meters enable two-way communication between consumers and utility companies. This allows utilities to immediately know when your power is out enabling faster restoration.

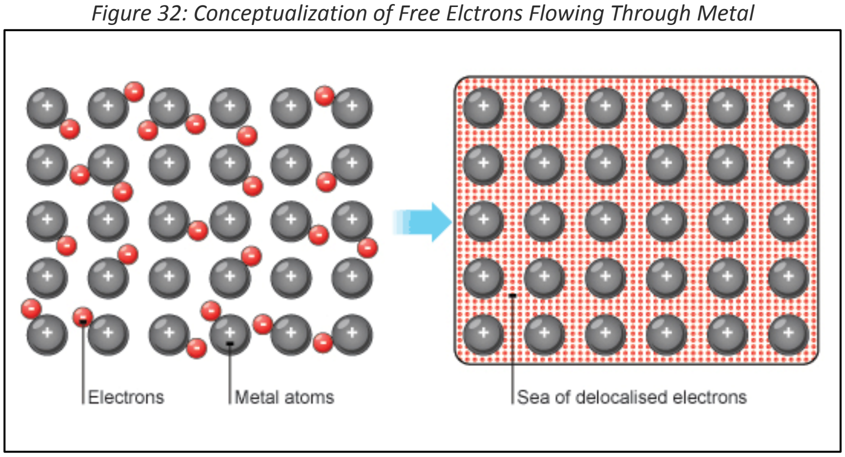
Appendix B: Circuit Basics

Electric Circuits

In a closed circuit, the flow of electrical current (I), must be induced by an electromotive force, or voltage (V). Circuit voltage is analogous to a pressure head of water in which current represents the flow of water. The opposition to current flow through a load, or electronic device is measured by the device's resistance (R). Ohm's law proves these metrics are proportional, in that V = IR, a common equation used for analyzing electric circuits.

Electricity flows through conductive materials such as metals, as well as water, which is an excellent electricity conductor. At the microscopic level, conductive, metallic materials such as copper and tin are three-dimensionally arranged in a cubed matrix of metallic atoms (illustrated in two dimensions in the graphic below). The electrons in orbital shells closest to the nucleus (not shown below) have strong bond attractions to positive protons in the atom's nucleus. The magnitude of bond attraction is a function of distance between the two opposite charges. The valence electrons in the outermost shells of metallic atoms (shown below) are under weak forces of attraction due to greater distances from positive charges, and can be transferred, under a voltage condition to form a sea of free-flowing, delocalized electrons.

Figure 32: Conceptualization of Free Elctrons Flowing Through Metal



Source: British Broadcasting Corporation

Units of Electric Power

Electricity is measured by units of power called watts (W). Kilowatts (kW) and megawatts (MW) are more realistic throughout industry in describing power units of larger scales such as a generator or a home. The larger the wattage of an electrical device or load, the more power it consumes—or produces in the case of a generator or power plant.

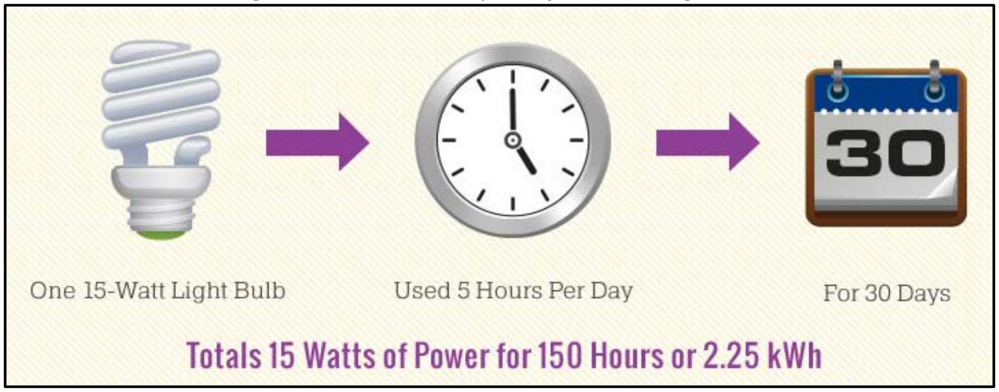
Figure 33: Electricity Terms, Derivations, and Conversions

Common Terms & SI Notation		Derivations	Unit Conversions	
Voltage: Volt [V]	Power: Watt, [W] = [V·A]	Voltage, V = IR	1 kW = 1,000 W	1 kV = 1,000 V
Current: Ampere [A] or [I]	Reactive Power: Volt-Ampere [VAR]	Power, P = IV	1 MW = 1,000 kW	1 MV = 1,000 kV
Resistance: Ohm, [Ω]	Power Delivery: Kilowatt hour, [kWh]	Power Delivery = P = PΔT	1 GW = 1,000 MW	

Source: U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability

The consumption of electric power over a period of time (delta T, [ΔT]) is expressed in kilowatt hours (kWh). For example, a 15 watt light bulb that stays lit for 5 hours a day, over a span of a month, will consume 2,250 watt hours, or 2.25 kWh of electricity. While consumption varies with respect to seasonality, time of day, and location, a typical home consumes around 900 kWh per month.

Figure 34: Power Consumption of a 15-Watt Light Bulb



Source: EEI

Alternating Current

The majority of America's power infrastructure operates synchronously on alternating current (AC). Alternating current is generated in phases, meaning that the source of voltage and current has three components changing direction periodically with time. For power systems in North American, the standard operating frequency is three-phase power generation at cycles of 60 Hertz (Hz). The figure below conceptually illustrates a three-phase AC generator and a representation of its voltage output over time. As the magnet rotates on a fixed axis within the generator, a dynamic current is generated within each coil, proportional to direction and speed of the magnetic field's rotation.

The presence of a magnetic field induces electrical currents and voltages that are directionally dependent due to the rotation of the magnetic field. In a power system, voltage and current can encounter elements that influence their directions out of synchrony, or out of phase, and during this occurrence in the cycle, electrical current is not transferred to the load as working current. These types of loads are considered to be reactive elements, and the currents they absorb, which are not utilized for useful work are known as reactive power.

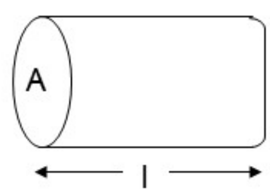
In a purely resistive AC circuit, no reactive elements exist and the voltage and current are fully in phase, meaning that power, the product of voltage and current, has a net positive value over an entire cycle, and all extractable, working current is consumed at the resistive load. In addition to resistive loads, realistic circuits also contain capacitive and inductive loads in which current flow is out of phase with voltage, meaning that a net transfer of positive working current is not delivered to the load over a full cycle; moreover, negative work transfer, or reactive power, is absorbed at the load and transferred back to the system.

In reality power has two directionally dependent current components, and is quantified as a vector sum of the active and reactive powers, known as complex, or apparent power. Transmission engineers must account for apparent power because even though reactive current performs no useful work at the load, it dissipates heat into the load and wastes energy. Conductors, transformers and generators must be sized and designed appropriately to conduct and withstand the total current, not just the portion that performs useful work.

Resistivity

Resistance depends on the *resistivity*, ρ, of the material and the length and cross-sectional area of the resistor.

$$R = \frac{\rho l}{A}$$



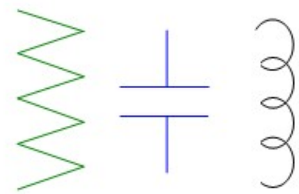
Material	*% Conductivity**
Aluminum, 99.5% pure	63.0
Copper, IACS (annealed)	100.0
Gold, 99.9% pure	72.6
Iron wire, EBB grade	16.2
Nickel	12.9
Platinum, pure	14.6
Silver, pure annealed	108.8
Steel wire	11.6
Tin, pure	12.2
Zinc, very pure	27.7

** Ratio of a substance's conductivity to the conductivity of standard copper.*

Note: Resistivity depends on temperature. For most conductors, it increases with temperature, since electron movement through a lattice becomes increasingly difficult at higher temperatures.

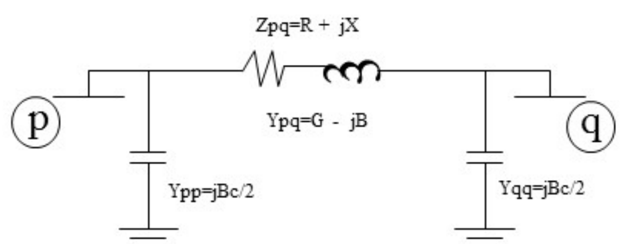
Three Passive Elements

- Resistors & Resistance:
  Heating and Lighting Loads
- Capacitors & Capacitance:
  Power Factor Correction and Voltage Support
- Inductors (or Reactors) and Inductance:
  Motor Loads



- All electric equipment has these three properties to a greater or lesser extent

- Loads and overhead transmission tend to be inductive:



Pi-Equivalent Model of a Transmission Line

Energy

E – Energy (Joules): stored work

Energy can be neither created nor destroyed – it can only be transformed (converted) from one form to another. Power plants are simply energy conversion facilities.

Some Energy Transformations

Home furnace using fuel oil, gas, or wood	Chemical to thermal and thermal to radiant
Automobile engine	Thermal to mechanical
Electric motor	Electrical to mechanical
Toaster, light bulb	Electrical to radiant
Sunlight warms ground	Radiant to thermal

Energy of Familiar Phenomena (MJ)

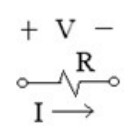
Bowling ball dropped 3 feet	0.000065
1 pound TNT	2
1 pound bread	5
1 person-day nutrition (2500 kcal)	10
1 gallon gasoline	130
Average lightning stroke	1,500
Average summer thunderstorm	160,000,000
1-GWe power plant running 1 day	260,000,000
Hydrogen bomb (1 megaton)	4,000,000,000

Power

Power (Watts): rate at which energy changes form or location

$$P = VI = (IR)I = I^2R$$

One watt is the power dissipated by a current of 1 ampere flowing across a resistance of 1 ohm.

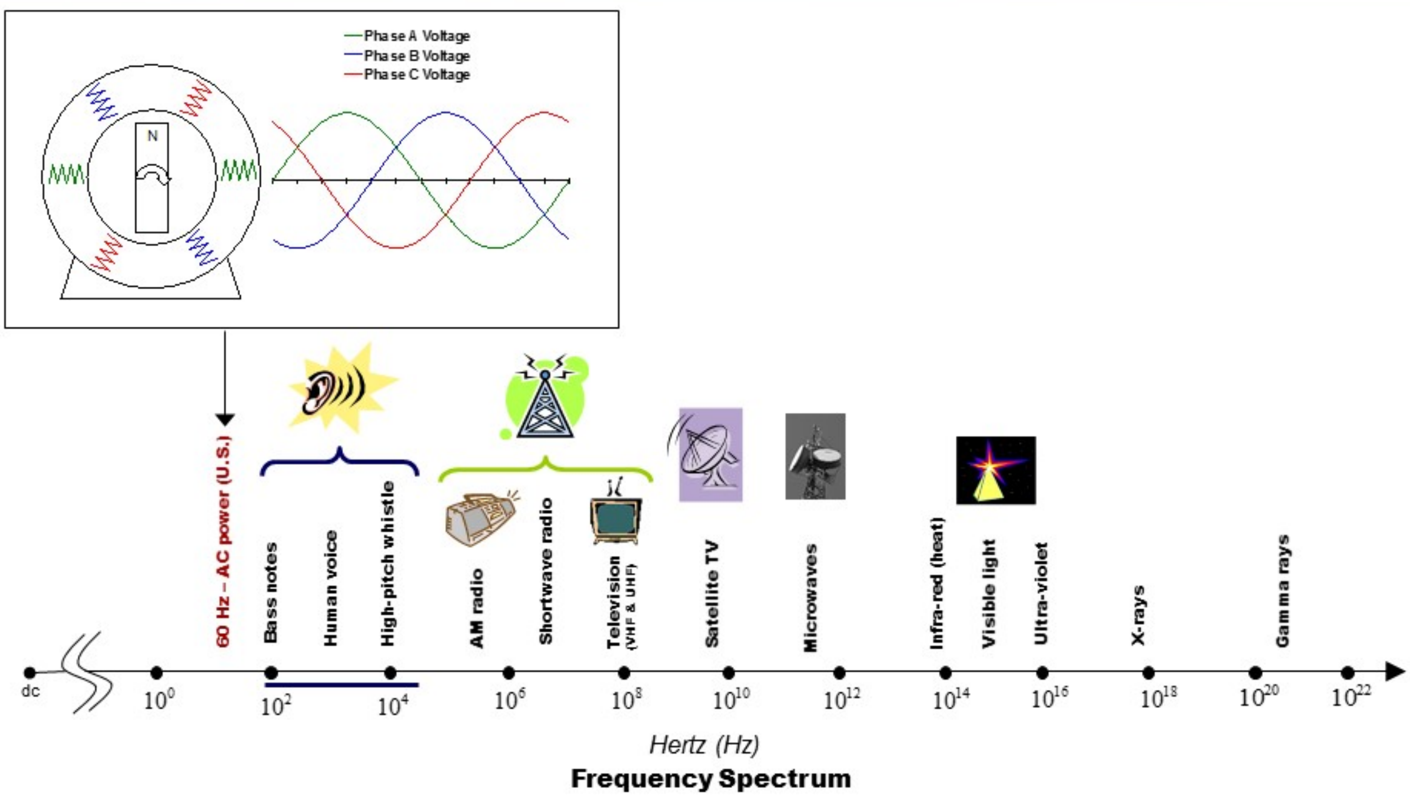


A *Kilowatt Hour (kWh)* is the unit by which residential and most business customers are billed for monthly electric use. It represents the use of one kilowatt (1,000 watts) of electricity for one hour, or a 100 watt light bulb burning for 10 hours. The average U.S. household uses 10.7 MWh (10,700 kWh) of electricity every year.

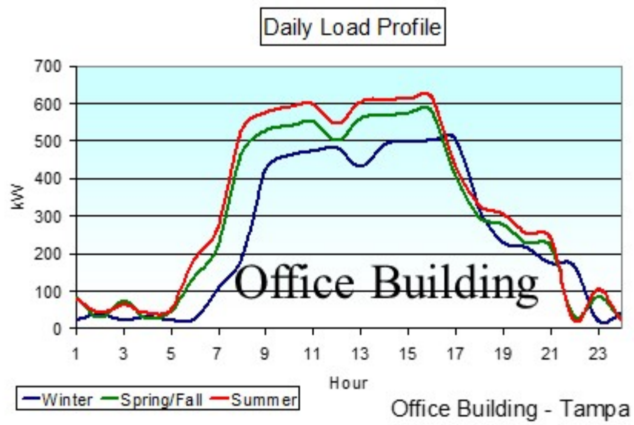
Customer Size

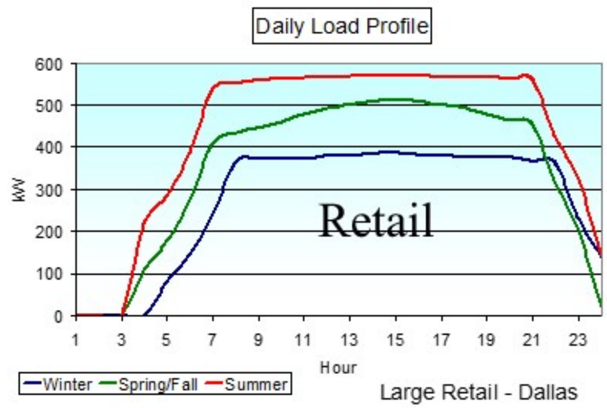
Customer Size		kWe
Industrial	Semiconductor Manufacturer	30,000+
	Plastics Plant	20,000+
	Paper Mill	5,000+
Large Commercial	Shopping Mall/ Large Office Bldg	3,000+
	Food Processing	2,500
	Hospital	500 - 1,000
	Hotel	250 - 500
Small Commercial	Small Office Bldg	100
	Gas Station/ Fast food	75
Residential	Multi-family	5 - 50
	Home	2 - 25

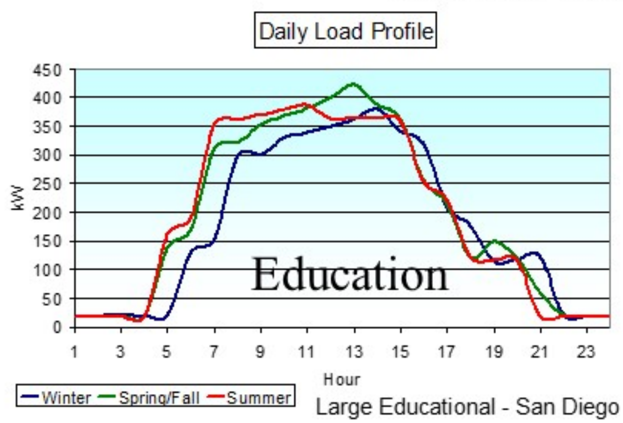
Frequency


Phase A Voltage
Phase B Voltage
Phase C Voltage
N
60 Hz – AC power (U.S.)
Bass notes
Human voice
High-pitch whistle
AM radio
Shortwave radio
Television (VHF & UHF)
Satellite TV
Microwaves
Infra-red (heat)
Visible light
Ultra-violet
X-rays
Gamma rays
dc
10^0
10^2
10^4
10^6
10^8
10^{10}
10^{12}
10^{14}
10^{16}
10^{18}
10^{20}
10^{22}
Hertz (Hz)
Frequency Spectrum

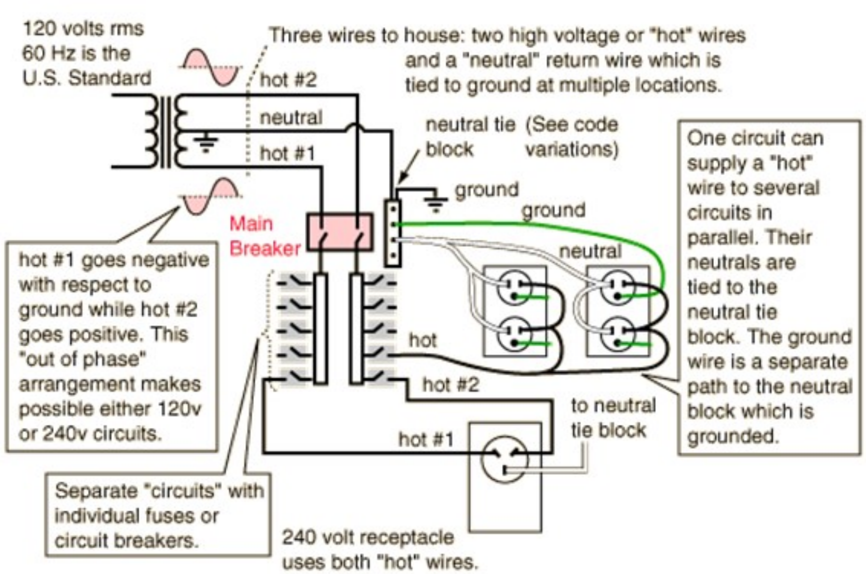
Other Load Profiles



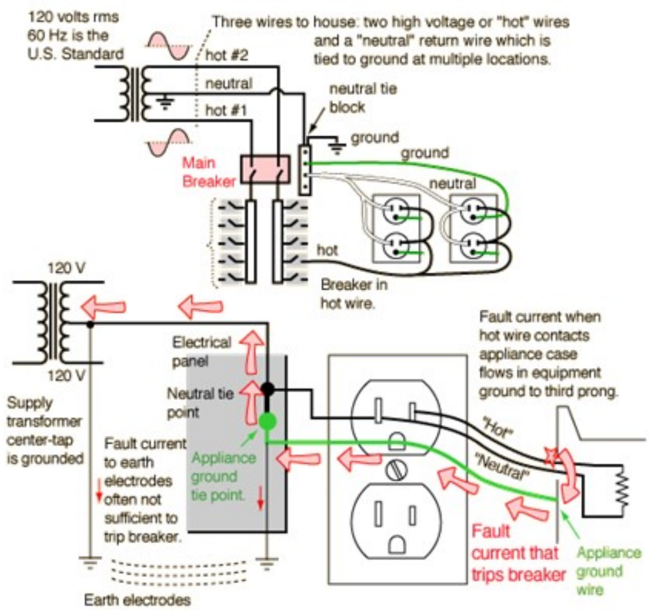


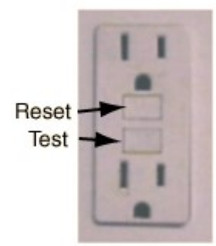


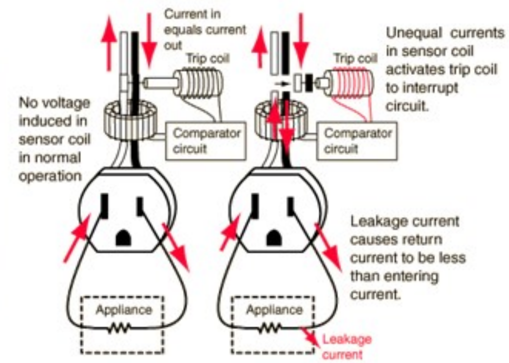
Household Wiring



Ground Faults



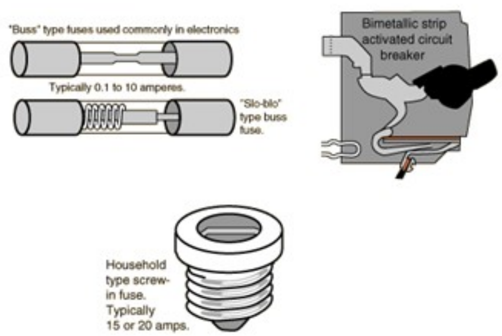


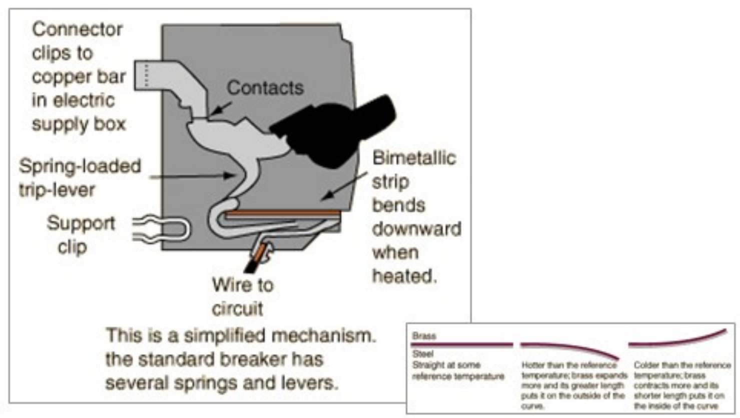


Electric Current (1 second contact)	Physiological Effect
1 mA	Threshold of feeling, tingling sensation.
10-20 mA	"Can't let go!" current - onset of sustained muscular contraction.
100-300 mA	Ventricular fibrillation, fatal if continued

Fuses and Breakers

- Fuses and breakers limit the current which can flow in a circuit. The metal filament in the fuse melts and breaks the connection, whereas in a breaker, the heating effect on a bimetallic strip causes it to bend and trip a spring-loaded switch.



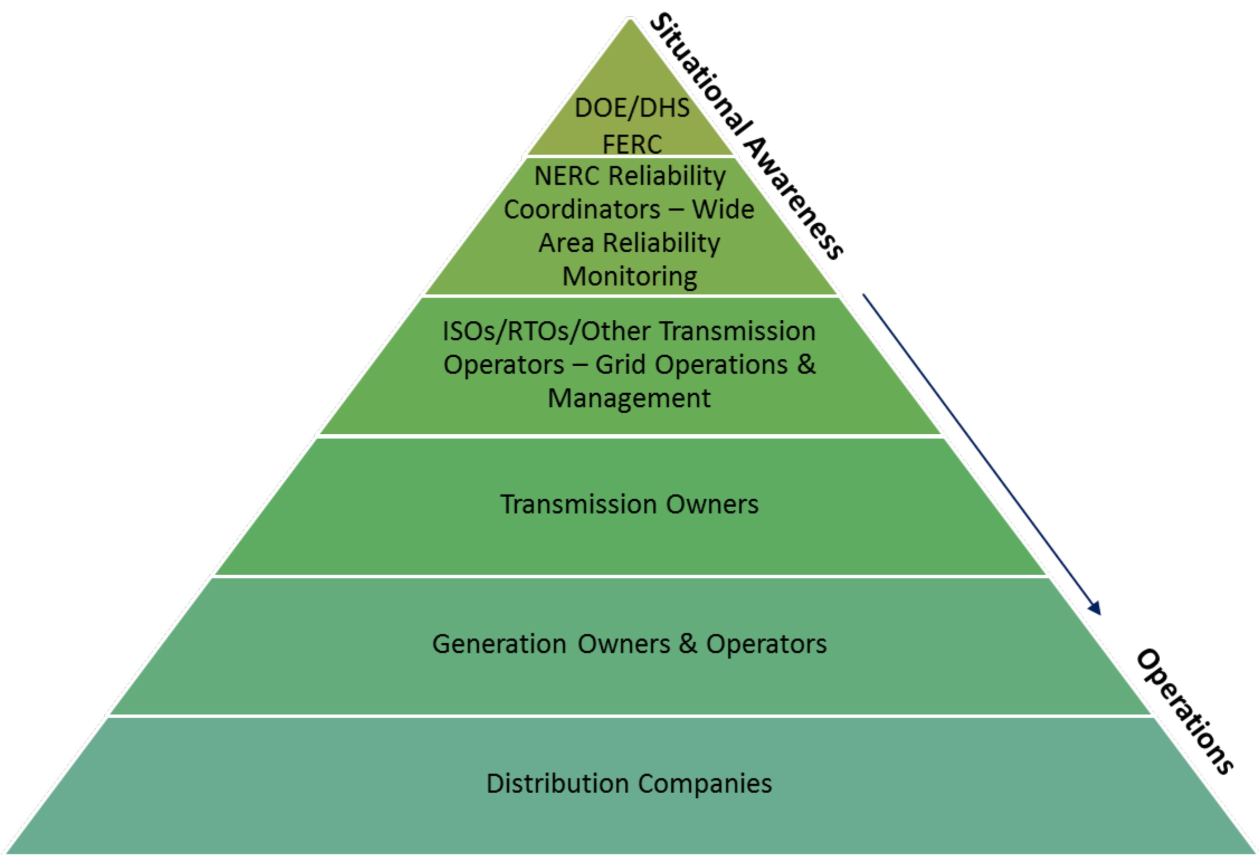


APPENDIX C: RELIABILITY STANDARDS

Electric Reliability

The Northeast Blackout of 2003 created an urgent need for a new set of rules that would help prevent similar mass outages. The Energy Policy Act of 2005 authorized FERC to designate a national ERO. In 2006, FERC issued an order establishing NERC as the ERO for the United States. Prior to being the National ERO, NERC's guidelines for power system operations and planning were not mandatory, only strongly encouraged and voluntary. NERC worked to develop reliability standards, and was given the authority to enforce those standards through monetary and non-monetary penalties. The following figure shows the authorities responsible for electric reliability in the United States.

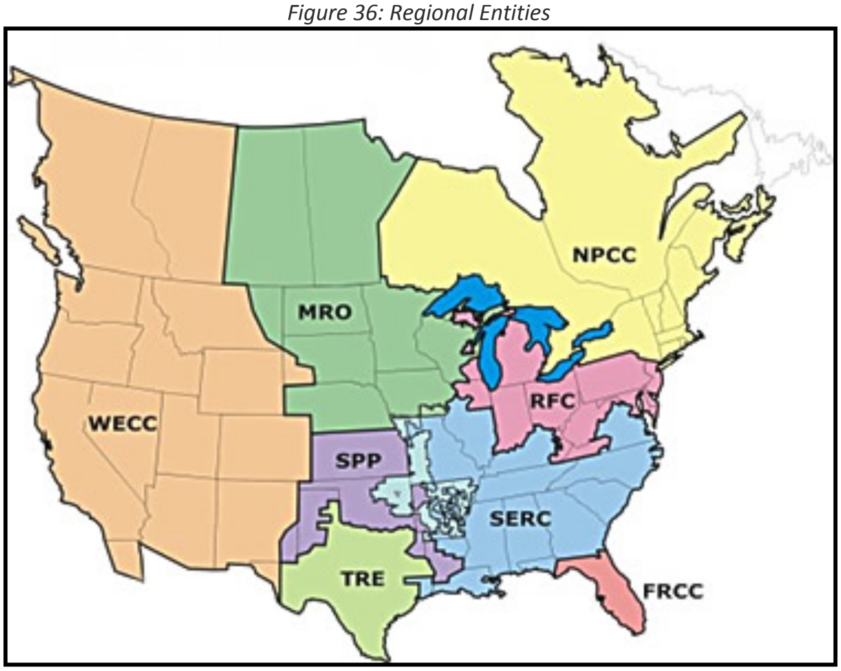
Figure 35: Hierarchy of Electric Reliability Monitoring



Source: Department of Homeland Security

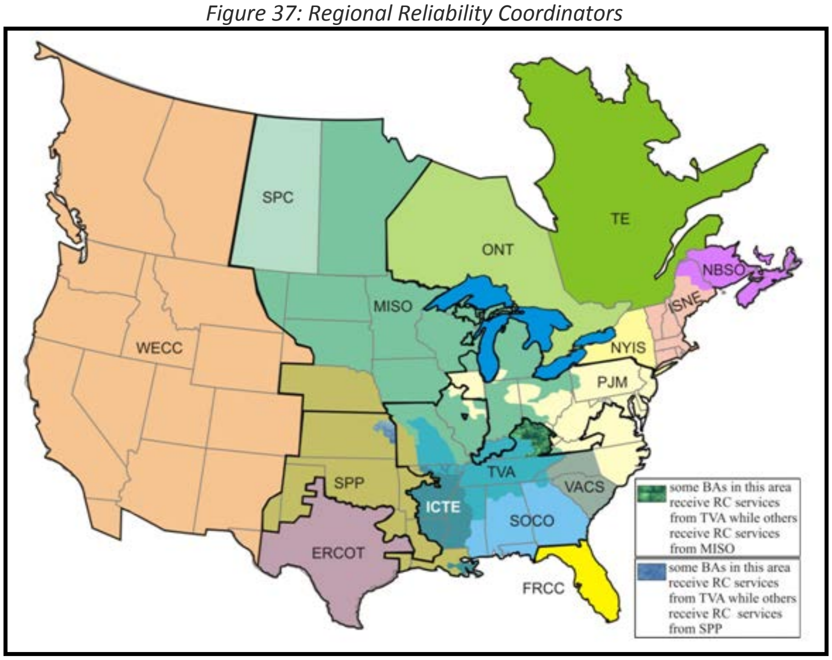
NERC uses Regional Entities (RE) to enforce its standards. Within each RE boundary there are one or more NERC-certified reliability coordinators. Figures 36 and 37 show the REs and Reliability Coordinators in North America. Reliability Coordinators are charged with the task of continuously monitoring the reliability of the transmission system. The coordinator has the authority to direct stakeholders (transmission operators, generators, and others that are involved with the electric grid's operations) to take action to preserve safe and reliable operation of the grid.

Figure 36: Regional Entities



Source: NERC

Figure 37: Regional Reliability Coordinators



Source: NERC

NERC Reliability Standards are summarized here:

1. **Supply and Demand Balancing:** Maintaining the supply and demand balance under business as usual conditions and making sure the grid is prepared for emergency situations
2. **Transmission Operations:** Ensuring that all Reliability Standards are followed by grid operators that coordinators and operators have the resources needed to address grid issues, and procedures are in place to resolve threats to the system
3. **Transmission Planning:** Ensuring that new transmission facilities are resilient to threats and emergencies
4. **Communication:** maintaining proper communication and coordination between reliability coordinators and operators of the grid
5. **Critical Infrastructure Program:** Ensuring that the grid's critical assets as protected from cyber and physical threats
6. **Emergency Preparedness:** Ensuring that grid operators are prepared for emergencies, and have the resources and authority to restore operations if there is a disruption
7. **Facilities Design, Connections and Maintenance:** Ensuring that transmission operators have properly rated their transmission equipment and that adequate maintenance is performed to maintain grid reliability
8. **Interchange Scheduling and Coordination:** Ensuring that electricity transmission between balancing authorities does not pose a threat to the grid
9. **Interconnection Reliability Operations and Coordination:** Making sure that reliability coordinators have the authority to enforce reliability by directing grid operators to take necessary action when a threat is perceived
10. **Data Analysis:** Making sure that grid operators are using accurate and consistent data for the use of transmission planning and reliability
11. **Nuclear Operations:** Making sure that there is proper coordination between nuclear plant and transmission operators
12. **Personnel Training:** Ensuring that grid operations personnel are properly trained and qualified to meet the Reliability Standards
13. **Protection and Control:** Ensuring that protection systems that protect the grid are operating as designed
14. **Voltage:** Ensuring that reactive power sources operate within their limits and maintain adequate voltage levels

Planning Reserve Margin

To ensure reliability of the electric system, REs establish regional reserve margin targets for entities within the RE footprint. Reserve margin is the percent of generation capacity that is above peak demand, thus having more supply than may be required. Calculated, reserve margin is (available capacity minus demand)/demand. For example, a reserve margin of 15 percent means that an electric system has excess capacity in the amount of 15 percent above the peak demand.

APPENDIX D: U.S. DEPARTMENT OF ENERGY AUTHORITIES AND KEY LEGISLATION

DEFENSE PRODUCTION ACT OF 1950 (DPA), as amended
64 Stat. 798 (1950) 50 U.S.C. app. §§ 2061-2170

The DPA serves as the primary authority to ensure the timely availability of resources for national defense and civil emergency preparedness and response. Sections 101(a), 101(c), and 708, 50 U.S.C. §§ 2071 (a), (c), 2158, authorizes the President to require companies to accept and give priority to contracts or orders that the President "*deems necessary or appropriate to promote the national defense.*" The DPA defines "national defense" to include critical infrastructure protection and restoration, as well as activities authorized by the emergency preparedness sections of the Stafford Act. Consequently, the DPA authorities are available for activities and measures undertaken in preparation for, during, or following a natural disaster or accidental or man-made event.

The Secretaries of Energy and Commerce have been delegated the President's authorities under sections 101(a) and 101(c) of the DPA to require the priority performance of contracts or orders relating to materials (including energy sources), equipment, or services, including transportation, or to issue allocation orders, as necessary or appropriate for the national defense or to maximize domestic energy supplies. DPA section 101(a) permits the priority performance of contracts or orders necessary or appropriate to promote the national defense. "*National defense*" is defined in DPA section 702(13) to include "*emergency preparedness activities conducted pursuant to title VI of the Robert T. Stafford Disaster Relief and Emergency Act and critical infrastructure protection and assurance.*"

The Secretary of Energy has been delegated (Executive Orders 12919 and 11790) DPA section 101(a) authority with respect to all forms of energy. The Secretary of Commerce has been delegated (Executive Order 12919) the section 101(a) authority with respect to most materials, equipment, and services relevant to repair of damaged energy facilities. Section 101(c) of the DPA authorizes contract priority ratings relating to contracts for materials (including energy sources), equipment, or services to maximize domestic energy supplies, if the Secretaries of Commerce and Energy, exercising their authorities delegated by Executive Order 12919, make certain findings with respect to the need for the material, equipment, or services for the exploration, production, refining, transportation, or conservation of energy supplies.

DPA priority contracting and allocation authorities can be used to expedite repairs to damaged energy facilities, and for other purposes, including directing the supply or transportation of petroleum products, to maximize domestic energy supplies, meet defense energy needs, or support emergency preparedness activities. In the case of both the section 101(a) and 101(c) authorities, if there are contracts in place between the entity requiring priority contracting assistance and one or more suppliers of the needed good or service, DOE (with respect to the section 101(c) authority) or DOC (with respect to the section 101(a) authority) would issue an order requiring suppliers to perform under the contract on a priority basis before performing other non-rated commercial contracts. If no contracts are in place, DOE or DOC would issue a directive authorizing an entity requiring the priority contracting assistance to place a rated order with a supplier able to provide the needed materials, equipment, or services. That contractor would be required to accept the order and place it ahead of other nonrated commercial orders.

Section 705 authorizes the President to subpoena or otherwise obtain information from any person as may be appropriate, in his discretion, to the enforcement or administration of the DPA (50 U.SC § 2155). Through Executive Order 13603, DOE has delegated Section 705 authority.

DPA section 708 provides a limited antitrust defense for industry participating in voluntary agreements "*to help provide for the defense of the United States through the development of preparedness programs and the expansion of productive capacity and supply beyond levels needed to meet essential civilian demand in the United States.*" In the event of widespread damage to energy production or delivery systems, this authority could be used to establish a voluntary agreement of service companies to coordinate the planning of the restoration of the facilities.

DEPARTMENT OF ENERGY ORGANIZATION ACT AND FEDERAL POWER ACT
Pub. L. No. 95-91, 91 Stat. 567 and 16 U.S.C. §§ 791a-828c, 10 C.F.R. §§ 205.350, 205.353

DOE has authority to obtain current information regarding emergency situations on the electric supply systems in the United States. DOE has established mandatory reporting requirements for electric power system incidents or possible incidents. This reporting is required to meet DOE's national security requirements and other responsibilities (e.g., OE-417 Electric Emergency Incident and Disturbance Reports).

Section 645 of the DOE Organization Act provides DOE with subpoena power for purposes of carrying out responsibilities under the DOE Organization Act and the Federal Energy Regulatory Commission with respect to the Natural Gas Policy Act of 1978 (42 U.S.C. § 7255).

ENERGY POLICY AND CONSERVATION ACT (EPCA)
42 U.S.C. 6201-6422

Provides for the establishment of the Strategic Petroleum Reserve
"§ 6231. Congressional finding and declaration of policy
(a) The Congress finds that the storage of substantial quantities of petroleum products will diminish the vulnerability of the United States to the effects of a severe energy supply interruption, and provide limited protection from the short-term consequences of interruptions in supplies of petroleum products.
(b) It is the policy of the United States to provide for the creation of a Strategic Petroleum Reserve for the storage of up to 1 billion barrels of petroleum products to reduce the impact of disruptions in supplies of petroleum products, to carry out obligations of the United States under the international energy program, and for other purposes as provided for in this chapter."

Directs the Secretary of Energy to establish, operate, and maintain the Strategic Petroleum Reserve

"§ 6234. Strategic Petroleum Reserve
(a) Establishment
A Strategic Petroleum Reserve for the storage of up to 1 billion barrels of petroleum products shall be created pursuant to this part.
(b) *Authority of Secretary*
The Secretary, in accordance with this part, shall exercise authority over the development, operation, and maintenance of the Reserve."
"§ 6239. Development, operation, and maintenance of the Reserve
(f) Powers of Secretary to develop and operate the Strategic Petroleum Reserve
In order to develop, operate, or maintain the Strategic Petroleum Reserve, the Secretary may—
(1) issue rules, regulations, or orders;
(2) acquire by purchase, condemnation, or otherwise, land or interests in land for the location of storage and related facilities;
(3) construct, purchase, lease, or otherwise acquire storage and related facilities;
(4) use, lease, maintain, sell or otherwise dispose of land or interests in land, or of storage and related facilities acquired under this part, under such terms and conditions as the Secretary considers necessary or appropriate;
(5) acquire, subject to the provisions of section 6240 of this title, by purchase, exchange, or otherwise, petroleum products for storage in the Strategic Petroleum Reserve;
(6) store petroleum products in storage facilities owned and controlled by the

United States or in storage facilities owned by others if those facilities are subject to audit by the United States;
(7) execute any contracts necessary to develop, operate, or maintain the Strategic Petroleum Reserve;
(8) bring an action, when the Secretary considers it necessary, in any court having jurisdiction over the proceedings, to acquire by condemnation any real or personal property, including facilities, temporary use of facilities, or other interests in land, together with any personal property located on or used with the land."

Provides for the Presidentially-directed drawdown of the Reserve through the Secretary of Energy

"§ 6241. Drawdown and sale of petroleum products
(a) Power of Secretary
The Secretary may drawdown and sell petroleum products in the Reserve only in accordance with the provisions of this section."
"(d) Presidential finding prerequisite to drawdown and sale
(1) Drawdown and sale of petroleum products from the Strategic Petroleum Reserve may not be made unless the President has found drawdown and sale are required by a severe energy supply interruption or by obligations of the United States under the international energy program.
(2) For purposes of this section, in addition to the circumstances set forth in section 6202(8) of this title, a severe energy supply interruption shall be deemed to exist if the President determines that—
(A) an emergency situation exists and there is a significant reduction in supply which is of significant scope and duration;
(B) a severe increase in the price of petroleum products has resulted from such emergency situation; and
(C) such price increase is likely to cause a major adverse impact on the national economy."
"(8) The term ''severe energy supply interruption'' means a national energy supply shortage which the President determines—
(A) is, or is likely to be, of significant scope and duration, and of an emergency nature;
(B) may cause major adverse impact on national safety or the national economy; and
(C) results, or is likely to result, from (i) an interruption in the supply of imported petroleum products,
(ii) an interruption in the supply of domestic petroleum products, or (iii) sabotage or an act of God."

Authorizes the Secretary to establish the Northeast Home Heating Oil Reserve

"§6250. Establishment
(a) Notwithstanding any other provision of this chapter, the Secretary may establish, maintain, and operate in the Northeast a Northeast Home Heating Oil Reserve."

"§ 6250a. Authority
To the extent necessary or appropriate to carry out this part, the Secretary may—
(1) purchase, contract for, lease, or otherwise acquire, in whole or in part, storage and related facilities, and storage services;
(2) use, lease, maintain, sell, or otherwise dispose of storage and related facilities acquired under this part;"

ENERGY SUPPLY AND ENVIRONMENTAL COORDINATION ACT OF 1974 (ESECA)
15 U.S.C. § 796

ESECA authorizes the Federal Energy Administrator (precursor to DOE Secretary) to prohibit any power plant and other major fuel burning installation from burning natural gas if the Administrator determines that such facility has the capability and necessary plant equipment to burn coal.

Section 11 of ESECA authorizes DOE to issue subpoenas and require answers to interrogatories within DOE-determined deadlines in order to obtain reliable energy information to assist in the formulation of energy policy and to meet the essential needs of the United States for fuels.

FEDERAL ENERGY ADMINISTRATION ACT OF 1974, SECTION 13
(Pub. L. No. 93-275, 15 U.S.C. 761 et seq.)

Grants DOE the authority to collect, assemble, evaluate, and analyze energy information

"INFORMATION-GATHERING POWER
SEC. 13. (a) The Administrator shall collect, assemble, evaluate, and analyze energy information by categorical groupings, established by the Administrator, of sufficient comprehensiveness and particularity to permit fully informed monitoring and policy guidance with respect to the exercise of his functions under this Act.
(b) All persons owning or operating facilities or business premises who are engaged in any phase of energy supply or major energy consumption shall make available to the Administrator such information and periodic reports, records, documents, and other data, relating to the purposes of this Act, including full identification of all data and projections as to source, time, and methodology of development, as the Administrator may prescribe by regulation or order as necessary or appropriate for the proper exercise of functions under this Act.
(c) The Administrator may require, by general or special orders, any person engaged in any phase of energy supply or major energy consumption to file with the Administrator in such form as he may prescribe, reports or answers in writing to such specific questions, surveys, or questionnaires as may be necessary to enable the Administrator to carry out his functions under this Act.

Such reports and answers shall be made under oath, or otherwise, as the Administrator may prescribe, and shall be filed with the Administrator within such reasonable period as he may prescribe…."

The Federal Energy Administration was terminated and functions vested by law in the Administrator thereof were transferred to the Secretary of Energy (unless otherwise specifically provided) by sections 7151(a) and 7293 of Title 42, The Public Health and Welfare.

FEDERAL POWER ACT, Sections 202(a) (c), 202(e), and 206(d), as amended
(16 U.S.C. § 824a (e))

Under Section 202(a) and the Public Utility Regulatory Policies Act, Section 209(b), the Secretary of Energy has authority with regard to reliability of the interstate electric power transmission system.

FERC has the authority to define reliability regions and encourage interconnection and coordination within and between regions. DOE also has the authority to gather information regarding reliability issues and to make recommendations regarding industry security and reliability standards.

Under Section 202(c), the Secretary of Energy has authority in time of war or other emergency to order temporary interconnections of facilities and generation, delivery, interchange, or transmission of electric energy that the Secretary deems necessary to meet an emergency.

"202(c) Temporary connection and exchange of facilities during emergency

*During the continuance of any war in which the United States is engaged, or whenever the Secretary of Energy determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Secretary of Energy shall have authority, either upon his own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in his judgment will best meet the emergency and serve the public interest. If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Secretary of Energy, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as he finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party."**

**Although the text of Section 202(c) actually refers to "the Commission", rather than the "Secretary of Energy", authority under that provision resides with the Secretary of Energy, rather than the Federal Energy Regulatory Commission ("FERC"). Under Section 301(d) of the Department of Energy Organization Act (the "DOE Act"), 42 U.S.C. § 7151(b) (2006), the powers previously vested in the Federal Power Commission under the FPA (and other statutes) and not expressly reserved to FERC were transferred to, and vested in, the Secretary of Energy.*

Under Section 202(e), DOE is required to authorize exports of electricity unless it finds that the proposed transmission "would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities. Exports of electricity from the United States to a foreign country are regulated by FERC pursuant to sections 301(b) and 402(f) of the Department of Energy Organization Act (42 U.S.C. 7151(b), 7172(f)) and require authorization under section 202(e) of the FPA.

NATURAL GAS ACT, SECTIONS 3 AND 7
15 U.S.C. § 717 et seq.

DOE has authority under Section 3 to issue orders, upon application, to authorize imports and exports of natural gas. Section 3 requires DOE to approve, without modification or delay, applications to import LNG and applications to import and export natural gas from and to countries with which there is a free-trade agreement in effect requiring national treatment for trade in natural gas.

Under Section 3 of the Natural Gas Act, Executive Order 10485, as amended by Executive Order 12038, and Sections 301(b), 402(e), and (f) of the Department of Energy Organization Act (42 U.S.C. § 7101 et seq.), the Secretary has delegated to FERC authority over the construction, operation, and siting of particular facilities, and with respect to natural gas, that involves the construction of new domestic facilities, the place of entry for imports or exit for exports. FERC also has authority to approve or deny an application for the siting, construction, expansion, and operation of an LNG terminal under Section 3 of the Natural Gas Act.

Section 7 provides FERC the authority to approve the siting of and abandonment of interstate natural gas facilities, including pipelines, storage, and LNG facilities. FERC authority under the Natural Gas Act is to review and evaluate certificate applications for facilities to transport, exchange, or store natural gas; acquire, construct, and operate facilities for such service; and to extend or abandon such facilities. In this context, FERC approvals include the siting of said facilities and evaluation of alternative locations. FERC jurisdiction does not include production, gathering, or distribution facilities, or those strictly for intrastate service.

NATURAL GAS POLICY ACT OF 1978 (NGPA), TITLE III, SECTIONS 301-303
Pub. Law 95-621, 15 U.S.C. § 717 et seq.

DOE has delegated authority under section 302 and 303, respectively, to “authorize purchases of natural gas” and to “allocate supplies of natural gas” in interstate commerce, upon a finding by the President under section 301 of an existing or imminent “severe natural gas shortage, endangering the supply of natural gas for high-priority uses.”

Under Sections 301-303, DOE may order any interstate pipeline or local distribution company served by an interstate pipeline to allocate natural gas in order to assist in meeting the needs of high-priority consumers during a natural gas emergency.
DOE has delegated authority (Executive Order 12235) under sections 302 and 303,

respectively, of the Natural Gas Policy Act, to authorize purchases of natural gas and to allocate supplies of natural gas in interstate commerce to assist in meeting natural gas requirements for high-priority uses, upon a finding by the President under section 301 of an existing or imminent natural gas supply emergency (15 U.S.C. §§ 3361-3363). The declaration of a natural gas supply emergency is the legal precondition for the emergency purchase and allocation authority in sections 302 and 303, respectively, of the Natural Gas Policy Act.

Although Executive Order 12235 delegates to the Secretary of Energy the emergency purchase and allocation authorities in sections 302 and 303, respectively, the President has not delegated his authority to declare a natural gas supply emergency. Nothing in the Natural Gas Policy Act would preclude such a presidential delegation.

Under section 301 of the Natural Gas Policy Act, the President may declare a natural gas supply emergency if he makes certain findings. The President must find that a severe natural gas shortage, endangering the supply of natural gas for high-priority uses, exists or is imminent in the United States or in any region of the country. Further, the President must find that the exercise of the emergency natural gas purchase authority under section 302 of the Natural Gas Policy Act, of the emergency allocation authority under section 303 of the Natural Gas Policy Act, or of the emergency conversion authority of section 607 of PURPA is reasonably necessary, having exhausted other alternatives to the maximum extent practicable, to assist in meeting natural gas requirements for high-priority uses. The emergency terminates on the date the President finds that a shortage either no longer exists or is not imminent, or 120 days after the date of the emergency declaration, whichever is earlier.

POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978
42 U.S.C. §§ 8301-8484

The President has authority under section 404(a) to allocate coal (and require the transportation of coal) for the use of any power plant or major fuel-burning installation upon a finding of a "severe energy supply interruption," as defined in section 3(8) of the Energy Policy and Conservation Act 42 U.S.C. § 6202(8). Title II of the Power plant and Industrial Fuel Use Act of 1978 (FUA), as amended (42 U.S.C. 8301 et seq.), provides that no new base load electric power plant may be constructed or operated without the capability to use coal or another alternate fuel as a primary energy source.

In order to meet the requirement of coal capability, the owner or operator of such facilities proposing to use natural gas or petroleum as its primary energy source shall certify, pursuant to FUA section 201(d), and Section 501.60(a) (2) of DOE's regulations to the Secretary of Energy prior to construction, or prior to operation as a base load power plant, that such power plant has the capability to use coal or another alternate fuel. The President may also exercise such allocation authority upon a published finding that a national or regional fuel supply shortage exists or may exist that the President determines is, or is likely to be, of significant scope and duration, and of an emergency nature; causes, or may cause, major adverse impact on public health, safety, welfare or on the economy; and results, or is likely to result, from an interruption in the supply of coal or from sabotage, or from an act of God. Section 404(e) stipulates that the President may not delegate his authority to issue orders under this authority.

FUA section 404(a) authority could be used to help provide coal as an alternative fuel source to electric power plants and other major fuel-burning installations that have received orders prohibiting the burning of natural gas or petroleum as a primary energy source, assuming these facilities actually have the capability to burn coal. This authority also could be used during a coal supply shortage to ensure that coal-burning electric power plants or major fuel-burning installations have adequate supplies of coal.

Those sections of the FUA that restricted the use of natural gas by industrial users and electric generation facilities were repealed in 1987.

ROBERT T. STAFFORD DISASTER RELIEF AND EMERGENCY ASSISTANCE ACT, as amended
42 U.S.C. 5121 et seq.

FEMA, following a presidential declaration of emergency or major disaster, provides assistance and may require other Federal agencies to provide resources and personnel to support State and local emergency and disaster assistance efforts. Requests for a presidential declaration of an emergency or major disaster must be made by the Governor of the affected State based on a finding by the Governor that the situation is of such severity and magnitude that effective response is beyond the capabilities of the State.

DOE supports DHS/FEMA relief efforts by assisting federal, State, and local government and industry with their efforts to restore energy systems in disaster areas. When necessary, DOE also may deploy response staff to disaster sites. DOE is the Sector-Specific Agency for energy and is also is the lead agency directing Emergency Support Function-12 (Energy), which assists the restoration of energy systems and provides an initial point-of-contact for the activation and deployment of DOE resources. These activities are performed pursuant to the Stafford Act, HSPD-5 (Management of Domestic Incidents), and the National Response Framework.

EXECUTIVE ORDER 12656 - ***Assignment of Emergency Preparedness Responsibilities***

Part 1,
"Sec. 105. *Interagency Coordination.*
(a) All appropriate Cabinet members and agency heads shall be consulted regarding national security emergency preparedness programs and policy issues. Each department and agency shall support interagency coordination to improve preparedness and response to a national security emergency and shall develop and maintain decentralized capabilities wherever feasible and appropriate.
(b) Each Federal department and agency shall work within the framework established by, and cooperate with those organizations assigned responsibility in, Executive Order No. 12472, to ensure adequate national security emergency preparedness telecommunications in support of the functions and activities addressed by this Order."

"Part 2--General Provisions
Sec. 201. General. The head of each Federal department and agency, as appropriate, shall:
(1) Be prepared to respond adequately to all national security emergencies, including those that are international in scope, and those that may occur within any region of the Nation;
(2)) Consider national security emergency preparedness factors in the conduct of his or her regular functions, particularly those functions essential in time of emergency. Emergency plans and programs, and an appropriate state of readiness, including organizational infrastructure, shall be developed as an integral part of the continuing activities of each Federal department and agency;
(3) Appoint a senior policy official as Emergency Coordinator, responsible for developing and maintaining a multi-year, national security emergency preparedness plan for the department or agency to include objectives, programs, and budgetary requirements;
(4) Design preparedness measures to permit a rapid and effective transition from routine to emergency operations, and to make effective use of the period following initial indication of a probable national security emergency. This will include:
(a) Development of a system of emergency actions that defines alternatives, processes, and issues to be considered during various stages of national security emergencies;
(b) Identification of actions that could be taken in the early stages of a national security emergency or pending national security emergency to mitigate the impact of or reduce significantly the lead times associated with full emergency action implementation;
(5) Base national security emergency preparedness measures on the use of existing authorities, organizations, resources, and systems to the maximum extent practicable;

(6) Identify areas where additional legal authorities may be needed to assist management and, consistent with applicable Executive orders, take appropriate measures toward acquiring those authorities;
(7) Make policy recommendations to the National Security Council regarding national security emergency preparedness activities and functions of the Federal Government;
(8) Coordinate with State and local government agencies and other organizations, including private sector organizations, when appropriate. Federal plans should include appropriate involvement of and reliance upon private sector organizations in the response to national security emergencies;
(9) Assist State, local, and private sector entities in developing plans for mitigating the effects of national security emergencies and for providing services that are essential to a national response;
(10) Cooperate, to the extent appropriate, in compiling, evaluating, and exchanging relevant data related to all aspects of national security emergency preparedness;
(11) Develop programs regarding congressional relations and public information that could be used during national security emergencies; 5
(12) Ensure a capability to provide, during a national security emergency, information concerning Acts of Congress, presidential proclamations, Executive orders, regulations, and notices of other actions to the Archivist of the United States, for publication in the Federal Register, or to each agency designated to maintain the Federal Register in an emergency;
(13) Develop and conduct training and education programs that incorporate emergency preparedness and civil defense information necessary to ensure an effective national response;
(14) Ensure that plans consider the consequences for essential services provided by State and local governments, and by the private sector, if the flow of Federal funds is disrupted;
(15) Consult and coordinate with the Director of the Federal Emergency Management Agency to ensure that those activities and plans are consistent with current National Security Council guidelines and policies.

Sec. 202. Continuity of Government. The head of each Federal department and agency shall ensure the continuity of essential functions in any national security emergency by providing for: succession to office and emergency delegation of authority in accordance with applicable law; safekeeping of essential resources, facilities, and records; and establishment of emergency operating capabilities.

Sec. 203. Resource Management. The head of each Federal department and agency, as appropriate within assigned areas of responsibility, shall:

(1) Develop plans and programs to mobilize personnel (including reservist programs), equipment, facilities, and other resources;
(2) Assess essential emergency requirements and plan for the possible use of alternative resources to meet essential demands during and following national security emergencies;
(3) Prepare plans and procedures to share between and among the responsible agencies resources such as energy, equipment, food, land, materials, minerals, services, supplies, transportation, water, and workforce needed to carry out assigned responsibilities and other essential functions, and cooperate with other agencies in developing programs to ensure availability of such resources in a national security emergency;
(4) Develop plans to set priorities and allocate resources among civilian and military claimants;
(5) Identify occupations and skills for which there may be a critical need in the event of a national security emergency.

Sec. 204. Protection of Essential Resources and Facilities. The head of each Federal department and agency, within assigned areas of responsibility, shall:
(1) Identify facilities and resources, both government and private, essential to the national defense and national welfare, and assess their vulnerabilities and develop strategies, plans, and programs to provide for the security of such facilities and resources, and to avoid or minimize disruptions of essential services during any national security emergency;
(2) Participate in interagency activities to assess the relative importance of various facilities and resources to essential military and civilian needs and to integrate preparedness and response strategies and procedures;
(3) Maintain a capability to assess promptly the effect of attack and other disruptions during national security emergencies.

Sec. 205. Federal Benefit, Insurance, and Loan Programs. The head of each Federal department and agency that administers a loan, insurance, or benefit program that relies upon the Federal Government payment system shall coordinate with the Secretary of the Treasury in developing plans for the continuation or restoration, to the extent feasible, of such programs in national security emergencies."

Sec. 206. Research. The Director of the Office of Science and Technology Policy and the heads of Federal departments and agencies having significant research and development programs shall advise the National Security Council of scientific and technological developments that should be considered in national security emergency preparedness planning."

“Part 7--Department of Energy
Sec. 701. Lead Responsibilities. In addition to the applicable responsibilities covered in Parts 1 and 2, the Secretary of Energy shall:
(1)) Conduct national security emergency preparedness planning, including capabilities development, and administer operational programs for all energy resources, including:
(a) Providing information, in cooperation with Federal, State, and energy industry officials, on energy supply and demand conditions and on the requirements for and the availability of materials and services critical to energy supply systems;
(b) In coordination with appropriate departments and agencies and in consultation with the energy industry, develop implementation plans and operational systems for priorities and allocation of all energy resource requirements for national defense and essential civilian needs to assure national security emergency preparedness;
(c) Developing, in consultation with the Board of Directors of the Tennessee Valley Authority, plans necessary for the integration of its power system into the national supply system;
(2) Identify energy facilities essential to the mobilization, deployment, and sustainment of resources to support the national security and national welfare, and develop energy supply and demand strategies to ensure continued provision of minimum essential services in national security emergencies;
(3) In coordination with the Secretary of Defense, ensure continuity of nuclear weapons production consistent with national security requirements;
(4) Assure the security of nuclear materials, nuclear weapons, or devices in the custody of the Department of Energy, as well as the security of all other Department of Energy programs and facilities;
(5) In consultation with the Secretaries of State and Defense and the Director of the Federal Emergency Management Agency, conduct appropriate international liaison activities pertaining to matters within the jurisdiction of the Department of Energy;
(6) In consultation with the Secretaries of State and Defense, the Director of the Federal Emergency Management Agency, the Members of the Nuclear Regulatory Commission, and others, as required, develop plans and capabilities for identification, analysis, damage assessment, and mitigation of hazards from nuclear weapons, materials, and devices;
(7)) Coordinate with the Secretary of Transportation in the planning and management of transportation resources involved in the bulk movement of energy;
(8) At the request of or with the concurrence of the Nuclear Regulatory Commission and in consultation with the Secretary of Defense, recapture special nuclear materials from Nuclear Regulatory Commission licensees where necessary to assure the use, preservation, or safeguarding of such material for the common defense and security;
(9) Develop national security emergency operational procedures for the control,

utilization, acquisition, leasing, assignment, and priority of occupancy of real property within the jurisdiction of the Department of Energy;
(10) Manage all emergency planning and response activities pertaining to Department of Energy nuclear facilities.

"Sec. 702. Support
Responsibilities.
The Secretary of Energy shall:
(1) Provide advice and assistance, in coordination with appropriate agencies, to Federal, State, and local officials and private sector organizations to assess the radiological impact associated with national security emergencies;
(2)) Coordinate with the Secretaries of Defense and the Interior regarding the operation of hydroelectric projects to assure maximum energy output;
(3)) Support the Secretary of Housing and Urban Development and the heads of other agencies, as appropriate, in the development of plans to restore community facilities;
(4)) Coordinate with the Secretary of Agriculture regarding the emergency preparedness of the rural electric supply systems throughout the Nation and the assignment of emergency preparedness responsibilities to the Rural Electrification Administration."

HOMELAND SECURITY PRESIDENTIAL DIRECTIVE 5 (HSPD-5) - Management of Domestic Incidents

This directive enhances the ability of the United States to manage domestic incidents by establishing a single, comprehensive National Incident Management System. It requires all Federal departments and agencies to cooperate with the Secretary of Homeland Security by providing their full and prompt cooperation, resources, and support, as appropriate and consistent with their own responsibilities for protecting the Nation's security. The directive provides direction for Federal assistance to State and local authorities when their resources are overwhelmed, or when Federal interests are involved.

"(1) To enhance the ability of the United States to manage domestic incidents by establishing a single, comprehensive national incident management system."

"(3) To prevent, prepare for, respond to, and recover from terrorist attacks, major disasters, and other emergencies, the United States Government shall establish a single, comprehensive approach to domestic incident management. The objective of the United States Government is to ensure that all levels of government across the Nation have the capability to work efficiently and effectively together, using a national approach to domestic incident management. In these efforts, with regard to domestic incidents, the

United States Government treats crisis management and consequence management as a single, integrated function, rather than as two separate functions."
"(18) The heads of Federal departments and agencies shall adopt the National Incident Management System (NIMS) within their departments and agencies and shall provide support and assistance to the Secretary in the development and maintenance of the NIMS. All Federal departments and agencies will use the NIMS in their domestic incident management and emergency prevention, preparedness, response, recovery, and mitigation activities, as well as those actions taken in support of State or local entities. The heads of Federal departments and agencies shall participate in the National Response Plan (NRP), shall assist and support the Secretary in the development and maintenance of the NRP, and shall participate in and use domestic incident reporting systems and protocols established by the Secretary."*

*The revised National Response Plan became the National Response Framework in 2008 under the Post-Katrina Emergency Management Reform Act.

PRESIDENTIAL POLICY DIRECTIVE 8 (PPD-8) - *National Preparedness*

Presidential Policy Directive 8 (PPD-8) – National Preparedness, replaces the prior national preparedness directive, Homeland Security Presidential Directive – 8 (HSPD-8) issued in 2003, and HSPD-8 Annex I - National Planning, issued in 2007.

PPD-8 takes an all of nation/whole of community capabilities-based approach to preparing for the wide range of threats and hazards the Nation faces. It involves federal partners, state, local, tribal and insular area leaders, the private sector, non-governmental organizations, faith-based and community organizations and the general public.

PPD-8 is comprised of the following:

- *National Preparedness Goal*, the cornerstone for implementation of PPD-8, it identifies the Nation's core capabilities in order to achieve the goal of a secure and resilient Nation;
- *National Preparedness System*, an integrated set of guidance, programs, and processes to enable the Nation to meet the National Preparedness Goal;
- *National Preparedness Report*, an annual summary of the progress being made toward building, sustaining, and delivering the core capabilities described in the Goal;
- *National Planning Frameworks,* coordinating structures that align key roles and responsibilities to deliver the necessary capabilities across each of the five mission areas— Prevention, Protection, Mitigation, Response, and Recovery; and
- *Federal Interagency Operational Plans*, guides that address the critical tasks, responsibilities and resourcing, personnel, and sourcing requirements for the core

capabilities.

With the implementation of PPD-8, the National Response Framework (NRF) will no longer stand alone, but functions as one of five national planning frameworks, each focusing on a different yet interdependent mission area; Prevention, Protection, Mitigation, Response, and Recovery. The revised NRF also focuses on how the Nation delivers these response core capabilities across the whole community, emphasizing the need for the involvement and integration of the whole community.

PRESIDENTIAL POLICY DIRECTIVE 21 (PPD-21) — CRITICAL INFRASTRUCTURE SECURITY AND RESILIENCE

Issued on February 12, 2013, Presidential Policy Directive 21 (PPD-21) — Critical Infrastructure Security and Resilience "…establishes national policy on critical infrastructure security and resilience" as a "shared responsibility among the Federal, state, local, tribal, and territorial (SLTT) entities, and public and private owners and operators of critical infrastructure" and "refines and clarifies the critical infrastructure-related functions, roles, and responsibilities across the Federal Government, as well as enhances overall coordination and collaboration."

PPD-21 has three strategic imperatives:

"1) Refine and clarify functional relationships across the Federal Government to advance the national unity of effort to strengthen critical infrastructure security and resilience;

2) Enable effective information exchange by identifying baseline data and systems requirements for the Federal Government; and

3) Implement an integration and analysis function to inform planning and operations decisions regarding critical infrastructure."

"All Federal department and agency heads are responsible for the identification, prioritization, assessment, remediation, and security of their respective internal critical infrastructure that supports primary mission essential functions. Such infrastructure shall be addressed in the plans and execution of the requirements in the National Continuity Policy."

Roles and Responsibilities

"Effective implementation of this directive requires a national unity of effort pursuant to strategic guidance from the Secretary of Homeland Security. That national effort must include expertise and day-to-day engagement from the Sector-Specific Agencies (SSAs) as well as the specialized or support capabilities from other Federal departments and agencies, and strong collaboration with critical infrastructure owners and operators and SLTT entities. Although the roles and responsibilities identified in this directive are directed at Federal departments and agencies, effective partnerships with critical infrastructure owners and operators and SLTT entities are imperative to strengthen the security and resilience of the Nation's critical infrastructure."

Sector-Specific Agencies

Recognizing existing statutory or regulatory authorities of specific Federal departments and agencies, and leveraging existing sector familiarity and relationships, SSAs shall carry out the following roles and responsibilities for their respective sectors:"
"1)" … "coordinate with the Department of Homeland Security (DHS) and other relevant Federal departments and agencies and collaborate with critical infrastructure owners and operators, where appropriate with independent regulatory agencies, and with SLTT entities, as appropriate";
2) Serve as a day-to-day Federal interface for the dynamic prioritization and coordination of sector-specific activities;
3) Carry out incident management responsibilities consistent with statutory authority and other appropriate policies, directives, or regulations;
4) Provide, support, or facilitate technical assistance and consultations for that sector to identify vulnerabilities and help mitigate incidents, as appropriate; and
5) Support the Secretary of Homeland Security's statutorily required reporting requirements by providing on annual basis sector-specific critical infrastructure information."
"7) The Nuclear Regulatory Commission (NRC) is to oversee its licensees' protection of commercial nuclear power reactors and non-power nuclear reactors used for research, testing, and training; nuclear materials in medical, industrial, and academic settings, and facilities that fabricate nuclear fuel; and the transportation, storage, and disposal of nuclear materials and waste. The NRC is to collaborate, to the extent possible, with DHS, DOJ, the Department of Energy, the Environmental Protection Agency, and other Federal departments and agencies, as appropriate, on strengthening critical infrastructure security and resilience."
"9) Federal departments and agencies shall provide timely information to the Secretary of Homeland Security and the national critical infrastructure centers necessary to support cross-sector analysis and inform the situational awareness capability for critical infrastructure."

Three Strategic Imperatives

1) Refine and Clarify Functional Relationships across the Federal Government to Advance the National Unity of Effort to Strengthen Critical Infrastructure Security and Resilience

"As part of this refined structure, there shall be two national critical infrastructure centers operated by DHS – one for physical infrastructure and another for cyber infrastructure. They shall function in an integrated manner and serve as focal points for critical infrastructure partners to obtain situational awareness and integrated, actionable information to protect the physical and cyber aspects of critical infrastructure." and "integration and analysis function (further developed in Strategic Imperative 3) shall be implemented between these two national centers."
"The success of these national centers, including the integration and analysis function, is dependent on the quality and timeliness of the information and intelligence they receive from the SSAs and other Federal departments and agencies, as well as from critical infrastructure owners and operators and SLTT entities." "These national centers shall not impede the ability of the heads of Federal departments and agencies to carry out or perform their responsibilities for national defense, criminal, counterintelligence, counterterrorism, or investigative activities."

2) <u>Enable Efficient Information Exchange by Identifying Baseline Data and Systems Requirements for the Federal Government</u>

"A secure, functioning, and resilient critical infrastructure requires the efficient exchange of information, including intelligence, between all levels of governments and critical infrastructure owners and operators. This must facilitate the timely exchange of threat and vulnerability information as well as information that allows for the development of a situational awareness capability during incidents. The goal is to enable efficient information exchange through the identification of requirements for data and information formats and accessibility, system interoperability, and redundant systems and alternate capabilities should there be a disruption in the primary systems."

