

Financial Impact Estimating Conference

Limits or Prevents Barriers to Local Solar Electricity Supply Serial Number 14-02

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Tab 1

Authorization



FLORIDA DEPARTMENT of STATE

RICK SCOTT
Governor

KEN DETZNER
Secretary of State

March 25, 2015

Financial Impact Estimating Conference
c/o Ms. 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 the sponsoring political committee has met the registration, submission, and signature criteria set forth in that section.

Floridians for Solar Choice, Inc. has successfully met the requirements of Section 15.21, Florida Statutes, for the initiative petition titled *Limits or Prevents Barriers to Local Solar Electricity Supply*, Serial Number 14-02. Therefore, I am submitting the proposed constitutional amendment for your review, along with a status update for the initiative petition, and a current county-by-county signature count.

Sincerely,

Ken Detzner
Secretary of State

KD/am

pc: Tory Perfetti, Chairperson
Floridians for Solar Choice, Inc.

Enclosures



FLORIDA DEPARTMENT OF STATE
DIVISION OF ELECTIONS

SUMMARY OF PETITION SIGNATURES

Political Committee: **Floridians for Solar Choice, Inc.**

Amendment Title: **Limits or Prevents Barriers to Local Solar Electricity Supply**

Congressional District	Voting Electors in 2012 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	356,435	2,851	28,515	95	
SECOND	343,558	2,748	27,485	3,241	***
THIRD	329,165	2,633	26,333	134	
FOURTH	351,564	2,813	28,125	917	
FIFTH	279,598	2,237	22,368	6,119	***
SIXTH	363,402	2,907	29,072	1,276	
SEVENTH	333,990	2,672	26,719	5,411	***
EIGHTH	365,738	2,926	29,259	2,162	
NINTH	277,101	2,217	22,168	3,601	***
TENTH	329,366	2,635	26,349	3,790	***
ELEVENTH	359,004	2,872	28,720	775	
TWELFTH	345,407	2,763	27,633	2,370	
THIRTEENTH	344,500	2,756	27,560	4,829	***
FOURTEENTH	295,917	2,367	23,673	3,615	***
FIFTEENTH	304,932	2,439	24,395	3,060	***
SIXTEENTH	360,734	2,886	28,859	1,523	
SEVENTEENTH	299,464	2,396	23,957	2,403	***
EIGHTEENTH	345,399	2,763	27,632	1,516	
NINETEENTH	323,317	2,587	25,865	559	
TWENTIETH	264,721	2,118	21,178	3,225	***
TWENTY-FIRST	326,392	2,611	26,111	2,392	
TWENTY-SECOND	329,816	2,639	26,385	3,533	***
TWENTY-THIRD	290,042	2,320	23,203	2,741	***
TWENTY-FOURTH	263,367	2,107	21,069	8,194	***
TWENTY-FIFTH	240,521	1,924	19,242	973	
TWENTY-SIXTH	268,898	2,151	21,512	1,715	
TWENTY-SEVENTH	247,023	1,976	19,762	1,856	
TOTAL:	8,539,371	68,314	683,149	72,025	

**Attachment for Initiative Petition
Limits or Prevents Barriers to Local Solar Electricity Supply
Serial Number 14-02**

1. **Name and address of the sponsor of the initiative petition:**
Tory Perfetti, Chairperson
Floridians for Solar Choice, Inc.
120 East Oakland Park Blvd. Ste. 105
Fort Lauderdale, FL 33334

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 March 25, 2015, the sponsor has not obtained the requisite number of signatures to have the proposed amendment placed on the ballot. A total of 683,149 valid signatures are required for placement on the 2016 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 March 25, 2015, the Supervisors of Elections have certified a total of 72,025 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 2016 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 8, 2016, provided the sponsor successfully obtains the requisite number of valid signatures by February 1, 2016.

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 March 25, 2015.

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: Limits or Prevents Barriers to Local Solar Electricity Supply

BALLOT SUMMARY: Limits or prevents government and electric utility imposed barriers to supplying local solar electricity. Local solar electricity supply is the non-utility supply of solar generated electricity from a facility rated up to 2 megawatts to customers at the same or contiguous property as the facility. Barriers include government regulation of local solar electricity suppliers' rates, service and territory, and unfavorable electric utility rates, charges, or terms of service imposed on local solar electricity customers

ARTICLE AND SECTION BEING CREATED OR AMENDED: Add new Section 29 to Article X

FULL TEXT OF PROPOSED AMENDMENT:

Section 29 Purchase and sale of solar electricity –

(a) PURPOSE AND INTENT It shall be the policy of the state to encourage and promote local small-scale solar-generated electricity production and to enhance the availability of solar power to customers. This section is intended to accomplish this purpose by limiting and preventing regulatory and economic barriers that discourage the supply of electricity generated from solar energy sources to customers who consume the electricity at the same or a contiguous property as the site of the solar electricity production. Regulatory and economic barriers include rate, service and territory regulations imposed by state or local government on those supplying such local solar electricity, and imposition by electric utilities of special rates, fees, charges, tariffs, or terms and conditions of service on their customers consuming local solar electricity supplied by a third party that are not imposed on their other customers of the same type or class who do not consume local solar electricity.

(b) PURCHASE AND SALE OF LOCAL SMALL-SCALE SOLAR ELECTRICITY

(1) A local solar electricity supplier, as defined in this section, shall not be subject to state or local government regulation with respect to rates, service, or territory, or be subject to any assignment, reservation, or division of service territory between or among electric utilities.

(2) No electric utility shall impair any customer's purchase or consumption of solar electricity from a local solar electricity supplier through any special rate, charge, tariff, classification, term or condition of service, or utility rule or regulation, that is not also imposed on other customers of the same type or class that do not consume electricity from a local solar electricity supplier.

(3) An electric utility shall not be relieved of its obligation under law to furnish service to any customer within its service territory on the basis that such customer also purchases electricity from a local solar electricity supplier.

(4) Notwithstanding paragraph (1), nothing in this section shall prohibit reasonable health, safety and welfare regulations, including, but not limited to, building codes, electrical codes, safety codes and pollution control regulations, which do not prohibit or have the effect of prohibiting the supply of solar-generated electricity by a local solar electricity supplier as defined in this section.

(c) DEFINITIONS For the purposes of this section

(1) "local solar electricity supplier" means any person who supplies electricity generated from a solar electricity generating facility with a maximum rated capacity of no more than 2 megawatts, that converts energy from the sun into thermal or electrical energy, to any other person located on the same property, or on separately owned but contiguous property, where the solar energy generating facility is located.

(2) "person" means any individual, firm, association, joint venture, partnership, estate, trust, business trust, syndicate, fiduciary, corporation, government entity, and any other group or combination.

(3) "electric utility" means every person, corporation, partnership, association, governmental entity, and their lessees, trustees, or receivers, other than a local solar electricity supplier, supplying electricity to ultimate consumers of electricity within this state.

(4) "local government" means any county, municipality, special district, district, authority, or any other subdivision of the state.

(d) ENFORCEMENT AND EFFECTIVE DATE This amendment shall be effective on January 3, 2017

Date: _____ X _____

(Date of signature)

(Signature of registered voter)

Initiative petition sponsored by Floridians for Solar Choice Inc 120 E Oakland Blvd Suite 105 Ft Lauderdale FL 33334

If paid petition circulator is used

Circulator's Name _____

Circulator's Address _____

For official use only

Serial number 14-02

Date approved 12/23/2014

Select Year:

The 2014 Florida Statutes

[Title IX](#)
ELECTORS AND
ELECTIONS

[Chapter 100](#)
GENERAL, PRIMARY, SPECIAL, BOND, AND
REFERENDUM ELECTIONS

[View Entire
Chapter](#)

100.371 Initiatives; procedure for placement on ballot.—

(1) Constitutional amendments proposed by initiative shall be placed on the ballot for the general election, provided the initiative petition has been filed with the Secretary of State no later than February 1 of the year the general election is held. A petition shall be deemed to be filed with the Secretary of State upon the date the secretary determines that valid and verified petition forms have been signed by the constitutionally required number and distribution of electors under this code.

(2) The sponsor of an initiative amendment shall, prior to obtaining any signatures, register as a political committee pursuant to s. [106.03](#) and submit the text of the proposed amendment to the Secretary of State, with the form on which the signatures will be affixed, and shall obtain the approval of the Secretary of State of such form. The Secretary of State shall adopt rules pursuant to s. [120.54](#) prescribing the style and requirements of such form. Upon filing with the Secretary of State, the text of the proposed amendment and all forms filed in connection with this section must, upon request, be made available in alternative formats.

(3) An initiative petition form circulated for signature may not be bundled with or attached to any other petition. Each signature shall be dated when made and shall be valid for a period of 2 years following such date, provided all other requirements of law are met. The sponsor shall submit signed and dated forms to the supervisor of elections for the county of residence listed by the person signing the form for verification of the number of valid signatures obtained. If a signature on a petition is from a registered voter in another county, the supervisor shall notify the petition sponsor of the misfiled petition. The supervisor shall promptly verify the signatures within 30 days after receipt of the petition forms and payment of the fee required by s. [99.097](#). The supervisor shall promptly record, in the manner prescribed by the Secretary of State, the date each form is received by the supervisor, and the date the signature on the form is verified as valid. The supervisor may verify that the signature on a form is valid only if:

(a) The form contains the original signature of the purported elector.

(b) The purported elector has accurately recorded on the form the date on which he or she signed the form.

(c) The form sets forth the purported elector's name, address, city, county, and voter registration number or date of birth.

(d) The purported elector is, at the time he or she signs the form and at the time the form is verified, a duly qualified and registered elector in the state.

The supervisor shall retain the signature forms for at least 1 year following the election in which the issue appeared on the ballot or until the Division of Elections notifies the supervisors of elections that the committee that circulated the petition is no longer seeking to obtain ballot position.

(4) The Secretary of State shall determine from the signatures verified by the supervisors of elections the total number of verified valid signatures and the distribution of such signatures by congressional districts. Upon a determination that the requisite number and distribution of valid signatures have been obtained, the secretary shall issue a certificate of ballot position for that proposed amendment and shall assign a designating number pursuant to s. [101.161](#).

(5)(a) Within 45 days after receipt of a proposed revision or amendment to the State Constitution by initiative petition from the Secretary of State, the Financial Impact Estimating Conference shall complete an analysis and financial impact statement to be placed on the ballot of the estimated increase or decrease in any revenues or costs to state or local governments resulting from the proposed initiative. The Financial Impact Estimating Conference shall submit the financial impact statement to the Attorney General and Secretary of State.

(b) The Financial Impact Estimating Conference shall provide an opportunity for any proponents or opponents of the initiative to submit information and may solicit information or analysis from any other entities or agencies, including the Office of Economic and Demographic Research.

(c) All meetings of the Financial Impact Estimating Conference shall be open to the public. The President of the Senate and the Speaker of the House of Representatives, jointly, shall be the sole judge for the interpretation, implementation, and enforcement of this subsection.

1. The Financial Impact Estimating Conference is established to review, analyze, and estimate the financial impact of amendments to or revisions of the State Constitution proposed by initiative. The Financial Impact Estimating Conference shall consist of four principals: one person from the Executive Office of the Governor; the coordinator of the Office of Economic and Demographic Research, or his or her designee; one person from the professional staff of the Senate; and one person from the professional staff of the House of Representatives. Each principal shall have appropriate fiscal expertise in the subject matter of the initiative. A Financial Impact Estimating Conference may be appointed for each initiative.

2. Principals of the Financial Impact Estimating Conference shall reach a consensus or majority concurrence on a clear and unambiguous financial impact statement, no more than 75 words in length, and immediately submit the statement to the Attorney General. Nothing in this subsection prohibits the Financial Impact Estimating Conference from setting forth a range of potential impacts in the financial impact statement. Any financial impact statement that a court finds not to be in accordance with this section shall be remanded solely to the Financial Impact Estimating Conference for redrafting. The Financial Impact Estimating Conference shall redraft the financial impact statement within 15 days.

3. If the members of the Financial Impact Estimating Conference are unable to agree on the statement required by this subsection, or if the Supreme Court has rejected the initial submission by the Financial Impact Estimating Conference and no redraft has been approved by the Supreme Court by 5 p.m. on the 75th day before the election, the following statement shall appear on the ballot pursuant to s. [101.161\(1\)](#): "The financial impact of this measure, if any, cannot be reasonably determined at this time."

(d) The financial impact statement must be separately contained and be set forth after the ballot summary as required in s. [101.161\(1\)](#).

(e)1. Any financial impact statement that the Supreme Court finds not to be in accordance with this subsection shall be remanded solely to the Financial Impact Estimating Conference for redrafting,

provided the court's advisory opinion is rendered at least 75 days before the election at which the question of ratifying the amendment will be presented. The Financial Impact Estimating Conference shall prepare and adopt a revised financial impact statement no later than 5 p.m. on the 15th day after the date of the court's opinion.

2. If, by 5 p.m. on the 75th day before the election, the Supreme Court has not issued an advisory opinion on the initial financial impact statement prepared by the Financial Impact Estimating Conference for an initiative amendment that otherwise meets the legal requirements for ballot placement, the financial impact statement shall be deemed approved for placement on the ballot.

3. In addition to the financial impact statement required by this subsection, the Financial Impact Estimating Conference shall draft an initiative financial information statement. The initiative financial information statement should describe in greater detail than the financial impact statement any projected increase or decrease in revenues or costs that the state or local governments would likely experience if the ballot measure were approved. If appropriate, the initiative financial information statement may include both estimated dollar amounts and a description placing the estimated dollar amounts into context. The initiative financial information statement must include both a summary of not more than 500 words and additional detailed information that includes the assumptions that were made to develop the financial impacts, workpapers, and any other information deemed relevant by the Financial Impact Estimating Conference.

4. The Department of State shall have printed, and shall furnish to each supervisor of elections, a copy of the summary from the initiative financial information statements. The supervisors shall have the summary from the initiative financial information statements available at each polling place and at the main office of the supervisor of elections upon request.

5. The Secretary of State and the Office of Economic and Demographic Research shall make available on the Internet each initiative financial information statement in its entirety. In addition, each supervisor of elections whose office has a website shall post the summary from each initiative financial information statement on the website. Each supervisor shall include the Internet addresses for the information statements on the Secretary of State's and the Office of Economic and Demographic Research's websites in the publication or mailing required by s. [101.20](#).

(6) The Department of State may adopt rules in accordance with s. [120.54](#) to carry out the provisions of subsections (1)-(5).

(7) No provision of this code shall be deemed to prohibit a private person exercising lawful control over privately owned property, including property held open to the public for the purposes of a commercial enterprise, from excluding from such property persons seeking to engage in activity supporting or opposing initiative amendments.

History.—s. 15, ch. 79-365; s. 12, ch. 83-251; s. 30, ch. 84-302; s. 22, ch. 97-13; s. 9, ch. 2002-281; s. 3, ch. 2002-390; s. 3, ch. 2004-33; s. 28, ch. 2005-278; s. 4, ch. 2006-119; s. 25, ch. 2007-30; s. 1, ch. 2007-231; s. 14, ch. 2008-95; s. 23, ch. 2011-40.

Tab 2

Current Law

Tab 2 – Current Law

Statutes

- ch. 203, F.S. – Gross Receipts Tax
- s. 366.02, F.S. – Public Utilities Definitions
- s. 212.05, F.S. – Sales Tax on Electricity
- s. 212.08(7)(hh), F.S. – Sales Tax Exemption for Solar Energy Systems
- s. 193.624, F.S. – Assessment of Residential Property
- s. 163.04, F.S. – Energy Devices Based on Renewable Resources
- s. 163.08, F.S. – Supplemental Authority for Improvements to Real Property
- s. 366.91, F.S. – Renewable Energy
- s. 377.705, F.S. – Solar Energy Center; Development of Solar Energy Standards
- s. 403.503, F.S. – Definitions Relating to Florida Electrical Power Siting Act
- s.166.231, F.S. – Municipalities; Public Service Tax
- s. 366.14, F.S. – Regulatory Assessment Fees

Rules

- 25-6.065 – Interconnection and Net Metering of Customer-Owned Renewable Generation
- 25-6.0131 – Regulatory Assessment Fees; Investor-owned Electric Companies, Municipal Electric Utilities, Rural Electric Cooperatives.

The Florida Senate

2014 Florida Statutes

Title XIV

TAXATION AND FINANCE

Chapter 203

GROSS RECEIPTS TAXES

CHAPTER 203

GROSS RECEIPTS TAXES

- 203.001 Combined rate for tax collected pursuant to ss. 202.12(1)(a) and 203.01(1)(b).
- 203.0011 Combined rate for tax collected pursuant to ss. 203.01(1)(b)4. and 212.05(1)(e)1.c.
- 203.01 Tax on gross receipts for utility and communications services.
- 203.0111 Application of tax increase.
- 203.012 Definitions.
- 203.02 Powers of Department of Revenue.
- 203.03 Penalties.
- 203.04 Construction of laws granting exemptions or exceptions.
- 203.06 Interest on delinquent payments.
- 203.07 Settlement or compromise of penalties and interest.

¹**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 6.8 percent comprised of 6.65 percent and 0.15 percent required by ss. 202.12(1)(a) and 203.01(1)(b)3., respectively, as long as 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.

¹**Note.**—

A. Also published at s. 202.12001.

B. Section 6, ch. 2010-149, provides that “[t]he Department of Revenue may, and all conditions are deemed met to, adopt emergency rules pursuant to ss. 120.536(1) and 120.54, Florida Statutes, for the purpose of promulgating such forms and instructions as are required to effectuate this act.”

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(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.

²(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.

¹(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.

¹(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.

¹(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.

¹**Note.**—

A. Section 5, ch. 2014-38, provides that “[t]he amendments to s. 212.05(1)(e)1.c. made in section 2 of this act and to s. 203.01 made in section 4 of this act apply to taxable transactions included on bills that are for utility services and that are dated on or after July 1, 2014.”

B. Section 12, ch. 2014-38, provides that “[t]he Department of Revenue may, and all conditions are deemed met to, adopt emergency rules pursuant to ss. 120.536(1) and 120.54, Florida Statutes, for the purpose of implementing the amendments to ss. 203.01, 212.05, 212.12, and 212.20, Florida Statutes, relating to changes to the taxation of electrical power or energy, made by this act. This section expires July 1, 2017.”

²**Note.**—Section 6, ch. 2010-149, provides that “[t]he Department of Revenue may, and all conditions are deemed met to, adopt emergency rules pursuant to ss. 120.536(1) and 120.54, Florida Statutes, for the purpose of promulgating such forms and instructions as are required to effectuate this act.”

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.—s. 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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<u>Title XXVII</u> RAILROADS AND OTHER REGULATED UTILITIES	<u>Chapter 366</u> PUBLIC UTILITIES Entire Chapter	SECTION 02 Definitions.
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366.02 Definitions.— As used in this chapter:

(1) “Public utility” means every person, corporation, partnership, association, or other legal entity and their lessees, trustees, or receivers supplying electricity or gas (natural, manufactured, or similar gaseous substance) to or for the public within this state; but the term “public utility” does not include either a cooperative now or hereafter organized and existing under the Rural Electric Cooperative Law of the state; a municipality or any agency thereof; any dependent or independent special natural gas district; any natural gas transmission pipeline company making only sales or transportation delivery of natural gas at wholesale and to direct industrial consumers; any entity selling or arranging for sales of natural gas which neither owns nor operates natural gas transmission or distribution facilities within the state; or a person supplying liquefied petroleum gas, in either liquid or gaseous form, irrespective of the method of distribution or delivery, or owning or operating facilities beyond the outlet of a meter through which natural gas is supplied for compression and delivery into motor vehicle fuel tanks or other transportation containers, unless such person also supplies electricity or manufactured or natural gas.

(2) “Electric utility” means any municipal electric utility, investor-owned electric utility, or rural electric cooperative which owns, maintains, or operates an electric generation, transmission, or distribution system within the state.

(3) “Commission” means the Florida Public Service Commission.

History.—s. 2, ch. 26545, 1951; s. 3, ch. 76-168; s. 1, ch. 77-457; ss. 2, 16, ch. 80-35; s. 2, ch. 81-318; ss. 1, 20, 22, ch. 89-292; s. 4, ch. 91-429; s. 14, ch. 92-284.

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212.08 Sales, rental, use, consumption, distribution, and storage tax; specified exemptions.—The sale at retail, the rental, the use, the consumption, the distribution, and the storage to be used or consumed in this state of the following are hereby specifically exempt from the tax imposed by this chapter.

(7) **MISCELLANEOUS EXEMPTIONS.**—Exemptions provided to any entity by this chapter do not inure to any transaction that is otherwise taxable under this chapter when payment is made by a representative or employee of the entity by any means, including, but not limited to, cash, check, or credit card, even when that representative or employee is subsequently reimbursed by the entity. In addition, exemptions provided to any entity by this subsection do not inure to any transaction that is otherwise taxable under this chapter unless the entity has obtained a sales tax exemption certificate from the department or the entity obtains or provides other documentation as required by the department. Eligible purchases or leases made with such a certificate must be in strict compliance with this subsection and departmental rules, and any person who makes an exempt purchase with a certificate that is not in strict compliance with this subsection and the rules is liable for and shall pay the tax. The department may adopt rules to administer this subsection.

(hh) *Solar energy systems.*—Also exempt are solar energy systems or any component thereof. The Florida Solar Energy Center shall from time to time certify to the department a list of equipment and requisite hardware considered to be a solar energy system or a component thereof.

212.02 Definitions.—The following terms and phrases when used in this chapter have the meanings ascribed to them in this section, except where the context clearly indicates a different meaning:

(26) “Solar energy system” means the equipment and requisite hardware that provide and are used for collecting, transferring, converting, storing, or using incident solar energy for water heating, space heating, cooling, or other applications that would otherwise require the use of a conventional source of energy such as petroleum products, natural gas, manufactured gas, or electricity.

TIP # 05A01-05

DATE ISSUED: June 1, 2005

SOLAR ENERGY SYSTEMS SALES AND USE TAX EXEMPTION NO LONGER SUBJECT TO REPEAL

Florida Law exempts from sales and use tax solar energy systems and all components of such systems. Previously set for repeal on July 1, 2005, the exemption's repeal date has been removed under an amendment to the law by the 2005 Florida Legislature. Accordingly, the exemption is no longer subject to an expiration date.

The term "solar energy system" means the equipment and requisite hardware that provide and are used for collecting, transferring, converting, storing, or using incidental solar energy for water heating, space heating and cooling, or other applications that would otherwise require the use of a conventional source of energy such as petroleum products, natural gas, manufactured gas, or electricity

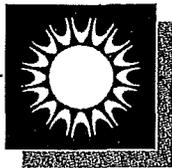
A list of equipment and requisite hardware considered to be a solar energy system or component thereof is included for your reference.

Sellers of solar energy systems or components thereof are required to document exempt sales. The following is a suggested form to be completed by the purchaser and presented to the seller

<p>The undersigned hereby certifies that all equipment and requisite hardware purchased or leased on the attached order is purchased or leased for use exclusively in a solar energy system.</p>	
Purchaser's Name	_____
Address	_____
By	_____ Date _____
(signature)	

References: Chapter 2005-83, Laws of Florida; Sections 212.02(26) and 212.08(7)(hh), Florida Statutes

FOR MORE INFORMATION



MAY 23 2005

September 2003

The Florida Solar Energy Center certifies the following list to the Department of Revenue, pursuant to Section 212.08(7)(hh), Florida Statutes.

SOLAR ENERGY SYSTEM COMPONENTS

COLLECTOR: The purpose of a solar collector in thermal applications is to gather radiant energy from the sun and transfer it in the form of heat to a fluid for the purpose of domestic water heating, pool heating, space heating and cooling. A collector may consist of an absorber plate and tubing which may or may not be enclosed in an insulated box with a transparent cover. The collector provides the primary energy input to the system. Solar electric systems considered eligible for the exemption collect the light energy from the sun and convert it to electricity. A solar photovoltaic powered attic fan ventilation system is eligible. A pool blanket is eligible as a "passive" solar collector whether used in conjunction with or independently from an active solar pool system

TYPICAL MATERIALS: Cover plate - glass, resin - fiberglass, plastic, vinyl; Absorber and tubing - copper, galvanized steel, aluminum, plastic, rubber; Coating - non-selective, moderately selective, and selective; Insulation - polyisocyanurate, homasote, urethane, ductboards, fiberglass; Box - aluminum, galvanized steel, exterior grade wood, molded fiberglass; Photovoltaic Array - photovoltaic modules.

PUMP AND CONTROLS: The equipment which regulates the circulation of the fluid between the storage medium and the collector.

TYPICAL MATERIALS: Pump - bronze, brass, stainless steel, cast iron; Controller - solid state transistorized controller, sensors, timer, snap switches, and photovoltaic modules.

PHOTOVOLTAIC POWER CONDITIONING EQUIPMENT. The equipment which receives the direct current from the photovoltaic array, converts it to alternating current for consumption and/or transfer to the electric utility grid.

TYPICAL MATERIALS: Inverters, transformers, junction boxes, meters, maximum power trackers, dc to dc converters, and charge controllers.

STORAGE UNIT: The equipment which receives thermal energy, or direct current in the case of a solar electric system, and retains it for future use.

TYPICAL MATERIALS: Conventional tank, solar specific tank, tank equipped with heat exchanger, expansion tank, heat storage by phase change material, desiccants, batteries, regulators, mechanical housing and venting.

ACCESSORIES (when used as an integral part of a solar system): Piping, insulation, air vents, relief valves, mixing valves, check valves, gate valves, assorted bolts, nuts, washers and screws, mounting brackets, angle irons and other structural support (other than roof), solder, flux, pitch and pitch pans or other sealant, drain down reservoir, fans, air handling units, air dampers, heat exchangers, heat transfer fluids, convectors, radiators, pool blankets, direct current wiring, and miscellaneous safety equipment required for P.V. applications; for example, blocking and bypass diodes, surge arrestors, disconnect switches, fuse holders, fuses, relays, junction boxes, ground fault detector and/or interrupter, grounding hardware, and utility-interconnection protection equipment.

NOTE: Amount of piping allowable for the exemption is limited to that used in collector construction and the feed and return lines between collector and storage. Piping from the tank to the taps would be required in a conventional system and therefore is not eligible for an exemption. A typical or rule of thumb piping length for feed and return would be a total of 80 to 100 feet. Wiring used in photovoltaic applications considered eligible for the exemption is limited to that wiring which is unique to the system. Therefore, alternating current wiring throughout the structure which would be present without regard to the photovoltaic system is not eligible for the exemption. Tangible personal property in which the solar equipment is integral to the property (such as calculators, patio lights, appliances and novelty items), and where the cost of the solar equipment cannot be or is not separate from the total product cost, is not considered to be a solar energy system.



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:

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

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.

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<u>Title XIV</u> TAXATION AND FINANCE	<u>Chapter 193</u> ASSESSMENTS	SECTION 624 Assessment of residential property.
	Entire Chapter	

193.624 Assessment of residential property. —

(1) As used in this section, the term “renewable energy source device” means any of the following equipment that collects, transmits, stores, or uses solar energy, wind energy, or energy derived from geothermal deposits:

- (a) Solar energy collectors, photovoltaic modules, and inverters.
- (b) Storage tanks and other storage systems, excluding swimming pools used as storage tanks.
- (c) Rockbeds.
- (d) Thermostats and other control devices.
- (e) Heat exchange devices.
- (f) Pumps and fans.
- (g) Roof ponds.
- (h) Freestanding thermal containers.
- (i) Pipes, ducts, refrigerant handling systems, and other equipment used to interconnect such systems; however, such equipment does not include conventional backup systems of any type.
- (j) Windmills and wind turbines.
- (k) Wind-driven generators.
- (l) Power conditioning and storage devices that use wind energy to generate electricity or mechanical forms of energy.
- (m) Pipes and other equipment used to transmit hot geothermal water to a dwelling or structure from a geothermal deposit.

(2) In determining the assessed value of real property used for residential purposes, an increase in the just value of the property attributable to the installation of a renewable energy source device may not be considered.

(3) This section applies to the installation of a renewable energy source device installed on or after January 1, 2013, to new and existing residential real property.

History.—s. 1, ch. 2013-77.

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<u>Title XI</u> COUNTY ORGANIZATION AND INTERGOVERNMENTAL RELATIONS	<u>Chapter 163</u> INTERGOVERNMENTAL PROGRAMS <u>Entire Chapter</u>	SECTION 04 Energy devices based on renewable resources.
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163.04 Energy devices based on renewable resources.—

(1) Notwithstanding any provision of this chapter or other provision of general or special law, the adoption of an ordinance by a governing body, as those terms are defined in this chapter, which prohibits or has the effect of prohibiting the installation of solar collectors, clotheslines, or other energy devices based on renewable resources is expressly prohibited.

(2) A deed restriction, covenant, declaration, or similar binding agreement may not prohibit or have the effect of prohibiting solar collectors, clotheslines, or other energy devices based on renewable resources from being installed on buildings erected on the lots or parcels covered by the deed restriction, covenant, declaration, or binding agreement. A property owner may not be denied permission to install solar collectors or other energy devices by any entity granted the power or right in any deed restriction, covenant, declaration, or similar binding agreement to approve, forbid, control, or direct alteration of property with respect to residential dwellings and within the boundaries of a condominium unit. Such entity may determine the specific location where solar collectors may be installed on the roof within an orientation to the south or within 45° east or west of due south if such determination does not impair the effective operation of the solar collectors.

(3) In any litigation arising under the provisions of this section, the prevailing party shall be entitled to costs and reasonable attorney's fees.

(4) The legislative intent in enacting these provisions is to protect the public health, safety, and welfare by encouraging the development and use of renewable resources in order to conserve and protect the value of land, buildings, and resources by preventing the adoption of measures which will have the ultimate effect, however unintended, of driving the costs of owning and operating commercial or residential property beyond the capacity of private owners to maintain. This section shall not apply to patio railings in condominiums, cooperatives, or apartments.

History.—s. 8, ch. 80-163; s. 1, ch. 92-89; s. 14, ch. 93-249; s. 1, ch. 2008-191; s. 3, ch. 2008-227.

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<u>Title XI</u> COUNTY ORGANIZATION AND INTERGOVERNMENTAL RELATIONS	<u>Chapter 163</u> INTERGOVERNMENTAL PROGRAMS <u>Entire Chapter</u>	SECTION 08 Supplemental authority for improvements to real property.
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163.08 Supplemental authority for improvements to real property.—

(1)(a) In chapter 2008-227, Laws of Florida, the Legislature amended the energy goal of the state comprehensive plan to provide, in part, that the state shall reduce its energy requirements through enhanced conservation and efficiency measures in all end-use sectors and reduce atmospheric carbon dioxide by promoting an increased use of renewable energy resources. That act also declared it the public policy of the state to play a leading role in developing and instituting energy management programs that promote energy conservation, energy security, and the reduction of greenhouse gases. In addition to establishing policies to promote the use of renewable energy, the Legislature provided for a schedule of increases in energy performance of buildings subject to the Florida Energy Efficiency Code for Building Construction. In chapter 2008-191, Laws of Florida, the Legislature adopted new energy conservation and greenhouse gas reduction comprehensive planning requirements for local governments. In the 2008 general election, the voters of this state approved a constitutional amendment authorizing the Legislature, by general law, to prohibit consideration of any change or improvement made for the purpose of improving a property's resistance to wind damage or the installation of a renewable energy source device in the determination of the assessed value of residential real property.

(b) The Legislature finds that all energy-consuming-improved properties that are not using energy conservation strategies contribute to the burden affecting all improved property resulting from fossil fuel energy production. Improved property that has been retrofitted with energy-related qualifying improvements receives the special benefit of alleviating the property's burden from energy consumption. All improved properties not protected from wind damage by wind resistance qualifying improvements contribute to the burden affecting all improved property resulting from potential wind damage. Improved property that has been retrofitted with wind resistance qualifying improvements receives the special benefit of reducing the property's burden from potential wind damage. Further, the installation and operation of qualifying improvements not only benefit the affected properties for which the improvements are made, but also assist in fulfilling the goals of the state's energy and hurricane mitigation policies. In order to make qualifying improvements more affordable and assist property owners who wish to undertake such improvements, the Legislature finds that there is a compelling state interest in enabling property owners to voluntarily finance such improvements with local government assistance.

(c) The Legislature determines that the actions authorized under this section, including, but not limited to, the financing of qualifying improvements through the execution of financing agreements and the related imposition of voluntary assessments are reasonable and necessary to serve and achieve a compelling state interest and are necessary for the prosperity and welfare of the state and its property owners and inhabitants.

(2) As used in this section, the term:

(a) "Local government" means a county, a municipality, a dependent special district as defined in s. [189.012](#), or a separate legal entity created pursuant to s. [163.01](#)(7).

(b) "Qualifying improvement" includes any:

1. Energy conservation and efficiency improvement, which is a measure to reduce consumption through conservation or a more efficient use of electricity, natural gas, propane, or other forms of energy on the property, including, but not limited to, air sealing; installation of insulation; installation of energy-efficient heating, cooling, or ventilation systems; building modifications to increase the use of daylight; replacement of windows; installation of

energy controls or energy recovery systems; installation of electric vehicle charging equipment; and installation of efficient lighting equipment.

2. Renewable energy improvement, which is the installation of any system in which the electrical, mechanical, or thermal energy is produced from a method that uses one or more of the following fuels or energy sources: hydrogen, solar energy, geothermal energy, bioenergy, and wind energy.

3. Wind resistance improvement, which includes, but is not limited to:

- a. Improving the strength of the roof deck attachment;
- b. Creating a secondary water barrier to prevent water intrusion;
- c. Installing wind-resistant shingles;
- d. Installing gable-end bracing;
- e. Reinforcing roof-to-wall connections;
- f. Installing storm shutters; or
- g. Installing opening protections.

(3) A local government may levy non-ad valorem assessments to fund qualifying improvements.

(4) Subject to local government ordinance or resolution, a property owner may apply to the local government for funding to finance a qualifying improvement and enter into a financing agreement with the local government. Costs incurred by the local government for such purpose may be collected as a non-ad valorem assessment. A non-ad valorem assessment shall be collected pursuant to s. [197.3632](#) and, notwithstanding s. [197.3632](#)(8)(a), shall not be subject to discount for early payment. However, the notice and adoption requirements of s. [197.3632](#)(4) do not apply if this section is used and complied with, and the intent resolution, publication of notice, and mailed notices to the property appraiser, tax collector, and Department of Revenue required by s. [197.3632](#)(3)(a) may be provided on or before August 15 in conjunction with any non-ad valorem assessment authorized by this section, if the property appraiser, tax collector, and local government agree.

(5) Pursuant to this section or as otherwise provided by law or pursuant to a local government's home rule power, a local government may enter into a partnership with one or more local governments for the purpose of providing and financing qualifying improvements.

(6) A qualifying improvement program may be administered by a for-profit entity or a not-for-profit organization on behalf of and at the discretion of the local government.

(7) A local government may incur debt for the purpose of providing such improvements, payable from revenues received from the improved property, or any other available revenue source authorized by law.

(8) A local government may enter into a financing agreement only with the record owner of the affected property. Any financing agreement entered into pursuant to this section or a summary memorandum of such agreement shall be recorded in the public records of the county within which the property is located by the sponsoring unit of local government within 5 days after execution of the agreement. The recorded agreement shall provide constructive notice that the assessment to be levied on the property constitutes a lien of equal dignity to county taxes and assessments from the date of recordation.

(9) Before entering into a financing agreement, the local government shall reasonably determine that all property taxes and any other assessments levied on the same bill as property taxes are paid and have not been delinquent for the preceding 3 years or the property owner's period of ownership, whichever is less; that there are no involuntary liens, including, but not limited to, construction liens on the property; that no notices of default or other evidence of property-based debt delinquency have been recorded during the preceding 3 years or the property owner's period of ownership, whichever is less; and that the property owner is current on all mortgage debt on the property.

(10) A qualifying improvement shall be affixed to a building or facility that is part of the property and shall constitute an improvement to the building or facility or a fixture attached to the building or facility. An agreement between a local government and a qualifying property owner may not cover wind-resistance improvements in buildings or facilities under new construction or construction for which a certificate of occupancy or similar evidence of substantial completion of new construction or improvement has not been issued.

(11) Any work requiring a license under any applicable law to make a qualifying improvement shall be performed by a contractor properly certified or registered pursuant to part I or part II of chapter 489.

(12)(a) Without the consent of the holders or loan servicers of any mortgage encumbering or otherwise secured by the property, the total amount of any non-ad valorem assessment for a property under this section may not exceed 20 percent of the just value of the property as determined by the county property appraiser.

(b) Notwithstanding paragraph (a), a non-ad valorem assessment for a qualifying improvement defined in subparagraph (2)(b)1. or subparagraph (2)(b)2. that is supported by an energy audit is not subject to the limits in this subsection if the audit demonstrates that the annual energy savings from the qualified improvement equals or exceeds the annual repayment amount of the non-ad valorem assessment.

(13) At least 30 days before entering into a financing agreement, the property owner shall provide to the holders or loan servicers of any existing mortgages encumbering or otherwise secured by the property a notice of the owner's intent to enter into a financing agreement together with the maximum principal amount to be financed and the maximum annual assessment necessary to repay that amount. A verified copy or other proof of such notice shall be provided to the local government. A provision in any agreement between a mortgagee or other lienholder and a property owner, or otherwise now or hereafter binding upon a property owner, which allows for acceleration of payment of the mortgage, note, or lien or other unilateral modification solely as a result of entering into a financing agreement as provided for in this section is not enforceable. This subsection does not limit the authority of the holder or loan servicer to increase the required monthly escrow by an amount necessary to annually pay the qualifying improvement assessment.

(14) At or before the time a purchaser executes a contract for the sale and purchase of any property for which a non-ad valorem assessment has been levied under this section and has an unpaid balance due, the seller shall give the prospective purchaser a written disclosure statement in the following form, which shall be set forth in the contract or in a separate writing:

QUALIFYING IMPROVEMENTS FOR ENERGY EFFICIENCY, RENEWABLE ENERGY, OR WIND RESISTANCE.—
The property being purchased is located within the jurisdiction of a local government that has placed an assessment on the property pursuant to s. [163.08](#), Florida Statutes. The assessment is for a qualifying improvement to the property relating to energy efficiency, renewable energy, or wind resistance, and is not based on the value of property. You are encouraged to contact the county property appraiser's office to learn more about this and other assessments that may be provided by law.

(15) A provision in any agreement between a local government and a public or private power or energy provider or other utility provider is not enforceable to limit or prohibit any local government from exercising its authority under this section.

(16) This section is additional and supplemental to county and municipal home rule authority and not in derogation of such authority or a limitation upon such authority.

History.—s. 1, ch. 2010-139; s. 1, ch. 2012-117; s. 64, ch. 2014-22.

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<u>Title XXVII</u>	<u>Chapter 366</u>	SECTION 91
RAILROADS AND OTHER REGULATED UTILITIES	PUBLIC UTILITIES	Renewable energy.
	<u>Entire Chapter</u>	

366.91 Renewable energy. —

(1) The Legislature finds that it is in the public interest to promote the development of renewable energy resources in this state. Renewable energy resources have the potential to help diversify fuel types to meet Florida's growing dependency on natural gas for electric production, minimize the volatility of fuel costs, encourage investment within the state, improve environmental conditions, and make Florida a leader in new and innovative technologies.

(2) As used in this section, the term:

(a) "Biomass" means a power source that is comprised of, but not limited to, combustible residues or gases from forest products manufacturing, waste, byproducts, or products from agricultural and orchard crops, waste or coproducts from livestock and poultry operations, waste or byproducts from food processing, urban wood waste, municipal solid waste, municipal liquid waste treatment operations, and landfill gas.

(b) "Customer-owned renewable generation" means an electric generating system located on a customer's premises that is primarily intended to offset part or all of the customer's electricity requirements with renewable energy.

(c) "Net metering" means a metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on site.

(d) "Renewable energy" means electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power. The term includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations and electrical energy produced using pipeline-quality synthetic gas produced from waste petroleum coke with carbon capture and sequestration.

(3) On or before January 1, 2006, each public utility must continuously offer a purchase contract to producers of renewable energy. The commission shall establish requirements relating to the purchase of capacity and energy by public utilities from renewable energy producers and may adopt rules to administer this section. The contract shall contain payment provisions for energy and capacity which are based upon the utility's full avoided costs, as defined in s. [366.051](#); however, capacity payments are not required if, due to the operational characteristics of the renewable energy generator or the anticipated peak and off-peak availability and capacity factor of the utility's avoided unit, the producer is unlikely to provide any capacity value to the utility or the electric grid during the contract term. Each contract must provide a contract term of at least 10 years. Prudent and reasonable costs associated with a renewable energy contract shall be recovered from the ratepayers of the contracting utility, without differentiation among customer classes, through the appropriate cost-recovery clause mechanism administered by the commission.

(4) On or before January 1, 2006, each municipal electric utility and rural electric cooperative whose annual sales, as of July 1, 1993, to retail customers were greater than 2,000 gigawatt hours must continuously offer a purchase contract to producers of renewable energy containing payment provisions for energy and capacity which are based upon the utility's or cooperative's full avoided costs, as determined by the governing body of the municipal utility or cooperative; however, capacity payments are not required if, due to the operational characteristics of the renewable energy generator or the anticipated peak and off-peak availability and capacity factor of the utility's avoided unit, the producer is unlikely to provide any capacity value to the utility or the electric grid during the contract term. Each contract must provide a contract term of at least 10 years.

(5) On or before January 1, 2009, each public utility shall develop a standardized interconnection agreement and net metering program for customer-owned renewable generation. The commission shall establish requirements relating to the expedited interconnection and net metering of customer-owned renewable generation by public utilities and may adopt rules to administer this section.

(6) On or before July 1, 2009, each municipal electric utility and each rural electric cooperative that sells electricity at retail shall develop a standardized interconnection agreement and net metering program for customer-owned renewable generation. Each governing authority shall establish requirements relating to the expedited interconnection and net metering of customer-owned generation. By April 1 of each year, each municipal electric utility and rural electric cooperative utility serving retail customers shall file a report with the commission detailing customer participation in the interconnection and net metering program, including, but not limited to, the number and total capacity of interconnected generating systems and the total energy net metered in the previous year.

(7) Under the provisions of subsections (5) and (6), when a utility purchases power generated from biogas produced by the anaerobic digestion of agricultural waste, including food waste or other agricultural byproducts, net metering shall be available at a single metering point or as a part of conjunctive billing of multiple points for a customer at a single location, so long as the provision of such service and its associated charges, terms, and other conditions are not reasonably projected to result in higher cost electric service to the utility's general body of ratepayers or adversely affect the adequacy or reliability of electric service to all customers, as determined by the commission for public utilities, or as determined by the governing authority of the municipal electric utility or rural electric cooperative that serves at retail.

(8) A contracting producer of renewable energy must pay the actual costs of its interconnection with the transmission grid or distribution system.

History.—s. 1, ch. 2005-259; s. 41, ch. 2008-227; s. 16, ch. 2010-139.

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<u>Title XXVIII</u> NATURAL RESOURCES; CONSERVATION, RECLAMATION, AND USE	<u>Chapter 377</u> ENERGY RESOURCES <u>Entire Chapter</u>	SECTION 705 Solar Energy Center; development of solar energy standards.
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377.705 Solar Energy Center; development of solar energy standards. —

(1) **SHORT TITLE.** — This act shall be known and may be cited as the Solar Energy Standards Act of 1976.

(2) **LEGISLATIVE FINDINGS AND INTENT.** —

(a) Because of increases in the cost of conventional fuel, certain applications of solar energy are becoming competitive, particularly when life-cycle costs are considered. It is the intent of the Legislature in formulating a sound and balanced energy policy for the state to encourage the development of an alternative energy capability in the form of incident solar energy.

(b) Toward this purpose, the Legislature intends to provide incentives for the production and sale of, and to set standards for, solar energy systems. Such standards shall ensure that solar energy systems manufactured or sold within the state are effective and represent a high level of quality of materials, workmanship, and design.

(3) **DEFINITIONS.** —

(a) “Center” is defined as the Florida Solar Energy Center of the Board of Governors.

(b) “Solar energy systems” is defined as equipment which provides for the collection and use of incident solar energy for water heating, space heating or cooling, or other applications which normally require or would require a conventional source of energy such as petroleum products, natural gas, or electricity and which performs primarily with solar energy. In such other systems in which solar energy is used in a supplemental way, only those components which collect and transfer solar energy shall be included in this definition.

(4) **FLORIDA SOLAR ENERGY CENTER TO SET STANDARDS, REQUIRE DISCLOSURE, SET TESTING FEES.** —

(a) The center shall develop and promulgate standards for solar energy systems manufactured or sold in this state based on the best currently available information and shall consult with scientists, engineers, or persons in research centers who are engaged in the construction of, experimentation with, and research of solar energy systems to properly identify the most reliable designs and types of solar energy systems.

(b) The center shall establish criteria for testing performance of solar energy systems and shall maintain the necessary capability for testing or evaluating performance of solar energy systems. The center may accept results of tests on solar energy systems made by other organizations, companies, or persons when such tests are conducted according to the criteria established by the center and when the testing entity has no vested interest in the manufacture, distribution or sale of solar energy systems.

(c) The center shall be entitled to receive a testing fee sufficient to cover the costs of such testing. All testing fees shall be transmitted by the center to the Chief Financial Officer to be deposited in the Solar Energy Center Testing Trust Fund, which is hereby created in the State Treasury, and disbursed for the payment of expenses incurred in testing solar energy systems.

(d) All solar energy systems manufactured or sold in the state must meet the standards established by the center and shall display accepted results of approved performance tests in a manner prescribed by the center.

History. — ss. 1, 2, 3, 4, ch. 76-246; s. 1, ch. 78-309; s. 400, ch. 2003-261; s. 45, ch. 2007-217; s. 56, ch. 2008-227.

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<u>Title XXIX</u> PUBLIC HEALTH	<u>Chapter 403</u> ENVIRONMENTAL CONTROL Entire Chapter	SECTION 503 Definitions relating to Florida Electrical Power Plant Siting Act.
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403.503 Definitions relating to Florida Electrical Power Plant Siting Act.— As used in this act:

- (1) “Act” means the Florida Electrical Power Plant Siting Act.
- (2) “Agency,” as the context requires, means an official, officer, commission, authority, council, committee, department, division, bureau, board, section, or other unit or entity of government, including a regional or local governmental entity.
- (3) “Alternate corridor” means an area that is proposed by the applicant or a third party within which all or part of an associated electrical transmission line right-of-way is to be located and that is different from the preferred transmission line corridor proposed by the applicant. The width of the alternate corridor proposed for certification for an associated electrical transmission line may be the width of the proposed right-of-way or a wider boundary not to exceed a width of 1 mile. The area within the alternate corridor may be further restricted as a condition of certification. The alternate corridor may include alternate electrical substation sites if the applicant has proposed an electrical substation as part of the portion of the proposed electrical transmission line.
- (4) “Amendment” means a material change in the information provided by the applicant to the application for certification made after the initial application filing.
- (5) “Applicant” means any electric utility which applies for certification pursuant to the provisions of this act.
- (6) “Application” means the documents required by the department to be filed to initiate a certification review and evaluation, including the initial document filing, amendments, and responses to requests from the department for additional data and information.
- (7) “Associated facilities” means, for the purpose of certification, those onsite and offsite facilities which directly support the construction and operation of the electrical power plant such as electrical transmission lines, substations, and fuel unloading facilities; pipelines necessary for transporting fuel for the operation of the facility or other fuel transportation facilities; water or wastewater transport pipelines; construction, maintenance, and access roads; and railway lines necessary for transport of construction equipment or fuel for the operation of the facility.
- (8) “Board” means the Governor and Cabinet sitting as the siting board.
- (9) “Certification” means the written order of the board, or secretary when applicable, approving an application for the licensing of an electrical power plant, in whole or with such changes or conditions as the board may deem appropriate.
- (10) “Completeness” means that the application has addressed all applicable sections of the prescribed application format, and that those sections are sufficient in comprehensiveness of data or in quality of information provided to allow the department to determine whether the application provides the reviewing agencies adequate information to prepare the reports required by s. [403.507](#).
- (11) “Corridor” means the proposed area within which an associated linear facility right-of-way is to be located. The width of the corridor proposed for certification as an associated facility, at the option of the applicant, may be the width of the right-of-way or a wider boundary, not to exceed a width of 1 mile. The area within the corridor in which a right-of-way may be located may be further restricted by a condition of certification. After all property interests required for the right-of-way have been acquired by the licensee, the boundaries of the area certified shall narrow to only that land within the boundaries of the right-of-way. The corridors proper for certification shall be those addressed in the application, in amendments to the application filed under s. [403.5064](#), and in notices of acceptance of proposed alternate corridors filed by an applicant and the department pursuant to s. [403.5271](#) as incorporated by

reference in s. [403.5064](#)(1)(b) for which the required information for the preparation of agency supplemental reports was filed.

(12) "Department" means the Department of Environmental Protection.

(13) "Designated administrative law judge" means the administrative law judge assigned by the Division of Administrative Hearings pursuant to chapter 120 to conduct the hearings required by this act.

(14) "Electrical power plant" means, for the purpose of certification, any steam or solar electrical generating facility using any process or fuel, including nuclear materials, except that this term does not include any steam or solar electrical generating facility of less than 75 megawatts in capacity unless the applicant for such a facility elects to apply for certification under this act. This term also includes the site; all associated facilities that will be owned by the applicant that are physically connected to the site; all associated facilities that are indirectly connected to the site by other proposed associated facilities that will be owned by the applicant; and associated transmission lines that will be owned by the applicant which connect the electrical power plant to an existing transmission network or rights-of-way to which the applicant intends to connect. At the applicant's option, this term may include any offsite associated facilities that will not be owned by the applicant; offsite associated facilities that are owned by the applicant but that are not directly connected to the site; any proposed terminal or intermediate substations or substation expansions connected to the associated transmission line; or new transmission lines, upgrades, or improvements of an existing transmission line on any portion of the applicant's electrical transmission system necessary to support the generation injected into the system from the proposed electrical power plant.

(15) "Electric utility" means cities and towns, counties, public utility districts, regulated electric companies, electric cooperatives, and joint operating agencies, or combinations thereof, engaged in, or authorized to engage in, the business of generating, transmitting, or distributing electric energy.