"Greater information sharing within the government and with the private sector can and must be done while respecting privacy and civil liberties. Federal departments and agencies shall ensure that all existing privacy principles, policies, and procedures are implemented consistent with applicable law and policy and shall include senior agency officials for privacy in their efforts to govern and oversee information sharing properly."

3) <u>Implement an Integration and Analysis Function to Inform Planning and Operational Decisions Regarding Critical Infrastructure"</u>
"The third strategic imperative"…"shall include the capability to collate, assess, and integrate vulnerability and consequence information with threat streams and hazard information to:

a. Aid in prioritizing assets and managing risks to critical infrastructure;
b. Anticipate interdependencies and cascading impacts;
c. Recommend security and resilience measures for critical infrastructure prior to,

during, and after an event or incident; and

d. Support incident management and restoration efforts related to critical infrastructure."

"This function shall not replicate the analysis function of the IC or the National Counterterrorism Center, nor shall it involve intelligence collection activities. The IC, DOD, DOJ, DHS, and other Federal departments and agencies with relevant intelligence or information shall, however, inform this integration and analysis capability regarding the Nation's critical infrastructure by providing relevant, timely, and appropriate information to the national centers. This function shall also use information and intelligence provided by other critical infrastructure partners, including SLTT and nongovernmental analytic entities."

Innovation and Research and Development

The Secretary of Homeland Security, in coordination with the Office of Science and Technology Policy (OSTP), the SSAs, DOC, and other Federal departments and agencies, shall provide input to align those Federal and Federally-funded research and development (R&D) activities that seek to strengthen the security and resilience of the Nation's critical infrastructure, including:

1) Promoting R&D to enable the secure and resilient design and construction of critical infrastructure and more secure accompanying cyber technology;
2) Enhancing modeling capabilities to determine potential impacts on critical infrastructure of an incident or threat scenario, as well as cascading effects on other sectors;
3) Facilitating initiatives to incentivize cybersecurity investments and the adoption of critical infrastructure design features that strengthen all-hazards security and resilience; and
4) Prioritizing efforts to support the strategic guidance issued by the Secretary of Homeland Security."

Implementation of the Directive

The Secretary of Homeland Security shall take the following actions as part of the implementation of this directive.

1) Critical Infrastructure Security and Resilience Functional Relationships. Within 120 days of the date of this directive, the Secretary of Homeland Security shall develop a description of the functional relationships within DHS and across the Federal Government related to critical infrastructure security and resilience. It should include the roles and functions of the two national critical infrastructure centers and a discussion of the analysis and integration function." "The Secretary shall coordinate this effort with the SSAs and other relevant Federal departments and agencies. The Secretary shall provide the description to the

President through the Assistant to the President for Homeland Security and Counterterrorism."

"2) Evaluation of the Existing Public-Private Partnership Model. Within 150 days of the date of this directive, the Secretary of Homeland Security, in coordination with the SSAs, other relevant Federal departments and agencies, SLTT entities, and critical infrastructure owners and operators, shall conduct an analysis of the existing public-private partnership model and recommend options for improving the effectiveness of the partnership in both the physical and cyber space."

"3) Identification of Baseline Data and Systems Requirements for the Federal Government to Enable Efficient Information Exchange. Within 180 days of the date of this directive, the Secretary of Homeland Security, in coordination with the SSAs and other Federal departments and agencies, shall convene a team of experts to identify baseline data and systems requirements to enable the efficient exchange of information and intelligence relevant to strengthening the security and resilience of critical infrastructure. "

"4) Update to National Infrastructure Protection Plan. Within 240 days of the date of this directive, the Secretary of Homeland Security shall provide to the President," "a successor to the National Infrastructure Protection Plan to address the implementation of this directive"… "The Secretary shall coordinate this effort with the SSAs, other relevant Federal departments and agencies, SLTT entities, and critical infrastructure owners and operators."

"5) National Critical Infrastructure Security and Resilience R&D Plan. Within 2 years of the date of this directive, the Secretary of Homeland Security, in coordination with the OSTP, the SSAs, DOC, and other Federal departments and agencies, shall provide to the President"

Designated Critical Infrastructure Sectors and Sector-Specific Agencies

"This directive identifies 16 critical infrastructure sectors and designates associated Federal SSAs. In some cases co-SSAs are designated where those departments share the roles and responsibilities of the SSA."

…" Energy:
Sector-Specific Agency: Department of Energy"

EXECUTIVE ORDER 13636 — IMPROVING CRITICAL INFRASTRUCTURE CYBERSECURITY

Released on February 12, 2013, the Executive Order outlines U.S. policy "to enhance the security and resilience of the Nation's critical infrastructure and to maintain a cyber-environment that encourages efficiency, innovation, and economic prosperity while promoting safety, security, business confidentiality, privacy, and civil liberties". The goals can be achieved "through a partnership with the owners and operators of critical infrastructure to improve cybersecurity information sharing and collaboratively develop and implement risk- based standards."

"Sec 4.

(c) To assist the owners and operators of critical infrastructure in protecting their systems from unauthorized access, exploitation, or harm, the Secretary" (of Homeland Security) "in collaboration with the Secretary of Defense, shall, within 120 days of the date of this order, establish procedures to expand the Enhanced Cybersecurity Services program to all critical infrastructure sectors." "This voluntary information sharing program will provide classified cyber threat and technical information from the Government to eligible critical infrastructure companies or commercial service providers that offer security services to critical infrastructure."

(d) The Secretary"…"shall expedite the processing of security clearances to appropriate personnel employed by critical infrastructure owners and operators, prioritizing the critical infrastructure identified in section 9 of this order."

"Sec. 5. Privacy and Civil Liberties Protections. (a) Agencies shall coordinate their activities under this order with their senior agency officials for privacy and civil liberties and ensure that privacy and civil liberties protections are incorporated into such activities. Such protections shall be based upon the Fair Information Practice Principles and other privacy and civil liberties policies, principles, and frameworks as they apply to each agency's activities."

"(b)… The Chief Privacy Officer and the Officer for Civil Rights and Civil Liberties of the Department of Homeland Security (DHS) shall assess the privacy and civil liberties risks of the functions and programs undertaken by DHS"…. "Senior agency privacy and civil liberties officials for other agencies engaged in activities under this order shall conduct assessments of their agency activities and provide those assessments to DHS for consideration and inclusion in the report." "The report shall be reviewed on an annual basis and revised as necessary. The report may contain a classified annex if necessary."

"Sec. 6. Consultative Process. The Secretary shall establish a consultative process to coordinate improvements to the cybersecurity of critical infrastructure. As part of the consultative process, the Secretary shall engage and consider the advice, on matters set forth in this order, of the Critical Infrastructure Partnership Advisory Council; Sector Coordinating Councils; critical infrastructure owners and operators; Sector-Specific Agencies; other relevant agencies; independent regulatory agencies; State, local, territorial, and tribal governments; universities; and outside experts."

"Sec. 7. Baseline Framework to Reduce Cyber Risk to Critical Infrastructure.

(a) The Secretary of Commerce shall direct the Director of the National Institute of Standards and Technology (the "Director") to lead the development of a framework to reduce cyber risks to critical infrastructure (the "Cybersecurity Framework")."

"…(d) In developing the Cybersecurity Framework, the Director shall engage in an open public review and comment process. The Director shall also consult with the Secretary, the National Security Agency, Sector- Specific Agencies and other interested agencies including OMB, owners and operators of critical infrastructure, and other stakeholders through the consultative process established in section 6 of this order."

"Sec. 8. Voluntary Critical Infrastructure Cybersecurity Program.

(a) The Secretary, in coordination with Sector- Specific Agencies, shall establish a voluntary program to support the adoption of the Cybersecurity Framework by owners and operators of critical infrastructure and any other interested entities (the "Program").

(b) Sector-Specific Agencies, in consultation with the Secretary and other interested agencies, shall coordinate with the Sector Coordinating Councils to review the Cybersecurity Framework and, if necessary, develop implementation guidance or supplemental materials to address sector-specific risks and operating environments.

(c) Sector-Specific Agencies shall report annually to the President, through the Secretary, on the extent to which owners and operators notified under section 9 of this order are participating in the Program."

"Sec. 9. Identification of Critical Infrastructure at Greatest Risk.

(a) Within 150 days of the date of this order, the Secretary shall use a risk-based approach to identify critical infrastructure where a cybersecurity incident could reasonably result in catastrophic regional or national effects on public health or safety, economic security, or national security. In identifying critical infrastructure for this purpose, the Secretary shall use the consultative process established in section 6 of this order and draw upon the expertise of Sector-Specific Agencies."

"(b) Heads of Sector-Specific Agencies and other relevant agencies shall provide the Secretary with information necessary to carry out the responsibilities under this section. The Secretary shall develop a process for other relevant stakeholders to submit information to assist in making the identifications required in subsection (a) of this section."

"(c) The Secretary, in coordination with Sector-Specific Agencies, shall confidentially notify owners and operators of critical infrastructure identified under subsection (a) of this section that they have been so identified, and ensure identified owners and operators are provided the basis for the determination."

"(e) Independent regulatory agencies with responsibility for regulating the security of critical infrastructure are encouraged to engage in a consultative process with the Secretary, relevant Sector-Specific Agencies, and other affected parties to consider prioritized actions to mitigate cyber risks for critical infrastructure consistent with their authorities."

NATIONAL SECURITY PRESIDENTIAL DIRECTIVE 51 (NSPD 510 AND HOMELAND SECURITY PRESIDENTIAL DIRECTIVE 20 (HSPD 20) – NATIONAL CONTINUITY POLICY

NSPD 51 and HSPD 20 prescribe continuity requirements for the Executive Branch, organized around National Essential Functions (NEFs). NEFs are government functions necessary to lead and sustain the nation during a catastrophic emergency. Primary Mission Essential Functions (PMEFs) are government functions that must be performed in order to support or implement the performance of NEFs. DOE PMEFs are detailed in the DOE Continuity of Operations Plan. DOE is responsible for the following PMEFs and NEFs:

NATIONAL ESSENTIAL FUNCTIONS (NEF)
NEF # 3: Defending the Constitution of the United States against all enemies, foreign and domestic, and preventing or interdicting attacks against the United States or its people, property, or interests

This NEF includes Federal executive department and agency functions to protect and defend the worldwide interests of the United States against foreign or domestic enemies, honor security agreements and treaties with allies, implement military operations ordered by the President, maintain military readiness, and maintain preparedness to achieve national objectives.

NEF #6: Providing rapid and effective response to and recovery from the domestic consequences of an attack or other incident

This NEF includes Federal executive department and agency functions to implement response and recovery plans, including, but not limited to, the implementation of the National Response Plan

NEF #8: Providing for critical Federal Government services that address the national health, safety, and welfare needs of the United States

This NEF includes Federal executive department and agency functions that ensure that the critical Federal-level health, safety, and welfare services of the Nation are provided during an emergency.

DOE #1: Assure Nuclear Materials Safety: Maintain the safety and security of nuclear materials in the Department of Energy (DOE) Complex at fixed sites and in transit. (NEF#3)

DOE #2: Respond to Nuclear Incidents: Respond to a nuclear incident, both domestically and internationally, caused by terrorist activity, natural disaster or accident, including by mobilizing the resources to support these efforts. (NEF #6)

DOE #3: Manage Energy Infrastructure: Manage the National Energy Infrastructure, the drawdown of Strategic Petroleum Reserve and/or the Northeast Home Heating Oil Reserve. (NEF #6 and #8)

PRIMARY MISSION ESSENTIAL FUNCTION (PMEF) DOE #1

Maintain the safety and security of nuclear materials in the Department of Energy (DOE) Complex at fixed sites and in transit.

Descriptive Narrative: Assure the credibility, viability, reliability and security of U.S. nuclear weapons capability. Assure the prompt availability of technical experience, skills, and capabilities, including from the DOE nuclear weapons complex laboratories, to support essential nuclear weapons work. Assure the safety and security of essential nuclear weapons complex materials, equipment, facilities, and other DOE nuclear materials.

- Securely handle, store, and transfer nuclear materials at all times.
- Validate nuclear materials inventories (accountability).
- Direct and oversee nuclear weapons development, assessment, and certification activities required to maintain the stockpile in a safe and reliable state.
- Support resolution of safety and performance issues associated with the stockpile; ensure the evaluation and assessment of nuclear weapons in the active stockpile to support certification.
- Oversee the qualification of replacement weapon components that are necessary to support essential stockpile requirements.

Implications if Not Conducted: If the Department does not ensure the safety, security, and reliability of nuclear weapons, they may not be readily available when required and nuclear material or weapons could be diverted to unauthorized uses, which could compromise National security. Loss of control or accountability of nuclear materials could also lead to severe economic and/or public health consequences. A by-product of not ensuring security and reliability of the nuclear weapons stockpile is that our nuclear weapons program could lose credibility, thereby eroding National and international confidence in our deterrence capabilities.

Associated National Essential Function (NEF): # 3
Timing: Within 12 hours

Partners: Various State and local law enforcement, Federal Bureau of Investigation (FBI), Department of Defense (DOD), National Laboratories

PRIMARY MISSION ESSENTIAL FUNCTION (PMEF) DOE #2

Respond to a nuclear incident, both domestically and internationally, caused by terrorist activity, natural disaster or accident, including by mobilizing the resources to support these efforts.

Descriptive Narrative: Execute responsibilities under the NRF and other similar plans and agreements. Maintain the capability to immediately notify, alert, mobilize, and deploy radiological emergency response assets, assistance, and/or support on both a domestic and international basis because of emergencies or significant incidents. Provide technical expertise on nuclear and radiological matters and available analytical capabilities of DOE sites and National Laboratories.

- Rapidly respond to emergencies involving nuclear weapons, materials, or facilities, including securing vulnerable foreign nuclear materials.
- Respond to a nuclear incident, both domestically and internationally, resulting from terrorist activity, natural disaster, or accident.
- Nuclear Weapons Incident Response - Nuclear Emergency Support Team provides technical assistance to a lead Federal Agency on various incidents including terrorist's threats involving the use of nuclear materials.
- National Technical Nuclear Forensics Program, which enables operational support for pre- detonation and post-detonation nuclear forensics and attribution program.
- National Weapons Incident Response - Stabilization Implementation Program - leverages and develops "Render Safe" technologies that can be applied by teams to isolate and stabilize a nuclear device until the National response teams arrive to render it safe.

Implications if Not Conducted: If the Department does not respond effectively to emergencies or incidents involving nuclear and radiological materials, the safety and health of citizens would be jeopardized.

Associated National Essential Function (NEF): # 6
Timing: Within 12 hours
Partners: Various State and local law enforcement, Environmental Protection Agency, Department of State (DOS), FBI, Department of Agriculture, DOD, DOE National Laboratories and Field offices, Federal Emergency Management Agency

PRIMARY MISSION ESSENTIAL FUNCTION (PMEF) DOE #3

Primary Mission Essential Function (PMEF) DOE #3: Continuously monitor and manage the National energy infrastructure including the drawdown of Strategic Petroleum Reserve and/or the Northeast Home Heating Oil Reserve. Respond to energy infrastructure disruptions to ensure rapid recovery of energy supplies.

Descriptive Narrative: Monitor and publish information regarding the Nation's Energy Infrastructure including the status of energy facilities and resources (storage, production, and transmission facilities) that support National security and welfare. Manage the Strategic Petroleum Reserve, the Northeast Heating Oil Reserve, and the Federal Power Marketing Administrations. Manage and direct the DOE National Laboratory capabilities to provide necessary technical support to respond to significant energy infrastructure disruptions. Advise National leadership on the allocation of energy resources.
Execute responsibilities under ESF #12 in the National Response Framework. Coordinate National energy related issues:

- Conduct assessments and analyses of impacts to energy storage.
- Conduct assessments of power production, generation, transmission, and distribution.
- Assess the infrastructure and transportation systems related to oil, gas, and coal.
- Collect, evaluate, assemble, analyze, and disseminate data and information related to energy resources, production, demand, technology, and related economic and statistical information.

Implications if Not Conducted: If the Department does not act in response to a wide-scale, energy- related emergency, the energy infrastructure will be forced to attempt matter resolution on a State-by- State or region-by-region basis.

Associated National Essential Functions (NEFs): #6 and 8
Timing: Within 12 hours
Partners: Various States, utilities, private companies, DHS, DOE National Laboratories and program offices, Nuclear Regulatory Commission

APPENDIX E: COMMON INDUSTRY TERMS

Glossary[8]

(Note: For reference purposes)

Access Charge: A fee levied for access to a utility's transmission or distribution system.

Alternating Current (AC): An electric current that reverses its direction of flow periodically, AX is wave of electrons that flow back and forth through a conductor wire.

Ampere (amp): A unit of measuring electric flow

Ancillary Services: Services necessary to support the transmission of electric energy from resource loads, while maintaining reliable operation of the transmission system. Examples include spinning reserve, supplemental reserve, reactive power, regulation and frequency response, and energy imbalance.

Available Transmission Capacity (ATC): A measure of the electric transfer capability remaining in the physical transmission network for sale over and above already committed users.

Biomass: In the contest of electric energy, any organic material that is converted to electricity, including woods, canes, grasses, farm manure, and sewage.

Blackout: Emergency loss of electricity due to fail of generation, transmission, or distribution

Black Start: the process of restoring a power station to operation without relying on the external electric power transmission network.

British Thermal Unit (BTU): A unit of energy equivalent to 1,055 Joules, and is also the energy required to raise 1 pound of water 1 degree Fahrenheit at 39 degrees Fahrenheit.

Bulk Power System: All generating plants, transmission lines and equipment.

Busbar Cost: The cost of producing one KWh of electricity delivered to, but not through the transmission system.

Busbar: The point at which power is available for transmission.

Capacitor: A device that maintains or increases voltage in power lines and improves efficiency of the system by compensating for inductive losses.

Cascading Outage: The uncontrolled, successive loss of system elements triggered by an incident at any location. Results in widespread service interruption that cannot be restrained.

Circuit: A path through which electric current can flow.

Commission: The regulatory body having jurisdiction over a utility.

Congestion: Transmission paths that are constrained, which may limit power transactions because of insufficient capacity. Congestion can be relieved by increasing generation or by reducing load.

[8] Source: energy.gov/sites/prod/files/oeprod/DocumentsandMedia/primer.pdf

Control Area: Electric power system in which operators match loads to resources within the system, maintain scheduled interchange between control areas, maintain frequency within reasonable limits, and provide sufficient generation capacity to maintain operating reserves.

Curtailment: A reduction in the scheduled capacity or energy delivery due to a transmission constraint.

Demand: The amount of power consumers require at a particular time. Demand is synonymous with load. System demand is measured in megawatts (MW).

Demand Response (DR): Deliberate intervention by a utility in the marketplace to influence demand for electric power or shift the demand to different times to capture cost savings.

Direct Current: Electricity flowing continuously in one direction, the constant flow of electrons in a wire.

Dispatch: The physical inclusion of a generator's output onto the transmission grid by an authorized scheduling utility.

Distributed Generation (DG): Electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side of the meter, or on the customer side.

Electrical Energy: The generation or use of electric power over a period, usually expressed in megawatt hours (MWh), kilowatt hours (KWh) or gigawatt hours (GWh), as opposed to electric capacity which is measured in kilowatts.

Federal Energy Regulatory Commission (FERC): A federal agency created in 1977 to regulate, among other things, interstate wholesale sales and transportation of gas and electricity at "just and reasonable" rates.

Firm Transmission Right (FTR): An FTR is a tradable entitlement to schedule 1 megawatt for use of a flow path in a particular direction for a particular hour.

Firm Transmission: Transmission service that may not be interrupted for any reason except during emergency when continued delivery of power is not possible.

Forced Outage: Shutdown of a generating unit, transmission line or other facility for emergency reasons. Forced outage reserves consist of peak generating capability available to serve loads during forced outages.

Frequency: The oscillatory rate in Hertz (Hz-cycles per second) of the alternating current in a circuit. The standard frequency across the bulk power system is 60 Hz in the United States and 50 Hz in Europe. Maintaining standard system frequency of the grid within acceptable limits is the responsibility of the control area operator (CAO).

Grid: Layout of the electrical transmission system; a network of transmission lines and the associated substations and other equipment required to move power.

High Voltage Lines: Used to transmit power between utilities. The definition of "high" varies, but it is opposed to "low" voltage lines that deliver power to homes and most businesses.

Incremental Rates: The allocation of cost for an additional service or construction project directly to those who benefit from the service instead of rolling it into overall rates. To determine the incremental unit cost, the added cost is divided by the added capacity or output (See Rolled-in Pricing).

Independent System Operator (ISO): Entity that controls and administers nondiscriminatory access to electric transmission in a region across several systems, independent from the owners of the facilities.

Interchange (or Transfer): The exchange of electric power between control areas.

Interconnection: A specific connection between one utility and another. NERC's definition: "When capitalized, any one of the four bulk electric system networks in North America: Eastern, Western, ERCOT and Quebec. When not capitalized, the facilities that connect two systems or control areas.

Intertie: Usually refers to very high voltage lines that carry electric power long distances. A term also used to describe a circuit connecting two or more control areas or systems of an electric system ("tie line").

Joule (J): A unit of energy equivalent to 1 Watt of power used over 1 second.

Kilovolt (kV): Electrical potential equal to 1,000 volts.

Kilowatt (kW): A unit to measure the rate at which electric power is being consumed. One kilowatt equals 1,000 watts.

Kilowatt-Hour (kWh): The basic unit for pricing electric energy; equal to 1 kilowatt of power supplied continuously for one hour. (Or the amount of electricity needed to light 10 100-watt light bulbs for one hour.) One kilowatt hour equals 1,000 watt hours.

Line losses: Power lost in the course of transmitting and distributing electricity.

Load: The amount of power demanded by consumers. It is synonymous with demand.

Load Balancing: Meeting fluctuations in demand or matching generation to load to keep the electrical system in balance.

Load Forecast: An attempt to determine energy consumption at a future point in time.

Load Profiling: The process of examining a consumer's energy use in order to gauge the level of power being consumed and at what times during the day.

Load Serving Entity (LES): Any entity providing service to load.

Load Shedding: The process of deliberately removing (either manually or automatically) preselected demands from a power system, in response to an abnormal condition (such as very high load), to maintain the integrity of the system.

Load Shifting: Shifting load from peak to off-peak periods, including use of storage water heating, storage space heating, cool storage, and customer load shifts.

Locational Marginal Pricing (LMP): Under LMP, the price of energy at any location in a network is equal to the marginal coast of supplying an increment of load at that location.

Loop Flow: The unscheduled use of another utility's transmission, resulting from movement of electricity along multiple paths in a grid, whereby power, in taking path of least resistance, might be physically delivered through any of a number of possible paths that are not easily controlled.

Market Clearing Price: Price determined by the convergence of buyers and sellers in a free market.

Megawatt (MW): One megawatt equals one million kilowatts.

Megawatt-hour (MWh): One megawatt hour is equal to one million kilowatt hours.

Megawatt-mile Rate: An electric transmission rate based on distance, as opposed to postage stamp rates, which are based on zones.

Megawatt-year and megawatt-months: Units to measure and price transmission services. A megawatt-year is 1 megawatt of transmission capacity made available for one year. Similarly, a megawatt-month is 1 megawatt of capacity made available for one month.

Network: A system of transmission or distribution lines cross-connected to permit multiple supplies to enter the system.

Network Transmission (NT): A transmission contract or service as described in a transmission provider's Open Access Transmission Tariff filed with the Federal Energy Regulatory Commission.

Non-firm Transmission: Transmission service that may be interrupted in favor of firm transmission schedules or for other reasons.

North American Electric Reliability Council (NERC): Former in 1968 to promote the reliability of generation and transmission in the electric utility industry. Consists of 10 regional reliability councils and one affiliate encompassing all the electric systems in the United States, Canada, and the northern part of Baja, Mexico.

Ohm (Ω): A unit of electric resistance equivalent to 1 volt per ampere.

Open Transmission Access: Transmission is offered equally to all interested parties

Outage: Removal of generating capacity from service either forced or scheduled. Pancaking: Fees that are tacked on as electricity flows through a number of transmission systems.

Parallel Path Flows: The difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path.

Synonyms: Loop flows, unscheduled power flows, and circulating power flows.

Peak Demand: The maximum (usually hourly) demand of all customer demands plus losses. Usually expressed in MW.

Performance-based Regulation: Rates designed to encourage market responsiveness. They can be automatically adjusted from an initial cost-of-service rate based on a company's performance. Performance indicators generally reflect consumer and societal values.

Point of Delivery: The physical point of connection between the transmission provider and a utility. Power is metered here to determine the cost of the transmission service.

Point-to-Point Transmission Service: The reservation and/or transmission of energy on either a firm basis and/or a non-firm basis from point(s) of receipt to point(s) of delivery under a tariff, including any ancillary services that are provided by the transmission provider.

Postage Stamp Rates: Flat rates charged for transmission service without regard to distance.

Power Pool: Two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs.

Public Utility Holding Company Act (PUHCA): Legislation enacted in 1935 to protect utility stockholders and consumers from financial and economic abuses of utility holding companies. Generally, ownership of 10 percent or more of the voting securities of a public utility subjects a company to extensive regulation under the Securities and Exchange Commission. The Comprehensive National Energy Policy Act of 1992 opened the power market by granting a class of competitive generators exemption from PUHCA regulation. Radial: An electric transmission or distribution system that is not networked and does not provide sources of power.

Rate Base: The investment value established by a regulatory authority upon which a utility is permitted to earn a specified rate of return.

Reactive Power: The out-of-phase component of the total volt-amperes in an electric circuit, usually expressed in VAR (volt-ampere-reactive). It represents the power involved in the electric fields developed when transmitting alternating-current power (the alternating exchange of stored inductive and capacitive energies in a circuit). Used to control voltage on the transmission network, particularly the power flow incapable of performing real work or energy transfer.

Real Power: Portion of the electrical flow capable of performing real work or energy transfer. Expressed in megawatts.

Real Time Pricing: Time-of-day pricing in which customers receive frequent signals on the cost of consuming electricity at that moment.

Regional Transmission Organization (RTO): An independent regional transmission operator and service provider that meets certain criteria, including those related to independence and market size, established by FERC Order 2000.

Reliability Practices: The methods of implementing policies and standards designed to ensure the adequacy and security of the interconnected electric transmission system in accordance with applicable reliability criteria (i.e., NERC, local regional entity criteria).

Reliability: Term used to describe a utility's ability to deliver an uninterrupted stream of energy to its customers and how well the utility's system can handle an unexpected shock that may affect generation, transmission or distribution service.

Right-of-Way: Strip of land used for utility lines. Most utilities negotiate easements with property owners or use the right of eminent domain to gain access. In some cases, the land is purchased outright.

Rolled-in Pricing: The allocation of cost for an additional service or construction project into overall rates, regardless of the cause or beneficiary of the cost.

Schedule: An agreed-upon transaction size (mega-watts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the contracting parties and the control area(s) involved in the transaction.

Scheduled Outage: Scheduled outages occur when a portion of a power system is shut down intentionally, typically to allow for pre-planned activities such as maintenance.

Seams: The interface between regional entities and/or markets at which material external impacts may occur. The regional entities' actions may have reliability, market interface, and/or commercial impacts (some or all).

Service Territory: Physical area served by a utility.

Spinning Reserve: Electric generating units connected to the system that can automatically respond to frequency deviations and operate when needed.

Spot Market: A market characterized by short-term, typically interruptible or best efforts contracts for specified volumes. The bulk of the natural gas spot market trades on a monthly basis, while power marketers sell spot supplies on an hourly basis.

Standards of Conduct: When FERC established the requirement for companies to use OASIS systems in electric transmission (Order 889), it also established a code of conduct to ensure that transmission owners and their affiliates would not have an unfair competitive advantage in using the transmission lines to sell power.

Standby Demand: The demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for the outage of the customer's primary source. Standby demand is intended to be used infrequently by any one customer.

Step-Down/Step-Up: Step-down is the process of changing electricity from a higher to a lower voltage. Step-up is the opposite. Step-up transformers usually are located at generator sites, while step-down transformers are found at the distribution side.

Substation: Equipment that switches, steps down, or regulates voltage of electricity. Also serves as a control and transfer point on a transmission system.

Superconductivity, High Temperature (HTS): A technology for transmitting electricity that uses a conductor designed to offer no resistance to electrical voltage. No resistance allows power to be transmitted without losses. Materials typically have no resistance at temperatures approaching absolute zero (-273°C). High temperature, for this purpose, means a temperature high enough to maintain cost-effectively while maintaining superconductivity.

Supervisory Control and Data Acquisition (SCADA): A system of remote control and telemetry used to monitor and control the electric transmission system.

Tariff: A document, approved by the responsible regulatory agency, listing the terms and conditions, including a schedule of prices, under which utility services will be provided.

Total Transmission Capability (TTC): The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner at a given time.

TRANSCO (Transmission Company): A company engaged solely in the transmission function;

another kind of regional transmission organization. A TRANSCO owns and operates the regional transmission system. Also refers to the portion of an electric utility's business that involves bulk transmission of power, operated separately from any other power functions the utility might own or operate.

Transfer Capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. Generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, power pool, control area, sub-region or NERC region, or a portion of any of these.

Transformer: Electrical device that changes the voltage in AC circuits.

Transmission Loading Relief (TLR): Procedures developed by NERC to mitigate operating security limit violations.

Transmission Operating Agreement (TOA): An agreement between an RTO and a utility, whereby the utility assigns control over the utility's transmission system in exchange for an RTO agreement to make payment to the utility to cover the utility's transmission system costs.

Transmission Reliability Margin (TRM): Amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

Transmission: The process of transporting wholesale electric energy at high voltages from a supply source to utilities.

Vertical Integration: Refers to the traditional electric utility structure, whereby a company has direct control over its transmission, distribution and generation facilities and can offer a full range of power services.

Volt: The unit of electromotive force or electric pressure which, if steadily applied to a circuit having a resistance of 1 ohm, would produce a current of one ampere.

Voltage-Ampere-Reactive (VAR): The unit of measurement for reactive power. Recall that 1 Watt = 1 Volt-Ampere.

Watt: The electrical unit of real power or rate of doing work, equivalent to 1 ampere flowing against an electrical pressure of 1 volt. One watt is equivalent to about 1/746 horsepower, or 1 joule per second.

Wheeling: In the electric market, "wheeling" refers to the interstate sale of electricity or the transmission of power from one system to another.

Wholesale Competition: A system in which a distributor of power would have the option to buy its power from a variety of power producers, and the power producers would be able to compete to sell their power to a variety of distribution companies.

Wholesale Electricity: Power that is bought and sold among utilities, nonutility generators and other wholesale entities, such as municipalities.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (that sell to retail customers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Wholesale Wheeling: The transmission of electricity from a wholesale supplier to another wholesale supplier by a third party.

Wires Charge: A fee that is imposed on retail power providers or their customers to use a utility's transmission and distribution system.

APPENDIX B

Electric and Gas Reliability Workshop

April 17, 2012

History of Electric Deregulation in ERCOT

Tom Hunter

Public Utility Commission of Texas

ERCOT Facts

- Covers 75% of the land and 85% of the electric load in Texas
- Includes the cities of Houston, Dallas, Fort Worth, San Antonio, Austin, Corpus Christi, Midland & the Rio Grande Valley
- 23 million customers
- Regulated by the PUC with oversight from the Texas Legislature
- ERCOT is one of 10 North American Independent System Operators/Regional Transmission Organizations

ERCOT Boundaries

Brief History of ERCOT

- **ERCOT** stands for Electric Reliability Council of Texas, Inc.
- **1941** – Texas utilities band together to form the Texas Interconnected System (TIS) to aid war effort; several utilities interconnect to send their excess power to provide reliable power to manufacturing companies on Gulf Coast for energy intensive aluminum smelting
- **1970** – **TIS forms ERCOT** to comply with North American Electric Reliability Corporation (NERC)
- **1992** – Energy Policy Act of 1992, encouraging the Federal Energy Regulatory Commission (FERC) to foster competition in wholesale energy markets

Brief History of ERCOT (cont'd)

- **1995** – Texas Legislature deregulates wholesale generation market; PUC adopts rules to facilitate efficient use of electric grid by all market participants
- **1999** – Texas Legislature passes **Senate Bill 7** requiring retail electric market to be opened to competition by 2002

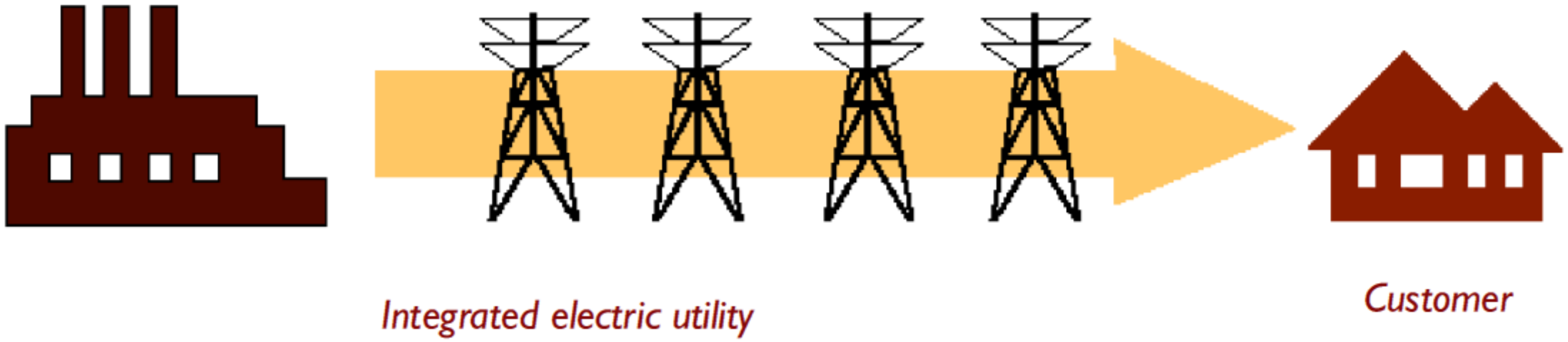
Before Competition: Pre-1975

- **Before 1975, Cities regulated electric utility service and rates**
  - Generally, a declining cost industry – rate applications most often filed to decrease rates

- **1975 Texas Legislature enacted the Public Utility Regulatory Act (PURA) to implement state regulation of electric utility service and rates. Cities retain original jurisdiction over rates within their city limits**
  - PUC created; opened for business in September 1976
  - Service area, transmission line and generating plants subject to certification by PUC
  - Cost of service rate regulation (utilities allowed cost of service plus reasonable return on investment)
  - Rates based on historical test year costs and original costs of infrastructure, less depreciation
  - Service quality regulation

Electric Utility Structure Before Competition

Each utility was vertically integrated, from generation to customer service.



Before Competition: 1976-1995

- **U.S. Fuel Use Act (1978) passed by Congress in response to 1973 oil crisis and gas curtailments of mid-70s; required utilities to discontinue use of natural gas in new industrial boilers and new electric power plants; encouraged the use of coal and nuclear for fuel**

- **Inflation, volatile fuel costs and the need for new generating capacity continued to increase electricity rates**

- **Rate proceedings at PUC became increasingly adversarial**
  - Consumer groups concerned about frequency and amount of rate increases, caused in part by new nuclear plants
  - Utilities concerned with PUC cost disallowances which utilities believed were at odds with the regulatory compact and eroded rates of return

- **Larger customers (industrials primarily) concerned with subsidizing other ratepayers and sought opportunities to by-pass regulated rates and obtain choice of suppliers**
  - Advocated wholesale competition and transmission open access

- **Natural gas was favored again when the 1978 U.S. Fuel Use Act was repealed in 1987**

Wholesale Competition: Senate Bill 373

1995: Texas Senate Bill 373, creating wholesale competition within ERCOT, enacted

- Required utilities to provide independent generators with non-discriminatory, open access to transmission to support wholesale competition in ERCOT
- Recognized new, unregulated participants in ERCOT wholesale market
  - Exempt wholesale generators
  - Power marketers
- Allowed non-utility wholesale market participants to offer market-based prices in ERCOT
- Deregulated electric cooperative distribution rates that were previously regulated by the PUC

ERCOT Designated Independent System Operator

1996 : ERCOT was designated the Independent System Operator (ISO) to insure impartial, third-party organization to oversee equal access to power grid.

This change was officially implemented September 11, 1996, when the ERCOT Board of Directors restructured its organization and initiated operations as a not-for-profit ISO, making ERCOT:

- The first ISO in the U.S.
- The only ISO created under state law, not by FERC.

Retail Competition In ERCOT: Texas Senate Bill 7

1999: Senate Bill 7, creating retail competition in ERCOT, is passed

- 1997 competition effort failed; success in 1999.
- Competition in ERCOT retail market begins January 2002
- Municipally-owned utilities (i.e., Austin, San Antonio) and electric cooperatives may "opt-in" to competition, but not required to do so
  - To date, only one co-op (Nueces Electric) has opted in; no munis have opted in
- Incumbent utilities allowed to recover stranded cost
- Providers of last resort designated in all areas where choice is in effect
- PUC designates ERCOT as Independent Organization to:
  - maintain system reliability
  - insure open access to transmission system
  - facilitate competitive retail market
  - facilitate competitive wholesale market

Electric Utility Structure in Competitive Market 2002-Present

Incumbents were required to separate business activities into the following units:

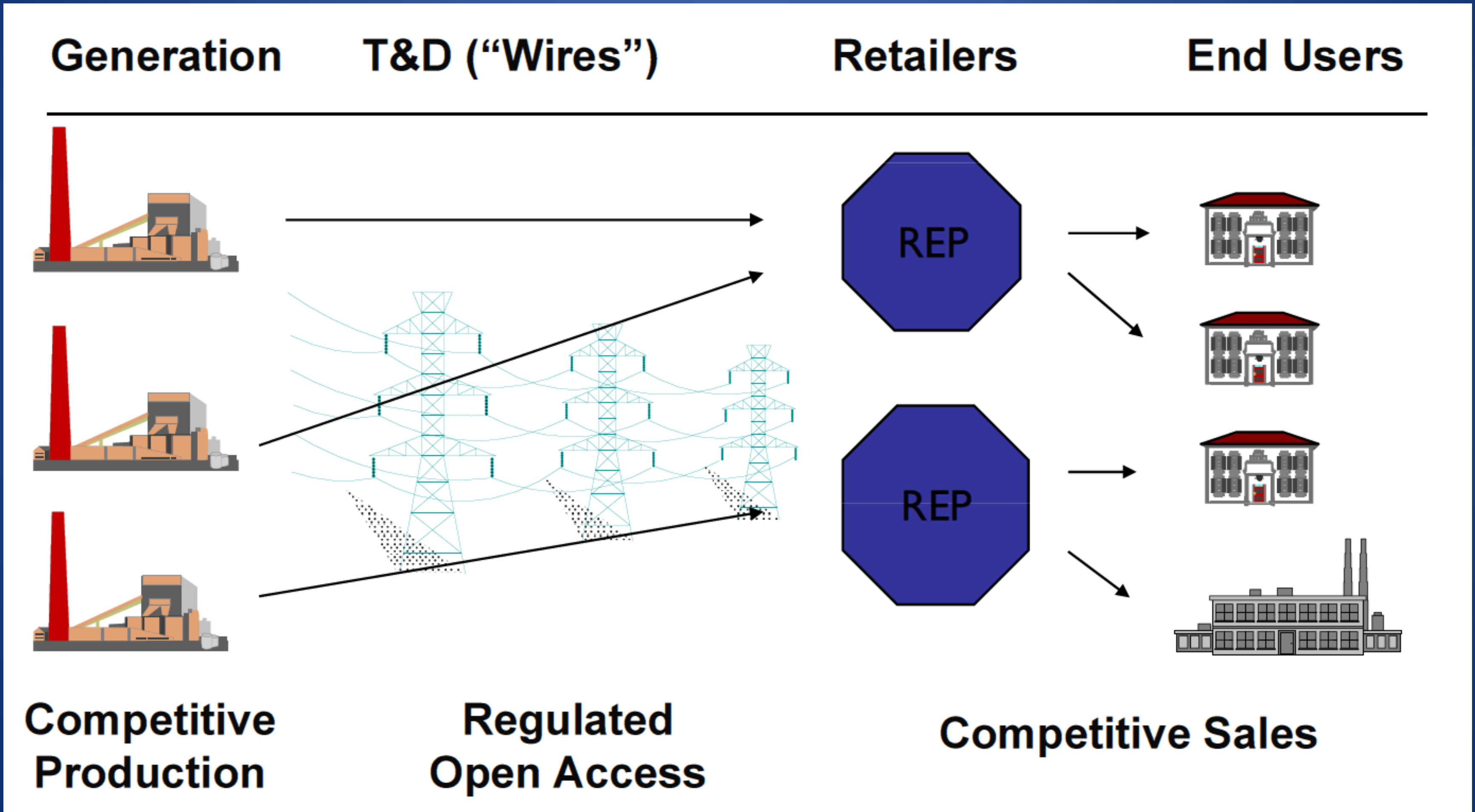
- Power generation company
- Transmission and distribution utility
- Retail electric provider (REPs)

Generation and retail businesses are not traditionally regulated, but:

- Power generation companies must be registered with PUC
  - May not own and control more than 20% of installed capacity in ERCOT
  - No market power abuse
  - Follow market rules established by PUC, ERCOT
- REPs must be certified by PUC
  - Subject to customer-protection rules adopted by PUC

Transmission and distribution businesses remain regulated utilities (cost of service ratemaking)

ERCOT Competitive Market Structure

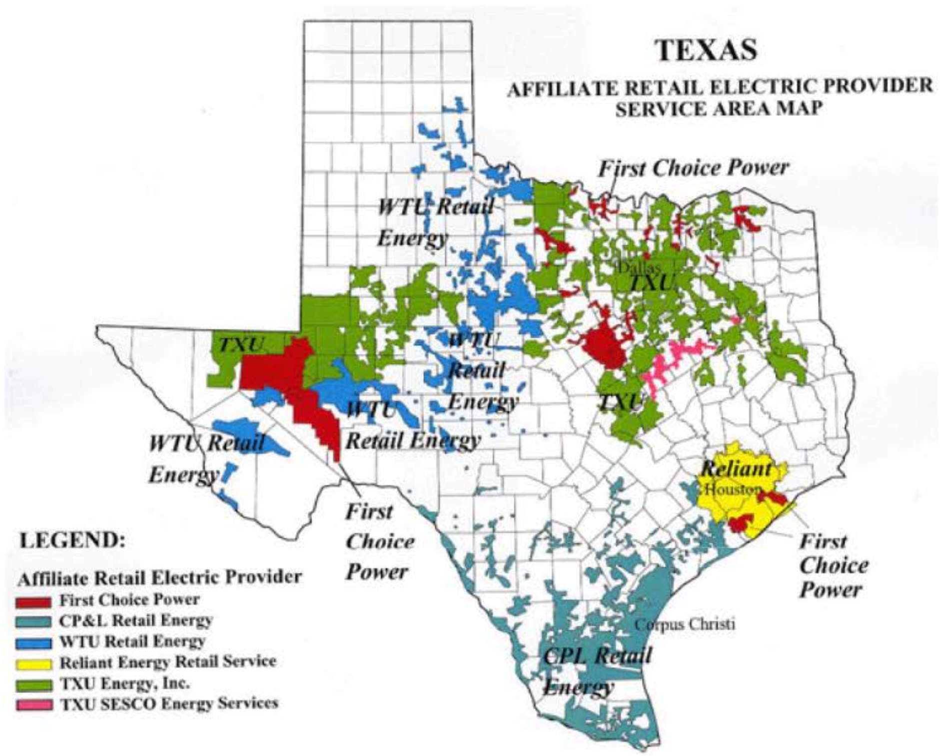


ERCOT Retail Competition Map

- This map shows the regions of Texas that are open to retail competition
- These are the areas served by the former monopoly investor-owned utilities (IOUs)

IOU Transmission Providers

- AEP Texas Central and North
- CenterPoint Energy
- Oncor Electric Delivery
- Texas-New Mexico Power Company



ERCOT After Retail Competition

- Customers shop for and choose electric provider (powertochoose.com for rate comparison)
- Competitive choice customers—74% of load; 6.6 million electric service IDs (premises)
- Switches to competitive providers:
  - 56 % of residential load (Dec 2011)
  - 83% of small commercial load (Dec 2011)
  - 179 competitive REPs; were 5 in 2002

Electricity choice should be a fundamental right. As Teddy Roosevelt said, “Where trust becomes a monopoly the state has an immediate right to interfere.” Since the legislature has not interfered to break up electric monopolies, this ballot initiative will.

Traditional monopoly utility service has been in place for a century which includes generation, transmission, and sales. It is time to change that in Florida. Thirteen states, all of the European Union, and Japan have electricity choice. After studying best practices for many years, Japan is moving towards something very similar to the Texas model, which this ballot initiative also does.

Texas was the last retail competitive market established in the US. They reviewed the competitive markets in the US and around the world before deciding on the frame work for their competitive market. They required the monopoly utilities to separate the generation sales of electricity, and transmission, just like this ballot initiative will do. The transmission will continue to be regulated by the state guaranteeing continued reliability of the infrastructure and quick repair when hurricanes or other calamities befall the state.

Thirteen states, all of the European Union, and Japan have electricity choice. After studying best practices for many years, Japan is moving towards something very similar to the Texas model, which this ballot initiative also does. They are doing it, because it works in lowering prices and bringing more green power to the market, just like this initiative will do if passed.

Almost two decades ago Texas restructured its market and here are the results today:

Almost 60% of their current capacity generation is new and much of the new capacity is green. This is over $50 billion of investors’ money not rate payers. NextEra, owner of Florida Power and Light, alone has built over 4000 MW of wind power in Texas since it restructured its market with no guarantee from the ratepayers. They chose to take this risk without them.

In Texas over $7 billion dollars in transmission upgrades for reliability and service has happened since restructuring their market.

Texas crushed their renewable goal of 8% and are currently over 25%

At the same time the customers are paying less than they were before they had choice. I was in Dallas last week. My Uber driver had lived there for 40 years. I asked him about electricity choice. HE said he loves it. People compete for his business. He said before choice he was paying sourness $300 a month and now is paying between $80-$100. If you check the powertochoose.com website, there are many 100% renewable plans that are less than the least expense rate in Florida.

Again this electricity choice amendment is modeled after Texas, a system that has shown great by reducing prices to the consumer, building green power, and providing reliable power. Other states have restructured their electricity markets differently and have had varying degrees of success, but none have done it like Texas and its model is a shining star among all of them. So data from other states is irrelevant because their models are significantly different. Only Texas data must be used for comparison purposes.

The utilities will tell you that the local city and counties will lose their franchise fees and affect teachers, police and firefighters because they assert franchise fees will go away. This isn't true. The amendment requires comprehensive legislation for enactment and this would necessarily include a provision for franchise fees. As far as Texas goes, which this amendment is based on in the city of Houston, before electricity restructuring they collected \$80-\$90 million in franchise fees. In 2017 and 2018 they collected over \$100 million.

The Perryman group did a study showing that Florida would save 5 – 7.5 billion dollars per year if Florida restructures its electricity market in the style of Texas and currently Texas is saving over \$5 billion per year because of their restructured electricity market.

Some Florida utilities have said that it isn't real choice because you can't choose the current utility. This is false since they can form or buy a subsidiary to sell electricity Florida, much like NextEra did in Texas when they purchased GEXA to sell electricity in Texas.

If Florida is to compete with other states, if Florida really wants an abundance of green power it must embrace one of the ideals of this nation that is accepted practice in almost all other industries save electricity, capitalism. Teddy Roosevelt was right to break up monopolies and now, a century later, it is time to do the same in Florida so that consumers can reap the benefits of choice instead of the stagnation and the burden of high prices that comes with state sponsored monopolies.

Potential Economic Benefits of Statewide Competition in the Florida Electric Power Market: A Preliminary Assessment

December 2017

The Perryman Group

The Perryman Group was recently asked to examine the potential economic benefits of statewide competition in the Florida electric power market. Outcomes in other areas which have increased competition (fully adjusted for Florida economic and demographic patterns) were used as a basis for estimating the potential benefits.

As an initial phase of this analysis, The Perryman Group estimated the direct savings by customer class which could be expected under statewide electric power competition. The Perryman Group's US Multi-Regional Impact Assessment System was then used to quantify the potential overall economic benefits of statewide competition.

Summary results from The Perryman Group's preliminary assessment are presented below, with additional detail (including results by sector) in the Appendices.

Direct Savings

In order to determine the direct effects for use in the impact analysis, it is necessary to estimate the likely outcomes from the implementation of an orderly and effective competitive framework for the Florida retail electric market. For purposes of illustration, estimates are derived for both 2016 (the latest year for which all relevant electric price and usage data is available) and 2030. The 2016 analysis examines the counterfactual scenario in which a competitive framework is already in place and mature. The purpose of this segment is to illustrate the benefits that would be currently occurring if competition presently existed. The 2030 analysis provides an assessment of the reasonable outcomes assuming that competition is implemented in the near future and has an opportunity to mature.

As an initial point of departure, an analysis was conducted to determine the relative savings achieved in Texas from an effective competitive framework. While attempts at competitive markets have occurred in numerous states (and countries throughout the world), the Texas model is widely regarded as the most successful.[1] The Texas case should be representative of the potential in Florida in that (1) it is reasonable to assume that any state embarking on a competitive framework would be influenced by the best practices that have emerged over the past two decades and (2) both states are large enough to achieve reasonable scale and derive a substantial portion of their generation from natural gas facilities.[2]

Two methods were used in this process, both of which seek to compare the current pricing in competitive regions with what it would likely be if providers had remained subject to traditional rate-of-return regulation. One method, which is used on an ongoing basis by the Public Utility Commission of Texas (PUCT), compares current average retail rates with those that would likely prevail in a regulated framework. The regulated rates are estimated by adjusting the rates that prevailed at the time competition was introduced for subsequent inflation. Using this approach, the average savings is determined to be about 27.1%, although many consumers receive much larger reductions.

The second method compares the change in average retail prices that has occurred in competitive regions to those observed in the regulated areas. This approach was recently adopted in an analysis by the Center for Energy Studies at the Baker Institute for Public Policy at Rice University.[3] Depending on the region examined, the relative reduction ranges from about 23.3% to 27.9% (for an average of 25.6%). This finding is virtually identical to that in a 2009 study by The Perryman Group which used a similar methodology and

[1] Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, Rice University, June 2017; Michaels, Robert J., Competition in Texas Electric Markets: What Texas Did Right & What's Left to Do, Texas Public Policy Foundation, March 2007; Why is Texas the Model for Energy Deregulation?, Bounce Energy, (n.d.), https://www.bounceenergy.com/articles/texas-electricity/why-is-texas-the-model-for-energy-deregulation.

[2] Table 55.1 Texas Regional Entity, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017; Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.

[3] Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, Rice University, June 2017. Results in other states have also illustrated notable benefits from retail competition. See, for example, Simeone, Christina and John Hanger, A Case Study of Electric Competition Results in Pennsylvania: Real Benefits and Important Choices Ahead, Kleinman Center for Energy Policy, University of Pennsylvania, October 28, 2016; Thomas, Andrew R., William M. Bowen, Edward W. Hill, Adam Kanter, and Taekyoung Lim, Electricity Customer Choice in Ohio: How Competition Has Outperformed Traditional Monopoly Regulation, Energy Policy Center, Cleveland State University, November 2016. In addition, numerous studies have demonstrated the economic gains from greater efficiencies in power allocation and investment. See, for example, Cicala, Steve, Imperfect Markets versus Imperfect Regulation in U.S. Electricity Generation, NBER Working Paper No. 23053, January 2017; Hibbard, Paul, Susan Tierney, and Katherine Franklin, Electricity Markets, Reliability and the Evolving U.S. Power System, Analysis Group, June 2017; Putting Competitive Power Markets to the Test, The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies, Global Energy Decisions, July 2005.

determined average direct savings at the time to be 25.1%.[4] For purposes of the present analysis, The Perryman Group used 23.3% as the Low Case (the lower value in the Rice University study) and 27.1% in the High Case (the estimate from the PUCT).

The next phase of the analysis involves estimation of the incremental electricity consumption that would occur as a result of lower prices. While the demand for electricity is inelastic (less than proportionate response to price changes), reductions of this magnitude would induce additional purchases in the residential, commercial, and industrial sectors. This segment of the analysis involves the determination of demand elasticity estimates for each major usage category. Dynamic logarithmic multiple regression models were specified and estimated which related consumption to real prices and relevant economic and demographic control variables. The requisite data series were obtained from the Energy Information Administration, the US Department of Commerce, and the US Department of Labor. All of these equations exhibited excellent statistical properties and all of the elasticity coefficients were statistically significant. The estimated elasticities for residential, commercial, and industrial usage were determined to be, respectively, -0.117, -0.094, and -0.118. The resulting induced increases in electricity consumption are found to be approximately 2.73% for residential, 2.19% for commercial, and 2.74% for industrial consumption in the Low Case Scenario, with the High Case gains being modestly higher.

Once this determination is completed, the direct savings can be computed for 2016 by calculating the savings associated with the estimated percentage reductions as applied to actual annual consumption and the incremental induced purchases determined above. The same method is used to project the savings in 2030, with the baseline values for usage and prices by major market segment being based on the projections generated and maintained by Energy Information Administration.[5] These results are displayed in the following table. All monetary values are given in constant (2016) dollars.

[4] Power to the People!!! A Retrospective on Ten Years of Electric Competition in Texas and Considerations for Future Success, The Perryman Group, April 2009.

[5] Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2017&region=3-2&cases=ref2017.

Potential Direct Savings from the Introduction of Statewide Electric Competition in Florida (Dollar Amounts in Millions of 2016 Dollars)				
LOW CASE[1]				
	Residential	**Commercial**	**Industrial**	**TOTAL**
2016[2]	$2,944.320	$1,972.683	$238.577	**$5,155.580**
2030[3]	$3,621.705	$2,455.634	$374.486	**$6,451.825**
HIGE CASE[4]				
2016[2]	$3,430.953	$2,298.724	$278.009	**$6,007.686**
2030[3]	$4,220.294	$2,861.498	$436.380	**$7,518.172**

Notes:. (1) The Low Case is based on results achieved in Texas based on lower end of range based on relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017.

(2) The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.

(3) The 2030 values represent the estimated direct savings that will occur in Florida assuming statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.

(4) The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017.

Source: The Perryman Group

Impact Assessment

The final element of the determination of direct inputs to the impact assessment involves allocating the savings identified above across appropriate appreciate categories of spending. For the residential sector, it was assumed that the incremental funds would be expended in accordance with typical patterns as determined by the *Consumer Expenditure Survey* compiled by the US Department of Labor and the *Cost of Living Index* maintained by the Council for Community and Economic Research. The estimated cost savings is apportioned across these sectors in both the Low Case and High Case Scenarios for both 2016 and 2030.

For the commercial and industrial segments, the requirements coefficients for electric service as an input were obtained from the US Multi-Regional Impact Assessment System (described below) for each of more than 500 detailed sectors to provide estimates of the outlays per dollar of total spending. These parameters were then multiplied by total spending in each detailed sector to estimate total electric spending, partitioned between commercial and industrial categories, and calibrated with respect to the total revenues to provide a reasonable allocation of outlays for electric service. These savings for the Low Case and High Case Scenarios derived above ae them allocated in this manner for both the 2016 and 2030, with adjustment for the induced purchases resulting from the reduced retail costs of electricity. The result of this process is a set of expenditure vectors which provide the direct inputs for the impact analysis.

Multiplier effects were then measured using The Perryman Group's input-output assessment model (the US Multi-Regional Impact Assessment System), which is described in further detail in the Appendices to this report. The system has been consistently maintained and updated since it was developed by the firm about 35 years ago, has been peer-reviewed on many occasions, and has been used in hundreds of analyses for clients ranging from major corporations to government agencies. In particular, it has been implemented on dozens of occasions to measure the effects of electric generation and transmission projects, including many related to wind development. It uses a variety of data (from surveys, industry information, and other sources) to describe the various goods and services (known as resources or inputs) required to produce another good/service. This process allows for estimation of the total economic impact (including multiplier effects) of construction and operations of the performing arts facility. The models used in the current analysis reflect the specific industrial composition and characteristics of Florida.

These total economic effects are quantified for key measures of business activity:

- **Total expenditures** (or total spending) measure the dollars changing hands as a result of the economic stimulus.
- **Gross product** (or output) is production of goods and services that will come about in each area as a result of the activity. This measure is parallel to the gross domestic product numbers commonly reported by various media outlets and is a subset of total expenditures.
- **Personal income** is dollars that end up in the hands of people in the area; the vast majority of this aggregate derives from the earnings of employees, but payments such as interest and rents are also included.

- **Job gains** are expressed as permanent jobs.

Summary results are reported in the body of this report, with other measures and industry-level detail in the Appendices. Monetary values were quantified on a constant (2016) dollar basis to eliminate the effects of inflation. See the Appendices to this report for additional information regarding the methods and assumptions used in this analysis.

Economic Benefits

The Perryman Group estimated the economic benefits stemming from the potential direct savings described above. Under the Low Case Assumptions, gains in Florida business activity associated with the introduction of statewide competition in the market for electric power were estimated to include (when multiplier effects are considered)

- $6.6 billion in gross product and over 72,000 permanent jobs if statewide competition had been in place in 2016 and
- $8.3 billion in gross product and approximately 90,000 permanent jobs by 2030 if statewide competition is soon implemented.

Potential Economic Benefits of Statewide Competition in the Florida Market for Electric Power: Low Case (Dollar Amounts in Billions of 2016 Dollars and Permanent Jobs)				
2016: If statewide competition had been in place				
	Residential	Commercial	Industrial	**TOTAL**
Total Expenditures	$7.850	$4.972	$0.682	**$13.503**
Gross Product	$3.909	$2.442	$0.290	**$6.641**
Personal Income	$2.291	$1.385	$0.173	**$3.848**
Employment	43,036	26,202	$2,842	**72,080**
2030: If statewide competition is soon implemented				
Total Expenditures	$9.655	$6.189	$1.070	**16.915**
Gross Product	$4.808	$3.040	$0.456	**8.304**
Personal Income	$2.818	$1.724	$0.271	**4.813**
Employment	52,937	32,617	4,460	**90,014**

Notes: The Low Case is based on results achieved in Texas using the lower end of the range of relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017.
The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the Energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
Source: The Perryman Group

Under High Case Assumptions, the estimated increase in Florida business activity associated with the introduction of statewide competition in the market for electric power (when multiplier effects are considered) rises to

- $7.7 billion in gross product and nearly 84,000 permanent jobs if statewide competition had been in place in 2016 and
- $9.7 billion in gross product and close to 105,000 permanent jobs by 2030 if statewide competition is soon implemented.

Potential Economic Benefits of Statewide Competition in the Florida Market for Electric Power: High Case (Dollar Amounts in Billions of 2016 Dollars and Permanent Jobs)				
2016: If statewide competition had been in place				
	Residential	Commercial	Industrial	**TOTAL**
Total Expenditures	$9.147	$5.794	$0.794	**$15.735**
Gross Product	$4.555	$2.846	$0.338	**$7.739**
Personal Income	$2.670	$1.614	$0.201	**$4.485**
Employment	50,149	30,533	3,311	**83,993**
2030: If statewide competition is soon implemented				
Total Expenditures	$11.251	$7.212	$1.247	**$19.710**
Gross Product	$5.603	$3.542	$0.531	**$9.676**
Personal Income	$3.284	$2.009	$0.316	**$5.608**
Employment	61,686	38,008	5,197	**104,892**

Notes: The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017.
The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the Energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
Source: The Perryman Group

Conclusion

Increasing competition in the market for electric power can lead to significant savings to consumers, enhanced consumer choice, less volatility in prices, and other benefits. As a result, there are substantial gains to the economy.

The Perryman Group estimates that if implemented in the near future, statewide competition in the Florida electric power market could generate benefits by 2030 including $8.3 billion in gross product and over 90,000 jobs under Low Case assumptions, with $9.7 billion in gross product and nearly 105,000 jobs if High Case results are obtained.

Appendix A: About The Perryman Group

- The Perryman Group (TPG) is an economic research and analysis firm based in Waco, Texas. The firm has about 35 years of experience in assessing the economic impact of corporate expansions, regulatory changes, real estate developments, public policy initiatives, and myriad other factors affecting business activity. TPG has conducted hundreds of impact analyses for local areas, regions, and states throughout the United States. Impact studies have been performed for hundreds of clients including many of the largest corporations in the world, governmental entities at all levels, educational institutions, major health care systems, utilities, and economic development organizations.
- Dr. M. Ray Perryman, founder and President of the firm, developed the US Multi-Regional Impact Assessment System (used in this study) in the early 1980s and has consistently maintained, expanded, and updated it since that time. The model has been used in hundreds of diverse applications and has an excellent reputation for reliability. A major study developed using the relevant model was recently published in *The Journal of Medical Economics*.
- The Perryman Group has extensive expertise in analysis of the electric power industry and has performed numerous studies including, among others, rate analysis, impact assessments of potential additions to generation capacity (gas, wind, coal, and nuclear) and transmission infrastructure, demand forecasts, price forecasts, fuel diversity analysis, usage analysis, power adequacy analysis, and major policy studies. TPG has also analyzed the effects of competition in the electric power industry on multiple occasions, including major studies before, during, and after the introduction of competition in Texas and played a key role in the introduction of wholesale and retail competition into the state. Dr. M. Ray Perryman, founder and president of the firm, has testified before the US Department of Energy, the US Department of Agriculture, the Public Utility Commission of Texas, the Oklahoma Corporation Commission, the Texas Railroad Commission, the Texas Legislature (House and Senate), and numerous other legislative and regulatory bodies on electric industry and other energy matters. He has also spoken to major industry conferences on dozens of occasions. Additionally, the firm has performed other studies related to the effects of introducing competition in a variety of sectors, including telecommunications, financial services, natural gas, trucking, and railroads, with Dr. Perryman offering testimony on multiple occasions.
- With regard to renewable energy, TPG has analyzed the economic and fiscal impact of construction and operation of numerous specific wind farm projects. In addition, the firm performed a detailed county-by-county assessment of the impact of the Competitive Renewable Energy Zones (CREZ) project in Texas, a large-scale, multi-billion dollar investment program to provide transmission infrastructure to support the development of wind energy in the state. Similar analyses has been conducted, involving both wind power generation and transmission, regarding the delivery of wind power from Oklahoma and Kansas to the Tennessee Valley Authority along the Plains & Eastern Clean Line transmission system and from Texas to the southeastern US along the Southern Cross Transmission system.

Appendix B: Methods Used

- The basic modeling technique employed in this study is known as dynamic input-output analysis. This methodology essentially uses extensive survey data, industry information, and a variety of corroborative source materials to create a matrix describing the various goods and services (known as resources or inputs) required to produce one unit (a dollar's worth) of output for a given sector. Once the base information is compiled, it can be mathematically simulated to generate evaluations of the magnitude of successive rounds of activity involved in the overall production process.
- There are two essential steps in conducting an input-output analysis once the system is operational. The first major endeavor is to accurately define the levels of direct activity to be evaluated. In the case of a prospective evaluation, it is necessary to first calculate reasonable estimates of the direct activity. This process was described at length in the report.
- The second major phase of the analysis is the simulation of the input-output system to measure overall economic effects of these incremental outlays. The present study was conducted within the context of the US Multi-Regional Impact Assessment System (USMRIAS) which was developed and is maintained by The Perryman Group. This model has been used in hundreds of diverse applications across the country and has an excellent reputation for accuracy and credibility. The systems used in the current simulations reflect the unique industrial structure and characteristics of Florida.
- The USMRIAS is somewhat similar in format to the Input-Output Model of the United States and the Regional Input-Output Modeling System, both of which are maintained by the US Department of Commerce. The model developed by TPG, however, incorporates several important enhancements and refinements. Specifically, the expanded system includes (1) comprehensive 500-sector coverage for any county, multi-county, or urban region; (2) calculation of both total expenditures and value-added by industry and region; (3) direct estimation of expenditures for multiple basic input choices (expenditures, output, income, or employment); (4) extensive parameter localization; (5) price adjustments for real and nominal assessments by sectors and areas; (6) measurement of the induced impacts associated with payrolls and consumer spending; (7) embedded modules to estimate multi-sectoral direct spending effects; (8) estimation of retail spending activity by consumers; and (9) comprehensive linkage and integration capabilities with a wide variety of econometric, real estate, occupational, and fiscal impact models. Moreover, the model uses specific local taxing patterns to estimate the fiscal effects of activity on a detailed sectoral basis. The models used for the present investigation have been thoroughly tested for reasonableness and historical reliability.
- The impact assessment (input-output) process essentially estimates the amounts of all types of goods and services required to produce one unit (a dollar's worth) of a specific type of output. For purposes of illustrating the nature of the system, it is useful to think of inputs and outputs in dollar (rather than physical) terms. As an example, the construction of a new building will require specific dollar amounts of lumber, glass, concrete, hand tools, architectural services, interior design services, paint, plumbing, and numerous other elements. Each of these suppliers

must, in turn, purchase additional dollar amounts of inputs. This process continues through multiple rounds of production, thus generating subsequent increments to business activity. The initial process of building the facility is known as the *direct effect*. The ensuing transactions in the output chain constitute the *indirect effect*.

- Another pattern that arises in response to any direct economic activity comes from the payroll dollars received by employees at each stage of the production cycle. As workers are compensated, they use some of their income for taxes, savings, and purchases from external markets. A substantial portion, however, is spent locally on food, clothing, health care services, utilities, housing, recreation, and other items. Typical purchasing patterns in the relevant areas are obtained from the *ACCRA Cost of Living Index*, a privately compiled inter-regional measure which has been widely used for several decades, and the *Consumer Expenditure Survey* of the US Department of Labor. These initial outlays by area residents generate further secondary activity as local providers acquire inputs to meet this consumer demand. These consumer spending impacts are known as the *induced effect*. The USMRIAS is designed to provide realistic, yet conservative, estimates of these phenomena.
- Sources for information used in this process include the Bureau of the Census, the Bureau of Labor Statistics, the Regional Economic Information System of the US Department of Commerce, and other public and private sources. The pricing data are compiled from the US Department of Labor and the US Department of Commerce. The verification and testing procedures make use of extensive public and private sources.
- Impacts were measured in constant 2016 dollars to eliminate the effects of inflation.
- The USMRIAS generates estimates of the effect on several measures of business activity. The most comprehensive measure of economic activity used in this study is Total Expenditures. This measure incorporates every dollar that changes hands in any transaction. For example, suppose a farmer sells wheat to a miller for $0.50; the miller then sells flour to a baker for $0.75; the baker, in turn, sells bread to a customer for $1.25. The Total Expenditures recorded in this instance would be $2.50, that is, $0.50 + $0.75 + $1.25. This measure is quite broad, but is useful in that (1) it reflects the overall interplay of all industries in the economy, and (2) some key fiscal variables such as sales taxes are linked to aggregate spending.
- A second measure of business activity frequently employed in this analysis is that of Gross Product. This indicator represents the regional equivalent of Gross Domestic Product, the most commonly reported statistic regarding national economic performance. In other words, the Gross Product of Texas is the amount of US output that is produced in that state; it is defined as the value of all final goods produced in a given region for a specific period of time. Stated differently, it captures the amount of value-added (gross area product) over intermediate goods and services at each stage of the production process, that is, it eliminates the double counting in the Total Expenditures concept. Using the example above, the Gross Product is $1.25 (the value of the bread) rather than $2.50. Alternatively, it may be viewed as the sum of the value-added by the farmer, $0.50; the miller, $0.25 ($0.75 - $0.50); and the baker, $0.50 ($1.25 - $0.75). The total value-added is, therefore, $1.25, which is equivalent to the final value of the bread. In

many industries, the primary component of value-added is the wage and salary payments to employees.