(16) "Federally delegated or approved permit program" means any environmental regulatory program approved by an agency of the Federal Government so as to authorize the department to administer and issue licenses pursuant to federal law, including, but not limited to, new source review permits, operation permits for major sources of air pollution, and prevention of significant deterioration permits under the Clean Air Act (42 U.S.C. ss. 7401 et seq.), permits under ss. 402 and 404 of the Clean Water Act (33 U.S.C. ss. 1251 et seq.), and permits under the Resource Conservation and Recovery Act (42 U.S.C. ss. 6901 et seq.).

(17) "License" means a franchise, permit, certification, registration, charter, comprehensive plan amendment, development order or permit as defined in chapters 163 and 380, or similar form of authorization required by law, including permits issued under federally delegated or approved permit programs, but it does not include a license required primarily for revenue purposes when issuance of the license is merely a ministerial act.

(18) "Licensee" means an applicant that has obtained a certification order for the subject project.

(19) "Local government" means a municipality or county in the jurisdiction of which the electrical power plant is proposed to be located.

(20) "Modification" means any change in the certification order after issuance, including a change in the conditions of certification.

(21) "Nonprocedural requirements of agencies" means any agency's regulatory requirements established by statute, rule, ordinance, zoning ordinance, land development code, or comprehensive plan, excluding any provisions prescribing forms, fees, procedures, or time limits for the review or processing of information submitted to demonstrate compliance with such regulatory requirements.

(22) "Notice of intent" means that notice which is filed with the department on behalf of an applicant prior to submission of an application pursuant to this act and which notifies the department of an intent to file an application.

(23) "Person" means an individual, partnership, joint venture, private or public corporation, association, firm, public service company, political subdivision, municipal corporation, government agency, public utility district, or any other entity, public or private, however organized.

(24) "Preliminary statement of issues" means a listing and explanation of those issues within the agency's jurisdiction which are of major concern to the agency in relation to the proposed electrical power plant.

(25) "Public Service Commission" or "commission" means the agency created pursuant to chapter 350.

(26) "Regional planning council" means a regional planning council as defined in s. [186.503\(4\)](#) in the jurisdiction of which the electrical power plant is proposed to be located.

(27) "Right-of-way" means land necessary for the construction and maintenance of a connected associated linear facility, such as a railroad line, pipeline, or transmission line as owned by or proposed to be certified by the applicant. The typical width of the right-of-way shall be identified in the application. The right-of-way shall be located within the certified corridor and shall be identified by the applicant subsequent to certification in documents filed with the department prior to construction.

(28) "Site" means any proposed location within which will be located an electrical power plant's generating facility and onsite support facilities, or an alteration or addition of electrical generating facilities and onsite support facilities resulting in an increase in generating capacity, including offshore sites within state jurisdiction.

(29) "State comprehensive plan" means that plan set forth in chapter 187.

(30) "Ultimate site capacity" means the maximum gross generating capacity for a site as certified by the board, unless otherwise specified as net generating capacity.

(31) "Water management district" means a water management district, created pursuant to chapter 373, in the jurisdiction of which the electrical power plant is proposed to be located.

History.—s. 1, ch. 73-33; s. 1, ch. 76-76; s. 1, ch. 79-76; s. 3, ch. 81-131; s. 14, ch. 86-173; s. 22, ch. 86-186; s. 3, ch. 90-331; s. 6, ch. 93-94; s. 383, ch. 94-356; s. 134, ch. 96-410; s. 20, ch. 2006-230; s. 67, ch. 2008-227.

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Title XII MUNICIPALITIES	Chapter 166 MUNICIPALITIES	SECTION 231 Municipalities; public service tax.
	Entire Chapter	

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.

The Florida Senate

2014 Florida Statutes

<u>Title XXVII</u> RAILROADS AND OTHER REGULATED UTILITIES	<u>Chapter 366</u> PUBLIC UTILITIES Entire Chapter	SECTION 14 Regulatory assessment fees.
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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.

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25-6.065 Interconnection and Net Metering of Customer-Owned Renewable Generation.

(1) Application and Scope. The purpose of this rule is to promote the development of small customer-owned renewable generation, particularly solar and wind energy systems; diversify the types of fuel used to generate electricity in Florida; lessen Florida's dependence on fossil fuels for the production of electricity; minimize the volatility of fuel costs; encourage investment in the state; improve environmental conditions; and, at the same time, minimize costs of power supply to investor-owned utilities and their customers. This rule applies to all investor-owned utilities, except as otherwise stated in subsection (10).

(2) Definitions. As used in this rule, the term.

(a) "Customer-owned renewable generation" means an electric generating system located on a customer's premises that is primarily intended to offset part or all of the customer's electricity requirements with renewable energy. The term "customer-owned renewable generation" does not preclude the customer of record from contracting for the purchase, lease, operation, or maintenance of an on-site renewable generation system with a third-party under terms and conditions that do not include the retail purchase of electricity from the third party.

(b) "Gross power rating" means the total manufacturer's AC nameplate generating capacity of an on-site customer-owned renewable generation system that will be interconnected to and operate in parallel with the investor-owned utility's distribution facilities. For inverter-based systems, the AC nameplate generating capacity shall be calculated by multiplying the total installed DC nameplate generating capacity by .85 in order to account for losses during the conversion from DC to AC.

(c) "Net metering" means a metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on-site.

(d) "Renewable energy," as defined in Section 377.803, F.S., means electrical, mechanical, or thermal energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen, biomass, solar energy, geothermal energy, wind energy, ocean energy, waste heat, or hydroelectric power.

(3) Standard Interconnection Agreements. Each investor-owned utility shall, within 30 days of the effective date of this rule, file for Commission approval a Standard Interconnection Agreement for expedited interconnection of customer-owned renewable generation, up to 2 MW, that complies with the following standards:

(a) IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems;

(b) IEEE 1547.1 (2005) Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems; and

(c) UL 1741 (2005) Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.

(d) A copy of IEEE 1547 (2003), ISBN number 0-7381-3720-0, and IEEE 1547.1 (2005), ISBN number 0-7381-4737-0, may be obtained from the Institute of Electric and Electronic Engineers, Inc. (IEEE), 3 Park Avenue, New York, NY, 10016-5997. A copy of UL 1741 (2005) may be obtained from COMM 2000, 1414 Brook Drive, Downers Grove, IL 60515.

(4) Customer Qualifications and Fees.

(a) To qualify for expedited interconnection under this rule, customer-owned renewable generation must have a gross power rating that:

1. Does not exceed 90% of the customer's utility distribution service rating; and

2. Falls within one of the following ranges:

Tier 1 – 10 kW or less;

Tier 2 – greater than 10 kW and less than or equal to 100 kW; or

Tier 3 – greater than 100 kW and less than or equal to 2 MW.

(b) Customer-owned renewable generation shall be considered certified for interconnected operation if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in subsection (3).

(c) Customer-owned renewable generation shall include a utility-interactive inverter, or other device certified pursuant to paragraph (4)(b) that performs the function of automatically isolating the customer-owned generation equipment from the electric grid in the event the electric grid loses power.

(d) For Tiers 1 and 2, provided the customer-owned renewable generation equipment complies with paragraphs (4)(a) and (b), the investor-owned utility shall not require further design review, testing, or additional equipment other than that provided for in

subsection (6). For Tier 3, if an interconnection study is necessary, further design review, testing and additional equipment as identified in the study may be required.

(e) Tier 1 customers who request interconnection of customer-owned renewable generation shall not be charged fees in addition to those charged to other retail customers without self-generation, including application fees.

(f) Along with the Standard Interconnection Agreement filed pursuant to subsection (3), each investor-owned utility may propose for Commission approval a standard application fee for Tiers 2 and 3, including itemized cost support for each cost contained within the fee.

(g) Each investor-owned utility may also propose for Commission approval an Interconnection Study Charge for Tier 3.

(h) Each investor-owned utility shall show that their fees and charges are cost-based and reasonable. No fees or charges shall be assessed for interconnecting customer-owned renewable generation without prior Commission approval.

(5) Contents of Standard Interconnection Agreement. Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement shall, at a minimum, contain the following:

(a) A requirement that customer-owned renewable generation must be inspected and approved by local code officials prior to its operation in parallel with the investor-owned utility to ensure compliance with applicable local codes.

(b) Provisions that permit the investor-owned utility to inspect customer-owned renewable generation and its component equipment, and the documents necessary to ensure compliance with subsections (2) through (4). The customer shall notify the investor-owned utility at least 10 days prior to initially placing customer equipment and protective apparatus in service, and the investor-owned utility shall have the right to have personnel present on the in-service date. If the customer-owned renewable generation system is subsequently modified in order to increase its gross power rating, the customer must notify the investor-owned utility by submitting a new application specifying the modifications at least 30 days prior to making the modifications.

(c) A provision that the customer is responsible for protecting the renewable generating equipment, inverters, protective devices, and other system components from damage from the normal and abnormal conditions and operations that occur on the investor-owned utility system in delivering and restoring power; and is responsible for ensuring that customer-owned renewable generation equipment is inspected, maintained, and tested in accordance with the manufacturer's instructions to ensure that it is operating correctly and safely.

(d) A provision that the customer shall hold harmless and indemnify the investor-owned utility for all loss to third parties resulting from the operation of the customer-owned renewable generation, except when the loss occurs due to the negligent actions of the investor-owned utility. A provision that the investor-owned utility shall hold harmless and indemnify the customer for all loss to third parties resulting from the operation of the investor-owned utility's system, except when the loss occurs due to the negligent actions of the customer.

(e) A requirement for general liability insurance for personal and property damage, or sufficient guarantee and proof of self-insurance, in the amount of no more than \$1 million for Tier 2, and no more than \$2 million for Tier 3. The investor-owned utility shall not require liability insurance for Tier 1. The investor-owned utility may include in the Interconnection Agreement a recommendation that Tier 1 customers carry an appropriate level of liability insurance.

(f) Identification of any fees or charges approved pursuant to subsection (4).

(6) Manual Disconnect Switch.

(a) Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement may require customers to install, at the customer's expense, a manual disconnect switch of the visible load break type to provide a separation point between the AC power output of the customer-owned renewable generation and any customer wiring connected to the investor-owned utility's system. Inverter-based Tier 1 customer-owned renewable generation systems shall be exempt from this requirement, unless the manual disconnect switch is installed at the investor-owned utility's expense. The manual disconnect switch shall be mounted separate from, but adjacent to, the meter socket and shall be readily accessible to the investor-owned utility and capable of being locked in the open position with a single investor-owned utility padlock.

(b) The investor-owned utility may open the switch pursuant to the conditions set forth in paragraph (6)(c), isolating the customer-owned renewable generation, without prior notice to the customer. To the extent practicable, however, prior notice shall be given. If prior notice is not given, the utility shall at the time of disconnection leave a door hanger notifying the customer that their customer-owned renewable generation has been disconnected, including an explanation of the condition necessitating such action. The investor-owned utility shall reconnect the customer-owned renewable generation as soon as the condition necessitating disconnection is remedied.

(c) Any of the following conditions shall be cause for the investor-owned utility to disconnect customer-owned renewable generation from its system:

1. Emergencies or maintenance requirements on the investor-owned utility's electric system;
2. Hazardous conditions existing on the investor-owned utility system due to the operation of the customer's generating or protective equipment as determined by the investor-owned utility;
3. Adverse electrical effects, such as power quality problems, on the electrical equipment of the investor-owned utility's other electric consumers caused by the customer-owned renewable generation as determined by the investor-owned utility;
4. Failure of the customer to maintain the required insurance coverage.

(7) Administrative Requirements.

(a) Each investor-owned utility shall maintain on its website a downloadable application for interconnection of customer-owned renewable generation, detailing the information necessary to execute the Standard Interconnection Agreement. Upon request the investor-owned utility shall provide a hard copy of the application within 5 business days.

(b) Within 10 business days of receipt of the customer's application, the investor-owned utility shall provide written notice that it has received all documents required by the Standard Interconnection Agreement or indicate how the application is deficient. Within 10 business days of receipt of a completed application, the utility shall provide written notice verifying receipt of the completed application. The written notice shall also include dates for any physical inspection of the customer-owned renewable generation necessary for the investor-owned utility to confirm compliance with subsections (2) through (6), and confirmation of whether a Tier 3 interconnection study will be necessary.

(c) The Standard Interconnection Agreement shall be executed by the investor-owned utility within 30 calendar days of receipt of a completed application. If the investor-owned utility determines that an interconnection study is necessary for a Tier 3 customer, the investor-owned utility shall execute the Standard Interconnection Agreement within 90 days of a completed application.

(d) The customer must execute the Standard Interconnection Agreement and return it to the investor-owned utility at least 30 calendar days prior to beginning parallel operations and within one year after the utility executes the Agreement. All physical inspections must be completed by the utility within 30 calendar days of receipt of the customer's executed Standard Interconnection Agreement. If the inspection is delayed at the customer's request, the customer shall contact the utility to reschedule an inspection. The investor-owned utility shall reschedule the inspection within 10 business days of the customer's request.

(8) Net Metering.

(a) Each investor-owned utility shall enable each customer-owned renewable generation facility interconnected to the investor-owned utility's electrical grid pursuant to this rule to net meter.

(b) Each investor-owned utility shall install, at no additional cost to the customer, metering equipment at the point of delivery capable of measuring the difference between the electricity supplied to the customer from the investor-owned utility and the electricity generated by the customer and delivered to the investor-owned utility's electric grid.

(c) Meter readings shall be taken monthly on the same cycle as required under the otherwise applicable rate schedule.

(d) The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation in accordance with normal billing practices.

(e) During any billing cycle, excess customer-owned renewable generation delivered to the investor-owned utility's electric grid shall be credited to the customer's energy consumption for the next month's billing cycle.

(f) Energy credits produced pursuant to paragraph (8)(e) shall accumulate and be used to offset the customer's energy usage in subsequent months for a period of not more than twelve months. At the end of each calendar year, the investor-owned utility shall pay the customer for any unused energy credits at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(g) When a customer leaves the system, that customer's unused credits for excess kWh generated shall be paid to the customer at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(h) Regardless of whether excess energy is delivered to the investor-owned utility's electric grid, the customer shall continue to pay the applicable customer charge and applicable demand charge for the maximum measured demand during the billing period. The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation at the investor-owned utility's otherwise applicable rate schedule. The customer may at their sole discretion choose to take service under the investor-owned utility's standby or supplemental service rate, if available.

(9) Renewable Energy Certificates. Customers shall retain any Renewable Energy Certificates associated with the electricity

produced by their customer-owned renewable generation equipment. Any additional meters necessary for measuring the total renewable electricity generated for the purposes of receiving Renewable Energy Certificates shall be installed at the customer's expense, unless otherwise determined during negotiations for the sale of the customer's Renewable Energy Certificates to the investor-owned utility.

(10) Reporting Requirements. Each electric utility, as defined in Section 366.02(2), F.S., shall file with the Commission as part of its tariff a copy of its Standard Interconnection Agreement form for customer-owned renewable generation. In addition, each electric utility shall report the following, by April 1 of each year.

- (a) Total number of customer-owned renewable generation interconnections as of the end of the previous calendar year;
- (b) Total kW capacity of customer-owned renewable generation interconnected as of the end of the previous calendar year;
- (c) Total kWh received by interconnected customers from the electric utility, by month and by year for the previous calendar year;
- (d) Total kWh of customer-owned renewable generation delivered to the electric utility, by month and by year for the previous calendar year; and
- (e) Total energy payments made to interconnected customers for customer-owned renewable generation delivered to the electric utility for the previous calendar year, along with the total payments made since the implementation of this rule.
- (f) For each individual customer-owned renewable generation interconnection:
 - 1. Renewable technology utilized;
 - 2. Gross power rating;
 - 3. Geographic location by county; and
 - 4. Date interconnected.

(11) Dispute Resolution. Parties may seek resolution of disputes arising out of the interpretation of this rule pursuant to Rule 25-22.032, F.A.C, Customer Complaints, or Rule 25-22.036, F.A.C., Initiation of Formal Proceedings.

Rulemaking Authority 350.127(2), 366.05(1), 366.92 FS. Law Implemented 366.02(2), 366.04(2)(c), (5), (6), 366.041, 366.05(1), 366.81, 366.82(1), (2), 366.91(1), (2), 366.92 FS. History—New 2-11-02, Amended 4-7-08.

25-6.0131 Regulatory Assessment Fees; Investor-owned Electric Companies, Municipal Electric Utilities, Rural Electric Cooperatives.

(1) As applicable and as provided in Section 350.113, F.S., each company, utility, or cooperative shall remit to the Commission a fee based upon its gross operating revenue. This fee shall be referred to as a regulatory assessment fee. Regardless of the gross operating revenue of a company, a minimum annual regulatory assessment fee of \$25 shall be imposed.

(a) Each investor-owned electric company shall pay a regulatory assessment fee in the amount of .00072 of 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.

(b) Each municipal electric utility and rural electric cooperative shall pay a regulatory assessment fee in the amount of 0.00015625 of its gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, and rural cooperatives or any combination thereof.

(2) Regulatory assessment fees are due each January 30 for the preceding period or any part of the period from July 1 until December 31, and on July 30 for the preceding period or any part of the period from January 1 until June 30.

(3) If the due date falls on a Saturday, Sunday, or a holiday, the due date is extended to the next business day. If the fees are sent by registered mail, the date of the registration is the United States Postal Service's postmark date. If the fees are sent by certified mail and the receipt is postmarked by a postal employee, the date on the receipt is the United States Postal Service's postmark date. The postmarked certified mail receipt is evidence that the fees were delivered. Regulatory assessment fees are considered paid on the date they are postmarked by the United States Postal Service or received and logged in by the Commission's Division of Administrative Services Tallahassee. Fees are considered timely paid if properly addressed, with sufficient postage and postmarked no later than the due date.

(4) Commission Form PSC/ECR 68 (01/99), entitled "Investor-Owned Electric Utility Regulatory Assessment Fee Return"; Form PSC/ECR 69 (07/96), entitled "Municipal Electric Utility Regulatory Assessment Fee Return"; and Form PSC/ECR 70 (07/96), entitled "Rural Electric Cooperative Regulatory Assessment Fee Return" are incorporated into this rule by reference and may be obtained from the Commission's Division of Administrative Services. The failure of a utility to receive a return form shall not excuse the utility from its obligation to timely remit the regulatory assessment fees.

(5) Each company, utility, or cooperative shall have up to and including the due date in which to:

(a) Remit the total amount of its fee; or

(b) Remit an amount which the company, utility, or cooperative estimates is its full fee.

(6) Where the company, utility, or cooperative remits less than its full fee, the remainder of the full fee shall be due on or before the 30th day from the due date and shall, where the amount remitted was less than 90 percent of the total regulatory assessment fee, include interest as provided by paragraph (8)(b) of this rule.

(7) A company may request from the Division of Administrative Services a 30-day extension of its due date for payment of regulatory assessment fees or for filing its return form.

(a) The request for extension must be written and accompanied by a statement of good cause.

(b) The request for extension must be received by the Division of Administrative Services at least two weeks before the due date.

(c) Where a company, utility, or cooperative receives an extension of its due date pursuant to this rule, then the entity shall remit a charge in addition to the regulatory assessment fee, as set out in Section 350.113, F.S.

(8) The delinquency of any amount due to the Commission from the company, utility, or cooperative pursuant to the provisions of Section 350.113, F.S., and this rule, begins with the first calendar day after any date established as the due date either by operation of this rule or by an extension pursuant to this rule.

(a) A penalty, as set out in Section 350.113, F.S., shall apply to any such delinquent amounts.

(b) Interest at the rate of 12 percent per annum shall apply to any such delinquent amounts.

Specific Authority 350.127(2) FS. Law Implemented 350.113, 366.14 FS. History—New 5-18-83, Amended 2-9-84, Formerly 25-6.131, Amended 6-18-86, 10-16-86, 3-7-89, 2-19-92, 7-7-96, 1-1-99.

25-6.065 Interconnection and Net Metering of Customer-Owned Renewable Generation.

(1) Application and Scope. The purpose of this rule is to promote the development of small customer-owned renewable generation, particularly solar and wind energy systems; diversify the types of fuel used to generate electricity in Florida; lessen Florida's dependence on fossil fuels for the production of electricity; minimize the volatility of fuel costs; encourage investment in the state; improve environmental conditions; and, at the same time, minimize costs of power supply to investor-owned utilities and their customers. This rule applies to all investor-owned utilities, except as otherwise stated in subsection (10).

(2) Definitions. As used in this rule, the term.

(a) "Customer-owned renewable generation" means an electric generating system located on a customer's premises that is primarily intended to offset part or all of the customer's electricity requirements with renewable energy. The term "customer-owned renewable generation" does not preclude the customer of record from contracting for the purchase, lease, operation, or maintenance of an on-site renewable generation system with a third-party under terms and conditions that do not include the retail purchase of electricity from the third party.

(b) "Gross power rating" means the total manufacturer's AC nameplate generating capacity of an on-site customer-owned renewable generation system that will be interconnected to and operate in parallel with the investor-owned utility's distribution facilities. For inverter-based systems, the AC nameplate generating capacity shall be calculated by multiplying the total installed DC nameplate generating capacity by .85 in order to account for losses during the conversion from DC to AC.

(c) "Net metering" means a metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on-site.

(d) "Renewable energy," as defined in Section 377.803, F.S., means electrical, mechanical, or thermal energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen, biomass, solar energy, geothermal energy, wind energy, ocean energy, waste heat, or hydroelectric power.

(3) Standard Interconnection Agreements. Each investor-owned utility shall, within 30 days of the effective date of this rule, file for Commission approval a Standard Interconnection Agreement for expedited interconnection of customer-owned renewable generation, up to 2 MW, that complies with the following standards:

(a) IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems;

(b) IEEE 1547.1 (2005) Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems; and

(c) UL 1741 (2005) Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.

(d) A copy of IEEE 1547 (2003), ISBN number 0-7381-3720-0, and IEEE 1547.1 (2005), ISBN number 0-7381-4737-0, may be obtained from the Institute of Electric and Electronic Engineers, Inc. (IEEE), 3 Park Avenue, New York, NY, 10016-5997. A copy of UL 1741 (2005) may be obtained from COMM 2000, 1414 Brook Drive, Downers Grove, IL 60515.

(4) Customer Qualifications and Fees.

(a) To qualify for expedited interconnection under this rule, customer-owned renewable generation must have a gross power rating that:

1. Does not exceed 90% of the customer's utility distribution service rating; and

2. Falls within one of the following ranges:

Tier 1 – 10 kW or less;

Tier 2 – greater than 10 kW and less than or equal to 100 kW; or

Tier 3 – greater than 100 kW and less than or equal to 2 MW.

(b) Customer-owned renewable generation shall be considered certified for interconnected operation if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in subsection (3).

(c) Customer-owned renewable generation shall include a utility-interactive inverter, or other device certified pursuant to paragraph (4)(b) that performs the function of automatically isolating the customer-owned generation equipment from the electric grid in the event the electric grid loses power.

(d) For Tiers 1 and 2, provided the customer-owned renewable generation equipment complies with paragraphs (4)(a) and (b), the investor-owned utility shall not require further design review, testing, or additional equipment other than that provided for in

subsection (6). For Tier 3, if an interconnection study is necessary, further design review, testing and additional equipment as identified in the study may be required.

(e) Tier 1 customers who request interconnection of customer-owned renewable generation shall not be charged fees in addition to those charged to other retail customers without self-generation, including application fees.

(f) Along with the Standard Interconnection Agreement filed pursuant to subsection (3), each investor-owned utility may propose for Commission approval a standard application fee for Tiers 2 and 3, including itemized cost support for each cost contained within the fee.

(g) Each investor-owned utility may also propose for Commission approval an Interconnection Study Charge for Tier 3.

(h) Each investor-owned utility shall show that their fees and charges are cost-based and reasonable. No fees or charges shall be assessed for interconnecting customer-owned renewable generation without prior Commission approval.

(5) Contents of Standard Interconnection Agreement. Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement shall, at a minimum, contain the following:

(a) A requirement that customer-owned renewable generation must be inspected and approved by local code officials prior to its operation in parallel with the investor-owned utility to ensure compliance with applicable local codes.

(b) Provisions that permit the investor-owned utility to inspect customer-owned renewable generation and its component equipment, and the documents necessary to ensure compliance with subsections (2) through (4). The customer shall notify the investor-owned utility at least 10 days prior to initially placing customer equipment and protective apparatus in service, and the investor-owned utility shall have the right to have personnel present on the in-service date. If the customer-owned renewable generation system is subsequently modified in order to increase its gross power rating, the customer must notify the investor-owned utility by submitting a new application specifying the modifications at least 30 days prior to making the modifications.

(c) A provision that the customer is responsible for protecting the renewable generating equipment, inverters, protective devices, and other system components from damage from the normal and abnormal conditions and operations that occur on the investor-owned utility system in delivering and restoring power; and is responsible for ensuring that customer-owned renewable generation equipment is inspected, maintained, and tested in accordance with the manufacturer's instructions to ensure that it is operating correctly and safely.

(d) A provision that the customer shall hold harmless and indemnify the investor-owned utility for all loss to third parties resulting from the operation of the customer-owned renewable generation, except when the loss occurs due to the negligent actions of the investor-owned utility. A provision that the investor-owned utility shall hold harmless and indemnify the customer for all loss to third parties resulting from the operation of the investor-owned utility's system, except when the loss occurs due to the negligent actions of the customer.

(e) A requirement for general liability insurance for personal and property damage, or sufficient guarantee and proof of self-insurance, in the amount of no more than \$1 million for Tier 2, and no more than \$2 million for Tier 3. The investor-owned utility shall not require liability insurance for Tier 1. The investor-owned utility may include in the Interconnection Agreement a recommendation that Tier 1 customers carry an appropriate level of liability insurance.

(f) Identification of any fees or charges approved pursuant to subsection (4).

(6) Manual Disconnect Switch.

(a) Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement may require customers to install, at the customer's expense, a manual disconnect switch of the visible load break type to provide a separation point between the AC power output of the customer-owned renewable generation and any customer wiring connected to the investor-owned utility's system. Inverter-based Tier 1 customer-owned renewable generation systems shall be exempt from this requirement, unless the manual disconnect switch is installed at the investor-owned utility's expense. The manual disconnect switch shall be mounted separate from, but adjacent to, the meter socket and shall be readily accessible to the investor-owned utility and capable of being locked in the open position with a single investor-owned utility padlock.

(b) The investor-owned utility may open the switch pursuant to the conditions set forth in paragraph (6)(c), isolating the customer-owned renewable generation, without prior notice to the customer. To the extent practicable, however, prior notice shall be given. If prior notice is not given, the utility shall at the time of disconnection leave a door hanger notifying the customer that their customer-owned renewable generation has been disconnected, including an explanation of the condition necessitating such action. The investor-owned utility shall reconnect the customer-owned renewable generation as soon as the condition necessitating disconnection is remedied.

(c) Any of the following conditions shall be cause for the investor-owned utility to disconnect customer-owned renewable generation from its system:

1. Emergencies or maintenance requirements on the investor-owned utility's electric system;
2. Hazardous conditions existing on the investor-owned utility system due to the operation of the customer's generating or protective equipment as determined by the investor-owned utility;
3. Adverse electrical effects, such as power quality problems, on the electrical equipment of the investor-owned utility's other electric consumers caused by the customer-owned renewable generation as determined by the investor-owned utility;
4. Failure of the customer to maintain the required insurance coverage.

(7) Administrative Requirements.

(a) Each investor-owned utility shall maintain on its website a downloadable application for interconnection of customer-owned renewable generation, detailing the information necessary to execute the Standard Interconnection Agreement. Upon request the investor-owned utility shall provide a hard copy of the application within 5 business days.

(b) Within 10 business days of receipt of the customer's application, the investor-owned utility shall provide written notice that it has received all documents required by the Standard Interconnection Agreement or indicate how the application is deficient. Within 10 business days of receipt of a completed application, the utility shall provide written notice verifying receipt of the completed application. The written notice shall also include dates for any physical inspection of the customer-owned renewable generation necessary for the investor-owned utility to confirm compliance with subsections (2) through (6), and confirmation of whether a Tier 3 interconnection study will be necessary.

(c) The Standard Interconnection Agreement shall be executed by the investor-owned utility within 30 calendar days of receipt of a completed application. If the investor-owned utility determines that an interconnection study is necessary for a Tier 3 customer, the investor-owned utility shall execute the Standard Interconnection Agreement within 90 days of a completed application.

(d) The customer must execute the Standard Interconnection Agreement and return it to the investor-owned utility at least 30 calendar days prior to beginning parallel operations and within one year after the utility executes the Agreement. All physical inspections must be completed by the utility within 30 calendar days of receipt of the customer's executed Standard Interconnection Agreement. If the inspection is delayed at the customer's request, the customer shall contact the utility to reschedule an inspection. The investor-owned utility shall reschedule the inspection within 10 business days of the customer's request.

(8) Net Metering.

(a) Each investor-owned utility shall enable each customer-owned renewable generation facility interconnected to the investor-owned utility's electrical grid pursuant to this rule to net meter.

(b) Each investor-owned utility shall install, at no additional cost to the customer, metering equipment at the point of delivery capable of measuring the difference between the electricity supplied to the customer from the investor-owned utility and the electricity generated by the customer and delivered to the investor-owned utility's electric grid.

(c) Meter readings shall be taken monthly on the same cycle as required under the otherwise applicable rate schedule.

(d) The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation in accordance with normal billing practices.

(e) During any billing cycle, excess customer-owned renewable generation delivered to the investor-owned utility's electric grid shall be credited to the customer's energy consumption for the next month's billing cycle.

(f) Energy credits produced pursuant to paragraph (8)(e) shall accumulate and be used to offset the customer's energy usage in subsequent months for a period of not more than twelve months. At the end of each calendar year, the investor-owned utility shall pay the customer for any unused energy credits at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(g) When a customer leaves the system, that customer's unused credits for excess kWh generated shall be paid to the customer at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(h) Regardless of whether excess energy is delivered to the investor-owned utility's electric grid, the customer shall continue to pay the applicable customer charge and applicable demand charge for the maximum measured demand during the billing period. The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation at the investor-owned utility's otherwise applicable rate schedule. The customer may at their sole discretion choose to take service under the investor-owned utility's standby or supplemental service rate, if available.

(9) Renewable Energy Certificates. Customers shall retain any Renewable Energy Certificates associated with the electricity

produced by their customer-owned renewable generation equipment. Any additional meters necessary for measuring the total renewable electricity generated for the purposes of receiving Renewable Energy Certificates shall be installed at the customer's expense, unless otherwise determined during negotiations for the sale of the customer's Renewable Energy Certificates to the investor-owned utility.

(10) Reporting Requirements. Each electric utility, as defined in Section 366.02(2), F.S., shall file with the Commission as part of its tariff a copy of its Standard Interconnection Agreement form for customer-owned renewable generation. In addition, each electric utility shall report the following, by April 1 of each year.

- (a) Total number of customer-owned renewable generation interconnections as of the end of the previous calendar year;
- (b) Total kW capacity of customer-owned renewable generation interconnected as of the end of the previous calendar year;
- (c) Total kWh received by interconnected customers from the electric utility, by month and by year for the previous calendar year;
- (d) Total kWh of customer-owned renewable generation delivered to the electric utility, by month and by year for the previous calendar year; and
- (e) Total energy payments made to interconnected customers for customer-owned renewable generation delivered to the electric utility for the previous calendar year, along with the total payments made since the implementation of this rule.
- (f) For each individual customer-owned renewable generation interconnection:
 - 1. Renewable technology utilized;
 - 2. Gross power rating;
 - 3. Geographic location by county; and
 - 4. Date interconnected.

(11) Dispute Resolution. Parties may seek resolution of disputes arising out of the interpretation of this rule pursuant to Rule 25-22.032, F.A.C, Customer Complaints, or Rule 25-22.036, F.A.C., Initiation of Formal Proceedings.

Rulemaking Authority 350.127(2), 366.05(1), 366.92 FS. Law Implemented 366.02(2), 366.04(2)(c), (5), (6), 366.041, 366.05(1), 366.81, 366.82(1), (2), 366.91(1), (2), 366.92 FS. History—New 2-11-02, Amended 4-7-08.

Tab 3

State Reports

**Reporting Requirements for
Interconnection and Net Metering of Customer-Owned Renewable Generation** (re: Section 25-6.065 (10) F.A.C.)
For year ending December 31, 2013

RGI - Renewable Generation Interconnections
GPR - Gross Power Rating (AC)

Type	Name of Utility	Date Filed	# Solar PV RGI	# Wind RGI	# Other RGI	Total # of RGI*	Solar GPR (kW)	Wind GPR (kW)	Other GPR (kW)	Total kW GPR (kW)	Total kWh rec'd. by cust. fm utility	Total kWh del. to the utility	Total pmt. made to cust. by utility
IOU	Florida Power & Light (FPL)	4/1/2014	2,562	11	1	2,565	22,632	94	750	23,476	371,051,442	10,500,816	\$23,559.00
	Florida Public Utilities Company (FPU)	4/11/2014	52			52	238			238	644,348	101,377	\$34.04
	Gulf Power Company (GPC)	4/1/2014	299	7		306	1,175	17		1,192	4,806,755	690,470	\$1,293.36
	Duke Energy Florida, Inc. (DEF)	4/1/2014	1,480	3		1,483	13,149	4		13,153	665,807,390	5,601,865	\$29,447.00
	Tampa Electric Company (TEC)	4/1/2014	425		1	426	6,682		50	6,732	175,355,214	1,691,584	\$9,346.32
Total IOU			4,818	21	2	4,832	43,876	115	800	44,791	1,217,665,149	18,586,112	\$63,679.72
Municipal	Alachua, City of (ALA)	4/1/2014	3			3	40			40	420,027	37,947	\$0.00
	Bartow, City of (BAR)	3/17/2014	7	1		8	45	2		47	392,105	13,988	\$0.00
	Beaches Energy Services (formerly Jacksonville Bch)	3/31/2014	30			30	214			214	637,481	92,564	\$11,146.00
	Blountstown, City of (BLT)	3/10/2014	0			0	0			0			\$0.00
	Bushnell, City of (BUS)	3/31/2014	0			0	0			0			\$0.00
	Chattahoochee, City of (CHA)	4/11/2014	0			0	0			0			\$0.00
	Clewiston, City of (CLE)	3/31/2014	0			0	0			0			\$0.00
	Fort Meade, City of (FMD)	3/31/2014	0			0	0			0			\$0.00
	Fort Pierce Utilities Authority (FTP)	3/31/2014	7			7	21			21	51,912	12,205	\$310.32
	Gainesville Regional Utilities (GRU)	3/25/2014	193			193	1,638			1,638	N/A	871,726	\$104,710.00
	Green Cove Springs, City of (GCS)	3/31/2014	4			4	52			52	114,339	14,139	\$492.00
	Havana, Town of (HAV)	3/31/2014	3			3	35			35	47,511	18,363	\$0.00
	Homestead, City of (HST)	3/28/2014	1			1	18			18	113,140	0	\$0.00
	JEA (formerly Jacksonville Electric Authority)	3/27/2014	151	1		151	787	3		790	7,230,281	448,455	\$0.00
	Keys Energy Services (formerly Key West Utility Bd)	3/31/2014	31			31	215			215	515,859	103,974	\$9,306.47
	Kissimmee Utility Authority (KUA)	3/31/2014	23			23	144			144	1,529,121	63,081	\$2,021.57
	Lake Worth Utilities Authority (LWU)	3/19/2014	6			6	30			30	59,516	21,336	\$2,384.21
	Lakeland, City of (LAK)	3/31/2014	99			99	345			345	1,036,146	283,324	\$0.00
	Leesburg, City of (LEE)	3/31/2014	9			9	55			55	108,449	30,195	\$1,033.63
	Moore Haven, City of (MHN)	3/27/2014	0			0	0			0			\$0.00
	Mount Dora, City of (MTD)	3/11/2014	2			2	11			11	23,649	6,020	\$689.00
	Newberry, City of (NEW)	3/31/2014	3			3	17			17	260,727	144	\$0.00
	New Smyrna Beach, Utilities Commission of (NSB)	3/31/2014	20			20	83			83	168,719	56,487	\$780.44
	Ocala Electric Utility (OEU)	3/31/2014	81			81	608			608	324,227	0	\$0.00
	Orlando Utilities Commission (OUC)	4/1/2014	81			81	5,880			5,880	11,266,804	1,464,182	\$14,042.58
	Quincy, City of (QUI)	4/11/2014	0			0	0			0			\$0.00
	Reedy Creek Utilities (RCU)	3/24/2014	1			1	19			19	15,400	11,720	\$475.00
	Starke, City of (STK)	3/31/2014	2			2	30			30	37,873	18,040	\$571.47
	St. Cloud, City of (STC)	4/1/2014	29			29	186			186	2,922,546	70,532	\$790.34
	Tallahassee, City of (TAL)	4/1/2014	198			198	1,142			1,142	10,766,053	233,262	\$0.00
	Vero Beach, City of (VER)	3/14/2014	16			16	134			134	131,642	1,565	\$186.00
Wauchula, City of (WAU)	5/22/2014	0			0	0			0			\$0.00	
Williston, City of (WIL)	4/14/2014	0			0	0			0			\$0.00	
Winter Park, City of (WPK)	3/27/2014	7			7	38			38	117,653	26,472	\$0.00	
Total Municipal			1,007	2	0	1,008	11,787	5	0	11,792	38,291,180	3,899,721	\$148,939.03

Type	Name of Utility	Date Filed	# Solar PV RGI	# Wind RGI	# Other RGI	Total # of RGI	Solar GPR (kW)	Wind GPR (kW)	Other GPR (kW)	Total kW GPR (kW)	Total kWh rec'd. by cust. fm utility	Total kWh del. to the utility	Total pmt. made to cust. by utility	
Rural Electric Coop	Central Florida Electric Cooperative, Inc. (CFC)	2/5/2014	24			1	25	137		1000	1,137	4,550,614	238,859	\$12,314.07
	Choctawhatchee Electric Cooperative, Inc. (CHW)	3/31/2014	44				44	187			187	314,755	92,868	\$6,527.38
	Clay Electric Cooperative, Inc. (CEC)	1/15/2014	122				122	779			779	919,777	100,489	\$2,843.84
	Escambia River Electric Cooperative, Inc. (ESC)	3/7/2014	8				8	47			47	87,555	25,662	\$1,011.07
	Florida Keys Electric Cooperative, Inc. (FKE)	2/7/2014	34				34	187			187	716,279	117,110	\$11,288.00
	Glades Electric Cooperative, Inc. (GEC)	5/27/2014	21				21	122			122	210,858	78,560	\$665.08
	Gulf Coast Electric Cooperative, Inc. (GUC)	3/31/2014	7				7	73			73	59,193	55,896	\$2,571.22
	Lee County Electric Cooperative, Inc. (LEC)	3/20/2014	150				150	695			695	1,883,321	317,682	\$1,244.26
	Okefenoke Rural Electric Cooperative, Inc. (OKC)	3/12/2014	11				11	47			47	131,465	17,845	\$58.82
	Peace River Electric Cooperative, Inc. (PRC)	3/12/2014	46				46	315			315	558,066	187,334	\$2,885.67
	Sumter Electric Cooperative, Inc. (SMC)	3/3/2014	190	1			191	1,021	2		1,023	41,408,200	555,569	\$60,230.18
	Suwannee Valley Electric Cooperative, Inc. (SVC)	3/4/2014	9			1	10	44		600	644	3,145,656	1,599,917	\$5,945.50
	Talquin Electric Cooperative, Inc. (TRC)	1/22/2014	69				69	656			656	8,908,819	390,180	\$38,411.27
	Tri-County Electric Cooperative, Inc. (TRC)	2/6/2014	10				10	62			62	110,887	27,727	\$3,216.33
	West Florida Electric Cooperative, Inc. (WFC)	4/1/2014	9				9	37			37	66,596	27,189	\$1,458.49
Withlacoochee River Electric Cooperative, Inc.(WRC)	2/4/2014	99	1			100	456	5		461	N/A	11,684	N/A	
Total Rural Electric Cooperative			853	2		2	4,865	7	1600	6,472	63,072,041	3,844,571	\$150,671.18	

Grand Totals as of December 31, 2013

Type of Utility	# Utilities w/ RGI	# RGI Solar	# RGI Wind	# RGI Digester	# RGI Total	Solar GPR - kW	Wind GPR - kW	Digester GPR - kW	Total GPR - kW	Total kWh rec'd. by cust. fm utility	Total kWh del. to the utility	Total pmt. made to cust. by utility
Total IOU	5	4,818	21	2	4,832	43,876	115	800	44,791	1,217,665,149	18,586,112	\$ 63,679.72
Total Municipal	25	1,007	2	0	1,008	11,787	5	0	11,792	38,291,180	3,899,721	\$ 148,939.03
Total Rural Electric Cooperative	16	853	2	2	857	4,865	7	1,600	6,472	63,072,041	3,844,571	\$ 150,671.18
Grand Total	46	6,678	25	4	6,697	60,528	127	2,400	63,055	1,319,028,370	26,330,404	\$ 363,289.93

* For the calculation of Total # of RGI, customers of FPL, GPC, and JEA with both Solar PV and Wind units were counted as only one interconnection.

Extract From March 3, 2015

Public Service Commission

Meeting Packet

State of Florida



Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 27, 2015
TO: Braulio L. Baez, Executive Director
FROM: Walter Clemence, Public Utility Analyst II, Office of Industry Development and Market Analysis *w*
 David Dowds, Public Utilities Supervisor, Office of Industry Development and Market Analysis
 Mark Futrell, Director, Office of Industry Development and Market Analysis *mf*
RE: Overview of Solar Energy in Florida

Critical Information: Please place on the March 3, 2015 Internal Affairs.
BRIEFING ONLY

This memorandum is to provide an informational overview of current and new solar deployments in Florida, cost trends for solar installations, and a discussion of customer-owned renewable generation and statistics on customer-owned installed capacity. No Commission action is requested.

Existing Solar Resources

Florida has 218 megawatts (MW) of installed solar capacity as of December 31, 2013. Florida utilities have installed approximately 117 MW of solar photovoltaic (PV) and solar thermal capacity in Florida. Utilities have contracted for an additional 39.5 MW of installed capacity, and customers have installed approximately 60.5 MW of distributed solar generation behind their meters.

Utility Owned			Gross MW
FPL	Desoto Next Gen Solar Energy Center	PV	25
FPL	Space Coast	PV	10
FPL	FPL Juno Beach Living Lab	PV	0.0970
FPL	Business PV for Schools	PV	0.1600
FPL	Martin Solar	Thermal	75.0
TECO	Museum of Science & Industry	PV	0.0182
TECO	Walker Middle School	PV	0.0034
TECO	Manatee Viewing Center	PV	0.0372
TECO	Middleton High School	PV	0.0089
TECO	Tampa's Lowry Park Zoo	PV	0.0128

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TECO	Florida Aquarium	PV	0.0086
DEF	Econlockhatchee Photovoltaic Array	PV	0.0070
DEF	DEF owned Installations	PV	0.9230
FMPA	NOAA Eco-Discovery Center	PV	0.0300
GRU	Small Distributed Rooftop PV Panels	PV	0.0086
OUC	OUC Reliable Plaza PV System	PV	0.0320
TAL	Multiple Utility-owned installations	PV	0.2230
JEA	Multiple Utility-owned installations	PV	0.2220
LAK	Airport Phase 1	PV	2.3000
LAK	Airport Phase 2	PV	3.0000
LAK	Sun Edison - Civic Center	PV	0.2500
	Source: Ten Year Site Plan	Utility Owned	117.34

Existing Non-Utility Owned Generation			Gross MW
FPL	Rothenbach Park	PV	0.2500
FPL	First Solar	PV	0.2000
GRU	Multiple Aggregated Distributed Facilities	PV	18.6
OUC	Fleet Solar Project	PV	0.3350
OUC	Gardenia Solar Project	PV	0.2680
OUC	Stanton Solar Farm	PV	5.1
JEA	Jacksonville Solar	PV	15.0
	Source: Ten Year Site Plan	Non-Utility	39.73

Customer-Owned Solar Generation

In 2002 the Commission adopted Rule 25-6.065, Florida Administrative Code, to allow residential customers to interconnect customer-owned solar systems of up to 10 KW and provided that any excess energy generated by the customer's system would be purchased by the utility. In 2008, the FPSC approved a revised rule that applies to all customers and provides for an expedited interconnection process and allows for net metering of customer-owned renewable energy systems of up to 2 MW.

In 2008, the effective year of the revised rule, customer-owned renewable solar generation accounted for approximately 3 MW of renewable capacity. As of 2013, approximately 60.5 MW MW was customer-owned solar PV.

Customer-Owned Solar Generation												
	# of Customer-Owned Solar Systems						kW Gross Power Rating					
	2008	2009	2010	2011	2012	2013	2008	2009	2010	2011	2012	2013
IOU	383	1,045	1,855	2,803	3,799	4,818	1,696	7,653	12,442	19,441	30,401	43,876
Municipal	137	313	493	614	791	1,007	797	3,378	4,099	5,002	7,021	11,787
Rural Electric Cooperative	57	267	461	549	684	853	272	1,955	2,667	3,262	4,099	4,865
TOTAL	577	1,625	2,809	3,966	5,274	6,678	2,765	12,986	19,208	27,705	41,521	60,528

Proposed Solar Resources

The most recent Ten Year Site Plans showed that utilities planned to add 4.5 MW of solar PV during the 2014-2023 timeframe.

Planned Utility-Owned Generation			Gross MW
FPL	Business PV for Schools	PV	0.5000
FPL	CISP (Community Solar)	PV	3.8800
TECO	LEGOLAND	PV	0.0255
TAL	Multiple Installations	PV	0.1200
	Source: Ten Year Site Plan	Utility Owned	4.53

As part of the Ten Year Site Plan process, utilities also identified the as-available energy contracts that they plan to enter into within the 2014-2023 timeframe, as shown in the following chart.

Planned Non-Utility Generation			Gross MW
DEF	Blue Chip Energy Lake Mary	PV	10.00
DEF	Blue Chip Energy Sorrento	PV	40.00
DEF	National Solar Gadsden	PV	50.00
DEF	National Solar Hardee	PV	50.00
DEF	National Solar Suwannee	PV	50.00
DEF	National Solar Highlands	PV	50.00
DEF	National Solar Osceola	PV	50.00
TAL	TBD	PV	1.70
TAL	Innovation Park	PV	0.40
TAL	Yulee Street	PV	0.85

LAK	Sun Edison	PV	6.00
LAK	Sun Edison-Sutton	PV	6.00
LAK	Sun Edison-TBA	PV	7.50
LAK	Sun Edison-TBA	PV	5.00
	Source: Ten Year Site Plan	Non-utility	327.45

In addition to the aforementioned projects, staff highlights below a few projects that were announced subsequent to the release of the 2014 Ten Year Site Plans.

Florida Power and Light Company's Solar Projects

- On January 26, 2015, FPL announced its plans to construct three 74 MW solar photovoltaic facilities by the end of 2016, at three sites:
 - Citrus Solar Energy Center – DeSoto County, near FPL's existing 25 MW solar photovoltaic facility which opened in 2009.
 - Babcock Ranch Solar Energy Center – Charlotte County.
 - Manatee Solar Energy Center – Manatee County, on the site of FPL's Manatee generating facilities.
- According to FPL, the three sites have sufficient transmission and substation infrastructure in place.
- FPL has not announced plans for the recovery of costs associated with the proposed facilities.
- As shown in the utility's Ten Year Site Plan, the utility plans to add 3.88 MW of community solar in the 2014-2023 timeframe.
- On February 20, 2015, FPL announced its plans to construct a 1.7 MW grid-tied solar PV facility at Daytona International Speedway. Construction is to begin in the fall of 2015 with the goal that the system will be operational by the end of the year.

Florida Power and Light Company's Voluntary Solar Partnership Pilot Program¹

- Offers customers an opportunity to voluntarily contribute \$9.00 per month toward supply-side solar generation facilities owned by FPL in its service territory.
 - Available to all residential, commercial, and industrial customers.
- FPL will use the contributions to support the net revenue requirement of constructing and operating relatively small solar generating facilities.
- The electricity generated by the solar generation facilities will displace fuel that otherwise would have been used for generation, resulting in avoided fuel and emissions costs.
- The size of the solar projects will be determined based on the contributions received.
- Customers may enroll or cancel their enrollment at any time.

¹ See Order No. PSC-14-0468-TRF-EI, issued August 29, 2014 in Docket No. 140070-EI, In re: Petition for approval of voluntary solar partnership pilot program and tariff, by Florida Power & Light Company.

Tampa Electric Company - Tampa International Airport Project

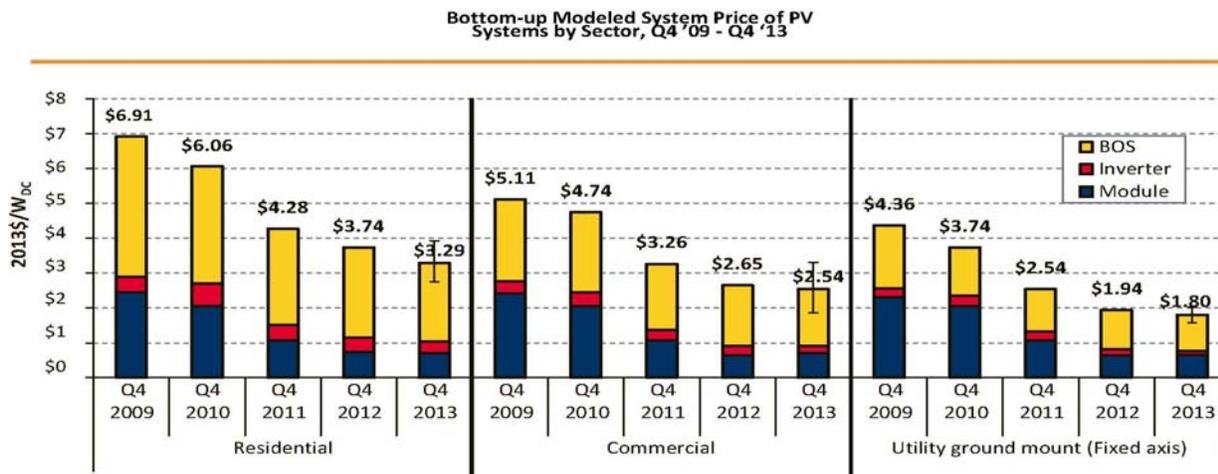
- On September 30, 2014, Tampa Electric Company (TECO) announced it will construct 2 MW of solar PV at the airport.
- The project is to be completed by the end of 2015.
- TECO will own the solar PV and will lease the airport garage roof on which the solar PV is to be located for \$15,000/year.
- TECO will receive the 30% federal tax credit.
- Energy from the solar PV will be fed into TECO’s grid and not be consumed directly by the airport.

Gulf Power Company’s Solar Petition – Docket No. 150035-EI

- On January 22, 2015, Gulf Power Company filed for approval of three purchased power agreements totaling 120 MW for solar photovoltaic projects to be located at military installations:
 - Eglin Air Force Base, Okaloosa County – 30 MW
 - Holley Naval Landing Field, Santa Rosa County – 40 MW
 - Saufley Naval Landing Field, Escambia County – 50 MW
- A recommendation on the petition is currently scheduled for the April 16, 2015 Agenda Conference.

Cost Trends

The costs associated with the installation of solar PV have been steadily decreasing. The graph below shows that the declines have been seen in all three sectors -- residential, commercial, and utility scale installations. The graph shows that over the period 4th quarter 2009 – 4th quarter 2013, the bottom-up modeled system prices have declined by 52%, 50%, and 59% for residential, commercial, and utility scale installations, respectively.



Source: 2014 Edition of DOE’s Photovoltaic System Pricing Trends

Information provided by the investor-owned electric utilities in the 2014 goal setting proceeding also recognized the declining cost of solar PV for residential and commercial installations. For example, Duke Energy's witness testified that the cost of solar PV for residential installations declined from \$5.01/watt_{dc} in 2011 to \$4.13/watt_{dc} in 2013. Similarly, the cost of solar PV for commercial installations declined from \$5.33/watt_{dc} in 2011 to \$3.89 in 2013. Gulf Power Company reported that the installed cost of solar PV systems (residential and commercial) dropped from an average of \$5.54/watt_{dc} in 2011 to \$3.42/watt_{dc} in 2014.

Demand Side Management Solar Pilot Programs

Section 366.82, F.S., directs the Commission to adopt appropriate goals for increasing the development of demand-side renewable energy systems. In developing goals, the Commission is to take into consideration the benefits and costs to the consumer participating in the measure and the benefits and costs to the general body of ratepayers. In the 2009 goal setting proceeding, the Commission found that solar measures, including solar PV and solar thermal, did not pass the cost-effectiveness tests required by Rule 25-17.008, F.A.C. However, the Commission ordered the investor-owned electric utilities (IOUs) to develop solar pilot programs in order to address the intent of the Legislature to place added emphasis on demand-side renewable resources.² The Commission established a spending cap for the IOUs of approximately \$24.5 million per year total in order to protect ratepayers from undue rate increases. The approved solar pilot programs provide customer rebates to offset a portion of the installation costs for solar photovoltaic and solar hot water heating systems, and also provide solar energy equipment to low-income customers and to schools. The following data provides information on program participation, costs, and installed solar PV capacity.

Solar Pilot Program Participation and Expenditures

The table below shows that during the period 2011-2013, a total of nearly \$50 million was expended for the solar pilot programs and 5,845 customers participated in the programs.

Solar Pilot Program Expenditures and Participation 2011-2013 (Includes both PV and Thermal)		
	Expenditures	Participants
FPL	\$29,853,514	3,962
DEF	\$13,788,013	1,318
TECO	\$3,793,723	325
GULF	\$2,300,000	240
Total	\$49,735,250	5,845
Source: 2014 conservation goals proceeding.		

² See Order No. PSC-09-0855-FOF-EG, issued December 30, 2009, in Docket Nos. 080408-EG, 080409-EG, 080410-EG, 080412-EG, 080413-EG, In re: Commission Review of numeric Conservation Goals.

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The following tables provide more detailed information on solar pilot program participation and expenditures during 2011-2013.

Florida Power and Light Company 2011-2013	Number of Participants	Total Expenditures	Average Expenditure/Participant
Solar Water Heating - Residential & Low Income New Construction	2968	\$4,469,845	\$1,506
Solar Water Heating - Business	38	629,408	16,563
Photovoltaic (PV) - Residential	774	11,045,895	14,271
Photovoltaic (PV) - Business	153	5,488,461	35,872
Photovoltaic (PV) - Business PV for Schools	29	4,057,967	139,930
Research & Demonstration	n/a	1,158,841	
Non-program Specific	n/a	3,003,097	
TOTAL	3962	\$29,853,514	\$7,535

Source: 2014 Energy Conservation Goals Proceeding.

Duke Energy Florida, Inc. 2011-2013	Number of Participants	Total Expenditures	Average Expenditure/Participant
Solar Water Heating Low Income	63	\$321,874	\$5,109
Solar Water Heating - Residential	847	587,132	693
Photovoltaic (PV) - Residential	346	5,522,911	15,962
Photovoltaic (PV) - Commercial	39	2,755,173	70,645
Photovoltaic (PV) for Schools	23	4,097,400	178,148
Research and Demonstration	n/a	504,523	
TOTAL	1318	\$13,788,013	\$10,461

Source: 2014 Energy Conservation Goals Proceeding.

Tampa Electric Company 2011-2013	Number of Participants	Total Expenditures	Average Expenditure/Participant
Photovoltaic (PV) - Residential	168		
Photovoltaic (PV) - Commercial	24		
PV Systems for Schools	3		
Solar Water Heating - Residential	120		
Solar Water Heating - Low Income	10		
Total	325	\$3,793,723	\$11,673

Source: 2014 Energy Conservation Goals Proceeding.

Gulf Power Company 2011-2013	Number of Participants	Total Expenditures	Average Expenditure/Participant
Photovoltaic (PV) - Residential & Commercial	132	\$1,289,000	\$9,765
PV Systems for Schools	2	209,000	104,500
Solar Water Heating - Residential	76	88,000	1,158
Solar Water Heating - Low Income	30	145,000	4,833
Administrative Expenses	n/a	569,000	
TOTAL	240	\$2,300,000	\$9,583

Source: 2014 Energy Conservation Goals Proceeding.

Solar Pilot Program Costs – Incentives & Other Expenses

The following tables provide data on program expenses divided between incentives and all other expenses. Incentives refer to the monetary rebates provided to qualifying customers who installed a solar PV or water heating system. Other expenses include payroll, marketing and other overhead.

Solar Pilot Program Costs 2011-2013					
Duke Energy Florida, Inc.					
Program	Other Expenses	% of Total	Incentives	% of Total	Total
Solar Water Heating with EM	\$153,187	26.1%	\$433,945	73.9%	\$587,132
Research and Demonstration	\$504,523	100.0%	\$0	0.0%	\$504,523
Solar Water Heating Low Income	\$78,970	24.5%	\$242,905	75.5%	\$321,875
Photovoltaic for Schools Pilot	\$161,299	3.8%	\$4,133,050	96.2%	\$4,294,349
Residential Solar Photovoltaic	\$370,971	7.0%	\$4,954,991	93.0%	\$5,325,962
Commercial Solar Photovoltaic	\$155,848	5.7%	\$2,599,325	94.3%	\$2,755,173
Total	\$1,424,798	10.3%	\$12,364,216	89.7%	\$13,789,014
Florida Power and Light Company					
Program	Other Expenses	% of Total	Incentives	% of Total	Total
Res. Solar H2O Heating Pilot	\$796,850	22.5%	\$2,752,000	77.5%	\$3,548,850
Res. Solar H2O Heating (Low Inc.) Pilot	\$131,990	14.3%	\$789,005	85.7%	\$920,995
Residential Photovoltaic Pilot	\$415,216	3.8%	\$10,630,678	96.2%	\$11,045,894
Business Solar H2O Heating Pilot	\$249,463	39.6%	\$379,945	60.4%	\$629,408
Business Photovoltaic Pilot	\$317,603	5.8%	\$5,170,859	94.2%	\$5,488,462
Business Photovoltaic for Schools Pilot	\$570,856	100.0%	\$0	0.0%	\$570,856
Renewable Research and Demo. Project	\$1,158,841	100.0%	\$0	0.0%	\$1,158,841
Solar Pilot Projects Common Expenses	\$2,075,160	100.0%	\$0	0.0%	\$2,075,160
Total	\$5,715,979	22.5%	\$19,722,487	77.5%	\$25,438,466
Gulf Power Company					
Program	Other Expenses	% of Total	Incentives	% of Total	Total
Renewable Energy Plan Common	\$569,452	100.0%	\$0	0.0%	\$569,452
Solar for Schools	\$139,906	100.0%	\$0	0.0%	\$139,906
Solar Thermal Water Heating	\$12,187	13.8%	\$76,000	86.2%	\$88,187
Solar PV	\$11,835	0.9%	\$1,277,330	99.1%	\$1,289,165
Solar Thermal Water Heating - Low Income	\$0	0.0%	\$144,776	100.0%	\$144,776
Total	\$733,380	32.9%	\$1,498,106	67.1%	\$2,231,486
Tampa Electric Company					
Program	Other Expenses	% of Total	Incentives	% of Total	Total
Renewable Energy Systems Initiative	\$598,495	15.8%	\$3,195,228	84.2%	\$3,793,723
Total	\$598,495	15.8%	\$3,195,228	84.2%	\$3,793,723
Source: Energy Conservation Cost Recovery Clause Schedules.					

Solar Photovoltaic Capacity Installed – 2011-2013

The table below provides the capacity of solar PV systems installed by customers. Duke Energy Florida, Inc. and Gulf Power Company reported that some customers installed solar PV systems with capacity in excess of the capacity provided by the maximum rebate. Data is provided for the incentivized capacity and the total capacity installed.

Solar PV Installed Capacity Funded by Solar Pilot Programs				
kW DC Rating 2011-2013				
Duke Energy Florida, Inc.				
	2011	2012	2013	Total
Residential Solar PV - Incentivized	557	733	1,205	2,495
Residential Solar PV - Total Installed	567	753	1,239	2,559
Commercial Solar PV - Incentivized	632	593	609	1,834
Commercial Solar PV - Total Installed	1,667	1,996	631	4,294
Solar for Schools - Incentivized	190	200	190	580
Solar for Schools - Total Installed	197	200	190	587
Total Incentivized	1,379	1,526	2,004	4,909
Total Installed	2,431	2,949	2,060	7,440
Florida Power and Light Company				
	2011	2012	2013	Total
Residential Solar PV	1,690	1,650	2,272	5,612
Business Solar PV	598	1,526	2,534	4,658
Solar for Schools	0	0	190	190
Total	2,288	3,176	4,996	10,460
Gulf Power Company				
	2011	2012	2013	Total
Solar PV - Incentivized	204	218	218	639
Solar PV - Total Installed	267	273	288	828
Solar for Schools	0	10	10	20
Total Incentivized	204	228	228	659
Total Installed	267	283	298	848
Tampa Electric Company				
	2011	2012	2013	Total
Residential Solar PV	311	495	479	1,285
Commercial Solar PV	74	61	90	225
Solar for Schools	10	10	10	30
Total	395	566	579	1,540

Source: FPSC staff data request.

2014 Goal Setting Proceeding - Cost-Effectiveness Analysis Results

As part of the 2014 goal setting proceeding, the Commission evaluated the cost-effectiveness of the Solar Pilot Programs, solar PV and solar hot water heating measures. The tables below provide the results of the cost-effectiveness tests required by Rule 25-17.008, F.A.C. The Commission found that the programs are not cost-effective and experience gained since the 2009 goals proceeding indicates that consumers have continued to install systems without any rebates. The Commission noted that the rebates associated with the solar pilot programs represent a large subsidy from the general body of ratepayers to a very small segment of each utility's customers.

Florida Power and Light Company Solar Pilot Programs	Benefit Cost Ratio		
	RIM	TRC	Participant
Solar Water Heating - Residential	0.51	0.18	0.50
Solar Water Heating - Low Income New Construction	0.21	0.28	1.52
Solar Water Heating - Business	0.34	0.19	0.58
Photovoltaic (PV) - Residential	0.46	0.27	0.74
Photovoltaic (PV) - Business	0.64	0.33	0.67
Photovoltaic (PV) - Business PV for Schools	0.13	0.15	1.19

Source: 2014 Energy Conservation Goals Proceeding

Duke Energy Florida, Inc. Solar Pilot Programs	Benefit Cost Ratio		
	RIM	TRC	Participant
Solar Water Heating for Low-income Residential	0.274	0.454	1.83
Solar Water Heating with Energy Management	0.596	0.580	0.79
Photovoltaic - Residential	0.376	0.547	1.23
Photovoltaic - Commercial	0.422	0.628	1.35
Photovoltaic for Schools	0.141	0.163	1.18

Source: 2014 Energy Conservation Goals Proceeding

Tampa Electric Company Solar Measures	Benefit Cost Ratio		
	RIM	TRC	Participant
Residential PV	0.38	0.41	1.20
Commercial PV	0.40	0.39	1.10
Residential Solar Water Heating	0.56	0.28	0.71

Source: 2014 Energy Conservation Goals Proceeding

Gulf Power Company Solar Measures	Benefit Cost Ratio		
	RIM	TRC	Participant
Solar PV (combined residential and commercial)	0.88	0.67	1.005 – 1.05
Solar Thermal Water Heating (Single Family)	0.74	0.56	0.98

Source: 2014 Energy Conservation Goals Proceeding

cc: Lisa Harvey, Charlie Beck

State of Florida



Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: March 2, 2015

TO: Art Graham, Chairman

FROM: Walter Clemence, Public Utility Analyst II, Office of Industry Development and Market Analysis ✓
David L. Dowds, Public Utilities Supervisor, Office of Industry Development and Market Analysis
Mark A. Futrell, Director, Office of Industry Development and Market Analysis *MF*

RE: Solar Payback Information

The charts below are illustrative of what a customer in Florida may use for an economic analysis to determine the benefits of installing solar photovoltaic. The chart provides a simple payback calculation of installing an average system for both a residential and commercial customer.

Residential 5kW		
	w/Utility Rebate	No Utility Rebate
System Cost (\$3290 kW)	\$16,450	\$16,450
Utility Rebate (\$2/watt)	\$10,000	\$0
Federal Tax Credit (30%)	\$1,935	\$4,935
Total Cost	\$4,515	\$11,515
Approximate monthly kWh produced	657	657
Approximate monthly value of energy	\$70	\$70
Years to recover investment	5.35	13.65

Parties/Staff ✓ Handout ✓
Internal Affairs/Agenda
on 03/03/2015
Item No. 1

State of Florida



Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

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Parties/Staff ✓
Internal Affairs/Agenda ✓
on 03/03/2015
Item No. 1

Chairman Graham Memorandum
March 2, 2015

Commercial 200 kW		
	w/Utility Rebate	No Utility Rebate
System Cost (\$2540 kW)	\$508,000	\$508,000
Utility Rebate (Max)	\$50,000	\$0
Federal Tax Credit (30%)	\$137,400	\$152,400
Total Cost	\$320,600	\$355,600
Approximate monthly kWh produced	26,280	26,280
Approximate monthly value of energy	\$2,418	\$2,418
Years to recover investment	11.05	12.26

The investment cost data used in the charts above are an approximation of the costs found in the 2014 Edition of DOE's Photovoltaic System Pricing Trends. The cost is based on a bottom-up modeled PV system. IOU solar pilot program rebates were approved by the Commission for 2011-2015.

The utility rebate assumes a rebate of \$2.00/watt first 10kW, \$1.50/Watt 10-25KW, \$1.00/watt >25kW with a \$50,000 maximum rebate.

The Federal Tax Credit is 30% of the actual cost of the system, applied net of any utility-provided rebate. The Federal Tax Credit for residential and commercial solar installations is available until December 31, 2016. After that time, the residential credit drops to zero and commercial credit drops to 10%.

The value of the energy produced assumes that all the energy is used on-site. This provides the greatest benefit for the consumer. The energy being used on-site offsets the consumer's need to purchase power from the utility. Therefore, it is valued at the retail cost of electricity.

The estimated monthly system kWhs produced assumes an 18% capacity factor. The approximate monthly value of energy is based on a retail electricity price (excluding taxes) of \$0.107 per kWh for residential and \$0.092 per kWh for commercial. The Years to recover investment is derived by dividing the net system cost by the monthly values of energy, then dividing the result by 12 to yield payback in years.

The charts above show that the inclusion of the utility rebates greatly reduces the amount of time necessary to recover the investment in the solar generation for a residential or commercial

Chairman Graham Memorandum
March 2, 2015

system. The inclusion of the utility rebate reduces the time to recover the investment from 13.65 years down to 5.35 for a residential installation. For a commercial installation the time to recover the investment is reduced from 12.26 years down to 11.05 years.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric conservation goals (Florida Power & Light Company).	DOCKET NO. 080407-EG
In re: Commission review of numeric conservation goals (Progress Energy Florida, Inc.).	DOCKET NO. 080408-EG
In re: Commission review of numeric conservation goals (Tampa Electric Company).	DOCKET NO. 080409-EG
In re: Commission review of numeric conservation goals (Gulf Power Company).	DOCKET NO. 080410-EG
In re: Commission review of numeric conservation goals (Florida Public Utilities Company).	DOCKET NO. 080411-EG
In re: Commission review of numeric conservation goals (Orlando Utilities Commission).	DOCKET NO. 080412-EG
In re: Commission review of numeric conservation goals (JEA).	DOCKET NO. 080413-EG ORDER NO. PSC-09-0855-FOF-EG ISSUED: December 30, 2009

The following Commissioners participated in the disposition of this matter:

MATTHEW M. CARTER II, Chairman
LISA POLAK EDGAR
NANCY ARGENZIANO
NATHAN A. SKOP
DAVID E. KLEMENT

APPEARANCES:

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On behalf of Florida Power & Light Company (FPL)

DOCUMENT NUMBER-DATE

12263 DEC 30 09

FPSC-COMMISSION CLERK

ORDER NO. PSC-09-0855-FOF-EG

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On behalf of Florida Public Utilities Company (FPUC)

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On behalf of JEA

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On behalf of ITRON, Inc.

JEREMY SUSAC, Executive Director, Florida Energy and Climate Commission, 600 South Calhoun Street, Suite 251, Tallahassee, Florida 32399-0001

On behalf of the Florida Energy and Climate Commission (FECC)

VICKI GORDON KAUFMAN, JON C. MOYLE, JR., ESQUIRES, Keefe Anchors Gordon & Moyle, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301; and JOHN W. MCWHIRTER, JR., ESQUIRE, McWhirter Law Firm, Post Office Box 3350, Tampa, Florida 33601-3350

On behalf of the Florida Industrial Power Users Group (FIPUG)

ORDER NO. PSC-09-0855-FOF-EG

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080413-EG

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On behalf of the Natural Resources Defense Council (NRDC) and Southern Alliance for Clean Energy (SACE)

KATHERINE E. FLEMING and ERIK L. SAYLER, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399

On behalf of the Florida Public Service Commission (Staff)

MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399

Advisor to the Florida Public Service Commission

FINAL ORDER APPROVING NUMERIC CONSERVATION GOALS

BY THE COMMISSION:

BACKGROUND

Sections 366.80 through 366.85, and 403.519, Florida Statutes (F.S.), are known collectively as the Florida Energy Efficiency and Conservation Act (FEECA). Section 366.82(2), F.S., requires us to adopt appropriate goals designed to increase the conservation of expensive resources, such as petroleum fuels, to reduce and control the growth rates of electric consumption and weather-sensitive peak demand. Pursuant to Section 366.82(6), F.S., we must review the conservation goals of each utility subject to FEECA at least every five years. The seven utilities subject to FEECA are Florida Power & Light Company (FPL), Progress Energy Florida, Inc. (PEF), Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Public Utilities Company (FPUC), Orlando Utilities Commission (OUC), and JEA (referred to collectively as the FEECA utilities). Goals were last established for the FEECA utilities in August 2004 (Docket Nos. 040029-EG through 040035-EG). Therefore, new goals must be established by January 2010.

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In preparation for the new goals proceeding, we conducted a series of workshops exploring energy conservation initiatives and the requirements of the FEECA statutes. The first workshop, held on November 29, 2007, explored how we could encourage additional energy conservation. A second workshop held on April 25, 2008, examined how the costs and benefits of utility-sponsored energy conservation or demand-side management (DSM) programs, that target end-use customers, should be evaluated.

In 2008, the Legislature amended Section 366.82, F.S., such that when goals are established, we are required to: (1) evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems, (2) establish goals to encourage the development of demand-side renewable energy systems, and (3) allow efficiency investments across generation, transmission, and distribution as well as efficiencies within the user base. The Legislature also authorized us to allow an investor-owned electric utility (IOU) an additional return on equity of up to 50 basis points for exceeding 20 percent of their annual load-growth through energy efficiency and conservation measures and may authorize financial penalties for those utilities that fail to meet their goals. The additional return on equity shall be established by this Commission through a limited proceeding. Finally, the amendments to Section 366.82, F.S., provided funds for this Commission to obtain professional consulting services if needed. These statutes are implemented by Rules 25-17.001 through 25-17.0015, Florida Administrative Code (F.A.C.).

We held a third workshop on June 4, 2008, focused on appropriate methodologies for collecting information for a technical potential study. On June 26, 2008, seven dockets (080407-EG through 080413-EG) were established and represent the fourth time that we will set numeric conservation goals for each of the FEECA utilities. On November 3, 2008, we held a fourth workshop on the development of demand-side and supply-side conservation goals, including demand-side renewable energy systems. The results of the Technical Potential Study, conducted by the consulting firm ITRON on behalf of the seven FEECA utilities were presented at a fifth Commission workshop held on December 15, 2008.

On November 13, 2008, our staff contracted with GDS Associates, Inc. (GDS) to provide independent technical consulting and expert witness services during the conservation goal-setting proceeding. GDS is a multi-service engineering and management consulting firm, headquartered in Marietta, Georgia, with offices in Alabama, Texas, Maine, New Hampshire, Wisconsin, and Virginia. The firm has a broad array of management, strategic, and programmatic consulting expertise and specializes in energy, energy efficiency, water and utility planning issues. GDS was retained to review and critique the overall goals proposed by each utility, provide expert testimony and recommendations on alternative goals, where warranted. As an independent consultant, GDS was neither a separate party nor a representative of the staff. As such, GDS did not file post-hearing position statements or briefs.

By Order No. PSC-08-0816-PCO-EG, issued December 18, 2008, these dockets were consolidated for purposes of hearing and controlling dates were established. By Order No. PSC-09-0152-PCO, issued March 12, 2009, the controlling dates were revised, requiring the utilities

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to file direct testimony and exhibits on June 1, 2009. FPUC requested, and was granted, an extension of time to file its direct testimony on June 4, 2009.

The Natural Resources Defense Council and the Southern Alliance for Clean Energy (NRDC/SACE) were granted leave to intervene by the Commission on January 9, 2009.¹ The Florida Solar Coalition (FSC) was granted leave to intervene on January 27, 2009.² We acknowledged the intervention of the Florida Energy and Climate Commission (FECC) on March 11, 2009.³ The Florida Industrial Power Users Group (FIPUG) was granted leave to intervene on July 15, 2009.⁴

An evidentiary hearing was held on August 10 - 13, 2009. We have jurisdiction over this matter pursuant to Sections 366.80 through 366.82, F.S.

On August 28, 2009, the FECC filed post-hearing comments in the proceeding. While the FECC took no position on any issues, the FECC concluded in its post-hearing comments that:

The PSC should approve a level of goals for each utility that satisfies the utility's resource needs and results in reasonably achievable lower rates for all electric customers. As called for in the recent legislation, the PSC should also take into account environmental compliance costs that are almost a certainty over this goals-planning horizon. In this regard, the FECC supports a reasonably achievable level of DSM Goals based on measures that pass the E-RIM and Participants Tests to achieve the least-cost strategy for the general body of ratepayers. Additionally, the FECC believes that coupling cost-effective measures that satisfy E-RIM with solar measures that do not satisfy E-RIM will increase the customer take rate of solar applications at the lowest possible cost.

TECHNICAL POTENTIAL STUDY

For the current goal setting proceeding, the seven FEECA utilities invited NRDC/SACE to form a Collaborative to conduct an assessment of the technical potential for energy and peak demand savings from energy efficiency, demand response, and customer-scale renewable energy in their service territories.⁵ The Collaborative then developed a request for proposal to conduct the study. The proposals were evaluated and the ITRON team was selected by the Collaborative to conduct the Technical Potential Study.⁶

FPL contended that the Technical Potential Study employed an iterative process that began with a list of measures that were provided within its original request for proposal (RFP).

¹ Order No. PSC-09-0027-PCO-EG, issued January 9, 2009 (NRDC/SACE).

² Order No. PSC-09-0062-PCO-EG, issued January 27, 2009 (FSC).

³ Order No. PSC-09-0150-PCO-EG, issued March 11, 2009 (FECC).

⁴ Order No. PSC-09-0500-PCO-EG, issued July 15, 2009 (FIPUG).

⁵ Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. 1-1.

⁶ Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. 1-1 – 1-2.

PEF stated that the study focuses on measures that will work in Florida, have the greatest potential impact, and have a realistic possibility for adoption. TECO argued that using the collaborative process allowed each member to draw upon the collective judgment of the group, which would insure the ultimate proposals were the product of a rigorous and orderly process. Gulf asserted that NRDC/SACE were able to submit additional measures to be considered for analysis in the technical potential. FPUC argued that the study provides an adequate assessment of the technical potential. JEA/OUC argued that the study used measures and assessment techniques that were fully vetted through the collaborative process. The FEECA utilities contended that the study commissioned by the Collaborative satisfies Section 366.82(3), F.S.

NRDC/SACE argued that the study did not provide an adequate assessment of the technical potential. NRDC/SACE stated that the technical potential does not consider the full technical potential of all available demand- and supply-side efficiency measures. FSC argued that ranking measure savings by the use of "stacking" by the Collaborative is incorrect. FSC also criticized the study for omitting solar hybrid systems. FIPUG's brief and the comments filed by the FECC did not specifically address the Technical Potential Study.

Analysis

Witness Rufo, Director in the Consulting and Analysis Group at ITRON, stated that the technical potential is a theoretical construct that represents an upper limit of energy efficiency. Technical potential is what is technically feasible, regardless of cost, customer acceptance, or normal replacement schedules. The Technical Potential Study was conducted for each FEECA utility and then combined to create a statewide technical potential.

According to the testimony of witness Rufo, the Collaborative's first step was to identify and select the energy efficiency, demand response, and solar photovoltaic (PV) measures to be analyzed. The energy efficiency measures were developed with the FEECA utilities, ITRON, and NRDC/SACE, all proposing measures. Once a master list was developed, ITRON conducted assessments of data availability and measure specific modeling issues. Demand response measures were identified using a combination of literature reviews of current programs and discussions within the Collaborative. The PV measures were identified by explicitly considering six characteristics specific to PV electrical systems. The six characteristics are: (1) PV material type, (2) energy storage, (3) tracking versus fixed, (4) array mounting design, (5) host sites, and (6) on- versus off-grid systems.

The ITRON assessment of the full technical potential included 257 unique energy efficiency measures, seven demand response programs, and three unique PV measures. Included in the energy efficiency list were 61 residential measures, 78 commercial measures, and 118 industrial measures. The demand response list included five residential, and two commercial/industrial measures. The PV list included one residential (roof top application) and two commercial measures (one rooftop application and one parking lot application).

Some of the 257 measures, such as Seasonal Energy Efficiency Ratio (SEER) 19 central air conditioners, hybrid desiccant-direct expansion cooling systems, and heat pump water heaters are likely to face supply constraints in the near future. The energy efficiency list also includes some end-use specific renewable measures, e.g., solar water heating and PV-powered pool pumps. While some measures may have obstacles to overcome regarding customer acceptance, it is appropriate to include them in the technical potential.

The table below shows the results of the Statewide Technical Potential Study. Baseline energy is the total electricity sales for the FEECA utilities in 2007.⁷

Sector	Annual Energy			Summer System Peak			Winter System Peak		
	Base line (2007)	Technical Potential		Base line (2007)	Technical Potential		Base line (2007)	Technical Potential	
	(GWh)	(GWh)	(%)	(MW)	(MW)	(%)	(MW)	(MW)	(%)
Residential	94,745	36,584	38.6%	22,263	10,032	45.1%	22,728	6,461	28.4%
Commercial	65,051	19,924	30.6%	9,840	4,079	41.5%	7,490	2,206	29.5%
Industrial	11,877	2,108	17.7%	1,721	265	12.8%	1,289	217	17.5%
Total	171,672	58,616	34.1%	33,825	14,375	42.5%	31,508	8,883	28.2%

None of the parties offered any alternatives that were Florida-specific. They only showed that other states showed greater potential. They were unable to show how savings in other states could be achieved in Florida. Witness Rufo testified that criticisms of the ITRON data and modeling methods by NRDC/SACE and the staff witness are either without merit, inaccurate, or insignificant. Witness Rufo further testified that the baseline and measure data used in the Technical Potential Study reflect the best available data given the time and resources available.

The FEECA utilities did not develop supply-side conservation or efficiency measures to the same degree that they did demand-side measures. Generating utilities made note of their ongoing or planned efficiency and savings projects, but did not subject supply-side measures to the same analysis, nor did they develop the extensive lists of measures, that were examined by ITRON for demand-side savings. Supply-side measures require substantially different analytical methods than do demand-side systems and provide results that are difficult to combine with conservation goals. Supply-side efficiencies and conservation, rendered properly, would result either in less fuel being required or less loss along the transmission and distribution network. The Commission routinely addresses opportunities for supply-side efficiency improvements in our review of Ten-Year Site Plans. Therefore, such measures are better addressed separately from demand-side measures where their options can be better explored.

⁷ Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. 3-14.

Conclusion

Based on the record, we find that the Collaborative provided an adequate assessment of the technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems, pursuant to Section 366.82(3), F.S.

ACHIEVABLE POTENTIAL

Each of the FEECA utilities agreed that an adequate assessment of achievable potential was provided. The FEECA utilities that addressed the supply-side options, likewise, agreed that it was better addressed through a separate proceeding.

FSC, in its post-hearing brief, found the assessment insufficient for the five IOUs. FSC took no position on the municipal utilities. FSC's objection in the case of the IOUs mainly related to problems it had with the cost-effectiveness testing used in the process, which is further addressed below. NRDC/SACE, in its post-hearing brief, argued that the achievable potential was insufficient across the board and cited opposition to the cost-effectiveness testing.

Following the development of the DSM technical potential, previously discussed, three steps were used to develop the achievable potential: initial cost-effectiveness screening, determination of incentive levels, and development of achievable potential for six separate scenarios. Discussion of each step follows. FPUC, JEA, and OUC did not use this process and are discussed separately.

Initial Cost-Effectiveness Screening

During this phase of the process, the four generating IOUs (FPL, PEF, TECO, and Gulf) applied three cost-effectiveness tests to each measure: Enhanced Rate Impact Measure Test (E-RIM), Enhanced Total Resource Cost Test (E-TRC), and the Participants Test. None of the three tests included incentives that could be provided to participating customers. During this phase of the testing, the utilities also identified measures that had a payback period of less than two years in order to identify the free riders. Rule 25-17.0021(3), F.A.C., reads, in part:

Each utility's projection shall reflect consideration of overlapping measures, rebound effects, free riders, interactions with building codes and appliance efficiency standards, and the utility's latest monitoring and evaluation of conservation programs and measures.

In order to meet the requirements of this Rule, the four generating IOUs removed certain measures because of participant "payback" periods of less than two years. Savings realized from such measures exceeded their costs within two years, according to utility analysis. These savings result from reduced kWh usage and, resultantly, a lower bill. The costs of such measures are up-front capital costs, where they exist, of installing or beginning the measure. Measures must both pass the Participants Test and have a payback of two years or less without any incentives to

be removed during this step. We initially recognized a two-year payback period to address the free-ridership issue following the 1994 conservation goals hearing. By Order No. PSC-94-1313-FOF-EG,⁸ we initially recognized FPL's use of the two-year payback period, and it has been used consistently ever since.

The two-year payback period was agreed to by the Collaborative as a means of addressing the free-ridership issue. In his testimony, FPL witness Dean described the rationale for the two-year period. He noted that estimates of the annual return on investment required to spur purchase of energy efficiency measures range from approximately 26 percent, which represents a payback period of just under four years, to over 100 percent, which represents a payback period less than a year. He further noted that most studies place the annual return on investment necessary to incent purchase in the 40 to 60 percent range. A 50 percent figure, which represents a payback of exactly two years, is squarely in the middle of that range.

The two-year payback criterion identified a substantial amount of energy savings from demand-side measures. For an illustrative example, the following chart demonstrates the amount of energy savings that could potentially be achieved from such measures:

Utility	(A) Maximum Achievable E-TRC (GWh)*	(B) E-TRC + 2-year payback measures (GWh)*	(C) Amount excluded due to 2-year screen (GWh) (B-A)	(D) Percent excluded due to 2-year screen (C/B)
FPL	2177.0	12066.9	9889.9	82.0%
PEF	1584.5	4689.8	3105.3	66.2%
TECO	310.3	1939.9	1629.6	84.0%
Gulf	251.4	1279.9	1028.5	80.4%
JEA	138.5	1070.7	932.2	87.1%
OUC	78.8	511.2	432.4	84.6%
FPUC	12.9	59.2	46.3	78.2%
Total	4553.4	21617.6	17064.2	78.9%

Even though the utilities did not include such measures in their proposed goals, customers are still free to adopt such measures and realize the resultant financial savings the measures represent. We are concerned that the utilities' use of the two-year payback criteria had the effect of screening out a substantial amount of potential savings. In order to recognize this potential, we have included in the residential goals for FPL, PEF, Gulf and TECO, savings from

⁸ Order No. PSC-94-1313-FOF-EG, issued October 25, 1994, Docket No. 93-0548-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by Florida Power and Light Company; Docket No. 93-0549-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by Florida Power Corporation; Docket No. 93-0550-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by Gulf Power Company; Docket No. 93-0551-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by Tampa Electric Company.

the residential measures included in the top-ten energy savings measures that were screened-out by the two-year payback criterion.

Incentive Levels

The second step in the process for the four generating IOUs was to establish proper incentive levels. As a result, incentive levels for measures that did not pass the Participants Test during the initial cost-effectiveness screening (without incentives) were adjusted until the measures passed. Following this action, the E-RIM and E-TRC tests were re-run using costs that included the resulting incentive. Some measures that could not pass the Participants Test cost-effectiveness screening without incentives were removed from the achievable potential at this stage. Because measures were required to pass the Participants Test as well as E-RIM or E-TRC, incentives added to measures to allow them to be cost-effective for customers rendered some measures no longer cost-effective under either the E-RIM or E-TRC tests.

Scenario Analysis

In the third step of the process, the four generating IOUs analyzed measures that passed cost-effectiveness screening with incentives, in order to develop six scenarios for achievable potential. These utilities developed low, mid, and high incentive scenarios for both E-RIM and E-TRC. From these six scenarios, the achievable potential was developed. This achievable potential formed the basis of the goals proposed by the utilities in the next step of the overall process.

Other FEECA Utilities

FPUC, OUC, and JEA allowed ITRON to develop the achievable potential for them. ITRON followed a similar process in developing the achievable potential for the three small utilities that was followed for the generating IOUs in making their calculations. In each of these three cases, ITRON found no DSM measures that passed the E-RIM Test. As a result, the achievable potential for each of these three utilities was zero in all categories. These utilities are all smaller than the generating IOUs. Because of fewer customers, administrative costs and program development tend to render measures less cost-effective than they are for the generating IOUs.

Demand-Side Renewable Energy Systems

The Collaborative analyzed a small range of renewable energy systems in their analysis of achievable potential.⁹ These measures were confined to geothermal heat pumps, solar water heaters, and small photovoltaic (PV) systems. These renewable energy systems were subjected to the same range of cost-effectiveness testing as the DSM measures discussed above. The generating IOUs found that some geothermal heat pumps did pass the cost-effectiveness tests

⁹ Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. A1 – A27.

and were included in the achievable potential. PEF also included some solar thermal measures in its achievable potential. No FEECA utility found that Solar PV measures passed the economic screening and thus should not be included in the achievable potential. Renewable energy systems were subject to the same analysis as conventional energy efficiency measures and either were incorporated into or excluded from achievable potential by the same standards.¹⁰

Conclusion

Each of the FEECA utilities, with the aid of ITRON, performed an adequate analysis of the demand-side conservation and efficiency measures, including demand-side renewable energy systems. The FEECA utilities did not provide an analysis of supply-side measures. We agree, however, that the methods appropriate to analyze demand-side measures are not well-suited to weighing supply-side measures. As a result, supply-side measures are best addressed in a separate proceeding.

REQUIRED COST-EFFECTIVENESS TESTS

Recent amendments to Section 366.82, F.S., provide greater specificity as to what we must consider when establishing conservation goals. The recent amendments, in relevant part, are as follows:

- (3) In developing the goals, the commission shall evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems. In establishing the goals, the commission shall take into consideration:
 - (a) The costs and benefits to customers participating in the measure.
 - (b) The costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions.

Appropriate Test for Section 366.82(3)(a), F.S.

All parties, except FSC, agreed that the Participants Test captures all of the relevant costs and benefits for customers who elect to participate in a DSM measure. The parties further agreed that the requirements of Section 366.82(3)(a), F.S., are reflected in the proposed goals because all included measures pass the Participants Test.

FSC argued that the goals proposed by FPL, PEF, TECO, Gulf, and FPUC do not adequately reflect the costs and benefits to customers participating in the measures pursuant to Section 366.82(3)(a), F.S. FSC appears to take issue with the techniques employed by the IOUs in calculating the energy savings and incentives for solar measures and argued that these flawed calculations cause solar measures to fail the Participants Test. In its analysis, FSC explained

¹⁰ Technical Potential for Electric Energy and Peak Demand Savings in Florida, Final Report, pp. ES5 – ES 6.

how the impact of “stacking” increases the necessary incentive and lowers the energy savings attributed to solar technologies, thereby increasing the likelihood that these measures will fail the Participants Test. FSC took no position regarding OUC and JEA.

Section 366.82(3)(a), F.S., requires that we take into consideration the costs and benefits to customers participating in any measure to be included in a utility’s DSM program. In addition, Rule 25-17.008, F.A.C., incorporates our Cost Effectiveness Manual.¹¹ The Cost Effectiveness Manual requires the application of the Participants Test in order to determine the cost-effectiveness of conservation programs by measuring the impact of the program on the participating customers. The customers’ benefits of participation in programs may include bill reductions, incentives, and tax credits. Customer’s costs may include bill increases, equipment and materials, and operations and maintenance.

Although FSC expressed its opinion that the inputs to the Participants Test are flawed, it agreed with the application of this test in general, along with the E-TRC Test. However, FSC offered no alternative inputs for the investor-owned utilities, nor did it provide any alternative to the results obtained from the application of the Participants Test. The FSC questioned ITRON on its use of “stacking” in the Technical Potential Study. Stacking is a means to understand the interaction between available measures to make sure that savings are not double counted. Witness Rufo testified that the use of “stacking” is an accepted practice to eliminate double counting that could occur if the measures were not stacked. We believe that “stacking” is useful and justified as it is a means to ensure that the savings from a program are not counted if those savings would be offset by the savings in a different measure.

We find that the Participants Test, as used by the utilities in this proceeding, satisfies the requirements of Section 366.82(3)(a), F.S. As described in Rule 25-17.008, F.A.C., the Participants Test measures the impact of the program on the participating customers. Based on the evidence in the record, as well as existing Commission Rules, we find that the Participants Test must be considered when establishing conservation goals in order to satisfy Section 366.82(3)(a), F.S.

Appropriate Test for Section 366.82(3)(b), F.S.

The FEECA utilities agreed that Section 366.82, F.S., does not specify or require a single cost-effectiveness test, but that a combination of two tests is sufficient to meet the requirements, specifically the RIM and Participants Tests. The TRC Test is considered by the utilities to be insufficient to meet the statute, and goals based upon it would have an upward pressure on rates. They also agreed that their analysis was comprehensive, including effects from a variety of sources, such as building codes, overlapping measures, appliance standards, and other sources. Four of the seven FEECA utilities filed “enhanced” versions of the RIM and TRC tests, referenced as E-RIM and E-TRC. These tests included benefits from avoided carbon compliance costs.

¹¹ Florida Public Service Commission Cost Effectiveness Manual for Demand Side Management Programs and Self-Service Wheeling Proposals, effective July 17, 1991.

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NRDC/SACE asserted that the language found in Section 366.82(3)(b), F.S., clearly describes the TRC Test. NRDC/SACE argued that the TRC Test is the cost-effectiveness test that focuses on the “general body of ratepayers as a whole.” NRDC/SACE further elaborated that the TRC Test, unlike the RIM Test, includes both “utility incentives and participant contributions.” In addition, a flaw in the calculation of benefits is the denial of value for reduced demand until the in-service date of the avoided unit. Also, the possibility of avoiding units that are already approved but have not yet finished construction should be considered. Finally, NRDC/SACE contended that administrative costs allocated to measures were unreasonable and caused an inappropriate reduction of the goals.

FIPUG suggested that we primarily consider the final impact on customers, and that any goals should not present an undue rate impact upon customers. FIPUG contended that we should continue to give significant weight to the RIM Test. FIPUG asserted, however, that the test should be performed consistently and uniformly between utilities.

FSC asserted that the analysis by the investor-owned utilities was insufficient, and that the reduction of savings associated with solar measures was reduced by inappropriately stacking measures. FSC supported the E-TRC and Participants Tests, and further suggested that measures should be considered in combination or on a portfolio basis.

Section 366.82(3)(b), F.S., requires this Commission to consider “[t]he costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions.” Both the RIM and TRC Tests address costs and benefits beyond those associated solely with the program participant. Four of the seven FEECA utilities filed “enhanced” versions of the RIM and TRC tests, referenced as E-RIM and E-TRC. These tests are identical to the RIM and TRC tests but include an estimate of avoided carbon compliance costs. As such, E-RIM and E-TRC portfolios will have greater savings than RIM or TRC portfolios respectively.

Rule 25-17.008, F.A.C., and the Cost Effectiveness Manual were adopted as part of the implementation of Section 366.82, F.S., prior to the recent amendments. Rule 25-17.008(3), F.A.C., directs us to evaluate the cost-effectiveness of conservation measures and programs utilizing the following three tests: (1) the Participants Test, (2) the Total Resource Cost Test (TRC), and (3) the Rate Impact Measure Test (RIM). Rule 25-17.008(4), F.A.C., allows a party to provide additional data for cost-effectiveness reporting, such as the E-RIM and E-TRC tests. The figure below provides an illustration of the costs and benefits evaluated under each test.

Summary of Cost Effectiveness Test Components

	Participant	Total Resource Cost	Rate Impact Measure
Benefits	Bill Savings	Avoided Generation	Avoided Generation
	Incentives	Avoided Distribution	Avoided Distribution
	Tax Credits	Net System Fuel	Net System Fuel
Costs	Measure Cost	Equipment	Equipment
		Administrative	Administrative
		Measure Cost	Incentives
			Lost Revenues

It should first be noted that the RIM and TRC tests both consider benefits associated with avoiding supply side generation, i.e., construction of power plants, transmission, and distribution. The RIM and TRC tests also consider costs associated with additional supplies and costs associated with the utilities cost to offer the program. While some similarities exist between the two tests, it is the differences that are significant in determining which one, if not both, complies with Section 366.82(3)(b), F.S., and should be used to establish goals. The table below focuses on the differences in costs between the two tests.

Difference Between RIM and TRC Tests

	Total Resource Cost	Rate Impact Measure
Costs	Measure Cost	Incentives
		Lost Revenues

As illustrated above, the RIM Test considers utility offered incentives which are specifically required in Section 366.82(3)(b), F.S. Utility offered incentives are recovered through the Energy Conservation Cost Recovery clause and are a cost borne by all ratepayers. Therefore, a customer participating in a program, which is incentivized by the utility, receives a benefit; however, the incentive paid by the utility results in a cost to the general body of ratepayers. The TRC Test does not consider costs associated with utility incentives.

The TRC Test, as described in Rule 25-17.008, F.A.C., measures the net costs of a conservation program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The consideration of costs incurred by the participant is specifically required by Section 366.82(3)(b), F.S. Because the TRC Test excludes lost revenues, a measure that is cost-effective under the TRC Test would be less revenue intensive than a utility's next planned supply-side resource addition. However, the rate impact may be greater due to the reduced sales.

When establishing conservation goals, Section 366.82(3)(d), F.S., requires us to consider the costs imposed by state and federal regulations on the emission of greenhouse gases. The statute does not define "greenhouse gases," nor requires us to consider projected costs that may be imposed. However, in considering this requirement, the utilities viewed CO₂ as one of the generally accepted greenhouse gases close to being regulated. Other regulated gases, such as sulfur dioxide (SO_x) and nitrous oxides (NO_x), are already regulated by federal statute and the costs are included in the standard RIM and TRC tests. Each utility's calculation of a measure's cost-effectiveness employed modified versions of the RIM and the TRC tests that added a cost impact of CO₂ to the calculations. The revised tests are referred to as the E-RIM and E-TRC Tests. The utilities used different sources to establish the cost of CO₂ emissions, thereby employing different values in their cost-effectiveness testing. Therefore, FPL's goals could not be determined using TECO's estimated CO₂ costs.

Conclusion

While all parties agreed that the Participants Test is required by Section 366.82(3)(a), F.S., the same consensus does not exist when determining the appropriate test or tests for Section 366.82(3)(b) and (d), F.S. The seven FEECA utilities believe that the E-RIM Test satisfies the requirements of the statute while NRDC/SACE and FSC believe the E-TRC Test satisfies the requirements. We would note that the language added in 2008 did not explicitly identify a particular test that must be used to set goals. Based on the analysis above, we find that consideration of both the RIM and TRC tests is necessary to fulfill the requirements of Section 366.82(3)(b), F.S. Both the RIM and the TRC Tests address costs and benefits beyond those associated solely with the program participant. By having RIM and TRC results, we can evaluate the most cost-effective way to balance the goals of deferring capacity and capturing energy savings while minimizing rate impacts to all customers. The "enhanced" versions of the RIM and TRC tests, referenced as E-RIM and E-TRC, are identical to the RIM and TRC tests, but include an estimate of avoided carbon compliance costs. As such, E-RIM and E-TRC portfolios will have greater savings than RIM or TRC portfolios respectively.

COMMISSION APPROVED GOALS

The goals proposed by each utility rely upon the E-RIM Test. Our intention is to approve conservation goals for each utility that are more robust than what each utility proposed. Therefore, we approve goals based on the unconstrained E-TRC Test for FPL, PEF, TECO, Gulf, and FPUC. The unconstrained E-TRC test is cost effective, from a system basis, and does not limit the amount of energy efficiency based on resource reliability needs. The E-TRC test

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includes cost estimates for future greenhouse gas emissions, but does not include utility lost revenues or customer incentive payments. As such, the E-TRC values are higher than the utility proposed E-RIM values. In addition, we have included the saving estimates for the residential portion of the top ten measures that were shown to have a payback period of two years or less in the numeric goals for FPL, PEF, TECO, and Gulf. When submitting their programs for our approval, the utilities can consider the residential portion of the top ten measures, but they shall not be limited to those specific measures.