- The third gauge of economic activity used in this evaluation is Personal Income. As the name implies, Personal Income is simply the income received by individuals, whether in the form of wages, salaries, interest, dividends, proprietors' profits, or other sources. It may thus be viewed as the segment of overall impacts which flows directly to the citizenry.
- The fourth measure, Retail Sales, represents the component of Total Expenditures which occurs in retail outlets (general merchandise stores, automobile dealers and service stations, building materials stores, food stores, drugstores, restaurants, and so forth). Retail Sales is a commonly used measure of consumer activity.
- The final aggregates used are Permanent Jobs and Person-Years of Employment. The Person-Years of Employment measure reveals the full-time equivalent jobs generated by an activity. It should be noted that, unlike the dollar values described above, Permanent Jobs is a "stock" rather than a "flow." In other words, if an area produces $1 million in output in 2016 and $1 million in 2017, it is appropriate to say that $2 million was achieved in the 2016-2017 period. If the same area has 100 people working in 2016 and 100 in 2017, it only has 100 Permanent Jobs. When a flow of jobs is measured, such as in a construction project or a cumulative assessment over multiple years, it is appropriate to measure employment in Person-Years (a person working for a year). This concept is distinct from Permanent Jobs, which anticipates that the relevant positions will be maintained on a continuing basis.

Appendix C: Detailed Results

Low Case: 2016

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida Low Case—Residential—2016				
Category	**Total Expenditures** (2016 Dollars)	**Gross Product** (2016 Dollars)	**Personal Income** (2016 Dollars)	**Employment** (Permanent Jobs)
Agriculture	$171,062,841	$49,574,351	$31,966,262	509
Mining	$117,014,355	$27,195,140	$15,722,652	94
Construction	$157,975,682	$82,952,172	$68,357,757	974
Nondurable Manufacturing	$734,475,151	$202,026,622	$106,170,474	1,784
Durable Manufacturing	$173,277,487	$68,490,166	$44,451,184	625
Transportation and Utilities	$745,476,747	$274,022,542	$155,380,625	1,676
Information	$244,826,750	$150,970,183	$65,166,942	624
Wholesale Trade	$1,154,482,186	$781,184,995	$450,438,226	5,190
Retail Trade (including Restaurants)	$1,259,457,037	$882,269,774	$501,952,733	17,360
FIRE	$1,599,554,236	$514,858,364	$138,631,705	1,404
Business Services	$334,710,118	$194,404,807	$158,584,508	1,958
Health Services	$415,885,808	$294,801,981	$249,257,807	4,178
Other Services	$741,324,195	$386,045,571	$304,868,066	6,658
TOTAL	**$7,849,522,593**	**$3,908,796,667**	**$2,290,948,940**	**43,036**

Notes: The Low Case is based on results achieved in Texas using the lower end of the range of relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017. The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida Low Case—Commercial—2016				
Category	Total Expenditures (2016 Dollars)	Gross Product (2016 Dollars)	Personal Income (2016 Dollars)	Employment (Permanent Jobs)
Agriculture	$151,835,156	$44,607,752	$29,240,820	467
Mining	$61,107,897	$15,769,537	$9,218,546	63
Construction	$209,533,675	$102,010,384	$84,062,908	1,198
Nondurable Manufacturing	$425,100,613	$119,968,335	$63,343,333	1,049
Durable Manufacturing	$118,805,836	$46,564,614	$30,008,452	431
Transportation and Utilities	$264,246,019	$111,634,167	$66,106,954	773
Information	$100,310,850	$60,958,588	$26,951,928	287
Wholesale Trade	$207,967,401	$140,677,378	$81,115,834	935
Retail Trade (including Restaurants)	$774,949,269	$572,402,643	$331,233,580	10,549
FIRE	$1,611,372,054	$595,824,825	$152,744,139	1,522
Business Services	$367,792,949	$236,330,725	$192,785,312	2,380
Health Services	$257,040,419	$174,929,074	$147,904,158	2,479
Other Services	$421,939,564	$220,355,680	$170,223,722	4,069
TOTAL	**$4,972,001,702**	**$2,442,033,702**	**$1,384,939,686**	**26,202**

Notes: The Low Case is based on results achieved in Texas using the lower end of the range of relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017. The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida Low Case—Industrial—2016				
Category	**Total Expenditures (2016 Dollars)**	**Gross Product (2016 Dollars)**	**Personal Income (2016 Dollars)**	**Employment (Permanent Jobs)**
Agriculture	$28,001,636	$6,590,949	$4,380,737	68
Mining	$16,010,610	$3,800,970	$2,084,122	10
Construction	$11,140,028	$6,171,861	$5,086,004	71
Nondurable Manufacturing	$190,833,053	$58,046,387	$30,037,133	430
Durable Manufacturing	$93,498,646	$39,808,944	$25,655,192	334
Transportation and Utilities	$94,408,346	$38,643,017	$23,107,844	272
Information	$30,493,907	$18,546,859	$7,947,078	72
Wholesale Trade	$23,575,227	$15,952,373	$9,198,279	106
Retail Trade (including Restaurants)	$64,943,628	$48,843,556	$28,417,360	879
FIRE	$66,781,602	$17,443,251	$6,884,173	68
Business Services	$19,684,396	$11,890,967	$9,699,970	118
Health Services	$15,352,181	$10,741,309	$9,081,863	151
Other Services	$26,931,671	$13,784,385	$11,024,878	263
TOTAL	**$681,654,930**	**$290,264,827**	**$172,604,634**	**2,842**

Notes: The Low Case is based on results achieved in Texas using the lower end of the range of relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017. The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

**The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida
Low Case—Total—2016**

Category	Total Expenditures (2016 Dollars)	Gross Product (2016 Dollars)	Personal Income (2016 Dollars)	Employment (Permanent Jobs)
Agriculture	$350,899,633	$100,773,051	$65,587,819	1,044
Mining	$194,132,861	$46,765,648	$27,025,321	167
Construction	$378,649,385	$191,134,417	$157,506,669	2,244
Nondurable Manufacturing	$1,350,408,817	$380,041,344	$199,550,940	3,264
Durable Manufacturing	$385,581,969	$154,863,724	$100,114,829	1,391
Transportation and Utilities	$1,104,131,113	$424,299,727	$244,595,423	2,722
Information	$375,631,508	$230,475,629	$100,065,948	983
Wholesale Trade	$1,386,024,814	$937,814,746	$540,752,339	6,231
Retail Trade (including Restaurants)	$2,099,349,935	$1,503,515,972	$861,603,672	28,788
FIRE	$3,277,707,892	$1,128,126,439	$298,260,017	2,995
Business Services	$722,187,462	$442,626,499	$361,069,790	4,456
Health Services	$688,278,408	$480,472,365	$406,243,828	6,808
Other Services	$1,190,195,430	$620,185,636	$486,116,666	10,990
TOTAL	**$13,503,179,225**	**$6,641,095,197**	**$3,848,493,260**	**72,080**

Notes: The Low Case is based on results achieved in Texas using the lower end of the range of relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017. The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

Low Case: 2030

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida Low Case—Residential—2030				
Category	**Total Expenditures (2016 Dollars)**	**Gross Product (2016 Dollars)**	**Personal Income (2016 Dollars)**	**Employment (Permanent Jobs)**
Agriculture	$210,418,358	$60,979,658	$39,320,569	626
Mining	$143,935,225	$33,451,782	$19,339,879	116
Construction	$194,320,307	$102,036,537	$84,084,463	1,198
Nondurable Manufacturing	$903,451,942	$248,505,811	$130,596,550	2,194
Durable Manufacturing	$213,142,516	$84,247,334	$54,677,832	769
Transportation and Utilities	$916,984,616	$337,065,451	$191,128,219	2,062
Information	$301,152,738	$185,703,090	$80,159,553	768
Wholesale Trade	$1,420,087,760	$960,908,071	$554,068,153	6,385
Retail Trade (including Restaurants)	$1,549,213,617	$1,085,248,887	$617,434,327	21,354
FIRE	$1,967,555,170	$633,309,088	$170,525,963	1,727
Business Services	$411,715,094	$239,130,487	$195,069,202	2,408
Health Services	$511,566,443	$362,625,505	$306,603,224	5,139
Other Services	$911,876,708	$474,861,021	$375,007,440	8,190
TOTAL	**$9,655,420,494**	**$4,808,072,720**	**$2,818,015,374**	**52,937**

Notes: The Low Case is based on results achieved in Texas using the lower end of the range of relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017. The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida
Low Case—Commercial—2030

Category	Total Expenditures (2016 Dollars)	Gross Product (2016 Dollars)	Personal Income (2016 Dollars)	Employment (Permanent Jobs)
Agriculture	$189,007,403	$55,528,611	$36,399,550	581
Mining	$76,068,318	$19,630,232	$11,475,429	78
Construction	$260,831,660	$126,984,542	$104,643,169	1,491
Nondurable Manufacturing	$529,173,645	$149,338,955	$78,851,033	1,306
Durable Manufacturing	$147,891,853	$57,964,552	$37,355,115	537
Transportation and Utilities	$328,938,668	$138,964,418	$82,291,243	962
Information	$124,868,929	$75,882,455	$33,550,293	357
Wholesale Trade	$258,881,931	$175,117,980	$100,974,593	1,163
Retail Trade (including Restaurants)	$964,672,167	$712,538,124	$412,326,107	13,132
FIRE	$2,005,867,782	$741,694,518	$190,138,923	1,895
Business Services	$457,835,932	$294,189,157	$239,982,967	2,963
Health Services	$319,968,995	$217,755,169	$184,114,019	3,086
Other Services	$525,238,709	$274,303,106	$211,897,854	5,065
TOTAL	**$6,189,245,993**	**$3,039,891,821**	**$1,724,000,295**	**32,617**

Notes: The Low Case is based on results achieved in Texas using the lower end of the range of relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017. The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida Low Case—Industrial—2030				
Category	Total Expenditures (2016 Dollars)	Gross Product (2016 Dollars)	Personal Income (2016 Dollars)	Employment (Permanent Jobs)
Agriculture	$43,953,147	$10,345,572	$6,876,284	107
Mining	$25,131,271	$5,966,245	$3,271,371	16
Construction	$17,486,096	$9,687,746	$7,983,315	112
Nondurable Manufacturing	$299,543,685	$91,113,298	$47,148,193	675
Durable Manufacturing	$146,761,416	$62,486,648	$40,270,020	524
Transportation and Utilities	$148,189,338	$60,656,535	$36,271,540	427
Information	$47,865,174	$29,112,328	$12,474,239	113
Wholesale Trade	$37,005,174	$25,039,858	$14,438,203	166
Retail Trade (including Restaurants)	$101,939,646	$76,667,948	$44,605,694	1,379
FIRE	$104,824,645	$27,380,035	$10,805,835	107
Business Services	$30,897,878	$18,664,817	$15,225,690	185
Health Services	$24,097,758	$16,860,242	$14,255,470	237
Other Services	$42,273,662	$21,636,847	$17,305,349	412
TOTAL	**$1,069,968,892**	**$455,618,116**	**$270,931,201**	**4,460**

Notes: The Low Case is based on results achieved in Texas using the lower end of the range of relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017. The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida Low Case—Total—2030				
Category	**Total Expenditures (2016 Dollars)**	**Gross Product (2016 Dollars)**	**Personal Income (2016 Dollars)**	**Employment (Permanent Jobs)**
Agriculture	$443,378,909	$126,853,841	$82,596,403	1,314
Mining	$245,134,813	$59,048,258	$34,086,679	210
Construction	$472,638,063	$238,708,825	$196,710,947	2,802
Nondurable Manufacturing	$1,732,169,272	$488,958,064	$256,595,775	4,176
Durable Manufacturing	$507,795,786	$204,698,534	$132,302,966	1,830
Transportation and Utilities	$1,394,112,623	$536,686,403	$309,691,002	3,451
Information	$473,886,841	$290,697,873	$126,184,085	1,238
Wholesale Trade	$1,715,974,866	$1,161,065,909	$669,480,949	7,714
Retail Trade (including Restaurants)	$2,615,825,430	$1,874,454,959	$1,074,366,128	35,865
FIRE	$4,078,247,597	$1,402,383,641	$371,470,722	3,729
Business Services	$900,448,904	$551,984,461	$450,277,858	5,556
Health Services	$855,633,196	$597,240,916	$504,972,713	8,462
Other Services	$1,479,389,079	$770,800,974	$604,210,643	13,667
TOTAL	**$16,914,635,378**	**$8,303,582,657**	**$4,812,946,870**	**90,014**

Notes: The Low Case is based on results achieved in Texas using the lower end of the range of relative change in retail prices for regulated and unregulated regions in Texas following the introduction of competition in portions of Texas. See Hartley, Peter R., Kenneth B. Medlock III, and Olivera Jankovska, Electricity Reform and Retail Pricing in Texas, Center for Energy Studies, Baker Institute, June 2017. The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

High Case: 2016

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida
High Case—Residential—2016

Category	Total Expenditures (2016 Dollars)	Gross Product (2016 Dollars)	Personal Income (2016 Dollars)	Employment (Permanent Jobs)
Agriculture	$199,335,828	$57,767,918	$37,249,593	593
Mining	$136,354,296	$31,689,909	$18,321,266	109
Construction	$184,085,645	$96,662,372	$79,655,816	1,135
Nondurable Manufacturing	$855,868,007	$235,417,252	$123,718,156	2,079
Durable Manufacturing	$201,916,507	$79,810,109	$51,798,004	729
Transportation and Utilities	$868,687,929	$319,312,541	$181,061,682	1,953
Information	$285,291,316	$175,922,288	$75,937,628	728
Wholesale Trade	$1,345,293,119	$910,297,978	$524,885,922	6,048
Retail Trade (including Restaurants)	$1,467,618,043	$1,028,089,884	$584,914,662	20,229
FIRE	$1,863,925,953	$599,953,315	$161,544,527	1,636
Business Services	$390,030,460	$226,535,717	$184,795,097	2,281
Health Services	$484,622,736	$343,526,372	$290,454,731	4,869
Other Services	$863,849,049	$449,850,553	$355,256,163	7,759
TOTAL	**$9,146,878,890**	**$4,554,836,208**	**$2,669,593,246**	**50,149**

Notes: The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017. The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida High Case—Commercial—2016				
Category	**Total Expenditures** (2016 Dollars)	**Gross Product** (2016 Dollars)	**Personal Income** (2016 Dollars)	**Employment** (Permanent Jobs)
Agriculture	$176,930,223	$51,980,448	$34,073,695	544
Mining	$71,207,710	$18,375,901	$10,742,173	73
Construction	$244,165,059	$118,870,494	$97,956,688	1,396
Nondurable Manufacturing	$495,360,549	$139,796,506	$73,812,616	1,223
Durable Manufacturing	$138,441,871	$54,260,738	$34,968,200	503
Transportation and Utilities	$307,920,171	$130,084,881	$77,033,003	901
Information	$116,890,064	$71,033,724	$31,406,499	334
Wholesale Trade	$242,339,914	$163,928,305	$94,522,526	1,089
Retail Trade (including Restaurants)	$903,031,620	$667,008,419	$385,979,326	12,293
FIRE	$1,877,697,000	$694,301,780	$177,989,441	1,774
Business Services	$428,581,168	$275,391,082	$224,648,554	2,773
Health Services	$299,523,641	$203,841,067	$172,349,516	2,889
Other Services	$491,677,047	$256,775,707	$198,358,021	4,741
TOTAL	**$5,793,766,038**	**$2,845,649,052**	**$1,613,840,259**	**30,533**

Notes: The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017. The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida High Case—Industrial—2016				
Category	Total Expenditures (2016 Dollars)	Gross Product (2016 Dollars)	Personal Income (2016 Dollars)	Employment (Permanent Jobs)
Agriculture	$32,629,701	$7,680,290	$5,104,778	79
Mining	$18,656,817	$4,429,189	$2,428,583	12
Construction	$12,981,234	$7,191,937	$5,926,610	83
Nondurable Manufacturing	$222,373,629	$67,640,199	$35,001,622	501
Durable Manufacturing	$108,951,950	$46,388,501	$29,895,440	389
Transportation and Utilities	$110,012,003	$45,029,872	$26,927,070	317
Information	$35,533,890	$21,612,253	$9,260,558	84
Wholesale Trade	$27,471,702	$18,588,955	$10,718,555	123
Retail Trade (including Restaurants)	$75,677,405	$56,916,339	$33,114,135	1,024
FIRE	$77,819,156	$20,326,243	$8,021,978	80
Business Services	$22,937,800	$13,856,286	$11,303,165	138
Health Services	$17,889,564	$12,516,615	$10,582,899	176
Other Services	$31,382,894	$16,062,646	$12,847,052	306
TOTAL	**$794,317,746**	**$338,239,324**	**$201,132,446**	**3,311**

Notes: The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017. The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida High Case—Total—2016				
Category	Total Expenditures (2016 Dollars)	Gross Product (2016 Dollars)	Personal Income (2016 Dollars)	Employment (Permanent Jobs)
Agriculture	$408,895,752	$117,428,657	$76,428,066	1,216
Mining	$226,218,824	$54,494,998	$31,492,022	194
Construction	$441,231,938	$222,724,802	$183,539,115	2,614
Nondurable Manufacturing	$1,573,602,185	$442,853,958	$232,532,394	3,803
Durable Manufacturing	$449,310,329	$180,459,348	$116,661,645	1,621
Transportation and Utilities	$1,286,620,103	$494,427,294	$285,021,756	3,171
Information	$437,715,271	$268,568,266	$116,604,685	1,145
Wholesale Trade	$1,615,104,735	$1,092,815,238	$630,127,004	7,260
Retail Trade (including Restaurants)	$2,446,327,069	$1,752,014,641	$1,004,008,122	33,546
FIRE	$3,819,442,109	$1,314,581,338	$347,555,946	3,490
Business Services	$841,549,428	$515,783,085	$420,746,816	5,192
Health Services	$802,035,941	$559,884,054	$473,387,146	7,933
Other Services	$1,386,908,990	$722,688,906	$566,461,236	12,806
TOTAL	**$15,734,962,673**	**$7,738,724,584**	**$4,484,565,951**	**83,993**

Notes: The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017. The 2016 values represent the estimated direct savings that would have occurred in Florida had competition been fully implemented and mature in 2016.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

High Case: 2030

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida High Case—Residential—2030				
Category	**Total Expenditures (2016 Dollars)**	**Gross Product (2016 Dollars)**	**Personal Income (2016 Dollars)**	**Employment (Permanent Jobs)**
Agriculture	$245,195,962	$71,058,276	$45,819,409	729
Mining	$167,724,604	$38,980,638	$22,536,343	135
Construction	$226,437,250	$118,900,969	$97,981,806	1,397
Nondurable Manufacturing	$1,052,773,006	$289,578,447	$152,181,334	2,557
Durable Manufacturing	$248,370,364	$98,171,596	$63,714,895	896
Transportation and Utilities	$1,068,542,339	$392,775,079	$222,717,579	2,403
Information	$350,926,771	$216,395,793	$93,408,194	895
Wholesale Trade	$1,654,797,550	$1,119,725,390	$645,643,634	7,440
Retail Trade (including Restaurants)	$1,805,265,118	$1,264,617,053	$719,482,866	24,884
FIRE	$2,292,749,480	$737,981,382	$198,710,217	2,012
Business Services	$479,762,693	$278,653,584	$227,309,921	2,806
Health Services	$596,117,311	$422,559,657	$357,278,105	5,989
Other Services	$1,062,590,204	$553,345,277	$436,988,058	9,544
TOTAL	**$11,251,252,652**	**$5,602,743,141**	**$3,283,772,361**	**61,686**

Notes: The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017. The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida High Case—Commercial—2030				
Category	**Total Expenditures (2016 Dollars)**	**Gross Product (2016 Dollars)**	**Personal Income (2016 Dollars)**	**Employment (Permanent Jobs)**
Agriculture	$220,246,239	$64,706,289	$42,415,609	677
Mining	$88,640,765	$22,874,685	$13,372,069	91
Construction	$303,941,491	$147,972,340	$121,938,422	1,738
Nondurable Manufacturing	$616,634,603	$174,021,454	$91,883,403	1,522
Durable Manufacturing	$172,335,178	$67,544,839	$43,529,107	626
Transportation and Utilities	$383,305,115	$161,932,231	$95,892,205	1,121
Information	$145,507,062	$88,424,184	$39,095,430	416
Wholesale Trade	$301,669,515	$204,061,195	$117,663,509	1,356
Retail Trade (including Restaurants)	$1,124,111,610	$830,305,263	$480,474,694	15,302
FIRE	$2,337,394,339	$864,280,579	$221,564,774	2,208
Business Services	$533,506,309	$342,812,261	$279,646,960	3,452
Health Services	$372,852,948	$253,745,389	$214,544,084	3,596
Other Services	$612,049,307	$319,639,476	$246,919,986	5,902
TOTAL	**$7,212,194,480**	**$3,542,320,185**	**$2,008,940,253**	**38,008**

Notes: The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017. The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida High Case—Industrial—2030				
Category	**Total Expenditures (2016 Dollars)**	**Gross Product (2016 Dollars)**	**Personal Income (2016 Dollars)**	**Employment (Permanent Jobs)**
Agriculture	$51,217,651	$12,055,471	$8,012,784	124
Mining	$29,284,926	$6,952,336	$3,812,058	19
Construction	$20,376,170	$11,288,921	$9,302,784	130
Nondurable Manufacturing	$349,051,777	$106,172,355	$54,940,769	787
Durable Manufacturing	$171,017,904	$72,814,339	$46,925,783	611
Transportation and Utilities	$172,681,831	$70,681,748	$42,266,441	497
Information	$55,776,252	$33,923,966	$14,535,960	132
Wholesale Trade	$43,121,329	$29,178,405	$16,824,526	193
Retail Trade (including Restaurants)	$118,788,064	$89,339,502	$51,978,050	1,607
FIRE	$122,149,892	$31,905,362	$12,591,806	125
Business Services	$36,004,629	$21,749,707	$17,742,167	216
Health Services	$28,080,596	$19,646,875	$16,611,590	276
Other Services	$49,260,584	$25,212,950	$20,165,549	480
TOTAL	**$1,246,811,606**	**$530,921,936**	**$315,710,268**	**5,197**

Notes: The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017. The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

The Estimated Total Impact of Implementing Statewide Retail Electric Competition on Business Activity in Florida
High Case—Total—2030

Category	Total Expenditures (2016 Dollars)	Gross Product (2016 Dollars)	Personal Income (2016 Dollars)	Employment (Permanent Jobs)
Agriculture	$516,659,852	$147,820,036	$96,247,802	1,531
Mining	$285,650,295	$68,807,658	$39,720,469	244
Construction	$550,754,911	$278,162,230	$229,223,012	3,265
Nondurable Manufacturing	$2,018,459,386	$569,772,256	$299,005,507	4,866
Durable Manufacturing	$591,723,445	$238,530,774	$154,169,785	2,133
Transportation and Utilities	$1,624,529,284	$625,389,057	$360,876,225	4,022
Information	$552,210,086	$338,743,943	$147,039,584	1,442
Wholesale Trade	$1,999,588,394	$1,352,964,990	$780,131,668	8,989
Retail Trade (including Restaurants)	$3,048,164,793	$2,184,261,818	$1,251,935,610	41,793
FIRE	$4,752,293,711	$1,634,167,323	$432,866,797	4,346
Business Services	$1,049,273,631	$643,215,553	$524,699,048	6,474
Health Services	$997,050,856	$695,951,921	$588,433,780	9,861
Other Services	$1,723,900,094	$898,197,702	$704,073,593	15,926
TOTAL	**$19,710,258,738**	**$9,675,985,262**	**$5,608,422,882**	**104,892**

Notes: The High Case is based on the differential between the estimated rates that would exist if the Texas competitive markets had remained regulated (which are also consistent with current US average rates) relative to current rates as determined by the Public Utility Commission of Texas. See Scope of Competition in Electric Markets in Texas, Report to the 85th Texas Legislature, Public Utility Commission of Texas, January 2017. The 2030 values represent the estimated direct savings that will occur in Florida assuming that statewide competition is introduced and reaches maturity by that time. Future usage by segment and baseline prices were obtained from projections provided by the energy Information Administration. See Table 55.2 Florida Reliability Coordinating Council, Electric Power Projections for Electricity Market Module Regions, Annual Energy Outlook 2017, U.S. Energy Information Administration, January 5, 2017.
SOURCE: US Multi-Regional Impact Assessment System, The Perryman Group

Overview of the Florida Public Service Commission

Presentation to the

Financial Impact Estimating Conference

Mark Futrell
Deputy Executive Director, Technical

February 11, 2019

Mission:

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

Economic Regulation

- Essential Services
  - o Society dependent upon services for quality of life and input to economic activity
  - o Demand relatively inflexible

- Natural Monopoly
  - o Demand satisfied at lower cost by single provider
  - o High capital cost, long-lived assets
  - o Duplicative systems wasteful and undesirable

Non-economic Regulation

- Public Policy Goals
  - o Health
  - o Safety
  - o Environmental protection
  - o Grid stability
  - o Efficient use of resources

Regulatory Compact

- Rate regulation occurs for essential services that are provided by <u>monopoly</u> firms

- Government protects the interests of both the <u>consumer</u> and the <u>supplier</u>

- In return, the supplier has <u>rights</u> AND <u>responsibilities</u>

Regulatory Compact

- Rights of the Utility:
  - Natural monopoly
  - Franchise for defined territories
  - Can charge rates to recover the prudent costs of service
  - Entitled to an opportunity to earn a fair and reasonable return on investments
- Responsibilities of the Utility:
  - Obligation to serve all customers in the defined territory
  - May not unduly discriminate in providing service or charging rates
  - Must provide safe and reliable service
  - May not build unnecessary facilities or incur costs for unnecessary services
  - Must open books to regulators

The “Public Interest”

- Regulators are tasked with making decisions that are in the public interest

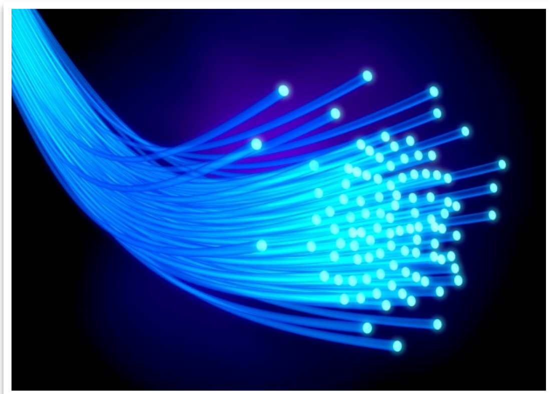
- Requires balancing several interests
  - Customers and the utility and its shareholders
  - Reliable service and cost
  - Long-term planning and short-term rate impacts

The FPSC Regulates

ELECTRIC

NATURAL GAS

WATER & WASTEWATER



TELECOMMUNICATIONS

FLORIDA PUBLIC SERVICE COMMISSION
STATE OF FLORIDA

FPSC Regulatory Overview

- The Public Service Commission is a Legislative agency with authority over the rates and service of the state’s investor-owned utilities (IOUs)

- Electricity, Natural Gas, and Water & Wastewater:
  - o The PSC regulates the electric and gas IOUs, and the water & wastewater IOUs in those counties that have given jurisdiction to the PSC
  - o The PSC also has limited jurisdiction over publicly-owned municipal and rural cooperative utilities

- Telecommunications:
  - o The PSC has regulatory authority over the wholesale relationships of the state's various telecommunications companies, and over certain retail programs such as Lifeline and Relay

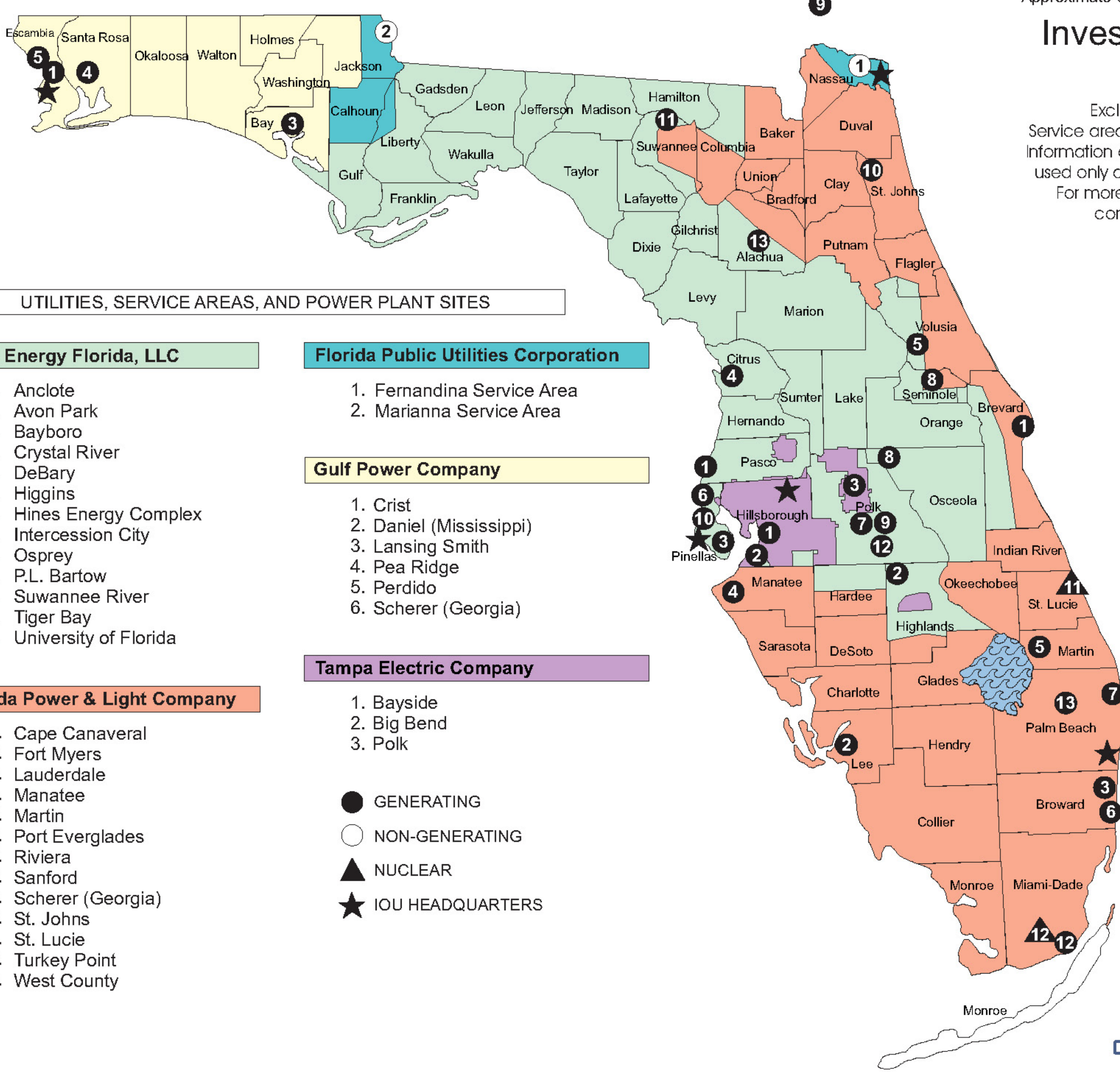
FPSC Regulatory Jurisdiction

- The PSC currently regulates the rates and service of:
  - 5 investor-owned electric utilities
  - 8 investor-owned natural gas utilities
  - 150 investor-owned water and wastewater utilities
- The PSC has limited jurisdiction over:
  - 18 rural electric cooperatives
  - 35 municipal electric utilities
  - 27 municipal natural gas utilities
  - 4 special gas districts
- The PSC exercises competitive market oversight for:
  - 10 incumbent local exchange telephone companies
  - 275 competitive local exchange telephone companies
  - 44 pay telephone service providers

Approximate Company Service Areas

Investor-Owned Electric

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



UTILITIES, SERVICE AREAS, AND POWER PLANT SITES

Duke Energy Florida, LLC

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

Florida Power & Light Company

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

Florida Public Utilities Corporation

1. Fernandina Service Area
2. Marianna Service Area

Gulf Power Company

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

Tampa Electric Company

1. Bayside
2. Big Bend
3. Polk

GENERATING
NON-GENERATING
NUCLEAR
IOU HEADQUARTERS

FLORIDA
PUBLIC
SERVICE
COMMISSION

FPSC Regulatory Authority

- Rate Base/Economic Regulation
  - Analyze requested rate changes
  - Conduct earnings surveillance to ensure that regulated utilities are not exceeding their authorized rates of return
- Consumer Protection, Safety, Reliability, and Service
  - Investigate and respond to consumer questions
  - Disseminate consumer education materials
  - Conduct safety inspections of gas systems and electric facilities
  - Oversight of the planning, development, and maintenance of the grid to assure an adequate and reliable source of energy
- Competitive Market Oversight
  - Facilitate the development of competitive markets, where directed by statute, and address issues associated with those markets

Electric Utility Regulation

- Establish rates and monitor quality of service of 5 investor-owned electric utilities (IOUs)
- Rate structure authority over 35 municipal and 18 rural co-op utilities
- Authority over electric safety and the planning, development, and maintenance of a coordinated electric power grid
- Oversight of utility ten-year plans for meeting customer energy needs
- Determine need for certain new power plants and transmission lines
- Set conservation goals for IOUs and two municipal electric utilities, and approve cost effective utility plans and programs to meet those goals
- Set buy-back rates and authorize cost recovery for purchases from renewable energy generators

Key Supreme Court Cases

- In 1923, in Bluefield Water Works v. Public Service Commission of West Virginia, the Supreme Court ruled that:
    - A public utility is entitled to rates that allow it to earn a return on the value of the plant and equipment it owns
    - While the public utility has no right to profits from speculative ventures
- In 1944, in FPC v. Hope Natural Gas, the Supreme Court ruled that:
    - From the investor or company perspective, prices are set such that there be enough revenue for operating expenses and to cover the costs of capital and debt expenses
    - Additionally, the return to equity owners should be commensurate with returns on firms with similar risks and to allow the utility to maintain its ability to attract capital

Regulatory Assessment Fees Statutory Authority

Florida Public Service Regulatory Trust Fund

- Section 350.113, F.S.
- Fees collected and credited to the trust fund are used in the operation of the Commission as authorized by the Legislature
- Each regulated company under the jurisdiction of the commission, shall pay a fee based upon gross operating revenues

Chapters 364, 366 and 367, F.S., establish maximum regulatory assessment fees to be paid by electric, natural gas, and water and wastewater utilities, and telecommunications companies.

Regulatory Assessment Fees – Electric Utilities Implementation

Maximum Fees Established by Section 366.14, F.S.

- Investor-owned electric utilities: 0.125%
- Municipal and rural electric cooperative utilities: 0.015625%

Commission Rule 25-6.0131, F.A.C., establishes the fee

- Investor-owned electric utilities: 0.072%
  - Reduced from 0.0833% in 1999
- Municipal and rural electric cooperative utilities: 0.015625%

Regulatory Assessment Fees – Electric Utilities
($ millions)

	Investor-Owned Utilities			Municipal and Rural Cooperative Utilities		
Fiscal Year	Percentage Rate	RAF Collected	Operating Revenues	Percentage Rate	RAF Collected	Operating Revenues
17/18	0.072%	$13.5	$18,794.8	0.015625%	$0.963	$6,171.2
16/17	0.072%	$12.7	$17,642.6	0.015625%	$0.968	$6,202.0
15/16	0.072%	$13.6	$18,827.8	0.015625%	$0.993	$6,363.2

Regulatory Assessment Fees – Electric Utilities

Regulated Company Under Commission Jurisdiction → Public Utility; Municipal Utility; Rural Electric Cooperative → Electricity Sales to Customers

→ Operating Revenues → RAF Assessment → RAFs Remitted to the Commission

Questions?

FL Chamber FIEC Comments

Deregulation of electricity markets is not a new discussion. As others will mention, the Constitutional Review Commission[1] just last year determined it was a bad idea for Florida. There, the Florida Chamber of Commerce led the effort to defeat the proposal and ultimately, the CRC agreed deregulation would have diminished Florida's future competitiveness. But yet, here we are, discussing an issue that has proven time and again to be bad for consumers, businesses, government and the economy.

A number of states across the country that decided to deregulate electricity have abandoned their decision and gone back to a regulated system after experiencing many negative outcomes. And, other states that have continued with the experiment of electricity deregulation – particularly Illinois[2], Massachusetts[3] and Connecticut[4] – are taking a hard look at repealing the scheme due to predatory marketing practices and sales scams targeting low-income and elderly customers. It is a simple fact: electricity deregulation costs consumers more money. Those same issues will face Florida consumers and business owners if we are short-sighted and move down this path.

There are many lessons to be learned from these states and others, including Maryland,[5] which also recently pointed to high costs. Chief among them is the fact that hundreds of millions of dollars was needlessly taken from consumers' pockets and placed in the pockets of marketers due to electricity rates that were higher than those of incumbent utilities. For example, in New York, residential and some small commercial customers overpaid by an estimated $817 million between January 2014 and June 2016.[6]

Increased electricity rates will directly reduce Floridian's disposable income. These are dollars that purchase goods, drive state and local economies, and put food on tables. Likewise, these are dollars that pay sales tax, property tax and other fees to local and state government. With less purchasing power, consumers and businesses will clearly generate less revenue for state and local governments. But, the question is, how much less?

If we allow this ballot initiative to move forward, we will be placing state and local governments into a situation where they will face years of revenue uncertainty as the initiative is implemented. Then, once implemented, it will be years more before we know the true impact.

Many studies will predict the future based on deregulating our electricity market. We will, in fact, be submitting our own study to this body that is currently underway. But, on a personal note, I would submit that the outcome will not be positive. Additionally, due to the lack of clarity regarding future government revenue, infrastructure planning and upgrades for roads and highways, water and sewer systems, schools and recreation centers, and, most importantly – jobs – will all be placed in limbo for years. Why would we do this to our economy?

This proposal will substantially impact multiple branches of government. I think we all recognize the risk to Florida's gross receipts tax, local franchise fees, and property taxes. Florida's gross receipts tax on electricity is levied solely on distribution companies, thereby effectively exempting the proposed electricity marketing companies from the current gross receipts tax. While it may be possible the Legislature addresses this inequity that future is far less certain after the recent passage of Amendment 5, which would require any new tax on electricity marketers to be filed in a separate bill and approved by a supermajority of both chambers of the Legislature.

A reduction in Florida's gross receipts tax would be a direct attack on public education. The gross receipts tax on electricity makes up approximately 2/3rds of the revenues distributed to the PECO trust fund. Passage of this proposal will have a substantial impact on Florida's schools and the state's ability to bond these revenues.

The proposal will also substantially impact the revenue streams of local governments. The proposal jeopardizes local franchise fees by expressly prohibiting the granting of exclusive franchises. The proposal risks ad valorem tax reductions on electrical generation equipment. For many rural counties, these taxes represent a massive percentage of their annual budgets.

In addition to expressly impacting the legislative branch, this proposal will substantially impact scope of the PSC under the executive branch, local government's ability to raise revenues as franchise fees or ad valorem taxes, and school's ability to access and bond PECO funds. This proposal impacts nearly all branches of Florida's government.

Florida needs to continue down the path of ensuring resilient, efficient, diverse and dependable electricity with rates that are already below the national average. So, what is wrong with a system that costs less and is highly dependable? What is driving this need for change and the possible jeopardy it will place on consumers, businesses and our state's economy?

That is one question we cannot answer because we do not see a need for creating such uncertainty and potentially dire consequences.

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[1] Florida CRC Rights of electricity customers

[2] See "AG Madigan: Scrap retail electricity sales to Illinois households" Steve Daniels, Crains Chicago Business 10/18

[3] See Press Release: AG Healey Calls for Shut Down of Individual Residential Competitive Supply Industry to Protect Electric Customers

[4] See Press Release: Time to End the Third-Party Residential Electric Supply Market

[5] Maryland's Residential Electric and Gas Supply Markets: Where Do We Go from Here?

[6] Competing to Overcharge Consumers: The Competitive Electric Supplier Market in Massachusetts

Supporting Material

Press Release

AG Healey Calls for Shut Down of Individual Residential Competitive Supply Industry to Protect Electric Customers

March 2018

https://www.mass.gov/news/ag-healey-calls-for-shut-down-of-individual-residential-competitive-supply-industry-to-protect

Two-Year Study by AG's Office Shows Competitive Supply Customers Paid $176.8 Million More; Companies Appear to Have Targeted Low-Income, Minority Neighborhoods in Gateway Cities

Citing aggressive sales tactics, false promises of cheaper electric bills and the targeting of low-income, elderly, and minority residents, Attorney General Maura Healey today issued a report calling for an end to the competitive electricity supply market for individual residential customers in Massachusetts.

Report

National Consumer Law Center

Competing to Overcharge Consumers: The Competitive Electric Supplier Market in Massachusetts

April 2018

http://www.nclc.org/images/pdf/pr-reports/competitive-energy-supply-report.pdf

Deregulation in Massachusetts began in 1997, but the goals of deregulation -- "promot[ing] the prosperity and general welfare of its citizens . . . by restructuring the electricity industry in the commonwealth to foster competition and promote reduced electricity rates" – have not been achieved. The other deregulated states (for electricity, Connecticut, Delaware, the District of Columbia, Illinois, Maine, Maryland, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, and Texas) have faced similar struggles, and none have found a way to operate a restructured electricity market without financial harm to residential customers. Are Consumers Benefiting from Competition?

Financial Impact Estimating Conference Public Workshop

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

February 11, 2019

AGENDA

- Introductions
- Key Impact Summary
- Florida's Investor-Owned Utilities
- Implementation Considerations
- Divestiture and Stranded Costs
- Impacts on Tax Revenues
- Reliability and Other Impacts
- Conclusion
- Appendices

Thank you for allowing us this opportunity to present to the FIEC.

INTRODUCTION

- John Reed, Chairman and CEO, Concentric Energy Advisors, Inc. and Terry Deason, Special Consultant, Radey Law Firm, are here on behalf of Florida's four major investor-owned utilities: Duke Florida, Florida Power & Light, Gulf Power Company and Tampa Electric Company.
- Mr. Reed and Mr. Deason collectively have more than 80 years of experience in the energy industry, including direct and practical experience in Florida and in the myriad of issues which would be created by the proposed constitutional amendment.
  - Mr. Deason served on the Florida Public Service Commission (FPSC) for 16 years, two times as its chairman.
  - Mr. Reed has advised numerous clients contemplating state-level restructuring, including managing the divestitures of thousands of MW of generation assets.
- We will highlight the many issues and shortcomings of the amendment today.
- A detailed report will be provided to the FIEC by the IOUs prior to February 21, 2019.

It is our collective expert assessment that the amendment would radically and permanently dismantle Florida's electricity industry and significantly increase costs and reduce revenues for state and local government.

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The amendment leaves many critical issues undefined or unaddressed but will clearly have significant negative consequences for the state, with financial impacts expected to exceed $1 billion.

KEY IMPACT SUMMARY

- Proponents summarize the constitutional amendment as:
  - "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."
- The amendment will:
  - Expel from Florida's electric energy market all of the state's investor-owned utilities (IOUs) that combined own more than 75% of electricity capacity used by Floridians. This enormous void will ostensibly be filled by yet-to-be identified and qualified providers of electric service in a so-called "competitive" market with none of the price or other protections currently provided through regulation by the FPSC; and
  - Force the state legislature, the executive branch of government and other agencies and organization to expend an enormous amount of time, resources and money to comply with the amendment, implement "competitive" electric markets, defend their decisions in litigation and manage the aftermath.

The amendment will dismantle Florida's electricity industry, with significant negative consequences for the state.

KEY IMPACT SUMMARY (CONTINUED)

- The amendment will:
  - Require the formation of an independent system operator, costing customers, including state and local government, hundreds of millions in start-up costs and on-going administrative costs.
  - Force the sale of at least 36 power plants, 150,000 miles of transmission and distribution lines and other critical electric infrastructure owned by the state's IOUs to yet-to-be identified and qualified parties. Every other state that forced the divestiture of generation did so at substantial losses or "stranded costs". Stranded costs are necessarily compensated by or through government action to avoid an unconstitutional "taking";
  - Result in significantly lower revenues to local government through reduced eligible franchise fees and property taxes;
  - Threaten reliability and expose Floridians to consumer fraud and market manipulation as has been the experience in restructured states; and
  - Put the state in the position of having to organizationally and financially backstop any aspect of the supply and delivery of electricity, including post-hurricane repairs or rebuilds, if the new market fails in any respect.

The fiscal impact of the amendment on state and local government will exceed <u>$1 billion</u>.

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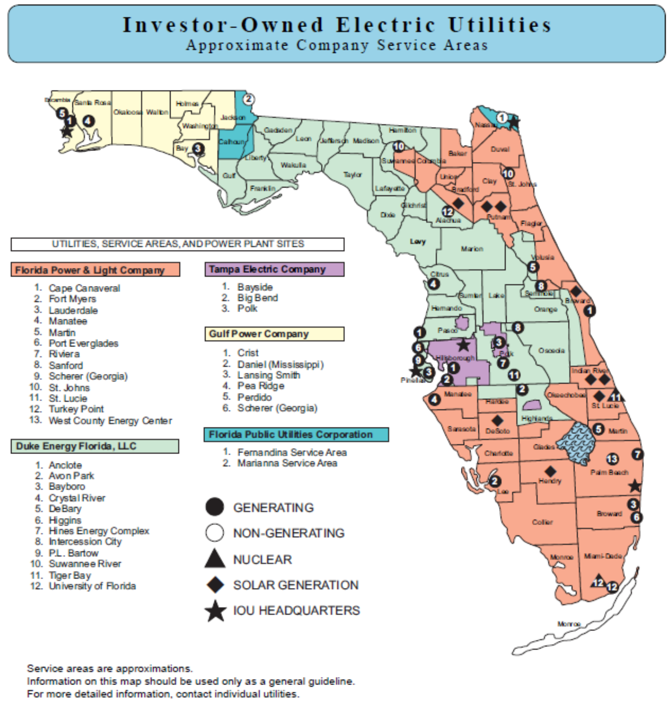
Investor-owned utilities supply electricity to most Floridians at rates regulated by the Florida Public Service Commission.

ROLE OF IOUs IN FLORIDA'S ELECTRICITY MARKET

- Each IOU has a specific area in which it provides non-discriminatory service to all customers at rates regulated by the FPSC.
  - IOUs have currently invested more than $60 billion in electric infrastructure to serve ~70% of Florida's residents including remotely-located, low income and other customers.
- Municipal & cooperative electric companies purchase a portion of the electricity for their customers from the IOUs.
  - For example, Lee County Electric Coop, one of the largest coops in the country, purchases 100% of its energy under a long term contract from Florida Power & Light.
  - These entities would be required to find new suppliers of electricity if the amendment passes.



Source:
Florida Public Service Commission

Investor-owned utilities supply electricity to most Floridians at rates regulated by the Florida Public Service Commission.

ROLE OF IOUs IN FLORIDA'S ELECTRICITY MARKET (CONTINUED)

- The IOUs also own150,000 miles of transmission and distribution (T&D) lines and other electric infrastructure used to deliver electricity to customers.
  - The amendment limits IOUs to the construction, operation and repair of T&D only.
- Florida Power & Light is the state's agent for the Florida Reliability Coordinating Council, responsible for the bulk electric system in peninsular Florida, which is critical to ensure the reliability in the state.
- Florida's IOUs have contracted for the bulk of the natural gas pipeline capacity coming into the state.

Florida's IOUs have been recognized for outstanding performance across many important categories and provide customers with exceptional reliability.

FLORIDA IOU PERFORMANCE AND RECOGNITION

- Florida's IOUs and their parent companies have received numerous national and industry awards and have been recognized for outstanding performance in many categories:
  - Reliability
  - Storm restoration and emergency recovery
  - Innovation
  - Customer service
  - Employer
- Customers of the four largest Florida IOUs enjoy exceptional reliability.
- The IOUs have achieved this level of service using systematic and transparent planning processes overseen by the state to evaluate and fill generation and transmission needs.
- The amendment threatens this exceptional reliability, in effect jeopardizing all of these critical functions.

Restructured markets in other states were initiated through legislation, took years to develop, and still have not produced results better than what Florida enjoys today.

WEIGHTED AVERAGE ELECTRICITY RATES (CENTS/KWH)

	Residential	Commercial	Industrial	All Sectors
Florida - IOU	**11.61**	**9.20**	**7.67**	**10.37**
Average in States with Restructured Electricity Markets	**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

Florida's IOUs rates are well-below both national averages and the average rates charged in states that have restructured their electricity markets.

Critical differences between this amendment and experiences in "restructured" states will result in significant consequences not faced by any other state.

THE AMENDMENT IS UNPRECEDENTED

- No other U.S. state has ever implemented electric market restructuring through a constitutional amendment.
- No other U.S. state has initiated restructuring at all in almost 20 years.
- No other U.S. state has limited its IOUs to "construction, operation, and repair of electrical transmission and distribution systems".
- As a peninsula, Florida faces unique fuel supply and interstate transmission access limitations and risks.
- The proposal is a market dismantlement; it is not a "restructuring" proposal.

The proposal eliminates IOUs as electric providers, eliminates any obligation to provide essential electric service on a non-discriminatory basis to all customers, and directs the legislature to figure out the consequences.

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Implementing the amendment will require the design, implementation and on-going administration and monitoring of a new market structure.

IMPLEMENTATION CONSIDERATIONS

- All U.S. states which have restructured their electric markets are part of either an independent system operator (ISO) or regional transmission organization (RTO).
  - States that have implemented ISOs/RTOs have spent years and hundreds of millions of dollars to do so.
  - States that have recently considered ISO/RTO formation have estimated that ***implementation could take up to 10 years and cost between $100 million and $500 million.***
  - Given the unique nature of Florida as a peninsula with limitations on inter-state infrastructure, implementation could cost even more.
  - Florida previously considered, and rejected, forming an RTO, in part due to the extensive implementation costs.
  - The amendment provides less than 5 years to complete the entire process.
- Substantial on-going costs related to ISO/RTO administration and operation, customer education, regulatory oversight and grid reliability will also be created. ***Annual operating budgets for ISOs/RTOs in the U.S. are between $200 million and $300 million.***

Designing and implementing a new market structure will require the Florida Legislature and Executive Branch to commit extensive time, resources and costs.

IMPACT ON LEGISLATURE AND EXECUTIVE BRANCH

- The Florida Legislature and the Executive Branch will be required to design and implement a complex series of laws and regulations in an effort to comply with the amendment as written, including but not limited to determining:
  - How to fill the market void left by IOUs;
  - 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 FPSC;
  - How to provide for competitive wholesale electric markets as required by the amendment without infringing upon the jurisdiction of the U.S. Federal Regulatory Commission (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 stricken so as to ensure the "purposes" of the amendment are met;
  - 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);
  - How to reconcile public policy mandates such as renewables and conservation with the competitive market required by the constitutional amendment;

The Legislature and Executive Branch will be faced with answering many questions unaddressed in the amendment.

IMPACT ON LEGISLATURE AND EXECUTIVE BRANCH (CONTINUED)

- 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.
- 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.

The State of Florida will have the ultimate responsibility to ensure that any new system works properly, with significant financial exposure to the state.

STATE EXPOSURE

- In attempting to implement the amendment, the Legislature and the Executive Branch will have to determine what role the state might have to play (and at what cost):
  - To ensure 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;
  - To ensure that all residents and businesses in Florida continue to have the right to affordable and reliable electric service;
  - To ensure that Florida's electric infrastructure is promptly repaired or rebuilt following a hurricane or natural disaster and how those costs would be funded; and
  - To ensure that Florida's electric grid continues to be properly operated and coordinated minute by minute, 24/7, although much of the regulatory responsibility will be shifted to the Federal government (which has been challenged in meeting this responsibility).

Whether due to political realities or newly enshrined constitutional rights, the state will face significant exposure for market failures.

Restructuring of Florida’s electricity market will result in extensive regulatory and litigation expense.

LITIGATION COSTS – STATE GOVERNMENT

- Implementation of electricity market restructuring in other states in the 1990s and 2000s was accompanied by extensive litigation.
- The proposed constitutional amendment would substantially broaden the opportunity for litigation. The amendment:
  - Provides for any Florida citizen to seek judicial relief if the legislature does not “adopt complete and comprehensive legislation” to implement the amendment “in a manner fully consistent with its broad purpose and stated terms”; and
  - Leaves open many critical issues and questions, increasing the likelihood that the Legislature and Executive Branch will be challenged on anything they attempt to implement.
- Litigation throughout the legislative and administrative processes and the inevitable amendments, refinements, addendums, or complete “re-dos” that will be identified or mandated by the courts as necessary, will further complicate and add cost.

Hundreds of millions of dollars will be spent on lawyers and consultants to support both litigation and regulatory proceedings.

Local governments will also incur extensive litigation expenses.

LITIGATION COSTS – LOCAL GOVERNMENT

- Significant legal expenses will also be incurred by local government including but not limited to the following:
  - Termination of territorial agreements and power purchase agreements between IOUs and municipal electric utilities;
  - Legal costs to enter into and manage new power purchase contracts with unregulated generation entities;
  - Citizen pressure/potential litigation related to municipal “opt-in” rights granted to municipalities under the petition;
  - Disputes/litigation over current long-term power purchase obligations when municipal electric utilities attempt to “opt-in” to competitive markets; and
  - Review by municipalities of every regulation or implementing statute that might impact a municipality, including participation and attendance at multiple legislative and regulatory proceedings at multiples levels of government.

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IOUs will be forced to divest assets at an expected loss due to the uncertainty and risk of a new market.

ELIMINATION OF IOUs FROM THE MARKET

- IOUs supply electricity by making substantial investments in power plants, transmission structures and lines and distribution poles and wires.
  - These investments are reviewed and approved by the FPSC to ensure they are appropriate and reasonable.
  - The FPSC then establishes the electric rates on the basis of the cost of providing service ("cost of service based ratemaking").
  - Ownership of the full electric system value chain allows IOUs to recognize significant economies of scale and efficiencies.
- By limiting IOUs to only the "construction, operation, and repair of electrical transmission and distribution systems", IOUs would be prohibited from owning the plants that generate electricity or the poles and wires that deliver electricity to customers.
- IOUs will be forced to sell these assets into a market that will be limited, and in some cases, non-existent, due to limited ownership eligibility and the high-risk associated with a new and uncertain market structure.

The forced sale or divestiture of generating assets will leave Florida's government, residents and businesses with billions of dollars of "stranded" costs.

STRANDED COSTS

- Stranded costs are the difference between the value of generating and related assets (e.g., power purchase agreements, fuel contracts) in the competitive energy markets that would be formed in Florida and what has been invested in these plants by IOUs.
- The experience of other IOUs who divested their generation assets in response to state electric market restructuring is clear – substantial stranded costs were created.
- Forcing IOUs to sell these in a new and uncertain market structure, a virtual "fire sale" of assets serving more approximately 70% of Floridians today, could result in losses easily in the billions of dollars.
- The State of Florida would have to fund the compensation for property "taken" as a result of the amendment.
  - Alternatively it would choose to pass those costs on to current customers (including state and local government customers) through a recovery charge on electric bills as others states have elected to do.
- Whether or not a customer (including state or local governmental customers) is able to secure a lower rate from a new unregulated service provider, every customer will bear stranded costs either in the form of higher state taxes to fund the compensated "taking" or an additional non-bypassable charge on its electric bill if the legislature opts for that form of recovery.

A portion of the over $1 billion dollars of property tax revenue paid by IOUs to municipalities counties and school districts would be at risk.

REDUCTION OF PROPERTY TAX REVENUE

- Florida's IOUs pay more than $1 billion annually in property taxes.
  - Ad valorem, or property taxes, are currently assessed by municipalities, counties and school districts on IOUs' real and tangible business property.
  - Property taxes are typically assessed on utility property based on net book value.
- Forced divestiture of utility property at prices substantially below book value will decrease property tax base and the amount of revenue collected by local government.
- Local governments will be forced to implement new taxes to replace this lost revenue from franchise fees or reduce services provided to residents.

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Florida's IOUs contribute significantly to the revenues that support the budgets of state and local government.

TAXES AND FEES COLLECTED AND PAID BY IOUs

- At the state level, IOUs pay:
  - Sales Tax – 4.35% on sales to commercial customers (~$430 million);
  - Gross Receipts Tax – ~2.5% on sales to all customers (~$430 million); and
  - Corporate income tax – 5.5% on net income.
- IOUs also pay taxes and fees to more than 300 Florida municipalities and counties in the form of:
  - Franchise fees – ~6% of gross billings to all customers (~$650 million); and
  - Property or ad valorem taxes – rates vary, based on property value (more than $1 billion).
- IOUs also act as the agent collecting municipal utility tax for the municipalities (~$840 million).
  - Municipalities may charge up to 10%.
- An elimination of electricity sales by IOUs would lead to a decrease in tax revenue that would need to be made up by tax collections from new entrants.
  - While there is a potential that some of those tax revenue 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 also a likelihood of increased legal and other costs.

Franchise fee revenue of over $650 million paid to local municipal government by Florida IOUs would be significantly reduced or eliminated.

REDUCTION OR ELIMINATION OF FRANCHISE FEE REVENUE

- A utility franchise agreement is a long-term agreement between a municipal government and a utility that grants a franchise to the utility to provide utility services within that government's jurisdiction.
- Typically, a municipality will collect franchise fees from a utility for franchise rights, and those payments are often based on a percentage of the utility's gross billings.
- If IOUs no longer bill customers for generation, transmission and distribution costs, the revenue from these fees will be significantly reduced or even eliminated completely.
- Local governments will be forced to seek new taxes to replace this lost revenue from franchise fees or reduce services provided to residents.

The recently passed amendment requiring a supermajority vote of the legislature to impose new taxes or to increase current taxes will make it more difficult for the Legislature to mitigate tax losses resulting from restructuring the state's electric industry.

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Exceptional reliability of electric service currently enjoyed by Florida residents, businesses and government entities will be jeopardized by elimination of statewide resource planning.

RELIABILITY IMPACTS

- Electric system reliability and sustainability will be jeopardized by system planning changes resulting from this amendment.
  - Statewide resource planning is currently overseen by the FPSC.
- While Floridians currently enjoy exceptional reliability, many states that have restructured their electricity markets face the prospect of rolling black-outs due to insufficient generation capacity.
  - Restructured states rely on market economics to motivate investment in generation infrastructure and have all struggled to make this system work since inception with many regions continually “re-doing” or refining their markets at a great cost of time and money.
- As a peninsular state, Florida also has unique geographical concerns which have not been faced in other restructured states.
  - Limited connectivity to fuel and energy supply from other states.

While the amendment promises consumer protections, other states have struggled to protect consumers from deceptive marketing practices.

CONSUMER PROTECTION AND FRAUD

- While the amendment language promises consumer protections, states with restructured electricity markets have experienced extensive consumer fraud and market manipulation. For example:
  - 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 residential customers.
  - Illinois' Attorney General has also called for an end to residential choice, based on similar deceptive marketing practices.
  - Last week, 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.
- Florida's large population of elderly residents would be especially vulnerable and state agencies would need to incur additional expenses to ensure they are protected.
- Millions of dollars in civil penalties for market manipulation in restructured markets have been imposed by the U.S. FERC.

The amendment will also negatively impact state and local government by harming economic development in the state and introducing new expenses.

OTHER ECONOMIC IMPACTS

- Increased electricity costs, reduced revenues, and other costs of the amendment will negatively impact state and local economies.
- State and local governments will no longer be able to purchase electricity from the IOUs that have served them for 100+ years.
  - Instead, state and local governments will need to purchase electricity from new unregulated companies, resulting in costs to secure electricity and manage these new contracts.
- Electricity market restructuring will transfer decision-making power from the Florida Public Service Commission to the U.S. FERC.
  - This presents an enormous resource challenge for states to keep up with issues before the U.S. 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.
  - Participating as a litigant in U.S. FERC proceedings is also a resource-intensive and expensive proposition.

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The proposed amendment will reduce revenues and increase costs for state and local government. The financial impact will exceed $1 billion and could be significantly higher.

CONCLUSION

- The state legislature, the executive branch of government and other agencies and organizations will be forced to expend an enormous amount of time, resources and money to comply with the amendment, implement "competitive" electric markets, defend their decisions in litigation and respond to the many concerns of citizens.
- IOUs will be expelled from Florida's electric energy market and forced to sell more than 30 power plants, 150,000 miles of T&D and other electric infrastructure. The resulting substantial stranded costs will be paid for by customers, including state and local government.
- Property taxes and other taxes and fees paid or collected by Florida's IOUs to state and local government will be significantly reduced.
- The exceptional reliability enjoyed by the state today will be threatened.
- The state will be the ultimate back-stop for market failures and will be exposed to substantial new risks.

We look forward to the opportunity to provide more detailed cost information in our report which we expect to provide to the FIEC before February 21, 2019.

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CONCENTRIC ENERGY ADVISORS, INC.

- Concentric specializes in management consulting and financial advisory services with an exclusive focus on the North American energy industry. Our staff possesses expertise in all aspects of the power and natural gas markets at both the wholesale and retail levels, as well as the oil pipeline industry.
- Our energy industry experts have held positions with utility companies, regulatory agencies, integrated energy companies, regional transmission organizations, retail marketing companies, and utility management consulting firms. Many members of our team have been working together for more than 30 years.
- Concentric offers a broad range of services that enable our clients to address diverse needs comprehensively without the difficulty of retaining and coordinating multiple resources.
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  - CE Capital Advisors, Inc. is a wholly-owned subsidiary of Concentric. CE Capital is a securities firm that provides services relating to corporate mergers and acquisitions, the valuation of securities, and capital market advisory support.
  - CE Capital also assists clients with transactions involving the acquisition or disposition of large assets and with the purchase and sale of business units and divisions. CE Capital often provides services as an extension of Concentric's management consulting services, including rendering fairness opinions for transactions and corporate valuations for financings, litigation and strategic assignments.

CONCENTRIC'S AREAS OF: PRACTICE

Concentric offers a broad range of services that enable our clients to address diverse needs comprehensively without the difficulty of retaining and coordinating multiple resources.

Financial Advisory
Our team is comprised of senior financial, economic, and industry professionals who advise clients on all aspects of the structure, negotiation, and implementation of asset-based and corporate transactions.

Utility Regulation
Our team includes former regulators and utility executives who have served as decision-makers and expert witnesses on a broad range of policy and rate matters in state, provincial, and federal regulatory proceedings across North America.

Markets & Resource Planning
Our analytical work in the energy industry spans all aspects of the natural gas and electric markets, including both wholesale and retail levels.

Litigation
We provide clients with expert-based litigation and arbitration support services on matters pertaining to the North American energy industry.

Concentric Energy Advisors

John J. Reed, Chairman and CEO, Concentric Energy Advisors, Inc.

Mr. Reed has more than 42 years of experience in the energy industry and has worked as an executive in, and consultant and economist to, the energy industry. Over the past 42 years, Mr. Reed directed the energy consulting services of Concentric, Navigant Consulting, and Reed Consulting Group. He has served as Vice Chairman and Co-CEO of the nation's largest publicly-traded consulting firm and as Chief Economist for the nation's largest gas utility. Mr. Reed has provided regulatory policy and regulatory economics support to more than 100 energy and utility clients and has provided expert testimony on regulatory, economic, and financial matters on more than 200 occasions before the Federal Energy Regulatory Commission, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. Mr. Reed provided advisory services in the areas of energy contract negotiations, mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, and energy market analysis, as well as rate and regulatory matters to clients across North and Central America; and he has worked for dozens of electric utilities across North America on utility rates, terms of service, resource planning, construction, regulatory policy, contracting, and financial and economic analysis assignments.

RADEY LAW FIRM

- Based in Tallahassee, Florida, Radey is an AV-rated firm consisting of lawyers who practice regularly before a variety of state agencies and in all state and federal courts. Our practice areas include insurance regulation and business transactions, public utility law, telecommunications, administrative litigation (including bid protests), civil litigation, including class action defense, and labor and employment law. We are also firmly committed to having a positive impact on our community by supporting many local causes with our time and financial backing.
- Our lawyers use their extensive regulatory and litigation experience to serve clients with problems, generally with governmental agencies and frequently in class action or other complex litigation. Several of our members have practiced insurance regulatory law for years, and two are former regulators. Our lawyers have substantial experience before almost every Florida state agency and many federal agencies. This experience, accrued over 30 years, spans a variety of substantive areas, including labor and employment law. Publicly reported cases show the type of experience and results achieved by our litigators. Publications such as Martindale-Hubbell, Florida Trend and Chambers USA have all recognized the outstanding work of our lawyers.
- We emphasize providing service to clients that is efficient and dedicated. Success for clients is our success. We vigorously marshal the facts and law in a cost-effective manner with the goal to avoid, settle, or win disputes to achieve clients' objectives. Our dedication to excellence, integrity, humanity, and community.

Terry Deason, Special Consultant, Radey Law Firm

Mr. Deason received his undergraduate degree in Accounting (summa cum laude) from Florida State University in 1975 and a Master of Accounting degree in 1989, also from FSU. Mr. Deason began his professional career in the banking industry and then began his career in public utility regulation as an analyst in the Florida Office of Public Counsel in 1977. Mr. Deason has held various positions specializing in utility regulation, including six years as Chief Advisor to Public Service Commissioner Gerald L. Gunter and four years as Chief Analyst for the Florida Office of Public Counsel.

Mr. Deason was first appointed to the Florida Public Service Commission in 1991 by the Florida Public Service Commission Nominating Council. He was subsequently reappointed to three additional four-year terms, once by Governor Lawton Chiles and twice by Governor Jeb Bush. Mr. Deason served as the Commission's Chairman for two separate terms and was awarded the Bonbright Distinguished Service Award from the Bonbright Utilities Center at the University of Georgia in 2001. During his sixteen-year tenure on the Florida Public Service Commission, Mr. Deason was active in the National Association of Regulatory Utility Commissioners, serving on NARUC's Finance and Technology Committee, the Communication's Committee and the Electricity Committee. Mr. Deason also served on NARUC's Board of Directors for thirteen years.

Following his retirement from the Florida Public Service Commission at the end of 2006, Mr. Deason joined the Radey Law Firm as a Special Consultant in the fields of energy, telecommunications, water & wastewater, and public utilities generally. In this role, Mr. Deason has been providing consulting services and expert testimony on behalf of various clients, including public service commission advocacy staff, local governments, and regulated utility companies. Mr. Deason has also testified before various legislative committees on regulatory policy matters.