OUC and JEA proposed goals of zero, yet committed to continue their current DSM program offerings. We are setting goals for OUC and JEA based on their current programs so as not to unduly increase rates. The annual numeric goals for each utility are shown below:

Commission-Approved Conservation Goals for FPL

Residential									
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	25.2	42.5	67.7	20.9	12.3	33.2	29.1	90.5	119.6
2011	37.2	42.5	79.7	30.1	12.3	42.4	55.3	90.5	145.8
2012	47.7	42.5	90.2	38.0	12.3	50.3	78.3	90.5	168.8
2013	56.0	42.5	98.5	44.0	12.3	56.3	96.2	90.5	186.7
2014	61.8	42.5	104.3	47.9	12.3	60.2	109.5	90.5	200.0
2015	58.2	42.5	100.7	43.6	12.3	55.9	102.5	90.5	193.0
2016	53.4	42.5	95.9	39.0	12.3	51.3	92.9	90.5	183.4
2017	48.9	42.5	91.4	34.7	12.3	47.0	83.7	90.5	174.2
2018	44.9	42.5	87.4	30.9	12.3	43.2	75.9	90.5	166.4
2019	40.8	42.5	83.3	27.1	12.3	39.4	67.0	90.5	157.5
Total	474.0	425.0	899.0	356.0	123.0	479.0	790.3	905.0	1,695.3

Commercial/Industrial									
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	42.7	0.0	42.7	8.1	0.0	8.1	84.7	0.0	84.7
2011	62.5	0.0	62.5	9.9	0.0	9.9	149.4	0.0	149.4
2012	76.3	0.0	76.3	11.6	0.0	11.6	191.5	0.0	191.5
2013	81.3	0.0	81.3	13.1	0.0	13.1	202.7	0.0	202.7
2014	79.3	0.0	79.3	14.4	0.0	14.4	194.1	0.0	194.1
2015	71.5	0.0	71.5	15.1	0.0	15.1	167.5	0.0	167.5
2016	60.0	0.0	60.0	15.0	0.0	15.0	134.2	0.0	134.2
2017	48.7	0.0	48.7	14.1	0.0	14.1	104.8	0.0	104.8
2018	41.3	0.0	41.3	13.2	0.0	13.2	86.9	0.0	86.9
2019	35.0	0.0	35.0	12.0	0.0	12.0	71.0	0.0	71.0
Total	598.7	0.0	598.7	126.3	0.0	126.3	1,386.7	0.0	1,386.7

Commission-Approved Conservation Goals for PEF

Year	Residential								
	Summer (MW)			Winter (MW)			Annual (GWh)		
	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	40.6	43.9	84.5	63.7	19.0	82.7	99.6	190.3	289.9
2011	42.5	43.9	86.4	69.2	19.0	88.2	105.6	190.3	295.9
2012	45.5	43.9	89.4	73.2	19.0	92.2	114.7	190.3	305.0
2013	47.5	43.9	91.4	75.9	19.0	94.9	120.7	190.3	311.0
2014	49.4	43.9	93.3	78.6	19.0	97.6	126.8	190.3	317.1
2015	54.8	43.9	98.7	83.3	19.0	102.3	147.9	190.3	338.2
2016	63.3	43.9	107.2	94.1	19.0	113.1	135.8	190.3	326.1
2017	62.9	43.9	106.8	93.5	19.0	112.5	129.8	190.3	320.1
2018	57.4	43.9	101.3	86.0	19.0	105.0	117.7	190.3	308.0
2019	42.9	43.9	86.8	61.5	19.0	80.5	108.6	190.3	298.9
Total	506.6	439.0	945.6	779.1	190.0	969.1	1,207.1	1,903.0	3,110.1

Year	Commercial/Industrial								
	Summer (MW)			Winter (MW)			Annual (GWh)		
	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	13.7	0.0	13.7	5.3	0.0	5.3	31.1	0.0	31.1
2011	16.2	0.0	16.2	5.3	0.0	5.3	33.0	0.0	33.0
2012	25.5	0.0	25.5	11.4	0.0	11.4	35.9	0.0	35.9
2013	25.9	0.0	25.9	11.5	0.0	11.5	37.7	0.0	37.7
2014	26.4	0.0	26.4	11.5	0.0	11.5	39.6	0.0	39.6
2015	27.6	0.0	27.6	11.7	0.0	11.7	46.2	0.0	46.2
2016	27.1	0.0	27.1	11.6	0.0	11.6	42.5	0.0	42.5
2017	27.0	0.0	27.0	11.6	0.0	11.6	40.6	0.0	40.6
2018	25.7	0.0	25.7	11.4	0.0	11.4	36.8	0.0	36.8
2019	22.3	0.0	22.3	11.3	0.0	11.3	34.0	0.0	34.0
Total	237.3	0.0	237.3	102.6	0.0	102.6	377.4	0.0	377.4

Commission-Approved Conservation Goals for TECO

Year	Residential								
	Summer (MW)			Winter (MW)			Annual (GWh)		
	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	2.7	1.9	4.6	2.8	3.6	6.4	4.8	5.0	9.8
2011	4.7	1.9	6.6	4.9	3.6	8.5	9.0	5.0	14.0
2012	6.5	1.9	8.4	6.6	3.6	10.2	12.7	5.0	17.7
2013	8.0	1.9	9.9	7.9	3.6	11.5	15.6	5.0	20.6
2014	8.9	1.9	10.8	8.6	3.6	12.2	17.6	5.0	22.6
2015	9.0	1.9	10.9	8.0	3.6	11.6	18.0	5.0	23.0
2016	7.9	1.9	9.8	6.5	3.6	10.1	16.3	5.0	21.3
2017	7.1	1.9	9.0	5.2	3.6	8.8	14.4	5.0	19.4
2018	6.4	1.9	8.3	4.4	3.6	8.0	13.3	5.0	18.3
2019	5.9	1.9	7.8	3.8	3.6	7.4	12.3	5.0	17.3
Total	67.1	19.0	86.1	58.7	36.0	94.7	134.0	50.0	184.0

Year	Commercial/Industrial								
	Summer (MW)			Winter (MW)			Annual (GWh)		
	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	2.5	0.0	2.5	0.9	0.0	0.9	6.5	0.0	6.5
2011	3.6	0.0	3.6	1.1	0.0	1.1	10.6	0.0	10.6
2012	4.3	0.0	4.3	1.4	0.0	1.4	15.4	0.0	15.4
2013	5.1	0.0	5.1	1.3	0.0	1.3	16.2	0.0	16.2
2014	5.4	0.0	5.4	1.5	0.0	1.5	19.5	0.0	19.5
2015	6.0	0.0	6.0	1.7	0.0	1.7	20.9	0.0	20.9
2016	6.2	0.0	6.2	1.6	0.0	1.6	21.6	0.0	21.6
2017	6.3	0.0	6.3	1.6	0.0	1.6	21.8	0.0	21.8
2018	6.4	0.0	6.4	1.7	0.0	1.7	22.1	0.0	22.1
2019	6.3	0.0	6.3	1.7	0.0	1.7	21.7	0.0	21.7
Total	52.1	0.0	52.1	14.5	0.0	14.5	176.3	0.0	176.3

Commission-Approved Conservation Goals for Gulf

Year	Residential								
	Summer (MW)			Winter (MW)			Annual (GWh)		
	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	1.90	5.60	7.50	1.90	4.00	5.90	2.8	32.20	35.00
2011	2.70	5.60	8.30	2.50	4.00	6.50	5.4	32.20	37.60
2012	3.80	5.60	9.40	3.40	4.00	7.40	8.4	32.20	40.60
2013	4.90	5.60	10.50	4.50	4.00	8.50	11.6	32.20	43.80
2014	6.10	5.60	11.70	5.50	4.00	9.50	14.6	32.20	46.80
2015	7.20	5.60	12.80	6.90	4.00	10.90	18.0	32.20	50.20
2016	8.40	5.60	14.00	8.10	4.00	12.10	21.4	32.20	53.60
2017	9.10	5.60	14.70	8.70	4.00	12.70	23.2	32.20	55.40
2018	9.30	5.60	14.90	9.30	4.00	13.30	24.0	32.20	56.20
2019	9.50	5.60	15.10	9.70	4.00	13.70	24.5	32.20	56.70
Total	62.90	56.00	118.90	60.50	40.00	100.50	153.9	322.00	475.90

Year	Commercial/Industrial								
	Summer (MW)			Winter (MW)			Annual (GWh)		
	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	1.20	0.00	1.20	0.50	0.00	0.50	3.20	0.00	3.20
2011	1.60	0.00	1.60	0.60	0.00	0.60	5.60	0.00	5.60
2012	2.10	0.00	2.10	0.80	0.00	0.80	7.70	0.00	7.70
2013	2.40	0.00	2.40	0.90	0.00	0.90	9.50	0.00	9.50
2014	2.70	0.00	2.70	1.00	0.00	1.00	10.80	0.00	10.80
2015	2.90	0.00	2.90	1.00	0.00	1.00	11.70	0.00	11.70
2016	3.00	0.00	3.00	1.20	0.00	1.20	12.30	0.00	12.30
2017	3.20	0.00	3.20	1.10	0.00	1.10	12.70	0.00	12.70
2018	3.10	0.00	3.10	1.10	0.00	1.10	12.50	0.00	12.50
2019	3.10	0.00	3.10	1.10	0.00	1.10	11.90	0.00	11.90
Total	25.30	0.00	25.30	9.30	0.00	9.30	97.90	0.00	97.90

Commission-Approved Conservation Goals for FPUC

Residential									
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2011	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2012	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2013	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2014	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2015	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2016	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2017	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2018	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
2019	0.2	N/A	0.2	0.1	N/A	0.1	0.5	N/A	0.5
Total	2.0	N/A	2.0	1.3	N/A	1.3	5.1	N/A	5.1

Commercial/Industrial									
	Summer (MW)			Winter (MW)			Annual (GWh)		
Year	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal	E-TRC	Residential <2-Yr. Payback	Commission Approved Goal
2010	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2011	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2012	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2013	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2014	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2015	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2016	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2017	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2018	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
2019	0.2	N/A	0.2	0.1	N/A	0.1	0.8	N/A	0.8
Total	2.3	N/A	2.3	0.6	N/A	0.6	7.8	N/A	7.8

Commission-Approved Conservation Goals for OUC

Year	Residential			Commercial/Industrial		
	Summer (MW)	Winter (MW)	Annual (GWh)	Summer (MW)	Winter (MW)	Annual (GWh)
2010	0.50	0.20	1.80	0.70	0.70	1.80
2011	0.50	0.20	1.80	0.70	0.70	1.80
2012	0.50	0.20	1.80	0.70	0.70	1.80
2013	0.50	0.20	1.80	0.70	0.70	1.80
2014	0.50	0.20	1.80	0.70	0.70	1.80
2015	0.50	0.20	1.80	0.70	0.70	1.80
2016	0.50	0.20	1.80	0.70	0.70	1.80
2017	0.50	0.20	1.80	0.70	0.70	1.80
2018	0.50	0.20	1.80	0.70	0.70	1.80
2019	0.50	0.20	1.80	0.70	0.70	1.80
Total	5.00	2.00	18.00	7.00	7.00	18.00

Commission-Approved Conservation Goals for JEA

Year	Residential			Commercial/Industrial		
	Summer (MW)	Winter (MW)	Annual (GWh)	Summer (MW)	Winter (MW)	Annual (GWh)
2010	2.0	1.6	6.9	2.4	1.4	22.1
2011	2.0	1.6	6.9	2.4	1.4	22.1
2012	2.0	1.6	6.9	2.4	1.4	22.1
2013	2.0	1.6	6.9	2.4	1.4	22.1
2014	2.0	1.6	6.9	2.4	1.4	22.1
2015	2.0	1.6	6.9	2.4	1.4	22.1
2016	2.0	1.6	6.9	2.4	1.4	22.1
2017	2.0	1.6	6.9	2.4	1.4	22.1
2018	2.0	1.6	6.9	2.4	1.4	22.1
2019	2.0	1.6	6.9	2.4	1.4	22.1
Total	20.3	15.5	69.0	24.0	14.3	221.0

INCENTIVES

FPL, PEF, TECO, and Gulf took the position that incentives do not need to be established at this time, but rather should be evaluated and established, if necessary, through a separate proceeding. FPUC argued that utility-owned energy efficiency and renewable energy systems are supply-side issues that are not applicable to it as a non-generating utility. Both OUC and JEA argued that, because municipal utilities are not subject to rate-of-return regulation, the issue

of incentives is not relevant to them. According to FIPUG, the type and amount of incentives and their impact on rates should determine whether incentives are established. FIPUG provided no additional comments on the issue of incentives for utilities in its brief or direct testimony. FSC argued that incentives should be established but offered no supporting comments in its brief and did not file testimony. While NRDC/SACE argued that we should establish an incentive that will allow utilities an opportunity to share in the net benefits that cost-effective efficiency programs provide customers, it agreed with the FEECA utilities that the issue of financial incentives should be deferred to a subsequent proceeding, with the caveat that incentives are only appropriate if linked to the achievement of strong goals.

Section 366.82(3)(c), F.S., requires this Commission to consider whether incentives are needed to promote both customer-owned and utility-owned energy efficiency and demand-side renewable energy systems. In addition, Section 366.82(9), F.S., authorizes this Commission to allow an investor-owned electric utility an additional return on equity of up to 50 basis points for exceeding 20 percent of its annual load-growth through energy efficiency and conservation measures. The statute further states that this Commission shall establish such additional return on equity through a limited proceeding. This provision clearly allows us to award an incentive based upon a utility's performance and specifies the procedural mechanism for doing so.

None of the parties favored establishing incentives as part of this proceeding, with the exception of FSC, who filed no supporting comments and did not file testimony. In addition, staff witness Spellman recommended that if we believe that at some point incentives are necessary and appropriate, then the specific mechanism can be developed, in accordance with the FEECA statutes, in a separate proceeding, but not at this time. There is limited discussion in the record regarding the need for performance incentives or penalties, or analysis of how they should be structured. We agree with witness Spellman that a more appropriate course of action is to address the issue of incentives in a future proceeding when the necessary analysis has been done and all interested stakeholders can participate.

Section 366.82(8), F.S., states:

The commission may authorize financial rewards for those utilities over which it has rate setting authority that exceed their goals and may authorize financial penalties for those utilities that fail to meet their goals, including, but not limited to, the sharing of generation, transmission, and distribution cost savings associated with conservation, energy efficiency, and demand-side renewable energy systems additions.

An IOU may choose to petition this Commission for an additional return on equity based upon its performance at any time the company believes such an incentive to be warranted. This Commission, on its own motion, may initiate a proceeding to penalize a utility for failing to meet its goals.

We believe establishing incentives during this proceeding would unnecessarily increase costs to ratepayers at a time when consumers are already facing financial challenges. Increasing rates in order to provide incentives to utilities is more appropriately addressed in a future proceeding after utilities have demonstrated and we have evaluated their performance.

With regard to customer-owned energy-efficiency and demand-side renewable energy systems, incentives are typically provided through each DSM program. Our staff evaluates each program proposed by a utility prior to making a recommendation as to whether it should be approved. Part of our staff's evaluation process includes an analysis of the cost-effectiveness tests performed by the utility, including the appropriateness of any incentives the utility proposes to offer to customers taking advantage of a particular program as well as the cost and benefits to all customers. Therefore, in our view, a mechanism for providing customers with incentives is already in place and we should continue to make decisions about customer incentives on an individual program basis. We find that it is not necessary to establish additional incentives for customers at this time as doing so would result in higher rates for all customers.

Conclusion

We find that incentives to promote energy efficiency and demand-side renewable energy systems should not be established at this time. We have met the requirements of Section 366.82(3)(c), F.S., by considering, during this proceeding, whether incentives are needed to promote energy efficiency and demand-side renewable energy systems. We will be in a better position to determine whether incentives are needed after we review the utilities' progress in reaching the goals established in these dockets. We may establish, through a limited proceeding, a financial reward or penalty for a rate-regulated utility based upon the utility's performance in accordance with Section 366.82(8) and (9), F.S. Utility customers are already eligible to receive incentives through existing DSM programs, and should not be harmed by considering additional incentives in a separate proceeding.

CONSIDERATION TO IMPACT ON RATES

The four generating IOUs agreed that the impact on rates should be considered in the goal setting process. FPUC, JEA, and OUC believed that we must continue to consider the impact on rates as a primary determinant in setting goals under FEECA.

FIPUG claimed that it is important that rate impact not be overlooked when conservation goals are set and programs are evaluated. FSC believed there are also other factors to be considered by us when setting conservation goals for the public utilities.

NRDC/SACE contended that consideration of the impact on rates does not belong in the goal setting process because of the 2008 FEECA amendments. Further, NRDC/SACE contended that customers are more interested in their monthly utility bills than in rates and would benefit most if energy efficiency programs are widely available.

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As specified in Section 366.01, F.S., the regulation of public utilities is declared to be in the public interest. Chapter 366 is to be liberally construed for the protection of the public welfare. Several sections within the Chapter, specifically Sections 366.03, 366.041, and 366.05, F.S., refer to the powers of the Commission and setting rates that are fair, just, and reasonable. The 2008 legislative changes to FEECA did not change our responsibility to set such rates.

Under FEECA, we are charged with setting goals and approving plans related to the promotion of cost-effective demand-side renewable energy systems and the conservation of electric energy. The 2008 changes to FEECA specified that this Commission is to take into consideration the costs and benefits of ratepayers as a whole, in addition to the cost and benefits to customers participating in a measure. FEECA makes it clear that we must consider the economic impact to all, both participants and non-participants. This can only be done by ensuring rates to all are fair, just, and reasonable.

When setting conservation goals there are two basic components to a rate impact: Energy Conservation Cost Recovery and base rates. The costs to implement a DSM Program consist of administrative, equipment, and incentive payments to the participants. These costs are recovered by the utility through the Energy Conservation Cost Recovery clause. Cost recovery is reviewed on an annual basis when true-up numbers are confirmed. When approved, the utility allocates that expense to its general body of ratepayers and rates immediately go up for all ratepayers until that cost is recovered. When new DSM programs are implemented or incentive payments to participants are increased, the cost of implementing the program will directly lead to an increase in rates as these costs are recovered.

Base rates are established by this Commission in a rate case. Between rate cases, we monitor the company's Return on Equity (ROE) within a range of reasonable return, usually + or - 1 percent or 100 basis points. If the ROE of a utility exceeds the 100 basis point range, we can initiate a rate case to adjust rates downward. If the ROE falls below the 100 basis point range, the utility may file a petition with this Commission for a rate increase.

Energy saving DSM programs can have an impact on a utility's base rates. Utilities have a fixed cost of providing safe, reliable service. When revenues go down because fewer kWh were consumed, the utility may have to make up the difference by requesting an increase in rates in order to maintain a reasonable ROE.

The downturn of the present economy, coupled with soaring unemployment, make rates and the monthly utility bill ever more important to utility customers. When speaking about customers who participate in a utility program and receive an incentive, FPL witness Dean testified that utility customers generally will use less energy and even though rates are higher for everyone, program participants purchase less energy and thus are net beneficiaries of the program because their lower consumption lowers their total bill. Witness Dean further testified that these costs disproportionately fall upon those who are unable to participate in programs. Similarly, JEA witness Vento testified that customers such as renters who do not or cannot implement a DSM measure, and therefore have no corresponding benefit of reduced consumption to offset the rate increase, will be subject to increased utility bills.

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Witness Pollock also recognized the importance of conservation in lowering utility bills as all consumers “face challenging economic times.” Witness Pollock testified that the importance of pursuing conservation programs must be balanced against their cost and impact of that cost on ratepayers. Witness Pollock further testified that consideration of rate impacts in the evaluation of conservation programs helps to minimize both rates and costs for ratepayers. Finally, PEF witness Masiello testified that this Commission should also balance the needs of all stakeholders and minimize any adverse impacts to customers.

Conclusion

As provided in Section 366.04, F.S., we are given “. . . jurisdiction to regulate and supervise each public utility with respect to its rates and service.” In past FEECA proceedings, the impact on rates has been a primary consideration of this Commission when establishing conservation goals and approving programs of the public utilities. The 2008 legislative changes to FEECA did not diminish the importance of rate impact when establishing goals for the utilities.

Those who do not or cannot participate in an incentive program will not see their monthly utility bill go down unless they directly decrease their consumption of electricity. If that is not possible, non-participants could actually see an increase in the monthly utility bill. Since participation in DSM programs is voluntary and this Commission is unable to control the amount of electricity each household consumes, we should ensure the lowest possible overall rates to meet the needs of all consumers.

Section 366.82(7), F.S., states that this Commission can modify plans and programs if they would have an undue impact on the costs passed on to customers. We believe that the Legislature intended for this Commission to be conscious of the impact on rates of any programs we evaluate to meet goals.

SEPARATE GOALS FOR DEMAND-SIDE RENEWABLE ENERGY SYSTEMS

All seven FEECA utilities took the position that we should not establish separate goals for demand-side renewable energy systems. FPL believed that the FEECA amendments, in particular, Section 366.82(3), F.S., “. . . require this Commission to consider renewable energy systems in the conservation goal setting process.” FPL contended that this statutory requirement was met because ITRON and FPL evaluated these resources in this goal setting process. FPL, PEF, TECO, and Gulf contended that demand-side renewable resources were evaluated as a part of the conservation goals analysis and these measures were not found to be cost-effective; therefore, a separate goal is not necessary. Gulf asserted that demand-side renewables should be evaluated with the same methodology that is used to evaluate energy efficiency measures. PEF currently offers demand-side renewable programs and is developing new initiatives. FPL noted that it will consider demand-side renewable measures in the program development stage. Gulf is currently evaluating a pilot solar thermal water heating program.

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FPUC, OUC, and JEA contended that, in setting goals, there should not be a bias toward any particular resource. Otherwise, FPUC, OUC, and JEA stated that goals could be set without appropriate consideration of costs and benefits to the participants and customers as a whole as required by Section 366.82(a) and (b), F.S. In addition, JEA and OUC argued that as municipal utilities, they cannot recover costs for demand-side renewable programs through the Energy Conservation Cost Recovery clause. JEA and OUC also noted that both companies offer demand-side renewable programs.

FSC contended that Section 366.82, F.S., requires this Commission to establish separate goals for demand-side renewables. FSC recommended that to meet this statutory obligation, we should require the FEECA IOUs to offer solar PV and solar water heating rebate programs to both residential and commercial customers. Further, FSC stated that we should authorize each IOU to recover up to 1 percent of annual retail sales revenue (based on 2008 revenues) to fund rebates for the next five years. FSC suggested a rebate of \$2 per watt for PV systems with a capacity up to 50 kW. FSC contended that we should establish a performance-based incentive program for PV systems with a capacity greater than 50 kW. FSC recommended that incentives be reduced over the five years to account for market development and any resulting reduction in PV prices. FSC did not take a position with respect to OUC and JEA, which each currently have programs to encourage customers to install solar resources.

Section 366.82(2), F.S., was amended in 2008. The entire text of Section 366.82(2), F.S., follows, with the amendments underlined.

The Commission shall adopt appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems, specifically including goals designed to increase the conservation of expensive resources, such as petroleum fuels, to reduce and control the growth rates of electric consumption, to reduce the growth rates of weather-sensitive peak demand, and to encourage development of demand-side renewable energy resources. The Commission may allow efficiency investments across generation, transmission, and distribution as well as efficiencies within the user base.

Because of the revisions to the statute, we requested that the utilities address demand-side renewables in their cost-effectiveness analyses. As previously discussed, the first step in the utilities' cost-effectiveness analysis for demand-side renewables was the Technical Potential Study performed by ITRON. Witness Rufo testified that ITRON estimated the technical potential for one residential rooftop PV system, one commercial rooftop PV system, one commercial ground-mounted PV system, and solar domestic hot water heaters. Witness Rufo testified that ITRON did not estimate the achievable potential for PV systems "due to the fact that PV measures did not pass the cost-effectiveness criteria established by the FEECA utilities for purposes of this study, i.e., TRC, RIM, and/or the Participants Test." Witness Rufo further testified that incentive levels were not calculated for solar measures (for JEA and OUC) because these measures did not pass RIM or TRC without incentives.

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FPL, TECO, Gulf, FPUC, OUC, and JEA did not include savings from solar measures toward their goals because no solar measures were found to be cost-effective. However, PEF, OUC, and JEA have existing solar programs. PEF currently offers two solar programs. PEF's Solar Water Heater with EnergyWise program combines a demand-response program with a rebate for solar water heaters. PEF's SolarWise for Schools program allows interested customers to donate their monthly credits from participating in a load control program to support the installation of PV systems in schools. Witness Masiello testified that PEF has also developed new solar initiatives that will possibly be included in PEF's DSM program filing. Witness Masiello further testified that a separate goal for demand-side renewables is not needed because PEF included these resources in its goals.

We believe that the amendments to Section 366.82(2), F.S., clearly require us to set goals to increase the development of demand-side renewable energy systems. As indicated above, the Section states that the "Commission shall adopt appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems. . . ." (Emphasis added) We believe that in making these amendments to Section 366.82(2), F.S., the Legislature has placed additional emphasis on encouraging renewable energy systems. FSC and NRDC/SACE argued that the amendments to 366.82(2), F.S., require goals for these resources. Witness Spellman testified that "the legislation clearly requires the Commission to focus some specific attention on demand-side renewable energy resources as part of its goal setting process."

As discussed above, none of the demand-side renewable resources were found to be cost-effective under any test in the utilities' analyses. In the past, we have set goals equal to zero in cases where no DSM programs were found to be cost-effective, for example, for JEA and OUC. Therefore, based purely on the cost-effectiveness test results, we have the option to set goals equal to zero for demand-side renewable resources. However, we note that by amending FEECA, the Legislature placed added emphasis on demand-side renewable resources. The Legislature has also recently placed emphasis on these resources by funding solar rebates through the Florida Energy and Climate Commission.

In its brief, FSC recommended that we should require the four largest IOUs to spend a specified annual amount on solar PV and solar thermal water heating programs. NRDC/SACE agreed with FSC's position. FSC suggested that solar water heaters and PV systems under 50 kW in capacity should receive an up-front rebate, while financial support to larger PV systems up to 2 MW should be performance-based. FSC recommended a rebate of \$2 per watt for residential and commercial PV systems up to 50 kW in capacity. FSC suggested that annual support should continue for five years, and decrease every year to account for market development and reductions in technology costs. FSC took no position on requiring programs for FPUC, JEA, and OUC.

Witness Spellman acknowledged that none of the solar PV and solar thermal technologies included in the ITRON study and utility cost-effectiveness analyses were found to be cost-effective. However, witness Spellman testified that research and development programs on these technologies will provide benefits "because of their potential for more efficient energy

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production, the environmental benefits, and the conservation of non-renewable petroleum fuels.” Witness Spellman believed that support for these technologies could result in lower costs over time. He also recommended that OUC and JEA be required to offer demand-side renewable programs, but recognized that we do not have ratemaking authority over these utilities. In order to protect the IOUs’ ratepayers, utilities would be allowed to recover a specified amount of expenses through the Energy Conservation Cost Recovery clause. Witness Spellman did not advocate specific demand or energy savings goals for demand-side renewables. Witness Spellman suggested that these programs should focus on solar PV and solar water heating technologies, and did not believe that the demand and energy savings resulting from these programs should be counted toward a utility’s conservation goals.

Witness Spellman recommended that expenditures on these solar programs should be capped at 10 percent of each IOU’s five-year average of Energy Conservation Cost Recovery expenses for 2004 through 2008. These dollar amounts should be constant over the five year period until goals are reset. Witness Spellman recommended that the funds be used for up-front rebates on solar PV and solar water heating technologies for both residential and commercial customers.

Conclusion

We find that the amendments to Section 366.82(2), F.S., require us to establish goals for demand-side renewable energy systems. None of these resources were found to be cost-effective in the utilities’ analyses. However, we can meet the intent of the Legislature to place added emphasis on these resources, while protecting ratepayers from undue rate increases by requiring the IOUs to offer renewable programs subject to an expenditure cap. We direct the IOUs to file pilot programs focusing on encouraging solar water heating and solar PV technologies in the DSM program approval proceeding. Expenditures allowed for recovery shall be limited to 10 percent of the average annual recovery through the Energy Conservation Cost Recovery clause in the previous five years as shown in the table below. Utilities are encouraged to design programs that take advantage of unique cost-saving opportunities, such as combining measures in a single program, or providing interested customers with the option to provide voluntary support.

Utility	Commission Approved Annual Expense
FPL	\$15,536,870
Gulf	\$900,338
PEF	\$6,467,592
TECO	\$1,531,018
FPUC	\$47,233
Total	\$24,483,051

ADDITIONAL GOALS FOR EFFICIENCY IMPROVEMENTS IN GENERATION,
TRANSMISSION, AND DISTRIBUTION

We agree with FPL, PEF, TECO, and Gulf that goals need not be established for generation, transmission, and distribution in this proceeding. Gulf expanded the discussion arguing that guidelines have not been developed that would provide a methodical approach to identifying, quantifying, and proposing goals for supply-side conservation and energy efficiency measures. OUC and JEA both offered only that efficiency improvements in generation, transmission, and distribution are supply-side issues which are more appropriately addressed in the utilities' resource planning processes, thereby seeming to imply that such goal-setting has no place in a conservation goal-setting proceeding. FPUC, a non-generating IOU, took no position.

FSC's position suggested that the IOUs should conduct technical potential studies of efficiencies in generation, transmission, and distribution. Afterwards, this Commission should establish efficiency improvement goals in a separate proceeding. FSC took no position on the issue as it pertains to the two municipal utilities.

NRDC/SACE went a step further, arguing that increasing generating plant efficiency and reducing transmission and distribution losses benefit customers and the environment. They recommended that we set a date certain by which the companies will perform technical economic and potential studies for efficiency improvements at their existing facilities. However, they did not specifically suggest that we should set goals in these areas.

State legislative direction provides, "[t]he commission may allow efficiency investments across generation, transmission, and distribution" (Section 366.82(2), F.S.) Section 366.82(3), is more affirmative stating: "[i]n developing the goals, the commission shall evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures" (Emphasis added) The FEECA utilities performed no technical

potential study of supply-side measures for this docket. The potential for supply-side improvements is an inherent element of the annual Ten-Year Site Plan submitted by each FEECA utility. Supply-side efficiency and conservation is also analyzed in every need determination for new sources of generation. In addition, efficiency improvements in generation, transmission, and distribution tend to reduce the potential savings available via demand-side management programs.

We believe that the utilities' motivation to deliver electric service to their customers in the most economically efficient means possible makes efficiency improvements in generation, transmission, and distribution a naturally occurring result of their operations. In the case of the five IOUs, such efficiency is inextricably tied to their efforts to make a profit. The two municipal utilities, while not driven by a profit motive per se, must still provide electrical service as efficiently and inexpensively as possible. Rule 25-17.001, F.A.C., supports this proposition because the rule states: ". . . general goals and methods for increasing the overall efficiency of the bulk electric power system of Florida are broadly stated since these methods are an ongoing part of the practice of every well-managed electric utility's programs and shall be continued."

Despite NRDC/SACE's observation that customers and the environment will benefit from facility efficiencies, they offer no evidence that utilities are not routinely seeking those efficiencies. FSC, in arguing that we should set goals in this area, likewise offers no support to suggest such action is warranted.

Conclusion

Efficiency improvements for generation, transmission, and distribution are continually reviewed through the utilities' planning processes in an attempt to reduce the cost of providing electrical service to their customers. With no evidence to suggest efficiency improvements in generation, transmission, and distribution are not occurring, we find that goals in these areas will not be set as part of this proceeding.

SEPARATE GOALS FOR ENERGY AUDIT PROGRAMS

The FEECA utilities, FIPUG, and FSC all agreed that separate goals for energy audits are not necessary. NRDC/SACE asserted that separate goals for residential and commercial/industrial customer participation in utility energy audit programs should be established by this Commission.

Section 366.82(11), F.S., mandates that we require utilities to offer energy audits and to report the actual results as well as the difference, if any, between the actual and projected results. The statute is implemented by Rule 25-17.003, F.A.C., which specifies the minimum requirements for performing energy audits as well as the types of audits that utilities offer to customers, and also details the requirements for record keeping regarding the customer's energy use prior to and following the audit. The utility can thereby ascertain whether the customer actually reduced his energy usage subsequent to the audit.

Witness Steinhurst testified that utility energy audit programs by themselves do not provide any direct demand reduction and energy savings. In order to conserve energy, the customer must implement some form of an energy saving measure. Witness Masiello testified that most if not all utilities require that an audit be performed before a customer can participate in DSM programs administered by the utility. This requirement means that having separate goals for audits would be duplicative, because the energy savings and demand reduction following the audits would be attributed to the individual measures that were recommended and implemented as a result of the audit, and therefore would already be counted towards savings goals. Witness Spellman testified that savings associated with energy saving measures installed by customers following a utility audit should be counted towards the savings of the particular program through which they obtained the measure and not the energy audit service. Witness Bryant testified that this is the method typically used to account for these savings.

Conclusion

The energy conservation achieved through customer education is included in the overall conservation goals and should be credited to the specific program into which the customer enrolls. In order to avoid duplication of demand reduction and energy savings, we find that no separate goals for participation in utility energy audit programs need be established.

EFFICIENT USE OF COGENERATION

FPL, PEF, Gulf, and TECO argued that no further action is needed concerning cogeneration due to the 2008 Legislative changes that were made to the FEECA statutes. Further, the Commission has addressed cogeneration in Chapter 25-17, F.A.C. FPUC, OUC, and JEA took no position on the issue of cogeneration. NRDC/SACE and FIPUG contended that there are barriers to the cogeneration process due to the unfair compensation rates afforded cogenerators by rule. Other parties were silent on the issue.

The Legislature recognizes the benefits of cogeneration in Section 366.051, F.S., where utility companies are required to purchase all electricity offered for sale by the cogenerator as outlined in Rule 25-17.082, F.A.C. We periodically establish rates for cogeneration equal to the utilities full avoided cost as guidelines for the purchase of energy. Rule 25-17.015, F.A.C., also allows each utility to recover its costs for energy conservation through cost recovery.

The FEECA utilities agree that this Commission need not take action regarding cogeneration in this goal setting proceeding. The 2008 Florida Legislature removed the term "cogeneration" from the FEECA statute, Section 366.82(2), F.S., replacing it with "demand side renewable energy systems." The utilities contend that cogeneration is not to be considered part of the FEECA ten-year goal setting process. The utilities also contend that cogeneration systems must be evaluated on a site-specific, case-by-case basis, which does not lend itself to the FEECA conservation goals-setting process. The FEECA proceedings were commenced to set overall conservation goals for the FEECA utilities, and not designed as proceedings to focus on promoting cogeneration.

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FIPUG believes there are barriers to the cogeneration process established by Commission Rule, which prevent industrial customers from full compensation for electricity generated by their cogeneration processes. FIPUG also believes it is a disadvantage if customers operate facilities at two or more different locations and cannot construct their own transmission lines to those locations. FIPUG contended cogenerator repayment at the utility's average fuel cost is much lower than the utility rate and that the reimbursement rate does not encourage cogeneration. The Legislature addressed the transmission and compensation issue of cogenerators in Section 366.051, F.S. This Commission has established "Conservation and Self-service Wheeling Cost" in Rule 25-17.008 F.A.C., "Energy Conservation Cost Recovery" in Rule 25-17.015 F.A.C., and "The Utility's Obligation to Purchase" in Rule 25-17.082 F.A.C.

Conclusion

The Florida Legislature recognizes cogeneration in Section 366.051, F.S., and in 2008 removed the term "cogeneration" from the FEECA statutes, Section 366.82, F.S. Cogeneration is encouraged by this Commission as a conservation effort, as evidenced by Rules 25-17.080 – 25-17.310, F.A.C. Therefore, the goals set do not need to address issues relating to cogeneration in this proceeding.

COMMISSION AUTHORITY OVER OUC AND JEA

Under FEECA, we have jurisdiction over OUC and JEA's conservation goals and plans. Section 366.81, F.S. (2008), states in pertinent part:

The Legislature . . . finds that the Florida Public Service Commission is the appropriate agency to adopt goals and approve plans The Legislature directs the commission to develop and adopt overall goals and authorizes the commission to require each utility to develop plans and implement programs for increasing energy efficiency and conservation and demand-side renewable energy systems within its service area, subject to the approval of the commission. . . . The Legislature further finds and declares that ss. 366.80-366.85 and 403.519 [FEECA] are to be liberally construed

(Emphasis added)

For purposes of the FEECA statutes, Section 366.82(1)(a), F.S. (2008), defines a utility as being:

"Utility" means any person or entity of whatever form which provides electricity or natural gas at retail to the public, specifically including municipalities or instrumentalities thereof . . . specifically excluding any municipality or instrumentality thereof, . . . providing electricity at retail to the public whose annual sales as of July 1, 1993, to end-use customers is less than 2,000 gigawatt hours.

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(Emphasis added)¹² Section 366.82(2), F.S., provides “[t]he commission shall adopt appropriate goals for increasing the efficiency of energy consumption”

Our statutory jurisdiction to set goals under FEECA is clear. The Legislature has required that we develop, establish, and adopt appropriate conservation goals for all utilities under the jurisdiction of FEECA. According to Section 366.82(1)(a), F.S., both OUC and JEA, as municipal utilities with sales exceeding 2,000 gigawatt hours, fall under our FEECA jurisdiction. Therefore, we must adopt appropriate conservation goals for OUC and JEA pursuant to Section 366.82(2) and (3), F.S.

Furthermore, this Commission has previously addressed whether it is prohibited under FEECA from considering conservation programs, and by correlation, goals that would increase rates for municipal and cooperative electric utilities. In Order No. PSC-93-1305-FOF-EG, issued September 8, 1993, this Commission considered that question and determined that FEECA contains no such prohibition, but this Commission would, as a matter of policy, attempt to set conservation goals that would not result in rate increases for municipal utilities.¹³

We disagree with OUC and JEA’s assertion that, because we lack ratemaking authority over these utilities, we are prohibited from establishing goals that might put upward pressure on rates. Ratemaking for public utilities is governed under Sections 366.06 and 366.07, F.S. Pursuant to Section 366.02(2), F.S., municipal and cooperative electric utilities are specifically excluded from the definition of public utility, and thus, we do not have ratemaking jurisdiction over these utilities. We believe that adopting conservation goals, or approving conservation programs, pursuant to FEECA is not ratemaking within the meaning of Chapter 366, F.S. We believe that the setting of conservation goals under FEECA for municipal electric utilities, therefore, does not infringe upon the municipal electric utilities’ governing boards’ authority to set rates.

At this time, it would be difficult to ascertain what affect, if any, the approved conservation goals would actually have upon OUC and JEA’s rates. Given the multitude of variables which also place upward and downward pressure on rates, we believe that OUC and JEA’s assertions that conservation goals alone would add upward pressure on rates is speculative at best. In the instant case, we believe that the proposed conservation goals for OUC and JEA should not apply upward pressure on the rates of OUC and JEA’s customers, especially

¹² The language of Section 366.82(1)(a), F.S., was amended in 1996 by the Legislature to exclude municipal electrics and Rural Cooperatives with annual sales less than 2,000 gigawatt hours. See s. 81, Ch. 96-321, Laws of Florida.

¹³ See Order No. PSC-93-1305-FOF-EG, issued September 8, 1993, in Docket Nos. 930553-EG, 930554-EG, 930555-EG, 930556-EG, 930557-EG, 930558-EG, 930559-EG, 930560-EG, 930561-EG, 930562-EG, 930563-EG, 930564-EG, In re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111) by City of Gainesville, City of Jacksonville Electric Authority, Kissimmee Electric Authority, City of Lakeland, Ocala Electric Authority, Orlando Utilities Commission, City of Tallahassee, Clay Electric Cooperative, Lee County Electric Cooperative, Sumter Electric Cooperative, Talquin Electric Cooperative, Withlacoochee River Electric Cooperative (hereinafter, 1993 FEECA Municipal DSM Goals Proceedings), at 5.

considering that the approved goals are based upon the conservation programs that OUC and JEA are currently implementing.

With regard to Order No. PSC-95-0461-FOF-EG, issued April 10, 1995, cited by OUC and JEA, the Commission stated:

We believe that as a guiding principle, the RIM test is the appropriate test to rely upon at this time. The RIM test ensures that goals set using this criteria would result in rates lower than they otherwise would be. All the municipal and cooperative utilities, with the exception of Tallahassee, stipulated to cost-effective demand and energy savings under the RIM test. However, Tallahassee's stipulated goals are higher than that cost-effective under RIM. . . . The Commission does not have rate setting authority over municipal and cooperative utilities. Therefore, we find it suitable to allow the governing bodies of these utilities the latitude to stipulate to the goals they deem appropriate regardless of cost-effectiveness.

Id. at 4-5 (Emphasis added) In 1995, this Commission recognized the RIM test as a “guiding principle” for setting goals for municipal and cooperative electric utilities, but the 2008 Legislative changes to FEECA have superseded this “guiding principle” consideration. We are now required to establish goals for all FEECA utilities pursuant to the requirements of Section 366.82(3), F.S., as amended and previously discussed.

Moreover, the order cited by OUC and JEA is distinguishable from the instant case because this Commission did not “set goals” for OUC and JEA but merely approved stipulated goals for these two utilities. The stipulated goals resulted from a settlement between OUC and JEA and the Florida Department of Community Affairs (DCA).¹⁴ Here, the goals being proposed for these utilities are not stipulated goals but are proposed goals following a full evidentiary hearing.

Conclusion

We have the authority to adopt conservation goals for all electric utilities under the jurisdiction of FEECA. OUC and JEA come within the meaning of utility as defined by FEECA. Developing, establishing, and adopting conservation goals is a regulatory activity exclusively granted to this Commission by FEECA and is not ratemaking within the meaning of Chapter 366, F.S. Therefore, we find that we have the authority to develop, establish, and adopt conservation goals for OUC and JEA as required by Section 366.82, F.S.

¹⁴ See Order No. PSC-95-0461-FOF-EG, issued April 10, 1995, In re: 1993 FEECA Municipal DSM Goals Proceedings. The DCA intervened in the 1993 DSM Goals Proceedings on behalf of the Governor of Florida. All the municipal and cooperative electric utilities who were parties to the 1993 DSM Goals Proceedings reached joint stipulations with DCA regarding conservation goals.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Florida Power & Light Company's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Progress Energy Florida, Inc.'s residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Progress Energy Florida, Inc.'s commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Gulf Power Company's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Gulf Power Company's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Tampa Electric Company's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Tampa Electric Company's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Florida Public Utilities Company's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that Florida Public Utilities Company's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that OUC's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that OUC's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that JEA's residential winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that JEA's commercial/industrial winter demand, summer demand, and annual energy conservation goals for the period 2010-2019 are hereby approved as set forth herein. It is further

ORDERED that within 90 days of the issuance of this Order, each utility shall file a demand-side management plan designed to meet the utility's approved goals. It is further

ORDERED that these dockets shall be closed if no appeal is filed within the time period permitted for filing an appeal of this Order.

By ORDER of the Florida Public Service Commission this 30th day of December, 2009.



ANN COLE
Commission Clerk

(SEAL)

KEF

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

Office of Energy Annual Report 2014

Updated February 13, 2015



Florida Department of Agriculture and Consumer Services
Adam H. Putnam, Commissioner



Dear Governor Scott, President Gardiner and Speaker Crisafulli,

I am pleased to provide you with the 2014 Annual Report of the Florida Department of Agriculture and Consumer Services' Office of Energy (FDACS OOE). This report reflects the FDACS OOE activities during 2014 and elaborates on the programs undertaken to help prepare Florida to meet the growing demand for energy in a diverse and sustainable manner.

A few of the highlights for this past year include:

- Florida's Renewable Energy Tax Incentives program provided nearly \$24 million in incentives and produced an estimated economic contribution of more than \$261.9 million with 909 jobs created and raised \$21.7 million in state and local taxes.
- The Natural Gas Fuel Fleet Vehicle Rebate Program provided approximately \$3.8 million in incentives during its first 6 months and produced an investment of \$79.3 million with 382 jobs created or retained as a result of this program.
- Florida's first sales tax holiday weekend on ENERGY STAR and WaterSense products proved a success. This program not only helped customers save an estimated \$1.6 million at the check-out counter, but will also save them energy, water and money on their bills over the long-term. Retailers reported large increases in sales over the previous year and provided positive feedback about the initiative.

I look forward to continue working with you to advance Florida's energy policy and support Florida's businesses, consumers and education infrastructure.

Sincerely,

A handwritten signature in black ink, which appears to read "Adam H. Putnam".

Adam H. Putnam
Commissioner of Agriculture

**FLORIDA DEPARTMENT OF AGRICULTURE
AND CONSUMER SERVICES**

OFFICE OF ENERGY

2014 ANNUAL REPORT

Adam H. Putnam, Commissioner

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1. Executive Summary

The Florida Department of Agriculture and Consumer Services' Office of Energy (FDACS OOE) is the legislatively designated state energy policy and program development office within Florida. The FDACS OOE evaluates energy related studies, analyses and stakeholder input in order to recommend to the Governor and Legislature energy policies and programs that will move Florida toward a more diversified, stable and reliable energy portfolio. Further, FDACS OOE uses available state and federal funds to develop and manage energy efficiency, renewable energy and energy education programs throughout the state.

This report reflects the FDACS OOE activities during 2014 and elaborates on the programs undertaken to help prepare Florida to meet the growing demand for energy in a diverse and sustainable manner. This report is submitted as required in Section 377.703(2)(f), Florida Statutes.

The FDACS OOE worked with Commissioner of Agriculture Adam H. Putnam to introduce energy proposals for consideration by the Legislature in 2014. Those recommendations were designed to help Florida capitalize on energy opportunities, use energy wisely and create jobs. Proposals included reducing energy tax costs for commercial businesses and using remaining tax revenues to provide a sustainable funding source for Florida's education infrastructure, as well as establishing the first ENERGY STAR and WaterSense Sales Tax Holiday in the state. This legislatively approved program helped Floridians not only save money at the check-out counter, but also save energy, water and money on their utility bills over time.

FDACS OOE continued to administer several renewable and alternative energy programs. Those programs included the Florida Renewable Energy Tax Incentives and the Natural Gas Fuel Fleet Vehicle Rebate Programs, both of which encourage the development and use of alternative fuels and create jobs in Florida.

It is important that Florida continue to evaluate its energy policy and update it to reflect changes in the industry, but also to continue to embrace the goals that are long term in nature and provide for a consistent and predictable energy policy that will improve the lives of all Floridians.

2. Florida's Energy Landscape

This chapter summarizes Florida's energy profile; it includes information on fuel diversity, electric generation, electric rates, infrastructure, transportation fuels, renewable fuels and energy efficiency measures. In addition to providing a summary of Florida's energy landscape, this chapter provides an outlook on potential areas of opportunity for the state.

2.1 Florida's Overall Consumption of Energy (Electricity and Transportation Fuel)

Florida is home to approximately 19 million people, and, as of December 2014, it is the third most populous state, according to the U.S. Census. With a population size of this magnitude, addressing Florida's energy needs are a top priority. As it relates to consumption, the United States Department of Energy's Energy Information Administration (US EIA) considered Florida to be the third largest energy-consuming state; however, in terms of per-capita energy consumption, Florida ranks 44th in the nation, consuming 210 million Btu¹s per person.

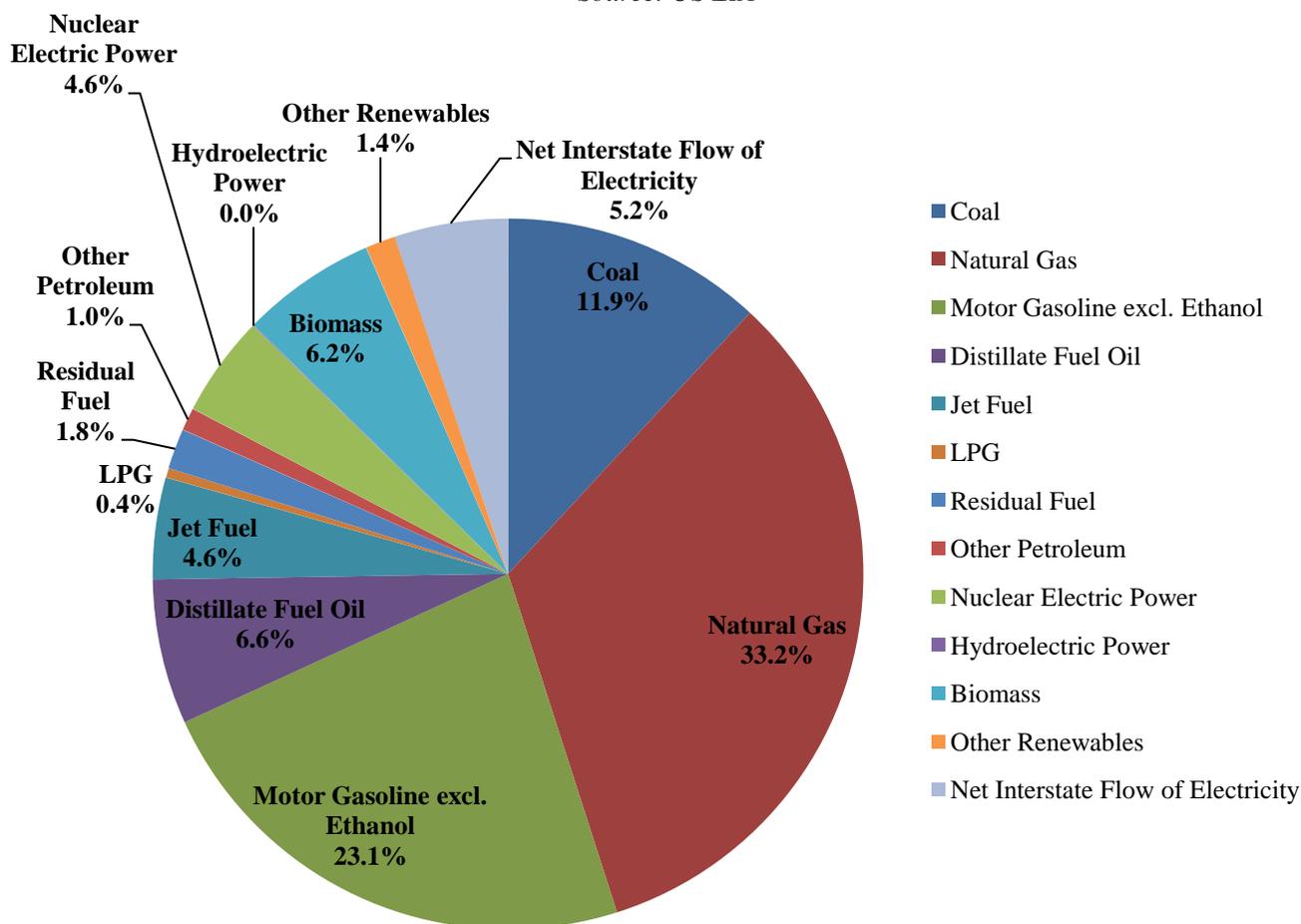
Florida's lower per-capita energy consumption ranking, relative to the national average, is due to below average industrial sector consumption. What drives energy consumption in the state is the transportation and residential sectors. In terms of electric generation and transportation fuel, Florida is heavily reliant on natural gas and petroleum. Florida consumes more energy than it produces, making it a net energy importer of natural gas and petroleum products.

The most recent Florida energy consumption data provided by US EIA is for the year 2012 and is provided in Figure 1. Figure 1 demonstrates the various fuel sources comprising Florida's energy landscape. Natural gas continues to be the dominant fuel source for traditional electricity generation. The figure further demonstrates that Floridians consumed 1,348.4 trillion Btus of natural gas in 2012, or 33.2 percent of its total energy consumption. Floridians also consumed 938.3 trillion Btus of motor gasoline, or 23.1 percent of total energy consumption for all sectors—residential, commercial, industrial, and transportation.

¹ British Thermal Unit (Btu) is a standard unit for measuring a quantity of heat. The unit is used to measure and compare the energy content of fuel.

Figure 1: Florida Energy Consumption Estimates 2012

Source: US EIA



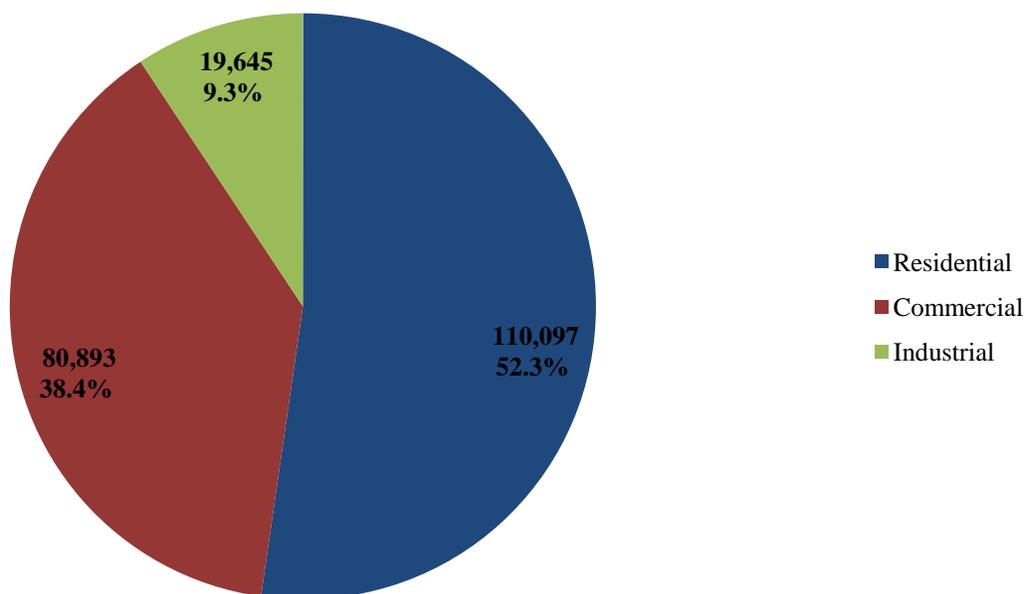
The Florida Public Service Commission (PSC) in its *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities* stated that “natural gas has become the dominant fuel in Florida within the last ten years...and is anticipated to serve future growth until the end of the planning period, when additional nuclear generation comes online.” As of December 31, 2013, the Florida Reliability Coordinating Council (FRCC) reports that Florida’s total electric generating capacity is 62,133 megawatts (MW), and the *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities* discusses the planned addition of approximately 12,570 MW of new utility-owned generation over the next ten years.

Florida receives the majority of its natural gas supplies from the Gulf Coast region, via two interstate pipelines: the Florida Gas Transmission line, and the Gulfstream pipeline. The Florida Gas Transmission line runs from Texas through the Florida Panhandle to Miami, and the Gulfstream pipeline is an underwater link from Mississippi and Alabama to central Florida. The Jacksonville area also receives supplies from the liquefied natural gas (LNG) import terminal at Elba Island, Georgia via the Cypress Pipeline. Florida Power & Light is planning to build a third major pipeline through the center of the state coming from Georgia which would increase natural gas supplies to the state.

Nuclear energy capacity in Florida is projected to increase slightly during the current 2014 ten-year planning period. There are four online nuclear power plants in the state, all of which are owned by Florida Power & Light (FPL). Nuclear energy is capital intensive in nature and requires a significant amount of lead time to construct. FPL is the only Florida electric utility that has a planned addition of two new nuclear units within the next ten years, according to the PSC's *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities*. The two new proposed units, Turkey Point units 6 and 7, have in-service dates scheduled for 2022 and 2023, respectively.

Florida's humid and warm climate leads to an increased demand for energy in order to address the state's cooling needs. In terms of electricity usage, Florida's residential sector consumes the majority of energy generated, as compared with the commercial and industrial sectors. In 2013, Florida's residents consumed 110,097 gigawatt hours (GWh), or 52.3 percent of all electric energy consumed in the state, as demonstrated in Figure 2 below. The PSC stated in its *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities* that Florida has 8,503,879 residential electric customers; comprising 88.7 percent of all electric customers in the state, with the remaining 11.3% made up of commercial and industrial users.

Figure 2: Energy Usage in 2013 (GWh)
Source: PSC 2014 Ten-Year Site Plan Review



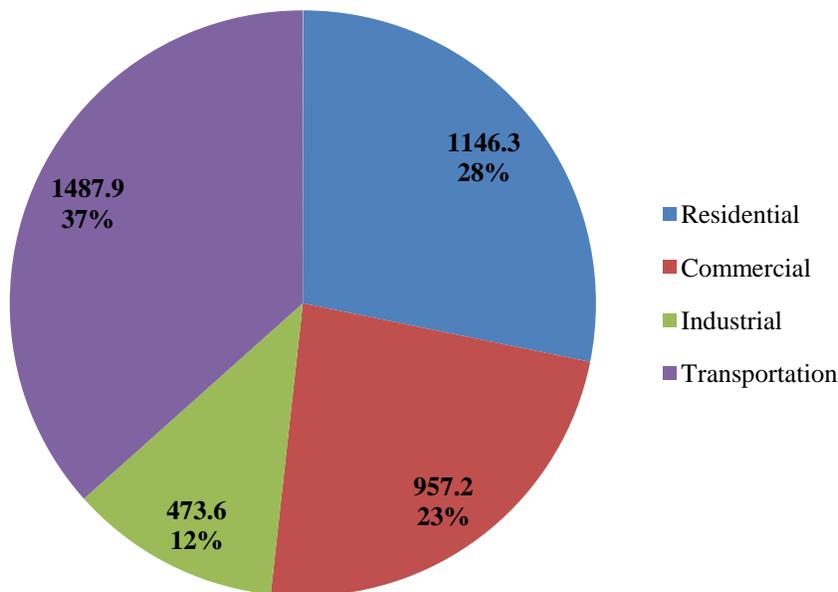
With Florida being the third most populous state, transportation fuel consumption is high relative to the rest of the nation. According to the US EIA, Florida is ranked third in the nation in terms of transportation fuel consumption, using 1,487.9 trillion Btus; this accounts for 5.6 percent of the total United States share of transportation fuel.

Florida has no oil refineries to serve the state's transportation sector and relies on petroleum products delivered by tanker and barge to marine terminals near the state's major coastal cities. Due in part to

Florida’s tourist industry, demand for petroleum-based transportation fuels (motor gasoline and jet fuel) is among the highest in the United States, Figure 3, below, illustrates that the transportation sector accounts for the majority of energy consumed in the state.

Figure 3: Florida 2012 Energy Consumption by End-Use Sector (Trillion Btu)

Source: US EIA

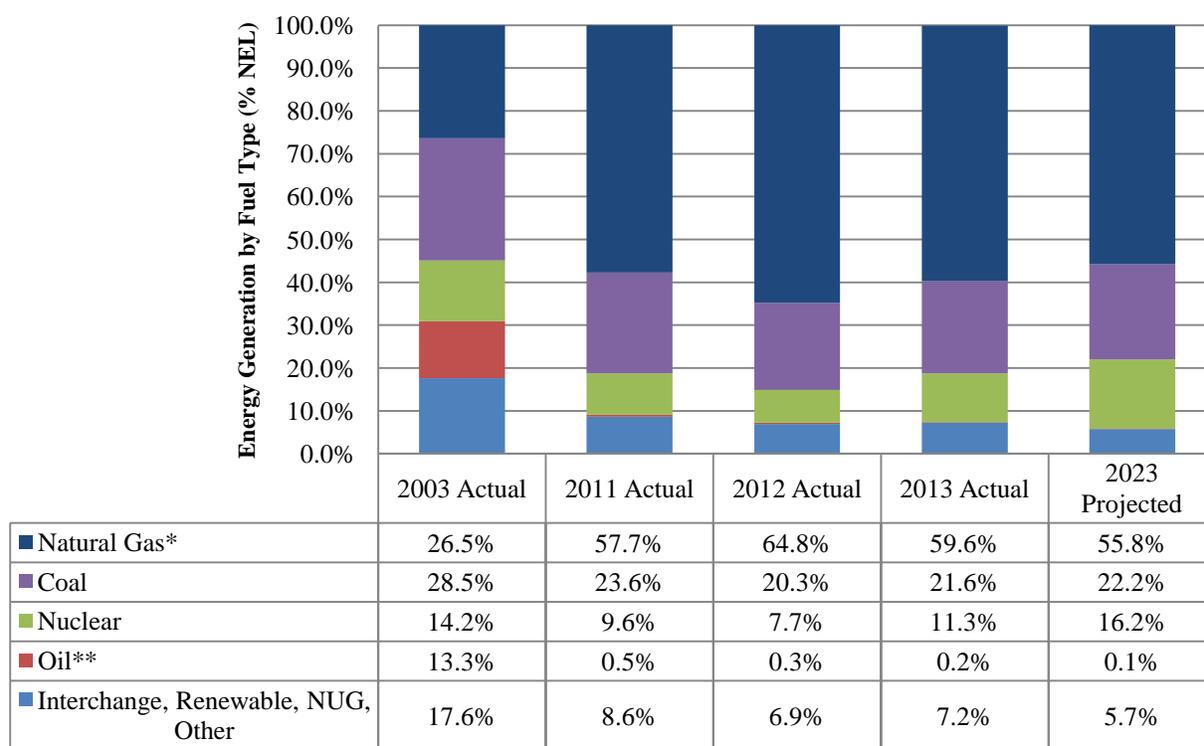


2.2 Florida Sources of Energy in the Power Sector

Florida’s power sector utilizes various fuel sources in order to address the state’s electrical needs. Figure 4 shows the mix of fuel sources Florida uses to generate electricity, including a projection to 2023. Figure 4 also shows Florida’s electric generation in 2003, which highlights a time period when Florida’s electric utilities attempted to maintain a more balanced fuel mix compared with today’s fuel mix. Natural gas is the dominant fuel source for electricity as of 2013, currently comprising approximately 60% of Florida’s electric generation and projected to continue at that percentage through 2023.

Figure 4: Florida Electric Generation Fuel Source Mix

Source: PSC Ten Year Site Plan Review 2012, 2013, 2014



* Includes both utility and non-utility generation

** Includes both residual and distillate oil

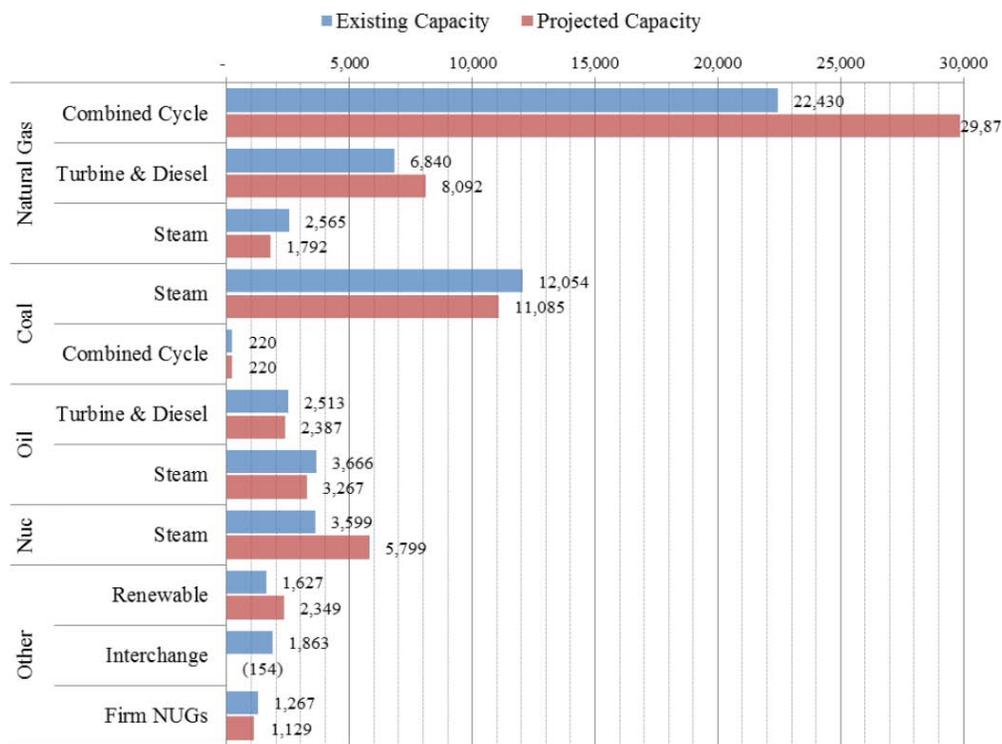
In the past, Florida's utilities adopted more of a balanced approach in terms of its electric generation fuel source mix. By building diverse plants that utilize different fuel sources, it provides a stability mechanism if one fuel source became unavailable or too costly. For example, in 2009, Florida's coal and nuclear plants provided stability from the highly volatile natural gas prices. Over time, Florida's utility industry has moved away from this balanced approach. This change is based on a number of factors including:

- Cleaner and less expensive natural gas generation facilities
- The high cost, lengthy permitting and construction time of nuclear power facilities
- The high environmental and regulatory cost of coal generation

Future Electric Generation Capacity, Facilities, and Retirements

Florida's electric utilities plan for future generating capacity in order to meet the growing demand for energy from their constantly increasing customer base. The electric utilities also plan on generation facility retirements or phase outs, and these plans are done on a ten-year rolling basis. Figure 5 below, highlights the current installed capacity and the 2023 projected capacity.

Figure 5: Florida Current and Projected Installed Capacity by Fuel and Technology (MW)
 Source: PSC 2014 Ten-Year Site Plan Review, page 39, Figure 17



Electric Rates

The rates for residential customers in Florida vary from utility to utility. They are based on many factors including the number of customers they serve, whether they generate their own electricity (or purchase it from another utility), and what type of fuel source provides their electricity, such as natural gas, nuclear, and coal. The following is a brief synopsis of the PSC’s Comparative Rate Statistics as of December 31, 2013:

Table 1: Residential Utility Rate Comparison High/Low per 1,000 kWh			
Investor-Owned Electric Utilities	Average Bill \$115.05	High	\$131.96
		Low	\$92.73
Municipal Electric Utilities	Average Bill \$119.40	High	\$141.15
		Low	\$100.49
Cooperative Electric Utilities	Average Bill \$128.53	High	\$146.99
		Low	\$113.50

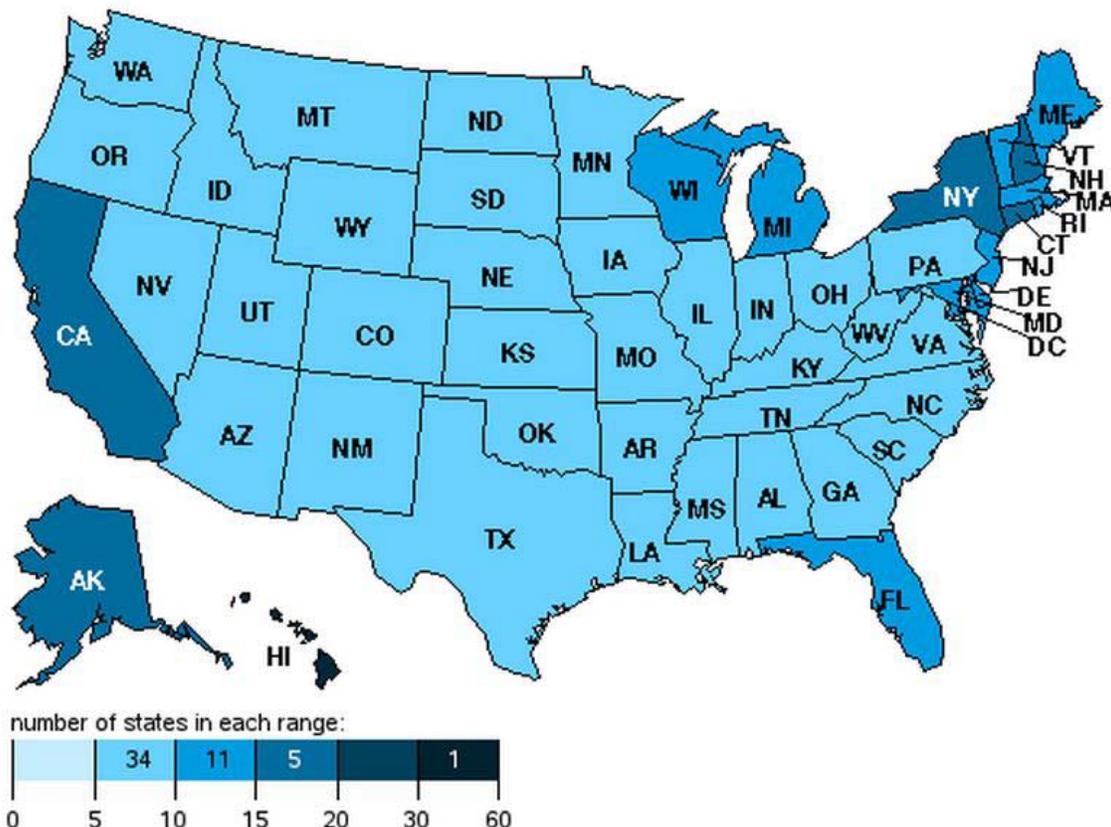
Source: PSC December 2013 Comparative Rate Statistics

Table 2: Commercial/Industrial Utility Rate Comparison High/Low per 150,000 kWh			
Investor-Owned Electric Utilities	Average Bill \$14,612.67	High	\$16,128.00
		Low	\$12,900.00
Municipal Electric Utilities	Average Bill \$17,329.47	High	\$22,125.00
		Low	\$13,188.00
Cooperative Electric Utilities	Average Bill \$16,003.25	High	\$19,899.00
		Low	\$13,702.00

Source: PSC December 2013 Comparative Rate Statistics

In November 2014, the average of all of Florida’s electric rates (residential, commercial and industrial) was 11.00 cents per kilowatt hour (kWh) of electricity, which is slightly higher than the national average of 10.15 cents per kWh (US EIA). Florida’s residential rates, however, are lower than the national average— 12.20 cents per kWh of electricity, as compared with the national average of 12.46 cents per kWh.

Figure 6: U.S. Electric Industry Average Revenue per Kilowatt-hour, November 2014

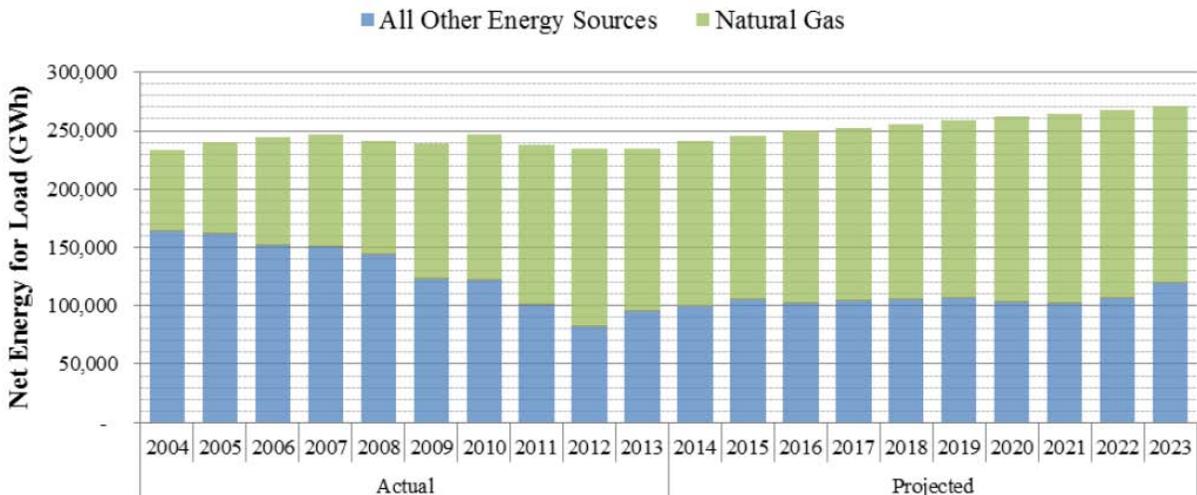


Source: Energy Information Administration http://www.eia.gov/electricity/monthly/update/end_use.cfm#tabs_prices-3

Natural Gas Usage

Natural gas has grown from being one of many sources of energy used in Florida to being the dominant fuel source for electric generation. The price of natural gas has dropped significantly primarily due to increases in technological innovation. Figure 7 shows how natural gas compares to all energy sources used in Florida’s energy consumption; the figure also contains projections to 2023.

Figure 7: Natural Gas Contribution to Florida Energy Consumption



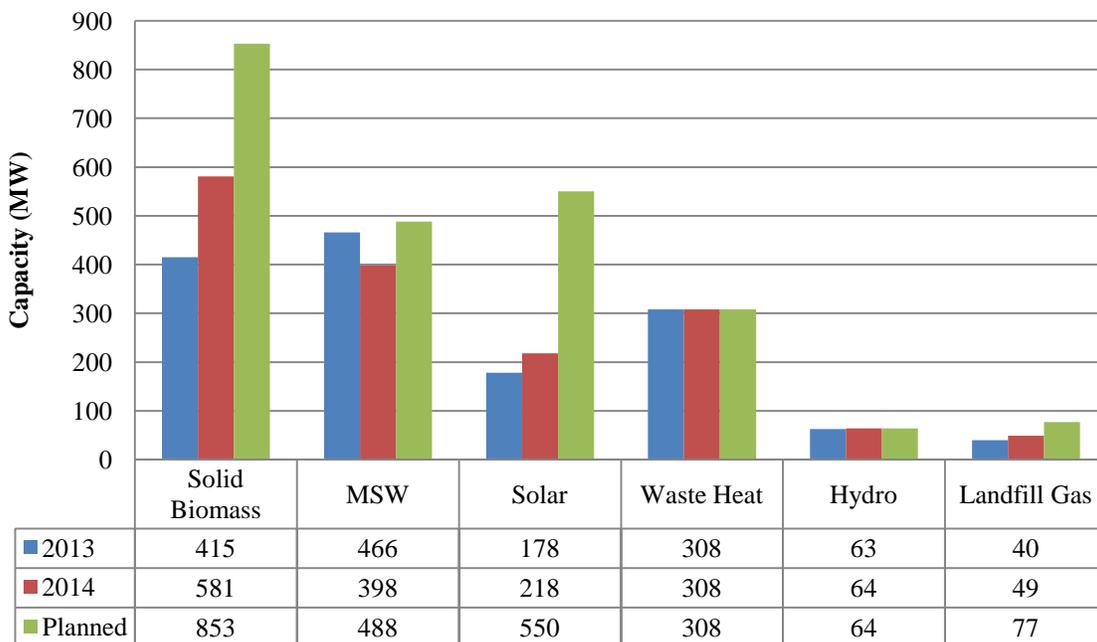
Source: PSC 2014 Ten-Year Site Plan Review, Figure 15, pg. 37

Renewable Energy

According to the PSC’s *Review of the 2014 Ten-Year Site Plans of Florida’s Electric Utilities*, Florida’s renewable energy facilities currently provide approximately 1,617 MW of generating capacity, representing 2.8 percent of Florida’s overall generation capacity; eighty-four percent of this existing generation capacity comes from non-utility generators. As of December 2014, Florida has planned for an additional 722 megawatts of renewable energy by 2023, with the majority anticipated to come from solar and biomass projects.

Figure 8: Renewable Energy Capacity Comparison (MW)

Source: PSC 2014 Ten Year Site Plan Review



As shown in Figure 8, as of 2014, solid biomass is the largest source of renewable energy in Florida, and is expected to remain so through 2023. Due to Florida's year-round growing season, Florida has more biomass resources than any other state. According to the Florida Energy Systems Consortium (FESC), Florida has the potential to account for seven percent of the U.S. total biomass resources. Energy production from biomass processing also has the potential to be a significant economic driver, especially in rural locations. However, in most cases, the bio-energy facility must be located near the intended feedstock to make the process economically viable.

Florida's second largest source of renewable energy comes from municipal solid waste (MSW). MSW uses residential waste as a feedstock and burns the waste to create steam which turns the electricity producing turbine. As of 2014, MSW accounts for 398 megawatts of electrical capacity in Florida, and is expected to grow to 488 megawatts by 2023. MSW facilities are equipped with advanced scrubbers to remove pollutants and reduce emissions. MSW is attractive to major population centers, because it diverts waste from entering the existing overburdened landfills while providing the benefit of a renewable energy source.

Currently, Florida's solar capacity is 218 megawatts which includes approximately 63 MW of customer owned renewable capacity from nearly 6,700 systems. Those 63 MW represents a 60 MW increase of distributed solar generation since 2008. While lagging behind waste heat as a fuel source, solar is expected to be the second largest renewable energy source by 2023 at 550 megawatts. It is generally expected that 550 megawatts is a low estimate considering Florida Power & Light's recently announced their plans to install an additional 225 MW of solar by 2016; the main driver of solar installations is the declining costs of photovoltaic panels. Additionally, there are major initiatives, such as the Sunshot Initiative, that are focusing on reducing the "soft costs" of solar which will increase the economic viability of solar. Soft costs include permitting, labor, and financing.

Waste heat currently provides 308 megawatts of renewable generation capacity, and is expected to remain constant through 2023. Large industries, such as orange juice processors, can create waste heat while manufacturing their products. To capture and utilize that waste heat they must redirect the waste heat or steam from their manufacturing process into a turbine to produce electricity. The process of capturing and redirecting the heat or steam is a large undertaking. Often times the excess heat is used to offset energy usage by heating the building, sterilizing equipment, or heating water instead of direct energy production.

2.3 Florida's Energy Efficiency and Conservation Efforts

In 1980, the Florida Legislature enacted the Florida Energy Efficiency and Conservation Act (FEECA), which made reducing Florida's peak electric demand and energy consumption a statutory objective. FEECA requires utilities reduce the growth rates of electric demand, conserve expensive resources, increase the overall efficiency and cost-effectiveness of electricity and reduce energy consumption. There are seven utilities that are statutorily subject to FEECA. The five investor-owned utilities - Florida Power & Light, Duke Energy of Florida, Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Company, and two large municipally-owned utilities - Orlando Utilities Commission and Jacksonville Electric Authority. FEECA requires the PSC to set appropriate energy efficiency and conservation goals for the utilities and requires a review of those goals at least once every five years with the most recent review during 2014.

In July of 2014, the PSC held an evidentiary hearing on the FEECA dockets. As directed by Statute, FDACS participated in this proceeding as one of the parties. During the hearing, the PSC heard testimony from all parties in the docket on each issue. The parties filed their Post-Hearing Briefs in September. In its post-hearing brief, FDACS stated that the PSC should continue to balance the goals of energy efficiency and conservation with the impact of the associated costs on all customers, thereby ensuring that all customers benefit from utility-sponsored programs. A diverse, least-cost strategy should be employed to ensure that sound principles of energy efficiency and conservation measures are achieved. The major points made in FDACS' brief were:

- The state can encourage the development of energy efficiency and conservation programs separate from implementing utility-sponsored programs;
- Changes to Florida's building codes requiring homes to be more energy efficient have resulted in significant gains in energy efficiency over the last decade;
- Florida should continue to identify ways to educate customers and provide them with the information and resources needed to pursue energy efficiency and conservation;
- In an effort to balance the equity of the costs and benefits, programs may need to be designed and targeted to capture the needs of low-income customers while eliminating free riders from higher income groups; and
- Based on results of the five year solar pilot programs, the solar pilot programs have not been cost-effective and have created a large cross-subsidy from the general body of ratepayers to a small number of wealthy customers who could afford to invest in solar photo voltaic systems.

On November 25, 2014, the PSC voted to establish goals for the FEECA Utilities based upon a cost-effectiveness analysis that allows all ratepayers, participants and non-participants, to benefit from the utilities' demand-side management programs. The PSC set the utilities' annual goals based upon the Rate Impact Measure (RIM) test to be equal to their achievable potential. While the PSC took the Participant Test and the Total Resource Cost test into consideration, they found that the RIM test allows for a larger amount of cost-effective demand-side management with more potential participants while minimizing cross-subsidization.

In addition, the PSC voted to continue the utilities' solar energy programs until December 31, 2015 and to hold a workshop in 2015 to examine the issues related to solar in Florida including the true cost of solar, existing barriers, and appropriately setting the net metering rate.

The 2015 demand-side management goals approved by the PSC are lower than they have been in previous years even though the PSC is using the same determination methodology. This is a direct result of the current market conditions which are outside the control of the utilities. The cost-effectiveness of demand-side management measures has declined due to several factors, including declining customer usage, new federal appliance efficiency standards (i.e., ENERGY STAR), efficiency improvements in state building codes, and a decline in the price of natural gas. Each of these factors is contributing to the goal of FEECA set by the Florida Legislature, which was to reduce Florida's peak electric demand and energy consumption.

Now that the PSC has set the FEECA goals, the utilities will submit for PSC approval, cost-effective demand-side management (DSM) plans designed to meet those goals. The proposal and approval of the plans will occur in subsequent dockets during 2015. All costs incurred by utilities to implement the FEECA required demand-side management plans are recovered from their customers through a line item on the customers' bills.

Attachment A of this report provides the Executive Summary of the PSC's annual FEECA report. The report details the energy efficiency and conservation efforts by Florida's utilities.

2.4 Transportation Energy

Florida's large population, evolving demographics and projected growth, require the state to develop and maintain a reliable and conveniently accessible transportation system. In addition, Florida's tourism industry is one of the largest contributors to the state's economy, and a progressive and diversified transportation system is vital to the tourist industry.

Florida's Transportation Infrastructure

Florida is unique compared to other states in that it consists of a 447-mile long peninsula, which extends from the Georgia border south to the Florida Keys, a northern panhandle that stretches over 360 miles from the Atlantic to Alabama and nearly 1,200 miles of shoreline, totaling 54,157 square land miles. Within Florida is a strategic system of public roads and highways, maintained by Florida's Department of Transportation (FDOT) and the United States Department of Transportation (USDOT). According to the USDOT's Bureau of Transportation Statistics, Florida has 121,829 miles of public roads, 1,495 miles of interstate, 2,902 miles of railroad tracks used for freight transport, 12,070 road bridges, 1,540 miles of inland waterways, and 129 public use airports.

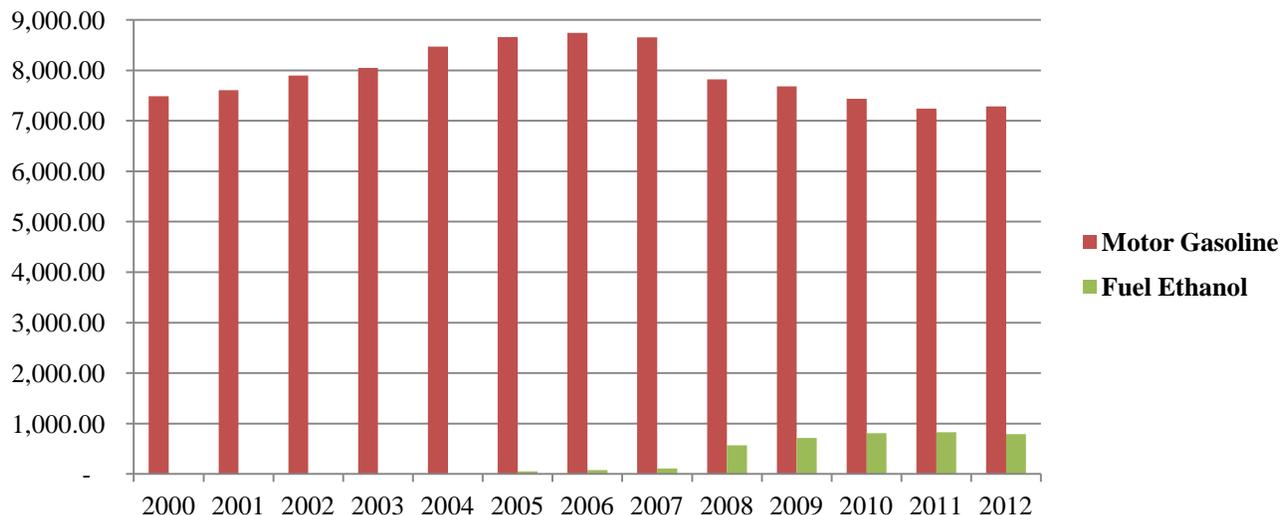
Petroleum Use

Florida's transportation sector accounts for more than one third of the total energy used in the state, with nearly all transportation fuel being imported. The USDOE Office of Energy Efficiency and Renewable Energy (EERE) states that Florida's per capita energy consumption of motor gasoline was 425 gallons in 2011. This is 15 gallons less than the state consumed in 2010. The US EIA's State Energy Data System (SEDS) reports that Florida consumed more than 7.2 billion gallons of motor fuel and more than 790 million gallons of ethanol in 2012, as highlighted in Figure 9.

In the most recent data reported in 2011 by the US EIA, Florida has a total of 5,839 motor gasoline stations, accounting for 5.3 percent of the total U.S. share. While Florida does not have any in-state refineries to process crude oil, the Florida Department of Environmental Protection, Bureau of Mining and Minerals Regulation, states that Florida produced 2,023,454 barrels of crude oil in 2011, with the majority of it coming from Jay Field in Escambia County.

**Figure 9: Annual Motor Gasoline and Fuel Ethanol Consumption
(in million gallons)**

Source: US EIA



Natural Gas

In addition to becoming Florida's dominant fuel source of choice for electric generation, natural gas is also growing in popularity in the transportation sector. This low-cost transportation fuel has given fleet vehicle owners an alternative fuel choice, resulting in lower fuel and maintenance costs, as compared with diesel fuel. According to the US EIA's Annual Energy Outlook for 2014, natural gas consumption is expected to grow as a fuel source from 25.6 trillion cubic feet (Tcf) in 2012 to 31.6 Tcf in 2040. Although it is considered a dominant fuel source, Florida's heavy reliance on natural gas is a concern for policy makers as it places the state in a scenario where it is susceptible to price volatility and fuel availability.

Florida's Alternative Transportation Use

A number of Florida's private commercial fleet owners, as well as local governments and school boards, have begun the process of converting their fleets to natural gas in order to realize cost savings. There is a growing interest in using propane, compressed natural gas (CNG), and liquefied natural gas (LNG), for large vehicles, and commercial operators. Also, governments have looked into the economic feasibility and are converting their fleets. According to the USDOE Alternative Fuels Data Center, the state of Florida has 758 total public and private alternative fuel stations, and of that amount, 42 are CNG stations, and 62 are propane stations. The state of Florida also has a rebate program for the purchase, lease or conversion of fleet vehicles to natural gas.

Electric vehicles (EV) are also an emerging alternative transportation energy source, especially as technological advancements increase and range anxiety is reduced. Consumers, as well as private businesses and local governments, have been making the investment in electric vehicles as well as the infrastructure to support the charging of these vehicles. The USDOE Alternative Fuels Data Center also states that there are a total of 572 public and private charging stations installed throughout the state.

Florida also has three USDOE designated Clean Cities Coalitions' (CCCs), Southeast Florida, Central Florida, and the state's newest Tampa Bay. The CCCs are responsible for promoting clean energy and alternative fuels for transportation throughout the state. They are tasked with working with vehicle fleets, fuel providers, community leaders, and other stakeholders to reduce Florida's dependence on petroleum use.

2.5 New Trends

Florida is home to more than 19 million residents, with expectations for this number to increase in the future. Changes to Florida's demographic and population profile will affect Florida's demand for stable and reliable energy sources over the next 10 years. The University of Florida's Bureau of Economic and Business Research predicts that by 2040, Florida's population will grow to 25,603,577 people, which can impact the way energy is consumed in the state. Florida also expects to realize a wave of technological advancements in the coming future; while such advancements are typically correlated with higher energy efficiency, more electronics will be used per-capita. Collectively, these factors are expected to yield an exponential increase in energy consumption in the future.

The following technologies are expected to have a significant effect on Florida's energy sector:

Solar Energy

The USDOE's National Renewable Energy Laboratory (NREL) published an article in October 2014 discussing how the price of distributed solar photovoltaic (PV) system prices dropped by 19-20 percent nationwide in 2013. The USDOE's 2012 Renewable Energy Data Book suggests that "solar electricity generating capacity grew by a factor of over 21 between 2000 and 2012, and currently accounts for 0.3 percent of annual U.S. electricity generation." In addition, "30 MW of new concentrating solar power (CSP) capacity came online in the United States in 2012. Solar power generation is also expected to grow in Florida. Florida expects to see an increase in its solar power generation with 332 MW of solar power generating capacity to be installed by 2023.

Electric Vehicles

As technological advancements are made in the battery industry, adoption of electric vehicles continues to grow. The PSC stated in its *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities* that electric vehicles are "anticipated to grow rapidly throughout the planning period resulting in almost a half-million electric vehicles operating within the electric service territories by the end of 2023." The PSC also estimates that Floridians can realize potential gasoline savings of 480 gallons per year by switching to an EV that runs purely on electric power. There are also programs growing in the state to promote the adoption of electric vehicles. The USDOE's Clean Cities Coalitions have been working together to promote the widespread adoption of electric vehicles by means of driver education programs, collaboration with business owners to offer financial incentives for their employees and with customers who drive electric.

Ocean Energy

As noted in past reports, the state of Florida is well positioned to take advantage of the Gulf Stream as a base load renewable energy resource. This resource has an estimated potential to provide 4 to 10 gigawatts of capacity. In 2014, Florida saw a major step forward in harnessing this source of energy as the Florida Atlantic University (FAU) was provided a lease by the Bureau of Ocean Energy Management (BOEM) to begin testing small scale turbines. FAU already has several companies interested in testing turbine at their facility and many of these companies expect commercial viability

before 2020. In addition, the first Florida Renewable Energy Task Force was held by BOEM on December 11, 2014, to begin establishing a regulatory process to deal with these types of issues. The regulatory framework is the major determining factor in regards to the proliferation of these types of technologies.

3. 2014 Accomplishments

The FDACS OOE had an active year administering renewable energy tax incentives, natural gas fleet vehicle conversion rebates, initiating an ENERGY STAR and Water Sense Sales Tax Holiday and working with the Florida Legislature to lower commercial electric taxes to name just a few programs. The following section describes the programs FDACS OOE administered in 2014.

3.1 Florida Renewable Energy Tax Incentives

The Florida Renewable Energy Tax Incentives consists of three available tax incentives and represents a total of \$89 million in potential tax credits or sales tax refunds over the life of the program. The three Florida Renewable Energy Tax Incentives include:

- 1) The *Florida Renewable Energy Technologies Sales Tax Refund*, which provides \$1 million per fiscal year for a refund of previously paid Florida sales tax for eligible expenditures,
- 2) The *Florida Renewable Energy Technologies Investment Tax Credit*, which provides \$10 million per fiscal year for an annual corporate tax credit equal to 75 percent of all eligible costs made in connection with the production, storage and distribution of biodiesel, ethanol and other renewable fuel; and
- 3) The *Florida Renewable Energy Production Credit*, which provided \$5 million for the first fiscal year of the program and \$10 million for subsequent years for an annual corporate tax credit equal to \$0.01/kWh of renewable electricity produced.

The intended goals of the programs are to increase renewable energy production within the state and create new jobs for Floridians.

FDACS estimates that in 2014, a total investment of nearly \$24 million for the Renewable Energy Tax Incentives produced an estimated total economic contribution of more than \$261.9 million. Further, an estimated total of 909 jobs were created or supported statewide as a result of these incentives. These programs were also responsible for raising an estimated \$21.7 million in state and local taxes and generating an estimated \$56 million in labor income.

Full reports on the utilization and economic contribution of the Florida Renewable Energy Tax Incentives are available on the FDACS website: <http://www.freshfromflorida.com/Energy/Reports-Publications>.

3.2 Natural Gas Fuel Fleet Vehicle Rebate Program

Chapter 377.810 Florida Statutes authorized the creation of the Natural Gas Fuel Fleet Vehicle Rebate Program. The FDACS OOE is responsible for administering the program. The program is appropriated \$6 million annually for the next five years for the purpose of incentivizing fleets to purchase, lease or convert to natural gas fueled vehicles.

The program took effect on July 1, 2013, and FDACS OOE began rule development on July 2, 2013. Three public workshops were held during the rule development, two in Tallahassee and one in Orlando. The proposed rule was released on October 21, 2013. On January 7, 2014, the rules implementing the Florida Fuel Fleet Vehicle Rebate became effective and the department began accepting applications.

The first year of the program ran on a six-month timeframe from January 7, through June 30, 2014. Though the first year of the rebate program was abbreviated, the FDACS OOE received 572 applications.

The annual assessment of the program found that, even in a shortened first year, the program incentivized an investment of approximately \$79.3 million. The assessment also estimated that a total of 382 jobs paying an average of \$49,682 a year were created or retained as a result of the program. Additionally, the program's contribution to Florida's Gross Domestic Product was estimated at \$127.9 million.

During the first program year, 272 of the 572 received applications were approved and funded for a total rebate expenditure of \$3,871,603.34.

The full report is available on the FDACS website: <http://www.freshfromflorida.com/Energy/Reports-Publications>.

3.3 Florida Energy Systems Consortium Research Developments

The Florida Energy Systems Consortium (FESC) was created in 2008 and is unique in the United States; no other state has a statewide energy consortium involving all of its public universities. The concept combines all of the state's university resources into one statewide center to advance energy research, technology transfer/commercialization, energy education and outreach in this rapidly changing and critically important field.

FESC has been integral in the success of many energy related initiatives. For example, FESC research into hydrogen fuel cells at Florida State University (FSU) led to the creation of Bing Energy, Inc., in Tallahassee. Nine companies were formed with the University of Florida technology, which was developed, in part, with FESC funds and a total 19 companies were created throughout the FESC university system. Also, the USDOE designated Florida Atlantic University (FAU) as a national center for ocean energy research and development which was recently granted the first lease in the Atlantic Ocean to conduct ocean energy research. FAU's facility already has several out-of-state companies interested in utilizing their facility for testing purposes.

Looking forward, FESC would like to capitalize on past successes by utilizing each university's individual strengths. For example, the University of Central Florida is focusing on electric vehicles and charging infrastructure, wireless charging and Photovoltaic; FSU has hired 11 faculty with research expertise in light harvesting materials, polymer characterization, multi-scale material modeling and thermal transport; the University of South Florida will focus on testing a pilot scale thermal energy storage system in collaboration with an electric utility in Florida and developing a novel catalysts for converting carbon dioxide to fuels using solar energy; and FAU is looking to develop a second facility that will be able to support large-scale testing and include transmission capabilities.

3.4 Commercial Sales Tax Decrease and Public Education Capital Outlay (PECO) Increase

HB 5601 was passed in 2014 by the Florida Legislature, which included a reduction in the electricity consumption tax on commercial businesses by 0.05 percent. Commercial businesses include large stores, restaurants, hotels and small "Mom & Pop shops". Further, it transferred the use of 2.6 percent of the remaining tax revenues to support the Public Education Capital Outlay and Debt Service Trust

Fund (PECO). PECO is the sole funding source for the development of Florida's kindergarten through 12th grade education infrastructure (schools, administrative buildings, education infrastructure improvements, etc.) and prior to this allocation did not have a sustainable source of funding. This reduction of sales and use taxes on commercial electric consumption of electricity will benefit commercial businesses in Florida by reducing their overall utility bill. By shifting a large portion of the remaining commercial electric consumption sales and use tax revenue to PECO, it will provide a sustainable revenue stream for local school boards to use in building new schools or making improvements on existing education facilities.

3.5 ENERGY STAR and WaterSense Sales Tax Holiday

Also within HB 5601, the Florida Legislature initiated the first ever Florida ENERGY STAR and WaterSense Sales Tax Holiday on the purchase of energy saving and water saving appliances and fixtures. The sales tax holiday applied to the first \$1,500 of specified ENERGY STAR and WaterSense products for the three day period beginning Friday September 19, 2014, through Sunday September 21, 2014. Customers were limited to one purchase of each specific type of ENERGY STAR or Water Sense product with a sales price of \$500 or more. ENERGY STAR certified products designated for the purposes of the tax exemption are products approved by the United States Environmental Protection Agency (USEPA) that are affixed with an ENERGY STAR label, including air conditioners, air purifiers, ceiling fans, clothes washers, clothes dryers, dehumidifiers, dishwashers, freezers, refrigerators, water heaters and packages of light bulbs. WaterSense certified products for purposes of the tax exemption are products approved by USEPA that are affixed with a WaterSense label, including bathroom sink faucets, faucet accessories, high-efficiency toilets, showerheads and weather or sensor-based irrigation controllers.

The ENERGY STAR and WaterSense sales tax holiday provided a financial incentive to consumers to invest in ENERGY STAR and Water Sense products. Through the purchase of these products, consumers realized a reduction in the appliance or product price and once home they will save energy, water, and money each month on their utility bills. Florida's first sales tax holiday weekend on ENERGY STAR and WaterSense products proved a success. This program not only helped customers save an estimated \$1.6 million at the check-out counter, but will also save them energy, water and money on their bills over the long-term. Retailers reported large increases in sales over the previous year and provided positive feedback about the initiative. Through the Florida Retail Federation, several retailers provided high level sales information indicating the sales tax holiday was a success. One major retailer, for example, reported \$1 million in increased sales, and indicated that many customers took advantage of the sales tax holiday to purchase whole ENERGY STAR appliance packages. Another major retailer reported huge increases year over year (comparing sales during the sales tax holiday weekend to the same weekend the previous year) in sales for dishwashers (456%), laundry appliances (423%) and refrigerators (373%). The retailer also stated that WaterSense products showed a significant increase year over year of 25% increase for faucets, 36% increase for high efficiency toilets and 22% increase for showerheads.

3.6 Grant Activities

One of the functions of the FDACS OOE has been to develop, award and manage various state and federal grant programs. From February 2009 to July 2012, the primary focus of the FDACS OOE was the disbursement of American Recovery and Reinvestment Act (ARRA) funds. The state of Florida received approximately \$176 million in federal stimulus funds, which were distributed to 150

individual sub-grantees for energy efficiency and renewable energy projects. As of December 31, 2014, the grant is closed.

The ARRA grant provided the seed money to fund the Florida Multi-family Energy Retrofits program in perpetuity. The FDACS OOE will continue to manage that grant, with the Florida Housing Finance Corporation, for the operation of the \$8.3 million Multi-family Energy Retrofit Program (MERP) revolving loan fund. This program provides low-interest loans to multi-family housing owners for energy efficiency improvements.

The FDACS OOE is also responsible for administering the state funded Farm to Fuel and Renewable Energy and Energy Efficient Technologies (REET) grant programs. The Farm to Fuel program currently funds six grants with Florida universities for bio-fuel research and development. The REET matching grant program is currently accepting applications for research, development and commercialization projects for renewable energy and energy efficient technologies.

Under a federal cooperative agreement with the US EIA, the FDACS OOE collects propane price information on a weekly basis, based on a sample provided by US EIA. Data for the State Heating Oil and Propane Program (SHOPP) is collected from October through March and assists the US EIA in tracking residential propane prices (<http://www.eia.gov/petroleum/heatingoilpropane/>). Prices are aggregated for the state, so price data for individual propane dealers remains confidential.

FDACS OOE allocated \$1.1 million from the USDOE and created the Energy Efficient Retrofits for Public Facilities grant program, under Title III, Energy Policy and Conservation Act. The program provides funds to local governments and nonprofit organizations to implement energy efficiency projects in public buildings. The competitive grant opportunity was announced in October 2014 and closed in November 2014. FDACS OOE received 25 applications, and those that will be funded must complete work on their projects by July 31, 2015.

3.7 Energy Clearinghouse of Information

FDACS OOE continues to host and expand the Florida Energy Clearinghouse in accordance with Section 570.0741, Florida Statutes. The Florida Energy Clearinghouse provides Floridians the information they need to be knowledgeable energy consumers and make more informed decisions about the energy choices they make every day. Through the online platform, users can compare energy saving technologies, learn more about renewable energy technologies, browse research being conducted at Florida's universities and learn more about energy usage and production.

A major component of the clearinghouse is the "My Florida Home Energy" tool that identifies energy efficient products, services and potential energy and monetary savings for a Florida homeowner based on information provided by the homeowner, as well as publicly accessible data. By educating Floridians on wise energy use, this tool has the potential to improve the quality of their life, both financially and environmentally. The Florida Energy Clearinghouse can be found at: <http://www.freshfromflorida.com/Energy/Florida-Energy-Clearinghouse>.

3.8 Multifamily Energy and Water Efficiency Study

Multifamily housing accounts for a significant share of energy and water consumption and represents an important segment of the market for efficiency retrofits, yet this market is difficult to penetrate and capture at scale. While the costs of investment in multifamily buildings' energy efficiency typically fall on the shoulders of the property owners/landlords, the stream of benefits from such improvements (primarily in the form of reduced utility bills) typically accrue to the tenants, resulting in a pervasive "split incentive" challenge.

In light of recent reports projecting vast energy and water savings potential and financial returns from multifamily retrofits, the FDACS OOE initiated a study to identify multifamily housing incentives specific to Florida. The multifamily efficiency study is expected to be completed in January 2015. The project team conducting the study includes personnel from the University of Florida (UF) Public Utility Research Center (PURC), who will focus on policy analysis, the UF Program for Resource Efficient Communities (PREC), who will focus on program analysis, and the University of Central Florida's (UCF) Florida Solar Energy Center (FSEC), who will focus on analysis of codes and modeled savings potential.

The goal of this study is to collect and synthesize information from existing literature, industry stakeholders and thought leaders to identify the most promising options for Florida to provide incentives to landlords to retrofit their multifamily properties, saving energy and water and reducing the utility cost burdens on tenants.

3.9 Response to Environmental Protection Agency's Clean Power Plan

In addition to the programs administered on the state level, the FDACS OOE has been following various federal actions and evaluating their potential impacts on Florida. On June 2, 2014, the U.S. Environmental Protection Agency (EPA) proposed updates to 111(d) of the Clean Air Act, also known as the Clean Power Plan (CPP). After a thorough evaluation of the CPP and its potential impacts on Florida, Commissioner Putnam submitted comments expressing his concerns, which include: 1) the EPA's overreach far beyond its jurisdiction in proposing this rule and 2) the failure to fully estimate the economic hardship that will result should these requirements be implemented.

In his letter, Commissioner Putnam urged the EPA to consider the following recommendations before advancing its proposed plan:

- Give states flexibility to determine goals and plans that are in the best interest of their constituents.
- Acknowledge each state's definition for renewable energy is unique to them based on the resources available to them within their borders and include these generation sources for compliance.
- Recognize each state's existing initiatives and programs that can count toward their offsets, such as electric vehicle incentives and energy efficiency requirements.
- Allow additional time required to create and implement plans to avoid disruption to supply and limit the exorbitant costs imposed on consumers.

4. On the Horizon

In 2015, FDACS OOE will continue to work with the Legislature and Governor to advance policies and programs with the objective to secure a stable, reliable and diverse supply of energy for Florida. FDACS OOE is currently developing two new programs to help Florida's farmers adopt practices to increase energy and water efficiency. Those programs are:

Farm Renewable and Efficiency Demonstrations (FRED) Program

In September 2014, the FDACS OOE received a \$1 million Conservation Innovation Grant from the United States Department of Agriculture, Natural Resources Conservation Service (USDA-NRCS). Matched by \$2 million from the Farm to Fuel program, these funds will be used to establish the Farm Renewable and Efficiency Demonstrations (FRED) program, an innovative program to promote the adoption of technologies and practices that increase energy efficiency and renewable energy use in Florida agriculture.

Direct energy use represents approximately \$375 million annually, or 6.5% of Floridian farm production expenses. Each objective and phase of FRED has been designed to address one or more market barriers identified by the FDACS OOE as hindering adoption of energy efficiency and renewable energy technologies in the agriculture industry.

Farm Energy & Water Efficiency Realization (FEWER) Program

Over the past year, Farm to Fuel funds that have been returned to the FDACS OOE are being re-obligated to assist farmers in implementing energy and water efficiencies. The objective of the program is to conduct on-site evaluations of the potential for energy efficiency, renewable energy upgrades and water saving measures and practices on individual farms and help protect water resources and reduce energy consumption. In order to achieve this objective, FDACS will contract with the Suwannee County Conservation District (Contractor) to contract with one or more of the USDA-NRCS Technical Service Providers to conduct on-site evaluations. In addition, they will contract with one or more procured entities to engineer, design, and implement the energy efficiency measures identified in the on-site evaluation report. The Contractor will provide administrative services for this project, including project-funding administration.