DEREGULATION

FACTS & EXPERIENCE

About Energy Fairness

Founded in 2009

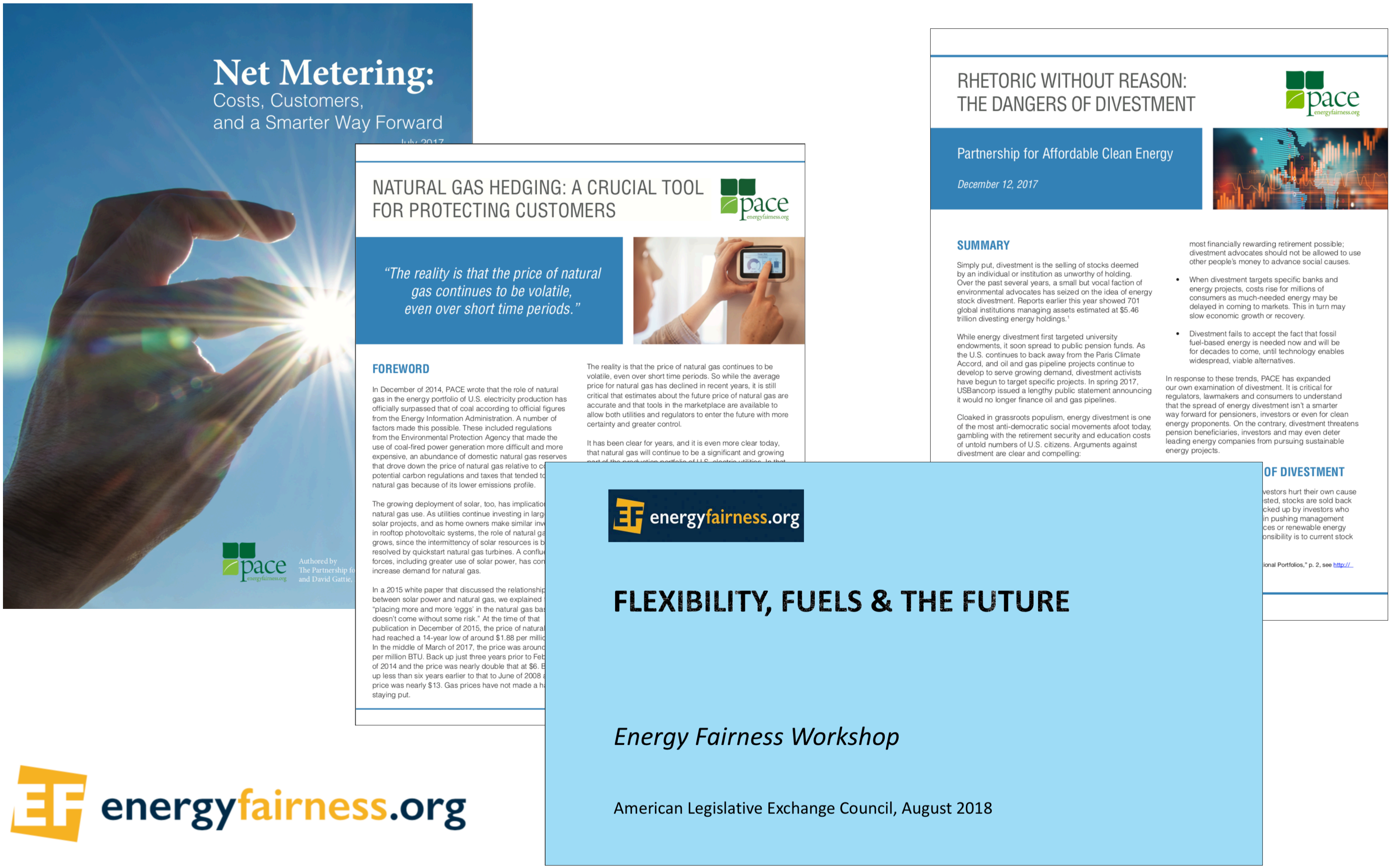
National not-for-profit organization focused on energy best practices for consumers

Active nationwide in discussions that affect electricity prices and reliability

10 years of experience weighing in with state and federal policymakers on energy matters

energyfairness.org

A HISTORY OF ADVOCACY



energyfairness.org

HISTORY & BACKGROUND

TESTIMONY & INTERVENTION

Testified before numerous Public Service Commissions and legislative bodies across various states and federal bodies both as a formal intervenor and through public comments.

EDUCATION AND ADVOCACY

Publishes twice weekly commentary on current energy topics, with a focus on educating lawmakers and the public about potential impacts on electricity price and reliability.

PART OF THE CONVERSATION

Whether it is wind issues in Oklahoma, solar issues in Arizona and Florida, or nuclear issues in Alabama and Tennessee, Energy Fairness has consistently weighed in on the topics that affect electricity customers.

DEREGULATION

WHAT WE KNOW

HISTORY & BACKGROUND

1. Since the 1990s, many states have explored deregulating their electricity markets.
2. Although official accounts vary depending on definition, our definition includes 17 states and DC that are currently deregulated.
3. Policymakers now have a great deal of data spanning twenty years about how electricity deregulation affects consumers and markets.
4. A number of states, notably California and Montana, abandoned deregulation after years of bad outcomes.
5. Today, in states that remain deregulated, consumers are plagued with higher prices, threatened reliability, and fraudulent practices.

COST

1. In 2017, deregulated states paid an average of 2.6¢ per kWh - or 21% more - than regulated states.

2. In every year since 1997, the average residential customer in regulated states has paid a lower rate for electricity than their counterparts in deregulated states.

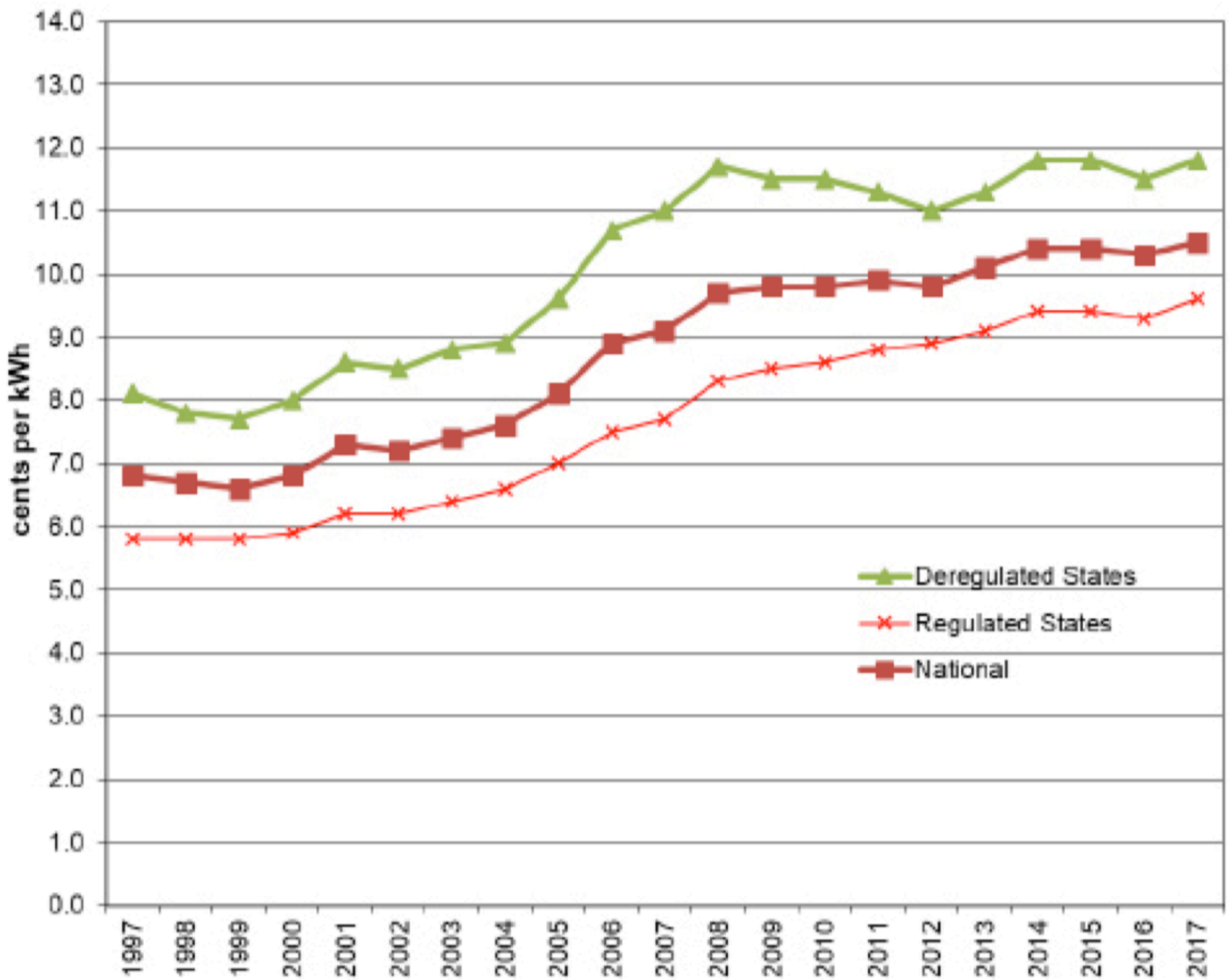
3. As of September 2018, residential customers in deregulated electricity states pay 38% more for power than Florida residential customers.

4. 88% of all Massachusetts residential customers who switched power companies paid more during the two-year period.

5. In Texas, rates in deregulated areas have been between 9.2% (2002) and 46.5% (2014) higher than regulated areas.

The data simply doesn't lie: deregulation costs consumers more.

AVERAGE ELECTRICITY RATES, DEREGULATED VS. REGULATED STATES, 1997-2017



AMERICAN PUBLIC POWER ASSOCIATION™

Powering Strong Communities

RELIABILITY

1. In Texas's deregulated retail market, consumers experienced brownouts in 2011, 2014, and 2015. In 2011, rolling blackouts forced Texas to import power from Mexico.

2. Deregulation in Texas has discouraged the building of new power plants, leaving the state's power supplies vulnerable as the state's population continues to grow.

3. Deregulation has in some cases achieved the exact opposite of what it promises and has *increased* the role of government in the residential energy market.

4. In a hurricane-prone state, investing in long-term infrastructure is critical to protecting the grid and ensuring it can bounce back from natural disasters.

FRAUD

1. In the past 3 years, the Massachusetts Attorney General's Office has received more than 700 complaints about suppliers engaging in aggressive and deceptive tactics.
2. In 2014, the New Jersey attorney general sued three companies, alleging that they defrauded hundreds of consumers by misrepresenting the savings they'd get.
3. The attorney general in Pennsylvania reported receiving more than 7,500 complaints about spikes in the cost of electricity over a four-month period.
4. From 2014 through the 2016, New York Public Service Commission staff and the office of the NY Attorney General received 14,000 complaints about suppliers.
5. Low-income customers are especially vulnerable, paying higher prices in the competitive supply market.


MASSACHUSETTS ATTORNEY GENERAL
MAURA HEALEY
Competitive electric suppliers promise big energy savings but are actually burdening customers with hundreds of dollars in extra costs.
I'm calling for an end to this industry because that's the best way to protect our seniors, low-income residents, and minority communities from these persistent scams.

CASE STUDIES

A HISTORY OF UNINTENDED CONSEQUENCES

TEXAS

DECREASED RELIABILITY

Deregulation in Texas has discouraged the building of new power plants, leaving the state's power supplies vulnerable as the state’s population continues to grow.

Texas consumers experienced brownouts in 2011, 2014, and 2015, leaving hundreds of thousands without power.

COMPLAINTS PER YEAR

BEFORE DEREGULATION

~1,300

AFTER DEREGULATION

~10,500

NEVADA

RESOUNDING DEFEAT OVER CONCERNS

In 2018, a deregulation ballot proposal similar to Florida's was resoundingly defeated by voters by a 2-to-1 margin.

The state utility regulatory body released an in-depth report examining that proposal and found it would "require an immediate and unprecedented commitment by Nevadans of financial, legislative, and legal resources."

POPULATION: 3 MILLION

ESTIMATED COSTS

INITIAL IMPLEMENTATION COST

$100 MILLION

NEW ANNUAL OPERATION AND MAINTENANCE COSTS

$45 MILLION

FLORIDA

TROUBLING QUESTIONS

FLORIDA QUESTIONS

WHAT HAPPENS TO RURAL TAX REVENUES?

Rural areas that are heavily reliant on revenue from property taxes could experience considerable decreases in their property tax revenue if generation assets decrease in value following deregulation.

WHERE WILL THE POWER COME FROM?

With the four largest energy suppliers in the state no longer being allowed to produce or sell energy, it will be hard to know where energy supply will come from for the majority of the state's electric customers.

WHAT HAPPENS TO STORM RESPONSE?

With traditional power providers no longer serving customers, the storm response customers have come to depend on is thrown into question. The availability of electric linemen is of particular concern.

Testimony of Florida TaxWatch to the Fiscal Impact Estimating Conference
February 11, 2019

Presented by Robert Weissert, Executive Vice President

As the eyes and ears of Florida taxpayers for 40 years, Florida TaxWatch is currently conducting a fiscal and economic impact analysis of the proposed constitutional amendment "Right to Competitive Energy Market for Consumers of Investor-Owned Utilities; Allowing Energy Choice" which we expect to complete soon.

Today, I want to share with you some of the findings from our extensive research and analysis to date. Like your charge, the focus of our analysis is to project the impact of the proposed amendment on state and local tax collections – and we are considering the likely impact on consumer energy prices in Florida and Florida's economy more broadly.

First, I would be remiss if I did not express the grave concern that TaxWatch has generally about the proposal you have in front of you. As I explained before the 2018 Constitutional Revision Commission regarding a similar proposal, constitutional amendment is a concerning and potentially dangerous avenue for this type of nuanced and complex policy discussion.

As I'm sure you are aware, electricity deregulation of the magnitude proposed in this ballot initiative has not been attempted anywhere in the nation[1] and this amendment would make Florida would be the only state ever to deregulate its electricity market through a constitutional amendment, which – of course – would make it more difficult to correct or reverse course in the future as the impacts of such a policy become clearer.

Second, the findings of our analysis to date, which I expect to be completed soon, clearly indicate that this proposal will reduce state and local government revenues, cost taxpayers in the short-run because of implementation and transition expenses, and likely either produce little or – more likely – no reduction in energy prices. Together, these findings point to an overall detrimental fiscal and economic impact.

The Fiscal & Economic Impact Analysis

There is a wealth of information about the potential impacts of energy deregulation. A number of states have either implemented partial deregulation or explored the possibility thereof, largely beginning in the late 1990s, and a number of public and private analyses have

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[1] Among other factors demonstrating the unprecedented magnitude of this proposal for deregulation, there is no current or previous deregulated electric market that has eliminated the ability for the largest incumbent utilities in the state to produce or sell electricity as part of the market, nor prohibit them from owning the distribution and transmission systems.

been completed. As we continue to compare the outcomes of those deregulated states with the regulated ones, it is apparent that many of the positive promises that drove deregulation were overstated or entirely unrealized. As we have examined the literature and compared outcome data, it has become increasingly apparent why no state has deregulated its electricity system for nearly 20 years.[2]

But I know you have a specific task at hand: to estimate the financial impact on state and local governments. TaxWatch currently has a team of policy experts, tax experts, and economists – led by Richard Harper, Ph.D. of Pensacola – reviewing this very question.

Concerning the fiscal impacts

1. As you know, the electricity industry is a very important source of revenue for Florida's state and local governments. The current Investor Owed Utilities (IOUs) pay or collect approximately $3.7 billion annually in franchise fees and public services, property, income, gross receipts, and sales and use taxes.
    - More than half of that revenue goes to local governments, which is especially critical for cities, where the public service tax on electricity is by far their largest tax source – generating nearly $800 million—which is more than discretionary sales tax and communications services tax revenue combined.
    - Similarly, the nearly $600 million in electric franchise fees collected by cities represents their largest permit and fee revenue source, more than double that of all impact fees combined.
2. Our analysis is exploring the impact on the following state and local revenue sources:
    - Property Tax (on real estate and tangible property)
    - Franchise Fees
    - Gross Receipts Taxes
    - State Sales Taxes & Local Option Sales Taxes
    - Public Service Taxes
    - Corporate Income Taxes
3. Based on our analysis, this initiative is likely to cause some loss of direct revenues for local governments
4. The potential impact on revenues from some of these sources is apparent based on reasonable assumptions, but there remain some important and unanswered questions

[2] Other than the state of Virginia, no deregulation has taken place in the electric market since 2002.

that would significantly change the results – most crucially the question of nexus for collecting taxes from out of state companies.

In addition, the $680 million in franchise fees paid by IOUs would be impacted. While ostensibly payment for use of public rights of way, the real value to utilities is the granting of the right to be the exclusive seller. In a competitive marketplace, that value is lost. Typically, franchise fees are based on the gross revenues received by the utility from the area. With the loss of vertical integration, the revenue attributable to one company will be reduced. Franchise fees will likely have to be restructured, such as based on the value of energy distributed through a facility, but will franchises be as valuable as they are now? Even a 25% reduction in revenues means a $170 million loss to local governments.

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.

IOUs paid more than a $1 billion in property taxes in 2018 – $350 million is attributable to generation facilities. If deregulation results in out-of-state generation of electricity and a corresponding loss in in-state generation, Florida's property tax base will be reduced. In addition, if in-state divested IOU property is sold at below appriased value, the taxable of that property may be reduced.

5. One additional consideration is the possibility, if not likelihood, of tax policy changes that will recover or at least mitigate the revenue losses. It is apparent from literature that such policies to compensate from the revenue loss are not uncommon or unlikely.[3]
    - As examples, after deregulation, Illinois developed: The Electricity Excise Tax, The Electric Maintenance Infrastructure Fee, The Renewable Energy Resources and Coal Development Assistance Charge, and The Energy Assistance Charge. Pennsylvania enacted the Revenue Neutral Reconciliation Tax. And Connecticut created: A Systems Benefits Charge; The Energy Conservation and Load Management Fund Charge; The Renewable Energy Investment Fund Charge; A Competitive Transition Assessment; and an Administrative Expense Assessment.

Concerning the cost of implementation and transition

1. The complexity of revolutionizing Florida's entire electricity market is clearly a daunting challenge. It will almost certainly require a tremendous amount of public resources to develop the new legislation, rules, and operating requirements needed to implement the change required by this initiative. Additionally, the level of necessary legal staff and

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[3] See, e.g., Cynthia Woo, "Deregulation and its impact on taxation of electric services," TAXWARE International Inc. PMA Online Magazine(October 2000); available at www.retailenergy.com/articles/deregtax.htm#_ednref16

the amount of government resources that will be spent on the inevitable lawsuits that will come from these changes will also have a direct revenue impact.

2. While the policy and experience of states that have deregulated vary, in some cases deregulation has increased the role – and therefore cost – government. After deregulation, Illinois created a new independent state agency to oversee the electricity planning and procurement process, so a new taxpayer-funded government agency was essentially created to perform duties that had previously been handled by a regulated utility.[4]

Concerning the effect on prices and the economy

3. Florida's current consumer energy prices are below the national average and below the average of deregulated states. According to the latest available data from the Energy Information Administration, last year the average residential electricity rate of the deregulated states was 32% higher than Florida's average residential rate.[5] Certainly, a potential 32% increase in Florida's electricity rates will have a negative impact on all levels of the economy, both public and private sector.

4. Just looking at one state that deregulated – Connecticut from 2015 through 2018 – consumers using third-party electric suppliers paid an estimated $200 million more than consumers on electric utility standard service.[6] There are many such examples of the experiences of other states and our report will more flush out those comparisons and how they can be instructive for Florida.

Upcoming TaxWatch Analysis

As I have mentioned, TaxWatch will soon be producing an analysis of the data and information to project the fiscal and economic impacts of the proposed constitutional amendment. That analysis will be publicly available on the Florida TaxWatch website at www.floridataxwatch.org.

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[4] Public Sector Consultants, "Electric Industry Deregulation: A look at the experiences of three states," October 2013; available at https://publicsectorconsultants.com/wp-content/uploads/2016/12/Electric-Industry-Deregulation-Case-Studies.pdf

[5] TaxWatch analysis based on U.S. Department of Energy's Energy Information Agency (EIA) data available at https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_06_b. Finding compares the 2018 residential rates of Florida against all states that have a deregulated residential electricity market: California, Connecticut, Washington, DC, Delaware, Illinois, Massachusetts, Maryland, Maine, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, and Texas.

[6] Michael Humes,"T ime to End the Third-Party Residential Electric Supply Market," AARP (02/4/2019); available at https://states.aarp.org/time-to-end-the-third-party-residential-electric-supply-market/.

Closing

Members, you have a tough job ahead. I hope the information I have provided – and the Florida TaxWatch will continue to provide – is helpful to you in your deliberation. Estimating the financial impact of this proposal is a critically important decision for Florida's citizens, its economy and, its local and state governments.

I look forward to continuing discussion. Thank you for your time and your service to the taxpayers of Florida.

Time to End the Third-Party Residential Electric Supply Market

Michael Humes

After nearly two decades of implementing legislative and regulatory policies, it is time to provide consumers with the ultimate protection from the confusing – often abusive and illegal – marketing tactics of third-party electric suppliers.

Consumer Counsel Elin Swanson Katz, in collaboration with AARP and other consumer advocates, as well as U.S. Senator Richard Blumenthal, called for the end of the third-party residential electric market that economically harms consumers at a press conference today.

The group of leaders underscored the destructive economic impact of the residential third-party supplier market on consumers and their budgets at a time when Connecticut is making strides to strengthen the economy. From 2015 through 2018, Connecticut consumers using third-party electric suppliers paid an estimated $200 million more than consumers on electric utility standard service. The victims range across the economic spectrum, although notably many of the customers who are losing money through the confusing system of third-party suppliers are already struggling to pay their electric bills and simply cannot afford unfair and unscrupulous overcharging.

"Third-party electric suppliers rely on predatory sales tactics to trick folks into unwittingly signing up for contracts," said Katz. "What's more, our residents – especially those who are low-income, elderly, use English as a second language, and other vulnerable populations – are getting ripped off by these third-party suppliers which often charge significantly higher rates than the electric utility default service. Enough is enough. We've heard it all – aggressive marketing tactics on our own doorsteps, harassing telemarketing calls laced with lies, utility company impersonation, slamming, and more. The time has come to eliminate this economic burden and protect all consumers – including our most vulnerable – from deceitful marketing while at the same time creating innovative ways to offer renewable energy products and products that will reward electric usage reductions. Let's keep our hard-earned dollars where they belong – in Connecticut consumer wallets."

Senator Blumenthal said, "Third-party electric suppliers are predatory players in the retail electric market – deploying deceitful, destructive and disgraceful marketing tactics and ripping off customers with exorbitant rates and fees. Consumers desperately need and deserve protection from abuses in the residential electric supply market. Ending this fraught market – so hazardous and harmful to consumer pocketbooks – should be a priority."

John Erlingheuser, AARP Connecticut advocacy director added, "Choosing an electric supplier is complex and confusing without the tricks of unscrupulous suppliers, which are misleading at best and corrupt at worst. Even if we could eradicate all of the deceptive suppliers and build a wall of consumer protections around the third-party market, ratepayers will still be stuck with contracts that cost more money than the traditional default standard electric service. The process does not allow for an apples to apples comparison."

Janice Flemming-Butler of the Voices of Women of Color said, "Third-party suppliers are exploiting poor communities. I've seen it firsthand. People make honest efforts to try to save money on their electric bills or find quality employment but end up being deceived, overcharged, and taken advantage of by these companies. They have betrayed the trust of the communities in which they do business."

The Connecticut leaders join the efforts of Massachusetts Attorney General Maura Healey, who earlier last month proposed legislation to end the residential retail choice market in Massachusetts.

Attorney General Healey added, "Competitive electric suppliers have cheated Massachusetts residential customers out of millions of dollars by falsely promising them big savings on their electricity bills, while overcharging them month after month. My office is working to put an end to these predatory practices in Massachusetts and we stand with Consumer Counsel Katz as she works to protect Connecticut's electric customers from these scams as well."

In 2000, in an effort to bring down electricity prices and provide innovative services, Connecticut "deregulated" its retail electric market, or opened it to competition. This allowed residential customers to choose their electric supply from a third-party electric supplier or remain on their electric utility's standard service default rate, which changes each January 1 and July 1 through a procurement process with regulatory oversight. Simply put, retail electric deregulation is a failed experiment for residential customers. Not only has it cost electric consumers more money but it has also failed to bring meaningful innovation into the electric market. In her proposal to end residential retail electric choice, Consumer Counsel Katz supports utility default standard service that will include renewable products and innovative rate structures.

"The truth is that third-party electric suppliers both overcharge consumers on average and do not bring meaningful employment to our state since the transitory commission-based marketing jobs are often located outside of Connecticut. For years, our office has represented electric consumers in regulatory enforcement proceedings where we've been steeped in the marketing and business practices of these companies," Consumer Counsel Katz said.

Despite the enactment of robust consumer protections by the Connecticut Legislature in 2014 and a first-in-the-nation variable rate ban in 2015, consumer harm in the residential retail choice market persists. The agency tasked with regulating third-party electric suppliers – the Public Utilities Regulatory Authority (PURA) – has conducted numerous enforcement proceedings investigating the marketing practices of individual suppliers yet consumer harm is still rampant. Notably, large settlements have stemmed from PURA consumer protection enforcement proceedings – Energy Plus settled claims for $4.5 million in 2014, North American Power settled claims for $2.6 million in 2015, and Palmco Power settled claims for $5 million in 2017. In addition to these huge settlements, PURA has also levied civil penalties against third-party electric suppliers for over one million dollars for violations of Connecticut consumer protection laws. Conducting such regulatory proceedings has drained thousands of hours of state resources, millions in taxpayer and ratepayer dollars, and adds tens of millions to the state's electric costs.

Because all of the legislative and regulatory efforts expended over the years have not created a residential electric supply market that provides a net benefit to Connecticut, Consumer Counsel Katz, AARP Connecticut, U.S. Senator Blumenthal, CT Citizen Action Group, CT Clean Water Action, Operation Fuel and Connecticut Legal Services, Inc. call for the Connecticut Legislature to protect the Connecticut economy and consumers by ending residential retail choice.

Tagged: AARP Connecticut, energy, utilities

Deregulation and its Impact on Taxation of Electric Services

DEREGULATION AND ITS IMPACT ON TAXATION OF ELECTRIC SERVICES

By Cynthia Woo
Senior Tax Council
TAXWARE International Inc.

(*originally published by PMA OnLine Magazine: 00/10*)

This is a dynamic time for the electric industry. As of August 1, 2000, 24 states have enacted restructuring legislation. The majority of the remaining states either have regulatory orders issued, pending or are involved in on-going analysis of restructuring.[i] Deregulation of the industry is requiring states to review and revise tax laws to address unbundled charges and other costs due to restructuring. As a result, state tax laws are constantly changing. This presents a challenge for existing utility companies and new market entrants, such as marketers, brokers, and independent power producers, who must collect and remit various fees and state taxes on charges for electricity and electric services. Below is a survey of tax law changes in various states across the country.

Historically, the electric industry was a monopoly regulated by the Federal Energy Regulation Commission (FERC) and state utility regulatory commissions. The impetus for deregulation occurred at a time when residential prices for electricity began to rise in the mid 1970's due to the oil embargo and Iranian crisis. In 1978, Congress enacted the Public Utility

Regulatory Policies Act (PURPA). PURPA required utility companies to purchase excess power from qualifying facilities (QFs) and offer stand by and maintenance services. A QF is a non-utility that produces energy from renewable sources, such as hydro, geothermal, solar and wind. The Energy Policy Act (EPAct) of 1992 created a new type of wholesale generator called Exempt Wholesale Generators (EWGs) which are exempt from the Public Utilities Holding Company Act of 1938. Moreover, the EPAct gave the FERC authority to open up the transmission lines making it possible for QFs, EWGs and other non-traditional utility companies to sell power directly to consumers.

Prior to deregulation, the same electric utility company would provide both the electricity and electric services to consumers who would receive one bill containing all the charges. Consumers had no choice regarding from which utility company they purchased electricity and electric services. This scenario has changed due to deregulation and restructuring of the electric industry. As a result, energy prices are more competitive and services have improved as consumers now have a choice from which utility company they purchase electricity.

Another result of deregulation is that charges on consumers' bills will now be unbundled. Unbundling refers to the disaggregation of electric utility services into individual components with separate rates. Consumers will see itemized charges on their bills for generation, transmission, distribution, ancillary services and restructuring related costs.[ii] For example, adoption of restructuring legislation in Massachusetts offered consumers a choice in purchasing electricity and electric services, but also changed the way consumers were billed. Instead of one bundled charge, there are seven unbundled charges on the bill. These charges include a Generation Charge, Transmission Charge, Distribution Charge, Transition Charge, Customer Charge, Renewable Resources Charge, and Energy Efficiency Charge.[iii]

The changes in the way electric services are billed have required States that tax the sale of electricity and electric services to re-examine their tax laws and determine the taxability of the unbundled charges. Numerous states have issued explainations and amended tax laws in varying degrees to ensure that unbundled charges are taxed appropriately. For example, New York's Public Service Commission has opened up the electric industry and is phasing in deregulation on a utility-by-utility basis. In preparation of full retail competition, the Department of Taxation and Finance has issued numerous memoranda stating that charges for the service of providing electricity to a customer are subject to state and local sales tax and that the service will fall under the statutory reference to electric service of "whatever nature".[iv]

Some states required relatively minor adjustments in their tax laws to address the unbundled charges. To illustrate, Maryland amended its definition of taxable service to include transportation services for transmission, distribution or delivery of electricity when the sale or use of electricity is subject to the sales and use tax.[v] Similarly, Arizona revised its utilities classification definition to include in the Transaction Privilege Tax base charges for providing ancillary services, electric distribution services, electric generation services, electric transmission services and other services related to providing electricity.[vi] Other taxable electricity services include metering, meter reading services, billing and collection services.

Deregulation of the electric industry brought about more extensive tax law changes in a couple of states. First, in New Jersey, the Energy Tax Reform legislation repealed the gross receipts and franchise tax on electric utilities and replaced it with a business tax on utilities and a sales and use tax on electricity and electric services. Sales of electricity and charges for transporting electricity are also subject to sales tax.[vii] Additionally, the definition of "vendor" was amended to include energy sellers and transporters.[viii]

Second, restructuring of the industry led to an overhaul of the tax system in Illinois. Section 2-202 of the Public Utilities Revenue Act was repealed and new laws were enacted to collect taxes for consumption of electricity and electric services. The Electricity Excise Tax[ix] is imposed on consumers and based on kilowatt hours delivered. Non-residential consumers are allowed to self-assess this tax. In addition to the excise tax, various fees and charges were also enacted. The Electric Maintenance Infrastructure Fee[x] is imposed on consumers and collected by electricity transporters. The last delivering supplier is responsible for collecting and remitting the excise tax and maintenance fee. Municipal electric utilities and electric cooperatives may impose a Renewable Energy Resources and Coal Development Assistance Charge[xi] and an Energy Assistance Charge.[xii] These charges are assessed monthly upon residential and non-residential electric service accounts.

In addition to the new taxes and fees addressed above, there are numerous charges assessed on consumers that provide electric utility companies a method to recover investment costs that might otherwise be lost in the shift to a competitive market. The charges vary by state.

When Pennsylvania initiated restructuring, the state passed revenue replacement measures to minimize revenue loss caused by restructuring. The Revenue Neutral Reconciliation Tax is designed to replace lost revenue and help ease the transition from a regulated industry to a competitive one.[xiii] Beginning on January 1, 2000, a tax of 0.06% is imposed upon the gross receipts of electric distribution companies and electric generation suppliers. The Revenue Neutral Reconciliation Tax is in addition to the existing Utilities Gross Receipts Tax, state sales tax and county taxes that are imposed on sales of electric energy. Sales of electric energy are defined to include the retail sales of electric generation, transmission, distribution or supply of electric energy, dispatching services, customer services, competitive transition charges, intangible transition charges and universal service and energy conservation charges and other retail sales which, if bundled, would have been deemed to be electric energy prior to the effective date of the law change.[xiv]

Connecticut has also levied various fees associated with restructuring. New charges that became effective January 1, 2000 are the Systems Benefits Charge[xv], the Energy Conservation and Load Managment Fund Charge[xvi], and the Renewable Energy Investment Fund Charge[xvii]. These charges are based on a per kilowatt hour and are imposed on electric distribution utility customers. End use customers in Connecticut will also be charged a Competitive Transition Assessment[xviii] on distribution services until stranded costs are fully recovered. Competitive transition charges and rate reduction bonds are two methods approved by the Connecticut Department of Public Utility Control to allow utility companies to recover costs incurred by divestiture. These charges are in addition to the Administrative Expense Assessment, which is based on charges for distribution services and imposed on consumers[xix].

Deregulation of the electric industry brings with it many benefits and changes. Through the forces of competition, the power to choose energy suppliers will result in lower prices and improved service for consumers. The electric industry is a lucrative business and deregulation will give the industry a much needed jump start. Newcomers are eager to enter and establish themselves in the wholesale electricity market, while existing electric utility companies are focusing on expanding their consumer base by encroaching into new jurisdictions. Deregulation is forcing states to modify tax laws, broaden definitions of taxable services and add new taxes and fees. Utility and non-utility companies are faced with the daunting task of tracking state tax laws, which will continue to evolve until full retail competition is achieved nationwide.

[i] Source: Energy Information Administration

[ii] Generation refers to the process of producing electric energy; Distribution refers to the delivery of electric energy to an end user; Transmission refers to the transfer of electrical energy to a distribution system where it is transformed for delivery to consumers. Source: Energy Information Administration

[iii] Technical Information Release 98-16, November 6, 1998.

[iv]TSB-M-99(1.1)S; TSB-M-99(1.2)S; TSB-M-99(1.3)S; TSB-M-99(1.4)S, effective April 1, 2000; N.Y. Stat. Sec 1105(b) Tax Law.

[v] MD. CODE ANN., TAX-GEN. §11-101 (1999) (As amended by Ch. 1, Laws 1992, 1st Sp. Sess.; as relettered by Ch. 685, Laws 1994; as amended by Ch. 6 (H.B. 366), Laws 1999, effective January 1, 2000, applicable to all taxable years beginning after December 31, 1999.)

[vi] ARIZ. REV. STAT. §42-5063 (1999)

[vii] N.J. REV. STAT. §54:32B-3(b)(7) (As added by Ch. 162, Laws 1997, effective January 1, 1998.)

[viii] N.J. REV. STAT. §54:32B-3(i)(1)(G) State Tax News, Department of Treasury, Division of Taxation, Winter 1997;

[ix] 35 ILL. COMP. STAT. 640/2-4 (1997) (P.A. 90-561, Laws 1997, effective August 1, 1998)

[x] 35 ILL. COMP. STAT. 645/5-5 (1997) (P.A. 90-561, Laws 1997, effective August 1, 1998)

[xi] ILL. ADMIN. CODE tit. 86 § 517.120 (1998)

[xii] ILL. ADMIN. CODE tit. 86 § 516.120 (1998)

[xiii] 66 PA. CONS. STAT. §2810(b) (1997)

[xiv] 66 PA. CONS. STAT. §2810(j) (1997)

[xv]Sec. 18, Act 28, Laws 1998, effective January 1, 2000.

[xvi]Sec. 33, Act 28, Laws 1998, effective January 1, 2000.

[xvii]Sec. 44, Act 28 Laws 1998, effective January 1, 2000.

[xviii]Sec. 10, Act 28, Laws 1998, effective January 1, 2000.

[xix]CT G.S. Sec. 16-49.

RESEARCH TRIANGLE INSTITUTE

September 1999

State and Local Tax Considerations in Electric Industry Restructuring

Volume 1—Task 3
Final Report

Prepared for

Legislative Study Commission on the
Future of Electric Service in North Carolina
300 N. Salisbury Street
Suite 545
Raleigh, NC 27603-5925

Prepared by

Research Triangle Institute
Center for Economics Research
Research Triangle Park, NC 27709

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Robert L. Peace, Professor of Accounting, Charles R. Knoeber, Professor of Economics, at North Carolina State University, and Allen K. Miedema and W. Brad Eccles at Research Triangle Institute (RTI) were primary contributors to this report. Tax experts at the Research Division and Fiscal Research Division of the Legislative Services Office of the North Carolina General Assembly, the North Carolina Department of Revenue, the North Carolina League of Municipalities, the North Carolina Association of County Commissioners, and the electric utilities provided critical tax data and commentary on tax issues. Steven J. Rose and Esther E. Manheimer of the Study Commission provided substantial guidance on legal issues and careful editorial review. Other contributors at RTI were Sheryl C. Cates, Stephen A. Johnston, and Tikku Verghese.

Contents

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Executive Summary

This report describes how retail competition in the electricity industry may affect the tax revenues of state and local government in North Carolina. In particular, we examine the potential effects of retail competition on North Carolina tax revenues for each of the following four taxes:

- corporate income tax,
- property tax,
- gross receipts tax, and
- sales tax.

Altogether, remittances of these four taxes by electricity suppliers accounted for about $634 million in 1997 tax revenues in North Carolina. Roughly one-third of this total was from the gross receipts tax, slightly less than one-third was from the sales tax, and about one-sixth each was from property and corporate income taxes. Those revenues are ultimately spent by all three levels of North Carolina government, accounting for about 3.25 percent of total state tax revenues, 2.25 percent of county tax revenues, and 6.9 percent of municipal tax revenues.

In Volume 1, we review all North Carolina taxes that may be affected by retail competition and provide our quantitative estimates of potential changes in tax revenues for the same set of assumptions that we used in our companion reports on stranded costs and benefits and detriments. We refer to this set of assumptions as the “reference case,” and this is consistent with other RTI reports to the Legislative Study Commission on the Future of Electric Service in North Carolina ("Study Commission"). The key elements of the reference case are as follows:

- start date of retail competition = January 1, 2004
- benchmark market-clearing price of power under competition = intermediate estimate as reported in *Stranded Cost Estimates for a Restructured Electric Utility Industry in North Carolina, Volume 3—Task 4* (RTI, 1999)
- discount rate = cost of equity for investor-owned utilities (IOUs), cost of debt for other utilities- used to compute the discounted present value of annual stranded costs
- capital additions to preserve capacity and efficiency ratings of existing generation are included as potential stranded costs

All projections of tax revenues in this report cover the period from the assumed start date for competition through 2015.

The Executive Summary of Volume 2 presents an intuitive summary of the modeling techniques and assumptions used in our projections of tax revenue changes; the remainder of Volume 2 describes our modeling approach at a more technical level that requires familiarity with the logic and algebra of microeconomic theory. To avoid confusion and to keep our presentation simple, we have presented quantitative results only for the reference case. However, our model is capable of producing a full set of alternative tax projections for a wide variety of alternative assumptions.

Throughout this report we have focused solely on the prospective changes in tax revenues from electricity suppliers due to retail competition. We have not attempted to estimate changes in taxes that could be attributed to changes in the number and type of jobs or facilities in North Carolina due to changes in electricity prices. These secondary effects would tend to reduce our estimates of tax losses.

Certain restructuring options could also affect tax revenues. For example, in our report, *Policy Options for North Carolina's Municipal Power Agencies* (RTI, 1999), we discussed Divestiture and Dissolution options. Both would involve the transfer of assets from entities that are exempt from certain taxes to others that may not be exempt. For example, IOUs could acquire properties now held by the municipal power agencies (MPAs) and begin paying taxes that are not paid by the power agencies. Such a transfer could reduce the tax losses discussed in this report, since we assume no ownership changes for this analysis.

E.1 ISSUES AFFECTING FUTURE NORTH CAROLINA TAX REVENUES

The two most important policy decisions affecting North Carolina tax revenues are those relating to the recovery of stranded costs and the establishment of nexus. Therefore, we have considered tax revenue consequences under all four possible outcomes regarding these issues. These outcomes constitute the four policy cases that we review in this report and detail for our modeling approach in Volume 2:

- Case 1: No Nexus, No Recovery of Stranded Costs
- Case 2: Nexus, No Recovery of Stranded Costs
- Case 3: No Nexus, Recovery of Stranded Costs
- Case 4: Nexus, Recovery of Stranded Costs

All projections of tax revenues in this report assume that tax policies in North Carolina remain unchanged, except for the establishment of nexus. However, as discussed further below, several tax policy changes could be implemented to offset any tax losses.

Stranded cost recovery decisions can affect North Carolina tax revenues in three significant ways. First, the aggregate amount of stranded costs significantly affects the difference between current electricity prices and competitive prices, so the amount of stranded costs affects the amount of potential price reductions under competition. Those price changes significantly affect electricity revenues and, hence, revenue-based tax proceeds. Second, stranded costs may affect property tax revenue because of the way in which utility property is appraised for tax purposes, as discussed in Section 2.2. Third, the state's decision on the recovery of stranded costs would have critical tax revenue implications, because stranded cost recovery payments are presumed to be taxable. Therefore, recovery of stranded costs would automatically offset part of the tax losses that would otherwise occur during the transition period.

Retail competition would likely introduce new electricity suppliers to North Carolina, some of them located in other states. Whether these out-of-state providers will be liable to pay North Carolina taxes remains an issue, generally described as the nexus issue. Nexus refers to the authority of a state to levy taxes on any out-of-state seller, historically based on physical presence (that is, an out-of-state provider's having sufficient property, employees, or other presence in a state to justify taxation). However, an exact legal definition of physical presence has not been established for the purpose of taxing electricity sales. As detailed in Volume 2, the existence of nexus would affect the competitive price of electricity and, therefore, the amount of stranded costs. As a result, revenues from the gross receipts tax, sales tax on electricity, and corporate income tax would be higher with nexus than without it. Therefore, North Carolina has an obvious incentive to establish nexus or to implement alternative tax policies that have the same effect as nexus.

Table E-1 summarizes the potential impact of retail competition on North Carolina tax revenues for each of the four cases we considered in this report. We assume that stranded cost recovery payments are taxable, so income taxes and sales and gross receipts taxes increase when stranded costs are recovered. For all taxes, the smallest negative effects occur when both nexus and stranded cost recovery are assumed to exist.

Table E-1. Percentage Change in North Carolina Taxes Remitted by Electric Utilities: Retail Competition for the Period 2004–2015[a]

	Potential Change in Tax Remittances (%)				
Case[b]	Gross Receipts Tax	Sales Tax on Electricity	Corporate Income Tax	Property Tax	Total
Case 1: No Nexus, No Recovery	-18.22%	-18.22%	-30.3%	-10.71%	-18.7%
Case 2: Nexus, No Recovery	-10.88%	-10.88%	-10.97%	2.71%	-8.95%
Case 3: No Nexus, Recovery	-9.98%	-9.98%	-9.39%	-10.71%	-10.01%
Case 4: Nexus, Recovery	-6.14%	-6.14%	-5.66%	2.71%	-4.82%

[a]Percentage changes in the *discounted present value* of annual tax remittances.

[b]Recovery refers to stranded cost recovery.

The effect of competition on the aggregate revenue from all four types of taxes will likely vary significantly from one policy case to another, although we project that total tax revenues will decline in all cases. Without nexus or stranded cost recovery (Case 1), total North Carolina tax revenues from electric utilities may decline by nearly 19 percent; with nexus and stranded cost recovery (Case 4), tax revenue losses are substantially reduced (to about 5 percent).

Because sales and gross receipts taxes account for almost two-thirds of taxes remitted by electric utilities, they also account for most of the projected tax losses. They account for 70 to 90 percent of the projected aggregate tax revenue losses depending on the policy scenario. The projected percentage losses are identical for these taxes because both are collected as a percentage of electricity revenues.

The projected percentage changes in tax revenues from one policy to another are greatest for the corporate income and property taxes. In fact, establishing both retail competition and nexus may increase property tax revenues as shown in Table E-1. Essentially, this increase would be due to increases in the market value of existing North Carolina generating plants, as competitive electricity prices begin to rise above the plant costs that utilities could otherwise recover in the prices charged under regulation.

Table E-2 summarizes the potential impact of retail competition on North Carolina tax revenues by government entity. As shown in Table E-2, municipalities are likely to suffer the highest proportionate tax revenue losses under retail competition because of the impact on property taxes and municipal proceeds of gross receipts tax collections. In this model, projected changes in county tax revenues are strictly dependent on changes in property tax proceeds, and thus (like property taxes themselves), are assumed to be unaffected by stranded cost recovery. Any county-level tax revenue impacts from property tax reassessments will be widespread. Counties that depend more heavily on utility property taxes, especially counties that have a large apportionment of the assessed value of utility properties, and counties that are served by utilities with large stranded costs, may experience much greater than average effects due to these reassessments. Finally, tax revenues to the state of North Carolina are projected to decline by

Table E-2. Percentage Change in Total Tax Receipts, By Government Entity: Retail Competition for the Period 2004-2015[a]

Case[b]	Municipal	County	State
Case 1: No Nexus, No Recovery	-1.17%	-0.24%	-0.75%
Case 2: Nexus, No Recovery	-0.59%	0.06%	-0.38%
Case 3: No Nexus, Recovery	-0.70%	-0.24%	-0.34%
Case 4: Nexus, Recovery	-0.32%	0.06%	-0.21%

[a]Percentage changes in the *discounted present value* of annual tax receipts.

[b]Recovery refers to stranded cost recovery.

about 0.8 percent, 0.4 percent, 0.3 percent, and 0.2 percent for Cases 1 through 4, respectively.

E.2 TAX POLICY OPTIONS

If retail competition reduces electricity prices in North Carolina and there are no changes in tax policies, there will be commensurate reductions in state and local tax bases. Several tax policy options are available to lawmakers:

- no change,
- allow stranded cost recovery,
- change tax rates, and
- restructure existing taxes.

The relative attractiveness among these options depends on the resolution of the nexus issue.

We have projected that average electricity prices are likely to decline under retail competition. Unless the state implements offsetting tax policies, revenues from electricity-related taxes are also projected to decline due to the loss of dollar sales (see Section 4). Thus, even though the state does have the option of leaving current tax policies in place, the likely consequence is that state, county, and municipal governments would experience tax revenue shortfalls unless some policies are changed.

One option for policy change is to allow stranded cost recovery- a decision that has critical implications for mitigating tax shortfalls that may be created by retail competition. Tax law suggests that revenue from stranded cost recovery surcharges would be taxed just like any other component of electric utility revenues. Thus, gross receipts and sales taxes would be levied on recovery surcharges. In addition, revenue from stranded cost recovery would contribute to the utilities' income, and any resulting profits would be subject to the state income tax. Therefore, stranded cost recovery would have the effect of mitigating some tax revenue losses during the transition period. This is the case, whether nexus is established or not, since recovery surcharges are applied to all customers regardless of whether they buy power from in-state or out-of-state generators.

The state could also offset projected tax losses by increasing the rates of one or more of the taxes considered in this report. But this option is practical only if nexus is established. Because gross receipts and sales tax on electricity account for the largest share of tax revenue, these tax rates would likely be the most prominent candidates for change.

Tax restructuring options include introducing an entirely new tax or applying a surcharge on an existing tax. Two of the most promising options for offsetting potential revenue losses are (1) a consumption tax, also referred to as an excise tax; and (2) an electricity surcharge, which is a tax based on dollar sales. However, as is the case for changes in tax rates, an electricity surcharge is practical only if nexus is established.

A consumption (excise) tax is a new tax that is designed to recover equivalent tax revenues under retail competition, but in a more uniform way than is possible with sales or gross receipts taxes. This tax would be levied on kilowatt hours instead of dollar sales and would be collected by the North Carolina entities that sell electricity at the retail level (i.e., distributors). It would be collected regardless of whether those distributors purchase their bulk power from in-state or out-of-state generation companies.

In summary, our analysis suggests that if the state can establish nexus and ensures full recovery of stranded costs, losses of total tax revenues related to electricity will be fairly modest, about 5 percent. This would amount to an overall loss of about 0.2 percent in total tax receipts in North Carolina. If nexus is established (Cases 2 and 4), the most promising tax option for offsetting potential tax revenue losses may be to change existing tax rates. In all cases, tax revenue losses will be decreased if the state allows stranded cost recovery whether or not nexus can be established. If North Carolina cannot establish nexus, a consumption or excise tax appears to be the preferred option for offsetting potential tax revenue losses. The recent adoption of a consumption tax on natural gas in North Carolina provides an important precedent, suggesting that in the absence of nexus such a tax will be an effective measure for offsetting other tax losses due to retail competition.

1 Introduction

This report describes how retail competition in the electricity industry may affect the tax revenues of state and local governments in North Carolina. We have considered the effects of possible future tax and regulatory policies as required by our contract with the Legislative Study Commission on the Future of Electric Service in North Carolina ("Study Commission"). In particular, we examine the potential effects of retail competition on North Carolina tax revenues for each of the four following taxes:

- corporate income tax,
- property tax,
- gross receipts tax, and
- sales tax.

Section 2 provides an overview of each of these taxes remitted by North Carolina electric utilities. Section 3 discusses the three major issues that are likely to affect tax revenues if retail competition occurs in North Carolina. Section 4 presents quantitative estimates of the potential impacts of retail competition on North Carolina tax revenues. The impact estimates are called potential because they depend on several policy and market outcomes. Finally, Section 5 identifies potential options for offsetting tax losses due to retail competition.

To prepare this report, we collected and reviewed the academic and professional literature on the impact of retail competition on tax revenues. In addition, we assembled a portfolio of court decisions and legislation on this topic. Finally, we conducted in-person and telephone interviews with

- tax executives from electric utilities in North Carolina;
- North Carolina government officials from state offices, including the
  - ✓ Research Division of the Legislative Services Office of the North Carolina General Assembly,
  - ✓ Fiscal Research Division of the Legislative Services Office of the North Carolina General Assembly,
  - ✓ North Carolina Office of State Budget and Management,
  - ✓ Public Staff of the North Carolina Public Utilities Commission,
  - ✓ North Carolina Department of Revenue's Income Tax Division,
  - ✓ North Carolina Department of Revenue's Franchise Tax Division, and
  - ✓ North Carolina Department of Revenue's Ad Valorem Tax Division; and
- state revenue officials, utility tax executives, and other tax professionals in California, Illinois, Iowa, Maine, Minnesota, Montana, Nevada, New Jersey, Pennsylvania, and Rhode Island.

The Reference section lists articles and books reviewed, cases and statutes studied, and individuals interviewed as part of this study.

Throughout this report we have focused solely on the prospective changes in tax revenues from electricity suppliers due to retail competition. We have not attempted to estimate changes in taxes that could be attributed to changes in the number and type of jobs or facilities in North Carolina due to changes in electricity prices. These secondary effects would tend to reduce our estimates of tax losses.

Certain restructuring options could also affect tax revenues. For example, in our report, *Policy Options for North Carolina's Municipal Power Agencies* (RTI, 1999), we discussed Divestiture and Dissolution options. Both would involve the transfer of assets from entities that are exempt from certain taxes to others that may not be exempt. For example, IOUs could acquire properties now held by the MPAs, and begin paying taxes that are not paid by the power agencies. Such a transfer could reduce the tax losses discussed in this report, since we assume no ownership changes for this analysis.

Restructuring with retail competition could also bring about fundamental changes in the way electric utilities are organized and operated. They may develop new markets and services and alter their cost structures. There may also be changes in the value of intangible assets held by electric utilities. All of these changes could eventually have some tax revenue implications. However, these changes are extremely difficult to anticipate and, therefore, constitute other types of secondary market effects that we have not attempted to model.

We have divided this report into two volumes. In Volume 1, we review all North Carolina taxes that may be affected by retail competition and provide our quantitative estimates of potential changes in tax revenues for the same set of assumptions that we used in our companion reports on stranded costs and benefits and detriments. We refer to this set of assumptions as the "reference case."

The Executive Summary of Volume 2 presents an intuitive summary of the modeling techniques and assumptions used in our projections of tax revenue changes. The remainder of Volume 2 describes our modeling approach at a more technical level that requires familiarity with the logic and algebra of microeconomic theory. Volume 2 will be most helpful to experts who wish to examine the details of our model. To avoid confusion and to keep our presentation simple, we have presented quantitative results only for the reference case. However, our model is capable of producing a full set of alternative tax projections for a wide variety of alternative assumptions.

2 Taxes Paid by North Carolina's Electric Utilities

This section describes the North Carolina taxes that are paid by electricity suppliers or their customers. These taxes provide revenue to the state, county, and municipal governments of North Carolina. Table 2-1 shows each of the four North Carolina taxes we considered and indicates which suppliers remit each type of tax. Table 2-2 shows the recipients of each type of tax. We briefly describe each type of tax below.

Table 2-1. Sources of North Carolina Tax Remittances

	Corporate Income Tax	Property Tax	Gross Receipts Tax	Sales Tax
Investor-Owned Utilities (IOUs)	●	●	●	●
Municipal Power Agencies (MPAs)		●	●	
MPA Member Cities				●
North Carolina Electric Membership Corporation (NCEMC)		●		
Electric Membership Cooperatives		●	●	●

Table 2-2. Recipients of North Carolina Taxes

	Corporate Income Tax	Property Tax	Gross Receipts Tax	Sales Tax
State	●		●	●
County		●		
Municipal		●	●	

2.1 CORPORATE INCOME TAX

Like all for-profit corporations located in North Carolina, the investor-owned utilities (IOUs) pay corporate income tax. Suppliers affiliated with the municipalities and rural electric cooperatives are not-for-profit and therefore are not subject to the corporate income tax.[1] The corporate income tax is levied by the state of North Carolina and is calculated in two steps. In the first step, utilities must apportion their taxable business income between North Carolina and other states in their service territory based on sales in each state. For example, North Carolina utilities serving customers in South Carolina apportion some of their income to South Carolina for taxation there. Likewise, an out-of-state provider selling electricity in North Carolina might have some of its taxable income apportioned to North Carolina *provided that company has nexus with North Carolina*–that is, provided the company has sufficient property, employees, or other presence in the state to enable North Carolina authorities to levy state and local taxes on it. In the second step, the North Carolina portion of taxable income is multiplied by the North Carolina income tax rate to yield the total amount of income taxes due. The tax rate is as follows:

- In 1997 7.5%
- In 1998 7.25%
- In 1999 7.0%

2.2 PROPERTY TAX

Property tax is paid on generation, transmission, distribution, and other affected property owned by each electric utility. As shown in Table 2-1, member cities do not pay property taxes on their electric systems because they are municipal properties.[2] The value of the property comprising the entire system owned by each taxable electric utility is appraised each tax year by tax officials at the North Carolina Department of Revenue. Each utility's total system value is then

[1]Technically this is true for electric cooperatives only so long as they derive 85 percent or more of their income from their members. Generally, all municipal and cooperative electricity suppliers must observe certain restrictions on their commercial activities to avoid jeopardizing their tax-exempt status. We assume throughout this report that they do observe those restrictions and remain tax exempt.

[2]However, North Carolina Local Government Commission (LGC) guidelines suggest that MPA member cities' electric funds may contribute to the state's general fund in lieu of property taxes.

allocated to county and local taxing jurisdictions where tax rates are applied and a tax bill is rendered to the utility by the county or municipality. For example, suppose that the appraised value of a utility's total system is $6 billion. If the system property located within the jurisdiction of a particular county was installed at an original cost of $200 million and the original cost of the entire system was $8 billion, that county's allocation of system property will be ($200 million/$8 billion) x $6 billion = $150 million.

North Carolina tax officials consider two factors in appraising system property: (1) average system property cost net of depreciation (the "cost factor" approach), and (2) the system's income-earning capacity, derived by capitalizing a utility's income stream (the "capitalized income factor" approach). Tax officials have discretion under law (see *In re Southern Railway*, 59 N.C. App. 119 [1985]) in determining their emphasis on either the cost factor or the capitalized income factor when establishing a system's appraised value.

Local government authorities such as county commissioners and city councils establish property tax rates. These rates are multiplied by the appraised values to determine the total amount of property tax revenue in each jurisdiction.

As shown in Table 2-2, both county and municipal tax authorities collect property taxes. In some cases, the county collects the tax for some or all of the municipalities in the county and then distributes the funds. Counties and municipalities use property tax revenues primarily to operate schools and to pay for services provided by local government, including health care, police protection, fire protection, public libraries, and waste disposal.

Property tax revenues are more uncertain than other tax revenues under retail competition for two main reasons: (1) the method of appraising utility properties incorporates a substantial degree of judgment on the part of North Carolina tax authorities, who make an administrative determination on the relative influence of the cost factor and capitalized income factor approaches; and (2) the influence of stranded cost recovery payments on utility property values has not yet been determined by North Carolina tax authorities.

To maintain simplicity in our tax projection model, we have incorporated the following assumptions with respect to these issues:

- the income factor approach will be the sole approach to determining utility property valuation, and
- recovery of stranded costs will have no effect on utility property valuations.

With regard to our first assumption, we anticipate that tax authorities will ultimately be more likely to emphasize the income factor approach for appraisal since the accounting or book value of some generating plants may seriously overstate their market value in a competitive environment. With regard to our second assumption, we assume that property tax appraisers would not attribute income from stranded cost payments to individual power plants for the purpose of tax valuation. The process of subdividing stranded cost recovery payments and imputing payment shares to individual plants may be unduly complex. Both of these assumptions are contestable and subject to final determination by the North Carolina Department of Revenue. However, the effect of both assumptions is to lower property tax projections, thereby yielding conservative estimates of property tax revenue losses under retail competition. A more detailed explanation of these assumptions is provided in Volume 2.

2.3 GROSS RECEIPTS TAX

All utilities (i.e., electric, gas, water) located in North Carolina are required to pay a gross receipts tax. The gross receipts tax is a franchise or privilege tax on utilities that is imposed in lieu of any other franchise privilege or license tax. Currently, the tax is applied at a rate of 3.22 percent to the gross receipts derived from sales within North Carolina. The tax is not applied to wholesale power sales (i.e., electricity that is resold- for example, electricity purchased by a municipal power system for resale to its customers).

Utilities remit the tax proceeds to the North Carolina Department of Revenue each month and file tax returns quarterly. On its tax return each taxpaying utility shows the amount of the tax that is due to each municipality within its service territory. That amount is calculated as the product of the gross revenues derived within each municipality's corporate limits times a tax rate of 3.09 percent. The Department of Revenue distributes most of the revenue collections back to the cities where the power was purchased. The balance of funds remaining after distribution to the municipalities goes into the North Carolina General Fund.

The gross receipts tax is a transaction tax similar to a sales tax. North Carolina cannot impose taxes on the gross receipts of out-of-state providers unless nexus is established as detailed in Section 3.3.

2.4 SALES TAX ON ELECTRICITY

Electricity distributors collect sales tax from customers and remit it to the state. As shown in Table 2-1, these distributors include IOUs, electric cooperatives, and member cities that own their distribution systems. The sales tax on electricity in North Carolina is imposed on all sales of electricity and applies to all customer charges related to providing electricity. Some buyers of electricity are exempt from the sales tax on electricity. Exempt buyers include suppliers who resell electricity, federal government agencies, and the North Carolina Department of Transportation.

Two different sales tax rates are applied depending on the specific electricity use: a tax rate of 2.83 percent is applied to electricity sales related to specified farming, manufacturing, and commercial applications, while a tax rate of 3 percent is applied to all other retail electricity sales. Sales tax revenues are used to support public school systems and other state government needs. Because the sales tax is a transaction tax (like the gross receipts tax), the nexus requirements for taxing out-of-state providers also apply to this tax.

2.5 SALES AND USE TAX ON PURCHASES

Sales tax on purchases is a tax on tangible personal property sold within the state for use within the state. Use tax is a tax on tangible personal property purchased outside North Carolina but used within North Carolina. The tax rate in both cases is 6 percent, but certain items are taxed at a lower rate. For example, machinery used directly in the process of producing electricity and in pollution control facilities is subject to a 1 percent tax rate with a maximum of $80 per single article. The sales and use tax on purchases is separate from the sales tax on electricity and does not apply to sales of electric services.

Because it is unlikely that retail competition will have any effect on the sales and use tax on purchases, we do not include this tax in our analysis.

2.6 SUMMARY

North Carolina IOUs (Carolina Power & Light [CP&L], Duke Power, and Virginia Electric Power Company) remit corporate income taxes and sales taxes on electricity to the state of North Carolina and property taxes to the county and municipal governments in North Carolina. In addition, they remit gross receipts taxes to the state of North Carolina, a portion of which is shared with North Carolina municipalities. Publicly-owned utilities (the MPAs and municipal systems) and customer-owned utilities (electric cooperatives and NCEMC) remit sales and gross receipts taxes. Both also pay property taxes, except that property tax is not levied on municipal distribution systems. Table 2-3 summarizes the tax remittances of all electric utilities for calendar year (CY) 1997. Altogether, the tax remittances from electric utilities totaled approximately $634 million in 1997. As shown in Figure 2-1, taxes related to electricity sales are dominated by the gross receipts tax (35 percent) and the sales tax on electricity (30 percent). Duke Power and CP&L remit about 80 percent of the total taxes related to electricity supply (see Figure 2-2).

Table 2-3. Summary of 1997 (CY) Electric Utility Tax Remittances in North Carolina ($million)

	Corporate Income Tax	Property Tax	Gross Receipts Tax	Sales Tax on Electricity	Sales and Use Tax on Purchases	Total
Carolina Power & Light	$45.0	$34.0	$67.0	$58.0	$8.0	$212.0
Duke Power	$56.0	$51.0	$92.0	$82.0	$12.0	$293.0
Virginia Electric Power Company	$3.1	$2.7	$6.6	$5.8	$0.3	$18.5
MPAs and Member Cities	N/A	$5.0	$21.0	$19.5[a]	- [b]	$45.5
NCEMC and Rural Electric Cooperatives	N/A	$8.4	$29.3	$27.4	N/A	$65.1
Totals	$104.1	$101.1	$215.9	$192.7	$20.3	$634.1

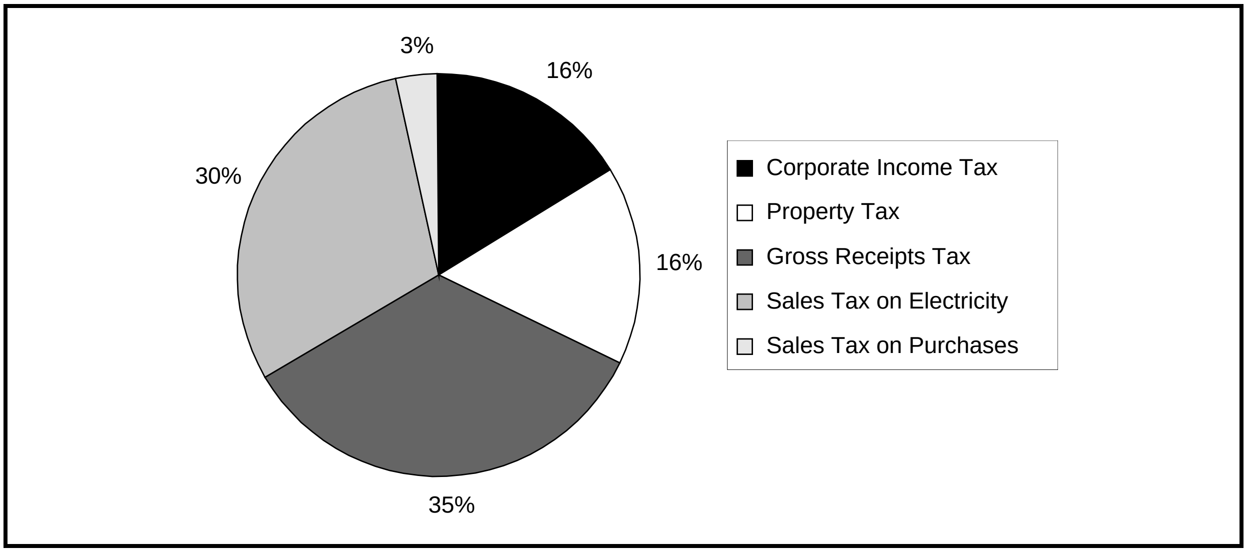
NA = not applicable.

[a]MPAs' sales tax is collected by municipal electric utilities they serve.

[b]The MPAs report that they paid about $128,000 in sales and use taxes in 1997. In addition, they paid these taxes through their ownership share of generation plant costs, even though the operating IOUs remitted the payments.

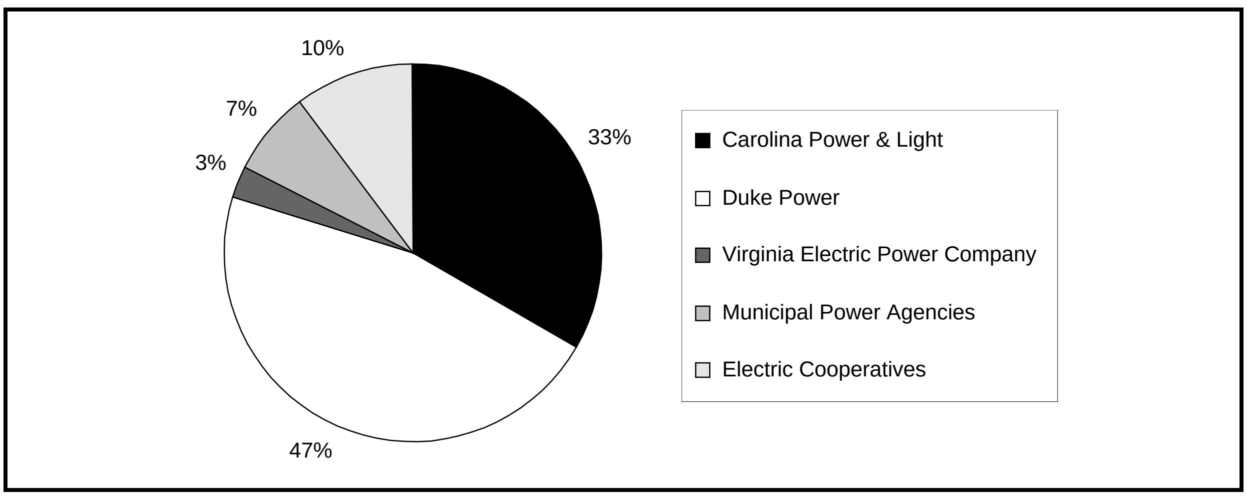
Sources: Data provided by tax managers of all taxpaying entities and verified with 1997 revenue collection data from the North Carolina Office of State Budget and Management and the Fiscal Research Division of the Legislative Services Office of the North Carolina General Assembly.

Figure 2-1. Summary of 1997 (CY) Electric Utility Tax Remittances in North Carolina, By Type of Tax



Sources: Data provided by tax managers of all taxpaying entities and verified with 1997 revenue collection data from the North Carolina Office of State Budget and Management and the Fiscal Research Division of the Legislative Services Office of the North Carolina General Assembly.

Figure 2-2. Summary of 1997 (CY) Electric Utility Tax Remittances in North Carolina, By Source



Sources: Data provided by tax managers of all taxpaying entities and verified with 1997 revenue collection data from the North Carolina Office of State Budget and Management and the Fiscal Research Division of the Legislative Services Office of the North Carolina General Assembly.

Table 2-4 shows the approximate distribution of 1997 tax remittances to state, county, and municipal governments. The state retains all corporate income and sales tax proceeds but only 39 percent of gross receipts tax proceeds and none of the property tax revenue.

Table 2-4. Distribution of 1997 (CY) Electric Utility Tax Remittances to North Carolina Government Entities ($million/%)

	Corporate Income Tax	Property Tax	Gross Receipts Tax	Sales Tax
State	$104.1 (100%)	N/A	$84.5 (39%)	$192.7 (100%)
County	N/A	$81.1 (80%)	N/A	N/A
Municipal	N/A	$20.0 (20%)	$131.3 (61%)	NA

Table 2-5 summarizes the percentage share of total state, county, and municipal tax receipts derived from electric utility tax remittances. These remittances account for 3.26 percent of state tax receipts, 2.26 percent of county tax receipts, and 6.91 percent of municipal tax receipts.

Table 2-5. Percentage Share of 1997 (CY) North Carolina Tax Receipts Derived from Electric Utility Tax Remittances

	Revenue Share by Level of Government		
Tax Type	State[a]	County	Municipal
Corporate Income Tax	0.99%	0.00%	0.00%
Property Tax	0.00%	2.26%	1.14%
Gross Receipts Tax	0.63%	0.00%	5.77%
Sales Tax	1.64%	0.00%	0.00%
Total	3.26%	2.26%	6.91%

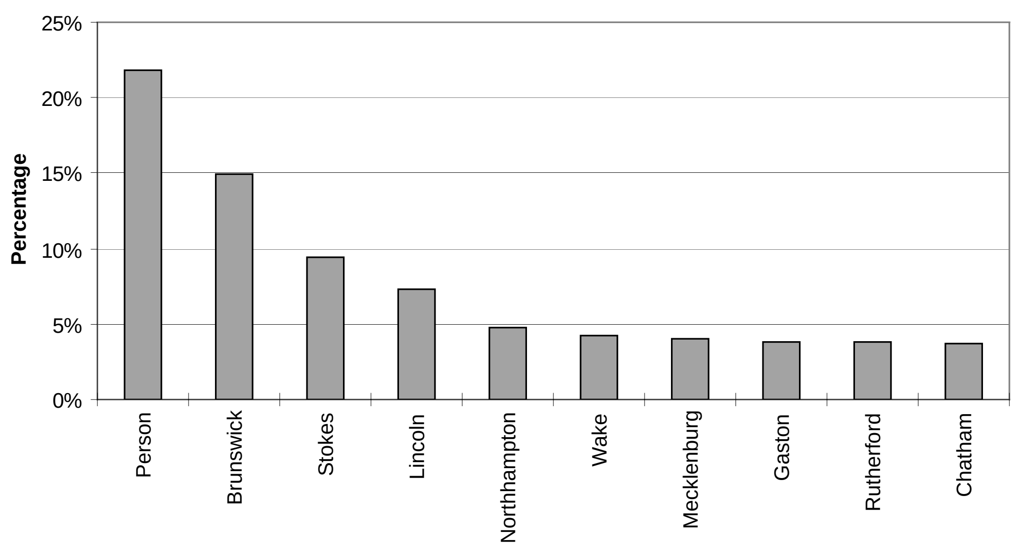
[a]The percentages shown are for the state general fund; thus, they do not include the portion of gross receipts tax that is distributed back to the municipalities.

Sources: Data provided by tax managers of all taxpaying entities and verified with 1997 revenue collection data from the North Carolina Office of State Budget and Management and the Fiscal Research Division of the Legislative Services Office of the North Carolina General Assembly and the North Carolina Department of Revenue, 1997.

On average, counties obtain a relatively small share of their tax receipts from property taxes paid by electric utilities. However, some counties, particularly those with generating plants, rely heavily on the property taxes paid by electric utilities to fund public services.

Figure 2-3 shows the 10 North Carolina counties with the highest percentage of tax receipts from electric utility property taxes. The two counties with the highest percentage of tax revenues from electric utility property taxes- Brunswick and Person- had $42 million and $14 million, respectively, in total property tax revenue in 1997.

Figure 2-3. North Carolina Counties with the Highest Percentage of Tax Receipts from Electric Utility Property Taxes in 1997 (CY)



Source: North Carolina Department of Revenue, 1997.

3 Issues Affecting Future North Carolina Tax Revenues

Several issues will affect the potential impacts of retail competition on North Carolina tax revenues. In this section, we first discuss each of the three key issues:

- ➤ future electricity prices,
- ➤ stranded costs, and
- ➤ nexus.

We then discuss other, less significant, issues affecting our tax projections. Volume 2 details how we modeled the potential effects of all these issues.

3.1 FUTURE ELECTRICITY PRICES

Proponents of retail competition claim that future prices for electricity will decline after competition begins. In fact, our stranded cost report incorporates three different projections of those price changes (RTI, 1999) and details the sources and basis for our projected price series. All of the price series in our reports project that the competitive price for electricity will be lower on average than current electricity prices in the next few years.

A substantial number of empirical studies have shown that when the price of any product or service declines the quantity purchased will typically increase. But for some products the amount purchased is not likely to increase very much. In fact, even though the amount purchased may increase, total dollar sales may sometimes fall. Many other empirical studies have shown that this is the case for electricity-when the price of electricity declines, the quantity of electricity used typically increases at the same time that dollar sales decline.[1] Consequently, we project that electricity revenues would decline under retail competition, at least when we assume the future price series that we developed for our stranded cost study.

Reductions in electricity revenues would have serious implications for North Carolina tax revenues. Unless the state implements offsetting tax policies, we would expect revenues from all revenue-based taxes to decline. Both sales and gross receipts taxes are levied directly on the dollar value of electricity sales, so revenues from those two taxes would clearly decline. In addition, electricity revenue losses may reduce property and income tax revenues depending on several factors discussed in Volume 2 of this report.

3.2 STRANDED COSTS

As previously mentioned, retail competition would require competitive pricing of electricity. In other words, all electricity suppliers who wish to remain competitive in North Carolina would charge prices that are comparable to those offered by any outside supplier. As indicated in our report on stranded costs, that would require all electricity suppliers presently serving North Carolina retail customers to lower their prices (RTI, 1999). Yet the prices now charged by North Carolina suppliers are set at the levels needed to recover the costs of all their past investment expenditures incurred to serve their North Carolina customers. The costs of those investments that cannot be recovered when electricity is sold at competitive prices are known as stranded costs.

Stranded costs are composed of three major types of investments that North Carolina utilities have undertaken during the past several years. The largest component of stranded costs in North Carolina is attributable to the nuclear generating facilities. Typically, the

[1] A decline in dollar sales in conjunction with a price decrease will always occur when a parameter called the "elasticity of demand" for electricity has a value between zero and -1. Whenever the elasticity value is in that range we say that demand is "inelastic." Our reference case assumes a demand parameter value of -0.25, as is commonly reported in the empirical literature on electricity demand (Bohi, 1981).

current market value of those plants is well below their current accounting value as stated on their owners' balance sheets. Accounting value equals the difference between the facilities' initial cost and the amount of that initial cost already charged to customers in past years. The difference between accounting values and market values for these assets is a significant part of stranded costs. A second component of stranded costs is associated with power purchase contracts. Some North Carolina providers are bound for several years by contracts to buy wholesale or bulk power at prices well above expected wholesale prices in a competitive market environment. The excess cost of those contracts above competitive prices is stranded. The third major component of stranded costs is known as "regulatory assets." These are other utility expenses undertaken in past years but as yet not charged to customers, in many cases at the direction of regulatory authorities. Examples include the cost of energy conservation programs or electricity price discount programs for low-income customers.

Stranded cost recovery decisions could affect North Carolina tax revenues in three significant ways. First, the aggregate amount of stranded costs significantly affects the difference between current electricity prices and competitive prices, so the amount of stranded costs affects the amount of potential price reductions under competition. Those price changes significantly affect electricity revenues and, hence, revenue-based tax proceeds. Second, stranded costs may reduce property tax revenue because of the manner in which utility property is appraised for tax purposes, as discussed in Section 2.2. Third, the state's decision on the recovery of stranded costs would have critical tax revenue implications, because stranded cost recovery payments are presumed to be taxable.[2] Therefore, recovery of stranded costs would automatically offset part of the tax losses that would otherwise occur during the transition period.

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[2]It may be necessary for the state to enact specific legislation to authorize taxes on stranded cost recovery payments. Our model assumes that the full amount of such payments is taxable for IOUs, but not for tax-exempt municipal or cooperative suppliers.

3.3 NEXUS

Under retail competition any generating company would be free to sell electricity to North Carolina homes and businesses. As is already the case in states that have opened their markets to retail competition, this would likely introduce some new electricity suppliers to North Carolina who are located in other states. Whether those out-of-state companies will be liable to collect or pay North Carolina taxes remains an issue, generally described as the nexus issue.

Nexus refers to the authority of a state to levy a tax on a transaction or a person, or to require a person to collect taxes the state levies. Traditionally this has been an issue with out-of-state mail-order sales and, more recently, with Internet sales. The courts have established a state's authority to impose its taxes based on substantial presence. Substantial presence depends on a taxpayer having sufficient property, employees, or other presence in a state to justify taxation. Nonetheless, the courts and legislatures have not yet provided an exact legal definition of nexus for the purpose of taxing electricity sales.[3] Therefore, we must consider the potential tax consequences that would occur if nexus is not established.

As detailed in Volume 2, the existence of nexus would affect the competitive price of electricity and, therefore, the amount of stranded costs. With nexus, out-of-state suppliers would be forced to charge prices that adequately compensate for all their costs including the North Carolina taxes they must pay. Naturally their costs would be lower if they could avoid paying those taxes. In a competitive market environment without nexus this would typically affect enough out-of-state suppliers that they would all offer electricity to North Carolina buyers at lower prices reflecting the avoided cost of taxes. Consequently, revenues from the gross receipts tax, sales tax on electricity, and corporate income tax would be lower, and stranded costs would be higher without nexus

[3] It should be noted that the U.S. Congress has the power to regulate interstate commerce and has been considering legislation to address interstate electricity sales. Thus, the Congress could enact legislation that would establish the method for states to levy taxes on interstate electricity sales.

than with nexus.[4] Therefore, North Carolina and other states have an obvious incentive to establish nexus, or to implement alternative tax policies that have the same effect as nexus.

The legal precedent for sales tax nexus is established in two U.S. Supreme Court cases- *National Bellas Hess, Inc. v. Department of Revenue* (1967) and *Quill Corp. v. North Dakota* (1992). The Court in *Bellas Hess* ruled that a supplier must have some physical presence in a state to satisfy the U.S. Constitution's Due Process and Commerce Clause requirements for a fair tax. In this case, the tax was an Illinois sales tax on out-of-state catalog sales.

In *Quill*, another case involving out-of-state catalog sales, the Court reaffirmed the finding in *Bellas Hess* that an out-of-state supplier must have some physical presence in a state to justify sales tax collection under the Commerce Clause of the U.S. Constitution. The Commerce Clause prohibits states from passing laws that impede the flow of interstate commerce.

The *Quill* decision specifically addresses the issue of nexus as it relates to transaction taxes (e.g., gross receipts tax and sales tax on electricity). As a result, North Carolina tax authorities can subject an out-of-state provider to the gross receipts tax or the sales tax on electricity if that out-of-state provider has physical presence in North Carolina. Physical presence includes the regular and continuous presence of employees or the maintenance of an office or other place of business within the taxing state. Thus far, the issue of what constitutes physical presence has been left to the states to decide. Thus, the nexus issue as it relates to the gross receipts tax and sales tax on electricity is an important consideration for drafters of any North Carolina restructuring initiative.

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[4] Recent experience with American Electric Power (AEP) illustrates the potential impact on tax revenues of failing to establish nexus. AEP, an out-of-state provider, contracted to sell 200 MW of power to the North Carolina Electric Membership Corporation (NCEMC), resulting in a loss of $96 million in annual revenues to the North Carolina IOU that previously supplied this power. Although gross receipts tax and sales tax on electricity were unaffected in this example (since it involved the sale of power to an in-state provider for resale), corporate income tax was affected, resulting in a loss of approximately $19 million in taxable income and $1.425 million in corporate income tax revenues to North Carolina's Department of Revenue.

The nexus issue also affects the application of North Carolina's corporate income tax on out-of-state providers. The courts' interpretation of nexus appears to differ somewhat for income taxes as compared to transaction taxes like the gross receipts tax and sales tax on electricity. The Court in *Quill* left open the question of whether the physical presence test applies to other types of taxes like the income tax. However, the South Carolina Supreme Court held in *Geoffrey, Inc. v. South Carolina Tax Commission* (1993) that *Quill's* physical presence requirement does *not* apply to income tax. Although the issue remains unclear, there appears to be stronger grounds for successfully asserting income tax jurisdiction than for asserting gross receipts tax and sales tax jurisdiction over out-of-state providers.

3.4 OTHER ISSUES

Our tax projection model allows for variation in a number of other policy decisions and parameters that would affect our projections of North Carolina tax revenues. Although none of these are as significant as the three issues discussed above, the ultimate resolution of each issue mentioned here would nonetheless affect both the timing and level of future tax revenues.

3.4.1 Method of Stranded Cost Recovery

To keep the modeling and presentation of tax consequences as simple as possible, our reference case assumes that stranded costs would be recovered by imposing a uniform surcharge on all electricity sales in North Carolina. The uniform surcharge would be defined as a fixed dollar amount per kWh sold (e.g., 0.5¢/kWh).[5] However, our tax model explicitly incorporates two other policy alternatives for stranded cost recovery. One alternative creates four separate uniform tax rates based on four stranded cost pools. One pool combines the stranded costs of Carolina Power & Light and the North Carolina Eastern Municipal Power Agency. Another combines the stranded costs of Duke Power Company and the North Carolina Municipal Power Agency #1. In addition, both

[5]We assume that North Carolina distribution companies will collect any surcharges from customers so that there is no issue of nexus with respect to the authority to collect surcharges. Of course, we assume that these surcharges do not constitute tax-deductible business expenses for utilities, since the charges would be levied directly on their customers.

North Carolina Power and the electric membership cooperatives are maintained as two separate pools. The model then computes four separate uniform surcharges- one for each of these four pools- and projects tax consequences based on those surcharges. Finally, the model computes five independent uniform surcharges- one for the North Carolina municipal power agencies combined, one for the electric cooperatives, and one for each of the IOUs. None of these stranded cost recovery methods, including the method assumed in our reference case, is to be construed as a recommendation of a specific method of stranded cost recovery.

3.4.2 Competition Start Date

Our reference case assumes that retail competition would begin in 2004. However, our model also provides projections for start dates of 2002 or 2006. Furthermore, the model can be easily modified to provide projections for other start dates.

3.4.3 Length of Transition Period

The length of the transition period defines the number of years during which stranded costs would be recovered by North Carolina utilities. Our reference case assumes 5 years, but this can be varied over a reasonable range of values to see how those changes would affect tax revenues.

3.4.4 Writeoff of Regulatory Assets

Our model assumes that stranded costs payments constitute taxable income for IOUs. At the same time we assume that IOUs will continue to depreciate their assets against that and all other income. The model assumes that conventional assets like power plants will continue to be depreciated under their established depreciation schedules, regardless of their current market values. However, our reference case assumes that regulatory assets will be depreciated on a straight-line basis over 5 years beginning with retail competition. The length of this write-off period can also be varied in the model to assess its impact on tax revenues.

3.4.5 Tax Discount Rate

Our model forecasts annual tax revenues for each year between the onset of retail competition and 2015. In our reference case we convert that flow of tax revenues to a single number for each type of tax. We do so by using a standard method of financial analysis called the discounted present value method. That method uses a discount rate. For example, the present value of a tax dollar received at the end of a year would currently be worth about 95.5¢ assuming a discount rate of 5.5 percent. At the same rate of 5.5 percent, the discounted present value of a tax dollar received in each of 10 years (i.e., the value of $10 received in $1 annual increments) is $7.54. We used a discount rate of 5.5 percent in our reference case for calculating the present value of tax revenue changes, but this rate can be varied to examine its impact on tax revenue projections. We chose the rate of 5.5 percent as an approximate long-term borrowing rate for the state, corresponding to the relatively long tax projection period in our model.

4 Potential Impacts on Tax Revenues: Quantitative Estimates

This section quantifies the potential impact of retail competition on North Carolina tax revenues. All projections reported here are based on the same reference case used in our companion studies on stranded costs and benefits and detriments due to retail competition. The following are key elements of that reference case:

- ➤ Start date of competition = January 1, 2004
- ➤ Benchmark market clearing price of power under competition = intermediate estimate as reported in *Stranded Cost Estimates for a Restructured Electric Utility in North Carolina, Volume 3—Task 4* (RTI, 1999)
- ➤ Discount rate = cost of equity for investor-owned utilities (IOUs), cost of debt for other utilities-used to compute the discounted present value of annual stranded costs
- ➤ Capital additions to preserve capacity and efficiency ratings of existing generation are included as potential stranded costs

In addition, our reference case for estimating tax effects includes the other parameter assumptions discussed in Section 3.4.

The two most important policy decisions affecting North Carolina tax revenues are those relating to the establishment of nexus and the recovery of stranded costs. Therefore, we have considered tax revenue consequences under all of the four possible outcomes regarding these issues. Those outcomes constitute the four policy cases that we report in this Section and detail in our modeling approach discussed in Volume 2:

- Case 1: No Nexus, No Recovery of Stranded Costs
- Case 2: Nexus, No Recovery of Stranded Costs
- Case 3: No Nexus, Recovery of Stranded Costs
- Case 4: Nexus, Recovery of Stranded Costs

Case 1 assumes that nexus is not established, leaving out-of-state providers untaxed, and that stranded costs are not recovered. Case 2 assumes that nexus is established, meaning that out-of-state providers are subject to North Carolina taxes, and that stranded costs are not recovered. Case 3 assumes that nexus is not established but that stranded costs are recovered. Case 4 assumes that nexus is established and that stranded costs are recovered.

For each of these cases, we developed algorithms to estimate the potential effect of retail competition on tax revenues for four separate taxes: the gross receipts tax, the sales tax on electricity, the corporate income tax, and the property tax. These algorithms and their underlying logic are complicated. To maintain our focus on results in this Volume, we have confined our discussion of methodology to Volume 2. The Executive Summary of that volume provides a narrative overview of our method of projecting tax revenue changes; that overview should be accessible to most readers. The remainder of Volume 2 is significantly more technical and mathematical; it will be most accessible to readers who are familiar with microeconomic theory and economic modeling.

All projections of tax revenues in this section assume that tax policies in North Carolina remain unchanged, except for the establishment of nexus. As discussed in Section 5, several tax policy changes could be implemented to offset any tax losses. In addition, all projections cover the period from the assumed start date for competition through 2015.

Table 4-1 presents the projected impacts of retail competition on North Carolina tax revenues for each of the four policy cases, assuming a start date of 2004. These projections represent the discounted present value of the annual tax revenues for the entire

Table 4-1. Changes in North Carolina Taxes Remitted by Electric Utilities: Retail Competition for the Period 2004-2015[a]

	Potential Change in Tax Remittances ($millions)				
Case[b]	Gross Receipts Tax	Sales Tax on Electricity	Corporate Income Tax	Property Tax	Total
Case 1: No Nexus, No Recovery	-$522.3	-$501.6	-$301.0	-$117.8	-$1,442.8
Case 2: Nexus, No Recovery	-$311.8	-$299.5	-$108.4	$29.8	-$690.5
Case 3: No Nexus, Recovery	-$286.2	-$274.9	-$93.2	-$117.8	-$772.3
Case 4: Nexus, Recovery	-$176.0	-$169.1	-$56.2	$29.8	-$371.5

[a]Changes in the *discounted present value* of annual tax remittances.

[b]Recovery refers to stranded cost recovery.

period from 2004 through 2015,[1] rather than annual revenue amounts. We used a discount rate of 5.5 percent, as discussed in Section 3.4.5.

Table 4-2 reports these impact projections as percentage changes in the tax revenues paid by electric utilities. The projected effects of retail competition on the aggregate revenue from all four types of taxes vary widely, although total tax revenues decline in all cases. Those aggregate tax losses are reported in the final column of Table 4-2. We project that the largest decline in tax revenues would occur in Case 1 (no nexus, no recovery) amounting to a loss of about 19 percent. Our projections of aggregate tax revenue losses for Cases 2 (nexus, no recovery) and 3 (no nexus, recovery) are nearly the same at about 9 and 10 percent, respectively. The smallest negative effects are projected to occur if the state is able to establish nexus and simultaneously allows stranded cost recovery (Case 4). In that case, aggregate tax collections would decline by only about 5 percent.

[1]Our projection period for this report extends to 2015, instead of 2020 as in our report on stranded costs. The data to estimate tax changes through 2020 were not available. Specifically, systemwide forecasts of total electricity sales were not provided through 2020 by all of the affected suppliers. Ending our projection period at 2015 was also consistent with other RTI work on the benefits and detriments of retail competition. That work required using data from the Bureau of Economic Analysis, which did not extend beyond 2015.

Table 4-2. Percentage Changes in North Carolina Taxes Remitted by Electric Utilities: Retail Competition for the Period 2004-2015[a]

Case[b]	Potential Change in Tax Remittances (%)				
	Gross Receipts Tax	Sales Tax on Electricity	Corporate Income Tax	Property Tax	Total
Case 1: No Nexus, No Recovery	-18.22%	-18.22%	-30.3%	-10.71%	-18.7%
Case 2: Nexus, No Recovery	-10.88%	-10.88%	-10.97%	2.71%	-8.95%
Case 3: No Nexus, Recovery	-9.98%	-9.98%	-9.39%	-10.71%	-10.01%
Case 4: Nexus, Recovery	-6.14%	-6.14%	-5.66%	2.71%	-4.82%

[a]Percentage changes in the *discounted present value* of annual tax remittances.

[b]Recovery refers to stranded cost recovery.

Table 4-2 also shows how tax remittances are projected to change for each of the four affected taxes. As with aggregate tax revenues, the proceeds from each of these taxes decline the most under Case 1 (no nexus, no recovery). Because the sales and gross receipts taxes are levied on electricity revenues, the percentage changes for those taxes are identical in each of the four cases. We project that revenues from both of those taxes would decline between 6 and 18 percent, depending on nexus and stranded cost recovery decisions.

Corporate income taxes are projected to decline by about 9 to 11 percent under Cases 2 and 3, about the same as percentage losses of gross receipts and sales taxes for those cases. However, in Case 1 (no nexus, no recovery) corporate income taxes would decline much more, by about 30 percent. In that case, stranded costs are higher because there is no nexus, and those stranded costs will be written off against income without any offsetting income taxes on stranded cost recovery payments. In Case 4 with both nexus and recovery, corporate income taxes would decline by about 6 percent.

As detailed in Volume 2, our model assumes that property tax revenues are unaffected by whether the utility receives stranded cost recovery payments. However, we do assume that those payments constitute taxable income. Our assumption is that property value appraisers would not attribute income from stranded cost payments to individual power plants for the purpose of tax valuation. Under those assumptions, our property tax revenue projections are the same for Cases 1 and 3 (no nexus) indicating potential losses of about 11 percent. They are also the same for Cases 2 and 4 (nexus), but in these cases indicate potential gains of about 3 percent in property tax revenues.

At first this result seems anomalous. However, as detailed in Volume 2, retail competition would have complex and somewhat unexpected effects on tax revenues. The dollar values on which taxes are levied- dollar sales of electricity, tax values of utility properties, and utility income- would be affected in many different ways. For example, property tax revenues are proportional to the tax values assigned to utility properties, mainly power plants. Following the method of property valuation discussed in Section 2, our model assumes that those tax values are proportional to the income derived from the sale of electricity generated by those plants. For Cases 1 and 3 (no nexus), we project that those existing plants would generate lower revenue than under the current utility regulation. However, with nexus (Cases 2 and 4) we project that, on average, revenues from those plants will exceed the remaining recoverable costs (or attributable revenue) from those plants under regulation. This happens, of course, because projected electricity prices are higher in the nexus cases.

Yet if income to existing plants rises under nexus, why don't corporate income taxes rise? In fact, we have projected that corporate income taxes would decline by about 11 percent and 6 percent for nexus Cases 2 and 4. The answer is suggested by our discussion of the three components of stranded costs in Section 3.2- plants whose book value exceeds their market value, uneconomic purchase contracts, and regulatory costs. The last two components do not affect the tax value of power plants but do lower corporate income taxes as they are written off against income during the transition period.

Table 4-3 shows how the projected changes in tax proceeds will affect the amount of tax dollars ultimately received by state, county, and municipal governments in North Carolina. Table 4-4 reports those changes in percentage terms. Municipalities are likely to suffer the highest proportionate tax losses because of the impact on property taxes and municipal proceeds of gross receipts tax

Table 4-3. Changes in Total Tax Receipts, By Government Entity: Retail Competition for the Period 2004-2015 ($million)[a]

Case[b]	Municipal	County	State	Total
Case 1: No Nexus, No Recovery	-$341.0	-$94.5	-$1,007.2	-$1,442.7
Case 2: Nexus, No Recovery	-$183.8	$23.9	-$530.6	-$690.5
Case 3: No Nexus, Recovery	-$197.4	-$94.5	-$480.3	-$772.2
Case 4: Nexus, Recovery	-$101.2	$23.9	-$294.2	-$371.5

[a]Changes in the *discounted present value* of annual tax receipts.

[b]Recovery refers to stranded cost recovery.

Table 4-4. Percentage Changes in Total Tax Receipts, By Government Entity: Retail Competition for the Period 2004-2015[a]

Case[b]	Municipal	County	State
Case 1: No Nexus, No Recovery	-1.17%	-0.24%	-0.75%
Case 2: Nexus, No Recovery	-0.59%	0.06%	-0.38%
Case 3: No Nexus, Recovery	-0.70%	-0.24%	-0.34%
Case 4: Nexus, Recovery	-0.32%	0.06%	-0.21%

[a]Percentage changes in the *discounted present value* of annual tax receipts.

[b]Recovery refers to stranded cost recovery.

collections. Assuming no nexus and no recovery of stranded costs (Case 1), we estimate that total municipal tax revenues from all sources combined could decrease by about 1.2 percent as a result of retail competition. Under Cases 2 and 3 we project that total municipal tax revenues would decline by about 0.6 and 0.7 percent, respectively; under Case 4 with both nexus and stranded cost recovery we project a loss of about 0.3 percent. Thus, in a city with annual tax revenues of $25 million (Rocky Mount and Greenville have approximately this amount of revenue), projected annual municipal tax revenue losses would amount to about $300,000 (Case 1), $150,000 (Case 2), $175,000 (Case 3), and $50,000 (Case 4).

In our model, projected changes in aggregate county tax revenues due to competition are strictly dependent on changes in property tax proceeds. Therefore, the impacts on their revenues are, like property taxes themselves, unaffected by stranded cost recovery. We project that county-level tax revenues would decrease by about 0.24 percent in Cases 1 and 3 (no nexus), and increase by about 0.06 percent in Cases 2 and 4 (nexus).

Any county-level tax revenue impacts from property tax reassessments will be widespread. Property assessments for each utility are centralized at the state level and then apportioned to the counties within their service area. Counties that depend more heavily on utility property taxes, especially counties that have a large apportionment of assessed value and counties that are served by utilities with large stranded costs, may experience much greater than average effects due to these reassessments. For example, Brunswick and Person counties, both with a large share of property values in generating plants, may experience losses up to 4 percent of their total county tax collections.[2]

Under competition, total tax collections by the state of North Carolina are projected to decline by about 0.8 percent, 0.4 percent, 0.3 percent, and 0.2 percent for Cases 1 through 4, respectively. The relative magnitude of the losses from one case to another are determined by aggregate losses in gross receipts, sales, and income taxes. As shown in Table 4-1 projected revenues from all three of those taxes decline most for Case 1, somewhat less for Case 2, even less for Case 3, and least for Case 4. Therefore, all three types of taxes contribute proportionately to the overall decline in tax revenues to the state.

Figures 4-1 through 4-4 show projected percentage changes in the discounted present value of tax revenues for the three alternative start dates for retail competition. Effects are shown for the aggregate of all tax revenues (Figure 4-1), for sales and gross receipts tax revenues (Figure 4-2), for income tax revenues (Figure 4-3), and for property tax revenues (Figure 4-4). The overall projected effects of changing the start date are relatively small in percentage terms. Mainly this is because sales and gross receipts

[2] As stated in Section 2, our method assumes that the income factor approach will be the sole approach in determining utility property valuation. Under this method, the value of power plants would decline as future electricity prices decline below current levels. This is true for all types of plants, including coal plants such as those in Person County.

Figure 4-1. Changes in Aggregate North Carolina Tax Remittances by Electric Utilities under Alternative Policies

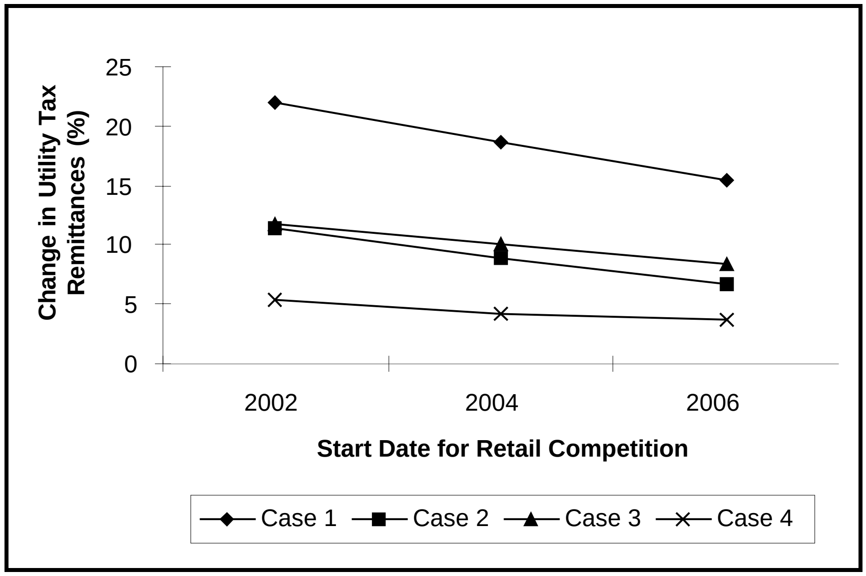


Figure 4-2. Changes in North Carolina Sales and Gross Receipts Tax Remittances by Electric Utilities under Alternative Policies

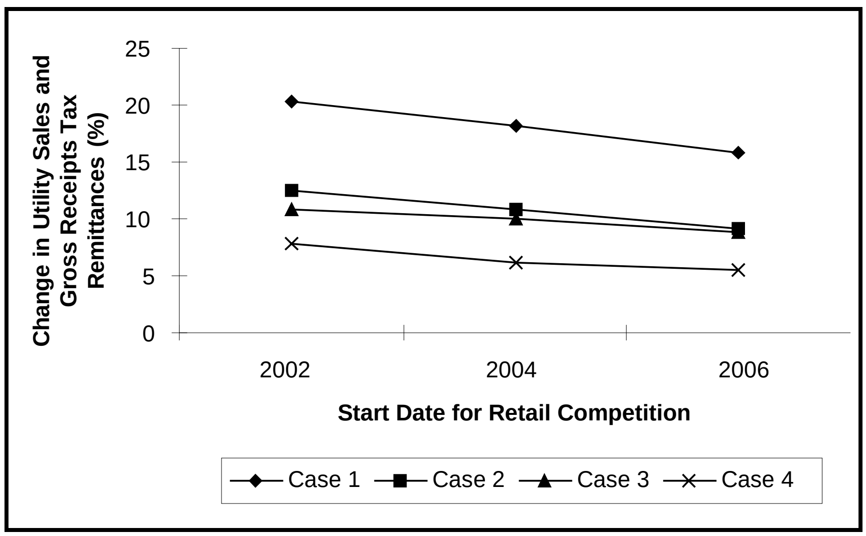


Figure 4-3. Changes in North Carolina Income Tax Remittances by Electric Utilities under Alternative Policies

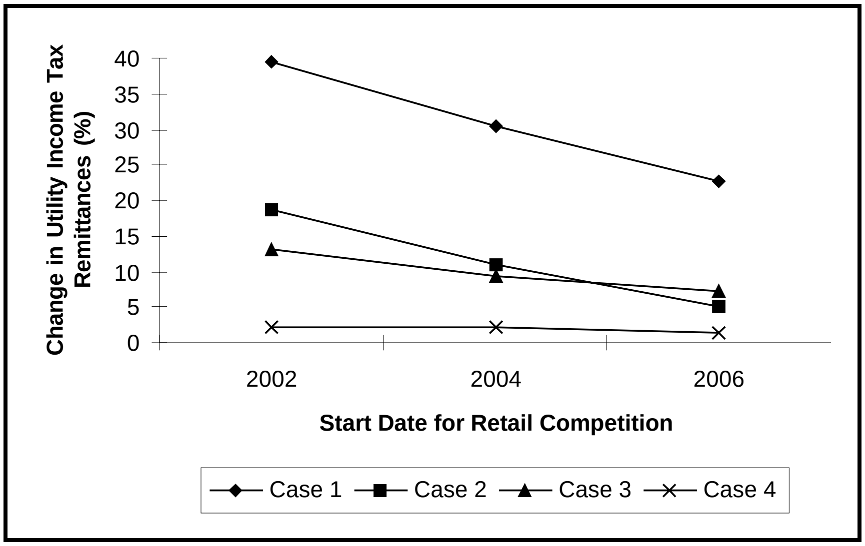
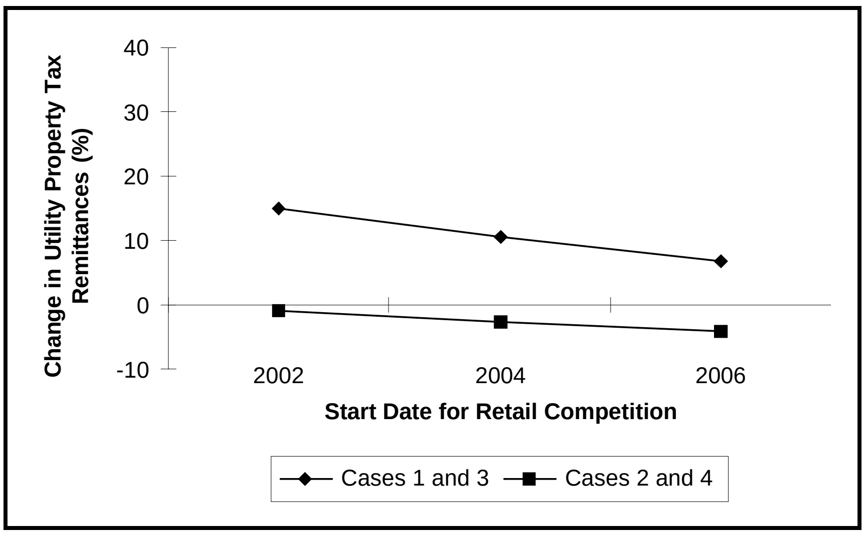


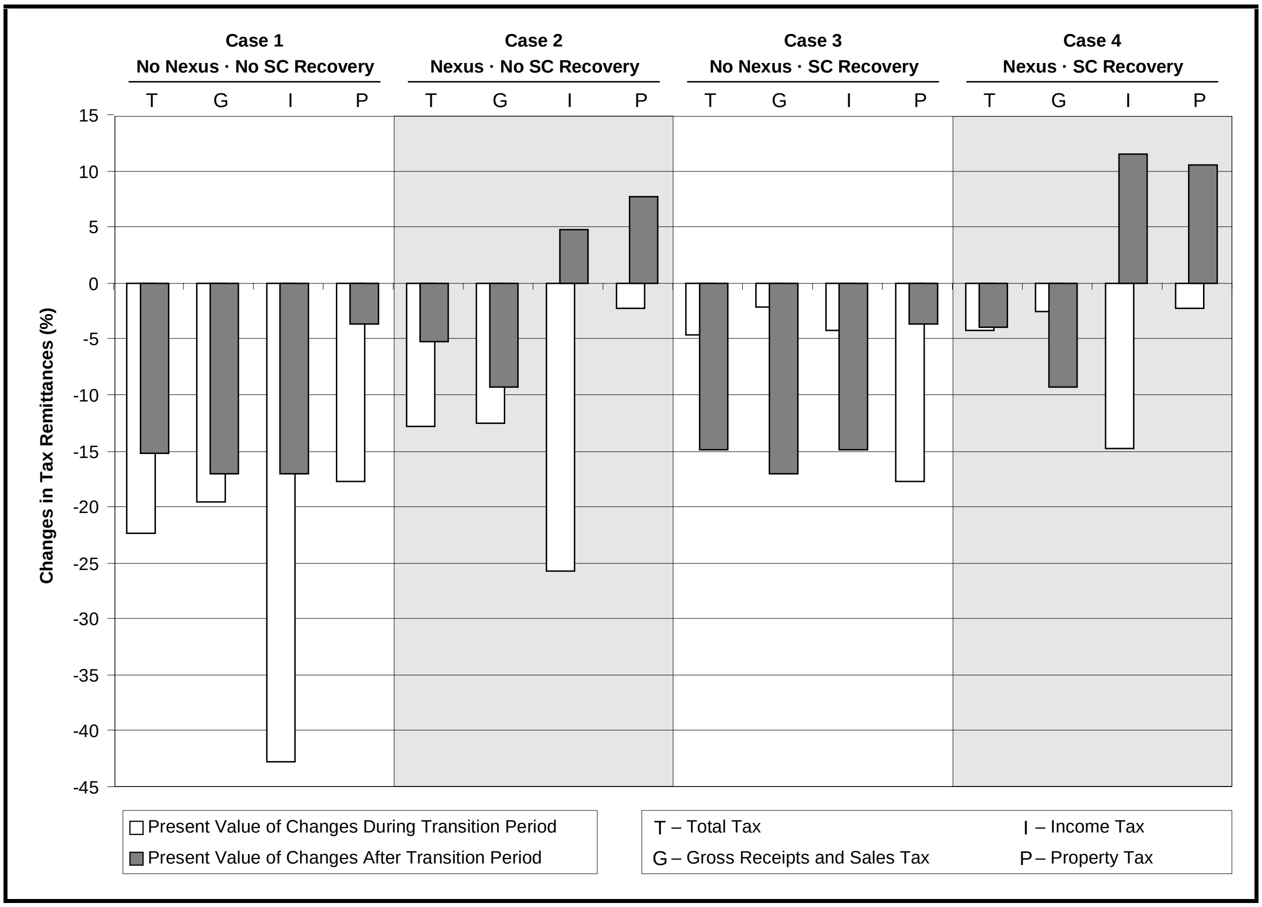
Figure 4-4. Changes in North Carolina Property Tax Remittances by Electric Utilities under Alternative Policies



taxes constitute a dominant share of total taxes, and the percentage change in those taxes is not likely to be greatly affected by changing the start date of competition. However, we project that income tax losses will be much smaller if the start date for competition is delayed, and a delay may even increase property tax collections.

Figure 4-5 shows how tax collections will vary during and after the transition period for each of the four policy cases when the starting date is 2004. The clear bars show the percentage changes in the discounted present value of taxes collected during the 5-year transition period; the shaded bars show those percentage changes for the post-transition period, 2009-2015. We show changes in aggregate tax revenues and in the revenues associated with each of the individual taxes. Generally, percentage tax losses are projected to be larger during the transition period than after without stranded cost recovery (Cases 1 and 2). With recovery, total percentage losses are projected to be greater (Case 3) or about the same (Case 4) during the post-transition period than during the transition period.

Figure 4-5. Changes in Tax Remittances During and After the 5-Year Transition Period: Retail Competition for the Period 2004-2015



Tax losses are obviously smaller with nexus- since all suppliers are taxed- than without nexus for all comparisons. Both income and property taxes are projected to increase in the post-transition period under nexus (Cases 2 and 4). The income tax effect is primarily due to an increased share of sales by taxable entities. Specifically, new kWh sales expansions are assumed to be delivered by entities that are subject to taxes, although those new entities may be owned by the incumbent suppliers in North Carolina. The property tax effect is explained previously in this section and is detailed in Volume 2.

Generally, it appears that changes in income tax revenues will vary the most between the transition and post-transition periods. The large income tax losses in Cases 1 and 2 reflect the income effect of unrecovered stranded costs for in-state providers.

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PERSONAL SOURCES

As part of this study, we conducted interviews either in-person or by telephone with the following individuals:

- ➤ California Department of Revenue
  - ✓ Don Jackson- Property Tax
  - ✓ Robert Zivkovich- Utility Taxation
- ➤ Carolina Power & Light Company
  - ✓ Carol Guyer- Tax Manager
  - ✓ Mitch Williams- Government Affairs
- ➤ Coopers & Lybrand
  - ✓ Paul Armstrong- North Carolina Offices
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- ➤ Duke Energy
  - ✓ Lynn Boyette- Tax Manager
  - ✓ John McAlister- Government Affairs
- ➤ ElectriCities
  - ✓ Alice Garland- Public Affairs
  - ✓ Karen Wood- Tax Manager
- ➤ Federation of Tax Administrators
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- Virginia Electric Power Company
  - ✓ Wynn Ryan- Tax Department
  - ✓ Michael Thompson- Government Affairs

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RETAIL CHOICE IN ELECTRICITY: WHAT HAVE WE LEARNED IN 20 YEARS?

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Electric Markets Research Foundation

Christensen Associates Energy Consulting conducted this study for the Electric Markets Research Foundation (EMRF). EMRF was established in 2012 as a mechanism to fund credible expert research on the experience in the United States with alternative electric utility market structures – those broadly characterized as the traditional regulated model where utilities have an obligation to serve all customers in a defined service area and in return receive the opportunity to earn a fair return on investments, and the centralized market model where generation is bid in to a central market to set prices and customers generally have a choice of electric supplier.

During the first few years of restructured markets, numerous studies were done looking at how these two types of electric markets were operating and the results were mixed. But since those early studies, limited research has been done regarding how centralized markets and traditionally regulated utilities have fared. The Electric Markets Research Foundation has been formed to fund studies by academics and other experts on electric market issues of critical importance.

Christensen Associates Energy Consulting

CA Energy Consulting is a wholly owned subsidiary of Laurits R. Christensen Associates, Inc., whose multi-disciplinary team of economists, engineers, and market research specialists has been serving the electric power industry (as well as other industries) since 1976. CA Energy Consulting's focus on energy markets covers a broad range of technical and regulatory policy issues concerning wholesale and retail electricity market restructuring, market design, power supply, asset evaluation, transmission pricing, market power, retail and wholesale rate design, and customer response to price signals.

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EXECUTIVE SUMMARY

Electric power industry restructuring in the United States in the 1990s was motivated by the expectation that substantial benefits were available through increased competition at the wholesale level – that is, in power sales among generators and utilities for resale to ultimate retail consumers. These expected benefits were of two types. First, competition in generation services would induce technological and management improvements in power production that would reduce generation costs and improve generators' performance. Second, the breaking down of barriers to trade among utilities and other wholesale market participants would foster competitive power trading that would substitute relatively cheap for relatively expensive generation.

In contrast to the very real expected benefits of wholesale restructuring, the potential gains from retail choice were speculative at best. By the time that restructuring occurred in the late 1990s, there was already a substantial body of evidence, from innovative retail electricity programs dating back to the 1970s, that customers' short-term response to electricity prices was small and that customers' willingness to be curtailed, even when they had promised to be available for curtailment, was even smaller. Nonetheless, through a confluence of hopes from disparate interest groups, particularly from industrial customers seeking lower electricity prices and terms of service better tailored to their needs, retail choice was adopted alongside wholesale restructuring in nearly half the states. Nearly two decades later, there is little evidence that retail choice has yielded any significant benefits.

Current Status of Retail Choice

"Retail choice" refers to customers' ability to choose the entity that provides them with electrical energy through the traditional power network. Australia, Korea, New Zealand, Turkey, and eight of the twenty-seven member states of the European Union (EU) appear to have real retail choice options. Fourteen U.S. states and the District of Columbia presently have retail choice, and eight states have suspended or rescinded retail choice. Because many states allow limited retail choice, however, the dividing line among states is somewhat ambiguous.

In U.S. jurisdictions with retail choice, roughly half of commercial and industrial load has switched to competitive suppliers, while under a tenth of residential load has done so. Because the gross benefits of switching suppliers are roughly proportional to a customer's size, larger customers are better able to overcome the transaction costs of switching than are smaller customers.

Retail Choice Outcomes

Retail choice appears to have the following impacts on innovative service offerings:

- Retail choice is extending the market penetration of dynamic pricing programs that reflect power system conditions. All other things equal, this improves the efficiency of use of power system resources, lowers the average costs of producing power, and tends to improve resource adequacy.
- Retail choice promotes renewable resources. To the extent that this raises the market penetration of intermittent resources such as wind and solar, it may raise resource adequacy issues because of the non-dispatchability of such resources.
- Retail choice has a mixed record in promoting demand response.
- Retail choice has not generally promoted smart metering.

The evidence indicates that retail choice has the following impacts on consumer prices:

- 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. The overall trend has been toward a lower price gap, though that is at least partly due to the happenstance of natural gas prices being low at the present time.
- Retail electricity prices in retail choice states vary more immediately with current fuel prices and other market factors than do retail prices in other states, and are therefore less stable than retail prices in other states.
- Retail electricity prices in retail choice states vary by location in a manner that mimics locational variations in wholesale electricity market prices.
- Neither price regulation nor the opening of retail markets seems to have had significant impact on average residential prices in the EU. The EU experience gives no clear signal about how retail choice affects retail electricity prices.
- The numerous statistical studies of the relationship of electricity prices to restructuring have reached contradictory conclusions about the price impacts of retail choice.

Implementation of retail choice has created some costs:

- Retail choice exacerbates the resource adequacy problem by materially adding to the financial uncertainties faced by investors in generating resources because it adds to uncertainties in the revenues that a generator will receive for its services. With retail choice, investors have sales contracts with durations that are only small fractions of the lives of their investments, which means that their revenues depend upon uncertain future market conditions. This uncertainty makes investment in new generation less attractive and makes long-term fuel contracting less attractive for existing generators, which may impinge upon resource adequacy and certainly raises the required returns on investment capital. This increase in required returns must ultimately be paid by consumers in the form of higher prices.

- The risk of retail supplier bankruptcies under retail choice is greater than under traditional regulation, which may increase the costs borne by consumers.
- Retail choice requires that billing procedures be adapted so that appropriate shares of customer payments go to the utility (for non-competitive services) and to third-party retail suppliers (for competitive services).
- Retail choice requires metering that is compatible with new retail service offerings.
- Under retail choice, retail suppliers incur marketing costs that must be recovered from customers.
- To facilitate the competition in generation services that is necessary for retail choice, there must be functional unbundling of utilities' generation function from its distribution and transmission functions. In most retail choice states, government encouraged or required utilities to divest generation assets or move them to separate affiliates, which, due to bad timing, ultimately cost customers tens of billions of dollars.

There is also evidence of the following additional impacts of retail choice:

- Some retail energy suppliers cherry pick customers. Some of the most attractive customers, namely industrial and large commercial customers, take advantage of lower prices in either the retail choice market or the regulated market, which may result in other customers bearing disproportionate shares of utilities' generation costs.
- There does not seem to be a clear relationship between retail choice and customer satisfaction. Results for U.S. residential customers are mixed. The EU experience suggests that retail choice, when well implemented, improves customer satisfaction.
- Retail choice decisions require business savvy that many consumers lack. Less educated or low-income consumers are more likely than other consumers to make poor retail supplier choices.

Directions for Future Policy

Policymakers should measure the success of retail choice according to the extent to which it reduces customers' bills relative to what they would have been for service from the incumbent utility, and according to the extent to which it creates service options of real value to consumers. Success should not be measured according to switching rates; and encouraging greater switching should not be a goal of public policy. In particular, smaller electricity consumers recognize that the transaction costs of switching are high relative to the prospective benefits of lower bills and better customer service, and can therefore rationally remain with their incumbent utilities.

Regulators in all states should encourage utilities to unbundle the pricing of generation services from that of other services, particularly distribution services, and charge consumers for non-competitive services when they choose an alternative generation supplier. Consumers should be able to clearly compare the prices of the generation services offered by competing suppliers, without the distraction of the prices of non-competitive services. Utilities should be able to recover the costs of non-competitive services regardless of the customer's choice of competing energy supplies whether obtained through the power system or outside of the power system.

Subsequent to unbundling of generation services from other services, regulators in retail choice states should encourage utilities to offer real-time pricing to all customers willing to pay the costs of the associated metering and billing. All customers can then have access to the wholesale market if they are willing to pay for such access.

To limit cherry-picking in retail choice states, customers who choose an alternative retail energy supplier should be ineligible to return to a conventional utility tariff. Instead, customers who want to return to the incumbent utility should be required to accept its real-time pricing rate or some other market-based rate.

Regulation in retail choice states needs to vigilantly protect consumers against retail energy suppliers' default and fraud.

RETAIL CHOICE IN ELECTRICITY: WHAT HAVE WE LEARNED IN 20 YEARS?

1. INTRODUCTION

1.1. Background

Traditionally, electric power was provided to U.S. consumers by vertically integrated utilities that owned generation, had exclusive retail franchises, and traded wholesale power through bilateral contracts. Beginning in the late 1990s, a new "restructured" market model was introduced under which regional transmission organizations (RTOs) or independent system operators (ISOs) operate centralized competitive wholesale markets in certain regions of the U.S. While about a third of the U.S. population continues to obtain electric power service based on traditional institutional arrangements, about two-thirds of the population now obtains electricity through restructured wholesale markets.

Although retail customers must obtain their power through transmission and distribution facilities that are owned and operated by regulated monopolies, it is technically feasible for them to obtain generation services (like electrical energy) and customer services (like special billing plans) through suppliers other than their traditional utilities. The prices and terms of transmission and distribution services thus continue to be determined through regulatory processes; but in states wherein retail choice is available, the prices and terms of generation and customer services can be set through market processes.

Retail choice – by which customers are allowed to choose their suppliers of generation and customer services – is available primarily in states located within regions served by the centralized wholesale markets, but they are also allowed such choice in a few states operating under traditional wholesale market structures.[1] In most states offering retail choice, competition at the retail level may therefore be regarded as an extension of the new competition at the wholesale level. Electricity markets with and without retail choice are thus distinguished, in part, by the nature of the corresponding competition at the wholesale level: retail choice states usually participate in restructured wholesale markets; while states without retail choice fall into both traditional and restructured wholesale markets.[2]

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[1] For example, under the traditional market structure in Georgia, new commercial and industrial customers with loads of 900 kW or higher are eligible for one-time electricity supplier choice. In Oregon, commercial and industrial customers that use at least 30 kW per month are eligible for electricity supplier choice.

[2] Borenstein and Bushnell [2015b, p. 4] note that "competitive generation is central to the retailer being able to offer better procurement options, different generation sources, or alternative billing mechanisms, which the retailer would likely want to balance with the wholesale contracts it has with producers."

1.2. Purpose of This Report

This report examines "retail choice," which we define as competition in the supply of the generation and customer components of retail electricity service *received through power systems*. It looks at the reasons why retail choice has been adopted in many jurisdictions, how it has evolved over the past few decades, the challenges in its implementation, and how it has affected power supply reliability and costs. This examination relies, in part, upon a comparison of U.S. electricity markets that have retail choice with U.S. electricity markets that do not have such competition, recognizing that such a comparison is complicated by the many factors that distinguish electricity markets with and without retail choice. These factors include weather, access to and costs of fuel, labor market and other input market conditions, and the characteristics of state laws and regulations. Moreover, each of these factors encompasses a range of conditions. For example, most states have laws or regulations that subsidize distributed resources directly through tax credits or indirectly through net metering rules that pay retail electricity prices for customers' self-generated electrical energy; but the states vary substantially in both the levels of the tax credits and the conditions that define net metering rules. It is thus a complex matter to determine the extent to which the reliability and cost differences among states are due to retail choice rather than to other factors.

This report also takes a limited look at retail competition in general. "Retail competition" not only includes retail choice, but also includes electricity or electricity substitutes available to consumers *through sources other than the power system*. These alternatives include self-generation such as solar panels, energy efficiency measures such as more efficient motors and better insulation, and other energy sources such as natural gas for heating. Some forms of retail competition are occurring in almost all states regardless of the status of retail choice. Such competition has been stimulated by a variety of factors including falling natural gas prices, renewable portfolio standards, net metering policies, and tax and other incentives to electricity customers to adopt renewable energy technologies like rooftop solar.

1.3. Organization of This Report

The first sections of this report are descriptive. Section 2 summarizes the current status of retail choice, with an emphasis on the U.S. and an overview of some other nations' policies and retail market structures. Section 3 describes the major technological and institutional factors that have driven the movement toward retail choice. Section 4 briefly reviews the history of how those technological and institutional factors have in fact induced states to adopt or choose not to adopt a retail choice policy. Section 5 identifies the technical and institutional factors that must be addressed by those jurisdictions that adopt retail choice.

Section 6 looks at what reliability agency reports, government agency reports and data, industry organization reports, and industry and academic literature tell us about the impacts of retail choice on customer service, power system costs, electricity market efficiency, retail electricity prices, power system resource adequacy, the division of financial risks among stakeholders, particular demographic groups, and electricity sector regulation. Section 7 interprets the analyses and data of Section 6, drawing inferences about how the actual net benefits of retail choice compare to the promised benefits, and offers suggestions for future public policy.

2. CURRENT STATUS OF RETAIL CHOICE

This section provides a brief overview of the status of retail choice in the U.S. and elsewhere.

2.1. Status in the U.S.

Retail competition comes in two forms. First, customers can choose the entity that provides them with electrical energy through the traditional power network, which we call "retail choice." Second, customers can procure part or all of their electrical energy through energy alternatives available to consumers through sources other than the power system. In this section, after looking at the status of retail choice, we look at one prominent energy alternative, namely self-generated solar power through rooftop photovoltaics.

2.1.1. Retail Choice

Nearly half the states have allowed competitive suppliers to supply electrical energy and other services to retail electricity consumers through the power network, though several of them have suspended or rescinded this form of retail competition. Figure 1 shows the present state-by-state status of retail choice. The fifteen green jurisdictions have retail choice, the eight red states have suspended or rescinded retail choice, and the white states never pursued retail choice. Four of the states that suspended or rescinded retail choice (California, Nevada, Oregon, and Virginia) still allow large industrial customers and some commercial customers to choose their suppliers.

Figure 1
Status of Retail Choice[3,4]

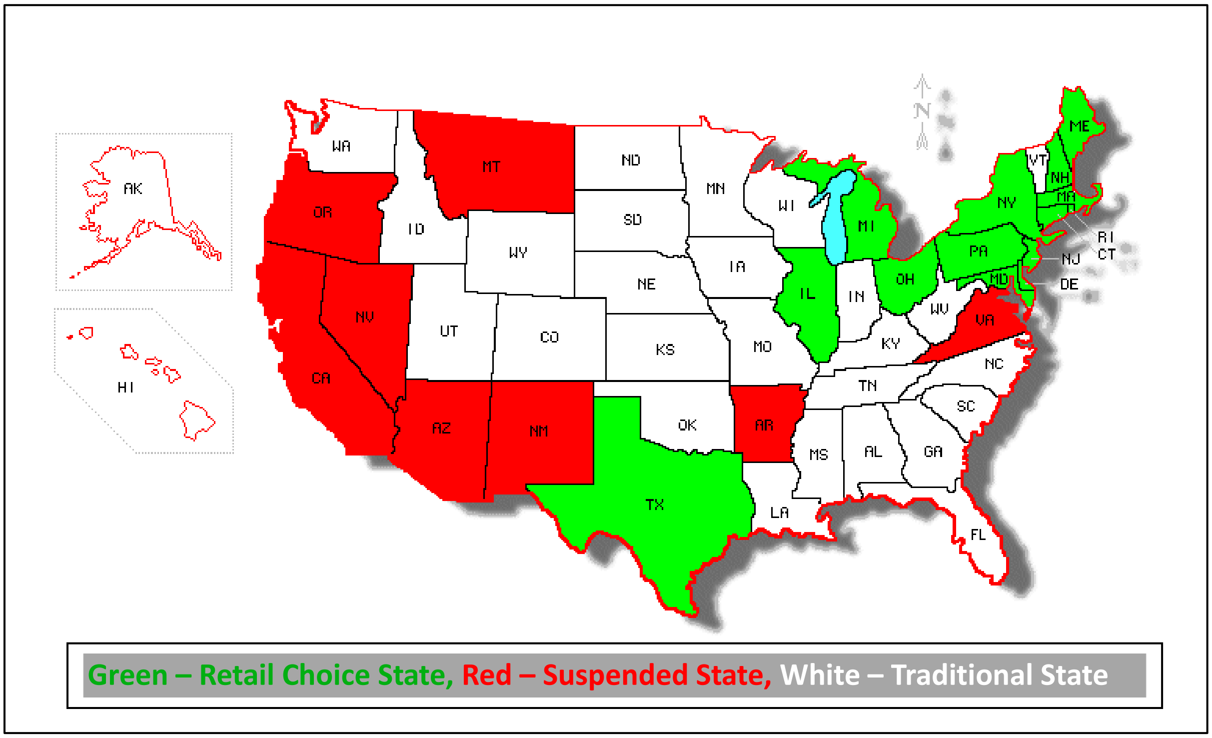

Figure 2 shows the extent to which retail customers have switched to competitive suppliers in sixteen states and the District of Columbia as of 2014. Shares are relative to total MWh sales for each class in each state. Of the seventeen jurisdictions shown in the figure, retail energy suppliers sold a majority of industrial load in eleven states and a majority of commercial load in eight states. As simple unweighted averages, 58% of industrial load, 44% of commercial load, and 7% of residential load in the seventeen jurisdictions have switched to competitive suppliers. The District had the highest switching rates for industrial customers (100%) and commercial customers (85%). While Texas had the highest switching rate (about 60%) for residential customers because the state requires retail choice program participation by all customers served by investor-owned utilities in the footprint of the Electric Reliability Council of Texas, Connecticut has the highest switching rate for residential customers (29%) among the

[3] Figure 1 is based on a composite of information from Belmont Electricity Supply Study Committee [2004, p. 19], http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html, and U.S. Energy Information Administration [2003, p. 3].

[4] The division among states is not entirely unambiguous. Georgia, which is denoted as lacking retail choice, nonetheless allows retail choice for customers with more than 900 kW of load. Michigan, which is denoted as having retail choice, caps allowable sales by non-utility suppliers at 10% of each utility's previous year's sales. Arizona, Oregon, and Virginia, which are denoted as having suspended retail choice, nonetheless permit retail choice for certain large electricity customers; and Virginia allows retail choice for residential customers seeking 100% renewable energy if the local utility does not provide that option.

states that lack such a mandate. Overall, 16% of the total electrical energy sold in the U.S. in 2014 was sold by competitive retail energy suppliers.

Figure 2
Competitive Retail Energy Suppliers' Retail Sales as Shares of Total MWh Sales, 2014[5]

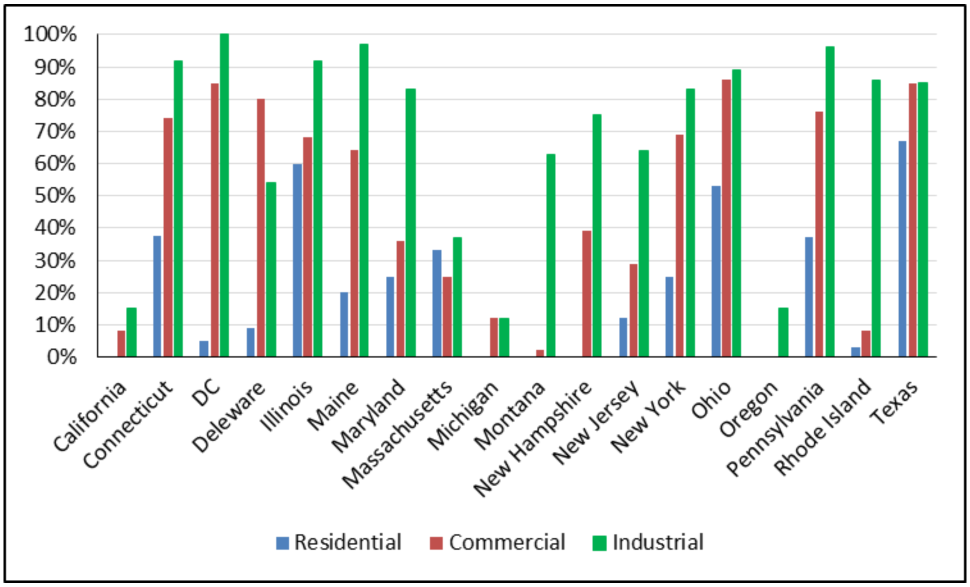

Figure 3 shows the extent to which residential customers have switched to competitive suppliers, though in this figure switching shares are measured according to *numbers of eligible customers* rather than according to *MWh sales*. For the fourteen jurisdictions shown in the figure, 44% of 37.8 million eligible customers took service from competitive suppliers in 2014. Only Illinois, Ohio, and Texas had majorities of residential customers taking service from competitive suppliers. Excluding Texas, which skews the results because all its eligible customers are required to shop, a more modest but still impressive 33% of eligible customers switched.

For all fourteen jurisdictions shown in the figure, the aggregate number of customers taking competitive supply fell 1.2% between 2013 and 2014, with half the states showing gains in numbers of switching customers and half showing losses. Of the fourteen jurisdictions, eleven rely primarily upon direct transactions between consumers and suppliers, while three rely primarily upon municipal aggregators.

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[5] Sales shares are based on the most recently available state migration statistics obtained from state public utility commission websites for calendar years close to 2014. Data for Montana are based on U.S. Energy Information Administration [2012].

Figure 3
Residential Customers Taking Competitive Electric Service as Shares of Eligible Customers, 2014[6]

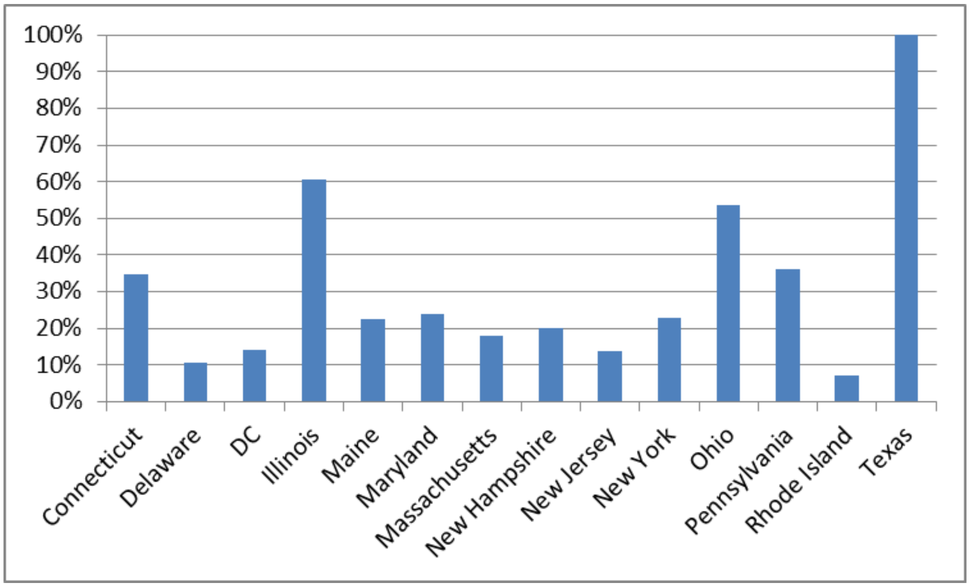


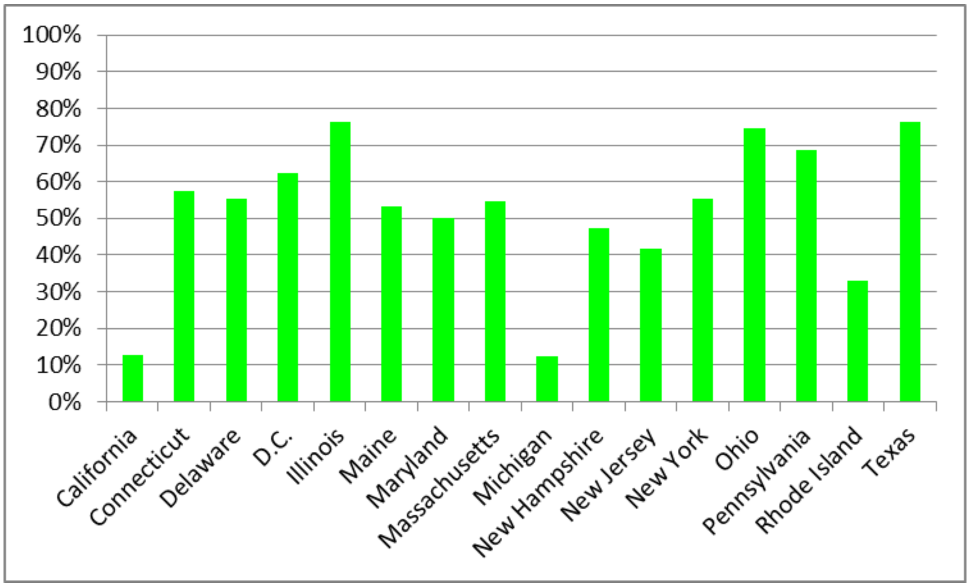
Figure 4 shows the extent to which commercial and industrial customers have switched to competitive suppliers, where the percentages, somewhat strangely, are "Percent of total jurisdictional sales, including the residential sector."[7] In this figure, switching includes only those loads that customers have chosen to take from entities other than the incumbent utility. The simple average switching rate is 52%, with Illinois, Ohio, and Texas again taking the lead. California and Michigan place limits on the extent of switching, which partly explains their relatively low percentages.

Customer size is the main reason that residential customers have adopted retail choice at much lower rates than commercial and industrial customers. The gross benefits of switching suppliers are roughly proportional to a customer's size. For a business, these benefits can be large enough to warrant spending staff time investigating electricity supplier options, and even large enough to justify having some staff dedicated to managing energy consumption decisions. For a residential consumer, by contrast, the gross benefits warrant only minimal consideration of options. Furthermore, businesses have abilities to manage information and financial risks in ways that are generally unavailable to residential consumers; so risk aversion will quite rationally induce residential consumers to stick with their low-risk incumbent supplier to a greater extent than it will so affect businesses.

[6] Distributed Energy Financial Group [2015, Table ES-1].

[7] Distributed Energy Financial Group [2015, Table ES-3].

Figure 4
Percent of Eligible Commercial & Industrial Loads Taking Competitive Electric Service from Non-Incumbent Providers, 2014[8]



To some extent, competition has been discouraged by the ways in which some states have required utilities to offer provider-of-last resort (POLR) service. This requirement has been intended to protect consumers by assuring that they can obtain electricity from incumbent utilities at reasonable prices. In addition to protecting consumers, however, state-mandated ceilings on POLR service prices also interfere with the establishment of retail prices that accurately reflect power system costs and reduce the profitability of offering competing retail electricity services.[9]

2.1.2. Retail Competition Through Rooftop Photovoltaics

Residential rooftop solar has successfully competed for a growing share of residential electricity consumption in recent years. Figure 5 shows that photovoltaic installations in general have skyrocketed in the U.S. over the past few years, in terms of both numbers and MW. Utility installations have been the majority of these installations, but residential and non-residential installations have increased rapidly as well.

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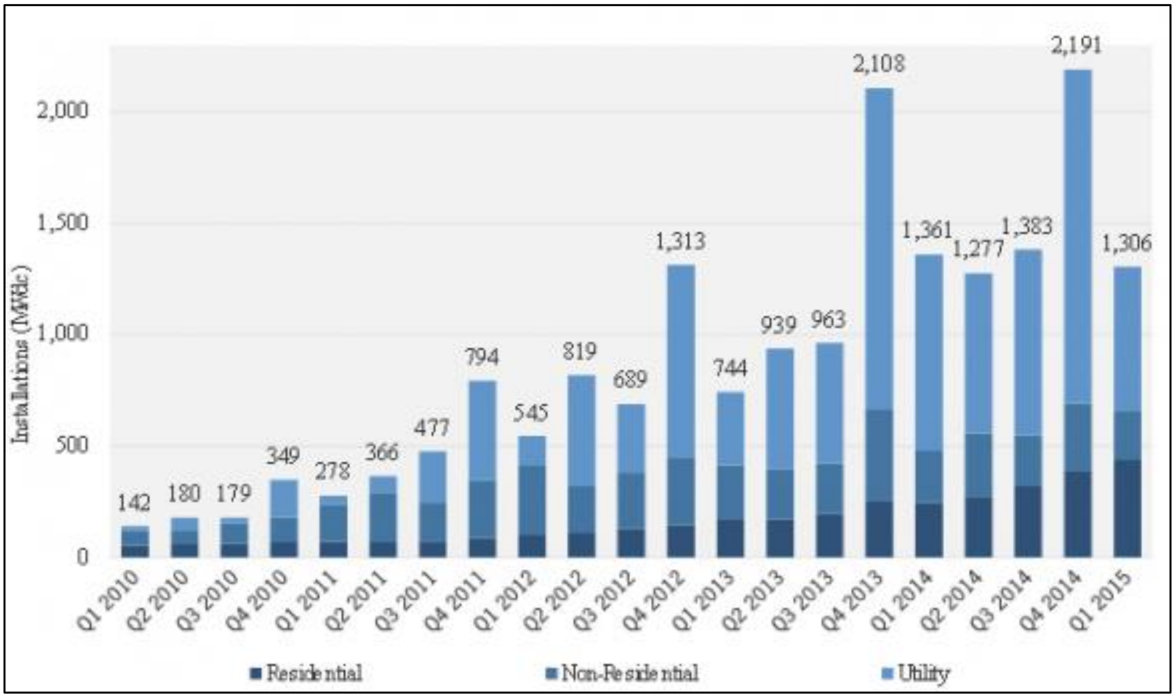
[8] Distributed Energy Financial Group [2015, Table ES-3].

[9] Electric Energy Market Competition Task Force [2006, p. 6].