Attachment A**Executive Summary of the Florida Public Service Commission's Energy Efficiency and Conservation Act (FEECA) Report**

The entire report as prepared by the Florida Public Service Commission, Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act, can be found at:
<http://www.floridapsc.com/publications/pdf/electricgas/FEECA2015.pdf>

Reducing Florida's peak electric demand and energy consumption became a statutory objective in 1980, when the Florida Energy Efficiency and Conservation Act (FEECA) was enacted. Codified in Sections 366.80 through 366.85 and Section 403.519, Florida Statutes (F.S.), FEECA emphasizes reducing the growth rates of weather-sensitive peak demand, reducing and controlling the growth rates of electricity consumption, and reducing the consumption of scarce resources, such as petroleum fuels. Section 366.82(2), F.S., requires the Public Service Commission (Commission or PSC) to set appropriate goals for the seven electric utilities subject to FEECA at least every five years. Commission rules have defined goals with respect to annual electric peak demand and energy savings over a ten-year period, with a review every five years. The seven utilities currently subject to FEECA are Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Public Utilities Company (FPUC), Orlando Utilities Commission (OUC), and JEA. Once goals are established, the utilities must submit for Commission approval, cost-effective demand-side management (DSM) plans, which contain the DSM programs designed to meet these goals.

This report fulfills two Commission statutory obligations. The Commission is required by Section 366.82(10), F.S., to provide an annual report to the Legislature and the Governor summarizing the adopted goals and progress achieved toward those goals. Section 377.703(2)(f), F.S., requires the Commission to file information on electricity and natural gas energy conservation programs with the Department of Agriculture and Consumer Services.

Section 1 of this report provides a history of FEECA, highlights savings produced by utility programs since 1980, and provides a description of existing tools for increasing conservation throughout the state. Section 2 discusses current goals and achievements of the FEECA utilities. For context, Section 3 provides an overview of Florida's electricity market. Section 4 discusses methods the Commission has used to educate consumers about conservation and provides a list of related web sites. Finally, Appendix 1 provides a description of the conservation programs currently offered by the FEECA utilities.

Conservation Achievements

Over the last thirty-three years, the FEECA utilities' DSM programs in total have reduced winter peak demand by an estimated 6,506 megawatts (MW) and summer peak demand by an estimated 6,871 MW. The demand savings from these programs have resulted in the deferral or avoidance of a substantial fleet of power plants. These programs have also reduced total electric energy consumption by an estimated 9,330 gigawatt-hours (GWh).

Since 1981, Florida's investor-owned electric utilities have recovered over \$6 billion of conservation expenditures for DSM programs through the Energy Conservation Cost Recovery (ECCR) clause. Over \$3 billion of the total conservation program expenditures recovered have occurred in the last ten years. In 2013, Florida's investor-owned electric utilities recovered over \$435 million in conservation program expenditures, performed more than 197,000 residential audits, and offered over 100 conservation programs for residential and commercial customers.

Consumer choice plays an important role in reducing the growth rates of electrical demand and energy in Florida. Consumers support electric energy conservation through a variety of actions including constructing smaller, more efficient homes, buying energy-efficient appliances, installing energy-efficiency upgrades to existing homes and installing demand-side renewable systems. The Commission's consumer education program offers several tools to promote consumer awareness of conservation and energy efficiency opportunities. Florida's utilities also play an active role in educating Florida's consumers on energy efficiency options.

Conversely, prescriptive mandates play a major role in conservation. The Florida Building Code is adopted and updated with new editions triennially by the Florida Building Commission. In addition, the Florida Building Code is amended annually to incorporate interpretations, clarifications and update standards. The 2014 draft of the building code emphasizes the thermal envelope of buildings. Specifically, the energy efficiency section of the code focuses on insulation and ventilation measures for air conditioning units, turn-on/turn-off switches for water heaters and pool heaters, and automatic temperature controls for hot water systems. The U.S. Environmental Protection Agency (EPA) is taking steps to boost clothes dryer efficiency. The EPA announced that beginning in 2015, the manufacturers will be able to use the Energy Star label on clothes dryers that use 20 percent less energy than the minimum efficiency standard. The EPA stated that if all residential clothes dryers in the U.S. meet the requirements, the utility cost savings will grow to more than \$1.5 billion per year. In addition, more than 22 billion pounds of greenhouse gas emissions would be prevented.

In 2013, the U.S. Department of Energy (DOE) issued an update for the energy conservation standards for residential microwave ovens which could reduce energy consumption by up to 75 percent in standby mode and revised energy conservation standards for residential room air conditioners. The DOE also initiated rulemaking to amend testing procedures for residential refrigerators and freezers to account for ice-making energy use and to update energy use for other features. Once finalized, the new standards for Energy Star certified refrigerators and freezers would use approximately 10 percent less energy than models meeting the current 2014 standards. Lighting standards have changed as well, with various watts of incandescent bulbs being phased out and becoming no longer available for purchase. Seventy-five watt incandescent bulbs were phased out as of January 1, 2013, and as of January 1, 2014, 60 watt and 40 watt incandescent bulbs are no longer available.

Section 2 of this report compares the FEECA utilities' demand and energy savings to the goals set by the Commission during the last goal-setting proceeding. The results of the 2013 achievements towards the 2009 goals illustrated that TECO, Gulf, JEA, and OUC surpassed all demand and energy savings goals in every category. FPL, DEF, and FPUC did not meet goals in every category in 2013. Of the utilities that did not achieve their annual Commission approved goals, most noted that while they failed to meet the goal requirements on an annual level, they were able to meet the requirements on a cumulative level when compared to the 2004 and 2009 goal proceeding requirements.

Section 2 also provides a summary of the Commission's most recent goal-setting proceeding. On November 25, 2014, the Commission voted to approve staff's recommendation regarding the FEECA utilities' proposed goals for the 2015 through 2024 period. The Commission voted to approve goals based on the Ratepayer Impact Measure (RIM) Test, noting that FPL's approved goals would be based on the unconstrained RIM test.² The RIM test is a cost-effectiveness analysis that ensures that all ratepayers, both participants and non-participants, benefit from utility-sponsored conservation programs and minimizes cross subsidies between customers. Utilities were also directed to show how all customers, including low-income customers will be made aware of conservation opportunities. The near term impact will lower the dollars for conservation currently being recovered from customers. In addition, the Commission voted to discontinue the investor-owned utilities' (IOU) solar pilot programs by the end of 2015. The Commission based its decision on evidence in the record that the existing solar pilot programs have not proven to be cost-effective and represented a subsidy between the general body of ratepayers and the few that participated in the program. The Commission also directed its staff to hold a workshop to explore more cost-effective ways to encourage solar adoption in Florida.

Conclusion

The potential demand and energy savings from utility-sponsored conservation programs are affected by consumer education and behavior, building codes, and appliance efficiency standards. Consumer actions to implement energy efficiency measures outside of utility programs as well as codes and efficiency standards, create a baseline for a new program's cost-effectiveness and reduce the amount of incremental energy savings available from utility programs. Utility programs are designed to encourage actions to conserve energy that exceeds the level of conservation resulting from current building codes and minimum efficiency standards. It should be noted that the level of savings from these programs are somewhat uncertain because they depend on voluntary participation from customers. However, the expense is shared by all customers. As such, customer participation, as well as customer education regarding utility-offered DSM and energy conservation programs, along with individual efforts to use electrical energy wisely, remain fundamental elements for reducing the demand for energy.

Conservation and renewable energy are expected to continue to play an important role in Florida's energy future. The Commission will continue its efforts to encourage cost-effective conservation and renewable energy to reduce the use of fossil fuels and defer the need for new generating capacity to ensure a balanced mix of resources that reliably and cost-effectively meet the needs of Florida's ratepayers.

² See Order No. PSC-14-0696-FOF-GU, issued December 16, 2014, in Docket Nos. 130199 through 130205, In re: Commission review of numeric goals (Florida Power & Light Company, Duke Energy Florida, Inc., Tampa Electric Company, Gulf Power Company, JEA, Orlando Utilities Commission, Florida Public Utilities Company).

Office of Energy

Analysis of the Economic Contribution of the Renewable Energy Tax Incentives

2014

Updated February 13, 2015



Florida Department of Agriculture and Consumer Services
Adam H. Putnam, Commissioner



Dear Governor Scott, President Gardiner and Speaker Crisafulli,

Pursuant to Section 377.703(2)(n), Florida Statutes, I am pleased to provide you with the attached Analysis of the Economic Contribution of the 2014 Renewable Energy Tax Incentives. This analysis is a critical assessment of the Renewable Energy Tax Incentives programs, including the Florida Renewable Energy Technologies Investment Tax Credit, the Florida Renewable Energy Production Credit and the Florida Renewable Energy Technologies Sales Tax Refund.

These tax incentives were designed to assist companies to expand renewable energy production within our state and create new jobs for Floridians. As you know, these tax incentives are not energy subsidies like the federal grants or loans that have been plagued with problems. Rather, they are incentives that are available to businesses that demonstrate they are making investments to diversify our state's energy portfolio.

I support and embrace your commitment to ensure that any investment of taxpayer dollars should benefit Florida. To that end, this analysis measures the return on investment of taxpayer dollars in these programs and evaluates whether the programs achieved their intended goals.

Based on the information gathered by the department from applicants, the overall economic contribution these programs have provided our state is substantial. The department estimates that a total investment of nearly \$24 million for the Renewable Energy Tax Incentives produced an estimated total economic contribution of more than \$261.9 million. Further, an estimated total of 909 jobs were created or supported statewide as a result of these incentives. These programs were also responsible for raising an estimated \$21.7 million in state and local taxes and generating an estimated \$56 million in labor income.

I hope you find this analysis informative. We look forward to continuing to work with you in order to create a stable, reliable and diverse supply of energy for Florida's future.

Sincerely,

A handwritten signature in black ink, which appears to read "Adam H. Putnam". The signature is fluid and cursive.

Adam H. Putnam
Commissioner of Agriculture

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Letter from Commissioner Adam H. Putnam

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1. Introduction

The 2012, the Florida Legislature reinstated the Renewable Energy Tax Incentives as a component of Florida's energy policy. The program consists of three possible tax incentives and represents a total of \$89 million in potential tax credits or sales tax refunds during the life of the program. The intended goals of the program are to increase renewable energy production within the state and create new jobs for Floridians.

This report, required by Section 377.703(2)(n), Florida Statutes, is an overview of the utilization of the Renewable Energy Tax Incentives granted this year, as well as a critical assessment to determine if the programs produced a positive economic impact on our state and created new jobs for Floridians.

Through its rules, the Florida Department of Agriculture and Consumer Services (FDACS) required that all applicants provide a description of the economic impact that the eligible project has had on the state. This information may include the total dollar value of additional investment made, the number of jobs created and the total dollar value of salaries and wages of jobs created as a result of the project. Regional economic modeling was used as the basis for this evaluation. FDACS also reviewed public response to the programs, including requests for technical assistance in completing 2015 applications.

2. Florida Renewable Energy Technologies Sales Tax Refund

Pursuant to Section 212.08(7)(hhh), Florida Statutes, the Florida Renewable Energy Technologies Sales Tax Refund Program provides a refund of previously paid Florida sales tax on materials used in the distribution, including fueling infrastructure, transportation and storage, of biodiesel (B10-B100), ethanol (E10-E100) and other renewable fuels. An eligible item is subject to a one-time refund and must be purchased between July 1, 2012, and June 30, 2016. This program is limited to \$1 million in Florida sales tax refunds each state fiscal year for all taxpayer applicants.

2.1 Utilization Summary

At the end of the program's first year, Fiscal Year 2012-2013, no refunds were issued as part of the Florida Renewable Technologies Sales Tax Refund. Given the lack of interest demonstrated from prospective participants, the department recommended repealing the program. However, utilization of the Florida Renewable Energy Technologies Sales Tax Refund Program increased in the second year, signaling an increase in interest from prospective participants. During Fiscal Year 2013-2014, FDACS approved \$261,686.16 in refunds to eligible applicants.

Given the increased utilization demonstrated in the second year of this program and the positive economic impact generated, as shown in Section 2.3, FDACS supports the continuation of the Florida Renewable Energy Technologies Sales Tax Refund Program.

FDACS will aim to further increase participation in the program by educating eligible businesses on program requirements and providing assistance during the application process. FDACS will also continue to monitor the program and carefully evaluate its impact to ensure that the investments made in this program result in a positive, measurable contribution to Florida's economy.

Table 1. Utilization of the Florida Renewable Energy Technologies Sales Tax Refund

Fiscal Year	Appropriation	Total Refunds Approved	Unused Refunds
FY2012-2013	\$1 million	\$0	\$1 million
FY2013-2014	\$1 million	\$261,686.16	\$738,131.84

FDACS received seven applications under the Florida Renewable Energy Technologies Sales Tax Refund Program in Fiscal Year 2013-2014. Four of the seven applications were approved, totaling \$261,686.16. The three applicants whose submissions were deemed incomplete received a full description of their application's deficiencies. Examples of the deficiencies include lack of supporting documentation in the form of invoices and proof of payments, sales tax calculated above the Florida sales tax rate of 6 percent, and failure to provide legible copies of invoices. The rule administering this program allows applicants to submit a corrected application. At this time, the applicants that were determined incomplete have not submitted corrected applications.

Table 2. FY2013-14 Approved Applicant List

Taxpayer	Approved Refund	Fueling Infrastructure	Transportation	Storage
Affordable Bio Feedstock, Inc.	\$40,806.76	\$40,806.76	\$0	\$0
Affordable Bio Feedstock of Port Charlotte, LLC	\$73,919.40	\$73,919.40	\$0	\$0
Florida Biodiesel Fuel, Inc.	\$73,710	\$0	\$0	\$73,710
Affordable Bio Feedstock of Daytona, LLC	\$73,250	\$0	\$0	\$73,250
Total	\$261,686.16	\$114,726.16	\$0	\$146,960

2.2 Methodology

The Renewable Energy Technologies Sales Tax Refund is awarded to eligible applicants as a reimbursement of state sales taxes paid on materials used in the distribution of biodiesel, ethanol, and other renewable fuels. These materials include those used to build, repair, or maintain fueling infrastructure, transportation, and storage facilities for renewable fuels in Florida. However, the total expenditures on renewable fuel distribution supported by this program are much larger than the refunds awarded, since the refunds represent just a small fraction of the total costs of these improvements. Specifically, the refunds amount to just 6% of the total expenditures in materials destined for renewable fuel distribution in the state.

To determine the contribution that the program has made to Florida's economy, a model of the state's economy was created using the IMPLAN regional economic modeling system (Minnesota Implan Group, Inc., 2013) and associated state database for 2011. The use of a regional economic model allows a descriptive analysis that tracks the gross economic activity created by the policy as the dollars cycle through the region's economy (Watson et al., 2007). IMPLAN databases incorporate federal and state economic statistics on commodity production, household and government final demand, industry output, employment, labor and property income, domestic and international trade, personal and business taxes, transfer payments, capital investment, and business inventories. The model estimates regional economic multiplier effects,

including direct changes in output or employment, indirect effects on supply chain activity and induced effects on employee household and government spending (Hodges & Spreen, 2012).

At a sales tax rate of 6%, the \$261,686.16 in tax refunds supported total equipment purchases for renewable fuel distribution of \$4,361,436. Broken down by spending category, \$114,726.16 was awarded for purchases in fueling infrastructure materials of \$1,904,942, while \$146,960 was awarded for purchases in fuel storage materials of \$2,449,333.33. Purchases of fueling infrastructure materials generally include items like pumps, piping, tubing and connectors, and therefore are entered into the IMPLAN model in the “fabricated pipe and pipe fitting manufacturing” sector. Similarly, purchases of fuel storage materials are likely to be large metal tanks, metal pipes, and other metallic structures, hence they were entered into the IMPLAN model in the “Metal tanks (heavy gauge) manufacturing” sector, which manufactures tanks, vessels and other containers by cutting, forming and joining heavy-gauge metals, as well as installs heavy-gauge metal tanks (IBIS World, 2014).

2.3 Results

Estimated direct, indirect, induced and total economic contributions of this program are summarized in Table 3. During the 2013-2014 fiscal year, sales tax refunds for renewable fuel distribution capital improvements of \$261,686.16 resulted in total purchases of new equipment above \$4.3 million and a total economic contribution more than \$7.7 million. These refunds also supported or created a total of 42 jobs with an average annual pay of \$52,798, for a total income contribution of \$2.2 million.

Table 3. Summary of Economic Impacts in 2014 for Renewable Energy Technologies Sales Tax Refund

Impact Type	Employment	Labor Income	Value Added	Output
Direct Effect	18.8	\$1,134,865	\$1,412,867	\$4,354,275
Indirect Effect	10.7	\$548,231	\$896,082	\$1,775,090
Induced Effect	12.5	\$534,440	\$964,494	\$1,627,905
Total Effect	41.9	\$2,217,536	\$3,273,442	\$7,757,270

Estimated local, state and federal taxes collected as a result of the economic activity supported by the program are summarized in Table 4. Total state and local taxes collected were estimated to be \$172,121, while total federal taxes collected were estimated to be \$450,265.

Table 4. Tax Impacts from the Renewable Energy Technologies Sales Tax Refund

Description	Employee Compensation	Proprietor Income	Tax on Production and Imports	Households	Corporations
Total State and Local Tax	\$1,666	\$0	\$159,660	\$7,610	\$3,185
Total Federal Tax	\$211,175	\$8,001	\$18,518	\$156,342	\$56,229

2.4 Additional Jobs Created

As part of the application process, businesses seeking the Renewable Energy Technologies Sales Tax Refund are required to submit a statement of the economic impact created by their investment. As part of their economic impact statement, all approved applicants reported the number of people they expect to employ at their facilities once these facilities become fully

operational and are running at full capacity. All of the applicants were able to expand their facilities as a result of the tax credit and have created new positions at their facilities. Across the state, approved applicants expect to employ 170 people once their facilities are operating at or near full capacity.

Table 5. Self-reported Number of Employees Expected at Full Operational Capacity by Businesses Approved for the Renewable Energy Technologies Sales Tax Refund in FY 2013-2014

Taxpayer	Reported Number of Jobs
Affordable Bio Feedstock, Inc.	120
Affordable Bio Feedstock of Port Charlotte, LLC	25
Florida Biodiesel Fuel Inc.	10
Affordable Bio Feedstock of Daytona, LLC	15
Total	170

2.5 Applicant Highlights

This section highlights one of the four applicants from the 2014 approved applications to provide a better understanding of the economic contribution these projects have on the state.

Affordable Bio Feedstock, Inc.

Affordable Bio Feedstock, Inc., (ABF) is a family-owned and operated business located in Kissimmee, Florida, that recycles brown grease for use as biodiesel feedstock. Brown grease is cooking oil recovered from a waste water plumbing component that has been contaminated with rotted food solids and considered unsuitable for re-use in most applications. Brown grease is commonly treated with lime and taken to a landfill. However, ABF uses a process called “thermal depolymerization” to transform the brown grease into a source of feedstock to produce biodiesel, organic compost and reclaimed water. During the last six years, ABF has recycled more than 50 million gallons of brown grease, creating more than 3 million gallons of brown grease feedstock and more than 10,000 tons of organic compost, and reclaiming more than 44.5 million gallons of water.

Since starting their business in 2008, ABF has created 120 jobs and invested more than \$5.6 million in their Kissimmee plant, \$2.5 million of which was invested in the last two years. According to owner Bill Freeman, reinstating the tax incentives allowed ABF to expand their existing plants and add an additional plant in Kissimmee and a new plant in Daytona. ABF is continuing to improve their plants efficiency as well as looking at additional markets in the northern part of the state for expansion.

3. Renewable Energy Technologies Investment Tax Credit

Pursuant to Section 220.192, Florida Statutes, the Renewable Energy Technologies Investment Tax Credit Program provides an annual corporate tax credit equal to 75 percent of all capital costs, operation and maintenance costs, and research and development costs in connection with an investment in the production, storage and distribution of biodiesel (B10-B100), ethanol (E10-E100) and other renewable fuel in the state. Eligible costs must be incurred between July 1, 2012, and June 30, 2016. This program allows \$1 million per state fiscal year for each taxpayer with a limit of \$10 million per state fiscal year.

3.1 Utilization Summary

FDACS received 19 applications under the Renewable Energy Technologies Investment Tax Credit Program in Fiscal Year 2013-2014. Eleven applications were approved under Fiscal Year 2013-2014, totaling \$10,000,000. One of the 11 approved applications was granted a partial credit as funding was exhausted. The rule administering this program allows approved applicants to remain in the first-come, first-served line for the next fiscal year of the program if funds are exhausted.

Seven applications, including the applicant who received a partial credit, did not receive a full credit under Fiscal Year 2013-2014 due to exhaustion of funds. These seven applications totaling more than \$6.6 million will receive a credit under Fiscal Year 2014-2015. Two of the 19 applications were not eligible for a tax credit as they had previously received a credit under Fiscal Year 2013-2014. Table 6 below shows the approved credit, broken down by capital costs, operation and maintenance costs, and research and development costs.

Table 6. Utilization of the Renewable Energy Technologies Investment Tax Credit

Fiscal Year	Appropriation	Capital Costs	Operation and Maintenance Costs	Research and Development Costs	Approved Credit
FY2012-13	\$10,000,000	\$6,418,643.43	\$2,007,596.33	\$799,414.46	\$6,878,263.96
FY2013-14	\$10,000,000	\$7,004,389.39	\$2,944,440	\$3,724,689.04	\$10,000,000

Table 7. FY2013-14 Approved Applicant List

Taxpayer	Capital Costs	Operation and Maintenance Costs	Research and Development Costs	Total Eligible Costs	Approved Credit
Treasure Coast Biodiesel Feedstock Supply, LLC	\$0	\$0	\$1,402,928.60	\$1,402,928.60	\$1,000,000
Viesel Fuel, LLC	\$1,228,102.76	\$68,724.68	\$41,972.14	\$1,338,799.58	\$1,000,000
Affordable Bio Feedstock, Inc.	\$669,605.56	\$368,173.87	\$270,905.35	\$1,308,684.78	\$981,513.59
FL Biofuels, LLC	\$37,732.72	\$1,450,460.70	\$0	\$1,488,193.42	\$1,000,000
Affordable Bio Feedstock of Port Charlotte, LLC	\$1,302,260	\$42,557.92	\$0	\$1,344,817.92	\$1,000,000
Florida Biodiesel Fuel Inc.	\$1,302,260	\$0	\$0	\$1,302,260	\$976,965
GGs Fort Myers	\$68,020.71	\$688,885.26	\$638,025.50	\$1,394,931.47	\$1,000,000
Green Energy Advisors Group, LLC	\$0	\$0	\$1,370,857.45	\$1,370,857.45	\$1,000,000
Green Gallon Solutions of North America, LLC	\$623,711.27	\$325,637.57	\$0	\$949,348.84	\$712,011.63
Affordable Bio Feedstock of Daytona, LLC	\$1,333,350	\$0	\$0	\$1,333,350	\$1,000,000
GGs Miami, LLC*	\$439,346.37	\$0	\$0	\$439,346.37	\$329,509.78
Total	\$7,004,389.39	\$2,944,440	\$3,724,689.04	\$13,673,518.43	\$10,000,000

*GGs Miami, LLC received a partial credit under Fiscal Year 2013-2014 due to exhaustion of funding.

All the applicants who received an investment tax credit are continuing to expand or enhance their operations and are expected to submit another application in 2015. In addition, FDACS has answered technical questions about the application process to companies who are in the process of either expanding their operations to Florida, or who are moving their entire operations to Florida in order to take advantage of the tax incentives. It is expected that the demand for this program will continue to grow.

3.2 Methodology

Applicants to the Renewable Energy Technologies Investment Tax Credit were required to provide the capital costs, operation and maintenance costs, and research and development costs incurred in connection with an investment in the production, storage and distribution of

renewable fuels for transportation in the state. The sum of these costs represents the investment in renewable fuels production that was directly supported by the program.

A total of \$7,004,389.39 of capital improvement costs were claimed by applicants to the program. These expenses were entered into the IMPLAN model in the “Construction of other new nonresidential structures”, which includes construction of facilities such as blast furnaces, petroleum refineries, chemical manufacturing plants, power plants and tank storage facilities. Similarly, applicants claimed \$2,944,440 in operation and maintenance costs and \$3,724,689.04 in research and development costs. These expenses were entered into the IMPLAN model in the “Other basic organic chemical manufacturing” sector, which includes manufacturing of organic fuel propellants and is commonly used to model the biofuels sector (Swenson & Eathington, 2006; Schlosser et al., 2008).

3.3 Results

Estimated direct, indirect, induced and total economic contributions of the program are summarized in Table 8. For Fiscal Year 2013-2014, a total program investment of \$10 million produced an estimated total output contribution of \$23.6 million, total value added contribution of \$9.6 million and total labor income contribution of \$6.9 million. Similarly, the program is estimated to have supported or created nearly 70 jobs in the construction and organic chemical manufacturing sectors, as well as 70 jobs in related and supporting industries, thereby having a total estimated employment contribution of 140 jobs.

Table 8. Summary of Economic Impacts in 2014 for Renewable Energy Technologies Investment Tax Credit

Impact Type	Employment	Labor Income	Value Added	Output
Direct Effect	69.7	\$3,600,516	\$4,074,306	\$13,673,518
Indirect Effect	31	\$1,655,485	\$2,527,145	\$4,955,345
Induced Effect	38.9	\$1,661,209	\$2,997,682	\$5,059,960
Total Effect	139.6	\$6,917,210	\$9,599,134	\$23,688,823

Estimated local, state, and federal taxes collected as a result of the economic activity fostered by the program are summarized in Table 9. Total state and local taxes collected were estimated to be \$547,179, while total federal taxes collected were estimated to be \$1.3 million.

Table 9. Tax Impacts from the Renewable Energy Technologies Investment Tax Credit

Description	Employee Compensation	Proprietor Income	Tax on Production and Imports	Households	Corporations
Total State and Local Tax	\$4,873	\$0	\$510,809	\$23,835	\$7,662
Total Federal Tax	\$617,692	\$40,583	\$59,247	\$489,695	\$135,289

3.4 Additional Jobs Created

As part of the application process, businesses seeking the Renewable Energy Technologies Investment Tax Credit are required to submit a statement of the economic impact created by their investment. As part of their economic impact statement, all approved applicants reported the number of people they expect to employ at their facilities once these facilities become fully operational and are running at full capacity. Many of the applicants were able to expand their facilities as a result of the tax credit and have created new positions at their facilities. Across the

state, approved applicants expect to employ 371 people once their facilities are operating at or near full capacity.

Table 10. Self-reported Number of Employees Expected at Full Operational Capacity by Businesses Approved for the Renewable Energy Technologies Investment Tax Credit in FY 2013-2014.

Taxpayer	Reported Number of Jobs
Treasure Coast Biodiesel Feedstock Supply, LLC	12
Viesel Fuel, LLC	55
Affordable Bio Feedstock, Inc.	120
FL Biofuels, LLC	16
Affordable Bio Feedstock of Port Charlotte, LLC	25
Florida Biodiesel Fuel Inc.	10
GGs Fort Myers	20
Green Energy Advisors Group, LLC	3
Green Gallon Solutions of North America, LLC	70
Affordable Bio Feedstock of Daytona, LLC	15
GGs Miami, LLC	25
Total	371

3.5 Applicant Highlights

This section highlights two of the applicants from the 2014 approved applications to provide a better understanding of the economic contribution these projects have on the state.

Green Gallon Solutions of North America, LLC

Green Gallon Solutions of North America, LLC (GGsNA) is located in Fort Myers, Florida, and is the largest producer of biodiesel in Southwest Florida. GGsNA is a growing Florida business that recycles used cooking oil into a biodegradable, non-toxic fuel which can be used directly in vehicles or blended with petroleum diesel. Since 2012, when the company was founded, GGsNA has invested more than \$14 million to build and manage their operations.

GGsNA currently produces nearly 8 million gallons of biodiesel a year and employs 40 full time positions ranging from plant operator to advanced degree positions in executive management, research and development, engineering and operations management. GGsNA has used their Renewable Energy Technologies Investment Tax Credit to expand their existing facilities in North Fort Myers by constructing facilities in Miami and Orlando. With the help of their tax credit, GGsNA is increasing their production capability to 12 million gallons per year and expanding their workforce to 70 full time positions.

Treasure Coast Biodiesel Feedstock Supply, LLC

Treasure Coast Biodiesel Feedstock Supply, LLC (Treasure Coast Biodiesel) is a Florida research and development company based in Stuart, Florida. Since their inception in 2013, Treasure Coast Biodiesel has invested well more than \$2.3 million to create a world-class laboratory and hired 15 employees with multiple and advanced degrees to develop alternative feedstocks for use in biodiesel produced by a unique enzymatic process. This enzymatic process requires less energy compared to traditional biodiesel production, and the enzyme process allows the use of a variety of inexpensive, high free fatty acid feedstocks that traditional biodiesel plants are unable to handle. The results of their work have been highlighted in various seminars, tradeshows and industry publications including Biodiesel Magazine.

Treasure Coast Biodiesel is using their approved Renewable Energy Technologies Investment Tax Credit to expand their research facility and continue to identify alternative feedstocks that are not only viable, but less expensive than traditional feedstocks. Treasure Coast Biodiesel expects the use of biodiesel produced by an enzymatic process to not only grow in the state, but throughout the country as well. As this new technology is accepted, Treasure Coast Biodiesel will be able to double their workforce and become a model for testing and research in biodiesel production.

4. Florida Renewable Energy Production Credit

Pursuant to Section 220.193, Florida Statutes, the Florida Renewable Energy Production Credit Program provides an annual corporate tax credit equal to \$0.01/kWh of electricity produced and sold by the taxpayer to an unrelated party during a given tax year. The credit may be claimed for electricity produced and sold on or after January 1, 2013, through June 30, 2016.

4.1 Utilization Summary and Public Response

FDACS approved 15 applications totaling \$13,773,587.53 for the production period beginning January 1, 2014, and ending December 31, 2014. Funding under Fiscal Year 2013-2014 and Fiscal Year 2014-2015 was exhausted under the 2014 production period.

Table 11. Florida Renewable Energy Production Credit Program Status

Fiscal Year	Appropriation	Total Credits Approved	Unused Credits
FY2012-13	\$5 million	\$5 million	\$0
FY2013-14	\$10 million	\$10 million	\$0
FY2014-15	\$10 million	\$10 million	\$0

Table 12: 2014 Production Year Approved Applicant List

Taxpayer	Type of Renewable Energy	Total Kilowatt Hours Produced	Facility Operation Date	New/ Expanded Facility	FY 2013-14 Credit	FY 2014-15 Credit	Total Approved Credit
Alliance Dairies	Biomass	7,646,863	12/12/2012	New	\$20,950.32	\$55,518.31	\$76,468.63
Florida Power and Light	Solar	108,997,000	12/10/2010	New	\$298,345.24	\$790,614.33	\$1,088,959.57
Florida Power and Light	Solar	17,551,000	4/15/2010	New	\$47,817.06	\$126,715.11	\$174,532.17
Florida Power and Light	Solar	50,714,000	10/27/2009	New	\$138,168.43	\$366,146.10	\$504,314.53
G2 Energy (Marion) LLC	Biomass	26,625,600	1/9/2009	New	\$72,540.47	\$192,232.12	\$264,772.59
Harvest Power Orlando, LLC	Biomass	14,412,243	12/22/2013	New	\$39,485.62	\$104,636.81	\$144,122.43
International Paper Company	Biomass	342,456,620	9/1/2007	New	\$930,777.61	\$2,466,558.98	\$3,397,336.57
Jacksonville Solar	Solar	21,198,952	9/1/2010	New	\$57,755.77	\$153,052.68	\$210,808.45
Mosaic Fertilizer, LLC	Waste Heat	160,118,250	8/15/2008	New	\$436,830.57	\$1,157,600.21	\$1,594,430.79
Mosaic Fertilizer, LLC	Waste Heat	108,191,400	5/9/2014	New	\$296,414.94	\$785,499.06	\$1,081,914
New Hope Power Company	Biomass	344,158,267	9/1/2006	New	\$935,387.30	\$2,478,774.63	\$3,414,161.94
Rayonier Products	Biomass	118,395,958	12/1/2006	New	\$323,806.62	\$858,086.96	\$1,181,893.58
Tropicana Manufacturing Company	Biomass	11,472,894	1/23/2013	New	\$31,432.60	\$83,296.34	\$114,728.94
WM Renewable Energy	Biomass	27,880,320	5/18/2009	New	\$75,958.91	\$201,290.97	\$277,249.88
WM Renewable Energy	Biomass	24,928,231	5/5/2011	New	\$67,916.05	\$179,977.41	\$247,893.46
TOTAL		1,384,747,598			\$3,773,587.53	\$10,000,000	\$13,773,587.53

The Florida Renewable Energy Production Credit Program was oversubscribed under the 2014 production period. FDACS expects all 15 applicants who were approved for the 2014 production period will also submit an application in January 2016 for the 2015 production period. In addition, FDACS is aware of other eligible projects in the state and has also answered technical questions about the production tax credit to businesses interested in building solar plants in

Florida. Based on applications received for the 2013 and 2014 production periods, plus the anticipated increase from other eligible projects, FDACS expects Florida businesses will continue to take full advantage of the tax credits available through this program.

4.2 Methodology

The program supported the production of 1,384,747,598 kilowatt-hours of electricity from renewable sources in the 2014 production period. At a state average price of 10.56 cents per kilowatt-hours during the last 24 months (Energy Information Administration), this amounts to an estimated \$146,229,346.35 in revenue from the sale of electricity. This estimate of total revenues from sales of renewable electricity supported by the program was entered into the IMPLAN model in the “Electric power generation, transmission, and distribution” sector, which includes establishments that perform one or more of the following activities: operate generation facilities that produce electric energy; operate transmission systems that convey the electricity from the generation facility to the distribution system; and operate distribution systems that convey electric power received from the generation facility or the transmission system to the final consumer.

4.3 Results

Estimated direct, indirect, induced and total economic contributions of the program are summarized in Table 13. For 2014, a total program investment of \$13.7 million produced an estimated total output contribution of \$230.5 million, total value added contribution of \$128.6 million, and total labor income contribution of \$46.9 million. Similarly, the program is estimated to have supported or created nearly 166 jobs in the electricity generation, transmission and distribution sector, as well as 562 jobs in related and supporting industries, thereby having an estimated total employment contribution of 728 jobs.

Table 13. Summary of Economic Impacts in 2014 for the Renewable Energy Production Credit

Impact Type	Employment	Labor Income	Value Added	Output
Direct Effect	166.4	\$21,619,100	\$87,687,299	\$149,220,284
Indirect Effect	301.1	\$14,021,908	\$22,507,106	\$46,666,162
Induced Effect	260.4	\$11,310,353	\$20,411,415	\$34,642,094
Total Effect	727.9	\$46,951,361	\$130,605,820	\$230,528,541

Estimated local, state, and federal taxes collected as a result of the economic activity fostered by the program are summarized in Table 14. Total state and local taxes collected were estimated to be \$21 million, while total federal taxes collected were estimated to be \$14.2 million.

Table 14. Tax Impacts from the Renewable Energy Production Credit

Description	Employee Compensation	Proprietor Income	Tax on Production and Imports	Households	Corporations
Total State and Local Tax	\$35,086	\$0	\$20,616,068	\$161,177	\$220,036
Total Federal Tax	\$4,447,167	\$178,531	\$2,391,168	\$3,311,368	\$3,885,145

4.4 Applicant Highlights

This section highlights two of the 15 applicants from the 2014 approved applications to provide a better understanding of the economic contribution these projects are having on the state.

New Hope Power Company

The New Hope Power Plant is the largest renewable energy facility of its kind in North America and one of the largest in the world. Located in West Palm Beach, the New Hope Power Plant is part of an agro-industrial complex which includes a sugar mill and refinery. Urban wood and vegetable waste along with leftover sugar cane fiber are used to supply renewable electricity to the grid and the sugar processing facilities. During 2014, the New Hope Power Plant generated 344,158 megawatt-hours of renewable electricity, which is enough energy to power 32,000 homes for a year. The New Hope Power Plant also diverted 900,000 tons of wood waste from landfills last year which saved 3.5 million cubic yards of valuable landfill space.

The vast majority of the New Hope Power Plant's operation and maintenance expenses remain in the local economy. During 2014, more than \$40 million was spent to procure locally sourced fuel and to operate and maintain the facility. The New Hope Power Plant has a permanent staff of 48 people that include supervisory and professional positions. A dedicated on-site contractor provides another 45 fulltime positions for operators and mechanics. In addition, the New Hope Power Plant typically spends more than \$8 million per year on outside contractors to perform non-routine, specialized and major maintenance. Using these figures, the New Hope Power Plant conducted an analysis to determine the economic benefit of their operations in Florida during 2014 and found their facility generated an estimated \$28 million of economic activity in Florida and saved ratepayers more than \$12 million.

Harvest Power Orlando

Harvest Power Orlando is the first of its kind in the U.S., converting organic waste, primarily yard trimmings and food scraps, into renewable electricity and natural fertilizers. Located within the Reedy Creek Improvement District, Harvest Power Orlando uses anaerobic digestion, a biological process that relies on trillions of naturally occurring bacteria, to produce renewable electricity. When operating at full capacity, the facility will process more than 120,000 tons of organic materials annually while producing 5.4 megawatts of combined heat and power. During 2014, Harvest Power Orlando generated more than 14,000 megawatt-hours of renewable energy.

Harvest Power Orlando invested more than \$30 million dollars to bring their renewable energy facility online. Ten fulltime employees, with an annual salary of \$800,000, are responsible for the daily operation of the plant. Harvest Power Orlando has also created new jobs for Floridians in the following industries: trucking, construction, hotel, entertainment, and restaurant. Harvest Power Orlando has attracted many visitors from around the world that are interested in replicating their renewable energy facility. Currently, Harvest Power Orlando has talks underway to create large scale recycling and landfill diversion programs with Miami Dade County, City of Tampa, Port of Tampa, Collier County, City of Pensacola, City of Sunrise, Port Canaveral, University of Miami, and the City of Gainesville.

According to the U.S. Environmental Protection Agency, compostable organic material is the largest and heaviest portion of the overall waste stream in the United States. The majority of organic material is discarded with waste and hauled to landfills. Central Florida businesses feed

more than 50 million visitors each year which creates more than 356,000 tons of food waste per year. In its first year of operation, Harvest Power Orlando processed more than 17 million gallons of waste water, 4.5 million gallons of kitchen grease trap grease and more than 25,000 tons of food waste.

5. Return on Investment

To examine the gains that result from the Renewable Energy Tax Incentives to the economy of Florida, FDACS developed a measure of the Return on Investment (ROI) of the policy and associated programs. Two variations of this measure show the economic contributions and tax revenues generated for each dollar that the state invested in the Renewable Energy Technologies Investment Tax Credit, the Renewable Energy Production Credit and the Renewable Energy Tax Incentives as a whole during 2014. The measure is calculated using the following equation:

$$ROI = \frac{Return}{Investment}.$$

In the equation, *Return* refers to either the estimated total economic contribution or state and local taxes collected as a result of the program, while *Investment* refers to the total amount of credits approved by the department. The ROI for each of the two individual programs, and for the policy as a whole, are shown in Table 15.

Table 15. Return on Investment (ROI) from the Renewable Energy Technologies Investment Tax Credit, Renewable Energy Production Credit, and Renewable Energy Tax Incentives Policy

Program	Contribution ROI	State and Local Tax ROI
Renewable Energy Technologies Sales Tax Refund (Program)	\$29.64	\$0.66
Renewable Energy Technologies Investment Tax Credit (Program)	\$2.37	\$0.05
Renewable Energy Production Credit (Program)	\$16.74	\$1.53
Renewable Energy Tax Incentives (Policy)	\$10.90	\$0.90

Calculation of the ROI from the Renewable Energy Tax Incentives shows that all of these programs provide positive and sizable returns to the state of Florida. Each dollar invested in the Renewable Energy Technologies Sales Tax Refund yields an estimated \$29.64 in economic output throughout the state, and an estimated 66 cents of each dollar returns to state and local government coffers in the form of taxes. Similarly, every dollar invested in the Renewable Energy Technologies Investment Tax Credit results in an estimated \$2.37 of economic activity throughout the state, and an estimated 5 cents of every dollar returns to state and local government as tax revenues. The Renewable Energy Production Credit has an even more impressive return on investment, as every dollar invested in this program results in an estimated \$16.74 of economic activity throughout the state, and an estimated \$1.53 returns to state and local government as tax revenues.

Combining the three programs together to measure the ROI of the policy as a whole yields similarly impressive results, as every dollar invested in these incentives results in an estimated \$10.90 in economic activity throughout the state, and an estimated 90 cents returns to state and local government in the form of tax revenues.

6. Annual Trends in Program Contribution

The monetary awards and economic contribution of the Renewable Energy Tax Incentives Program have grown significantly in the second fiscal year of program implementation. As shown in Figure 1, every component of the program has experienced increased use of funds, and the program as a whole has experienced an increase in annual disbursements of nearly \$5.8 million.

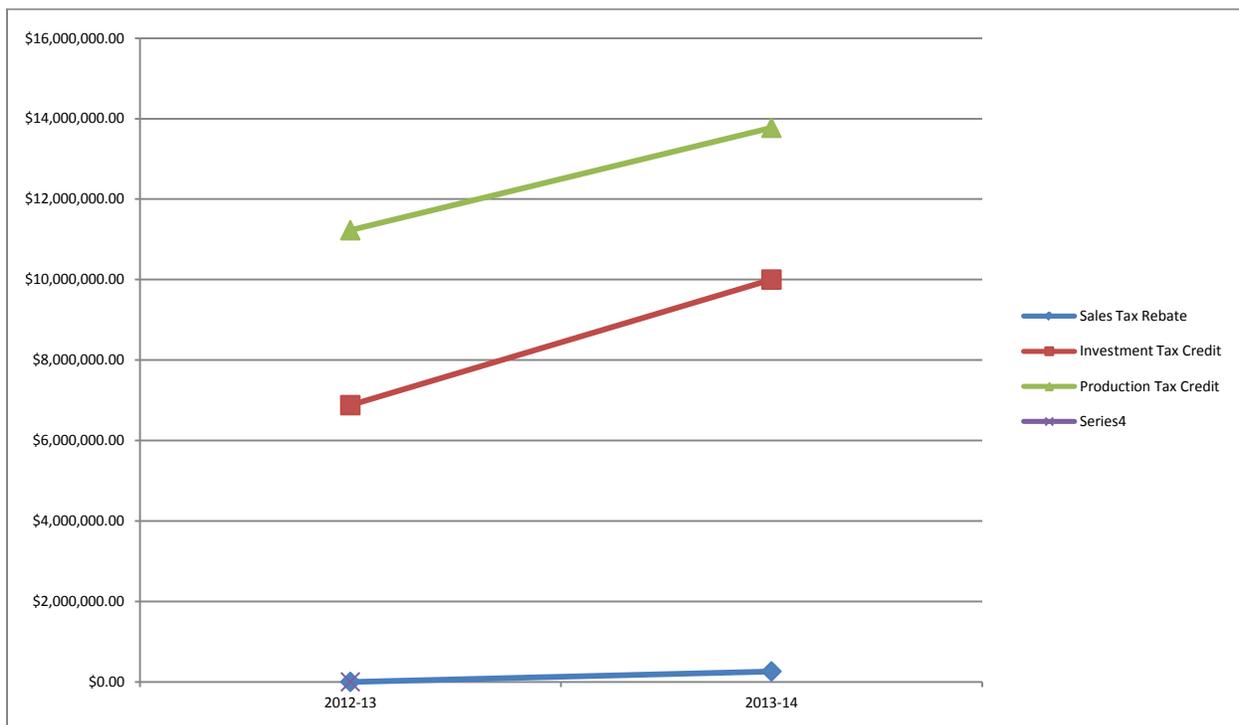


Figure 1. Funds awarded through the Renewable Energy Tax Incentives Program, FY2012-13 – FY2013-14.

Similarly, the economic contribution of the program has risen significantly since in the second year of program implementation. As Figure 2 shows, the economic contribution from every program component has increased in FY2013-14 over its FY2012-13 baseline. Overall, the program's statewide economic contribution has increased by a total of \$58 million during FY 2013-14.

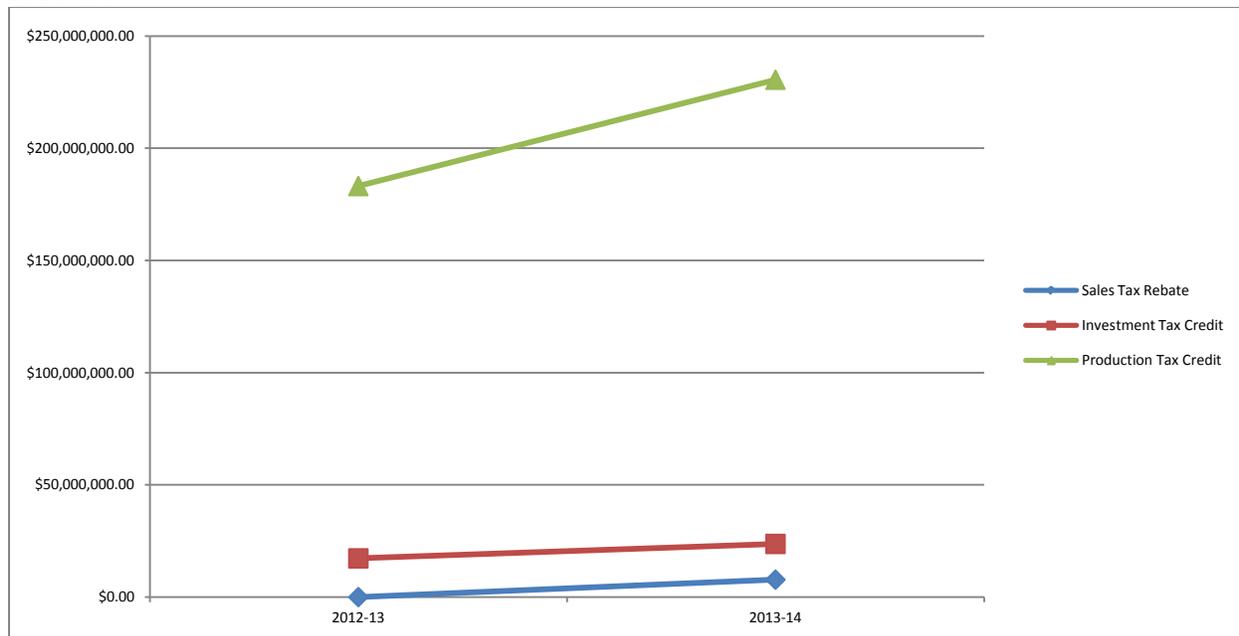


Figure 2. Economic contribution of the Renewable Energy Tax Incentives Program, FY2012-13 – FY2013-14.

7. Conclusion

The economic contribution of the Florida Renewable Energy Tax Incentives has been substantial. In 2014 alone, an investment in these programs of nearly \$24 million resulted in an estimated 909 jobs created or supported statewide. Similarly, these programs were responsible for raising an estimated \$21.7 million in state and local taxes, generating an estimated \$56 million in labor income and producing an estimated total economic contribution of more than \$261.9 million.

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COST EFFECTIVENESS MANUAL
FOR
DEMAND SIDE MANAGEMENT PROGRAMS
AND
SELF SERVICE WHEELING PROPOSALS

Florida Public Service Commission
Tallahassee, Florida
Adopted at June 11, 1991 Agenda Conference
Effective: July 17, 1991

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SECTION I. INTRODUCTION

This manual describes the minimum data requirements for the cost-effectiveness analyses used by the Florida Public Service Commission (FPSC) to evaluate utility proposed conservation programs, direct load control programs, and self-service wheeling proposals. The use of this manual is authorized by FPSC Rule 25-17.008, F.A.C.

Chapter 366.82, Florida Statutes, requires the FPSC to review and approve cost effective utility conservation programs. In addition, Chapter 366.051, Florida Statutes, requires public utilities to provide wheeling for self-service customers if such wheeling is not likely to result in higher cost electric service to the utility's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers. FPSC Rule 25-17.008 and this manual were adopted as part of the implementation of these Statutes.

There are three tests contained in this manual: the Total Resource Test, the Participants Test, and the Rate Impact Test. In evaluating conservation and direct load control programs, the Commission will review the results of all three tests to determine cost-effectiveness. The Rate Impact and Total Resource tests used for self-service wheeling projects are similar to those used for conservation and load control programs. A Participants Test is not specified for self-service wheeling since it is assumed that the proposal is cost-effective to the party requesting the wheeling. In addition to the Rate Impact and Total Resource tests, there are additional considerations listed for self-service wheeling projects.

Figure 1 is a pictorial comparison of the three cost effectiveness analyses set forth in this manual. Only very broad categories of costs and benefits are depicted so that the conceptual differences may be seen at a glance. The detailed definitions and applicable formulas are found in the manual proper.

The calculation of demand-reduction benefits for cost-effectiveness analyses performed under FPSC Rule 25-17.008 shall be on a revenue requirements basis for all programs under consideration. However, when the demand reduction achieved by a program cannot be reasonably projected to extend for the life of the avoided generating unit, the demand-reduction benefits shall also be calculated on a value of deferral basis.

The term "avoided generating unit" as used in this manual refers to a utility's proposed generating unit that is avoided in whole or in part by the demand-side management program. Avoided capacity charges shall be used in lieu of avoided generating unit costs, where appropriate, to determine cost effectiveness. Use of avoided capacity charges in lieu of avoided generating unit costs may be particularly appropriate by nongenerating utilities, wholesale power purchasers, or members of a power pool arrangement.

This manual does not address interruptible and curtailable load. However, nothing herein shall preclude the Commission from applying this methodology to such non-firm

load after explicit consideration of the matter by the Commission in a proceeding.

The delineation of the various ways of expressing test results is not meant to discourage the continued development of additional variations for expressing cost-effectiveness.

SECTION II. CONSERVATION AND DIRECT LOAD CONTROL

This Section describes the cost effectiveness tests that are required for conservation and direct load control programs. Three separate tests are defined. These are: the Total Resource Test, the Participants Test, and the Rate Impact Test.

The following information is provided for each test: (1) a definition; (2) the components of the benefits; (3) the components of the costs; (4) the formulas to be used to express the results in acceptable ways; and (5) the reporting format.

TOTAL RESOURCE COST TEST

DEFINITION:

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. This test may be turned into a Societal Test by excluding tax credit benefits, by including costs and benefits of externalities, and by using a societal discount rate, assuming that the costs and benefits of externalities are quantifiable.

GENERAL DESCRIPTION OF BENEFITS:

The benefits are the avoided supply costs, including avoided generation, transmission, and distribution costs. The avoided supply costs should be calculated using net savings, i.e., savings net of changes in energy use that would have happened in the absence of the program. Benefits include avoided supply costs for energy-using equipment not chosen by the participant.