Figure 5
U.S. Photovoltaic Installations, Q1 2010-Q1 2015[10]



The growth in residential installations has been fueled by third-party financing of rooftop solar, which has accounted for 72% of such installations in some jurisdictions in 2014.[11] There are two types of such financing.[12] Under both types of financing, the developer builds the solar facility on the customer's property, covers specified costs (e.g., design, permitting, installation, and maintenance), and owns the facility for a period of up to twenty years. The customer's payments to the developer, however, depend upon the type of financing.

- *Under a power purchase agreement*, there is no up-front cost to the customer, and the customer pays specified prices for energy consumed from the solar facility.
- *Under a traditional lease agreement*, there may or may not be an up-front cost to the customer, and the customer pays a monthly fee that is independent of energy consumed.

Under either type of financing, there will be some agreement regarding the customer taking over ownership after some period of time, perhaps for a buyout payment. The developer not

[10] Munsell [2015b].

[11] Munsell [2015a]. This source indicates that, in 2014, the leading companies in the U.S. residential solar installation market were SolarCity (34%), Vivint Solar (12%), and Sunrun (10%).

[12] Solar Energy Industries Association and U.S. Energy Information Administration [2013].

only receives revenue from the customers, but also receives substantial tax benefits as owner of the installation.

At least twenty-six states and the District of Columbia allow power purchase agreements, while seven states prohibit it.[13] Similar numbers allow and prohibit traditional lease agreements.[14]

The economics of residential solar installations primarily depend upon three factors. First and foremost, they depend upon tax incentives. The federal investment tax credit is critical, as it accounts for 40% to 50% of developers' net profit on residential solar installations. State incentives are also critical: of the ten jurisdictions with the highest rates of return on residential solar, only one (California) remains in the top ten without its state incentives. Second, the economics of residential solar depend upon retail electricity prices. When tax incentives are removed, the jurisdictions with the ten highest rates of return have residential electricity rates that average 42% higher than those of the second ten jurisdictions, even though their solar output is virtually identical. Third, residential solar economics depends upon the availability and characteristics of state net metering programs. Net metering policies, which are presently in place in forty-one states plus the District of Columbia,[15] have customers pay utilities for the electricity they consume net of the electricity that they produce. Net metering in effect pays customers not only for the electrical energy that they provide but also delivery and customer services that they do not provide, but instead use. The consequence is that the delivery and customer service costs of residential customers with solar power are heavily subsidized by customers without solar power. Somewhat ironically, solar irradiance – that is, how much the sun shines in a particular place – is a lesser factor in determining the profitability of investment in residential photovoltaic installations, even though it is a critical factor in determining how much electricity is actually produced.[16] The consequences of these tax and regulatory subsidies are inefficiently high investment in costly solar facilities and distortion of retail electricity prices.

2.2. Status Elsewhere

Liberalization of electricity markets began with Australia, Chile, and the United Kingdom in the 1980s, and reached the European Union (EU) in the 1990s.[17] As shown in Table 1, New Zealand was the first country to achieve full opening of its retail markets in which consumers have the right to choose their retailer suppliers. Nonetheless, the table shows that full retail market openings have occurred primarily in EU countries, with a smattering of other developed

[13] Database of State Incentives for Renewables & Efficiency [2016a].

[14] https://solarpowerrocks.com/solar-lease-map/.

[15] Database of State Incentives for Renewables & Efficiency [2016b].

[16] UBS [2015].

[17] In the EU, market liberalization has been implemented through three directives, the first of which, adopted in 1996, mandated open access to transmission and distribution networks, allowed customers to change suppliers, and promoted independent regulatory agencies. See European Commission [2012].

countries participating. In the U.S., only Maine (in 2000) and Texas (in 2002) have achieved comparable market liberalizations.

Table 1
Years of Full Retail Market Opening[18]

Country	Year
Australia	2002
Austria	2001
Belgium	2007
Czech Republic	2006
Denmark	2003
Finland	1998
France	2007
Germany	1998
Greece	2007
Hungary	2000
Ireland	2000

Country	Year
Italy	2002
Korea	2001
Netherlands	2001
New Zealand	1994
Norway	1997
Poland	2007
Portugal	2006
Spain	2003
Sweden	1996
Turkey	2003
United Kingdom	1999

Retail electricity market liberalization is different in different places. In several countries listed in Table 1, the transition to liberalized electricity sectors was preceded by state ownership of power systems and then followed by their privatization, with significant implications for the differing ways in which retail choice has been implemented. Furthermore, the extent and terms of retail choice often vary among the jurisdictions within a country.[19]

Table 2 summarizes the extent of competition in each of the member states of the EU in terms of the numbers of "main suppliers" with market shares of at least 5%, the market shares of those suppliers, and the market share of the largest supplier in 2010. The table divides EU member states into categories that reflect inferred values for the Herfindahl-Hirschman Index (HHI) of market concentration.[20] Only four member states have unconcentrated markets, and another four have moderately concentrated markets. These eight countries arguably have real retail choice options. Another seven member states have highly concentrated markets, which means that retail choice is limited at best. The last twelve countries basically have monopolies, meaning that retail choice is not offered or is offered in name only.

According to one source:

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[18] Cook [2011, pp. 22-23].

[19] See, for example, London Economics [2012, p. 33].

[20] The table follows the U.S. Department of Justice and Federal Trade Commission Horizontal Merger Guidelines § 5.2 (2010) in using an HHI value of 1,000 to separate "unconcentrated" from "moderately concentrated" markets; but it uses the relatively high HHI value of 2,500 to separate "moderately concentrated" from "highly concentrated" markets.

> …the moderately concentrated electricity retail markets of Denmark, Finland, Germany, Great Britain, Italy, the Netherlands and Norway perform relatively well, judged on the basis of key competition performance indicators (e.g. choice of suppliers and offers; switching rates; entry-exit activity; consumers' experiences; mark-up etc.)… Retail competition performance indicators show no or weak signs of competition in MSs [member states] with highly concentrated markets at the national level: in electricity in Bulgaria, Cyprus, Hungary, Latvia, Lithuania, Malta and Romania… According to a data sample based on offers in the capital cities, the electricity and gas markets of Germany, Great Britain, Denmark and the Netherlands are the relative best performers in relation to the number of offers and suppliers providing diversified products for electricity and gas consumers, such as the type of energy pricing, green offers, additional free services and/or dual fuel offers.[21]

The numbers of retailers in each country – and consequently, market concentration – vary over time. For example, large drops in numbers of retailers have been experienced in Denmark (from 113 retailers to 49) and Spain (from 375 to 162), both drops occurring mainly when retail markets were opened to residential customers.[22] Apparently, industry consolidation was induced by the relatively high costs of reaching large numbers of small customers. On the other hand, increases in numbers of retailers have occurred in other countries, like Germany, Italy, and the United Kingdom. More generally, in many countries (including some of those just named), numbers of retailers have risen and fallen over time.

Although the large numbers of retailers in some EU states suggests that retail markets are fragmented, Table 2 shows that all EU markets are, in fact, dominated by no more than eight main suppliers. Apparently, there is a large fringe of small suppliers in many EU states; and although the numbers of these small suppliers vary considerably over time, the numbers of main suppliers are fairly stable.

Customer switching behavior in the EU seems to be related to the degree of competition. In the United Kingdom, the retail energy market (both electric and gas) has an impressively high annual switching rate of 18%, with almost all consumers being aware of the right to change energy suppliers.[23] On the other hand, countries with weak competition have little product and price differentiation and therefore little inducement for consumers to seek new suppliers. The continuation of retail price regulation further discourages competition and switching.[24]

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[21] Agency for the Cooperation of Energy Regulators and Council of European Energy Regulators [2014, p. 9]. ACER/CEER's characterization of Italy as "moderately concentrated" is belied by its largest supplier having 85% of the market.

[22] Rathke [2015].

[23] Karan and Kazdagli [2011, p. 16].

[24] Agency for the Cooperation of Energy Regulators and Council of European Energy Regulators [2014, pp. 6-7].

Table 2
Competition in Retail Electricity Service in the European Union, 2010[25]

Member State	# of Main Suppliers	Mkt Share of Main Suppliers	Mkt Share of Largest Supplier
Unconcentrated Markets:			
Austria	8	69%	17%
Finland	4	45%	17%
Germany	3	25%	14%
Sweden	3	45%	19%
Moderately Concentrated:			
Denmark	3	59%	46%
Netherlands	4	79%	32%
Slovenia	5	99%	36%
United Kingdom	6	85%	24%
Highly Concentrated:			
Belgium	4	89%	61%
Czech Republic	3	87%	52%
Hungary	4	99%	45%
Ireland	3	98%	60%
Luxembourg	2	85%	68%
Slovakia	4	98%	35%
Spain	3	92%	41%
National or Regional Monopolies (RM):			
Bulgaria	3	100%	RM
Cypress	1	100%	100%
Estonia	1	94%	94%
France	1	92%	92%
Greece	1	100%	100%
Italy	1	85%	85%
Latvia	1	99%	99%
Lithuania	2	94%	RM
Malta	1	100%	100%
Poland	6	88%	RM
Portugal	1	93%	93%
Romania	4	100%	RM

[25] ECME Consortium [2010].

Although the EU mandated retail choice as a means of breaking up monopolies and improving the efficiency of the electricity sector, the various member states have chosen different methods for implementing retail choice, yielding a diversity of outcomes. The result is that only eight of the EU's twenty-seven member states have real retail choice options. It is notable that these eight countries tend to be wealthier EU members, and that the twelve countries that have maintained monopolies tend to be poorer EU members. Breaking up old monopolies thus appears to be a luxury that is easier for the wealthy to afford.

3. DRIVERS OF RETAIL CHOICE

At the height of the restructuring movement in the 1990s in the U.S., industrial electricity consumers led the charge for retail choice, primarily in the hope that it would provide them with opportunities to get lower electricity prices, secondarily in the hope that they could negotiate terms of service that would better be tailored to their needs. In this effort, industrial customers were supported by entities, most notoriously Enron but also including many utilities, that hoped to profit by selling into or trading in newly deregulated wholesale and retail electricity markets.

For example, John Anderson, executive director of the Electricity Consumers Resource Council, an industrial electric consumers' lobbying group, expected lower prices for his members:

> We think competition in any industry brings about not only lower prices but also increased innovation and technological stimulation.[26]

Steve Burton, President of the Electric Power Supply Association and of Sithe Energies, an independent power producer (IPP), foresaw lower prices and more services:

> Consumers will have choice as well as lower prices… They will be able to choose the type of service they want, how they want it delivered, and there will be a wider range of services.[27]

Another group of IPPs also foresaw low prices and innovation:

> Consumers will benefit. According to the US Energy Information Administration, the average price of electricity is projected to decline by one percent a year between 1996 and 2020 as the result of competition among electricity suppliers. As retail competition becomes more widespread and more customers throughout the country are allowed to choose their power suppliers, these suppliers can be expected to work harder and smarter to keep prices down, attract and retain customers, and provide better service. More than 70 percent of consumers surveyed by the Americans for Affordable Electricity, a coalition that supports giving customers the power to choose their electricity supplier, said they would prefer to have a choice when buying electricity.[28]

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[26] Jost [1997].

[27] Jost [1997].

[28] Competitive Power Supply Industry [2000, p. 10].

The Chairman of the nation's largest power trading firm was able to put a number on the benefits that consumers would enjoy:

> Enron's chairman, Kenneth L. Lay, says that consumers could save $60 billion-$80 billion per year if the electric power market were completely opened to competition.[29]

The extent to which these hopes were realized is the topic of Section 6 of this report. The present section focuses on the benefits of retail choice that were expected by the advocates of retail choice as restructuring was initiated. We divide these benefits into three categories: reducing retail electricity prices; offering customers a wider range of choices in service conditions; and promoting alternative resource technologies.

3.1. Reducing Retail Electricity Prices

The movement toward retail choice was partly driven by the hope that competition would result in retail electricity prices that are lower than they would otherwise be. Indeed, as later described in Section 4, the states with retail choice are generally those that had relatively high retail prices in the late 1990s, when restructuring activity was at its peak. The hope for lower prices was partly based upon the expectation that competition would drive improvements in the efficiency of electricity production and delivery, but was also driven by consumer groups hoping to capture economic rents from utility shareholders.

3.1.1. Price Reductions Due to Efficiency Improvements

In theory, retail choice can potentially lead to efficiency improvements in the provision of generation services and in retail electricity prices themselves.

With respect to improving generation services, competition in the provision of retail services may enhance the competitive positions of non-utility generators by expanding the market opportunities for these generators' services.[30] Such opportunities might increase the market shares of those generation firms that are most efficient, ultimately resulting in lower costs of providing electricity to final customers. These potential benefits of retail choice are different and much smaller than the benefits of wholesale competition, which has led to significant improvements in the commitment and dispatch of generation and transmission resources in regions with balkanized resource ownership. Nonetheless, retail choice may provide benefits that complement those of wholesale competition.

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[29] Jost [1997].

[30] Borenstein and Bushnell [2015b, p. 4] note that "a merchant generator would be in a very weak position if there were only one retail electricity provider to which it could sell its output. A monopoly retail provider (a distribution utility) could still engage in competitive procurement, but that creates a narrower spectrum for competitive generation and it means that the monopoly retailer is the single determinant of the range of products that might be procured for retail. For instance, the monopoly retailer might not pursue low-carbon sources even if there are many retail customers who would be willing to pay a premium for greener energy. Thus, retail competition potentially makes competitive generation more viable."

With respect to improvements in electricity prices, retail choice may drive retail prices toward the market's marginal costs. Utilities' retail electricity prices have traditionally been determined according to the average costs of the generation, transmission, distribution, and customer services that are required to produce electricity and deliver it to customers. These average cost-based cost-of-service rates partly depend upon the quality of utility management and partly upon the legacy of past cost commitments, such as decisions to build particular types of power plants or to commit to particular long-term fuel supplies. In a market setting, by contrast, the retail prices of electricity services subject to competition, particularly generation services like electrical energy, may move closer to the market's marginal costs of these services. These marginal costs are the costs of obtaining new supplies of these services, given current technologies and input prices, and are not dependent upon legacy costs. Retail prices based upon marginal costs could encourage customers to consume more power when power supplies are relatively abundant and to consume less power when power supplies are relatively scarce. This better match between retail prices and wholesale market conditions may improve resource adequacy through peak load reduction and may reduce the average costs of providing power to consumers, which could ultimately result in lower retail prices.

Utilities have long recognized the benefits of retail prices that reflect marginal costs. Consequently, they have offered time-of-use rates since the 1970s, real-time pricing rates since the 1980s, and other dynamic pricing programs in more recent years. Retail choice may potentially further this movement toward more efficient retail pricing.

Regardless of whether retail choice makes prices more efficient, it is likely to change the relative prices paid by different customer groups. As just noted, retail choice may move prices away from a cost-of-service basis toward short-run marginal costs. But it may also change the relative bargaining power of different customer groups. Under regulation, utilities' retail electricity prices have traditionally reflected not only their average costs of service but also the relative political power of different groups of electricity consumers. Under retail choice, prices will be influenced by the relative economic power of different customer groups, with relatively mobile customers or relatively large customers able to negotiate price discounts that are not available to less mobile or smaller customers.

3.1.2. Price Reductions Due to Capture of Economic Rents

Sometimes the marginal costs of generation services are lower than utilities' average costs, and sometimes they are higher. Marginal costs are higher than average costs during periods of high inflation, when the capital costs, fuel costs, and other operating costs of generators are higher than expected. Marginal costs are lower than average costs during periods of low inflation or when technological advances are greater than expected.

During years when marginal costs are lower than average costs, there is political pressure to open electricity markets to competition so that consumers can obtain lower-priced electricity. At such times, retail choice allows non-utility suppliers to attract customers away from utilities. During years when marginal costs are higher than average costs, by contrast, there is little or no political pressure to open electricity markets to competition, as customers prefer utilities' prices to those that would be available from the market.[31]

3.2. Wider Customer Choice in Service Conditions

In principle, competition can result in customers having a wider range of retail electricity products than is traditionally available, and can result in lower retail prices. Retail products can be differentiated along several dimensions, including the following:

- *Energy source*. The consumer can choose to buy electricity produced by renewable resources rather than by fossil or nuclear fuel.
- *Firmness of service*. Service can be guaranteed under all conditions (aside from transmission and distribution deliverability problems) or only some conditions. If the provider can curtail service, curtailments may or may not be limited by wholesale electricity market conditions, or by limitations on the required notice, frequency, and duration of interruptions.
- *Variability of price over time*. Price can be identical (fixed) in all time periods, or can vary by season, by peak or off-peak periods, or by hour.
- *Duration of price guarantee*. Price can be guaranteed for specific time periods, such as one year or five years.
- *Degree of price guarantee*. Price can be guaranteed for all wholesale electricity market conditions or for only some market conditions.
- *Flexibility of allowable consumption of electricity*. Price can be guaranteed for all or part of a customer's consumption. For consumption in excess of a subscribed quantity, price can be set according to wholesale electricity market conditions or to some formula.
- *Billing and payment arrangements*. Customers may be offered choices about the timing and frequency of billings. Customers may be offered flexible payment plans that do not require prompt payment of each month's bills, but spread payments over time.
- *Bundling of electricity and complementary products*. Customers may be offered special deals for energy efficiency services (i.e., home inspection or insulation) and for electricity-consuming equipment purchases or maintenance.
- *Additional incentives*. Customers may be offered "free" goodies like airline miles.

Utilities have long differentiated their retail products along many of the foregoing dimensions. Retail choice may potentially further such product differentiation.

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[31] Consistent with the text, Borenstein and Bushnell [2015b, p. 1] say "the greatest political motivation for restructuring [in the 1990s] was rent shifting, not efficiency improvements, and… this explanation is supported by observed waxing and waning of political enthusiasm for electricity reform." Borenstein and Bushnell [2015b, p. 2] say "Average cost is the basis for price setting under regulation, while marginal cost is the basis for pricing in a competitive market. During periods in which these two costs have diverged, consumer and political sentiment has tilted toward whichever regime (regulation or markets) offered the lowest prices at that time."

3.3. Promoting Alternative Resource Technologies

Retail choice allows competition in the promotion of "green power" that is generated by environmentally benign resources, of energy efficiency and management systems for homes and businesses, and of self-generation. Such resources may reduce the costs of electricity production, may facilitate a transition toward less-polluting renewable energy, and, when placed at some locations within a distribution system, may improve the reliability of local power systems.

Retail choice may be particularly compatible with the development of market-driven investment in distributed energy resources (DER). Although much of the substantial growth in DER over recent years has been due to tax subsidies, net metering subsidies, and renewable portfolio mandates, retail choice could foster market-driven growth in DER. First, retail choice can allow retail energy suppliers to offer DER as part of their portfolio of services. Second, retail choice can foster the unbundling of transmission and distribution wires service cost recovery from generation and customer service cost recovery, which could mitigate some of the inefficient cross-subsidies inherent in present retail electricity prices.

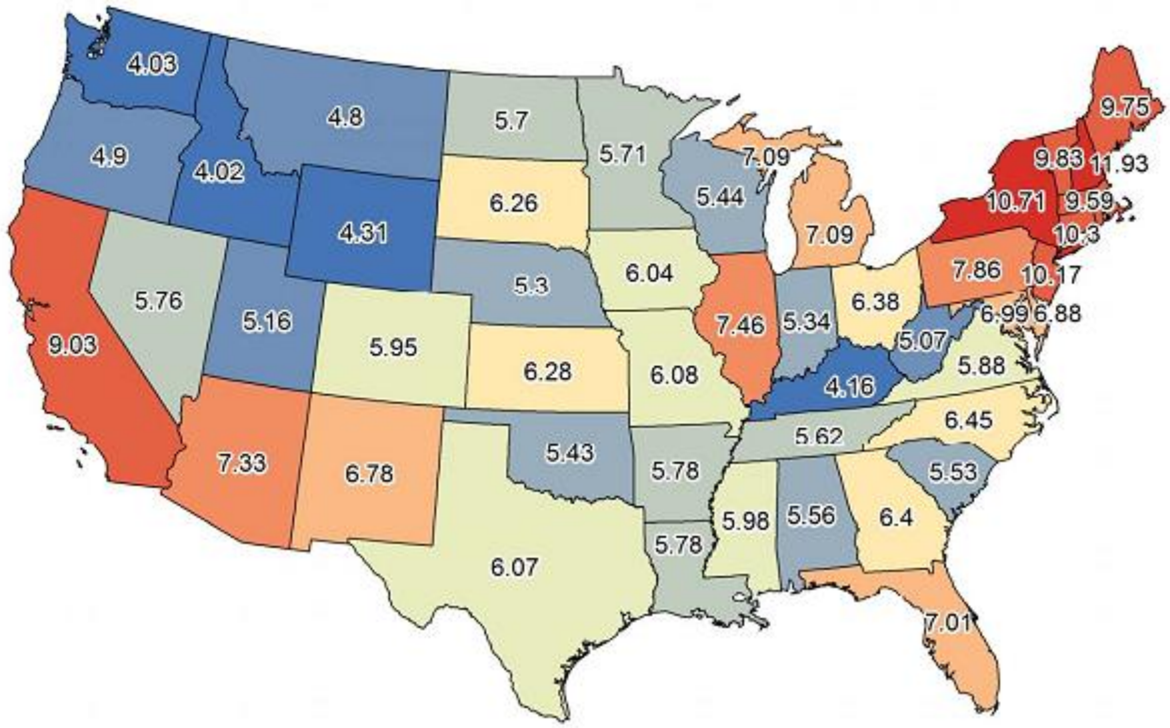
Thus, at least in theory, there are potential benefits to be gained from retail choice. But there are real questions about whether or not retail choice has lived up to its expectations, which is the subject of this study.

4. HISTORY OF RETAIL CHOICE IN THE U.S.

During the 1980s and 1990s, a confluence of factors undermined confidence in utility planning and cost-of-service regulation. These factors – including massive cost overruns on utilities' nuclear plant investments, falling costs of gas-fired generation technologies, and certain efficiency improvements fostered by IPPs – led to high retail electricity prices in several states and fostered the passage of the Energy Policy Act of 1992 at the federal level. This Act, together with supporting actions by the Federal Energy Regulatory Commission (FERC), opened wholesale electricity markets to competition and thus paved the way for competition at the retail level as well.

Figure 6 shows state-by-state average retail prices in 1998. Bluer states had lower prices, while redder states had higher prices. Comparing this map to the map of retail choice states shown in Figure 1, it is apparent that the states with retail choice are generally those that had relatively high retail prices when restructuring activity was at its peak. High retail prices, coupled with the hope that retail choice would help drive these prices down, were clearly a major reason for opening electricity markets to competition in most states wherein such an opening occurred.

Figure 6
Average Retail Prices by State, 1998 (cents per kWh)[32]



In the years 1996 through 2001, twenty-two states and the District of Columbia directed regulated utilities to prepare to open their retail markets through either legislative or regulatory action. These moves toward retail choice began in 1996, coincident with FERC's issuance of Order No. 888, which promoted non-discriminatory access to transmission facilities and thus promoted competition at the wholesale level.[33] The movement toward retail choice came to a sudden halt in 2001, when the Western power crisis made it clear that there were fundamental problems with the manner in which electricity sector restructuring had been implemented in some regions. The suspensions were also motivated by the bankruptcies of several merchant generating and trading companies; shrinking retail supply options; fraudulent trading, price reporting, and accounting practices by merchant firms; unanticipated high wholesale market price volatility; and rising retail electricity prices. Not coincidentally, the years 2000 and 2001 saw the first average real retail electricity price increases in the U.S. in fifteen years.

Table 3 lists the jurisdictions in which legislative or regulatory action promoted retail choice. The "Year Initiated" columns show the years in which such legislative or regulatory action began the retail market opening in each of twenty-three jurisdictions. The "Year Suspended"

[32] Borenstein and Bushnell [2015a], slide 5.

[33] U.S. Federal Energy Regulatory Commission [1996].

columns show the years in which eight states suspended or rescinded retail choice, though four of these states (California, Nevada, Oregon, and Virginia) still allow large industrial customers to shop. The table shows that the year 2001 was the sharp dividing line between actions initiating retail choice and actions suspending retail choice.

Table 3
Timing of State Retail Choice Initiation and Suspension[34]

Jurisdiction	Year Initiated/Year of Access for Residential Customers	Year Suspended or Legislation Repealed
Arkansas	1999/2003	2003
Arizona	1998/1998	2004
California	1996/1998	2001
Connecticut	1998/2000	
District of Columbia	2000/2001	
Delaware	1999/2000	
Illinois	1997/2002	
Massachusetts	1997/1998	
Maryland	1999/2000	
Maine	1997/2000	
Michigan	1999/2002	
Montana	1997	2002/2003

Jurisdiction	Year Initiated/Year of Access for Residential Customers	Year Suspended or Legislation Repealed
New Hampshire	1996/2001	
New Jersey	1997/1999	
New Mexico	1999/2007	2003
New York	1996/2001	
Nevada	1997	2001
Ohio	1999/2001	
Oregon	1999	2002
Pennsylvania	1996/1999	
Rhode Island	1996/1997	
Texas	1999/2001	
Virginia	1999/2004	2007

Realizing that transaction costs would be lowest for sales to large industrial electricity consumers, most states opting for retail choice implemented a phased approach to market opening – with the largest customers becoming eligible first – and required incumbent utilities to offer default (standard offer) service and POLR service for those customers who did not want to shop or whose retail energy supplier went bankrupt. To protect consumers from financially weak suppliers, most states required retail energy suppliers to obtain licenses for which they must offer evidence of financial soundness. A few states also required surety bonds or letters of credit from suppliers.

[34] Table 3 is based upon a composite of information from Belmont Electricity Supply Study Committee [2004, p. 19], http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html, and U.S. Energy Information Administration [2003, p. 3].

5. CHALLENGES IN IMPLEMENTING RETAIL CHOICE

There are both technical and institutional challenges to implementing retail choice. This section describes these challenges and the ways that states have striven to meet them.

5.1. Restructuring of Utility Organizations

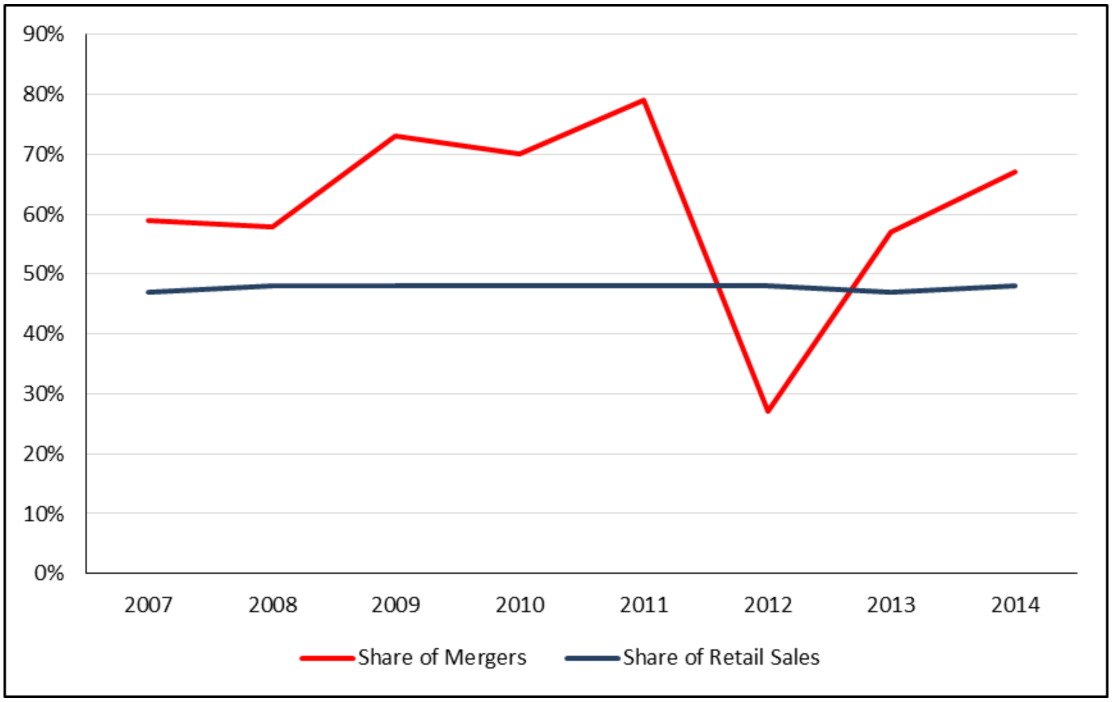
Retail choice in generation services requires that there be competition in generation services. Under the normal circumstance that a state's electricity service is provided by vertically integrated utilities, retail choice requires functional unbundling of utilities' generation function (and perhaps customer service function) from its distribution and transmission functions. Virtually all states that implemented retail choice required vertically integrated utilities to undertake such separation. Depending upon the state, separations have been accomplished through various combinations of functional unbundling of generation and customer services, spinning off generation assets to affiliates, and divestiture of generation assets.

In combination with wholesale market restructurings, retail choice has also induced revisions of longstanding reserve pooling arrangements and may have added to merger incentives. Although wholesale market restructurings were sufficient to induce mergers to gain scale economies in generation, retail choice provides additional merger incentives both to gain scale economies in retail marketing and maintain market share and (perhaps) market power.

During the years 2007 through 2014, 49% of retail choice states had utilities undergo consolidation via merger, while such consolidation occurred in only 10% of the non-retail choice states.[35] More specifically, the red line in Figure 7 shows that, from 2007 through 2014, merger activity in retail choice states ranged from a low of 27% of all electric industry mergers (2012) to a high of 79% of all electric industry mergers (2011), and averaged 61%. The dashed blue line shows that retail choice states have accounted for about 48% of sales during this whole period, so mergers have occurred to a disproportionate extent in retail choice states. While consolidation of the electric utility industry has been underway for several decades, it would seem that the restructuring of retail markets has recently been one of the drivers of that consolidation.

[35] Sonenshine [2015].

Figure 7
Shares of Electric Industry Mergers and Sales in Retail Choice States, 2007-2014[36]



5.2. Adaptation of Utility Power Operations

Retail choice must be accompanied by integration, into power system operations, of the resources that provide energy to customers. RTOs accomplish such integration on behalf of utilities that are located within RTO footprints. Utilities that are not located within RTO footprints must adapt their planning and operations to accommodate third-party resources.

5.3. Adaptation of Utility Administrative Operations

Retail choice requires that billing procedures be adapted so that appropriate shares of customer payments go to the utility (for non-competitive services) and to third-party retail suppliers (for competitive services). This can be accomplished either through separate billings by utilities and third-party retail suppliers or through the utility acting as billing agent on behalf of both itself and third-party retail suppliers.

Retail choice also requires metering that is compatible with new retail service offerings. For some utilities, the needed metering may already be in place to meet the utilities' own needs. For other utilities, it may be necessary to install meters with finer time differentiation (e.g., hourly), with peak demand metering, and/or with two-way flow measurement (e.g., for self-generation).

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[36] Sonenshine [2015] and U.S. Energy Information Administration [Form EIA-861].

5.4. Institutional Challenges

Each of the states that adopted open access retail markets faced some common policy challenges, which can be summarized as falling into the following categories:

- *Timing of retail choice*. Some states granted retail choice to all customer classes at the same time; but a few granted retail choice to larger customers before smaller customers, which allowed potential suppliers to ramp up their competitive efforts. In some states, retail choice for residential and commercial customers was delayed several years until the end of state-mandated controls on utilities' retail rates.
- *Retail rate controls*. Nearly all retail choice states improved the initial appeal of retail choice by mandating reductions in utilities' prices for captive retail customers; and many of these states also imposed rate freezes for a few years or placed caps on retail prices. Although these rate controls gave consumers immediate rate relief or insulated them from volatile wholesale market prices, they had the adverse effects of stifling potential competitors' ability to compete, impairing utility finances, and damaging market processes by imposing a substantial barrier between the supply and demand sides of the market.
- *Provider of last resort service*. All retail choice states require that utilities or their affiliates provide POLR service (also known as "default service") to customers who do not choose to be served by retail energy suppliers. Such requirements assure that electricity service continues to be available to all consumers, and can also support price reduction and income redistribution goals. In states that require POLR service to be supported by power procured through competitive auctions, POLR service also supports the strengthening of market competition. Because of customer inertia, however, over 90% of residential customers and roughly half of commercial and industrial customers in retail choice states continue to take standard offer or POLR service.[37]
- *Generation asset divestiture and stranded cost treatment*. Some states mandated divestiture of utility generation assets, while others encouraged or otherwise allowed utilities to make their own decisions. The divested assets were primarily coal-fired, gas-fired, and nuclear plants. The new owners were IPPs or utility affiliates. Table 4 shows the extent and timing of divestiture in each of the divesting states, distinguishing states according to whether they have retail choice. The table shows that generation plants were sold only during the period 1998 through 2001, and that divestitures came to a sudden halt in the aftermath of the Western power crisis of 2000-2001.[38] The table indicates that divestiture was significant in all regions of the contiguous U.S. except the Southeastern and Plains states.

[37] See Figure 2 and the accompanying text for details.

[38] Generation assets have been sold by utilities since 2000, but these transactions were not the direct consequence of orders or compromises reached in the process of retail choice reform.

Table 4
States Divesting Generation Assets[39]

State	Number of Plants	Percent Divested	Year of Divestiture
States With Retail Choice or Suspended Retail Choice			
California	29	44%	1998
Connecticut	13	80%	2000
District of Columbia	2	100%	2001
Delaware	7	100%	2001
Illinois	37	58%	2000
Massachusetts	34	100%	1998
Maryland	19	70%	2001
Maine	3	100%	1999
Montana	14	95%	2000
Nevada	10	52%	2000
New Hampshire	3	100%	2006
New Jersey	27	50%	2000
New York	32	54%	1999
Ohio	2	8%	2000
Pennsylvania	60	40%	1999/2000
Rhode Island	1	100%	1998
Texas	3	3%	2001
Virginia	3	5%	2001
States Without Retail Choice			
Indiana	2	5%	1998
Kentucky	5	20%	1998
Vermont	5	55%	2001
Washington	2	NA	2000
West Virginia	1	10%	2000

- *Stranded cost treatment*. "Stranded costs" are the amounts by which the book values of utility generation assets exceed their market values. Restructuring occurred at a time when stranded costs were high precisely because customers wanted access to then-cheap market-priced power. In virtually every state that allowed retail choice, this customer desire was frustrated by the imposition of charges that allowed utilities to recover their stranded costs from all customers, regardless of their supplier. The stranded cost charges generally offset any savings that customers might have gained by

[39] Data on Number of Plants and Year of Divestiture are from Bushnell and Wolfram [2004, Table 1, p. 32]. Percent Divested is computed on the basis of information from Bushnell and Wolfram [2004], Electric Power Supply Association [2002], and U.S. Energy Information Administration [Form EIA-860].

switching to competitive suppliers. Such charges were justified by utilities' need to recover stranded costs in order to maintain financial solvency. This need was often expressed as regulators' obligation to honor the "regulatory compact" of allowing cost recovery of utility investments previously deemed prudent by regulators.

- *Market rules for utility affiliates*. In states where incumbent utilities transferred their generation assets to unregulated affiliates, codes of conduct have been developed to assure that the incumbents do not give unfair advantages to their affiliates. Such advantages can include asymmetric information-sharing that would undermine competition and harm competitors, and cross-subsidization that would funnel monies from the regulated utility to its unregulated affiliate, thus raising regulated prices and harming captive retail customers
- *Protection for low-Income Customers*. Although states have longstanding policies to protect low-income electricity customers, several states implemented new protections for and allocated new funds to such customers in anticipation of new needs created by retail choice.

6. RETAIL CHOICE OUTCOMES

Measuring the success of retail choice programs is difficult because retail choice is only one of many factors that affect power systems and power markets. To assess retail choice in spite of these difficulties, the literature uses three basic methods:[40]

- Direct comparison of traditional versus retail choice markets, either across states (with and without retail choice) or across time (before and after the start of retail choice);
- Estimation of the effects of variations in regulation across states and time; and
- Estimation based upon underlying behavioral relationships.

Based upon the literature, this section summarizes the impacts of retail choice on several key characteristics of electric power markets. These characteristics are customer service, power system costs, electricity market efficiency, retail electricity prices, resource adequacy, financial risk allocation among stakeholders, demographic group welfare, and regulation.

6.1. Impacts on Customer Service

Retail choice has been promoted, in part, because of the prospect that competitive retail service providers may offer new and innovative services that will improve customer service. On the other hand, because non-utility providers of retail service are more lightly regulated than utilities, retail choice also raises consumer risks that have been largely absent for regulated utilities.

[40] See Kwoka [2006] for a more complete description of these methods.

6.1.1. Retail Innovation

A promised benefit of opening retail markets to competition was that it would encourage innovation and experimentation in both pricing of and types of services offered to retail customers. To assess this hope, we look at how much experimentation and innovation has taken place in the retail choice states relative to the traditional states and those states that suspended retail choice. We divide innovations into four categories: dynamic pricing programs; demand response programs; smart metering; and green pricing programs. In each case, we attempt to determine whether the evidence indicates that retail choice has made a difference. What we find is that retail choice induces relatively high participation in dynamic pricing programs, that it has a mixed record in promoting demand response, that it has not generally promoted smart metering, and that it does promote green pricing.

Dynamic Pricing Programs

In the U.S., conventional retail electricity tariffs have "flat pricing" by which the price of electricity is the same all year long, or at least the same within each season. Dynamic pricing programs, by contrast, have prices that change over time. The most prevalent forms of dynamic pricing are the following:

- Time-of-use (TOU) pricing programs have prices that vary by time period, but are constant within each period. Prices may differ by peak, off-peak, and shoulder periods within each week, and by season. TOU prices are set at least months in advance, and so reflect expected power system conditions rather than actual conditions. TOU programs induce customers to shift load from hours that are *expected* to have relatively high electricity production costs to hours that are *expected* to have relatively low costs.

- Real-time pricing (RTP) programs have prices that change every hour. Day-ahead RTP prices are set a day in advance while same-day prices are set almost contemporaneously with the hour to which they apply. In both cases, prices reflect expected or measured electricity production costs at the time they are set, which in RTO markets have an explicit hourly wholesale price benchmark. RTP programs induce customers to shift load from hours that *actually* have relatively high electricity production costs to hours that *actually* have relatively low costs.

- Critical peak pricing (CPP) programs have the prices of either TOU or flat pricing programs in most hours, but have high RTP-based prices in a limited number of extreme peak hours. The high RTP-based prices are not announced until shortly before they take effect. CPP programs induce customers to shift load away from the hours with the highest electricity production costs.

- Peak time rebates (PTR) are the mirror image of CPP. Like CPP, they have TOU or flat prices in most hours, and high RTP-based prices in a limited number of extreme peak hours. But instead of customers *paying* the high price for consumption in extreme peak hours as with CPP, customers receive the high prices for their consumption reductions in extreme peak hours under PTR. Like CPP, PTR programs induce customers to shift load from the hours with the highest electricity production costs.

TOU pricing is the most common form of dynamic pricing, while PTR is the least common.

Table 5 summarizes the numbers of retail electricity customers participating in dynamic pricing programs by state type (traditional, retail choice, and suspended) and by customer segment (residential, commercial, and industrial). The retail choice states have significantly greater numbers of customers in all segments participating in dynamic pricing programs than either the traditional states or the suspended states. This is significant because retail choice states account for less than half of all retail load and a similar share of customers; so retail choice states clearly have much higher participation rates than traditional states.

Table 5
Numbers of Customers Participating in Dynamic Pricing Programs, by Customer Segment, 2014[41]

State Type	Residential	Commercial	Industrial	Total
Traditional	1,078,298	243,599	27,531	1,349,428
Retail Choice	3,308,180	1,159,483	62,258	4,529,921
Suspended	968,599	43,895	4,472	1,016,966

Demand Response Programs

Table 6 summarizes recent demand response program outcomes for each of the state types and customer segments. The second column shows the numbers of customers enrolled in demand response programs. The third column shows outcomes measured in energy savings, which is a better measure than annual peak load reductions because many demand response programs seek goals other than or in addition to peak load reductions. The third column shows annual energy savings as a percentage of total annual energy consumption.

For the residential class, retail choice states have lower participation than traditional states in terms of both numbers of customers and energy saved. For the commercial class, retail choice states have higher participation in terms of both customers and energy savings. For the industrial class, retail choice states and traditional states have similar numbers of customers; but retail choice states lag behind traditional states in energy savings. On the whole, the evidence does not support the hypothesis that retail choice improves demand response outcomes.

[41] U.S. Energy Information Administration [Form EIA-861, Dynamic_Pricing2013.xls and Dynamic_Pricing2014.xls].

Table 6
Demand Response Program Outcomes, 2014[42]

State Type	Residential			Commercial			Industrial		
	Custs (000s)	Annual Savings (GWh)	Annual Savings (%)	Custs (000s)	Annual Savings (GWh)	Annual Savings (%)	Custs (000s)	Annual Savings (GWh)	Annual Savings (%)
Traditional	4,246	135	0.02%	102	57	0.01%	22	78	0.02%
Retail Choice	3,141	38	0.01%	478	222	0.03%	24	12	0.00%
Suspended	1,008	707	0.51%	24	183	0.14%	11	2	0.00%

Smart Metering

Expansion of product offerings– particularly including dynamic pricing and demand response programs – depends upon the adoption and implementation of "smart metering" technologies that enable communications among the customer, the retail energy supplier, and the power system operator. The feasibility of offering new products therefore depends, in part, upon the available smart metering infrastructure.

Twenty-five states have smart metering programs, some of which are pilots and others of which mandate universal residential coverage. These policies have been driven by the goal of replacing aging infrastructure with cutting-edge metering technologies that can implement dynamic pricing for both loads and distributed energy resources. Dynamic pricing of loads can improve the efficient utilization of power system resources, while dynamic pricing of distributed energy resources can help promote environmentally friendly power generation.[43]

As shown in Figure 8, about 50 million smart meters had been deployed in the U.S. as of July 2014. These cover 43% of American residences. Thirty utilities have achieved complete smart meter coverage of their customers.

[42] U.S. Energy Information Administration [Form EIA-861, Demand_Response2014.xls].

[43] Joskow and Wolfram [2012, pp. 5-6.]

Figure 8
Smart Meter Installation in the United States, 2007 to 2014[44]

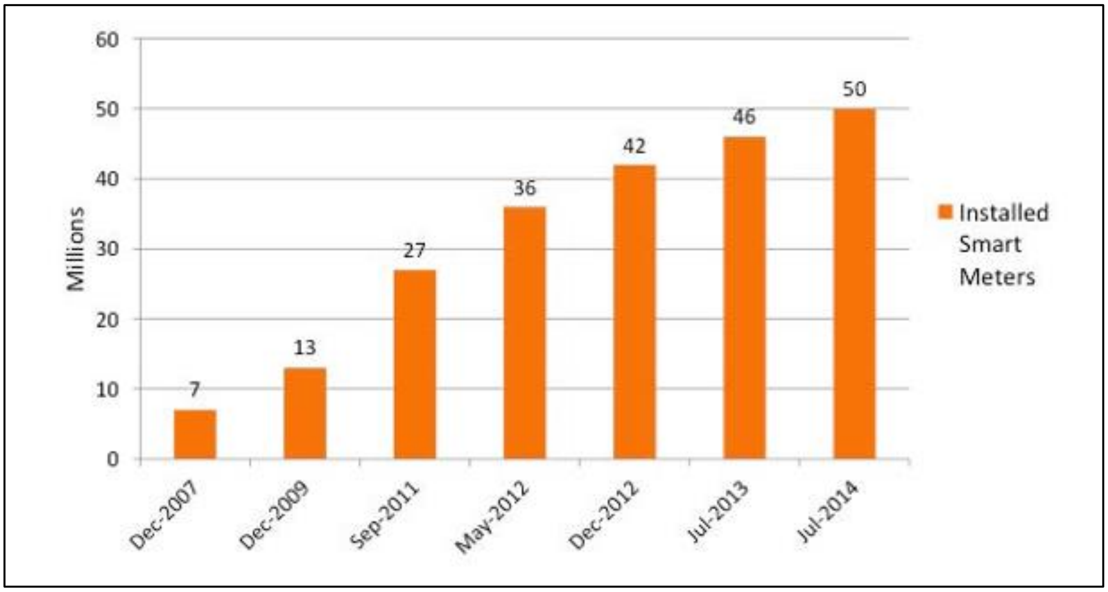


Table 7 shows the penetration of smart meters for each of the three groups of states over the period 2006 to 2014. Penetration is expressed as the share of smart meters in the total number of meters for the states in each group. The penetration of smart meters has grown rapidly everywhere, but more quickly in the traditional states and the suspended states than in the retail choice states. This result seems rather anomalous because metering is usually the responsibility of the distribution utility: if a state has chosen retail choice as a matter of policy, it should logically be inclined to promote smart metering as a matter of policy. Apparently, this logic is not supported by the evidence.

Table 7
Penetration of Smart Meters as a Percent of Total Meters[45]

State Type	2006	2008	2013	2014
Traditional	0.8%	4.6%	45.0%	43.6%
Retail Choice	0.3%	3.9%	24.0%	22.2%
Suspended	0.7%	2.7%	37.8%	36.7%

[44] Institute for Electric Innovation [2014, p. 1].

[45] U.S. Federal Energy Regulatory Commission [2006, Table III-2, p. 30], U.S. Federal Energy Regulatory Commission [2008, Table II-3, p. 12]. For 2013 and 2014, U.S. Energy Information Administration [Form 861, Advanced Meters_2013.xls and Advanced Meters_2014.xls].

Green Pricing

Green pricing programs offer customers the option of buying power from environmentally friendly generation resources, usually at a price premium relative to conventional generation resources.

Table 8 summarizes the number of green pricing program customers over the period 2010 to 2012, which has the most recent data available from Energy Information Administration (EIA). It is clear that the retail choice states have outperformed traditional states in terms of numbers of participants in green pricing programs and in participation rates. Furthermore, over the period shown, green pricing participation more than doubled in retail choice states while barely budging in traditional states. The significant differences between the traditional and retail choice states are due to more aggressive green pricing policies adopted by regulators and legislators in the retail choice states and to the vigorous competitive promotion of green pricing in the retail choice states.

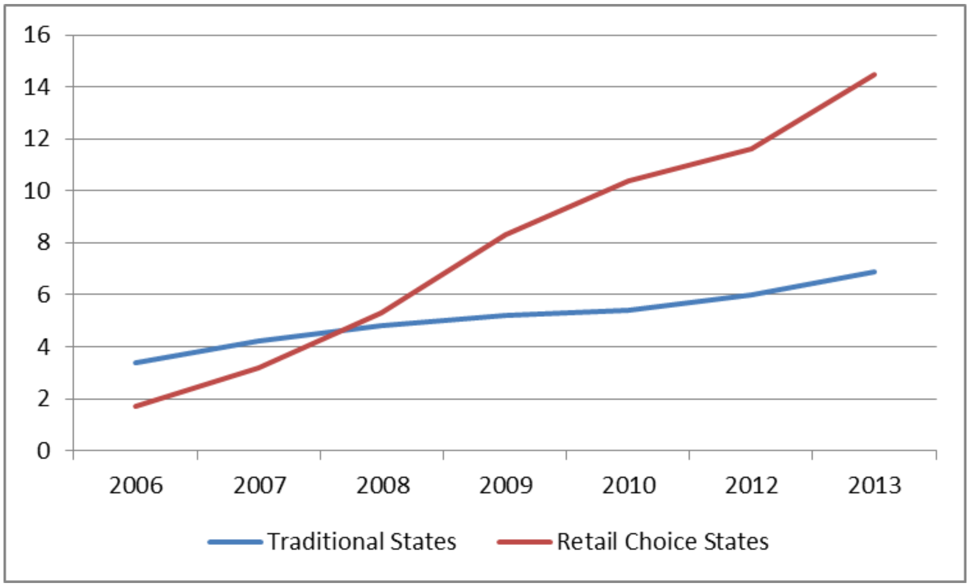
Table 8
Green Pricing Customers by State Type[46]

State Type	2010	2011	2012
Traditional	322,411	312,618	322,183
Retail Choice	730,698	800,246	1,768,571
Suspended	163,473	163,172	175,208

Figure 9 summarizes the estimated annual sales of green energy (in MWh) by market sector over the period from 2006 to 2013. While the retail choice states apparently lagged behind the traditional states at the beginning of the period, the subsequent growth in the retail choice states led them to have approximately twice the volume of green sales as in traditional states by 2013.

[46] U.S. Energy Information Administration [Form 861, Green_Pricing2010.xls, Green_Pricing2011.xls, and Green_Pricing2012.xls].

Figure 9
Estimated Annual Green Sales by State Type (Millions of MWh), 2006-2013[47]



6.1.2. Customer Satisfaction Surveys

Customer satisfaction is an important determinant of customer switching behavior, customer receptivity to proposed service changes and program innovations, and customer acceptance of rate increases. In traditional market settings, utilities with high customer satisfaction ratings may benefit from goodwill in ways that ease regulatory proceedings.

J.D. Power conducts annual electricity customer satisfaction surveys that measure satisfaction among residential customers of retail electric providers in retail choice states. Its most recent surveys have the following key findings:[48]

- Of the customers who switched providers in 2013,
  - 6% switched from another retail electric provider, with 64% of those doing so in response to a better price;
  - 11% enrolled for the first time with a retail provider; and
  - 24% renewed with their existing retail electric provider.
- In 2013, retail choice customers were more satisfied with price than customers of local electric utilities in the retail choice states.

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[47] National Renewable Energy Laboratory [2014, Table 2, p. 7]. For consistency with the designations in this report, the labels for market sector have been changed from "utility green pricing" and "competitive markets" in the original to "traditional states" and "retail choice states" in this presentation.

[48] J.D. Power [2010, 2013, 2014, 2015].

- Customer satisfaction is strongly tied to price perception, which is partly shaped by the level of price volatility experienced by customers on variable price plans.
- In retail choice states, price satisfaction is higher among customers on a fixed price contract than among those on a variable pricing plan.
- Residential customers do not switch from the local utility to an alternative retail provider because:
    - The savings from switching are not large enough to justify the move. Over one fourth of surveyed customers indicate that they would switch to a retail provider if they could save $20 on their monthly bill.
    - Customers are satisfied with service provided by the incumbent utility.
    - Customers' lack of knowledge about how to switch.
    - Customers' fear that service quality would decline.
- Satisfaction with alternative retail energy suppliers is lower under an aggregation program than when the customer chooses a provider themselves.
- In 2015, 57% of highly satisfied retail customers indicated they "definitely will" renew their contract, and 62% indicated they "definitely will" recommend their retail electric provider to other customers. In contrast, 21% of dissatisfied customers said they "definitely will" renew, and 3% indicated they "definitely will" recommend their provider to others.
- Residential electric customers' satisfaction with the overall price of service increases substantially as customers become more familiar with available energy efficiency programs.[49]

Another source of information about electricity customer satisfaction comes from the American Customer Satisfaction Index (ACSI). The ACSI measures the satisfaction of U.S. household consumers with the quality of products and services offered by both foreign and domestic firms with significant share in U.S. markets. The ACSI for the electric industry, investor-owned electric utilities in particular, has been conducted for about twenty years.[50] Customer satisfaction benchmarks are updated annually based on interviews with hundreds of residential customers about recent experiences with their service provider. Key metrics include customer expectations, customer perceptions about the value and quality of their actual experiences, customer complaints, and customer retention. The ACSI captures customer opinions about

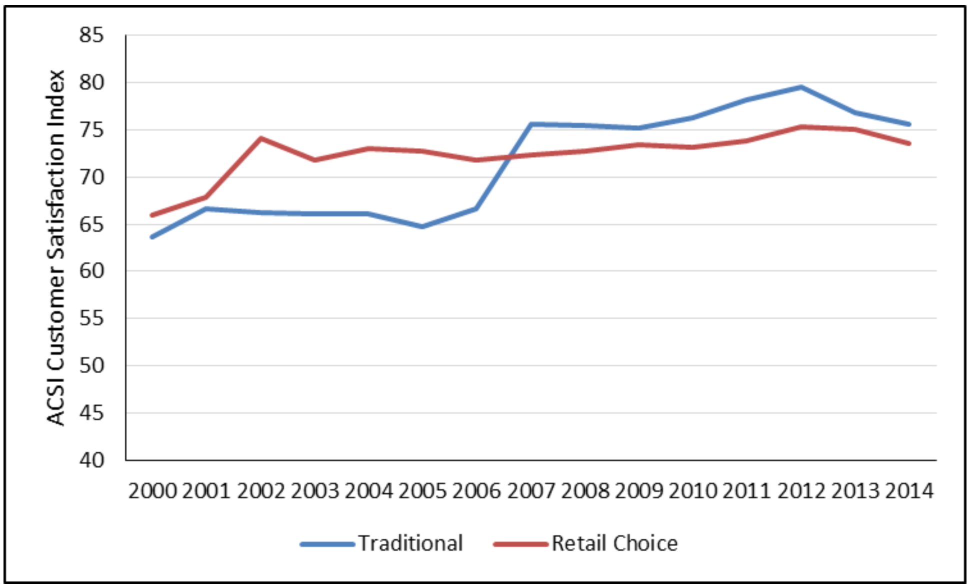
[49] Customers who understand that they have access to tools to help them manage their overall bills would logically be more satisfied than customers who don't know how or where to find help. In a time of increased upward pressure on utility rates, giving people assistance in managing bills through energy efficiency should be an important motivation to regulators and utilities.

[50] In 2011, the ACSI expanded its coverage of power suppliers to include both municipal and cooperative energy utilities.

critical elements of the residential customer experience, including the supplier's ability to provide reliable electric service and ability to restore electric service following a power outage.

Figure 10 summarizes the averages of the ACSI values for investor-owned electric utilities serving customers in traditional and retail choice states over the period 2000 to 2014. The satisfaction ratings in the retail choice states rose in the first couple of years, and have held fairly steady since. The average of ACSI scores for traditional states were below those of the retail choice states until 2007, when they suddenly jumped and thereby exceeded the latter until 2012, since which time the average rates have been statistically indistinguishable. The reason for the early rise in satisfaction in the retail choice states is probably that customers became comfortable with retail choice as it became familiar; but the reason for the 2007 jump in satisfaction in the traditional is not clear.

Figure 10
Average ACSI Scores for Traditional and Retail Choice States IOUs, 2000 - 2014[51]



Zarakas *et al* [2013] conducted a statistical regression analysis of the J.D. Power satisfaction scores for electric utilities to attempt to explain the differences in scores across utilities. The analysis found that customer satisfaction significantly depends upon the following factors:

- Service interruptions reduce satisfaction.
- Higher population density in the utility service area increases satisfaction.
- Higher retail price reduces satisfaction.

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[51] American Customer Satisfaction Index [2015]. Utilities or holding companies included in traditional state average are Dominion Resources, Southern Company, Entergy, NextEra Energy, Xcel Energy, Berkshire Hathaway, Duke Energy, and Small IOUs. Utilities or holding companies included in retail choice state average are Sempra, FirstEnergy, PPL, Ameren, Edison International, CMS Energy, DTE Energy, American Electric Power, Pepco, Public Service Electric & Gas, Exelon, Consolidated Edison, and Eversource Energy.

- Customer location in the Northeastern U.S. reduces satisfaction.[52]

The analysis looked for but did not find that satisfaction significantly depends upon spending on distribution systems or on customer service.

The experience of the EU indicates that retail choice is correlated with better service quality and higher customer satisfaction. This can be seen in Table 9, which shows the rankings of EU member states for the quality of the electricity service and consumer satisfaction. In this table, 1 is the best ranking and 27 is the worst, and countries are divided into groups according to their market concentrations as explained earlier in this report for Table 2. Table 9 highlights in yellow those quality of service and consumer satisfaction rankings that are in the top third of the class, and highlights in pink those rankings that are in the bottom third of the class. Almost half the top rankings are in the unconcentrated markets with the most retail choice. Although the worst rankings are generally held by the countries with monopolies, those countries also have nearly half of the top rankings.

In summary, there does not seem to be a clear relationship between retail choice and customer satisfaction. The ACSI results for U.S. residential customers are mixed. The EU experience suggests that retail choice, when well implemented, improves customer satisfaction. What is clear is that customers like prices that are low and stable, and they like service that is reliable.

[52] Zarakas *et al* [2013, p. 53] note that this "suggests an unfortunate locational distinction for Northeastern utilities. … It's possible that this geographic effect reflects cultural pre-dispositions; it also might be the result of cross correlations with storm-related service interruptions."

Table 9
Quality of Electricity Service and Consumer Satisfaction in the European Union, 2010[53]

Member State	Quality of Service	Consumer Satisfaction
Unconcentrated Markets:		
Austria	1	2
Finland	4	8
Germany	5	8
Sweden	7	13
Moderately Concentrated:		
Denmark	16	18
Netherlands	15	6
Slovenia	10	19
United Kingdom	12	11
Highly Concentrated:		
Belgium	17	12
Czech Republic	19	15
Hungary	13	20
Ireland	2	1
Luxembourg	11	5
Slovakia	21	10
Spain	24	22
National or Regional Monopolies:		
Bulgaria	27	27
Cypress	3	7
Estonia	6	16
France	14	4
Greece	25	25
Italy	20	21
Latvia	9	9
Lithuania	8	24
Malta	26	26
Poland	23	14
Portugal	22	23
Romania	18	17

[53] ECME Consortium [2010].

6.1.3. Fraudulent Advertising

Retail choice can create opportunities for less scrupulous retail energy suppliers to misrepresent the terms and prices of the services they offer, thereby enabling them to persuade customers to switch from the incumbent local utility provider. In the worst cases, fraudulent behavior has included the following:[54]

- falsely promising bill savings;
- vaguely describing the basis for determining retail electricity prices;
- levying charges that differ from written pricing disclosures;
- switching customers from their utility providers without the customers' consent;
- providing inadequate training to marketing agents;
- inadequately supervising marketing agents;
- requiring marketing agents to pay for their training;
- misrepresenting the identity of the marketing agent;
- distributing promotional materials that display the corporate logo of the incumbent utility;
- misrepresenting the nature of the utility's default service;
- using high-pressure sales tactics on low-income, elderly, and non-English speaking customers; and
- going out of business and thereby stranding customers, thus requiring the incumbent utility to provide POLR service.

Most retail energy suppliers have been legitimate. Nonetheless, all retail choice states have attempted to regulate suppliers' behavior by requiring retail energy suppliers to register and demonstrate financial soundness, and by specifying customers' rights and protections against fraudulent energy supplier behavior. Still, state resources to enforce the rules are limited. As Paula Carmody, the people's counsel for the state of Maryland, has complained, "An agency like mine is so tied up with regulated utility cases, rate cases, merger cases, we don't have the resources to consistently go in to monitor what's going on in the marketplace."[55]

Fraudulent business behavior is not unique to the retail electric industry. Smaller electricity customers, having been served historically by their incumbent utilities, will not initially be familiar with the challenges of finding reliable electricity providers and understanding contract terms, and may therefore be easy prey for scoundrels at the outset of retail choice. As retail choice matures, customers will become more alert to the possibilities of fraud; but the

[54] These examples are from Alexander [2015, pp. 5-6] concerning Blue Pilot Energy in Maryland, Newsham [2014] concerning Viridian Energy in Connecticut, and Meneimer [2014] concerning Viridian Energy and North American Power Company in Maryland.

[55] Meneimer [2014].

complexity of retail electricity sales terms may require significant continuing consumer protections.

6.1.4. Market Entry, Market Exit, and Bankruptcies

Ideally, competitive markets have low barriers to entry and exit. Given the substantial numbers of suppliers who have entered and exited the retail electricity market, it would appear that the barriers to entry and exit are not high in retail choice markets.

For retail energy suppliers, the threat of bankruptcy arises from mismatches between their costs of procuring power and the prices at which they sell power. For RTP programs that have sales prices that rise and fall with wholesale market prices, the supplier faces little risk. To offer customers fixed-price products, however, the supplier needs generating assets or long-term contracts that have relatively fixed costs.

Bankruptcies and significant financial stresses have plagued suppliers primarily when they have had fixed-price sales obligations and insufficient long-term purchase rights, and when wholesale electricity spot market prices suddenly jumped. Such events occurred, for example, during the California electricity crisis of 2001 and the polar vortex of the winter of 2014. In this latter event, Dominion Resources left the retail electricity business voluntarily while smaller players succumbed by defaulting on their obligations.[56]

Because retail energy suppliers in retail choice states face much larger financial uncertainties than do traditionally regulated utilities, the risk of retail supplier bankruptcies under retail choice are indisputably greater than under traditional regulation.

6.2. Impacts on Power System Costs

Retail choice can have direct and indirect impacts on power system costs.

The direct impacts come through whatever changes in load profiles are induced by retail choice. Table 5 (above) shows that retail choice is extending the market penetration of retail pricing programs that reflect power system conditions, thus shifting loads from peak to off-peak periods and lowering the average costs of producing power. The amount of this benefit will depend upon the extent to which retail choice is inducing load shifts.

The indirect impacts come through retail choice helping enable wholesale market restructuring. As indicated above by Table 4, retail choice played a large role in facilitating states' decisions to require or encourage utilities to divest their generation assets. These policy errors ultimately cost customers tens of billions of dollars.[57] In addition to these one-time cost impacts, wholesale market restructuring, abetted by retail choice, arguably has the following impacts:

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[56] Kuckro [2014].

[57] Most notoriously, generation asset divestitures played a decisive role in creating the Western power crisis of 2000-2001, which all by itself cost electricity consumers many billions of dollars. The States of Maryland and New Jersey had similar regrets a decade later, as they tried to regain control of their resource planning processes from PJM and the wholesale market. The states' loss of control over resource planning processes has contributed to

- It can reduce generation costs by encouraging entities to engage in cost-reducing power trades.
- It can induce improvements in generation technologies and management costs by giving stronger incentives to cut costs and increase production.
- It makes the recovery of generation investment costs more uncertain, and can thereby raise required returns on capital invested in generation relative to the returns needed in markets in which capital recovery is "guaranteed" by cost-of-service regulation.
- It can induce generation firms to be more aggressive in seeking lower fuel prices. On the other hand, because competitive generation firms lack the long-term electricity sales obligations of traditional utilities, wholesale market restructuring can also induce generation firms to seek shorter-term fuel contracts than are sought by traditional utilities. Shorter-term contracts likely make fuel costs more unstable and may make fuel supply more uncertain, but do not necessarily increase or reduce expected fuel costs in the long run.
- Wholesale market restructuring would likely have the impacts on generators' non-fuel operating costs that are similar to those on their fuel costs, namely more aggressive cost-cutting and shorter-term contracting.

Retail choice would contribute the foregoing impacts of wholesale market restructuring if retail choice somehow resulted in generators receiving different prices or different electricity sales contract durations than they would receive in the absence of retail restructuring.

6.3. Impacts on Market Efficiency

The efficiency benefits of retail choice depend upon retail service providers doing things that incumbent utilities are either unable or unwilling to do. As expressed by Paul Joskow at the outset of the retail choice movement, there are only a few such things.

> The physical attributes of electricity supply make many of the traditional "convenience services" provided by retailers in other industries irrelevant in electricity… [T]hese attributes provide a low-cost way for electricity consumers to buy directly in the wholesale market. In this way, retail consumers can receive the commodity price related benefits of competitive generation markets without incurring large increases in advertising, promotion and customer service costs. Electric distribution companies… can easily provide a Basic Electricity Service (BES) that makes it possible for all consumers to buy commodity electricity in competitive wholesale electricity markets at the spot market price. The availability of BES is especially important for residential and small commercial

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resource adequacy problems; but the more general result of the loss of control has been increases in the cost of maintaining adequate resources, as explained in the text. These resource adequacy and cost issues are due to wholesale restructuring, and can be attributed to retail choice only to the extent that retail choice motivated and enabled wholesale restructuring.

> customers for whom few new retail value-added services are evident. BES also provides an excellent competitive benchmark against which consumers can compare the value added associated with competitive supply offers from competing Electricity Service Providers (ESPs), helps to protect residential and small commercial customers from exploitation by ESPs, and mitigates wasteful expenditures on marketing and promotion by rent-seeking ESPs that will increase prices. The availability of BES helps to channel ESP competitive efforts toward providing value added services such as real time metering and control, energy management contracts, risk hedging and forward contracting, green power and other services… The success of retail competition should be judged by the new value added services it brings to the system, not by the number of customers who switch to ESPs…[58]

In other words, retail choice creates efficiency benefits only to the extent that alternative retail energy suppliers do a better job than utilities do at making wholesale electricity prices available to their customers or at offering value-added services. Specifically, retail choice creates efficiency benefits only if alternative retail energy suppliers do a better job than utilities at some of the following:

- If alternative retail energy providers expanded dynamic pricing programs, retail choice could improve customer response to power system conditions and thereby help improve the efficiency of use of power system resources. Table 5 indicates that this has, in fact, occurred to some extent.
- If alternative retail energy providers offered menus of products that offer different degrees of price guarantee, they could cater to customers' different tolerances for financial risk. Such diversity of price guarantee can improve the efficiency of meeting the risk preferences of different customers.
- If alternative retail energy providers were better than utilities at negotiating terms for the supply of power in securing forward contracts, they could do a better job of holding down costs and managing risks.
- If alternative retail energy providers induced entry of new generation into the market or invested in generation capacity of their own, they could help resource adequacy and might help mitigate wholesale market power.
- If alternative retail energy providers paid for the smart meters that support time-varying rates, they could better help induce consumers to shift consumption toward lower-cost hours and thereby improve the efficiency of the generation mix.
- If alternative retail energy providers offered attractive curtailable service rates, such rates might induce customers to accept relatively low-cost service curtailments that would avoid the need for costly generation investment.

[58] Joskow [2000, p. 1].

Aside from the evidence that competitive retailers are inducing greater participation in dynamic rate programs, we are not aware of evidence that the foregoing activities to improve wholesale market efficiency have been significantly affected by retail choice.

6.4. Impacts on Retail Prices

Retail prices depend upon myriad factors, of which retail choice is merely one. A rigorous analysis of the impacts of retail choice on retail prices requires statistical analysis that separates the effects of retail choice from the other factors.

This section begins with an overview of retail price histories relevant to retail choice in both the U.S. and the EU. It then summarizes the findings of many studies that have attempted to quantify the determinants of retail price, including retail choice.

6.4.1. Overview of Retail Price Histories in the U.S.

Although a casual analysis of retail prices over time and across regions cannot provide a definitive conclusion about the impacts of states' retail policy decisions or of RTO markets on retail prices, the historical path of retail prices *does* illustrate the general impact of retail choice in states that have adopted it compared to those that have not. In comparing these paths for states with and without retail choice, it is important to recognize that retail prices in RTO markets depend upon current fuel prices: because natural gas is the fuel that is most commonly at the margin, the RTOs' retail prices commonly reflect the current price of natural gas. Figure 11 shows that natural gas prices rose gradually through the 1990s, quadrupled between 1999 and 2005, and then fell by more than half following the financial crash of 2008. As will be seen, retail electricity prices in retail choice states partially mimic this pattern.

Figure 11
Real Annual Henry Hub Natural Gas Spot Prices, 1991-2014 (2015 dollars)[59]

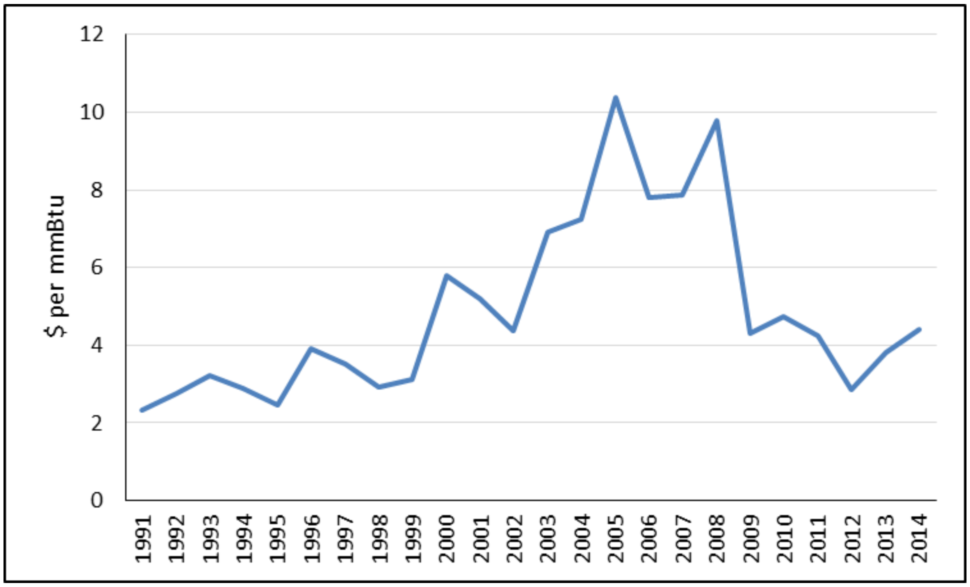


Figure 12, Figure 13, and Figure 14 show the paths of weighted average real revenue per kWh for residential, commercial, and industrial class customers, respectively, for the period 1990 to 2014 for the three groups of states. Weighted average real revenue is a close proxy for load-weighted average real retail prices, so the figures (and this discussion) refer to the results as "prices." The figures show that the real price gap between the retail choice states and the traditional states began to close in the late 1990s, when gas prices were still low and decisions were made to adopt retail choice. Following adoption of retail choice, however, the retail electricity price gap widened over the period 2000 to 2008 with rising fuel prices. During this period, regulated retail electricity prices, which depend upon an average of historical generation investment costs and contracted fuel costs, only rose slowly with spot fuel prices. As stated by Borenstein:

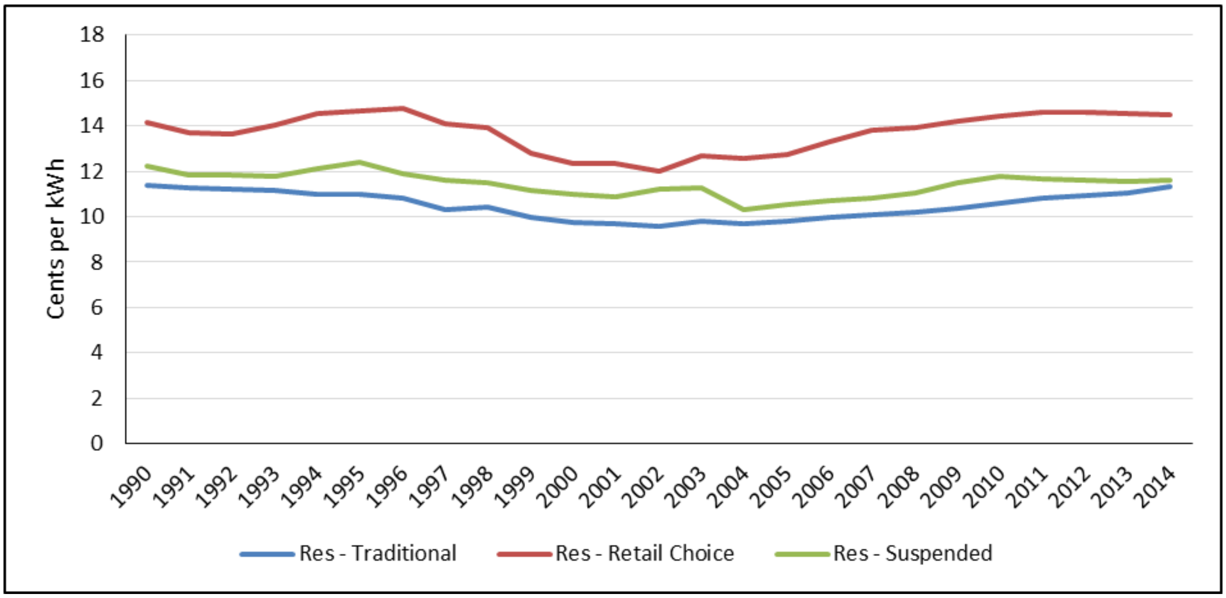
> Because gas generation comprises a minority share in most electricity markets, under average-cost based regulation it did not dominate rate making. Prices for deregulated generation, however, are driven by the marginal producer, which is much more commonly gas generation. Thus to a degree that was not appreciated at the time, 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

[59] Reuters [U.S. Henry Hub] for period 1991 to 1996, and U.S. Energy Information Administration [Henry Hub] for 1997 to 2014.

for infra-marginal generation were far greater than they would have been under regulation.[60]

Since 2008, the price gap has slightly narrowed along with the decline in fuel prices. It therefore appears that the states that embraced retail choice – nearly all of which were contained within RTO regions[61] – have only recently witnessed any significant reduction in the retail price gap relative to the other states.

Figure 12
Weighted Average Real Prices for Residential Customers, 1990 to 2014 (2015 dollars)[62]



[60] Borenstein, p. 14.

[61] Arizona, New Mexico, and Oregon adopted retail choice without being in RTOs. All of them have since suspended or rescinded retail choice.

[62] Data for this figure and for all other figures and tables in this section were obtained from U.S. Energy Information Administration [Form 861, 1990 to 2014].

Figure 13
Weighted Average Real Prices for Commercial Customers, 1990 to 2014 (2015 dollars)

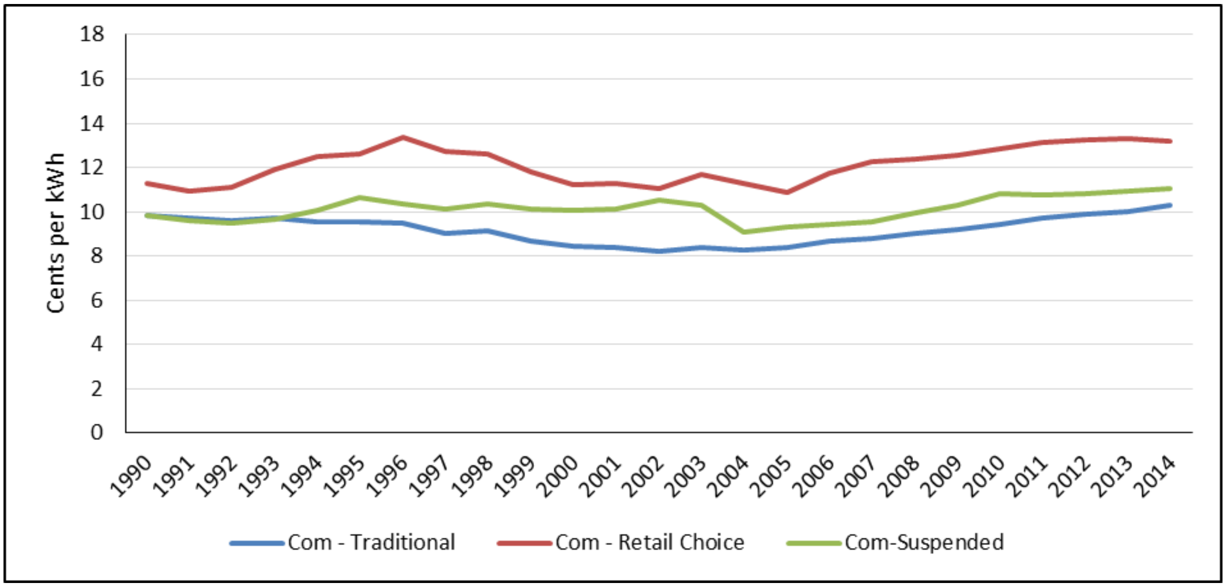


Figure 14
Weighted Average Real Prices for Industrial Customers, 1990 to 2014 (2015 dollars)

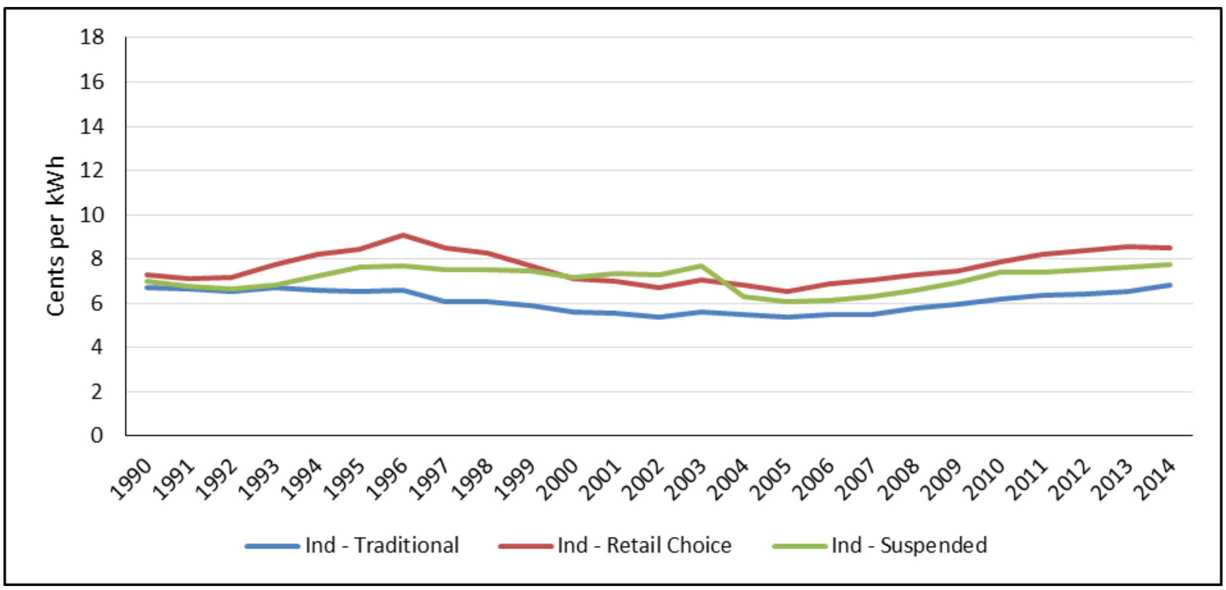
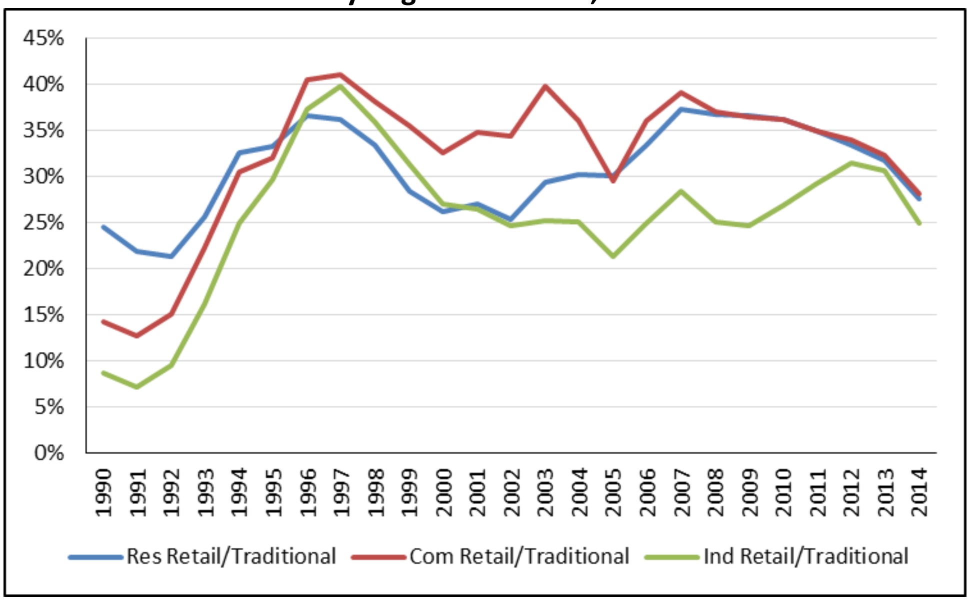


Figure 15 illustrates gains that might be attributable to retail choice. For each of the residential, commercial, and industrial classes, the figure shows the percentage amount by which load-weighted average revenue per kWh in the retail choice states exceeded those of traditionally regulated states over the period 1990 to 2014. Several characteristics of the percentage price gap are remarkable. First, average revenues in the retail choice states have persistently been higher than those in the traditionally regulated states, by averages of 31% for the residential class, 32% for the commercial class, and 25% for the industrial class. Second, the percentage gaps have fluctuated widely, from 21% to 37% for the residential class, from 13% to 41% for the commercial class, and from 7% to 40% for the industrial class. Third, the peaks and troughs have been somewhat similar for all three classes, tending to peak when natural gas prices are high and to trough when they are low.

Figure 15
Amounts by Which Average Revenues in Retail Choice States Exceeded Those in Traditionally Regulated States, 1990 to 2014



The drop in the price gap since 2008 has been driven by the very different ways that the two groups of states have been influenced by the recent recession. Although retail prices have been relatively flat or falling slightly in the retail choice states since 2008, they have been rising in traditional states and therefore significantly narrowing the price gap. This is attributable to two factors. First, customers in retail choice states have benefited from the recession-induced reductions in electricity demand and fuel prices and from the technology-induced reduction in natural gas prices, all of which have lowered wholesale market clearing prices and been partially passed on to end-use customers in those states. The drop in the price gap for industrial customers since 2012 has been larger than those for residential and commercial customers because industrial customers have higher participation rates in retail choice programs than do residential and commercial customers, and so are more directly exposed to changes in wholesale electricity market prices. Second, customers in the traditional states are experiencing the impacts of a spate of recent cost-of-service rate cases that are allowing regulated utilities to catch up with cost increases after many years without rate cases.

Table 10 presents the percentage changes in weighted average prices, in both nominal and real terms, from 1990 to 2014 by class for the three state groups. Retail choice states had the best price outcomes for all three customer classes, though this outcome is at least partly due to the happenstance of the timing of the recent fall in natural gas prices. States that suspended retail choice had better price outcomes than traditional states for the commercial and industrial classes, but a worse outcome for the residential class. The relatively mediocre performance of the traditional states may be partly due to their lack of retail choice, but is very likely due more to their having lower prices than the other states to begin with (as well as lower prices at the end of the period).

Table 10
Percentage Changes in Weighted Average Retail Prices, 1990-2014

State Group	Residential		Commercial		Industrial	
	Nominal	Real	Nominal	Real	Nominal	Real
Traditional	63%	0%	56%	-4%	60%	-2%
Retail Choice	59%	-2%	39%	-15%	39%	-14%
Traditional - Suspended	72%	6%	45%	-11%	47%	-10%

A recent national survey of electric customer average monthly bills conducted by Lincoln Electric System highlights the continuing price gap between retail choice states and traditional states.[63] This survey compares average monthly bills for rates in effect on January 1, 2015 for 106 U.S. cities. As shown in the rows of Table 11, the survey distinguishes between two usage levels for the residential class, four usage levels for the commercial class, and six usage levels for the industrial class. The table shows average monthly bills for the year.

The demand and monthly energy levels in the table are category boundaries selected by Lincoln Electric System. The Traditional State and Choice State columns show average monthly bills that we derived from the survey findings. These columns indicate that the price gap in 2015 between retail choice states and traditional states is significant for all customer classes and sizes, ranging from 37% for small residential customers up to 70% for large industrial customers. There is a very strong relationship between the price gap and customer size: the gap gets bigger as customers get bigger. This may be due to the fact that smaller customers in retail choice states, including large majorities of residential customers, are still being served by the incumbent local utility, which somewhat insulates them from the changes in wholesale market prices.

[63] Lincoln Electric System [2015].

Table 11
Typical Bills per the LES Survey Results, 2015[64]

	Demand Level (kW)	Average Monthly Energy (kWh)	Traditional State ($/Month)	Choice State ($/Month)	Price Gap ($/Month)	Percent Difference
Residential		500	64	88	24	37%
		1,000	118	169	51	43%
Commercial	40	10,000	1,138	1,593	455	40%
	40	14,000	1,441	2,021	581	40%
	500	150,000	15,304	23,119	7,815	51%
	500	180,000	17,062	26,399	9,337	55%
Industrial	75	15,000	1,856	2,542	685	37%
	75	30,000	2,851	4,130	1,278	45%
	75	50,000	4,051	6,159	2,108	52%
	1,000	200,000	23,821	34,989	11,168	47%
	1,000	400,000	35,368	56,284	20,916	59%
	1,000	650,000	48,586	82,779	34,193	70%

6.4.2. Prices in the EU's Electricity Markets

As discussed earlier, the EU has mandated retail choice in all its member states, with mixed outcomes for the extent of competition within each country. This mixture notwithstanding, Figure 16 shows average real retail electricity prices in 27 EU countries for medium-size customers in the residential and industrial classes over the period 2005 through 2015, including taxes for the residential class but excluding taxes for the industrial class.[65] Real average prices for medium-size residential customers rose 29% over this period, while real average prices for medium-size industrial customers rose 10%.

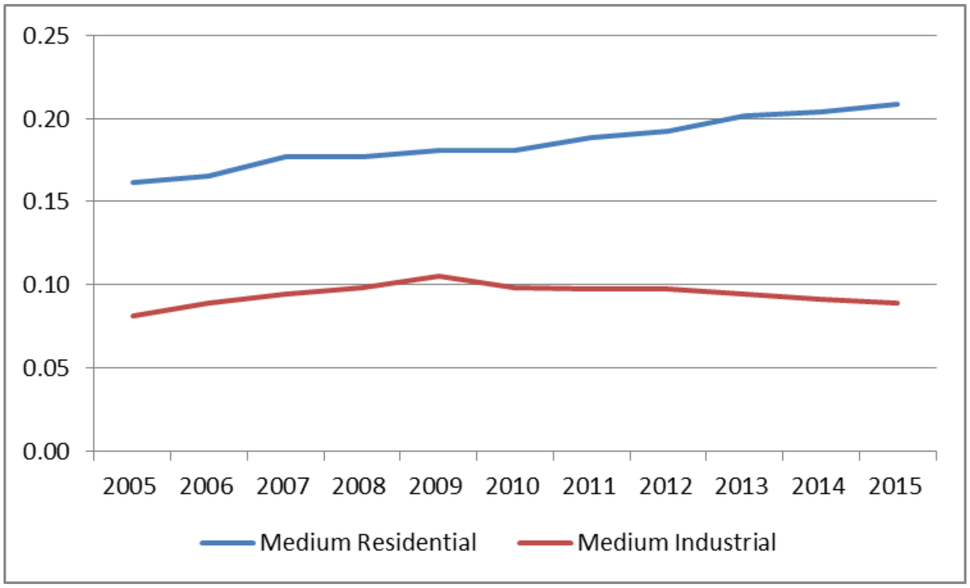
Figure 16 is remarkable in showing that real industrial prices peaked in 2009, at the time of the financial crisis, and have come down 15% since that time. Real residential prices, by contrast, have had a steady upward march, regardless of the financial crisis. This is very different from the U.S. experience, wherein falling fuel prices drove down the prices of retail choice customers of all classes. A large part of this difference is due to EU member states' non-contestable charges such as taxes, transmission and distribution charges, and charges for recovery of the costs of subsidized renewable resources. These non-contestable charges constitute more than

[64] Based upon Lincoln Electric System [2015]. 37 of the 106 cities in the survey were in retail choice states, with 31 of those served by investor-owned utilities. 85 of the 106 cities were served by investor-owned utilities.

[65] Medium-size residential customers are defined as consuming between 2,500 and 5,000 kWh per year. Medium-size industrial customers are defined as consuming between 500 and 2,000 MWh per year.

half the electricity bills in some countries. In Austria, Germany, Ireland and Slovenia in 2013, increases in renewable energy subsidies almost completely offset the drop in wholesale electricity prices. The large non-contestable charges have thus significantly undermined retail choice in the EU.[66]

Figure 16
Average Real Electricity Prices for Residential and Industrial Electricity Customers in 27 EU Countries, 2005-2015 (2015 € per kWh)[67]



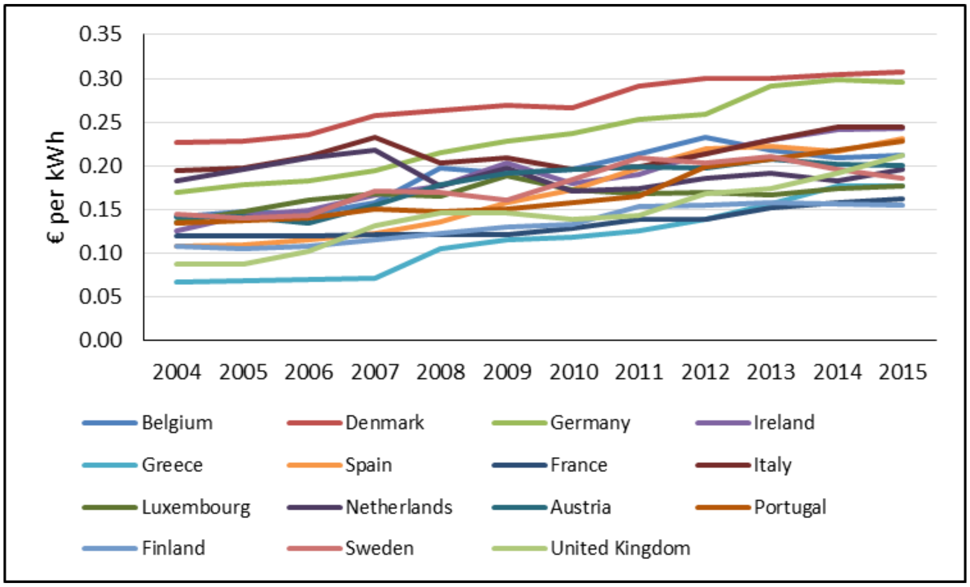
Residential price levels and trends have varied considerably among the EU-15 countries, as illustrated by Figure 17.[68] Over the 2004 through 2015 period, the Netherlands experienced the lowest increase in residential prices (7%), followed by Italy (26%), Sweden (29%), and Luxembourg (30%). At the other end of the spectrum, nominal residential prices more than doubled over this span of time in Spain (114%), the United Kingdom (142%), and Greece (163%). Nonetheless, Greece, Finland, and the United Kingdom have maintained the lowest residential prices over the period. These very different experiences indicate that retail choice is not the only factor influencing price.

[66] Agency for the Cooperation of Energy Regulators and Council of European Energy Regulators [2014, pp. 8-9].

[67] EUROSTAT [Electricity prices]. Prices are deflated by the EU's harmonized index of consumer prices as reported by Eurostat, http://appsso.eurostat.ec.europa.eu/nui/show.do.

[68] The EU-15 countries – Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden and the United Kingdom – are those that were members of the EU before May 2004.

Figure 17
EU-15 Nominal Residential Electricity Prices 2004-2015[69]

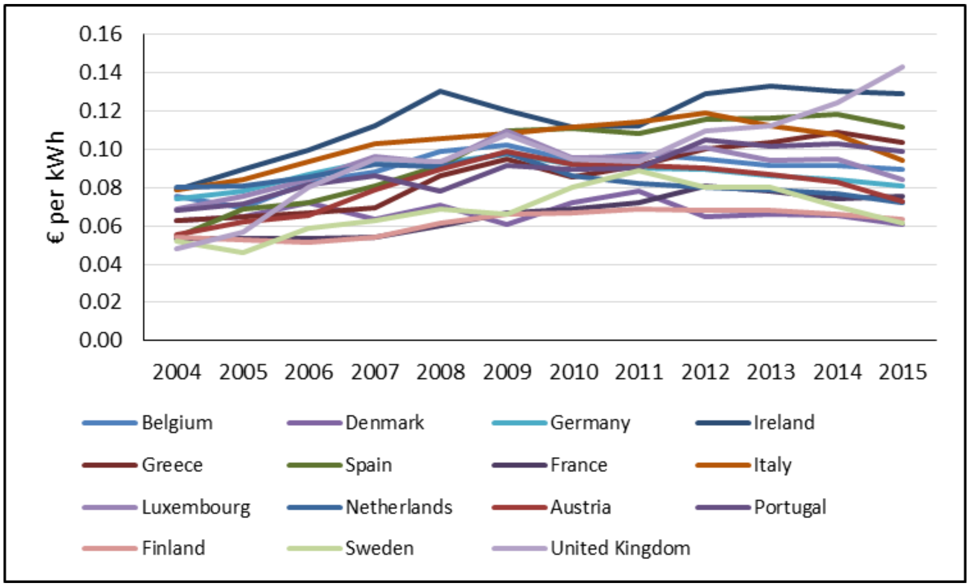


As illustrated by Figure 18, countries in the EU-15 with price decreases for industrial customers over the 2004 through 2015 period were the Netherlands (-11%) and Denmark (-3%). Industrial prices saw the greatest increases in the United Kingdom (200%), Spain (107%), and Greece (65%). Ireland has had the highest industrial prices over almost the entire period, with Sweden and Finland having the lowest prices. Again, this diversity shows that electricity prices are influenced by many factors, of which retail choice is only one.

Neither price regulation nor the opening of retail markets seems to have had significant impact on average residential prices. Two of the EU-15 countries – Finland and Portugal – saw price drops of about 10% in the three years immediately following market opening. In seven countries – Austria, Denmark, France, Germany, Luxembourg, Sweden and the United Kingdom – average prices rose less than 10% in the three years following market opening. Five countries had relatively large price increases after market opening: Belgium (22% after one year), Ireland (30% after three years), the Netherlands (36% after three years), Spain (37% after three years), and Greece (60% after two years). These price changes were due to multiple causes – in Ireland and Spain, for example, prices were already rising significantly before market opening – but it is apparent that retail choice alone was not sufficient to cause prices to drop. As illustrated by Figure 17 and Figure 18, prices for customers in the EU-15 countries continue to rise, with industrial customers experiencing a much flatter price trajectory in recent years.

[69] EUROSTAT [Electricity prices].

Figure 18
EU-15 Industrial Electricity Prices 2004 - 2015[70]



The EU experience gives no clear signal about how retail choice affects retail electricity prices. The difficulty is that prices are determined by a multiplicity of factors, and in some member states have been particularly driven by non-contestable charges such as taxes and renewable resource subsidies.

6.4.3. Review of Statistical Studies

Numerous studies have conducted statistical analyses of the relationship of electricity prices to restructuring and other factors likely to influence price. These studies have reached contradictory conclusions about the price impacts of retail choice, with the differences driven by differences in methodology and data series and by the fact that retail prices are determined by a complex mix of factors. Studies that particularly focused on retail choice have reached the following conclusions:

- Retail choice has reduced retail prices.[71]
- Restructuring and retail choice have improved generating plant efficiencies.[72]

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[70] EUROSTAT [Electricity prices].

[71] Andrews [2010] compared average retail prices in retail choice states versus traditional states over 1967-2007. Joskow [2006] statistically identified the determinants of industrial and residential rates by state for 1970-2003. Ros [2015] compared residential, commercial, and industrial prices in retail choice states versus traditional states over 1980s through late 2000s. Su [2014] compared residential, commercial, and industrial real average prices in retail choice vs. traditional states over 1990-2011.

[72] Craig and Savage [2009] compared heat rates of plants in retail choice states versus traditional states over 1996-2006.

- Retail choice has reduced retail prices in states with high participation rates and raised retail prices in states with low participation rates.[73]
- Retail choice has increased retail prices.[74]

Studies that focused on restructuring, without special consideration of retail choice, reached the following conclusions:

- Restructuring has provided substantial consumer benefits and/or significantly lower consumer prices.[75]
- Consumers in PJM have enjoyed savings due to restructuring.[76]
- Restructuring has not significantly affected customers' prices.[77]
- Restructuring has increased wholesale prices.[78]

Plainly, the studies have not reached consensus. Most of the reason for lack of consensus is that retail prices depend upon many factors, of which retail choice is only one; and statistical methods are unable to isolate the impacts of retail choice with precision. As stated by one analyst:

> …suppliers of full requirements retail service add to the wholesale [electricity] price additional costs and risks not directly related to the costs of energy. These may include capacity; ancillary services; transmission and RTO service charges; congestion charges; risk management costs; risks from fluctuating fuel prices; the risk that load will change; the risk that customers will migrate between suppliers; the risk of regulatory or

[73] Swadley and Mine Yücel [2011] statistically identified the determinants of retail choice states' prices over 1990-2010.

[74] Blumsack *et al* [2008] compared price-cost margins in retail choice states and traditional states over 1994-2005. Zarnikau and Whitworth [2006] and Zarnikau *et al* [2007] respectively analyzed residential and commercial retail prices in Texas as a function of Electric Reliability Council of Texas generation prices plus other bill components over the period 2000-2006, when rising gas prices fueled the results.

[75] Global Energy Decisions [2005] compared actual prices to simulated prices based on constructed costs under regulation for the Eastern Interconnection in 1999-2003. Harvey *et al* [2007] compared residential prices in RTO versus traditional markets in the southeast U.S.

[76] Center for the Advancement of Energy Markets [2003] compared PJM states to three non-restructured states, comparing 2002 to 1997. Energy Security Analysis [2005] simulated power flows and resulting costs within expanded PJM for 2005. Synapse Energy Economics [2004] compared actual wholesale generation prices for three PJM utilities to their implied costs under regulation in 1996-1997 as projected forward to 1999-2003.

[77] Apt [2005] compared rates of change in industrial prices before and after restructuring to rates of change without restructuring, by state and region, for 1990-2003. Tabor *et al* [2006] statistically identified the determinants of residential, commercial, and industrial prices, by utility, for 1990-2003.

[78] Lenard and McGonegal [2008] compared average wholesale power revenue in RTO versus non-RTO states for 1991-2006.

legislative changes; counterparty risks, and administrative, marketing, and legal costs to serve retail customers.[79]

Yet another reason for lack of consensus is that the experience with retail choice has occurred over only a limited number of years, so some of the statistical results have been heavily influenced by the happenstance of the events – like sharp fuel price changes or swings in the overall economy – that occurred during the years covered by the analysis. But statistical and data issues notwithstanding, it is apparent that there is no clear relationship between retail choice and retail price outcomes.

6.4.4. Cost-Shifting Among Customers

There is some evidence that retail energy suppliers cherry pick customers. The evidence also suggests that the most attractive customers, industrial and large commercial customers, take advantage of lower prices in either the retail choice market or the regulated market. Michigan is an example of this situation.

From 2001 to 2008, between 3% and 20% of Michigan's utility load participated in retail choice programs. Figure 14 shows that this participation moved in inverse proportion to wholesale energy prices and did so during this period. When wholesale energy prices were low, as it was before 2005 and after 2009, choice participation increased. When wholesale prices were increasing, as it was between 2005 and 2009, choice participation fell.

As Quackenbush *et al* note: "The nearly 11% load participation in the choice market today [2013] translates into 0.3% of total customers for DTE and 0.06% for Consumers Energy. The current rate structure essentially transfers fixed costs no longer recoverable from customers participating in choice to all remaining customers, creating a subsidy from more than 99% of customers to less than 1% of customers."[80]

Alternative retail energy suppliers target larger customers first because of the large size of their loads relative to the transaction costs of serving them. Likewise, large electricity customers will seek the lowest available electricity prices. The result of customers being able to shift between the market and utilities that price according to cost of service is rent-shifting: when large electricity customers leave for lower market prices, the utilities' fixed costs of service are borne by their remaining customers; and when large electricity customers return to the utility when market prices are high, the remaining customers share with the big guys the relatively low utility costs. For customers able to shift between the market and utilities, this is a heads-I-win, tails-you-lose proposition, for which the remaining customers are the losers.

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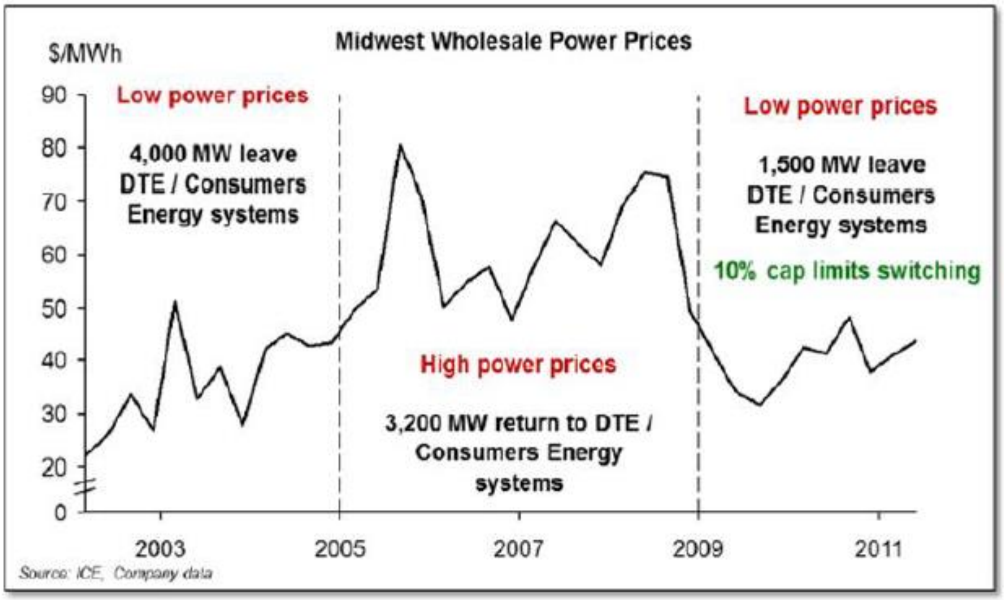
[79] Rose [2007, p. 21] examined the relationship of retail prices and wholesale market prices in 2006 in PJM's ComEd zone (i.e., Chicago and northern Illinois region).

[80] Quackenbush and Bakkal [2013, p. 16].

Figure 19
Relationship of Michigan Retail Choice Participation to Wholesale Power Prices[81]



6.5. Impacts on Resource Adequacy[82]

A power system has adequate resources if its supply- and demand-side resources reliably exceed its loads. Although resource adequacy can be measured in an operational timeframe, under which resources' total *available* capacity would need to exceed load by specified operating reserve margins in each hour or dispatch interval, it more generally refers to a planning timeframe, under which resources' total *nameplate* capacity must exceed annual peak load by a specified planning reserve margin. In both timeframes, the reserve margins are set so that the power system can respond, with a high probability of success, to generation and transmission equipment outages, load fluctuations, and other random events.

6.5.1. Investment Risk Impacts of Retail Choice

Resource adequacy requirements are determined by the North American Electric Reliability Corporation, the relevant regional reliability entities, and federal and state requirements. Resource adequacy outcomes are determined overwhelmingly by wholesale market structure, particularly the manner in which resource investors are compensated: in traditionally regulated regions, investors are more or less guaranteed cost recovery, including a return on capital, for investments that regulators deem prudent; while in RTO regions, cost recovery depends upon uncertain market-determined prices for energy, capacity, and ancillary services.

[81] Quackenbush and Bakkal [2013, Figure 2, p. 12].

[82] For a more detailed discussion of some of the issues raised in this section, see Morey *et al* [2014].

Some resource adequacy challenges arise from the ways in which wholesale electricity markets have been structured and planned. With respect to structure, most or all RTO regions have ceilings on allowable prices of or bids for electrical energy and ancillary services. The purposes of these ceilings are to limit the possible exercise of market power by resource owners and to limit price volatility; but another important effect of these ceilings is to limit the profits that resources may legitimately earn at times when reserves are thin. This holding down of energy and ancillary services prices makes resource investments less attractive. With respect to planning, planning reserves are generally set according to a nationwide reliability guideline by which resource-related outages may be expected to occur no more often than one event in ten years. This guideline implies an incremental cost for planning reserves that is at least 30 times what electricity consumers are willing to pay for reliability.[83] The consequence is that a free market mechanism cannot yield planning reserves that meet the standard; so the standard must instead be financed indirectly though administrative mechanisms, like mandatory reserve requirements, that recover their costs through hidden charges on consumption.

The price caps and high nationwide reliability guideline together make it difficult for energy and ancillary service market revenues to cover generators' costs. This can be seen in RTO reports that consistently show that these revenues fall short of covering costs. For example, Table 12 summarizes the findings, by the RTOs or their independent market monitors, regarding the estimated net revenues that would have been earned by a hypothetical new combustion turbine units operating in each of six RTOs in each of the years 2005 through 2014. Net revenues are defined as gross revenues from energy, ancillary services, and capacity markets (where they exist) minus operating expenses like fuel and labor. For a combustion turbine to break even or run a profit, its net revenues must at least equal the turbine's capacity costs. The table shows, in its rightmost column, the capacity costs estimated by the PJM Independent Market Monitor for each year.[84] Comparing the capacity costs of the rightmost column to the RTO-wide net revenues shown in the other columns, it is apparent that, with few exceptions, there is a persistent revenue insufficiency in all the RTO markets. This persistent revenue insufficiency is a hallmark of the "missing money" problem that arises from the wholesale market design flaws already identified.

Retail choice exacerbates the resource adequacy problem by materially adding to the financial uncertainties faced by investors in generating resources. These financial uncertainties arise from uncertainties in the revenues that a generator will receive for its services. In the absence of retail choice, the investor, being a monopoly utility, has a relatively high degree of certainty

[83] Astrape Consulting [2013, p. 1] notes that this reliability target implies customer willingness-to-pay of $300,000 per MWh to avoid curtailment. The $300,000 figure assumes that: a) the carrying cost of new capacity is $90,000 per MW-year; and b) that a typical resource-related firm load shed event lasts three hours. Thus, $300,000 = $90,000 per MW-year / [(3 hours per event) / (1 event per 10 years)]. This absurd result is equivalent to a homeowner with a 3 kW load paying $900 for one hour's worth of power, and is much higher than the $10,000 per MWh that is at the high end of the literature's estimates of consumers' outage costs.

[84] Capacity costs are in nominal dollars levelized over twenty years. Although the cost of new entry (CONE) varies among RTO markets, we use PJM's CONE estimates for simplicity of presentation. Use of the other RTOs' CONE estimates would show similar revenue insufficiency.

about the quantity of service that it will provide to its customers and, under cost-of-service regulation, about the revenues that it will receive for providing that service. With retail choice, investors have sales contracts with durations that are only small fractions of the lives of their investments, which means that their revenues depend upon uncertain future market conditions. This uncertainty makes investment in new generation less attractive and makes long-term fuel contracting less attractive for existing generators, which may impinge upon resource adequacy and certainly raises the required returns on investment capital. This increase in required returns must ultimately be paid by consumers in the form of higher prices.

Table 12
Comparison of Net Revenue for Combustion Turbine Gas Plant ($ per MW-month)[85]

Year	CAISO	ERCOT	ISO NE	MISO	NYISO	PJM	Levelized Cost
2005					1,917	833	6,000
2006					3,167	1,250	6,667
2007	4,333	3,333			4,167	4,083	7,583
2008	5,083	7,583			5,667	4,250	10,333
2009	4,917	3,667			5,250	4,833	10,750
2010	4,417	3,750	2,500	2,250	3,833	7,667	10,917
2011	3,750	9,167	2,333	2,250	3,333	7,167	9,250
2012	4,083	2,083	4,200	2,333	1,750	4,500	9,417
2013	4,200	7,700	6,700	2,500	7,083	4,500	9,144
2014	4,750	3,083	10,800	2,600	6,758	4,300[86]	9,050

Resource adequacy in traditional market states relies on implicit long-term contracts between regulated utilities and their customers in the aggregate. These long-term sales obligations to customers allow regulated utilities to engage in long-term planning processes to secure a generation and contract portfolio that satisfies load and reserve requirements, both now and in the future. In contrast, retail choice markets have relatively few long-term contracting options. Long-term contracting in retail choice states has been hindered by customers' ability to switch

[85] The RTOs assume that combustion turbine units have heat rates between 10,250 and 10,500 MMBtu per MWh. See Brattle Group [2013]; California Independent System Operator [2012, 2013, 2014, 2015]; Patton *et al* [2009, Figures 10 and 11, pp. 36-37; 2013, Figures A-14 and A-15, p. A-22; 2014, Figure A-17 through Figure A-22, pp. A-26 to A-29; 2015, Table A-5, p. A-31]; Potomac Economics [2013a, Figures 63 and 64, pp. 76 & 77; 2013b, Figure 6, p. 10; 2015, Figure 7, p. 12]; and Monitoring Analytics [2009, 2013, Net Revenue Analysis sections]. The MISO figures are averages across zones. The New York figures are averages of values for the Hudson Valley and Capital Zones for 2004-2007, and averages for the Hudson Valley, Capital, and West Zones for 2008-2012, and averages for 2013 for the Capital Zone, Hudson Valley, Long Island, NYC, and West Zone, and capacity weighted averages for 2014 across the Capital Zone, Hudson Valley, Long Island, NYC, and West Zone. 20-year levelized cost figures are from Monitoring Analytics [2009, 2013, 2014, 2015].

[86] PJM's market monitor notes that, due to the high energy prices associated with the polar vortex in January 2014, net revenues would have been sufficient to cover costs in ten of PJM's nineteen zones in 2014.

suppliers, by customers' ability to switch from alternative retail providers to the incumbent utility's standard offer or POLR service whenever the competitive market price rises above the regulated rate, by public policies that protect buyers from service curtailments when there is a power shortage and their own contracted supplies are insufficient to meet their load obligations, and by asymmetries in the positions held by buyers and sellers in retail choice markets.

The asymmetries arise from the fact that consumers and resource owners have radically different timeframes for their engagements in electricity markets. Residential consumers tend to move every several years and generally do not want contracts more than a few years long. Business consumers can be unsure about the longevity of their businesses and generally do not want contracts more than a few years long. Owners of generation, on the other hand, can best hedge their financial risks by selling power under long-term contracts with durations that match the lives of their assets. For generation owners, it is relatively risky to rely on the volatile spot market or short-term contracts for cost recovery. Retail energy suppliers are caught in the middle. If they purchase power and capacity to supply their load under long-term contracts with resource owners while they are unable to enter long-term contracts with retail customers, they face the risk that retail customers may switch to other providers, leaving them unable to recover the costs of their long-term contracts with resource owners. Merchant generators operating in the reformed wholesale markets consequently are unable to readily find either retail providers on the buy side of the market or power marketers on the sell side of the market interested in long-term deals.

6.5.2. Other Impacts of Retail Choice

Retail choice may affect resource adequacy in a few other ways.

First, retail choice might cause significant changes in customers' aggregate loads relative to what they would be without retail choice. For example, retail choice could make customers more accepting of pricing or curtailment terms that significantly reduce peak loads relative to a world without retail choice, thus improving resource adequacy. As shown above in Table 5, retail choice states have higher participation rates in dynamic pricing programs than do states without retail choice; and these higher participation rates may cause enough load shifting to improve resource adequacy by reducing aggregate peak loads.

Second, by allowing customers and generators to deal directly with one another, retail choice might increase the sales options available to generators and raise the net prices they receive, thus encouraging investment.

Third, retail choice may cause consumers to choose to support particular types of generation technologies, thus shifting the generation mix. As shown in Table 8 and Figure 9, retail choice is encouraging customer support toward renewable energy. If the result is a significant shift in generation mix toward intermittent resources such as wind and solar, that would raise resource adequacy issues because of the non-dispatchability of such resources, in particular as the share of intermittent resources in the total generation mix reaches significant levels.

Fourth, by facilitating wholesale market restructuring, retail choice arguably shares some of the credit or blame for the resource adequacy impacts of wholesale market restructuring. On the positive side, these include competition-driven improvements in generators' efficiency and availability. On the negative side, these include greater uncertainties in returns on investments.

6.5.3. Overview of Retail Choice Impacts

Public policy will not allow resource adequacy to be determined by the market, with or without retail choice. Some policies, like wholesale market price caps and other consumer protections, deliberately prevent consumers from seeing prices that reasonably reflect supply and demand conditions. Other policies, like requiring system operators or retail energy suppliers to maintain planning reserves that meet load under almost all conditions, prevent individual customers from choosing lower levels of reliability, and thereby require consumers to pay the costs of maintaining reliability that they may not need.

The consequence is that retail choice is unlikely to materially affect resource adequacy. Instead, retail choice is much more likely to affect the costs of maintaining the level of resource adequacy mandated by public policy and the distribution of these costs among consumers. By making investment returns more uncertain, retail choice raises costs. By promoting dynamic pricing programs, retail choice reduces costs. By promoting investment in intermittent generation resources, retail choice increases costs. By allowing customers to switch between alternative suppliers and incumbent utilities, retail choice can allow some customers to escape some of the costs of maintaining adequate resources.

6.6. Impacts on the Division of Financial Risks Among Stakeholders

Retail choice affects the division of financial risks between electricity producers and consumers. The financial risks are those arising from uncertain future electricity prices and those attending investments in long-lived generation and demand-side resources.

6.6.1. Division of Electricity Price Risk

Under retail choice, retail prices can vary substantially with changes in electricity market supply and demand conditions. This can be seen, for example, in the history of the past decade and a half, during which RTOs' electricity prices have generally swung up and down with the price of natural gas, which has often been the marginal fuel upon which electricity prices have been set. When gas prices have been low, retail choice consumers benefited from low electricity prices while generators suffered low or negative profit margins. When gas prices have been high, retail choice consumers have faced high electricity prices while generators enjoyed healthy profit margins. Consequently, retail choice can cause large variations in producers' profits and lead consumers to see large sudden changes in the prices they pay upon expiration of any limited-term price guarantees.

In principle, producers and retail choice consumers could mitigate electricity price risks through long-term contracts. In practice, however, such long-term contracts are a rarity. Although many retail energy suppliers have induced customers to switch from the incumbent utility to a competitive supplier by offering fixed rates, these fixed rates are of limited duration. Furthermore, the suppliers offering such fixed rates can and have experienced financial problems, including bankruptcy, that raise questions about the sustainability of some approaches to fixed-rate product offerings.

Traditional regulation minimizes price risks by implicitly imposing long-term contracts upon both producers and consumers. In essence, the generation investments of regulated utilities are dedicated to their customers, who have the right to use those investments at cost (including return on capital). Under traditional regulation, the costs paid by consumers do vary, particularly when large investment costs are incorporated into rate base and when there are large movements in fuel prices. Nonetheless, regulation implicitly hedges costs by fixing a large share of costs at the utility's original cost level. Consequently, the variation in prices seen by consumers is less under traditional regulation than under retail choice; and the variability of producers' profits is also less.

6.6.2. Division of Investment Risks

Investment risks arise from uncertainties in the future prices or values of inputs (like fuel and labor), in the future prices or values of outputs (like electrical energy and ancillary services), in the operational efficiencies and effectiveness of generation facilities, and in law and regulation. Some of these risks (like regulation of electricity market structures) are systematic in that they affect all investments. Some risks (like uranium prices and greenhouse gas limits) affect particular classes of investments. And some risks (like generation operational problems) are idiosyncratic to particular investments.

Traditional cost-of-service regulation more or less guarantees that producers will recover the costs of their prudently incurred resource investments, so that the financial risks of poor investments are largely (but not always) passed on to consumers. Under retail choice, by contrast, producers who make poor investments (due to bad management or bad luck) bear most of the financial risk and consumers bear little or no risk. If the market works well, the risk and attendant costs that producers bear in a retail choice environment will be efficient relative to those achieved in a traditional market setting. Even under retail choice, however, systematic risk increases the costs of all producers, thus reducing investment and raising electricity prices to a level that compensates producers for bearing this risk; so the costs of systematic risk are likely to be indirectly borne by consumers through the prices they pay for power and related services.

Leverage

Related to the division of investment risk is the manner in which utilities have tried to manage this risk with the introduction of retail choice. One of the major means of managing this risk is through the utility's capital structure as characterized by leverage, which is the ratio of the firm's total debt to its total assets. Regulated firms traditionally display a high leverage ratio compared to competitive firms, which means that regulated firms, being relatively low-risk, are willing and able to take on a relatively large amount of debt. One would expect utilities' leverage to decline with the transition to a competitive retail market as utilities reduce the relative amounts of their debt in the face of higher market risk.

Indeed, this is what has apparently occurred. Controlling for other factors that influence utilities' capital structure decisions, the passage of retail choice legislation appears to reduce utilities' leverage ratios by an average of 22%, a substantial drop that indicates that retail choice substantially increases utilities' risks. All other state policies associated with implementation of retail choice have much smaller effects on leverage. Furthermore, the greater the market risks posed by retail choice, the less debt that a utility will hold. In particular, a 1% increase in the potential customer switching share leads to a 0.02% decrease in the leverage ratio, indicating that utility risk increases as customer switching increases. When an incumbent utility is designated as the default provider, implying lower risk of market share loss, its leverage ratio increases by about 2%.[87]

Return on Equity

The American Public Power Association has summarized several key indicators of the "financial performance of companies that sell significant quantities of unregulated generation in the wholesale electricity market operated by the PJM Interconnection."[88] These indicators are return on equity, net income, and gross margin.

The relatively high returns of the unregulated subsidiaries may be due to several other causes as well. One possibility is that unregulated firms, facing greater financial risk, require higher returns on equity than regulated firms. Another possibility is that retail choice leads to higher retail electricity prices, hence higher returns on equity for unregulated firms. Yet another possibility is that the relative returns of unregulated and regulated firms fluctuate over time, and the two years in the table just happen to be years in which unregulated firms fared better. A great deal more analysis, including a longer time frame, would be required to reach any firm conclusions.

Table 13 summarizes the return on equity (ROE) estimates for the unregulated and regulated subsidiaries of four electric utility holding companies that operate in the PJM RTO wholesale market and that also serve customers in retail choice states in which the regulated subsidiaries operate. For holding companies with multiple regulated subsidiaries, there is a separate row indicating the ROEs for each subsidiary. The estimated ROEs suggest that the holding companies' unregulated generation segments generally earn higher returns from the wholesale market than their regulated subsidiaries engaged in local distribution service. The American Public Power Association attributes the higher returns of the unregulated affiliates to high gross margins (revenue net of fuel and purchased power costs) on electricity sales in the wholesale market due to "the drop in fuel costs… not being fully passed on to consumers."[89]

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[87] Sanyal and Bulan [2007].

[88] American Public Power Association [2012, p. 1].

[89] American Public Power Association [2012, p. 4].

The relatively high returns of the unregulated subsidiaries may be due to several other causes as well. One possibility is that unregulated firms, facing greater financial risk, require higher returns on equity than regulated firms. Another possibility is that retail choice leads to higher retail electricity prices, hence higher returns on equity for unregulated firms. Yet another possibility is that the relative returns of unregulated and regulated firms fluctuate over time, and the two years in the table just happen to be years in which unregulated firms fared better. A great deal more analysis, including a longer time frame, would be required to reach any firm conclusions.

Table 13
Estimated Returns on Equity for Selected Electric Industry Companies in PJM RTO[90]

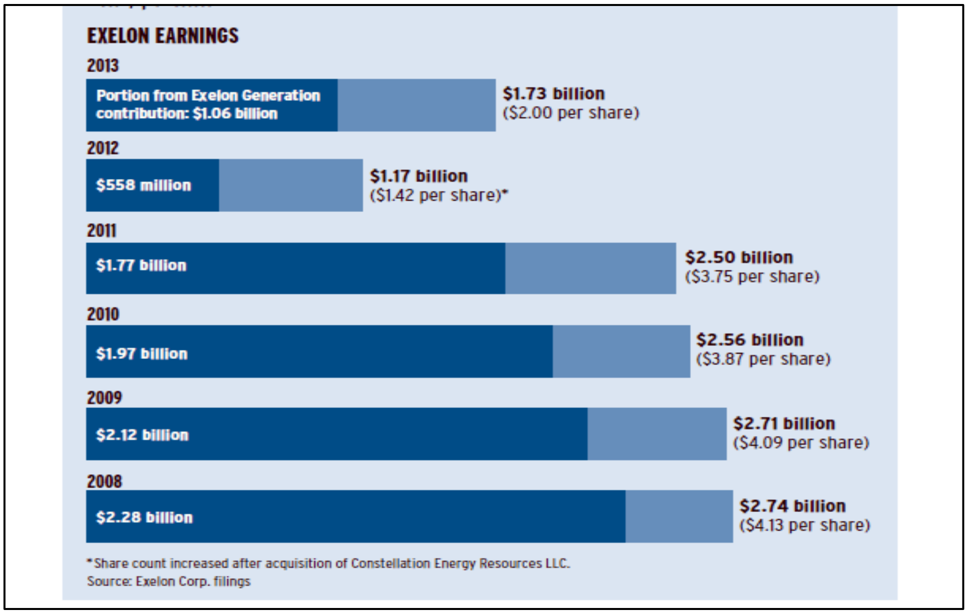
	Unregulated		Regulated	
Holding Company	**2010**	**2011**	**2010**	**2011**
Exelon Corporation	26.9%	23.0%	5.0%	6.0%
			14.0%	13.0%
PPL Corporation	22.0%	15.8%	6.0%	8.0%
PSEG Corporation	21.7%	15.5%	10.0%	11.0%
First Energy Corporation	13.0%	15.1%	6.0%	6.0%
			7.0%	8.0%
			5.0%	8.0%
			17.0%	18.0%
			7.0%	7.0%
			8.0%	9.0%

The separation of generation services from wires service in the majority of retail choice states does appear to have shifted the risk of investment return to generation owners. The fortunes of firms with significant unregulated generation subsidiaries, like Exelon and FirstEnergy, now have their fortunes tied to the vicissitudes of restructured wholesale markets such as PJM's. This can be illustrated by the recent trend in Exelon's earnings over the period 2008 through 2013 as shown in Figure 20. From 2008 to 2012, Exelon Generation's contribution to overall corporate earnings fell by about 75% from $2.28 billion to $0.56 billion as falling natural gas prices caused a fall in PJM's wholesale electricity prices. Exelon Generation in 2008 contributed 83% of Exelon's earning, but by 2012 contributed just 48%. Exelon's fortunes improved in 2013

[90] American Public Power Association [2011, p. 4] and American Public Power Association [2012, p. 7]. Exelon Corporation's unregulated subsidiary is Exelon Generation, and its regulated subsidiaries are Commonwealth Edison and Potomac Electric Power Company. PPL Corporation's unregulated subsidiary is PPL Energy Supply (which has some international operations and gas trading operations) and its regulated subsidiary is PPL Electric Utilities. PSEG Corporation's unregulated subsidiary is PSEG Power and its regulated subsidiary is PSEG. First Energy Corporation's unregulated subsidiary is FE Solutions and its regulated subsidiaries (in the order shown in the table) are Cleveland Electric, Jersey Central Power & Light, Metropolitan Edison, Ohio Edison, Pennsylvania Electric, and Toledo Edison.

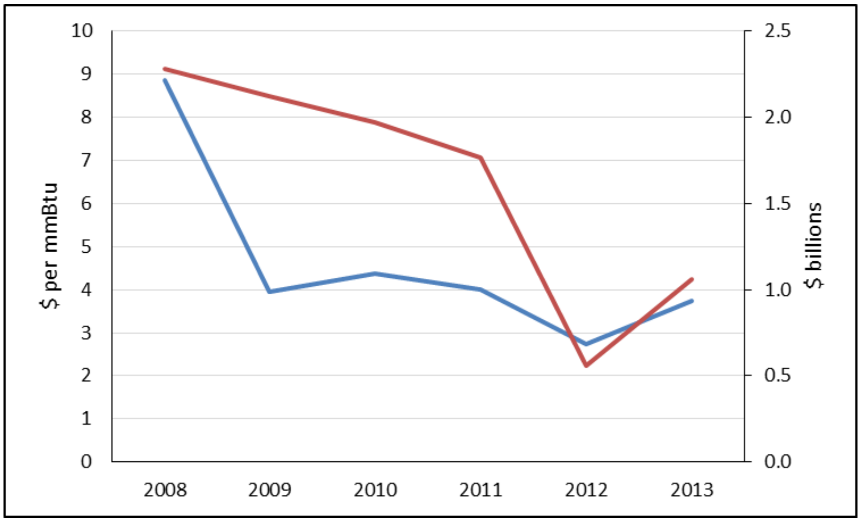
where Exelon Generation contributed 61% of corporate earnings. Because Exelon Generation's revenues primarily come from the sale of energy and capacity from its nuclear plants, its returns on generation investment are highly correlated with fuel costs of competing generation, natural gas in particular. This correlation is somewhat visible in Figure 21. Investors will require a risk premium for investments in the unregulated electricity generation sector, which ultimately affects retail customers' bills.

Figure 20
Exelon Earnings, 2008 to 2013[91]



[91] Daniels [2014].

Figure 21
Relation of Exelon Generation Revenues and Natural Gas Spot Price[92]



An additional indicator that retail market restructuring has shifted risk is the fact that recently there has been a realignment of diversification within the industry. One observer notes that:

> The last few years have seen many asset-level generation deals where IPPs and other financial investors have acquired baseload plants, mostly from diversified utilities, as low natural gas and power prices saw many discounted power plants come to market. Diversified utilities, on the other hand, have focused on optimizing assets and growing their regulated businesses.[93]

Without saying that retail restructuring has shifted risk from customers in a regulated market structure to generation investors in the relatively less regulated wholesale/retail markets, the same observer implies the same by stating that:

> The recent trend of US diversified utilities selling their non-regulated power plants, in order to focus solely on regulated businesses, is re-setting their trading multiples. In 2013, Missouri-based Ameren Corp. sold its merchant coal plants to Dynegy while California-based Edison International sold its non-regulated subsidiary, Edison Mission Energy. Other large caps, including Duke Energy and American Electric Power, have announced sales of Midwest power plants.
>
> Diversified companies, which are significantly levered to generation businesses, are acquiring regulated utilities to de-risk their asset bases. A notable example is PPL Corp. The company's acquisitions of regulated utilities in the US and UK over the last few years have transformed its business mix from 80/20 merchant/regulated to a 20/80 ratio. Also, the company recently announced

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[92] Exelon Generation revenues are per Daniels [2014]. Gas prices are per U.S. Energy Information Administration [Henry Hub].

[93] Rennie [2015, p. 8].

plans to spin off merchant assets into a separate IPP, making PPL a purely regulated company. Similarly, Exelon Corp. recently acquired Pepco Holdings, a regulated utility, in a move that will see regulated operations contributing about 60% to 65% of Exelon's total earnings over 2015-16 (up from expectations of 55% to 60% pre-deal).[94]

6.7. Impacts on Particular Demographic Groups

State policymakers and regulators are concerned about the impacts of retail choice on various demographic groups, particularly low-income customers and residential customers in general. Because wholesale prices in RTOs vary by location, there are further concerns that the retail prices available to customers in some locations will be systematically higher than those in other locations. This section discusses the impacts of retail choice along the dimensions of customer income, customer class, and customer location.

6.7.1. Low-Income Customers

According to long-time consumer advocate Barbara Alexander, "there is a growing body of preliminary evidence that many residential customers and particularly low income customers are paying higher prices than they would have paid for default service when they select an alternative supplier."[95] Alexander cites the following examples:

- In New York, a Public Utility Law Project evaluation of 8,709,449 residential customer gas and electric bills for the period August 2010 through July 2012 found that, among the customers who switched to alternative suppliers, 84% of the residential electric bills and 92% of the residential gas bills were higher than would have been charged by the incumbent utility. Over the 24-month period, this raised customers' bills by averages of about $500 for electricity and $260 for natural gas. For this same period, the average bills of low-income customers who switched were raised by about $400 for electricity and $275 for gas. Only 8.5% of low-income electricity customers and 6.6% of low-income natural gas customers realized savings, averaging $40 for electricity and $63 for gas. Over this period, customers served by alternative suppliers were sent 377,736 final termination notices due to nonpayment.
- In Pennsylvania, a study found that about 73% of PPL Electric's low-income customers served by alternative electric suppliers paid more than they would have paid to the incumbent utility. This analysis resulted in the same unfortunate finding — over 70% of the low income customers served by an alternative supplier were paying more than the PPL Electric default service price at the time of the evaluation.

[94] Rennie [2015, p. 10]

[95] Alexander [2013].

- In Illinois, the Citizens Utility Board study found that, since 2003, 94% of the alternative natural gas supplier plans resulted in higher prices for residential customers than they would have paid to the incumbent utility.
- In Ohio, Ohio Partners for Affordable Energy found that Columbia Gas of Ohio indicates that customers purchasing commodity natural gas from unregulated suppliers pay substantially more than the incumbent's default service price for natural gas, which in Ohio reflects wholesale market prices.

Alexander laments policies that push unwary consumers toward alternative suppliers.

> … the stability of default service and the residential customer preference for that service has been viewed as adverse to the development of a "fully" competitive market by some policymakers. Recently, many … state regulatory commissions are seeking to enhance and promote a reliance on retail energy markets and either reduce or eliminate the local utility' obligation to provide default service. Whether as a response to pressure from the alternative suppliers or the theory that default service constitutes a barrier to the creation of a retail energy market, some states have embarked on policies and programs designed to change the nature of default service and "push" residential customers into the arms of the retail suppliers. These regulatory initiatives as well as the increased marketing activities by many alternative suppliers, particularly with respect to door-to-door marketing in large urban areas, have sparked the need for this Report.[96]

Hortacsu *et al* find that retail choice disproportionately benefits well educated, high-income, white, urban customers. They measure the benefits of retail choice according to a metric they call "Percent Achieved," which is the fraction of potential savings that were realized by switching, relative to purchasing from the incumbent. They find the following:

> … households with a higher "Percent achieved" tend to be in neighborhoods with a higher educated population, a lower poverty rate, and a greater fraction of households in an urbanized area. In addition, a higher "Percent achieved" is realized in neighborhoods with *ceteris paribus* fewer senior citizens, more blacks, fewer Hispanics, and fewer houses with electric heating... and find that higher usage households realize a greater "Percent achieved". … We find that homes with higher value and higher electricity usage realize a higher "Percent achieved". To the extent that house value is a proxy of occupant wealth, this suggests that wealth is positively associated with "Percent achieved".[97]

In summary, there is evidence that retail choice decisions require business savvy that many consumers lack, and that less educated or low-income consumers are more likely than other consumers to make poor retail supplier choices.

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[96] Alexander [2013, pp. 19-20].

[97] Hortacsu *et al* [2012, pp. 13-14].

6.7.2. Residential Customers

State policymakers have been concerned that residential customers would be particularly prone to miss the benefits of retail choice, partly because competing retail energy suppliers would not solicit small customers and partly because inertia would cause most customers to remain with their incumbent utilities regardless of competitors' efforts. The relatively low switching rates of residential customers, as shown in Figure 2 and Figure 3, for example, support this concern. Furthermore, Hortacsu *et al*, in examining customer inertia issues in the Texas retail choice market, find that the

> …incumbent enjoys an economically very significant 'brand' effect – consumers value the incumbent's brand at nearly $80 per month… The 'search' and 'switching' cost components of decision-making also play important roles… While the percentage of households who actively search in a given month is not large, the search activity shows intuitive seasonal patterns: consumers are most likely to search in summer months, during which electricity bills tend to be high.[98]

We believe that the concern over residential switching rates is misplaced. Residential consumers rightly recognize that the transaction costs of switching are high relative to the prospective benefits of lower bills and better customer service. These transaction costs include those of gathering information, evaluating competing offers, hassling with the communications and paperwork necessary to implement a switch, and risking the uncertainties of doing business with a relatively unknown competitive supplier. Considering these transaction costs, the net benefits of retail choice to residential customers are likely to be small to non-existent. Residential customers rationally forego switching because they intuitively recognize the lack of benefits of doing so.

6.7.3. Customers' Geographic Locations

The cost of electricity varies by location, as is apparent from the significantly different locational prices found within each RTO footprint. Under traditional regulation, retail prices are generally identical at all locations within a utility's service territory because of the notion that it would be unfair for different customers of the same utility to pay different prices merely because of the happenstance of their locations and the power system's configuration. Under retail choice, competing suppliers are forced by locational differences in wholesale electricity prices to charge retail prices that reflect the locational costs of electricity. Consequently, the prices that customers pay under retail choice tend to vary by customers' locations. For example, a study of retail choice in Pennsylvania finds that the retail supply auctions conducted by Pennsylvania utilities consistently reflect the higher wholesale spot prices in eastern Pennsylvania, which is the more densely populated part of the state.[99]

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[98] Hortacsu *et al* [2012, p. 4].

[99] Kleit *et al* [2011].

Whether or not locational differentiation of retail prices is a bad thing depends upon notions of fairness. We accept that the prices of coal, natural gas, and apples, for example, will be lower close to the point of production than it will be elsewhere because of transportation costs; and we accept that the retail electricity prices for lower-cost utilities will be lower than for higher-cost utilities. But the electric power industry has a history of regarding retail price differences within a utility's service territory as inequitable, even if it is more costly to serve customers located far from generation resources than it is to serve customers close to those resources. The traditional uniformity of retail prices within utility service territories has been supported by an implicit system of cross-subsidies among captive utility customers. Retail choice results in retail prices that reflect the locational costs of electricity, and will do so unless retail choice programs are accompanied by similar systems of cross-subsidies. In the context of competition, such a system of cross-subsidies would be more complex and unwieldy than under traditional regulation. The most feasible way to avoid locational differentiation of retail electricity prices is to stick with traditional regulation.

6.8. Impacts on Regulation

Retail choice changes the role of state regulators in two somewhat opposite ways. On the one hand, state regulators have less to say about generation capacity and operating costs than under traditional regulation. This occurs because retail choice moves generation investment and fuel procurement decisions toward the market and away from regulators, especially where wholesale market prices of electricity are determined by RTOs' dispatch of regional generation resources. On the other hand, because of the issues raised in Section 6.1.3, state regulators have a new role with respect to consumer protection than they do under traditional regulation.

7. SUMMARY AND CONCLUSIONS

The Energy Policy Act of 1992 opened the floodgates to wholesale competition by creating a class of Exempt Wholesale Generators who were authorized to compete in wholesale markets. FERC's major response to this Act was Order No. 888 of 1996, which gave wholesale entities non-discriminatory access to transmission networks and thereby fostered competitive wholesale electricity markets. This legislation and regulatory response have together saved the U.S. many billions of dollars per year in generation costs.[100] The creation of RTOs, by more or less automating wholesale trades among participating entities, may have engendered additional savings (which have been at least partly offset by the RTOs' operating costs).

While the wholesale restructuring engendered by the Energy Policy Act of 1992 addressed some real barriers to trade, the dismantling of which has saved the U.S. many billions of dollars per year, the potential gains from retail choice were speculative at best. By the time that retail

[100] These savings began in the 1980s due to the impetus of competition in generation services engendered by the Public Utility Regulatory Policy Act of 1978. This competition provided strong incentives for unregulated generation firms to improve generators' efficiency and availability, which they in fact did. See, for example, the heat rate improvements (that is, increased electricity output per unit of fuel input) cited by Fabrizio *et al* [2007] and Chany *et al* [2012].

choice programs were introduced beginning in the mid-1990s, there was already a substantial body of evidence, from innovative retail electricity programs dating back to the 1970s, that customers' short-term response to electricity prices was small and that customers' willingness to be curtailed, even when they had promised to be available for curtailment, was even smaller.[101] Nonetheless, through a confluence of hopes from disparate interest groups, retail choice was adopted alongside wholesale restructuring. Nearly two decades later, there is little evidence that retail choice has yielded significant benefits beyond those from wholesale competition.

7.1. Expected Benefits and Costs of Retail Choice

At the time of its promotion in the late 1990s, the advocates of retail choice expected that it would produce two major categories of benefits: lower retail electricity prices; and wider range of retail customer service options.

7.1.1. Lower Retail Electricity Prices

There are three basic ways that retail choice might result in lower electricity prices.

First, as a complement to wholesale competition, retail choice might facilitate the development of competition that would drive improvements in the efficiency of electricity production and delivery, particularly through increased innovation and technological stimulation. This could occur because competition in the provision of retail services might enhance the competitive positions of non-utility generators by expanding the market opportunities for these generators' services.

Second, retail choice might promote more efficient retail pricing that would improve the efficiency of customers' use of the power system. This could occur particularly through greater customer participation in dynamic pricing programs. Such participation, while increasing the variability of prices paid by customers, would reduce the average prices paid by customers.

Third, retail choice would enable customers to capture economic rents from utility shareholders. This might have occurred if customers could have escaped responsibility for the costs of power plants that appeared to be expensive in the late 1990s, but turned out to be bargains just a few years later.