GENERAL DESCRIPTION OF COSTS:

The costs are the program costs incurred by the utility and any increased supply costs. All equipment costs, installation, operation and maintenance, and administration costs, no matter who pays for them, are included in this test.

FORMULAS:

$$B_{npv} = \text{Sum of } (B_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

$$C_{npv} = \text{Sum of } (C_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

where

B_{npv} is the net present value of program benefits

C_{npv} is the net present value of program costs

B_t are the total program benefits for year t

C_t are the total program costs for year t

D is 1 + the discount rate for the utility

n is the life of the program

B_t is further defined as follows:

$$B_t = AG_t + AT_t + AD_t + FS_t + TC_t + OB_t$$

where

AG_t are the avoided generation benefits
 AT_t are the avoided transmission benefits
 AD_t are the avoided distribution benefits
 FS_t are the fuel savings from decreased sales
 TC_t are any tax credits
 OB_t are any other quantifiable benefits

AG_t is further defined as follows:

$$AG_t = AC_t + AO_t + AF_t - RF_t$$

where

AC_t are avoided unit capacity costs
 AO_t are avoided unit O&M costs
 AF_t are avoided unit fuel costs
 RF_t are replacement fuel costs

AC_t may be calculated for either the Value of Deferral or Revenue Requirements Methodology.

For the purpose of the Revenue Requirements Methodology, AC_t is further defined as follows:

$$AC_t = 0 \text{ before the in-service year}$$

$$AC_t = CC * GPR_t * GKW \text{ Red}_t$$

where

CC is the avoided in-service year capacity costs including AFUDC
 GPR_t is the revenue requirement in percent of capital cost
 $GKW \text{ Red}_t$ is the number of Kilowatts of plant avoided

where

GPR_t is the Annual Revenue Requirement factor which is calculated on PSC Form CE 1.1A, by taking annual total fixed charges (Column 10) divided by in-service cost.

$$GKW \text{ Red} = \text{Cumulative Total Participating Customers} \times KW \text{ Red}$$

Cumulative Total Participating Customers is defined on PSC Form CE 1.2, Input Data -- Part 2, Col (3).

KW Red is defined in Section IV, PSC Cost Effectiveness Forms, PSC Form CE 1.1, Input Data -- Part 1.

AT_t and AD_t , avoided transmission plant and avoided distribution plant, are defined similarly to AC_t . The in-service year, the economic life, and the Revenue Requirement factor for transmission and distribution plant may differ from that of the avoided generating unit.

For the purpose of applying the Value of Deferral Methodology, AC_t is defined as follows:

$AC_t = 0$ before the in-service year

$AC_t = K \cdot CC \cdot (1-R)/(1-R^N)$ for the in-service year

$AC_t = AC_{t-1} \cdot (1+E_p)$ after the in-service year

where

N is the economic life of the avoided generating unit

K is the present value of carrying charges for one dollar of investment over N years

CC is the avoided in-service-year capacity costs including AFUDC

E_p is the plant cost escalation rate

$R = (1+E_p)/D$

AT_t and AD_t , avoided transmission plant and avoided distribution plant, are defined similarly to AC_t . The in-service year, the economic life, K factor, and plant escalation rate for transmission and distribution plant may differ from that of the avoided generating unit.

C_t is further defined as follows:

$C_t = IS_t + UC_t + PC_t + OC_t$

where

IS_t are any increased supply costs

UC_t are utility program costs

PC_t are participant program costs

OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the program is cost effective.

REPORTING FORMAT:

Input: PSC Forms CE 1.1, 1.1A, 1.1B, 1.2

Output: PSC Forms CE 2.1, 2.2, 2.3

PARTICIPANTS TEST

DEFINITION:

The Participants Test measures the impact of the program on the participating customers.

GENERAL DESCRIPTION OF BENEFITS:

The benefits include the reductions in the customers' bills, incentives paid by the utility or other third party, and any tax credits received. Savings estimates should be based on gross energy savings as opposed to net energy savings. (Net savings are gross savings minus savings that would have occurred even in the absence of the program.)

For fuel substitution programs, benefits include the avoided capital and operating costs of the equipment not chosen. For load building programs, benefits include any increases in productivity or services attributable to the load building program.

GENERAL DESCRIPTION OF COSTS:

The costs include increases in the customers' bills, equipment and materials purchased, ongoing operation and maintenance costs and any equipment removal costs.

FORMULAS:

$$B_{npv} = \text{Sum of } (B_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

$$C_{npv} = \text{Sum of } (C_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

where

B_{npv} is the net present value of program benefits

C_{npv} is the net present value of program costs

B_t are the total program benefits for year t

C_t are the total program costs for year t

D is 1 + the discount rate for part. customers

n is the life of the program

B_t is further defined as follows:

$$B_t = BS_t + TC_t + UR_t + OB_t$$

where

BS_t are savings in customer bills

TC_t are any tax credits

UR_t are utility rebates or incentives

OB_t are any other quantifiable benefits

C_t is further defined as follows:

$$C_t = EC_t + CM_t + OC_t$$

where

EC_t are customer equipment costs

CM_t are customer O&M costs

OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the program is cost effective.

REPORTING FORMAT:

Input: PSC Forms CE 1.1, 1.2

Output: PSC Forms CE 2.4

RATE IMPACT TEST

DEFINITION:

The Rate Impact Test is an indirect measure of the impact on customer rates caused by the program. Rates will go down more than they otherwise would have if the change in utility revenues minus the change in utility costs is positive. Rates will go up more than they otherwise would have if the change in utility revenues minus the change in utility costs is negative.

GENERAL DESCRIPTION OF BENEFITS:

The benefits are the avoided supply costs, including avoided generation, transmission, and distribution costs. The benefits also include any increased revenues generated by the program. Reductions in supply costs and revenue increases should be calculated using net energy savings. (Net savings are gross savings minus savings that would have occurred even in the absence of the program.)

GENERAL DESCRIPTION OF COSTS:

The costs include the program costs incurred by the utility, the incentives paid to participants, and increased supply costs. The costs also include any decrease in revenues caused by the program.

FORMULAS:

$$B_{npv} = \text{Sum of } (B_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

$$C_{npv} = \text{Sum of } (C_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

where

B_{npv} is the net present value of program benefits

C_{npv} is the net present value of program costs

B_t are the total program benefits for year t

C_t are the total program costs for year t

D is 1 + the discount rate for the utility

n is the life of the program

B_t is further defined as follows:

$$B_t = AG_t + AT_t + AD_t + FS_t + IR_t + OB_t$$

where

AG_t are the avoided generation benefits

AT_t are the avoided transmission benefits

AD_t are the avoided distribution benefits

FS_t are the fuel savings from decreased sales

IR_t are any increased revenues
 OB_t are any other quantifiable benefits
 AG_t is further defined as follows:

$$AG_t = AC_t + AO_t + AF_t - RF_t$$

where

AC_t are avoided unit capacity costs
 AO_t are avoided unit O&M costs
 AF_t are avoided unit fuel costs
 RF_t are replacement fuel costs

AC_t may be calculated for either the Value of Deferral or Revenue Requirements Methodology.

For the purpose of the Revenue Requirements Methodology, AC_t is further defined as follows:

$$AC_t = 0 \text{ before the in-service year}$$

$$AC_t = CC * GPR_t * GKW \text{ Red}_t$$

where

CC is the avoided in-service year capacity costs including AFUDC
 GPR_t is the revenue requirement in percent of capital cost
 GKW Red_t is the number of Kilowatts of plant avoided

where

GPR_t is the Annual Revenue Requirement factor which is calculated on PSC Form CE 1.1A, by taking annual total fixed charges (Column 10) divided by in-service cost.

GKW Red = Cumulative Total Participating Customers x KW Red

Cumulative Total Participating Customers is defined on PSC Form CE 1.2, Input Data -- Part 2, Col (3).

KW Red is defined in Section IV, PSC Cost Effectiveness Forms, PSC Form CE 1.1, Input Data -- Part 1.

AT_t and AD_t, avoided transmission plant and avoided distribution plant, are defined similarly to AC_t. The in-service year, the economic life, and the Revenue Requirement factor for transmission and distribution plant may differ from that of the avoided generating unit.

For the purpose of applying the Value of Deferral Methodology, AC_t is defined as follows:

$AC_t = 0$ before the in-service year

$AC_t = K \cdot CC \cdot (1-R)/(1-R^N)$ for the in-service year

$AC_t = AC_{t-1} \cdot (1+E_p)$ after the in-service year

where

N is the economic life of the avoided generating unit

K is the present value of carrying charges for one dollar of investment over N years

CC is the avoided in-service-year capacity costs including AFUDC

E_p is the plant escalation rate

$R = (1+E_p)/D$

AT_t and AD_t , avoided transmission plant and avoided distribution plant, are defined similarly to AC_t . The in-service year, the economic life, K factor, and plant escalation rate for transmission and distribution plant may differ from that of the avoided generating unit.

C_t is further defined as follows:

$$C_t = IS_t + LR_t + UC_t + UR_t + OC_t$$

where

IS_t are any increased supply costs

LR_t are lost revenues from reduced sales

UC_t are utility program costs

UR_t are utility rebates/incentives for participants.

OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the program is cost effective.

REPORTING FORMAT:

Input: PSC Forms CE 1.1, 1.1A, 1.1B, 1.2

Output: PSC Forms CE 2.1, 2.2, 2.5, 2.5S

SECTION III. SELF-SERVICE WHEELING

This Section describes the prescribed cost effectiveness tests for self-service wheeling proposals. The reason for a separate section is that there are costs and benefits unique to cogeneration facilities, such as supplemental and standby purchases.

A self-service wheeling proposal is one where a utility retail customer proposes to generate power at one of its locations and have it delivered to another of its locations through the utility's transmission or distribution system. Chapter 366.051, Florida Statutes, requires public utilities to provide wheeling for self-service customers if such wheeling is not likely to result in higher cost electric service to the utility's general body of retail and wholesale customers.

The Rate Impact and Total Resource tests used here are similar to those used for conservation and load control programs. No Participants Test is specified since it is assumed that the proposal is cost-effective to the party requesting the wheeling. In addition to the Rate Impact and Total Resource tests, there are additional considerations listed for self-service wheeling projects.

RATE IMPACT TEST FOR SELF-SERVICE WHEELING

DEFINITION:

The Rate Impact Test for Self-Service Wheeling is an indirect measure of the impact on customer rates caused by the wheeling proposal. Rates will go down more than they otherwise would have if the change in utility revenues minus the change in utility costs is positive. Rates will go up more than they otherwise would have if the change in utility revenues minus the change in utility costs is negative.

GENERAL DESCRIPTION OF BENEFITS:

The benefits include avoided generation, transmission, and distribution costs, and any increased revenues, such as wheeling revenues and increased standby revenues, generated by the proposed project.

GENERAL DESCRIPTION OF COSTS:

The costs include any decrease in revenues caused by the program and any increased supply costs. When marginal fuel cost is less than average fuel cost, the decrease in sales will cause an increase in average fuel cost that must be borne by the remaining customers. Costs also include loss of fixed plant costs collected through demand or non-fuel energy charges.

FORMULAS:

$$B_{npv} = \text{Sum of } (B_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

$$C_{npv} = \text{Sum of } (C_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

where

B_{npv} is the net present value of benefits
 C_{npv} is the net present value of costs
 B_t are the total benefits for year t
 C_t are the total costs for year t
 D is 1 + the discount rate for the utility
 n is the life of the program

B_t is further defined as follows:

$$B_t = AG_t + AT_t + AD_t + IR_t + FS_t + OB_t$$

where

AG_t are the avoided generation benefits
 AT_t are the avoided transmission benefits
 AD_t are the avoided distribution benefits
 IR_t are the increased revenues
 FS_t are the net fuel savings
 OB_t are any other quantifiable benefits

AG_t is further defined as follows:

$$AG_t = AC_t + AO_t + AF_t - RF_t$$

where

AC_t are avoided unit capacity costs
 AO_t are avoided unit O&M costs
 AF_t are avoided unit fuel costs
 RF_t are replacement fuel costs

AC_t may be calculated for either the Value of Deferral or Revenue Requirements Methodology.

For the purpose of the Revenue Requirements Methodology, AC_t is further defined as follows:

$$AC_t = 0 \text{ before the in-service year}$$

$$AC_t = CC * GPR_t * GWK Red_t$$

where

CC is the avoided in-service year capacity costs including AFUDC
 GPR_t is the revenue requirement in percent of capital cost
 $GWK Red_t$ is the number of Kilowatts of plant avoided

where

GPR_t is the Annual Revenue Requirement factor which is calculated on PSC Form CE 1.1A, by taking annual total fixed charges (Column 10) divided by in-service cost.

$GKW \text{ Red} = \text{Cumulative Total Participating Customers} \times KW \text{ Red}$

Cumulative Total Participating Customers is defined on PSC Form CE 1.2, Input Data -- Part 2, Col (3).

$KW \text{ Red}$ is defined in Section IV, PSC Cost Effectiveness Forms, PSC Form CE 1.1, Input Data -- Part 1.

AT_t and AD_t , avoided transmission plant and avoided distribution plant, are defined similarly to AC_t . The in-service year, the economic life, and the Revenue Requirement factor for transmission and distribution plant may differ from that of the avoided generating unit.

For the purpose of applying the Value of Deferral Methodology, AC_t is defined as follows:

$AC_t = 0$ before the in-service year

$AC_t = K \cdot CC \cdot (1-R) / (1-R^N)$ for the in-service year

$AC_t = AC_{t-1} \cdot (1+E_p)$ after the in-service year

where

N is the tax life of the avoided generating unit

K is the present value of carrying charges for one dollar of investment over N years

CC is the avoided in-service-year capacity costs including AFUDC

E_p is the plant escalation rate

$R = (1+E_p)/D$

AT_t and AD_t , avoided transmission plant and avoided distribution plant, are defined similarly to AC_t . The in-service year, the economic life, K factor, and plant escalation rate for transmission and distribution plant may differ from that of the avoided generating unit.

C_t is further defined as follows:

$C_t = FC_t + LR_t + OC_t$

where

FC_t are net increase in fuel costs

LR_t are lost revenues from reduced sales

OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the program is cost effective.

REPORTING FORMAT:

Input: PSC Forms CE 3.1, 1.1A, 1.1B, 3.2

Output: PSC Forms CE 2.1, 2.2, 3.3, 3.3S

TOTAL RESOURCE TEST FOR SELF-SERVICE WHEELING

DEFINITION:

The Total Resource Cost Test measures the net costs of a self-service wheeling project as a resource option based on the total costs of the project, including both the participants' and the utility's costs. This test may be turned into a Societal Test by excluding tax credit benefits, by including costs and benefits of externalities, and by using a societal discount rate, assuming that the costs and benefits of externalities are quantifiable.

GENERAL DESCRIPTION OF BENEFITS:

The benefits are the avoided supply costs, including avoided generation, transmission, and distribution costs.

GENERAL DESCRIPTION OF COSTS:

The costs are the project costs incurred by the utility and any increased supply costs. All equipment costs, installation, operation and maintenance, and administration costs, no matter who pays for them, are included in this test.

FORMULAS:

$$B_{npv} = \text{Sum of } (B_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

$$C_{npv} = \text{Sum of } (C_t / D^{t-1}) \text{ for } t = 1 \text{ to } n$$

where

B_{npv} is the net present value of project benefits

C_{npv} is the net present value of project costs

B_t are the total project benefits for year t

C_t are the total project costs for year t

D is $1 +$ the discount rate for the utility

n is the life of the project

B_t is further defined as follows:

$$B_t = AG_t + AT_t + AD_t + FS_t + TC_t + OB_t$$

where

AG_t are the avoided generation benefits

AT_t are the avoided transmission benefits

AD_t are the avoided distribution benefits

FS_t are the fuel savings from decreased sales

TC_t are any tax credits

OB_t are any other quantifiable benefits

AG_t is further defined as follows:

$$AG_t = AC_t + AO_t + AF_t - RF_t$$

where

AC_t are avoided unit capacity costs

AO_t are avoided unit O&M costs

AF_t are avoided unit fuel costs

RF_t are replacement fuel costs

AC_t may be calculated for either the Value of Deferral or Revenue Requirements Methodology.

For the purpose of the Revenue Requirements Methodology, AC_t is further defined as follows:

$$AC_t = 0 \text{ before the in-service year}$$

$$AC_t = CC * GPR_t * GKW \text{ Red}_t$$

where

CC is the avoided in-service year capacity costs including AFUDC

GPR_t is the revenue requirement in percent of capital cost

$GKW \text{ Red}_t$ is the number of Kilowatts of plant avoided

where

GPR_t is the Annual Revenue Requirement factor which is calculated on PSC Form CE 1.1A, by taking annual total fixed charges (Column 10) divided by in-service cost.

$GKW \text{ Red} = \text{Cumulative Total Participating Customers} \times KW \text{ Red}$

Cumulative Total Participating Customers is defined on PSC Form CE 1.2, Input Data -- Part 2, Col (3).

KW Red is defined in Section IV, PSC Cost Effectiveness Forms, PSC Form CE 1.1, Input Data -- Part 1.

AT_t and AD_t , avoided transmission plant and avoided distribution plant, are defined similarly to AC_t . The in-service year, the economic life, and the Revenue Requirement factor for transmission and distribution plant may differ from that of the avoided generating unit.

For the purpose of applying the Value of Deferral Methodology, AC_t is defined as follows:

$$AC_t = 0 \text{ before the in-service year}$$

$AC_t = K \cdot CC \cdot (1-R) / (1-R^N)$ for the in-service year

$AC_t = AC_{t-1} \cdot (1+E_p)$ after the in-service year

where

N is the economic life of the avoided generating unit

K is the present value of carrying charges for one dollar of investment over N years

CC is the avoided in-service-year capacity costs including AFUDC

E_p is the plant cost escalation rate

$R = (1+E_p)/D$

AT_t and AD_t , avoided transmission plant and avoided distribution plant, are defined similarly to AC_t . The in-service year, the economic life, K factor, and plant escalation rate for transmission and distribution plant may differ from that of the avoided generating unit.

C_t is further defined as follows:

$C_t = IS_t + UC_t + PC_t + OC_t$

where

IS_t are any increased supply costs

UC_t are utility program costs

PC_t are participant program costs

OC_t are other quantifiable costs

If $B_{npv} > C_{npv}$ the project is cost effective.

REPORTING FORMAT:

Input: PSC Forms CE 1.1, 1.1A, 1.1B, 1.2

Output: PSC Forms CE 2.1, 2.2, 2.3

OTHER CONSIDERATIONS

In addition to the Rate Impact and Total Resource tests, the following will be considered by the Commission in its determination of the cost-effectiveness of self-service projects:

- (1) The type of fuel used at the cogeneration project.
- (2) The fuel efficiency of the project.
- (3) The likelihood of a cogenerator building its own transmission line to its other location.
- (4) The materiality of any lost revenues indicated by the Rate Impact test.

SECTION IV. FPSC COST EFFECTIVENESS FORMS

This Section contains the forms to be used in conjunction with the tests discussed in the previous sections of this manual. The following list contains the FPSC Form designation, the name of the FPSC Form, and a brief description of each form. This is followed by sample forms to be used, showing column headings and other pertinent information.

PSC FORM CE 1.1 Input Data -- Part 1

This form, along with PSC FORM CE 1.2, specifies the input data to be used in the cost-effectiveness test for conservation and direct load control programs. Each element on the form is defined below:

I.(1) Customer KW Reduction at Meter

This is the maximum load reduction in kilowatts at the customer's meter.

I.(2) Generator KW Reduction Per Customer

This input is developed by taking into account such factors as reliability, line losses and customer diversity. A crude, but acceptable, method of calculating the KW reduction is to use the following formula:

$$\text{KW Red} = [\text{DS}_w(\text{WLOLP}) + \text{DS}_s(\text{SLOLP})] / [(\text{ALOLP})(1-\text{FOR})(1-\text{DL})]$$

where

DS_w is the demand saving at winter peak
 DS_s is the demand saving at summer peak
 WLOLP is the winter seasonal LOLP
 SLOLP is the summer seasonal LOLP
 ALOLP is the annual LOLP
 FOR is the forced outage rate
 DL is the kw line loss factor

and

$$(\text{WLOLP} + \text{SLOLP}) / \text{ALOLP} = 1$$

I.(3) KW Line Loss Percentage

This is the percentage reduction in KW from the generator to the customer.

I.(4) Generation KWH Reduction Per Customer

This is the annual KWH reduction given by the following formula:

$$\text{KWH Red} = \text{KWH}_m / (1 - \text{EL})$$

where

KWH_m is the KWH reduction at the customer's meter

EL is the energy line loss factor to account for losses from the generator to the customer location

I.(5) KWH Line Loss Percentage

This is the percentage reduction in KWH from the generator to the customer.

I.(6) Group Line Loss Multiplier

This is a factor used to take into account the fact that various groups of customers receive service at different voltage levels. It is used to adjust the fuel cost calculation for participating customers.

I.(7) Customer KWH Increase at Meter

For conservation programs, this input would normally be zero. But, for other programs such as thermal storage, there may be an increase in KWH during off-peak periods.

II.(1) Study Period for the Conservation Program

This is the economic life of the conservation program, and will generally be less than or equal to the life of the unit to be avoided.

II.(2) Generator Economic Life

This is the economic life of the avoided generating unit.

II.(3) Transmission and Distribution Economic Life

This is the economic life of the avoided transmission and distribution facilities.

II.(4) K Factor for Generation

This is the present value of carrying charges for a \$1 investment over the life of the generating unit. PSC FORM CE 1.1A must be filed showing in detail the calculation of this factor.

II.(5) K Factor for Transmission and Distribution

This is the present value of carrying charges for a \$1 investment over the life of the avoided transmission and distribution facilities. PSC FORM CE 1.1A must be filed showing in detail the calculation of this factor.

- III.(1) Utility Nonrecurring Cost per Customer
This represents nonrecurring costs in the base year that would be incurred by the utility, such as a one-time customer rebate.
- III.(2) Utility Recurring Cost per Customer
This represents recurring costs in the base year that would be incurred by the utility, such as O&M costs associated with the installed equipment.
- III.(3) Utility Cost Escalation Rate
This rate is used to escalate the costs identified in III.(2). Normally, this rate would be close to the rate at which the Consumer Price Index is projected to increase.

NOTE: As an alternative, annual program costs may be specified for each year on the appropriate FORM, but detailed documentation must be attached to show how these costs were computed.
- III.(4) Customer Equipment Cost
This is the base year cost for equipment incurred by each customer when the program is selected.
- III.(5) Customer Equipment Cost Escalation Rate
This rate is used to escalate the costs identified in III.(4). Normally, this rate would be close to the rate at which the Consumer Price Index is projected to increase.

NOTE: As an alternative, annual customer equipment costs may be specified for each year on the appropriate FORM, but detailed documentation must be attached to show how these costs were computed.
- III.(6) Customer O&M Cost
This is the base year cost for O&M incurred by each participating customer.
- III.(7) Customer O&M Cost Escalation Rate
This rate is used to escalate the costs identified in III(6). Normally, this rate would be close to the rate at which the Consumer Price Index is projected to increase.

NOTE: As an alternative, annual O&M costs may be specified for each year on the appropriate FORM, but detailed documentation must be attached to show how these costs were computed.
- IV.(1) Base Year

- This is the reference year for the present worth analyses and the first year for recording costs and benefits of the program.
- IV.(2) In-Service Year for Avoided Generator Unit
- This is the in-service year of the generating unit to be avoided or deferred by the conservation program.
- IV.(3) In-Service Year for Avoided T&D
- This is the in-service year of the transmission and distribution facilities to be avoided or deferred by the conservation program.
- IV.(4) Base Year Avoided Generating Unit Cost
- This is the base year cost in dollars per kilowatt of the generating unit to be avoided or deferred by the conservation program. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the unit in the in-service year, including AFUDC.
- IV.(5) Base Year Avoided Transmission Cost
- This is the base year cost in dollars per kilowatt of the transmission facilities to be avoided or deferred by the conservation program. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the facilities in the in-service year, including AFUDC.
- IV.(6) Base Year Avoided Distribution Cost
- This is the base year cost in dollars per kilowatt of the distribution facilities to be avoided or deferred by the conservation program. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the facilities in the in-service year, including AFUDC.
- IV.(7) Gen, Tran, and Dist Cost Escalation Rate
- This is the escalation rate to be used in escalating the costs in IV.(4) through IV.(6).
- IV.(8) Generator Fixed O&M Costs
- This is the annual fixed O&M costs for the generating unit to be avoided or deferred, stated in \$/KW/Year.
- IV.(9) Generator Fixed O&M Cost Escalation Rate
- This is the escalation rate to be used in escalating the costs in IV.(8).
- IV.(10) Transmission Fixed O&M Costs

This is the annual fixed O&M costs for the transmission facilities to be avoided or deferred, stated in \$/KW/Year.

IV.(11) Distribution Fixed O&M Costs

This is the annual fixed O&M costs for the distribution facilities to be avoided or deferred, stated in \$/KW/Year.

IV.(12) Trans and Distr Fixed O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in IV.(10) and IV.(11).

IV.(13) Avoided Generating Unit Variable O&M Costs

This is the base year variable O&M costs for the generating unit to be avoided or deferred, stated in cents/KWH.

IV.(14) Generator Variable O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in IV.(13).

IV.(15) Generator Capacity Factor

This is the projected capacity factor of the generating unit to be avoided or deferred.

IV.(16) Avoided Generating Unit Fuel Cost

This is the base year fuel costs for the generating unit to be avoided or deferred, stated in cents/KWH.

IV.(17) Avoided Generating Unit Fuel Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in IV.(16).

V.(1) Non Fuel Cost in Customer Bill

This is the base year non fuel charge in the participating customer's bill in cents per KWH.

V.(2) Non Fuel Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in V.(1).

V.(3) Demand Charge in Customer Bill

This is the base year demand charge in the participating customer's bill in \$/KW/Month. This would be zero for residential customers.

V.(4) Demand Charge Escalation Rate

This is the escalation rate to be used in escalating the costs in V.(3).

PSC FORM CE 1.1A Calculation of K Factor

This form specifies the data to be used when calculating the K Factor for the avoided generating unit and also for avoided transmission and distribution plant, if applicable. Each element on the form is defined below:

Col (1) Year

The years begin with the in-service year of the avoided unit (or avoided transmission and distribution plant) and extend through the life of the unit (or other avoided plant).

Col (2) Mid-Year Rate Base

This column contains, for each year, the value of the avoided investment at mid year. This is calculated by averaging the beginning-of-year and end-of-year rate bases. The end-of-year rate base is calculated by subtracting straight-line depreciation (Column 9) and deferred taxes (Column 7) from beginning-of-year rate base. See PSC Form CE 1.1A, Page 2 of 2 for this calculation. The beginning-of-year rate base is the in-service cost of the plant calculated on PSC FORM CE 1.1B.

Col (3) Debt

This column contains, for each year, the cost of debt associated with the investment given in Column (2).

Col (4) Preferred Stock

This column contains, for each year, the after-tax cost of preferred stock associated with the investment given in Column (2).

Col (5) Common Equity

This column contains, for each year, the after-tax cost of common equity associated with the investment given in Column (2).

Col (6) Taxes

This column contains, for each year, the taxes associated with the before-tax cost of preferred and common stock.

Col (7) Other Taxes & Insurance

This column contains all taxes and insurance not contained in Column (6).

Col (8) Depreciation

This column contains, for each year, the depreciation costs associated with the in-service cost of the avoided plant.

Col (9) Deferred Taxes

This column contains the deferred taxes for each year. The tax depreciation schedule is given as Page 2 of 2 of PSC FORM CE 1.1A.

Col (10) Total Fixed Charges

This column contains, for each year, the sum of column (3) through column (8).

Col (11) Present Worth Fixed Charges

This column is the present value of the corresponding numbers in the previous column, using the in-service year as the reference year.

Col (12) Cumulative Present Worth Fixed Charges

This column is the year by year accumulation of the numbers in the previous column.

As indicated in the example, this form must also contain the in-service cost of the plant, the book life of the plant, the capital structure, the effective tax rate, and the discount rate used to calculate present worth dollars.

PSC FORM CE 1.1B Calculation of AFUDC and In-Service Cost of Plant

This form specifies the data to be used when calculating AFUDC and the in-service cost of plant (generating unit or transmission and distribution plant). Each element on the form is defined below:

Col (1) Year

The years begin with the first year of construction for the avoided unit (or avoided transmission and distribution plant) and extend to the in-service year.

Col (2) Years Prior to In-Service Year

This column contains the number of years prior to the in-service year of the plant corresponding to each year in Column (1).

Col (3) Plant Escalation Rate

This column contains the plant escalation rate corresponding to each year in Column (1).

Col (4) Cumulative Escalation Rate

This column contains the cumulative escalation rate corresponding to each year in Column (3).

Col (5) Percent Expenditure

This column contains, for each year of construction, the percentage of the plant to be constructed. The sum of the percentages in this column should equal 100.

Col (6) Annual Spending

This column contains the year-end spending, in dollars per kilowatt, for each year of construction.

Col (7) Cumulative Average Spending

This column contains the cumulative average spending for each year of construction.

Col (8) Cumulative Spending with AFUDC

This column contains, for each year, the cumulative average spending for that year (from Column 7) plus the AFUDC that has accumulated through the previous year.

Col (9) Yearly AFUDC

This column contains the AFUDC applicable for each year.
Col (10) Incremental Year-End Book Value

This column contains the incremental value added to the plant each year.

Col (11) Cumulative Year-End Book Value

This column contains, for each year, the cumulative year-end book value for the plant. The final figure in this column represents the in-service year cost.

As indicated in the example, this form must also contain the in-service cost of the plant (in dollars per kilowatt), the base year construction cost (\$/KW), and the AFUDC rate.

PSC FORM CE 1.2 Input Data -- Part 2

This form, along with PSC FORM CE 1.1 specifies the input data to be used in the cost-effectiveness test for conservation and direct load control programs. Each element on the form is defined below:

Col (1) Year

The years begin with the Base Year and extend through the life of the conservation program.

Col (2) Cumulative Total Participating Customers

This column contains, for each year, the cumulative total participating customers without regard as to whether they would have adopted the conservation measure in the absence of a utility sponsored program.

Col (3) Adjusted Cumulative Total Participating Customers

This column contains, for each year, the cumulative total participating customers adjusted for the fact that some customers would have adopted the conservation measure in the absence of a utility sponsored program.

Col (4) Utility Average System Fuel Cost

This column contains, for each year, the annual average system fuel cost, including costs of purchases and sales.

Col (5) Avoided Marginal Fuel Cost

This column contains, for each year, the annual average avoided fuel costs in cents per KWH. These costs should reflect the fact that conservation programs have different impacts on the system, depending on the hour of the day. If the program reduces consumption on peak, the marginal fuel costs may be significantly higher than the average fuel costs, resulting in savings to all customers.

Col (6) Increased Marginal Fuel Cost

This column contains, for each year, the annual average increased fuel costs in cents per KWH. These costs reflect the fact that some conservation programs increase energy use during certain hours.

Col (7) Replacement Fuel Cost of Avoided Generating Unit

This column contains, for each year, the annual average replacement fuel costs in cents per KWH. This is the system fuel cost if the utility had built the unit to be avoided. If the avoided unit would have lowered system fuel costs, then these costs act as an offset to the savings gained by not building the unit. On the other hand, if the avoided unit would have raised system fuel costs,

there are additional savings to be achieved by avoiding the unit.

Col (8) Program KW Effectiveness Factor

This column contains, for each year, a factor that represents the degradation or improvement of the demand savings over time. Complete documentation must be supplied if a factor other than 1 is used.

Col (9) Program KWH Effectiveness Factor

This column contains, for each year, a factor that represents the degradation or improvement of the energy savings over time. Complete documentation must be supplied if a factor other than 1 is used.

PSC FORM CE 2.1 Avoided Generating Unit Benefits

This form is used to report the avoided generating unit benefits of a conservation program or self-service wheeling project. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program. Normally, benefits on this form will be zero until the in-service year of the avoided unit. Also, benefits will only accrue for the life of the conservation program.

Col (2) Avoided Generating Unit Capacity Cost

This column contains the avoided generating unit benefits as previously defined in Section II. These are value of deferral benefits that extend from the in-service year of the avoided unit through the life of the conservation program or the life of the avoided unit, whichever comes first.

Col (3) Avoided Generating Unit Fixed O&M

This column contains the avoided generating unit fixed O&M costs. This may be calculated by taking the dollars per kilowatt per year as reported on PSC FORM CE 1.1 times the kilowatts saved, with costs escalated appropriately.

Col (4) Avoided Generating Unit Variable O&M

This column contains the avoided generating unit variable O&M costs. This may be calculated by taking the dollars per kilowatt-hour reported on PSC FORM CE 1.1 times the kilowatts saved times the capacity factor times 8760, with costs escalated appropriately.

Col (5) Avoided Generating Unit Fuel Costs

This column contains the annual fuel costs for the avoided generating unit. This may be calculated by taking the fuel cost reported on PSC FORM CE 1.1 times the kilowatts saved times the capacity factor times 8760, with fuel costs escalated appropriately.

Col (6) Replacement Fuel Costs

This column contains the replacement fuel costs that occur because the avoided generating unit was not built. These costs may be calculated by multiplying the annual kwh generation of the avoided unit by the replacement fuel costs shown on PSC FORM CE 1.2. (The net fuel savings of the avoided plant would be calculated by subtracting this column from column 5). For a base loaded avoided unit, the net fuel savings might be large. At the other extreme, the net fuel savings for a peaker might be very small or slightly negative.

Col (7) Avoided Generating Unit Benefits

This column is the sum of columns (2) through (5) minus column (6).

This form also contains totals for each column and the cumulative net present value for each column.

PSC FORM CE 2.2 Avoided T&D, Program Fuel Savings, and Other Benefits

This form is used to report the avoided transmission benefits, avoided distribution benefits, program fuel savings, and other benefits of a conservation program or self-service wheeling project. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Avoided Transmission Capacity Cost

This column contains the avoided transmission capacity benefits as previously defined in Section II. These are value of deferral benefits that extend from the in-service year of the avoided transmission plant through the life of the conservation program or the life of the avoided generating unit, whichever comes first.

Col (3) Avoided Transmission Fixed O&M Cost

This column contains the avoided generating unit fixed O&M costs. This may be calculated by taking the dollars per kilowatt per year as reported on PSC FORM CE 1.1 times the kilowatts saved, with costs escalated appropriately.

Col (4) Total Avoided Transmission Cost

This is the sum of columns (2) and (3).

Col (5) Avoided Distribution Capacity Cost

This column is analogous to Column (2).

Col (6) Avoided Distribution Fixed O&M Cost

This column is analogous to Column (3).

Col (7) Total Avoided Distribution Costs

This is the sum of columns (5) and (6).

Col (8) Program Fuel Savings

This column contains the fuel savings generated by the conservation program. This is the product of the kwh saved per customer, the number of participating customers, and the appropriate marginal fuel cost.

PSC FORM CE 2.3 Total Resource Cost Test

This form is used for the Total Resources Cost Test. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Increased Supply Costs

This column contains any increased supply costs associated with the program. This includes both energy and capacity supply costs as well as costs for alternate fuels.

Col (3) Utility Program Costs

This column contains the costs of the program incurred by the utility, including equipment costs, administrative costs.

Col (4) Participant Program Costs

This column is the same as column (10), PSC FORM CE 2.4.

Col (5) Other Costs

This column contains other quantifiable costs attributable to the program, including environmental and other external costs.

Col (6) Total Costs

This column is the sum of the costs in columns (2) through (5).

Col (7) Avoided Generating Unit Benefits

This column is the same as column (7) on PSC FORM 2.1.

Col (8) Avoided Transmission and Distribution Plant Benefits

This column is the sum of columns (4) and (7) on PSC FORM CE 2.2.

Col (9) Program Fuel Savings

This column is the same as column (8) on PSC FORM CE 2.2.

Col (10) Other Benefits

This column contains any other quantifiable benefits. Complete documentation must be provided to support the figures in this column.

Col (11) Total Benefits

This column is the total of columns (7) through (11).

Col (12) Net Benefits

This is total costs minus total benefits.

Col (13) Cumulative Discounted Net Benefits

The figures in this column are obtained by discounting the figures in column (12) to the first year in column (1) and then accumulating these discounted figures year by year.

PSC FORM CE 2.4 Participant Costs and Benefits

This form is used to report the costs and benefits for the participating customers. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Savings in Participants' Bills

This column contains the savings in customer bills brought about by the reduction in kwh usage.

Col (3) Tax Credits

This column contains any tax credits received by the participant.

Col (4) Utility Rebates

This column contains any utility rebates to participating customers.

Col (5) Other Benefits

This column contains other quantifiable benefits to the participant attributable to the program. Complete documentation must be provided to support the figures in this column.

Col (6) Total Benefits

This column is the sum of the costs in columns (2) through (5).

Col (7) Customer Equipment Costs

This column contains equipment costs borne by the participating customer.

Col (8) Customer O&M Costs

This column contains O&M costs borne by the participant.

Col (9) Other Costs

This column contains other quantifiable costs borne by the participant. Complete documentation must be provided to support the figures in this column.

Col (10) Total Costs

This column is the total of columns (7) through (9).

Col (11) Net Benefits

The numbers in this column are calculated by subtracting column (9) from column (6).

Col (12) Cumulative Discounted Net Benefits

This column contains the cumulative discounted net benefits of the program. The figures in this column are obtained by discounting the figures in column (11) and accumulating them year by year.

This form also contains the in-service year of the avoided generating unit and the appropriate customer discount rate.

PSC FORM CE 2.5 Rate Impact Test

This form is used to report the costs and benefits from the standpoint of the impact on customer rates. If costs exceed benefits, rates would be higher than they otherwise would be if the program is implemented. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Increased Supply Costs

This column is identical to column (2), PSC FORM CE 2.3.

Col (3) Utility Program Costs

This column is identical to column (3), PSC FORM CE 2.3.

Col (4) Incentives

This column contains any utility incentives paid to the participating customers.

Col (5) Revenue Losses

This column contains any revenue losses for periods where the load has been decreased.

Col (6) Other Costs

This column contains any other quantifiable costs attributable to the program. Complete documentation must be provided to support the figures in this column.

Col (7) Total Costs

This column is the sum of columns (2) through (6).

Col (8) Avoided Gen Unit & Fuel Benefits

This column is the sum of columns (4) and (5), PSC FORM CE 2.1.

Col (9) Avoided T&D Benefits

This column is identical to column (8), PSC FORM CE 2.3.

Col (10) Revenue Gains

This column contains any revenue losses for periods where the load has been

increased.

Col (11) Other Benefits

This column contains other quantifiable benefits. Complete documentation must be provided for the numbers in this column.

Col (12) Total Benefits

This column is the sum of columns (8) through (11).

Col (13) Net Benefits

This column is calculated by subtracting column (7) from column (12).

Col (14) Cumulative Discounted Net Benefits

This column is the accumulation of the figures in column (13), discounted by the appropriate discount rate.

This form also contains the discount rate and the benefit/cost ratio.

PSC FORM CE 2.5S Supplementary Form on Revenue Gains and Losses

A supplementary form will be filed containing, for each year, an allocation of the revenue gains and losses reported in columns (5) and (10) to general and administrative, generation, transmission and distribution.

PSC FORM CE 3.1 Input Data, Self-Service Wheeling -- Part 1

This form, along with PSC FORM CE 3.2, specifies the input data to be used for self-service wheeling proposals. Each element on the form is defined below:

I.(1) Generator KW Reduction

This input is calculated by taking into account such factors as reliability, line losses and customer diversity.

I.(2) KW Line Loss Percentage

This is the percentage reduction in KW from the generator to the customer.

I.(3) KWH Line Loss Percentage

This is the percentage reduction in KWH from the generator to the customer.

I.(4) Group Line Loss Multiplier

This is a factor used to take into account the fact that various groups of customers receive service at different voltage levels.

II.(1) Study Period for the Proposal

This is the number of years in the analysis and will generally be less than or equal to the life of the avoided unit.

II.(2) Generator Economic Life

This is the economic life of the avoided generating unit.

II.(3) T&D Economic Life

This is the economic life of the avoided transmission and distribution facilities.

II.(4) K Factor for Generation

This is the present value of carrying charges for a \$1 investment over the life of the avoided generating unit. PSC FORM CE 1.1A must be filed showing in detail the calculation of this factor.

II.(5) K Factor for T&D

This is the present value of carrying charges for a \$1 investment over the life of the avoided transmission and distribution facilities. PSC FORM CE 1.1A must be filed showing in detail the calculation of this factor.

III.(1) Supplemental Billing KW Reduction

The reduction in billing demand for supplemental purchases because the QF

will serve load with its own generation.

III.(2) Supplemental MWH Reduction at Meter

The reduction in energy for supplemental purchases as a result of self-service wheeling.

III.(3) Self-Service Wheeling Charge

The charge for self-service wheeling.

III.(4) Wheeling Escalation Rate

The annual rate of escalation that applies to III.(6).

III.(5) Standby Billing KW Increase

The increase in billing demand for standby purchases as a result of self-service wheeling.

III.(6) Standby MWH Increase at Meter

The increase in billing energy for standby purchases as a result of self-service wheeling.

IV.(1) Utility Non-Recurring Cost

This represents non-recurring costs in the base year of the analysis.

IV.(2) Utility Recurring Costs

These are the recurring administrative costs of the utility as a result of the self-service wheeling proposal.

IV.(3) Utility Cost Escalation Rate

This rate is used to escalate the costs in IV.(2).

V.(1) Base Year

This is the reference year for the present worth analyses and the first year for recording costs and benefits of the proposal.

V.(2) In-Service Year of Avoided Gen Unit

This is the in-service year of the generating unit to be avoided by the self-service wheeling project.

V.(3) In-Service Year for Avoided T&D

This is the in-service year of the transmission and distribution facilities to be avoided by the self-service wheeling project.

V.(4) Base Year Avoided Gen Unit Cost

This is the base year cost in dollars per kilowatt of the generating unit to be avoided or deferred by the project. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the unit in the in-service year, including AFUDC.

V.(5) Base Year Avoided Transmission Cost

This is the base year cost in dollars per kilowatt of the transmission facilities to be avoided or deferred by the project. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the unit in the in-service year, including AFUDC.

V.(6) Base Year Avoided Distribution Cost

This is the base year cost in dollars per kilowatt of the distribution facilities to be avoided or deferred by the project. PSC FORM CE 1.1B must be filed showing in detail the calculation of the installed cost of the unit in the in-service year, including AFUDC.

V.(7) Gen, Trans, Dist Cost Escalation Rate

This rate is used to escalate the costs in V.(4), V.(5) and V.(6).

V.(8) Generator Fixed O&M Costs

This is the annual fixed O&M costs for the generating unit to be avoided or deferred, stated in \$/KW/Year.

V.(9) Generator Fixed O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in V.(8).

V.(10) Transmission Fixed O&M Costs

This is the annual fixed O&M costs for the transmission facilities to be avoided or deferred, stated in \$/KW/Year.

V.(11) Distribution Fixed O&M Costs

This is the annual fixed O&M costs for the distribution facilities to be avoided or deferred, stated in \$/KW/Year.

V.(12) Trans and Distr Fixed O&M Cost Escalation Rate

This is the escalation rate to be used in escalating the costs in V.(10) and

V.(11).

- V.(13) Avoided Generating Unit Variable O&M Costs
This is the base year variable O&M costs for the generating unit to be avoided or deferred, stated in cents/KWH.
- V.(14) Generator Variable O&M Cost Escalation Rate
This is the escalation rate to be used in escalating the costs in V.(13).
- V.(15) Generator Capacity Factor
This is the projected capacity factor of the generating unit to be avoided or deferred.
- V.(16) Avoided Generating Unit Fuel Cost
This is the base year fuel costs for the generating unit to be avoided or deferred, stated in cents/KWH.
- V.(17) Avoided Generating Unit Fuel Cost Escalation Rate
The rate of escalation that the cost in V.(16) would be escalated each year.
- VI.(1) Supplemental Service Rate, Non-Fuel
The non-fuel energy charge in the QF's bill for supplemental service.
- VI.(2) Supplemental Service Rate, Demand
The demand charge in the QF's bill for supplemental service.
- VI.(3) Supplemental Service Escalation Rate
The annual rate of escalation that applies to items VI.(1) and VI.(2).
- VI.(4) Standby Rate, Non-Fuel
The non-fuel energy charge in the QF's bill for standby service.
- VI.(5) Standby Rate, Demand
The demand charge in the QF's bill for standby service.
- VI.(6) Standby Escalation Rate
The annual rate of escalation that applies to items VI.(4) and VI.(5).

PSC FORM CE 3.2 Input Data, Self-Service Wheeling -- Part 2

This form, along with PSC FORM CE 3.1, specifies the input data to be used for self-service wheeling proposals. Each element on the form is defined below:

Col (1) Year

The years begin with the base year and extend through the life of the proposal.

Col (2) Utility Average System Fuel Cost

This is the utility's annual system fuel cost approved by the FPSC that includes fuel, purchases and sales.

Col (3) Utility Purchase Marginal Fuel Cost

This is the marginal fuel cost reduction caused by purchases of QF energy by the utility.

Col (4) QF Supplemental Marginal Fuel Cost

This is the marginal fuel cost reduction caused by the reduction in supplemental purchases by a QF that serves its own load.

Col (5) QF Standby Marginal Fuel Cost

This is the marginal fuel cost increase caused by the increase in standby purchases by the QF.

Col (6) Replacement Fuel Cost

This column contains, for each year, the annual average replacement fuel costs in cents per kwh. This is the system fuel cost if the utility had built the unit to be avoided. If the avoided unit would have lowered system fuel costs, then these costs act as an offset to the savings gained by not building the unit. On the other hand, if the avoided unit would have raised system fuel costs, there are additional savings to be achieved by avoiding the unit.

Col (7) QF Effectiveness Factor -- KW

This is a factor that is normally 1.00, but may be reduced or increased to simulate degradation or improvement on KW.

Col (8) QF Effectiveness Factor -- KWH

This is a factor that is normally 1.00, but may be reduced or increased to simulate degradation or improvement on KWH.

PSC FORM CE 3.3 Self Service Wheeling Rate Impact Test

This form is used to report the costs and benefits from the standpoint of the impact on customer rates of a self-service wheeling proposal. Each item to be reported is listed below:

Col (1) Year

The years begin with the base year of analysis and extend through the life of the program.

Col (2) Increased Fuel Costs

This column is used to report any increases in fuel costs attributable to the self-service wheeling proposal.

Col (3) Revenue Losses

This column is used to report any revenue losses resulting from the proposal.

Col (4) Other Costs

This column contains any other quantifiable costs. Complete documentation must be provided to support the numbers in this column.

Col (5) Total Costs

This column is the sum of columns (2) through (4).

Col (6) Avoided Gen Unit and Fuel Benefits

This column is the sum of columns (4) and (5), PSC FORM CE 2.1.

Col (7) Avoided T&D Benefits

This column is the sum of columns (4) and (7), PSC FORM CE 2.2.

Col (8) Revenue Gains

This column contains any revenue gains, such as wheeling revenues, resulting from the proposal.

Col (9) Other Benefits

This column contains other quantifiable benefits. Complete documentation must be provided for the numbers in this column.

Col (10) Total Benefits

This column is the sum of columns (7) through (10).

Col (11) Net Benefits

This column is calculated by subtracting column (6) from column (11).

Col (12) Cumulative Discounted Net Benefits

This column is the accumulation of the figures in column (12), discounted by the appropriate discount rate.

This form also contains the discount rate and the benefit/cost ratio.

PSC FORM CE 3.3S Supplementary Form on Revenue Gains and Losses

A supplementary form will be filed containing, for each year, an allocation of the revenue gains and losses reported in columns (3) and (8) to general and administrative, generation, transmission and distribution.

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, inspection fees, impact 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 user fees, rental fees, and franchise fees, are imposed pursuant to the exercise of the proprietary right of government. Such proprietary fees are governed by the principle that the fee payer 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 2012-13

County Governments						
Local Fiscal Year	# 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
2012-13	13	\$ 138,982,436	\$ 160,292,116	86.7%	\$ 35,293,287,441	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%	-	-
2005-06	13	\$ 142,123,668	\$ 171,207,441	83.0%	-	-
2004-05	14	\$ 123,553,216	\$ 145,991,416	84.6%	-	-
Municipal Governments						
Local Fiscal Year	# 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
2012-13 **	343	\$ 546,561,653	\$ 656,455,841	83.3%	\$ 31,927,999,565	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%	\$ 28,173,312,741	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	331	\$ 546,658,421	\$ 673,918,453	81.1%	-	-
2006-07	344	\$ 546,883,232	\$ 669,073,212	81.7%	-	-
2005-06	335	\$ 514,540,702	\$ 633,075,955	81.3%	-	-
2004-05	340	\$ 434,429,008	\$ 541,407,060	80.2%	-	-
Combined Total: County and Municipal Governments						
Local Fiscal Year	# Reporting Franchise Fees-Electricity Revenue	Franchise Fees-Electricity Revenue				
2012-13 **	356	\$ 685,544,089				
2011-12	361	\$ 705,348,237				
2010-11	358	\$ 712,793,570				
2009-10	356	\$ 722,984,473				
2008-09	352	\$ 758,135,415				
2007-08	344	\$ 700,994,649				
2006-07	357	\$ 687,213,593				
2005-06	348	\$ 656,664,370				
2004-05	354	\$ 557,982,224				

Notes:

- 1) This summary reflects aggregate revenues reported across all fund types within current Uniform Accounting System (UAS) Revenue Code series 323.100 - Franchise Fee-Electricity.
- 2) FY 2012-13 Annual Financial Reports for nine municipalities have not yet been submitted to or certified by the Department of Financial Services. Consequently, the 2012-13 revenue figures are not yet final, and the municipal and combined totals are subject to future revision.