On the other hand, as a complement to wholesale competition, retail choice would share some responsibility for the higher costs due to generators' increased financial risks under competition and due to the coordination problems accompanying the unbundling of the generation and transmission functions.

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[101] In a notorious episode in January 1994, a generator scheduling error in New York led to rotating blackouts in the mid-Atlantic states that shut down Washington, D.C. In the midst of this crisis, industrial electricity customers who were on curtailable tariffs refused be curtailed, and had their Congressmen go to bat for them (successfully) in pressuring utilities to continue giving them power while supposedly firm customers lost their power.

7.1.2. Wider Range of Retail Customer Service Options

Retail choice held out the promise of offering customers a larger menu of service options than was offered by utilities, and of allowing customers to negotiate terms of service that would better be tailored to their needs. The terms of service could conceivably vary by energy source, firmness of service, variability of price over time, duration of price guarantee, degree of price guarantee, allowed flexibility of the customer's electricity consumption, billing and payment arrangements, and bundling of electricity with other products. Retail choice was supposed to widen the menu of service options because competitive retail service providers would seek new ways to differentiate their products from those of their rivals. Within this range of service options, retail choice promised to facilitate promotion of renewable resources.

On the other hand, because non-utility providers of retail service would be more lightly regulated than utilities, retail choice also raised the prospect of consumer risks – from competitive retail service providers' performance problems, for example – that have been largely absent for regulated utilities.

7.2. Actual Benefits and Costs of Retail Choice

The promised benefits of retail choice were partly real and partly illusory. Those benefits could occur, and did occur, only to the extent that retail choice enhanced competition by broadening the market or that alternative retail energy suppliers could offer retail products that were somehow better than those offered by incumbent utilities.

The benefits and costs of electricity competition arise overwhelmingly from reforms at the wholesale level, not at the retail level. Disentangling the impacts of wholesale and retail reforms is difficult, as these impacts have arisen from a plethora of federal and state policy changes as well as major economic events like financial crises and major movements in national and international commodity markets. We nonetheless summarize the evidence on the actual benefits and costs of retail choice, following the same scheme used above for listing the expectations of the advocates of retail choice.

7.2.1. Lower Retail Electricity Prices

Measuring the price impacts of retail choice programs is difficult because retail choice is only one of many factors that affect power system costs. Statistical studies of the relationship of electricity prices to retail restructuring have reached contradictory conclusions about the price impacts of retail choice. Indeed, the EU experience indicates that the price impacts of retail choice are likely to be swamped by other factors, such as charges to support renewable resources, and that neither price regulation nor the opening of retail markets seems to have had significant impact on average residential electricity prices in the EU. Nonetheless, the evidence supports the following conclusions about price impacts of retail choice:

- Retail electricity prices in retail choice states vary with current fuel prices and other market factors, and are therefore less stable than retail prices in other states.

- Retail electricity prices in retail choice states vary by location in a manner that mimics locational variations in wholesale electricity market prices.
- 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. The overall trend has been toward a lower price gap, though that is at least partly due to the happenstance of natural gas prices being low at the present time.
- Retail choice is extending the market penetration of retail pricing programs that reflect power system conditions, thus shifting loads from peak to off-peak periods. All other things equal, this lowers the average costs of producing power and tends to improve resource adequacy.

Implementation of retail choice has involved some new costs:

- Retail choice requires that billing procedures be adapted so that appropriate shares of customer payments go to the utility (for non-competitive services) and to third-party retail suppliers (for competitive services).
- Retail choice requires metering that is compatible with new retail service offerings.
- To facilitate the competition in generation services that is necessary for retail choice, there must be functional unbundling of utilities' generation function from its distribution and transmission functions. In most retail choice states, government encouraged or required utilities to divest generation assets or move them to separate affiliates, which, due to bad timing, ultimately cost customers tens of billions of dollars.

The efficiency benefits of retail choice have been limited by various public policies designed to protect consumers, particularly those that put ceilings on wholesale electricity prices and on standard offer and POLR service prices. While the free market is lauded in theory, it is not allowed to work in practice at those times when supplies are scarce; so systems of implicit subsidies are created to hide high prices from consumers, with adverse impacts on generation investment, customer response, and the profitability of offering competing retail electricity services.

Retail choice, by facilitating competitive wholesale market structures that have increased the uncertainty of generators' returns on capital, may share part of the responsibility for raising the required returns on generation investments.

There is evidence that retail choice decisions require business savvy that many consumers lack, and that less educated or low-income consumers are more likely than other consumers to make poor retail supplier choices. In particular, low-income customers are more likely than other customers to pick alternative energy suppliers who charge more than the incumbent utility.

7.2.2. Wider Range of Retail Customer Service Options

Where retail choice is offered in the U.S., roughly half of commercial and industrial customers and roughly one out of fourteen residential customers have chosen non-utility service providers. The relatively low switching rate for residential customers is due, in large part, to the transaction costs of switching for these customers being high relative to the expected benefits of switching.

The EU experience indicates that customer switching behavior seems to be related to the degree of competition. It also indicates that where retail choice flourishes, there is reasonable hope for better service quality and higher customer satisfaction.

In the U.S., retail choice has induced relatively high participation in dynamic pricing programs, has a mixed record in promoting demand response programs, and has not generally promoted smart metering relative to traditional states.

Because retail energy suppliers in retail choice states face larger financial uncertainties than do traditionally regulated utilities, the risk of retail supplier bankruptcies under retail choice is greater than under traditional regulation. Bankruptcies and significant financial stresses have plagued retail energy suppliers primarily when they have had fixed-price sales obligations and insufficient long-term purchase rights, and when wholesale electricity spot market prices suddenly jumped.

Retail choice has engendered some fraudulent business behavior that is rare to non-existent among regulated utilities. Nonetheless, the evidence does not indicate that the problems in the electricity supply business are unusual for a retail services industry.

Retail choice has successfully promoted more green pricing participation, in terms of numbers of customers, than is typical for traditional utilities.

7.3. Directions for Future Policy

Policymakers should measure the success of retail choice according to the extent to which it adds value to basic energy and delivery services, particularly including whether it reduces customers' bills relative to what they would have been for service from the incumbent utility. The historical focus on measuring success in terms of the number of customers that have migrated to a competitive retailer or in terms of the share of megawatt hours of energy served by retail suppliers fails to capture the outcomes that matter, namely whether retailers are creating value that exceeds both the customer's switching costs and third-party provider costs. Policies to promote retail choice should refrain from forcing customers to choose an alternative retail provider and from providing any subsidy to retail providers, such as "head room" in standard offer or POLR service prices that is designed to facilitate third-party provider market entry. Smaller electricity consumers recognize that the transaction costs of switching are high relative to the prospective benefits of lower bills and better customer service, and can therefore rationally remain with their incumbent utilities.

In all states, regulators should encourage utilities to fully unbundle the pricing of generation services from that of other services, particularly distribution services. Consumers should be able to clearly compare the prices of the generation services offered by competing suppliers, without the distraction of the prices of non-competitive services. Utilities should be able to recover the costs of non-competitive services regardless of the customer's choice of competing energy supplies whether obtained through the power system or outside of the power system.

Subsequent to full unbundling of generation services from other services, regulators in retail choice states should encourage utilities to offer real-time pricing to all customers willing to pay the costs of the associated metering and billing. All customers can then have access to the wholesale market if they are willing to pay for such access. In addition to offering a real-time rate that is a simple pass-through of wholesale prices, it would be desirable for utilities and other retail energy suppliers to offer other dynamic pricing options (including curtailable service rates) and flexible pricing options with price guarantees that cater to customers' varying levels of tolerance for price risk.

To limit cherry-picking, customers who choose an alternative retail energy supplier should be ineligible to return to a conventional utility tariff. Instead, customers who want to return to the incumbent utility should be required to accept its real-time pricing rate or some other market-based rate.

In retail choice states, regulation needs to vigilantly protect consumers against retail energy suppliers' default and fraud.

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APPENDIX A. ACRONYMS

ACER	Agency for the Cooperation of Energy Regulators
ACSI	American Customer Satisfaction Index
CEER	Council of European Energy Regulators
CPP	critical peak pricing
DER	distributed energy resources
DSR	demand-side response
EU	European Union
FERC	Federal Energy Regulatory Commission
IOU	investor-owned utility
IPP	independent power producer
ISO	Independent System Operator
MW	megawatt
MWh	megawatt-hour
POLR	provider of last resort
PTR	peak time rebates
PV	photovoltaics
ROE	return on equity
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
RTP	real-time pricing
TOU	time of use

Electric Industry Deregulation:
A Look at the Experiences of Three States

Executive Summary

In the late 1990s, several states, including Michigan, began deregulating their electric utility industry in the hopes that competition in the generation and sale of electricity would drive down prices to consumers. The enthusiasm for deregulation had waned in Michigan in recent years, but interest in electric market choice is now rising again.

Public Sector Consultants Inc. (PSC) was hired to review the experiences of other states that deregulated their markets and identify trends or issues that might be relevant to the current discussion of Michigan's energy policy. PSC conducted case studies of Texas, Illinois, and New Jersey—three states that represent a range of geographies, political leadership, and deregulatory approaches and policy frameworks. The case studies looked at the success of these states' deregulatory efforts through the lens of:

- How reliability and affordability changed
- Whether deregulation provided for adaptable energy policy

In our analysis, PSC found that while there were some benefits of electric market competition, particularly for larger industrial customers, broad success for deregulation has either not materialized or has come with other regulatory and financial costs. Specifically, the case studies found that:

- Deregulation does not necessarily lower electricity rates
- Rates are often more volatile under deregulation
- There are significant challenges with pricing default electric service—the service provided to residential customers who do not opt for, or cannot obtain, competitive electric service
- Electric capacity and reliability can be a substantial challenge
- Deregulation can reduce a state's control of its energy policy because of the stronger role regional transmission organizations and the federal government play in where electricity is generated
- New forms of market/government intervention to address market failures often have been necessary

Introduction

Impetus and Purpose of the Research

The focus on electricity deregulation waned considerably after the price spikes, rolling blackouts, and utility bankruptcies that accompanied California's energy crisis in 2000–2001,[1] and as other states experienced similar challenges. By the early to mid-2000s, some states had repealed electric choice laws or otherwise pulled back such efforts, while others stayed the course, hoping to capture the potential benefits of deregulation. A third group of states had little choice on changing direction, since power plants had been spun off from utilities to other companies, as required under the deregulation legislation.

While there was considerable media coverage of state deregulation activity up through the mid-2000s, there has been little research on recent experiences. Since the U.S. has been experiencing a cycle of low prices for natural gas (which is a major fuel source for electricity generation) and wholesale power, there has been renewed interest in some states, including Michigan, to look at deregulation again in an effort to increase competition and reduce prices for more customers. Michigan's administration and legislature have sought input on whether Michigan should revisit its market structure, including the 10 percent cap on electric customer choice instituted in 2008. As a backdrop, Gov. Rick Snyder has called for energy decisions that provide for reliability, affordability, and environmental protection. He wants the state's energy policies to be adaptable—a "no regrets" approach.

Many of the deregulated states now have at least a decade of experience, which can help to inform the policy debate in Michigan. Accordingly, PSC was asked by Consumers Energy and DTE Energy to review key deregulated states through the lens of:

- How reliability and affordability changed
- Whether deregulation provided for adaptable energy policy

Using these as a guide for our research, we reviewed the experiences and impacts in three key deregulated states: Texas, Illinois, and New Jersey.

1 California partially deregulated its electricity industry in 1996, and subsequent market manipulations by energy companies such as Enron created artificial shortages that caused substantial wholesale electricity price increases. The high wholesale prices squeezed the revenue margins for utilities because of the deregulation-required customer price caps, bankrupting or nearly bankrupting the state's two largest utilities.

Study Approach

In choosing states to evaluate, PSC picked three that represented different regions (South, Midwest, and East Coast), included a range of deregulation systems and policy frameworks, and reflected different political leaderships (Democratic and Republican).

PSC conducted literature reviews of deregulation generally in the United States for comparison of approaches and implementation issues; reviewed and analyzed primary and secondary documents on the implementation approach, prices, competition, reliability, and regulatory changes in each of the three states; and conducted interviews with state energy regulatory staff in Texas and Illinois. The information was compared to national trends on prices, generation capacity, reliability, and rates of residential and commercial switching. PSC also reviewed any energy policy or regulatory changes that were made subsequent to deregulation in order to fine-tune or correct deficiencies in deregulation policies.

Although environmental protection is part of the governor's energy policy platform, PSC did not include it within the scope of this analysis because it would have required significant additional analysis to isolate the effects of deregulation on the environment from the effects of other state and federal policies.

It is difficult, if not impossible, to document what would have happened in states that implemented electric choice had they maintained their regulated utility system (and vice versa). But looking at trends and patterns among states over time can help policymakers identify factors that affect the success, or lack of success, of electric choice programs and shape future energy policy decisions in Michigan and elsewhere. These cases studies attempt to highlight some of these issues and contribute to the ongoing dialogue about the merits of electric industry deregulation.

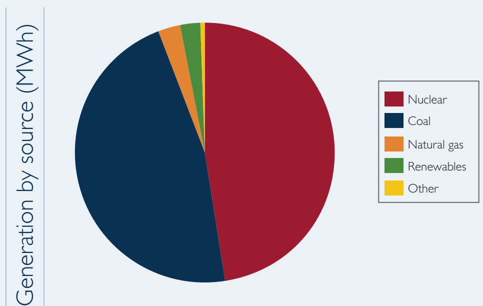
Deregulation in Illinois has—ironically—relied heavily on significant government intervention to control costs and encourage customer switching.

Summary

Illinois is an important state to review in the context of state experiments with electricity deregulation for two reasons. First, the deregulation process was protracted and highly controversial, and included years of legislative debate as well as a high-profile complaint and intervention by the state attorney general. Second, the turmoil associated with deregulation in Illinois—political, legislative, rate volatility, and other—reflected a lack of confidence in the ability of deregulation to ensure affordable, reliable power. This led Illinois policymakers to create new public entities and expanded roles for government in the purchase and sale of electricity in Illinois, essentially adding more regulation. Furthermore, it is not clear whether the recent price trends in Illinois are the result of deregulation, these new roles for government, or simply the result of current low natural gas and wholesale power prices.

History and Profile

- Deregulated in 1999 with commercial and industrial customers
- Regional transmission organization (RTO)/independent system operator (ISO): PJM and MISO
- Organized wholesale energy and capacity markets (PJM) and energy market (MISO), both under FERC jurisdiction
- Electricity sales (MWhs): 144,760,674 (#6 in nation)
- Average electricity price (cents/kWh in 2010): 9.13 (#24 in nation)



SOURCE: EIA, Illinois Electricity Profile, 2010.

Issues

Protracted Deregulation Process

Like many other states, Illinois went through a protracted process to deregulate its electric industry. It began in 1997 when the initial deregulation law was enacted and required the state's two investor-owned utilities, ComEd and Ameren, to spin off their generation to affiliated or unaffiliated companies. ComEd and Ameren continued to provide delivery of power and serve customers that did not select an alternative supplier. Retail access was initially limited to commercial and industrial customers in these service areas but expanded to residential customers.[1]

Deregulation did not take off as expected in terms of customer participation. The decade-long rate cap mandated in Illinois (which ended in January 2007) was one of the longest lasting rate caps in the nation, and it effectively discouraged alternative suppliers from entering the market. Through 2011, switching among residential customers was nearly non-existent. There was, however, a notable increase from 2011 to 2012—from 2% to about 22%, respectively—due in part to municipal aggregation efforts as discussed further below. Initial participation by small to medium-sized non-residential customers was also limited. In 2005, the state cautioned that the rate of switching among these customers was only around 5%. Participation among all types of customers has grown over time, however, particularly since 2011, and current levels are quite high in Illinois. According to the ABACCUS report for 2012, 22% of residential customers, 81% of medium-sized non-residential customers, and 93% of large customers had switched.[2]

TIMELINE

1997—Electric deregulation law passed

1999—Retail access available to some commercial and industrial (C&I) customers

2001—Retail access available to all C&I customers of investor-owned utilities

2002—Retail access available to residential customers

2007—Rate cap expires and prices surge; state attorney general files complaint against wholesale suppliers for market manipulation and excessive power prices; new legislation enacted that mandates $1B in rate relief for customers and creates Illinois Power Agency to procure power

2008—Residential customers first switch to alternative suppliers (participation low)

2010—Local governments authorized to aggregate load and solicit bids for sale and purchase of electricity

2012–13—500+ local governments pass referendums for municipal aggregation

Expanded Role for Government

In addition to mandating rate freezes, discounts, and customer refunds during the transition to deregulation, the Illinois legislature stepped in to create a new independent state agency, the Illinois Power Agency (IPA), to oversee the "electricity planning and procurement processes for residential and small commercial customers of Ameren and ComEd."[3] The IPA was created "in response to significant consumer electricity cost increases resulting from a utility-managed reverse auction process."[4] The utility auction process was eliminated as part of this reform and the new agency became responsible for procuring power; ensuring reliable, adequate service at the lowest total cost over time; and developing new resources, including coal, renewable energy, and others financed with state bonds. The legislative charge of the IPA is strikingly similar to the role of a regulated electric utility (see below), including the ability to develop generating facilities, except that the IPA is not permitted to sell directly to retail customers.

The IPA credits itself with lowering and stabilizing electricity prices in Illinois.[5] The agency reported in 2011 that its procurement activities have resulted in $1.64 billion in total savings for consumers since 2009.[6]

Role of IPA vs. Typical Regulated Utility

IPA (state agency)		Typical regulated utility
Yes	Develop electricity procurement plans	Yes
Yes	Provide adequate, affordable, efficient, and environmentally sustainable electric service at lowest cost over time	Yes
Yes	Conduct competitive procurement for supply resources	Yes
Yes	Develop and finance electric generation facilities	Yes
Yes	Sell electricity to other entities (e.g., municipal utilities)	Yes, but not always
No	Serve retail customers with electricity	Yes

● Yes ● Yes, but not always ○ No

SOURCE: Public Sector Consultants using information on IPA's mission and objectives from the *Annual Report FY 2012* and Public Act 095-0481.

Although proponents of deregulation argue that one of the key benefits is providing customers the ability to choose their supplier, many deregulated states have seen limited participation by residential and small commercial customers.[7] In the first decade under deregulation in Illinois, participation by such customers was almost non-existent. In response to these trends and recognizing the need to make deregulation "work," Illinois enacted legislation to promote the ability of local governments to arrange for the sale and purchase of electricity. These municipal aggregation programs effectively allow the local government to make the "choice" on behalf of their residents (and sometimes small businesses). That is, local governments aggregate customers in their respective jurisdictions in order to supply power. Individuals must proactively "opt out" of the program in order to avoid switching their service. The IPA facilitates municipal aggregation by negotiating and supplying the power.

Municipal aggregation in Illinois has been widely adopted but is still new. As of May 2013, a total of 529 communities (including Chicago) passed referendums for municipal aggregation.[8] The 2012 ABACCUS report states that an estimated 60% of "switching" by residential customers in the state was due to municipal aggregation, according to the Illinois Commerce Commission. That percentage appears to have increased since 2012, given the number of local governments with active municipal aggregation programs initiated since 2012 and their associated populations. The state publishes the total number of customers that switch providers, but does not break down switching rates for customers under aggregation versus those that switch suppliers on their own. Nonetheless, there are more households in areas with municipal aggregation (with a supplier under contract) than the total number of residential customers that have switched as of the first quarter of 2013.[9] This suggests that municipal aggregation is driving a large portion of the current switching activity in Illinois.

Of those local governments that have selected suppliers, the rates appear attractive (averaging 4.55 cents/kWh),[10] but these rates were negotiated during a time of depressed wholesale prices and they have limited terms. While the experience with aggregation to date appears positive and has improved the customer "switching" statistics in Illinois, the track record is short. Moreover, aggregation raises important policy questions: Is this an appropriate role for local governments?[11] Will this approach stay in favor once market conditions fluctuate? And will these customers simply return to the incumbent utilities when that happens?

Affordability

Cuts in retail rates of up to 20% were mandated as part of the transition to deregulation in Illinois, and rates were frozen for a decade.[13] Prices surged when price caps expired in 2007, resulting in considerable political turmoil. Customers experienced double- and triple-digit increases in their electric bills in 2007, with allegations from the state attorney general that customers would be paying an extra $4.3 billion from 2007 to 2009 because of manipulation of prices by wholesale suppliers (including affiliates of ComEd and Ameren) in the electricity auction used to set the utility rates under deregulation. The state's complaint alleged that the deregulated generation affiliate of ComEd was charging the utility three times its actual cost to generate electricity to serve the utility's customers.[14] After considerable squabbling in the state legislature over how to handle the rate increases, the state eventually brokered a deal in 2007 for major rate relief and other reforms with ComEd and Ameren to provide consumer refunds and credits totaling $1 billion. This was used to help offset some of the price increases.

Rate Shock in Illinois

Prices soar from 2006 to 2007 following expiration of rate cap.

ComEd

- 26–56% jump in residential prices from 2006 to 2007
- 60–70% increase for large commercial and industrial customers with some very large customers experiencing increases of over 100%

Ameren

- 49–125% jump in residential prices
- 80–130% increase for large commercial and industrial customers

Illinois has seen electricity prices come down, hovering around the national average—likely a function of the surplus capacity in wholesale markets and low commodity prices.[15] As seen elsewhere, including Michigan, the prices are largely a function of the initial rate freezes/caps and commodity prices, not the market structure (i.e., deregulation).[16] The Illinois Power Agency also purports to have played a key role in stabilizing prices.

> *"Five million Illinois residents are unnecessarily paying electricity prices that are double the actual cost of generating electricity…"*
>
> —Lisa Madigan, IL Attorney General, March 15, 2007[12]

As generation supplies tighten in the eastern United States with the retirement and retrofitting of older coal plants and if natural gas prices increase, regional wholesale prices could escalate and increase retail rates in Illinois.[17]

Conclusion

State and local governments have taken on expanded roles related to the purchase and sale of electricity in Illinois that suggest a fair amount of government intervention under deregulation. The government is essentially serving in critical roles traditionally provided by a regulated utility. This intervention is in response to what appears to be a perceived inability or lack of confidence in deregulation to ensure affordable, reliable service and bring about real competition. The initial trigger for state intervention in power procurement was the alleged market manipulation and excessive prices of wholesale suppliers in 2007. The state played a key role in investigating these issues and ultimately mandated refunds to customers in order to temper these rate increases. For local governments, the lack of customers electing to switch suppliers and the desire to stimulate competition has led to local governments effectively making this decision and negotiating prices for their residents. These state and local government roles bring into question whether this is a truly deregulated industry. Rather, it appears that the framework in Illinois has relied on new forms of market-based regulation, some of which have not been fully tested under alternative market conditions.

Endnotes

1. See Distributed Energy Financial Group, LLC, December 2012, *Annual Baseline Assessment of Choice in Canada and the United States* (2012 ABACCUS: An Assessment of Restructured Electricity Markets). Available: www.competecoalition.com/files/ABACCUS-2012.pdf (accessed 7-1-13). The ABACCUS report indicates that retail access was planned for 2002 for residential customers but moved up to late 1999/2000.

2. Distributed Energy Financial Group, LLC, *Annual Baseline Assessment of Choice*, p. 60.

3. Illinois Power Agency (IPA), *Fiscal Year 2012 Annual Report,* December 1, 2012. Available: www2.illinois.gov/ipa/Documents/Annual-Report-Illinois-Power-Agency-FY2012.pdf (accessed 6-5-13).

4. IPA, *Fiscal Year 2011 Annual Report.* Available: www2.illinois.gov/ipa/Documents/IPA_Annual_Report_2011_final.pdf (accessed 6-5-13).

5. IPA, *Fiscal Year 2011 Annual Report*, Executive Summary.

6. Ibid.

7. Surveys also suggest that, in general, many customers are not interested in selecting an alternative supplier.

8. A referendum is required to determine whether the aggregation shall be structured as an "opt out" program. For a list of communities, see Plug In Illinois, *List of Communities Pursuing an Opt-Out Municipal Aggregation Program* (updated June 28, 2013). Available: http://pluginillinois.org/MunicipalAggregationList.aspx?ob=1(accessed 7-1-13).

9. Illinois Commerce Commission, April 29, 2013, Electric Switching Statistics as of March 2013. Available: www.icc.illinois.gov/electricity/switchingstatistics.aspx (accessed 6-24-2013). Over 2.8 million customers have switched providers as of March 2013 and the number of households within areas with municipal aggregation with suppliers selected exceeds 3 million based on the 2010 U.S. Census. See also Plug In Illinois, *List of Communities Pursuing an Opt-Out Municipal Aggregation Program*.

10. Average calculated by Public Sector Consultants.

11. The IPA cautions local governments that "This is a multi-million dollar contract on behalf of constituents: protections for you (the municipality) and residents beyond the minimum in the law are desirable—and potentially necessary." Illinois Power Agency, March 2012, *Illinois Municipal & County Electric Aggregation: What Do I Need to Know?* (Web conference presentation). Available: www2.illinois.gov/ipa/documents/MunicipalAggregationMarchWebinarIPAPresentation3-12-12.pdf (accessed 6-13-2013).

12. Press release, March 15, 2007, "Attorney General Madigan Alleges Price Manipulation in 2006 Electricity Auction: Complaint Seeks Reduction in the Price ComEd and Ameren Pay for Electricity." Available: www.illinoisattorneygeneral.gov/pressroom/2007_03/20070315.html (accessed 7-2-13).

13. Distributed Energy Financial Group, LLC, May 2006, Annual Baseline Assessment of Choice, p. 57; Illinois Commerce Commission, *Competition in Illinois Retail Electric Markets in 2005*. Available: http://ipu.msu.edu/resources/pdfs/Commission-Reports/IL-Competition%20in%20Illinois%20Retail%20Electric%20Markets%20in%202005.pdf (accessed 7-1-13).

14. Complaint by the People of the State of Illinois, Illinois Attorney General Lisa Madigan v. Exelon Generation Company, LLC, et al., March 15, 2007, p. 10. Available: www.illinoisattorneygeneral.gov/pressroom/2007_03/FERC_Complaint_public.pdf (accessed 7-15-13).

15. Potomac Economics (Independent Market Monitor for MISO), June 2012, *2011 State of the Market Report for MISO Electricity Markets*, pp. i-v. Available: https://www.midwestiso.org/Library/Repository/Report/IMM/2011%20State%20of%20the%20Market%20Report.pdf (accessed 6-6-13).

16. See Public Sector Consultants, November 30, 2006, *Electricity Restructuring in Michigan: The Effects to Date of Public Act 141 and Potential Future Challenges*. Available: www.pscinc.com/Publications/tabid/65/articleType/ArticleView/articleId/225/Electricity-Restructuring-in-Michigan-The-Effects-to-Date-of-Public-Act-141-and-Potential-Future-Challenges.aspx (accessed 7-1-13); see also Joint Response from DTE Energy, Consumers Energy, and MEGA, on Overall Question 1 (Structural Drivers of Electric Rates) and Electric Choice Questions 9 and 11, April 25, 2013. Available: www.michigan.gov/energy/0,4580,7-230--293322--,00.html (accessed 7-2-13).

17. Potomac Economics, p. v. See also, Monitoring Analytics, LLC (Independent Market Monitor for PJM), State of the Market Report for PJM, May 16, 2013. Available: www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013q1-som-pjm.pdf (accessed 6-6-13).

Deregulation in New Jersey has not resulted in electricity price decreases or desired in-state generation. This has led to tensions between state and federal authorities over control of the state's energy future.

Summary

New Jersey is an important state to review in the context of electricity deregulation for four reasons. First, the reason stated most often for the enactment of the legislation that deregulated New Jersey's electricity market was high electricity rates. After almost 14 years of deregulation, however, electricity rates continue to be high compared to those in other states, and New Jersey's relative position nationally hasn't changed. Second, New Jersey is an example of a state that has relied on a "capacity market" pricing system designed and operated by the federally regulated regional transmission organization (RTO) to induce needed new generation capacity. The ability of this pricing model to actually attract the investment necessary to build this new capacity has been questioned, as little new generation has been built to meet New Jersey's growing energy needs. Third, dissatisfied with the results of the RTO capacity market system in terms of both the price of power and its availability, New Jersey enacted new legislation in 2011 designed to create its own incentives for the construction of new generating capacity within the state—that is, a new form of state regulation and intervention. This attempt, however, has been contested by the RTO, the Federal Energy Regulatory Commission (FERC), and energy providers that want to import electricity into the state from outside New Jersey. This has led to the fourth key feature of the New Jersey deregulation experience: a dispute regarding who will control New Jersey's energy future—the state or the federal government via the RTO and FERC.

History and Profile

New Jersey passed its Electric Discount and Energy Competition Act (EDECA) in early 1999, one of a number of states to enact similar legislation in the late 1990s. As with many of these states, the legislation deregulated the energy generation sector but maintained a traditional cost-of-service regulation approach for the transmission and distribution segments of the industry.[1] Under this deregulated system, the state's four main utilities continued to own distribution systems, regulated by the state Board of Public Utilities (NJBPU), and regional transmission firms were regulated by the FERC. Beginning in August 1999, customers in all classes had access to retail competition, and the legislation established a four-year transition time during which electricity prices were capped at 10% below the 1999 prices.

For the first decade of deregulation, New Jersey saw very little participation, or "switching," among residential or commercial customers. Initially, the price cap imposed by the EDECA did not provide much opportunity for new suppliers to make a profit, so there was little new offering of competitive prices. Even after the price cap was lifted, consumers were generally apathetic about switching and participation remained below 2% until about 2008. Recent declines in natural gas prices have brought additional providers offering lower prices into the market, and by July 2013 the number of customers that had switched service from their incumbent provider was approximately 17.5%.[2] This participation rate, however, is still well below rates in other deregulated states.

TIMELINE

1999—Electric deregulation law passed; retail access available to residential, commercial and industrial (C&I) customers

2003—Rate cap expires; minimal residential or commercial switching has occurred

2008—Natural gas prices begin to decline in late 2008, and forward electricity prices correspondingly drop

2010—Percentage of residential participation in alternative provider services increases from less than 1% to almost 10% with decline in market prices

2011—New Jersey Legislature passes Long-term Capacity Agreement Pilot Program (LCAPP) (P.L. 2011, Chapter 9), which promotes development of ~2,000 MW of new baseload or mid-merit generation facilities in New Jersey

2011—FERC approves PJM's proposed modifications to its Minimum Offer Price Rule, making the LCAPP more financially challenging

2012—Two of the proposed LCAPP generating facilities clear the PJM Base Residual Auction price, and one does not clear

2013—PJM's Markets and Reliability Committee abandons effort to add a long-term capacity auction or alternative multi-year mechanism to the revised PJM charter

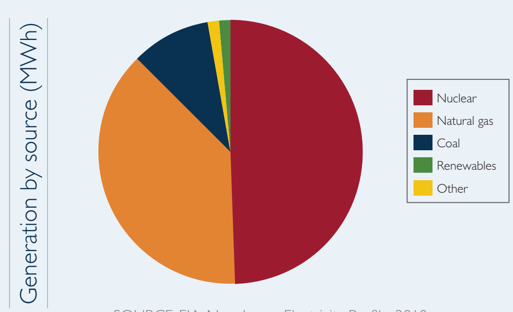
Market Share Served by Alternative Providers

18% of customers

44% of load (based on total MWh)

SOURCE: New Jersey Board of Public Utilities, *New Jersey Electric Switching Statistics*, July 2013.

- Deregulated in 1999
- Regional transmission organization (RTO)/ independent system operator (ISO): PJM
- Organized wholesale energy and capacity markets (PJM) under FERC jurisdiction
- Retail electricity sales (270 trillion BTUs): (#20 in nation)
- Average electricity price (cents/kWh in 2011): 14.3 (#6 in nation)



SOURCE: EIA, New Jersey Electricity Profile, 2010.

New Jersey, unlike Michigan, is fairly dependent on energy imports, with over 25% of its electricity bought on the wholesale market and transmitted to New Jersey from plants in other states.[3] This has influenced the success of deregulation, as discussed further below. New Jersey's in-state generation mix is largely made up of nuclear and natural gas, with a modest amount of coal, renewables, and other sources.[4]

New Jersey is a member of PJM, which is the RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. In order to assure that adequate generation capacity is available in the region to meet potential peak demand—that is, an adequate supply of electricity at all times—PJM established a "capacity market" and a capacity market pricing model in 2007 called the Reliability Pricing Model (RPM). According to PJM, its RPM capacity market is supposed to:

> *…create long-term price signals to attract needed investments in reliability in the PJM region…and stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity—resources that include not just generating plants, but demand response and transmission facilities.*[5]

Unhappy with the results of this capacity mechanism in terms of both its inability to stimulate new generation sources within the state and the price of electricity, the New Jersey legislature, with the support of Governor Chris Christie, enacted new legislation in 2011, the Long-term Capacity Agreement Pilot Program (LCAPP). This legislation represents a new form of state regulation and intervention designed to ensure adequate capacity generated by in-state facilities at acceptable prices.

The enactment of this legislation has sparked an ongoing battle between the State of New Jersey and the PJM, the FERC, and various out-of-state electricity providers that continues to this day both in federal court and at the FERC.

Issues

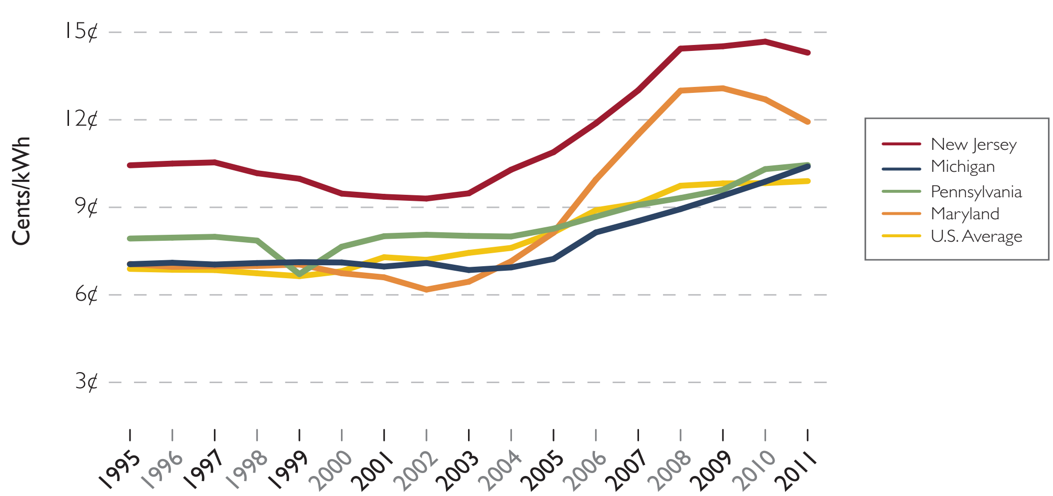
Affordability

New Jersey has historically had some of the highest electricity prices in the nation, consistently ranked 6th or 7th highest in the nation in the years just prior to deregulation. Lowering the cost of electricity was, in fact, one of the driving forces behind deregulation. Legislators and the Board of Public Utilities hoped that greater competition would drive down prices for New Jersey residents and businesses. When the EDECA passed the state legislature, electricity cost 9.98cents/kWh.[6]

Like other states that deregulated their electricity industry, New Jersey instituted a transition period during which electricity prices would be reduced and capped for a number of years in order to protect consumers from price increases while a new competitive market was developing. Although mandated price reductions or freezes obviously help consumers in the short term, they often deter new competitors from entering the market to compete with incumbents because there is not enough profit at the lower prices. In addition, dramatic price increases often occur once the caps are removed. This is precisely what occurred in New Jersey.

As the transition period ended in 2003, electricity prices in New Jersey began to climb again, going from 9.3 cents/kWh in 2002 to 14.3 cents/kWh in 2011—a 54% increase. New Jersey's electricity prices are highly correlated to natural gas prices, so the prices have dipped slightly during the last two years as natural gas prices have declined.[7] However, the state is still ranked 6th highest for electricity prices in the nation, and New Jersey electricity prices have been an average of 3.3 cents/kWh higher than the U.S. average price over the last 15 years.

New Jersey Prices Consistently Higher than Other States



SOURCE: EIA State Profiles and Energy Estimates database.

State Concern about the "Capacity Market" Pricing Model and Dependence on Out-of-State Electricity Imports

It has been the contention of the Christie administration and the NJBPU that PJM's capacity market and its RPM have not worked as intended or to the advantage of New Jersey because they have not resulted in new generation and keep New Jersey overly reliant on the transmission of expensive power from outside the state. Net electricity imports since 1999 have consistently been more than 20 million MWh/year, more than a quarter of its electricity use.

New Jersey contends that the capacity market is biased toward existing or expanding generators because it does not accommodate the need for long-term or multi-year price contracts. PJM allows capacity prices to be locked in for only one year, and therefore generators of new projects are unable to obtain financing at reasonable rates because of uncertain future revenue.[8] According to the state, this inhibits new generation in areas where it is most needed, such as in northern New Jersey where the grid is most congested.

New Jersey Electricity Imports

25% to 35%

over the last decade

New Jersey also points to the fact that clearing prices in the capacity market for New Jersey (and Maryland) are often quite a bit higher than those for unconstrained areas of PJM. For the 2016–2017 delivery year, for example, the clearing prices for the Public Service Electric and Gas (PSEG) Locational Deliverability Area (LDA), which covers New Jersey, rose 31% from the previous year, while all other PJM regions saw substantial decreases in prices (down 29% in the mid-Atlantic region and 68% in the northern Ohio area, for example). The New Jersey area was over $160/MW-day higher than the rest of the PJM area. PJM's summary of the 2016–2017 auction notes that the only LDA that saw price increases in the auction was PSEG, which has historically been transmission constrained. The PSEG area did not attract much of the new generation entry, and accounted for over half the electric generation facility deactivations since the last auction.[9]

A New Kind of State Regulation and Intervention Attempted

Dissatisfied with the results of deregulation and PJM's capacity pricing model in terms of reducing prices or stimulating new in-state capacity, the state created a new program, the LCAPP, which was designed to encourage new in-state generation. The LCAPP requires the state's regulated distribution-only utilities to enter into long-term contracts for new generation at a price that justifies the investment. The state issued a request for proposals to select generation projects and chose three gas-fired combined-cycle facilities that together would provide New Jersey with almost 2,000 MW of new capacity. The program allowed for contracts from the state that pay the new generators a subsidized minimum long-term price—one that is likely to be higher than the prices available on the PJM capacity market.

It is New Jersey's position that expanding in-state generation—by constructing or replacing power plants—would be cheaper and more reliable than depending on the PJM capacity pricing model and the transmission of electricity from western areas of PJM into New Jersey.[10 11]

State vs. Federal Control of New Jersey Energy Policy

New Jersey policymakers want generation sources located in New Jersey for additional reasons beyond attempting to lower electricity prices. The state wants to meet its electricity needs with a more diverse and "clean" portfolio of energy sources than the predominantly coal-fired generation sources that are currently imported into the state through the PJM market. New Jersey has also cited the value of more than 2,400 temporary and about 80 permanent jobs that would be created by the construction of the new LCAPP-awarded generation facilities.

PJM and its network of incumbent generators have opposed New Jersey's efforts to encourage new in-state generation through LCAPP. They argue that New Jersey would, in effect, be subsidizing these facilities, therefore artificially depressing prices that would create an unfair economic advantage for them compared to others in the PJM region. Critics have also claimed that New Jersey is just using a work-around of the PJM system, leaving perceived deficiencies of the system in place. They have argued that New Jersey should instead be working with PJM to evaluate and modify the system as a whole to make it more effective. However, PJM's Markets and Reliability Committee recently abandoned efforts to add a long-term capacity auction or alternative multi-year mechanism to the revised PJM charter, leaving New Jersey's concerns about the RPM unaddressed.[12]

PJM has been successful in persuading the FERC to change various rules regarding minimum price offers, which have kept the LCAPP program from fully moving forward as planned.[13] At the same time, incumbent PJM generators have filed suit in federal

> *"New Jersey is opposed to a FERC-imposed paradigm that impedes in-state generation development while simultaneously imposing on our ratepayers an investment premium for transmission projects that import power from out-of-state generation sources far away from the state's loads."*
>
> *—State of New Jersey*

court challenging the constitutionality of LCAPP under the federal supremacy clause.[14] The FERC rule changes and federal court challenges have limited New Jersey's ability to feasibly pursue its own energy policies as represented by LCAPP.

Conclusion

New Jersey's experience with deregulation has undoubtedly not been what the state had either desired or anticipated. Price decreases—the primary reason for enacting the original legislation in 1999—have not materialized. New Jersey began its experiment with deregulation as the 6th highest priced state in the nation for electricity prices, and it is still the 6th highest priced state in the nation. The persistence of relatively high electricity prices led New Jersey to the conclusion that it would be better to rely on new in-state generation rather than the transmission of power from other areas of the PJM region. Because PJM's capacity markets and the associated pricing model have not resulted in the development of this in-state generation, however, the state attempted a new type of government intervention to control electricity prices and supply—the LCAPP. This state policy effort has, however, been successfully opposed by both the regional transmission organization and the federal government (FERC). It is also being contested in federal court by out-of-state energy providers that have an interest in continuing to export power to New Jersey. Because of PJM rule changes, the two LCAPP-funded power plants that have gone forward cleared the capacity market at a price well below their state-guaranteed rate, requiring the state to subsidize the difference. This will cost New Jersey taxpayers over $40 million in the first year.

What began as an attempt to reduce prices with deregulation has resulted in further government intervention and a struggle between the state and the federal government over control of state energy policy, without the desired price reductions.

Endnotes

1. State of New Jersey, December 6, 2011, *2011 New Jersey Energy Master Plan*. Available: http://nj.gov/emp/docs/pdf/2011_Final_Energy_Master_Plan.pdf (accessed 7-28-13).

2. New Jersey Board of Public Utilities, July 2013, *New Jersey Electric Switching Statistics*. Available: www.state.nj.us/bpu/pdf/energy/edc07.pdf (accessed 8-12-13).

3. While Michigan is not a net importer of electricity, it is almost completely reliant on imports of energy feedstocks to supply its electric generating facilities. In total, 82% of Michigan's natural gas and 100% of coal and nuclear fuel are imported from outside the state, accounting for about 72 cents of every dollar spent for energy by Michigan's residents and businesses. Michigan Public Service Commission, October 2011, *Michigan Energy Overview*. Available: www.dleg.state.mi.us/mpsc/reports/energy/energyoverview/ (accessed 8-12-13).

4. U.S. Energy Information Agency (EIA), July 2012, *New Jersey State Profile and Energy Estimates*. Available: www.eia.gov/state/?sid=NJ (accessed 7-25-13).

5. PJM, Reliability Pricing Model website. Available: www.pjm.com/markets-and-operations/rpm.aspx (accessed 9-8-13).

6. The EIA tracks electric prices in all U.S states. Electricity prices noted in this paper are the EIA's average of residential, commercial, and industrial prices.

7. EIA, *New Jersey State Profile*.

8. State of New Jersey, *Energy Master Plan*.

9. PJM, N.d., *2016/2017 RPM Base Residual Auction Results* (PJM Docs #753726), p. 31. Available: www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx (accessed 8-18-13).

10. State of New Jersey, *Energy Master Plan*.

11. Tom Johnson, June 18, 2013, Assembly Panel Faults BPU for Failure of Deregulation, *NJSpotlight.* Available: www.njspotlight.com/stories/13/06/17/assembly-panel-faults-bpu-for-failure-of-deregulation/ (accessed 7-29-13).

12. "PJM Abandons Long-Term Capacity Effort," August 6, 2013, *RTO Insider*™, Available: www.pjminsider.com/long-term-capacity-1/ (accessed 8-21-13).

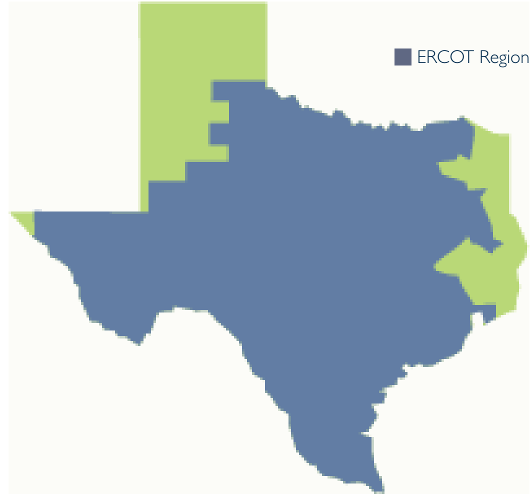
13. Three developers were selected under the LCAPP pilot program to provide new generation facilities: NRG, Hess Corporation, and Competitive Power Ventures (CPV). CPV and Hess cleared the capacity auction in May 2012, and both are under construction, but NRG has not cleared the last two auctions and that facility's future development is in question.

14. Roger Stark and Daniel Simon, January 1, 2012, Traps for Unwary Project Sponsors—the LCAPP Saga, *Electric Light and Power* (Jan/Feb 2012). Available: www.elp.com/articles/2012/01/traps-for-unwary-project-sponsors-the-lcapp-saga.html (accessed 7-28-13).

Rates have been higher and more volatile in the deregulated areas of Texas. But the state's more serious challenges relate to reliability and the adequacy of power supplies.

Summary

Texas is an important state to examine in the context of state deregulation of electricity markets, for a number of reasons. First, it was one of the earliest states to follow California in deregulating its electric industry—it began the effort in 1999 with the enactment of legislation for retail competition, and began full deregulation in 2002. Second, unlike a number of other states that began the process of deregulation but reversed course as they encountered problems, Texas has not abandoned deregulation. In fact, the organization that ranks and rates the various states on the degree of "competition" and "deregulation" rates Texas as the "competitive electricity market leader."[1] Third, although Texas is often classified as a "fully deregulated state," parts of Texas continue to operate under a fully regulated market structure, allowing for comparisons within the state of the impacts of deregulation and continued traditional regulation. Fourth, Texas is the only state in the nation that has jurisdiction over both the wholesale and retail electricity markets. All other states are limited to regulation over retail markets while the federal government—through the Federal Energy Regulatory Commission (FERC)—maintains regulatory authority over the wholesale market. Finally, Texas illustrates some of the key challenges that can plague deregulated electricity markets: reliability, affordability, and a number of unintended—and unanticipated—consequences.



History and Profile

Texas followed California and several other states in deregulating its electric industry. The state began this effort in 1995 by allowing generators open access in the wholesale market. Texas passed legislation for retail competition in 1999 and moved aggressively to introduce full deregulation on January 1, 2002. The transition continues to be a complex and lengthy process, with challenges to reliability and affordability.[2]

Texas's electric industry and regulatory framework are unique. It has limited electrical interconnection to other states and, therefore, the Public Utility Commission of Texas (PUC)—rather than the Federal Energy Regulatory Commission—has jurisdiction over electric transmission rates and the wholesale electric market within the Electric Reliability Council of Texas (ERCOT) region. Thus, the PUC oversees both the retail and wholesale markets within ERCOT, providing oversight over all aspects of the industry, including long-term reliability and retail and wholesale market operations. This avoids some of the challenges experienced in other states and the portion of Texas outside of ERCOT (East Texas, Panhandle, and El Paso region) that have overlapping state and federal jurisdiction related to electric deregulation.[3] The ERCOT region covers about 75% of the state's land area. Approximately 64% of the state's electric load (the majority of ERCOT) is under deregulation.

Texas relies on natural gas for the generation of electricity more than most other states, and this has influenced its wholesale and retail market design and performance under deregulation, as discussed further below.

TIMELINE

1995/1996—Wholesale competition introduced and ERCOT begins operations as independent system operator

1999—Deregulation law enacted; retail utility rates frozen as part of transition

2001—Retail access pilot; significant IT challenges for wholesale and retail billing

2002—Deregulation begins in ERCOT

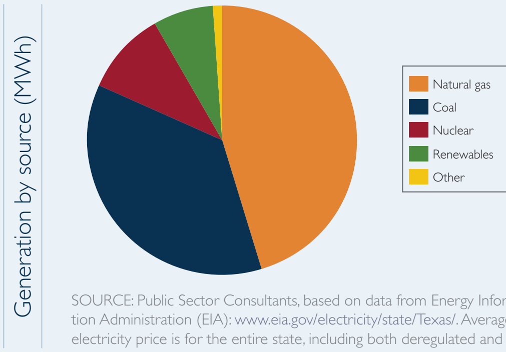
2004—Stranded cost "true-up" proceedings

2006—Prices in deregulated areas peak, 62–88% higher than 2002 prices (compared to increase of only 24% in regulated areas during this time frame)

2011—ERCOT acknowledges reserve levels below target; experiences supply emergency during record-setting weather and peak demand in August; preceded by rolling power outages in February 2011 due in part to cold snap and unplanned generation outages

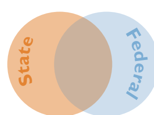
2012—The Brattle Group releases report for ERCOT on investment climate for new generation and options to address looming power shortages

2013—North American Electric Reliability Corporation (NERC) issues warning letter to ERCOT regarding reliability concerns due to low generation reserves



SOURCE: Public Sector Consultants, based on data from Energy Information Administration (EIA): www.eia.gov/electricity/state/Texas/. Average electricity price is for the entire state, including both deregulated and regulated areas.

- Deregulated in 2002 within ERCOT (except municipally owned and electric cooperatives that do not opt in); remains regulated outside ERCOT
- Regional transmission organization (RTO)/independent system operator (ISO): ERCOT
- "Energy-only" wholesale market (no capacity market)
- Electricity sales (MWhs): 358,457,550 (#1 in nation)
- Average electricity price (cents/kWh in 2010): 9.34 (#21 in nation)

	California Experience	**Texas Response**
Surge in wholesale power prices with capped retail rates 	Cap on retail rates resulted in wholesale prices exceeding retail prices and related problems, including financial distress for power providers and subsequent price spikes.	Rates for the default service charged by incumbents can fluctuate based on market conditions in order to keep incumbents solvent and attract and retain alternative suppliers.
Power shortages/ rolling blackouts 	Regulatory restrictions and market conditions dampened new power plant investment. Weather and environmental restrictions limited access to hydro-electric generation supplies in Pacific Northwest, contributing to California's power shortages.	Texas had significant excess generation capacity and market conditions to support new generation. Texas not dependent on significant quantities of hydro-electric generation.
Overlapping federal and state jurisdiction 	Claims that federal government did not intervene soon enough to prevent or mitigate market abuses by unregulated power generators such as Enron. Poorly designed wholesale market allowed manipulation and excessive prices.	Texas—not the federal government—can protect consumers from market manipulation by suppliers and properly designed market rules and state oversight can insure stable prices.

Texas deregulated the electric industry within the ERCOT region on the heels of the California meltdown in 2000 and 2001. Policy leaders in Texas emphasized how the state's situation was dramatically different from California, as highlighted above.

Indeed, Texas has been rated as the "competitive electricity market leader" for both residential and commercial markets in the *Annual Baseline Assessment of Choice in Canada and the United States* (ABACCUS) for numerous years, primarily because of customer "switching" rates and the number of alternative providers.

It is noteworthy that Texas has sustained this level of participation over time. Texas avoided some of the problems experienced in other states but has had its own share of challenges with reliability and affordability of electric service. The state continues to face problems, particularly related to the adequacy of power supplies.

Market Share Served by Alternative Providers

61% of customers (60% residential only)

76% of load (MWh)

SOURCE: Public Utility Commission of Texas, 2013, Summary of Performance Measure Data (Non-Confidential Version). Available at: www.puc.texas.gov/industry/electric/reports/RptCard/Default.aspx (accessed 6-3-13.) Note that some of the "alternative providers" are the predecessors of the incumbent utilities serving other parts of the state. Percentages apply to deregulated areas of Texas as of December 2012.

Issues

Reliability

Proponents of deregulation suggest that generation will be built where and when it is needed under deregulation. Not only has this not occurred in Texas, but the opposite has happened—that is, investment has actually declined as documented need has increased. State officials touted Texas's very high reserve margins prior to deregulation, and the state is now faced with significant reliability challenges due to generation reserve shortages.

> *"The electricity utility industry employs a simple strategy for maintaining reliability: always have more supply available than may be required."*
>
> —Energy Information Administration (EIA)

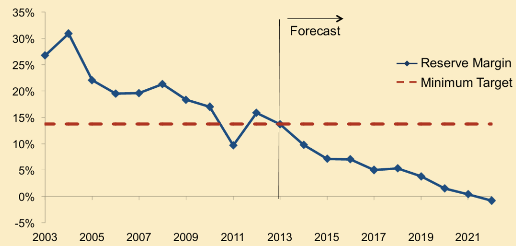
As with other areas of the country, Texas experienced a wave of new investment in the early 2000s, primarily natural gas plants. Investment losses followed, leaving investors more cautious and demanding more assurance that there will be stable revenues resulting from any new investments.[4] Meanwhile, population continued to grow steadily, with overall energy use and demand for electricity increasing about 2% annually on average in recent years. Extreme weather conditions in 2011 led to increased consumption and record-breaking peak demand that stressed the system. By the end of 2011, ERCOT reports revealed that development of new generation was not keeping pace with the need.[5] Investment had stalled despite reserve margins falling below target levels due to plant retirements and load growth.[6] A total of 15,223 MW of generation has been retired or mothballed since 1995 in ERCOT.[7] NERC, which is accountable for assessing the current and future reliability of the bulk-power system, issued a January 2013 warning letter to ERCOT, stating:

> *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 [reliability] 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…* ***These concerns are not new****, as NERC has raised this issue in prior assessments.[8] (emphasis added)*

ERCOT has acknowledged that there is a significant chance that it will need to declare an energy emergency alert in the near future. And if there are higher-than-normal power plant outages during a period of high demand or weather similar to 2011's heat wave, ERCOT expects that "rotating outages could become necessary to maintain the integrity of the system."[9] Faced with these challenges, ERCOT commissioned a study by a well-known national energy consulting firm, the Brattle Group, to analyze the reliability issues and the market's ability to attract investment in new generation. In its June 2012 report, the Brattle Group found that reserves are projected to fall to 9.8% by 2014, substantially below the current 13.75% reliability target.[10] It further concludes:

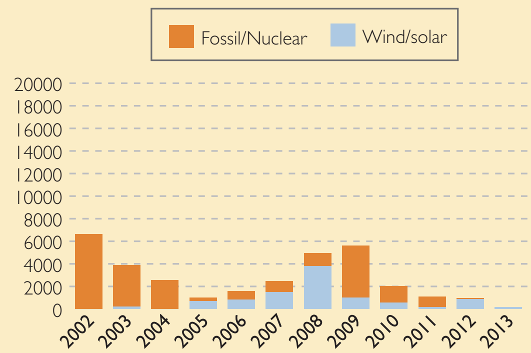
> *The year 2014 poses a particular challenge because it may be approaching too quickly to add some types of new capacity, even if market conditions would support such investments.[11]*

Dwindling Generation Reserves Put Reliability at Risk



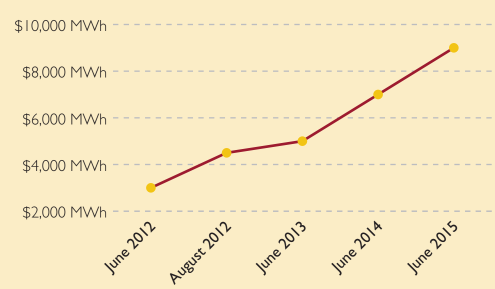
SOURCE: DTE Energy, March 25, 2013, Presentation at Detroit Forum for Readying Michigan to Make Good Energy Decisions, hosted by the MPSC and Michigan Energy Office, based on data from NERC (2012 Long-term Reliability Assessment) and Ventyx Velocity Suites – ERCOT.

Power Plant Investments Don't Keep Pace



SOURCE: PUCT, New Electric Generating Plants Since 1995 (excluding renewable), as of 1-23-13, www.puc.texas.gov/industry/maps/elecmaps/gentable.pdf (accessed 7-3-13).

Increasing Wholesale Price Caps



SOURCE: ERCOT, December 2012, Striking a Reliable Balance: 2012 State of the Grid Report, p. 9, www.ercot.com/content/news/presentations/2013/2012%20ERCOT%20State%20of%20the%20Grid_Web.pdf (accessed 7-3-13).

Faced with these challenges, the PUC responded, in part, by raising the cap on wholesale power prices–eventually to $9,000 per MWh, or roughly 300 times the average wholesale electricity price.[12] Generally, customers would not see this price directly, as prices would not reach that level except during extreme events and the rates actually charged to customers would level out these prices with lower prices during more normal conditions. Raising the cap allows wholesale prices to reach extremely high levels when supplies are tightest and should provide greater incentive for new investment given the shortages experienced and projected in Texas. However, prices would need to be sustained at extremely high levels with enough frequency to attract enough investment, and the greater the frequency, the greater the impact on prices. The Brattle Group concluded that **even with a $9,000 cap, a reserve margin of only 10% could be reached—far below the reliability target.**[13] NERC also points out the limitations of this partial solution in addressing the overall reliability concerns. And industrial customers in Texas—while supportive of efforts to ensure reliable power—cautioned that the increased cap could cost the state an additional $14 billion annually.[14]

Texas's challenges in the area of reliability are compounded by the mix of its generation. Low natural gas prices and new wind generation have led to lower margins for generators (which in turn lead to inadequate incentives to build new supply). The president of NRG Energy, the second largest generator in Texas, recently stated:

> *[T]here is little incentive for investors to build new, billion-dollar power plants because the price of electricity is so low. The cost of natural gas, among other factors, has driven energy prices down—good for consumers in the short term, but dangerous to long-term reliability because demand for power is growing faster than new generation is being built.*[15]

The market is responding to price signals—exactly what the proponents of deregulation want—and the signals are telling investors not to build new capacity. Ironically, even though demand for electricity is starting to outstrip supplies, it is difficult for merchant generators and the market as a whole to adapt to these market conditions and ensure that the right kind of generation is built at the right time. Unlike a regulated utility, investors are not looking at long-range needs to develop a balanced mix of generation based on cost, reliability, and supply diversity. Demand response does play an important role in Texas, but it does not obviate the need for additional supply-side resources.

Despite warning signs over several years and an urgent need for additional power sources to maintain reliability, there has not been the necessary investment. The PUC and ERCOT are considering whether additional interventions are necessary. Numerous entities, from generators to NERC to energy experts, have suggested that additional intervention beyond the increased price cap already adopted is needed to ensure adequate power supplies. One option that is under consideration is a capacity market similar to those in place in the Northeast. This would provide a mandated capacity payment to generation owners for being available in future years. This payment would be in addition to the payments to generators for the actual production of electricity and thereby provide a more stable revenue stream and incentive to build new generation. But like the increase in the price cap, capacity markets are expected to raise electricity costs overall. In an editorial advocating for a capacity market, NRG's president emphasizes the cost of inaction to the state's economy:

> *"The Texas economy is stronger than any other state's. We don't want to mess this up by creating conditions that lead businesses to believe Texas has an unreliable electric state."*
>
> —John Ragan, *Houston Chronicle* editorial, 6-11-13

> *In years past, Texas had a healthy reserve, meaning that rolling blackouts and outages have largely been avoided with the exception of a couple of freak occurrences. But our reserve margin is shrinking each year and we have recently seen repeated calls for emergency conservation. If we do that again—or, worse, if the lights go out—businesses that recently moved here, employ our citizens, and invest in Texas will begin to question that decision and they, as well as businesses contemplating moving here, may look to other states where power is more reliable.*[16]

Capacity markets have been used in other regions, although there have been challenges in the design and implementation of capacity markets and their effectiveness in actually spurring new investment remains in question. To date, Texas has rejected this form of market intervention to address its reliability challenges in part because many consider it a violation of "free market" principles—i.e., a government mandate that results in price increases.

Affordability

States that deregulated faced the need to protect consumers yet "create a market" during the time of transition. Many states put in place rate freezes or reductions for residential and small business customers during the transition period. While the capped rates may have protected such consumers in the short term, they often undermined the ability to attract and retain new providers to compete with the incumbent (because the capped rates were below market at times due to fluctuating fuel and wholesale power prices). Texas did a better job of balancing these two objectives to encourage new entrants and protect customers.

Texas required that electricity providers affiliated with the incumbent utility charge a "price to beat" until the incumbent lost sufficient market share to alternative providers. This price was designed as a price floor and ceiling. In other words, it was designed to prevent the incumbent from offering artificially low rates to stifle competition and undercut new market players. It was also intended to provide a cap, or ceiling, so that customers that didn't switch providers still received some benefit. When the price to beat was set, it included a 6% discount off the utility's base rates. (Rates were frozen as part of the restructuring law in 1999 and were expected to be reduced during this time period had regulation continued.)

Despite the 6% reduction, the fuel portion of the rate was indexed to natural gas prices, which fluctuated based on the market. This avoided some of the challenges that occurred in other deregulated states where the overall default rates were fixed, leading to significant unrecovered costs that were deferred and eventually caused large price spikes when the price caps expired. But Texans faced a different challenge—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. For over a decade, deregulated areas of Texas have consistently paid more for electricity than regulated areas of the state. And prices are more volatile in deregulated areas.

> *"With declining costs and the strong load growth in the State, it is likely that the commission could find itself facing a never-ending stream of rate cases in an attempt to harness utility over-earnings."*[17]
>
> —Public Utility Commission of Texas

This volatility is a function of deregulation. Regulated utilities pass through fuel costs without a markup. This includes the utility's actual costs based on its fleet of power plants (typically a mix of nuclear, coal, and natural gas). Although these costs and the amounts charged to customers can fluctuate over time as fuel costs change, the impact on customers is tempered because of the diversity in the fuel mix. In contrast, electricity prices in the deregulated areas are heavily dependent on the price of natural gas, which is often the marginal fuel used for electricity generation. Given the historic volatility of natural gas prices, this creates vulnerability for customers. Regulated areas have proven to be more adaptable to market fluctuations. Commercial and industrial rates in Texas have also been volatile, particularly under deregulation.

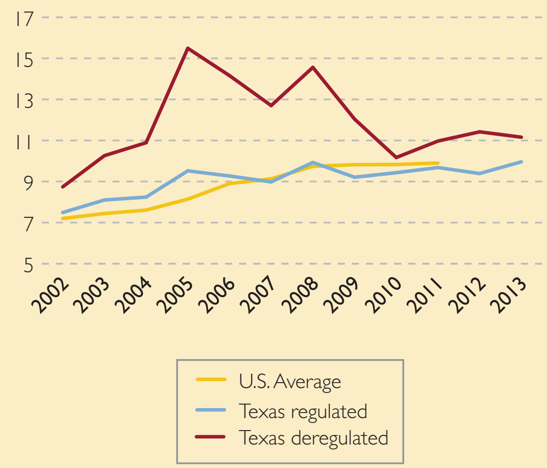
It was envisioned that deregulation would lower prices, but the data suggest the contrary occurred in Texas—prices in deregulated areas have been higher and more volatile than in regulated areas of the state.

Unintended Consequences

Texas policymakers crafted a comprehensive law to deregulate the electric industry with the goal of increasing competition and providing associated savings to customers. As the law was implemented, however, the state faced numerous unintended consequences, which illustrate the complexities and inherent uncertainties involved with deregulation. For example:

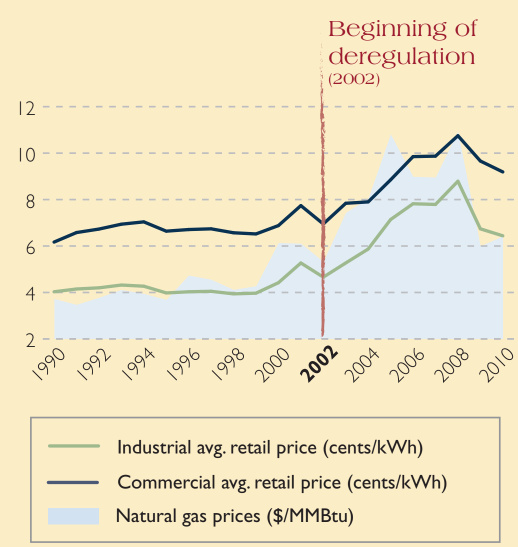
- IT struggles—Texas experienced major problems with billing and IT systems at the advent of the deregulation, which proved costly for customers and

Residential Rates
Texas vs U.S. Average



SOURCE: Public Sector Consultants, using data from Energy Information Administration and the Public Utility Commission of Texas.

C&I Electricity Prices vs. Natural Gas Prices
Texas 1990–2010



SOURCE: Public Sector Consultants, using data from Energy Information Administration and the Public Utility Commission of Texas.

providers.

- Provider of last resort—The state also faced major challenges setting up the "provider of last resort," or POLR, in deregulated areas because providers were unwilling to bid on such service as laid out in the law.
- Costly market redesign—There were also issues with market manipulation at times and a costly redesign of the wholesale market.
- Stranded costs—A major unintended consequence that will have a lasting impact on customers relates to stranded cost recovery. The Texas deregulation law allowed utilities to recover their stranded costs, or the difference between the market value and the book value of generation assets.

Estimates of stranded costs were calculated at various points during the transition to deregulation in order to provide for early mitigation and recovery, as applicable. 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, the total amount customers will pay amounted to over **$9.5 billion**.[18] Even though customers are on the hook for this amount, private equity investors resold the assets at a significant profit under better market conditions. While the state's policy was well intended, it did not adequately anticipate the rapidly changing market conditions. This experience has been costly for businesses and residents of Texas, and underscores the complexities and trade-offs of deregulation.

Conclusion

Texas has been successful in attracting and retaining alternative suppliers. The rates charged by the default provider during the transition to deregulation were allowed to fluctuate based on natural gas prices. Texas's approach avoided the situation other states experienced with wholesale prices exceeding capped retail rates, resulting in price spikes after the caps expired (due to the collection of deferred costs) and/or bankruptcies or other financial distress in the industry. The rates in Texas were also sufficiently high to allow new providers to enter the market and serve customers, including residential. Deregulation did not, however, bring about lower rates as initially envisioned. In fact, rates have been higher and more volatile in the deregulated areas of Texas. The state's more serious challenges relate to reliability and the adequacy of power supplies. The reliance on market forces to incent the right mix of investments has not resulted in investments necessary to ensure an adequate supply of electricity to residents and businesses in Texas.

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5. ERCOT, December 2012, *Striking a Reliable Balance: 2012 State of the Grid Report*. Available: www.ercot.com/content/news/presentations/2013/2012 ERCOT State of the Grid_Web.pdf (accessed 6-3-13).

6. Brattle Group, p. 1.

7. Public Utility Commission of Texas (PUCT) data. Available: www.puc.texas.gov/industry/maps/elecmaps/gentable.pdf (accessed 6-3-13).

8. Letter from Gerry Cauley, President and CEO, North American Electric Reliability Corporation, to Trip Doggett, ERCOT President and CEO, January 7, 2013. Available: www.ercot.org/content/news/presentations/2013/NERClettertoTripDoggettonResourceAdequacyJan72013.pdf (accessed 6-3-2013).

9. ERCOT, May 1, 2013, *Seasonal Assessment of Resource Adequacy for the ERCOT Region*, Summer 2013. Available: www.ercot.com/content/news/presentations/2013/SARA-Summer2013.pdf (accessed 6-3-13).

10. Brattle Group, p. 1. The Brattle Group has a more conservative target of 15.25% because it accounts for 2011 weather.

11. Brattle Group, p. 6.

12. Based on ERCOT North region average bilateral prices for 2012. See Federal Energy Regulatory Commission, January 2013, *Texas Annual Average Bilateral Power Prices*. Available: http://ferc.gov/market-oversight/mkt-electric/texas/elec-tx-yr-pr.pdf (accessed 6-3-13).

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15. Jonathan Ragan, "Ragan: Time for Texas to Add to State's Electric Grid," *Houston Chronicle*, June 11, 2013. Available: www.chron.com/opinion/outlook/article/Ragan-Time-for-Texas-to-add-to-state-s-electric-4594395.php (accessed 7-1-13).

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