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 and the Department 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

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://dor.myflorida.com/dor/governments/mpst/>

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 2012-13

County Governments						
Local Fiscal Year	# 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
2012-13	15	\$ 227,089,741	\$ 260,438,801	87.2%	\$ 35,293,287,441	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%	-	-
2005-06	12	\$ 222,739,494	\$ 278,902,292	79.9%	-	-
2004-05	12	\$ 205,788,970	\$ 257,256,077	80.0%	-	-
Municipal Governments						
Local Fiscal Year	# 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
2012-13 **	327	\$ 686,333,857	\$ 864,080,636	79.4%	\$ 31,927,999,565	2.1%
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%	\$ 28,173,312,741	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	318	\$ 581,414,018	\$ 829,153,910	70.1%	-	-
2006-07	318	\$ 560,530,030	\$ 808,793,559	69.3%	-	-
2005-06	308	\$ 522,270,643	\$ 772,981,528	67.6%	-	-
2004-05	305	\$ 505,856,228	\$ 741,201,140	68.2%	-	-
Combined Total: County and Municipal Governments						
Local Fiscal Year	# Reporting Public Service Tax-Electricity Revenue	Public Service Tax-Electricity Revenue				
2012-13 **	342	\$ 913,423,598				
2011-12	348	\$ 880,538,169				
2010-11	349	\$ 892,213,516				
2009-10	342	\$ 917,868,235				
2008-09	339	\$ 830,381,164				
2007-08	331	\$ 809,348,610				
2006-07	331	\$ 800,297,885				
2005-06	320	\$ 745,010,137				
2004-05	317	\$ 711,645,198				

Notes:

- 1) 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.
- 2) FY 2012-13 Annual Financial Reports for nine municipalities have not yet been submitted to or certified by the Department of Financial Services. Consequently, the 2012-13 revenue figures are not yet final, and the municipal and combined totals are subject to future revision.

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.

Rural Electric Cooperative Regulatory Assessment Fee Return

206

Florida Public Service Commission

(See Filing Instructions on Back of Form)

STATUS:

- _____ Actual Return
- _____ Estimated Return
- _____ Amended Return

PERIOD COVERED:

«Field3»

«Field2»

Please Complete Below If Official Mailing Address Has Changed

FOR PSC USE ONLY

Check # _____
 \$ _____ 06-02-001
 _____ 003001
 \$ _____ E
 \$ _____ P 06-02-001
 \$ _____ I 004011
 Postmark Date _____
 Initials of Preparer _____

 (Name of Utility) (Address) (City/State) (Zip)

LINE NO.	ACCOUNT CLASSIFICATION	INTRASTATE AMOUNTS	SALES FOR RESALE & INTERSTATE AMOUNTS	TOTAL REVENUES
1.	Sales of Electricity:			
2.	Residential Sales (440)	\$ _____	\$ _____	\$ _____
3.	Commercial Sales (442)	_____	_____	_____
	Industrial Sales (442)	_____	_____	_____
4.	Public Street and Highway Lighting (444)	_____	_____	_____
5.	Other Sales to Public Authorities (445)	_____	_____	_____
6.	Sales to Railroads and Railways (446)	_____	_____	_____
7.	Interdepartmental Sales (448)	_____	_____	_____
8.	Total Sales to Ultimate Consumers	\$ _____	\$ _____	\$ _____
9.	Sales for Resale (447)	_____	_____	_____
10.	Total Sales of Electricity	\$ _____	\$ _____	\$ _____
11.	Provision for Rate Refunds (449.1)	_____	_____	_____
12.	Total Revenue Net of Refunds	\$ _____	\$ _____	\$ _____
13.	Other Operating Revenues:			
14.	Forfeited Discounts (450)	_____	_____	_____
15.	Miscellaneous Service Revenues (451)	_____	_____	_____
16.	Sales of Water and Water Power (453)	_____	_____	_____
17.	Rent from Electric Property (454)	_____	_____	_____
18.	Interdepartmental Rents (455)	_____	_____	_____
19.	Other Electric Revenues (456)	_____	_____	_____
20.	Total Other Operating Revenues	\$ _____	\$ _____	\$ _____
21.	Total Electric Operating Revenues	\$ _____	\$ _____	\$ _____
22.	Adjustments: (Specify)			
23.	_____	\$ _____		
24.	_____	_____		
25.	_____	_____		
26.	_____	_____		
27.	_____	_____		
28.	Total Adjustments	\$ _____		
29.	Revenues Subject to Regulatory Assessment Fee	_____		
30.	REGULATORY ASSESSMENT FEE RATE	.00015625		
31.	REGULATORY ASSESSMENT FEE DUE (Line 29 x Line 30)	_____		
32.	Less: Payment for Jan. 1 – Jun. 30 Period	(_____)		
33.	NET REGULATORY ASSESSMENT FEE DUE (see #2 on back)	_____		
34.	Penalty For Late Payment (see #3 on back)	_____		
35.	Interest For Late Payment (see #3 on back)	_____		
36.	Extension Payment Fee (see #4 on back)	_____		
37.	TOTAL AMOUNT DUE	\$ _____		

⁽¹⁾As provided in Section 350.113, Florida Statutes, the **Minimum Annual Fee is \$25** (see Item #5 on back)

I, the undersigned owner/officer of the above-named vendor, have read the foregoing and declare that to the best of my knowledge and belief the above information is a true and correct statement. I am aware that pursuant to Section 837.06, Florida Statutes, whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree.

 (Signature of Utility Official) (Title) (Date)

 (Please Print Name) Telephone Number () Fax Number ()

FLORIDA PUBLIC SERVICE COMMISSION
Instructions For Filing Regulatory Assessment Fee Return
(Rural Electric Cooperative)

1. **WHEN TO FILE:** To avoid payment of penalties and interest, the Regulatory Assessment Fee Return and payment must be filed or postmarked:

On or before July 30 for the six-month period January 1 through June 30, **and**
On or before January 30 for the six-month period July 1 through December 31.

However, if July 30 or January 30 falls on a Saturday, Sunday, or holiday, the Regulatory Assessment Fee Return may be filed or postmarked on the next business day, without penalty.

2. **FEES:** Each utility shall pay the currently authorized percentage, as indicated on Line 30 on the reverse side, of its gross operating revenues derived from intrastate business. Gross Operating Revenues are defined as the total revenues before expenses. The currently authorized percentage was implemented by Section 25-6.0131(1)(b), Florida Administrative Code. Annual revenue amounts are to be reported on the return for the period ended December 31.
3. **FAILURE TO FILE BY DUE DATE:** A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due. Failure to file a return by the established due date will result in a penalty being added to the amount of fee due, 5% for each 30 days or fraction thereof, not to exceed a total penalty of 25% (Line 34). In addition, interest shall be added in the amount of 1% for each 30 days or fraction thereof, not to exceed a total of 12% per year (Line 35).
4. **EXTENSION:** A utility, for good cause shown in a written request, may be granted up to a 30-day extension. A request must be made by filing the enclosed *Regulatory Assessment Fee Extension Request* form (PSC/AIT 124), two weeks prior to the filing date. If an extension is granted, a charge shall be added to the amount due:

0.75% of the fee to be remitted for an extension of 15 days or less, *or*
1.5% of the fee for an extension of 16 to 30 days.

In lieu of paying the charges outlined above, a utility may file a return and remit payment based upon estimated gross operating revenues by checking the "Estimated Return" space in the top left-hand corner on the reverse side. If such return is filed by the normal due date, the utility shall be granted a 30-day extension period in which to file and remit the actual fee due without paying the above charges, provided the estimated fee payment remitted is at least 90% of the actual fee due for the period.

5. **REGULATORY ASSESSMENT FEE DUE:** Amounts are due and payable to the Commission by either January 30 or July 30 depending on the reporting period. If there are no revenues **OR** if revenues are insufficient to generate a minimum annual fee, remit the minimum fee. **A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due.**
6. **FEE ADJUSTMENTS:** The utility will be notified as to the amount and reason for any adjustment. Penalty and interest charges may be applicable to additional amounts owed to the Commission by reason of the adjustment. A utility may file a written request for a refund of any overpayments. The request should be directed to Fiscal Services at the below-referenced address.
7. **MAILING INSTRUCTIONS:** Please complete this form, make a copy for your file, and return the original in the enclosed preaddressed envelope. Use of this envelope should assure a more accurate and expeditious recording of your payment. If you are unable to use the enclosed envelope, please address your remittance as follows:

Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

ATTENTION: Fiscal Services

8. **ADDITIONAL ASSISTANCE:** If any additional assistance is required in preparing the Regulatory Assessment Fee Return, please contact the Division of Accounting and Finance at (850) 413-6900 or at the above-referenced address, directing correspondence to the attention of the division.

Investor-Owned Electric Utility Regulatory Assessment Fee Return

208

Florida Public Service Commission

(See Filing Instructions on Back of Form)

STATUS:

- Actual Return
- Estimated Return
- Amended Return

PERIOD COVERED:

«Field3»

«Field2»

FOR PSC USE ONLY

Check # _____

\$ _____ 06-02-002
003001

\$ _____ E

\$ _____ P 06-02-002
004011

\$ _____ I

Postmark Date _____

Initials of Preparer _____

Please Complete Below If Official Mailing Address Has Changed

(Name of Utility) (Address) (City/State) (Zip)

LINE NO.	ACCOUNT CLASSIFICATION	INTRASTATE AMOUNTS	SALES FOR RESALE & INTERSTATE AMOUNTS	TOTAL REVENUES
1.	Sales of Electricity:			
2.	Residential Sales (440)	\$ _____	\$ _____	\$ _____
3.	Commercial Sales (442)	_____	_____	_____
	Industrial Sales (442)	_____	_____	_____
4.	Public Street and Highway Lighting (444)	_____	_____	_____
5.	Other Sales to Public Authorities (445)	_____	_____	_____
6.	Sales to Railroads and Railways (446)	_____	_____	_____
7.	Interdepartmental Sales (448)	_____	_____	_____
8.	Total Sales to Ultimate Consumers	\$ _____	\$ _____	\$ _____
9.	Sales for Resale (447)	_____	_____	_____
10.	Total Sales of Electricity	\$ _____	\$ _____	\$ _____
11.	Provision for Rate Refunds (449.1)	_____	_____	_____
12.	Total Revenue Net of Refunds	\$ _____	\$ _____	\$ _____
13.	OTHER OPERATING REVENUES:			
14.	Forfeited Discounts (450)	_____	_____	_____
15.	Miscellaneous Service Revenues (451)	_____	_____	_____
16.	Sales of Water and Water Power (453)	_____	_____	_____
17.	Rent from Electric Property (454)	_____	_____	_____
18.	Interdepartmental Rents (455)	_____	_____	_____
19.	Other Electric Revenues (456)	_____	_____	_____
20.	Deferred Fuel Revenues	_____	_____	_____
21.	Deferred Conservation Revenues	_____	_____	_____
22.	Unbilled Revenues	_____	_____	_____
23.	Other	_____	_____	_____
24.	Total Other Operating Revenues	\$ _____	\$ _____	\$ _____
25.	Total Electric Operating Revenues	\$ _____	\$ _____	\$ _____
26.	Adjustments: (Specify)	_____	_____	_____
27.	_____	_____	_____	_____
28.	_____	_____	_____	_____
29.	_____	_____	_____	_____
30.	_____	_____	_____	_____
31.	_____	_____	_____	_____
32.	Total Adjustments	\$ _____	_____	_____
33.	Revenues Subject to Regulatory Assessment Fee	_____	_____	_____
34.	REGULATORY ASSESSMENT FEE RATE	.00072	_____	_____
35.	REGULATORY ASSESSMENT FEE DUE <i>(Line 33 x Line 34)</i>	_____	_____	_____
36.	Less: Payment for Jan. 1 – Jun. 30 Period	(_____)	_____	_____
37.	NET REGULATORY ASSESSMENT FEE DUE <i>(see #2 on back)</i>	_____	_____	_____
38.	Penalty For Late Payment <i>(see #3 on back)</i>	_____	_____	_____
39.	Interest For Late Payment <i>(see #3 on back)</i>	_____	_____	_____
40.	Extension Payment Fee <i>(see #4 on back)</i>	_____	_____	_____
41.	TOTAL AMOUNT DUE ⁽¹⁾	\$ _____	_____	_____

⁽¹⁾As provided in Section 350.113, Florida Statutes, the **Minimum Annual Fee is \$25** (see Item #5 on back)

I, the undersigned owner/officer of the above-named vendor, have read the foregoing and declare that to the best of my knowledge and belief the above information is a true and correct statement. I am aware that pursuant to Section 837.06, Florida Statutes, whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree.

(Signature of Utility Official) (Title) (Date)

(Please Print Name) Telephone Number () Fax Number ()

F.E.I. No. _____

FLORIDA PUBLIC SERVICE COMMISSION
Instructions For Filing Regulatory Assessment Fee Return
(Investor-Owned Electric Utility)

1. **WHEN TO FILE:** To avoid payment of penalties and interest, the Regulatory Assessment Fee Return and payment must be filed or postmarked:

On or before July 30 for the six-month period January 1 through June 30, **and**
On or before January 30 for the six-month period July 1 through December 31.

However, if July 30 or January 30 falls on a Saturday, Sunday, or holiday, the Regulatory Assessment Fee Return may be filed or postmarked on the next business day, without penalty.

2. **FEES:** Each utility shall pay the currently authorized percentage, as indicated on Line 34 on the reverse side, of its gross operating revenues derived from intrastate business. Gross Operating Revenues are defined as the total revenues before expenses. The currently authorized percentage was implemented by Section 25-6.0131(1)(a), Florida Administrative Code. Annual revenue amounts are to be reported on the return for the period ended December 31.
3. **FAILURE TO FILE BY DUE DATE:** A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due. Failure to file a return by the established due date will result in a penalty being added to the amount of fee due, 5% for each 30 days or fraction thereof, not to exceed a total penalty of 25% (Line 38). In addition, interest shall be added in the amount of 1% for each 30 days or fraction thereof, not to exceed a total of 12% per year (Line 39).
4. **EXTENSION:** A utility, for good cause shown in a written request, may be granted up to a 30-day extension. A request must be made by filing the enclosed *Regulatory Assessment Fee Extension Request* form (PSC/AIT 124), two weeks prior to the filing date. If an extension is granted, a charge shall be added to the amount due:

0.75% of the fee to be remitted for an extension of 15 days or less, *or*
1.5% of the fee for an extension of 16 to 30 days.

In lieu of paying the charges outlined above, a utility may file a return and remit payment based upon estimated gross operating revenues by checking the "Estimated Return" space in the top left-hand corner on the reverse side. If such return is filed by the normal due date, the utility shall be granted a 30-day extension period in which to file and remit the actual fee due without paying the above charges, provided the estimated fee payment remitted is at least 90% of the actual fee due for the period.

5. **REGULATORY ASSESSMENT FEE DUE:** Amounts are due and payable to the Commission by either January 30 or July 30 depending on the reporting period. If there are no revenues **OR** if revenues are insufficient to generate a minimum annual fee, remit the minimum fee. **A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due.**
6. **FEE ADJUSTMENTS:** Computational errors and/or differences in gross operating revenues reported for regulatory assessment fee purposes and those reported in the annual report may cause adjustments to amounts paid to the Commission. The utility will be notified as to the amount and reason for any adjustment. Penalty and interest charges may be applicable to additional amounts owed to the Commission by reason of the adjustment. A utility may file a written request for a refund of any overpayments. The request should be directed to Fiscal Services at the below-referenced address.
7. **MAILING INSTRUCTIONS:** Please complete this form, make a copy for your files, and return the original in the enclosed preaddressed envelope. Use of this envelope should assure a more accurate and expeditious recording of your payment. If you are unable to use the enclosed envelope, please address your remittance as follows:

Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

ATTENTION: Fiscal Services

8. **ADDITIONAL ASSISTANCE:** If any additional assistance is required in preparing the Regulatory Assessment Fee Return, please contact the Division of Accounting and Finance at (850) 413-6900 or at the above-referenced address, directing correspondence to the attention of the division.

Municipal Electric Utility Regulatory Assessment Fee Return

Florida Public Service Commission

(See Filing Instructions on Back of Form)

STATUS:

- Actual Return
- Estimated Return
- Amended Return

PERIOD COVERED:

«Field3»

«Field2»

Please Complete Below If Official Mailing Address Has Changed

FOR PSC USE ONLY

Check # _____

\$ _____ 06-02-001
003001

\$ _____ E

\$ _____ P 06-02-001
004011

\$ _____ I

Postmark Date _____

Initials of Preparer _____

(Name of Utility) (Address) (City/State) (Zip)

LINE NO.	ACCOUNT CLASSIFICATION	INTRASTATE AMOUNTS	SALES FOR RESALE & INTERSTATE AMOUNTS	TOTAL REVENUES
1.	Sales of Electricity:			
2.	Residential Sales (440)	\$ _____	\$ _____	\$ _____
3.	Commercial Sales (442)	_____	_____	_____
	Industrial Sales (442)	_____	_____	_____
4.	Public Street and Highway Lighting (444)	_____	_____	_____
5.	Other Sales to Public Authorities (445)	_____	_____	_____
6.	Sales to Railroads and Railways (446)	_____	_____	_____
7.	Interdepartmental Sales (448)	_____	_____	_____
8.	Total Sales to Ultimate Consumers	\$ _____	\$ _____	\$ _____
9.	Sales for Resale (447)	_____	_____	_____
10.	Total Sales of Electricity	\$ _____	\$ _____	\$ _____
11.	Provision for Rate Refunds (449.1)	_____	_____	_____
12.	Total Revenue Net of Refunds	\$ _____	\$ _____	\$ _____
13.	Other Operating Revenues:			
14.	Forfeited Discounts (450)	_____	_____	_____
15.	Miscellaneous Service Revenues (451)	_____	_____	_____
16.	Sales of Water and Water Power (453)	_____	_____	_____
17.	Rent from Electric Property (454)	_____	_____	_____
18.	Interdepartmental Rents (455)	_____	_____	_____
19.	Other Electric Revenues (456)	_____	_____	_____
20.	Total Other Operating Revenues	\$ _____	\$ _____	\$ _____
21.	Total Electric Operating Revenues	\$ _____	\$ _____	\$ _____
22.	Adjustments: (Specify)	_____	_____	_____
23.	_____	_____	_____	_____
24.	_____	_____	_____	_____
25.	_____	_____	_____	_____
26.	_____	_____	_____	_____
27.	_____	_____	_____	_____
28.	Total Adjustments	\$ _____	_____	_____
29.	Revenues Subject to Regulatory Assessment Fee	_____	_____	_____
30.	REGULATORY ASSESSMENT FEE RATE	.00015625		
31.	REGULATORY ASSESSMENT FEE DUE (Line 29 x Line 30)	_____	_____	_____
32.	Less: Payment for Jan. 1 – Jun. 30 Period	(_____)		
33.	NET REGULATORY ASSESSMENT FEE DUE (see #2 on back)	_____	_____	_____
34.	Penalty For Late Payment (see #3 on back)	_____	_____	_____
35.	Interest For Late Payment (see #3 on back)	_____	_____	_____
36.	Extension Payment Fee (see #4 on back)	_____	_____	_____
37.	TOTAL AMOUNT DUE	\$ _____	_____	_____

⁽¹⁾As provided in Section 350.113, Florida Statutes, the **Minimum Annual Fee is \$25** (see Item #5 on back)

THIS FORM MUST BE COMPLETED AND RETURNED REGARDLESS OF THE AMOUNT OF REVENUES REPORTED

I, the undersigned owner/officer of the above-named vendor, have read the foregoing and declare that to the best of my knowledge and belief the above information is a true and correct statement. I am aware that pursuant to Section 837.06, Florida Statutes, whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree.

(Signature of Utility Official) (Title) (Date)

(Please Print Name)

Telephone Number () _____ Fax Number () _____

F.E.I. No. _____

FLORIDA PUBLIC SERVICE COMMISSION
Instructions For Filing Regulatory Assessment Fee Return
(Municipal Electric Utility)

1. **WHEN TO FILE:** To avoid payment of penalties and interest, the Regulatory Assessment Fee Return and payment must be filed or postmarked:

On or before July 30 for the six-month period January 1 through June 30, **and**
On or before January 30 for the six-month period July 1 through December 31.

However, if July 30 or January 30 falls on a Saturday, Sunday, or holiday, the Regulatory Assessment Fee Return may be filed or postmarked on the next business day, without penalty.

2. **FEES:** Each utility shall pay the currently authorized percentage, as indicated on Line 30 on the reverse side, of its gross operating revenues derived from intrastate business. Gross Operating Revenues are defined as the total revenues before expenses. The currently authorized percentage was implemented by Section 25-6.0131(1)(b), Florida Administrative Code. Annual revenue amounts are to be reported on the return for the period ended December 31.
3. **FAILURE TO FILE BY DUE DATE:** A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due. Failure to file a return by the established due date will result in a penalty being added to the amount of fee due, 5% for each 30 days or fraction thereof, not to exceed a total penalty of 25% (Line 34). In addition, interest shall be added in the amount of 1% for each 30 days or fraction thereof, not to exceed a total of 12% per year (Line 35).
4. **EXTENSION:** A utility, for good cause shown in a written request, may be granted up to a 30-day extension. A request must be made by filing the enclosed *Regulatory Assessment Fee Extension Request* form (PSC/AIT 124), two weeks prior to the filing date. If an extension is granted, a charge shall be added to the amount due:

0.75% of the fee to be remitted for an extension of 15 days or less, *or*
1.5% of the fee for an extension of 16 to 30 days.

In lieu of paying the charges outlined above, a utility may file a return and remit payment based upon estimated gross operating revenues by checking the "Estimated Return" space in the top left-hand corner on the reverse side. If such return is filed by the normal due date, the utility shall be granted a 30-day extension period in which to file and remit the actual fee due without paying the above charges, provided the estimated fee payment remitted is at least 90% of the actual fee due for the period.

5. **REGULATORY ASSESSMENT FEE DUE:** Amounts are due and payable to the Commission by either January 30 or July 30 depending on the reporting period. If there are no revenues **OR** if revenues are insufficient to generate a minimum annual fee, remit the minimum fee. **A Regulatory Assessment Fee Return must be completed, signed, and filed even if there are no revenues to report or if the minimum amount is due.**
6. **FEE ADJUSTMENTS:** The utility will be notified as to the amount and reason for any adjustment. Penalty and interest charges may be applicable to additional amounts owed to the Commission by reason of the adjustment. A utility may file a written request for a refund of any overpayments. The request should be directed to Fiscal Services at the below-referenced address.
7. **MAILING INSTRUCTIONS:** Please complete this form, make a copy for your file, and return the original in the enclosed preaddressed envelope. Use of this envelope should assure a more accurate and expeditious recording of your payment. If you are unable to use the enclosed envelope, please address your remittance as follows:

Florida Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399-0850 ATTENTION: Fiscal Services

8. **ADDITIONAL ASSISTANCE:** If any additional assistance is required in preparing the Regulatory Assessment Fee Return, please contact the Division of Accounting and Finance at (850) 413-6900 or at the above-referenced address, directing correspondence to the attention of the division.

SUMMARY

QUESTION:

You have requested that the Department issue formal advice outlining the tax consequences of net metering.

Net metering is a method of metering the energy consumed and produced at a home or a business that has its own renewable energy generator. Under net metering, excess electricity produced at a home or a business is used to offset the electricity received from a utility provider.

ANSWER:

Taxpayer should remit the gross receipt tax based on the amount of money received from its customers for charges for utility services. This would be the net amount of electricity billed to the customer after allowing a credit for the excess electricity generated by the customer and returned to the utility.

The retail sale of electrical power or energy in the State of Florida is subject to sales tax. The incidence of the tax is on "charges for electrical power or energy," and the tax rate for such sales is 7 percent. Therefore, if a customer is charged on the net electricity that it used during a particular billing cycle, the utility company should collect and remit the 7 percent sales tax on the amount billed to the customer.

March 31, 2009

XXX

Re: Technical Assistance Advisement 09A-014
Florida Gross Receipts Tax/Florida Sales and Use Tax
Net Metering
Sections 203.01, 212.05, 212.08(7)(j), Florida Statute (F.S.)
Rule 12A-1.039, Florida Administrative Code (F.A.C.)
Petitioner: XXX ("Taxpayer")

Dear XXX:

This letter is a response to your petition dated June 4, 2008, for the Department's issuance of a Technical Assistance Advisement ("TAA") concerning the above referenced party and matter. Your petition has been carefully examined and the Department finds it to be in compliance with the requisite criteria set forth in Chapter 12-11, F.A.C. This response to your request constitutes a TAA and is issued to you under the authority of s. 213.22, F.S.

FACTS

Some homes and businesses in Florida install equipment that produces electricity, which the home or business uses to reduce the amount of electricity required from the local electric utility.

When the home or business does not use the entire amount of electricity that it produces, the excess electricity is delivered to the electric utility for resale to other consumers.

At the end of the billing period, the electric utility will offset the amount of electricity it delivered to the home or business with the amount of electricity the home or business delivered to the electric utility. The electric utility only charges the consumer for the “net” amount of electricity provided to the home or business. The act of offsetting the electricity amounts is called “net metering,” and Florida has recently required that utility providers implement net metering systems.

REQUESTED ADVISEMENTS

You have requested that the Department issue formal advice outlining the tax consequences of net metering.

ANALYSIS and DISCUSSION

Net metering is a method of metering the energy consumed and produced at a home or a business that has its own renewable energy generator. Under net metering, excess electricity produced at a home or a business is used to offset the electricity received from a utility provider.

Gross Receipts Tax

Section 203.01, F.S., imposes the gross receipts tax on the total amount of gross receipts **received** by a distribution company for utility services. [Emphasis supplied] The rate applied to utility services is 2.5 percent. Assuming the electric utility is a distribution company, it would be required to pay gross receipts tax on its total receipts from **charges** for utility service sold to a retail consumer. If the customer pays \$100 on the net electricity that the consumer purchased, the distribution company is taxed on the \$100 received.

Taxpayer should remit the gross receipt tax based on the amount of money received from its customers for charges for utility services. This would be the net amount of electricity billed to the customer after allowing a credit for the excess electricity generated by the customer and returned to the utility. In other words, if the bill from the utility shows electricity consumed by the customer in the amount of \$100 and a credit for excess customer-generated electricity in the amount \$25, resulting in a balance due of \$75, gross receipts tax is calculated on the net amount or \$75.

Sales and Use Tax

Section 212.05, F.S., provides it is the legislative intent that every person is exercising a taxable privilege that engages in the business of selling tangible personal property at retail in this state. For exercising such a privilege, a tax is levied on each taxable transaction or incident. The retail sale of electrical power or energy in the State of Florida is subject to sales tax. The incidence of the tax is on “charges for electrical power or energy,” and the tax rate for such sales is 7 percent. See Section 212.05(1)(e)1.c., F.S. Therefore, if a customer is charged \$100 on the net electricity

Technical Assistance Advisement

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that it used during a particular billing cycle, the utility company should collect and remit the 7 percent sales tax on the \$100 amount billed to the customer. Electricity that is provided to the customer before net metering would not be taxed. Although we are sure that you are well aware of this, we note that sales of electricity to residential households are exempt from sales tax pursuant to Section 212.08(7)(j), F.S.

Excess customer-generated electrical power or energy put on the grid is ultimately used by and billed to Taxpayer's other customers. Credits allowed by Taxpayer for such excess customer-generated electrical power or energy would be treated as exempt sales for resale under the provisions of Rule 12A-1.039, F.A.C.

Under the same scenario above, Florida sales and use tax would be calculated at the tax rate of 7 percent on the charge of \$75.

CONCLUDING STATEMENT

This response constitutes a Technical Assistance Advisement under Section 213.22, F.S., which is binding on the Department only under the facts and circumstances described in the request for this advice, as specified in Section 213.22, F.S. Our response is predicated on those facts and the specific situation summarized above. You are advised that subsequent statutory or administrative rule changes or judicial interpretations of the statutes or rules upon which this advice is based may subject similar future transactions to a different treatment than expressed in this response.

You are further advised that this response, your request and related backup documents are public records under Chapter 119, F.S., and are subject to disclosure to the public under the conditions of Section 213.22, F.S. Confidential information must be deleted before public disclosure. In an effort to protect confidentiality, we request you provide the undersigned with an edited copy of your request for Technical Assistance Advisement, the backup material and this response, deleting names, addresses and any other details which might lead to identification of the taxpayer. Your response should be received by the Department within 10 days of the date of this letter.

If you have any further questions with regard to this matter and wish to discuss them, you may contact me directly at 850-488-8026.

Kind Regards,

Alan R. Fulton
Tax Law Specialist
Technical Assistance & Dispute Resolution

ARF\lp
Record ID: 46454

SUMMARY

QUESTION:

You have requested that the Department issue formal advice outlining the tax consequences of net metering for electric cooperatives.

Net metering is a method of metering the energy consumed and produced at a home or a business that has its own renewable energy generator. Under net metering, excess electricity produced at a home or a business is used to offset the electricity received from a utility provider.

ANSWER:

Taxpayer should remit the gross receipt tax based on the amount of money received from its customers for charges for utility services. This would be the net amount of electricity billed to the customer after allowing a credit for the excess electricity generated by the customer and returned to the utility.

The retail sale of electrical power or energy in the State of Florida is subject to sales tax. The incidence of the tax is on "charges for electrical power or energy," and the tax rate for such sales is 7 percent. Therefore, if a customer is charged on the net electricity that it used during a particular billing cycle, the utility company should collect and remit the 7 percent sales tax on the amount billed to the customer.

June 24, 2009

XXX

Re: Technical Assistance Advisement 09A-029
Sales and Use Tax/Gross Receipts Tax – Net Metering
Sections: 203.01, 212.05, 212.08, 212.06, Florida Statutes (F.S.)
Rule: 12A-1.039, Florida Administrative Code (F.A.C.)
Petitioner: XXX. ("Taxpayer")

Dear XXX:

This letter is a response to your petition dated March 14, 2008, for the Department's issuance of a Technical Assistance Advisement ("TAA") concerning the above referenced party and matter. Your petition has been carefully examined and the Department finds it to be in compliance with the requisite criteria set forth in Chapter 12-11, F.A.C. This response to your request constitutes a TAA and is issued to you under the authority of s. 213.22, F.S.

FACTS

Taxpayer is the XXX XXX for XXX XXX XXX (XXX-XXX and XXX-XXX) who provide energy and electricity in Florida. Taxpayer XXX are XXX XXX who sell electricity at retail to XXX XXX and buy their power from XXX XXX providers or other utilities. XXX XXX buy

their power from other utilities and would directly buy back any excess power from a renewable generator. The XXX XXX XXX buys the excess power from the customer under their arrangement with the other XXX XXXs. For this reason, Taxpayer request will consist of issues which apply to all XXX XXX; issues which apply only to the XXX XXX who buy power from XXX XXX XXX; and issues which apply only to the XXX XXXs who buy power from other utilities.

Some of Taxpayer's XXXs own and operate small XXX XXX. To date, most of these are (less than 10kW) XXX (XXX) energy systems. Several of Taxpayer's XXX offer a net billing option, which allows customers to receive credits for excess electricity generated by their renewable generator. "Excess" electricity is the electricity that is generated by the customer that exceeds the customer's needs at that moment.

The metering/billing process is a multi-step transaction. Generally, after a customer notifies the distribution XXX that he or she would like to interconnect a renewable generator to the XXX's facilities, the XXX sends the customer a third-party interconnection agreement and request for verification of insurance. Under the terms of the interconnection agreement, any excess electricity generated by the customer is sold to the XXX XXX provider. [your emphasis] Once the distribution XXX receives the executed documents, the customer's meter is changed out for a special meter (unless the customer's meter is already capable of measuring electricity in both directions) that measures both the amount of electricity supplied by the distribution XXX to the customer and the excess electricity generated by the customer that is delivered to the XXX XXX.

The customer's account is set up to reflect the tariffed retail rate paid by the customer to the distribution XXX and the rate paid by the XXX XXX to the customer (these rates may not be the same) for the excess electricity. The excess power delivered from the customer to the XXX XXX is then resold to the distribution XXX. The resale of excess electricity generated by the customer to the XXX XXX is shown as a credit on the distribution XXX's XXX power bill. In turn, the distribution XXX reflects the credit on the customer's bill.

REQUESTED ADVISEMENTS

I. For all 15 XXXs, Taxpayer has asked advice regarding the following:

Issue 1: Is the electricity sold to a residential customer that has provided an exemption certificate to the XXX still exempt from sales tax on electricity under the household fuel exemption in Section 212.08(7)(j), F.S., even though the customer is now in the business of selling electricity?

Issue 2: Most renewable generators require the use of inverters on their systems. The utility supplies a small amount of electricity to these inverters. When the utility sells electricity that is used directly by the renewable generation system, is the residential customer's status changed to commercial for tax purposes?

Issue 3: Does the XXX have any sales tax liability for power generated and consumed by the customer that does not register on the XXX's meter (i.e., that is not excess power)?

Issue 4: Does the XXX have any gross receipts tax liability for power generated and consumed by the customer that does not register on the XXX's meter (i.e., that is not excess power)?

Issue 5: What is the proper method to calculate sales and gross receipts taxes for residential and commercial customers utilizing net billing (Can the distribution XXX apply the Net Billing Credit before the sales taxes are calculated and should it offset the distribution XXX's revenues for calculating its gross receipts tax)?

II. For the 13 XXXs, with XXX XXX power contracts, Taxpayer has asked advice regarding the following:

Issue 1: Is the sale of customer's excess electricity to the XXX XXX exempt from sales taxes as a sale for resale?

Issue 2: Is the sale of excess electricity from customer to the XXX XXX exempt from gross receipts tax as a sale for resale?

III. For the 2 XXXs, with power contracts with other utilities, Taxpayer has asked advice regarding the following:

Issue 1: Is the sale of customer's excess electricity directly to the distribution XXX exempt from sales taxes as a sale for resale?

Issue 2: Is the sale of excess electricity directly from the customer to the distribution XXX exempt from gross receipts tax as a sale for resale?

ANALYSIS and DISCUSSION

Gross Receipts Tax

Section 203.01, F.S., imposes the gross receipts tax on the total amount of gross receipts **received** by a distribution company for utility services. [Emphasis supplied] The rate applied to utility services is 2.5 percent. Assuming the electric utility is a distribution company, it would be required to pay gross receipts tax on its total receipts from **charges** for utility service sold to a retail consumer. If the customer pays \$100 on the net electricity that the consumer purchased, the distribution company is taxed on the \$100 received.

Taxpayer's XXX should remit the gross receipt tax based on the amount of money that they receive from its customers for charges for utility services. This would be the net amount of electricity billed to the customer after allowing a credit for the excess electricity generated by the customer and returned to the utility.

Sales and Use Tax

Section 212.05, F.S., provides it is the legislative intent that every person is exercising a taxable privilege that engages in the business of selling tangible personal property at retail in this state. For exercising such a privilege, a tax is levied on each taxable transaction or incident. The retail sale of electrical power or energy in the State of Florida is subject to sales tax. The incidence of the tax is on "charges for electrical power or energy," and the tax rate for such sales is 7 percent. See Section 212.05(1)(e)1.c, F.S. Therefore, if a customer is charged \$100 on the net electricity that it used during a particular billing cycle, the utility company should collect and remit the 7 percent sales tax on the \$100 amount billed to the customer. Electricity that is provided to the customer before net metering would not be taxed. Although we are sure that you are well aware of this, we note that sales of electricity to residential households are exempt from sales tax pursuant to Section 212.08(7)(j), F.S.

Excess customer-generated electrical power or energy put on the grid is ultimately used by and billed to other customers of Taxpayer's XXX. Credits allowed by Taxpayer's XXX for such excess customer-generated electrical power or energy would be treated as exempt sales for resale under the provisions of Rule 12A-1.039, F.A.C.

Under the facts presented in your letter, residential customers are not required to register as dealers with the Department and be responsible for all of the attendant responsibilities that go along with being a "dealer." The residential customer's delivery of excess electricity and the subsequent credit or "net-billing" do not defeat the exemption provided to residential customers. This conclusion also considers: (a) that the delivery of excess electricity is a "sale for resale" that carries out the Legislature's intent of promoting energy conservation and the use of solar energy; and, (b) under the facts presented, Florida sales tax would not be due because the customer to utility "sale" is an exempt "sale for resale," and Florida gross receipts tax would not be due because the "sale" is not to a "retail consumer."

RESPONSESection I:

Issue 1: Is the electricity sold to a residential customer that has provided an exemption certificate to the XXX still exempt from sales tax on electricity under the household fuel exemption in Section 212.08(7)(j), F.S., even though the customer is now in the business of selling electricity?

Response: Yes. The exemption for residential households is not defeated. The Department does not issue "exemption certificates" to residential households.

Issue 2: Most renewable generators require the use of inverters on their systems. The utility supplies a small amount of electricity to these inverters. When the utility sells electricity that is used directly by the renewable generation system, is the residential customer's status changed to commercial for tax purposes?

Response: No. The status of the customer would not change to commercial for tax purposes.

Issue 3: Does the XXX have any sales tax liability for power generated and consumed by the customer that does not register on the XXX's meter (i.e., that is not excess power)?

Response: No. The XXX would not be responsible for tax on power generated and consumed by its customer that is not registered on the XXX's meter.

Issue 4: Does the XXX have any gross receipts tax liability for power generated and consumed by the customer that does not register on the XXX's meter (i.e., that is not excess power)?

Response: No, the XXX would not be liable.

Issue 5: What is the proper method to calculate sales and gross receipts taxes for residential and commercial customers utilizing net billing (Can the distribution XXX apply the Net Billing Credit before the sales taxes are calculated and should it offset the distribution XXX's revenues for calculating its gross receipts tax)?

Response: Florida gross receipts tax is levied against the total amount of gross receipts **received** by a distribution company. [emphasis supplied] See Section 203.01(1)(c), F.S. The XXXs should remit gross receipts tax based on the gross receipts they actually receive (and bill for what they will actually be receiving). In other words, if the bill from the utility shows electricity consumed by the customer in the amount of \$XXX and a credit for excess customer-generated electricity in the amount \$XXX, resulting in a balance due of \$XXX, gross receipts tax, for purposes of calculating the gross receipts tax, is calculated on the net amount or \$XXX. Under the same scenario, Florida sales and use tax would be calculated at the tax rate of XXX percent on the charge of \$XXX. Electricity that is provided to the customer before net metering would not be taxed. Sales tax would only apply to sales to commercial customers; all sales to residential customers are specifically exempt from sales tax.

Section II:

Issue 1: Is the sale of customer's excess electricity to the XXX XXX exempt from sales taxes as a sale for resale?

Response: Yes. The sale of customer's excess electricity to the XXX XXX would be exempt from sales taxes as a sale for resale pursuant to Section 212.06(1)(b), F.S.

Issue 2: Is the sale of excess electricity from customer to the XXX XXX exempt from gross receipts tax?

Response: Yes. The gross receipts tax is not imposed on the sale or delivery of electricity to XXXs for resale, pursuant to Section 203.01(3)(a)2., F.S.

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Section III:

Issue 1: Is the sale of customer's excess electricity directly to the distribution XXX exempt from sales taxes as a sale for resale?

Response: Yes. The sale of customer's excess electricity to the XXX XXX would be exempt from sales taxes as a sale for resale pursuant to Section 212.06(1)(b), F.S.

Issue 2: Is the sale of excess electricity directly from the customer to the distribution XXX exempt from gross receipts tax?

Response: Yes. The gross receipts tax is not imposed on gross receipts received from the sale or delivery of electricity to XXXs for resale, pursuant to Section 203.01(3)(a)2., F.S.

CONCLUDING STATEMENT

This response constitutes a Technical Assistance Advisement under Section 213.22, F.S., which is binding on the Department only under the facts and circumstances described in the request for this advice, as specified in Section 213.22, F.S. Our response is predicated on those facts and the specific situation summarized above. You are advised that subsequent statutory or administrative rule changes or judicial interpretations of the statutes or rules upon which this advice is based may subject similar future transactions to a different treatment than expressed in this response.

You are further advised that this response, your request and related backup documents are public records under Chapter 119, F.S., and are subject to disclosure to the public under the conditions of Section 213.22, F.S. Confidential information must be deleted before public disclosure. In an effort to protect confidentiality, we request you provide the undersigned with an edited copy of your request for Technical Assistance Advisement, the backup material and this response, deleting names, addresses and any other details which might lead to identification of the taxpayer. Your response should be received by the Department within 10 days of the date of this letter.

If you have any further questions with regard to this matter and wish to discuss them, you may contact me directly at 850-488-8026.

Kind Regards,

Alan R. Fulton
Tax Law Specialist
Technical Assistance & Dispute Resolution

ARF\lp
Record ID: 43389



Executive Director
Lisa Echeverri

December 10, 2007

Ms. Michelle Hershel
Director, Regulatory Affairs
Florida Electric Cooperative Association, Inc.
2916 Apalachee Parkway
Tallahassee, FL 32301

Re. Letter of Technical Advice 07A-1462
Florida Electric Cooperatives Association
Gross Receipts Tax and Sales Tax – Tax Calculation on Net Billing Credits
involving residential solar energy systems
Sections 203.01, 212.02, 212.06, 212.08, and 366.81, F.S. ("Florida Statutes")
Rule 25-6.065(6), F.A.C. ("Florida Administrative Code")

Dear Ms. Hershel.

Pursuant to Rule 12-11.003, F.A.C., taxpayers may seek informal written technical advice from the Department of Revenue ("Department"). Such advice is issued in the form of a Letter of Technical Advice ("LTA"). This LTA is being issued in response to your written request for informal guidance of August 7, 2007, concerning the delivery of excess electricity (generated by solar energy systems) from residential customers to electric utilities. Please note that this LTA constitutes the opinion of the writer only and does not represent the official position of the Department.

REQUESTED ADVISEMENT

You request clarification on the collection of sales tax and gross receipts tax when a residential customer interconnects a photovoltaic ("PV") electric system (i.e., solar energy system) with a cooperative's facilities. Your letter provides, in part, the following:

Issue 1 Is the electricity sold to a residential customer that has provided an exemption certificate to the cooperative still exempt from sales tax on electricity under the household fuel exemption in Section 212.08(7)(j), F.S., even though the customer is now in the business of selling electricity?

Issue 2: Is the sale of the customer's excess electricity to the wholesale cooperative exempt from sales taxes as a sale for resale?

Child Support Enforcement – *Ann Coffin, Director* • General Tax Administration – *Jim Evers, Director*
Property Tax Oversight – *James McAdams, Director* • Administrative Services – *Nancy Kelley, Director*
Information Services – *Tony Powell, Director*

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Tallahassee, Florida 32399-0100

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Issue 3: Is the sale of excess electricity from the customer to the wholesale cooperative exempt from gross receipts tax as a sale for resale?

Issue 4: Does the cooperative have any sales tax liability for power generated and consumed by the customer that does not register on the cooperative's meter (i.e., that is not excess power)?

Issue 5: Does the cooperative have any gross receipts tax liability for power generated and consumed by the customer that does not register on the cooperative's meter (i.e., that is not excess power)?

Issue 6: What is the proper method to calculate sales and gross receipts taxes for residential and commercial customers utilizing net billing (Can the distribution cooperative apply the Net Billing Credit before the sales taxes are calculated and should it offset the distribution cooperative's revenues for calculating its gross receipts tax)?

FACTS

Your letter of August 7, 2007, provides, in part:

* * *

Some . . . customers own and operate small (less than 10kW) PV energy systems. [Certain electric cooperatives] ["the cooperatives"] offer a net billing option which allows customers to receive credits for excess electricity generated by their PV system. "Excess" electricity is the electricity that is generated by the customer that exceeds the customer's needs at that moment.

The metering/billing process is a multi-step transaction. Generally, after a customer notifies the cooperative that they would like to interconnect a PV electric system to the cooperative's facilities, the cooperative sends the customer an interconnection agreement and request for verification of insurance. Under the terms of the interconnection agreement, any excess electricity generated by the customer is sold to the **wholesale** cooperative provider. Once the distribution cooperative receives the executed documents, the customer's meter is changed out for a special meter (unless the customer's meter is already capable of measuring electricity in both directions) that measures both the amount of electricity supplied by the distribution cooperative to the customer and the excess electricity generated by the customer that is delivered to the wholesale cooperative.

The customer's account is set up to reflect the tariffed retail rate paid by the customer to the distribution cooperative and the rate paid by the wholesale cooperative to the customer (these rates may not be the same) for the excess electricity. The excess power delivered from the customer to the wholesale cooperative is then resold to the distribution cooperative. The resale of excess electricity generated by the customer to the wholesale cooperative is shown as a credit on the distribution cooperative's wholesale power bill. In

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turn, the distribution cooperative reflects the credit on the customer's bill. [emphasis in original]

* + *

The Florida Public Service Commission exercises regulatory authority over utilities Rule 25-6.065(6), F.A.C., governs the Interconnection of Small Photo Voltaic Systems. While the Rules of the Florida Public Service Commission do not guide us on Florida tax questions, this particular rule is relevant to our analysis because it provides for "net billing" and crediting. The rule provides, in part:

The utility may install an additional meter or metering equipment on the customer's premises capable of measuring any excess kilowatt-hours produced by the SPS [a small photovoltaic system] and delivered back to the utility. . . The value of such excess generation **shall be credited to the customer's bill** . . . If the utility does not install such a meter or metering equipment, the utility **shall** permit the customer to net meter any excess power delivered to the utility by a single standard watt-hour meter capable of reversing directions to offset recorded consumption by the customer. If the kilowatt-hour of energy produced by the SPS exceeds the customer's kilowatt-hour consumption for any billing period, such that when the meter is read the value displayed on the register is less than the value displayed on the register when it was read at the end of the previous billing period, the utility **shall carry forward credit for the excess energy to the next billing period**. Credits may accumulate and be carried forward for a 12-month period specified by the utility in the SPS Interconnection Agreement. **In no event shall the customer be paid for excess energy delivered to the utility at the end of the 12-month period.** [emphasis added]

RESPONSE

This response is based on the specific facts and circumstances presented in your letter. This response does not consider situations involving "co-generation," "small power producers," "industrial manufacturing" or persons who produce electricity as a substitute for electricity produced by a utility (except as to your specific question in Issues 4 and 5)

Generally:

There are several things to consider when responding to the issues you present in your letter

The first is determining whether the residential customer is "in the business" of selling electricity when it delivers excess electricity to the cooperative and receives a credit (or economic benefit under "net-billing") If so, the next question begs does this then defeat the exemption on the initial "cooperative to customer sale" for residential households?

"Business" is defined broadly at Section 212.02(2), F.S. It could be said that residential

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customers, under the facts presented, are "in the business" of selling excess electricity back to the cooperatives because the residential customers are engaged in an activity for private gain or benefit (such a residential customer likely says at some point "any excess electricity my PV generates, the cooperative must buy it back, and I will get a credit on my overall electric bill").

Next, if a residential customer is "in the business" of selling electricity and a "sale" is occurring (as that term is broadly defined at Section 212.02(15), F.S.), then arguably, the residential customer must register with the Department as a "dealer" (as that term is defined in Section 212.06(2), F.S.

Further, if a residential customer is "in the business" of selling electricity, then is the sale an exempt sale for resale because the cooperative will be reselling the electricity that it "bought" from the residential customer? The answer is: "yes." Your letter provides that under the terms of the interconnection agreements, any excess electricity generated by the residential customer is sold to the **wholesale** cooperative provider who then gives the **distribution** cooperative a credit on its bill.

But do these determinations involving "in the business" and "sales for resale" defeat the exemption enjoyed by residential customers under these facts. The answer is "no" for several reasons.

First, Section 212.08(7)(j), F.S., provides that the exemption is defeated if the utilities sold "are used" for a nonexempt purpose. Under these facts, the utilities sold by the cooperatives continue to be used for residential purposes by the residential households. The selling of excess electricity by the residential customer does not constitute a "use."

Secondly, we find it significant that utilities such as the cooperatives are required to credit and "net-bill" when residential customers deliver excess electricity to them. As we observed earlier, the Rules of the Florida Public Service Commission (and for that matter, Chapter 366, F.S. -- except for any specific provisions that involve the Department or laws it is charged to administer) do not direct the Department or the public on tax matters. However, the Department is mindful and respectful of the Legislative intent specifically provided for in Section 366.81, F.S. Rule 25-6.065(6), F.A.C., implements this Legislative intent. Section 366.81, F.S., provides, in part:

The Legislature finds that it is critical to utilize the most efficient and cost-effective energy conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens. ... The Legislature further finds that the Florida Public Service Commission is the appropriate agency to adopt goals and approve plans related to the conservation of electric energy [T]he Legislature intends that the use of solar energy ... be encouraged . . .

Under the facts presented in your letter, reading Sections 212.08(7)(j) and 366.81, F.S., together leads to the conclusion that it would be impractical and unreasonable to require residential customers (under these facts) to register as "dealers" with the Department and be responsible for all of the attendant responsibilities that go along with being a "dealer." The residential customer's

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delivery of excess electricity and the subsequent credit or "net-billing" does not defeat the exemption provided to residential customers. This conclusion also considers: (a) that the delivery of excess electricity is a "sale for resale" that carries out the Legislature's intent of promoting energy conservation and the use of solar energy; and (b) under the facts presented, Florida Sales Tax would not be due because the customer to cooperative "sale" is an exempt "sale for resale" and Florida Gross Receipts Tax would not be due because the "sale" is not to a "retail consumer "

Based on the discussion above, the Department turns to your specific issues.

Issue 1: Is the electricity sold to a residential customer that has provided an exemption certificate to the cooperative still exempt from sales tax on electricity under the household fuel exemption in Section 212.08(7)(j), F.S., even though the customer is now in the business of selling electricity?

Response: Yes. The exemption for residential households is not defeated. The Department does not issue "exemption certificates" to residential households.

Issue 2: Is the sale of the customer's excess electricity to the wholesale cooperative exempt from sales taxes as a sale for resale?

Response: Yes. The "customer to cooperative" sale is a "sale for resale" and is exempt from Florida Sales Tax.

Issue 3: Is the sale of excess electricity from the customer to the wholesale cooperative exempt from gross receipts tax as a sale for resale?

Response: Yes, but more fundamentally, it is not subject to Florida Gross Receipts Tax because the sale is not to a retail customer.

Issue 4: Does the cooperative have any sales tax liability for power generated and consumed by the customer that does not register on the cooperative's meter (i.e., that is not excess power)?

Response: A residential customer would still be exempt from Florida Sales and Use Tax. A commercial customer would be liable for use tax calculated on the cost price. See Section 212.06(1)(b), F.S. However, the commercial customer would be responsible for complying in that situation, not the cooperative.

Issue 5: Does the cooperative have any gross receipts tax liability for power generated and consumed by the customer that does not register on the cooperative's meter (i.e., that is not excess power)?

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Response: No, the cooperative would not be liable, but the customer would be. Section 203 01(1)(i), F.S., provides

Any person other than a cogenerator or small power producer described in paragraph (h) who produces for his or her own use electrical energy which is a substitute for electrical energy produced by an electric utility as defined in s. 366 02 is subject to the tax imposed by this section. The tax shall be applied to the cost price of such electrical energy as provided in s. 212 02(4) and shall be paid each month. The provisions of this paragraph do not apply to any electrical energy produced and used by an electric utility.

Issue 6: What is the proper method to calculate sales and gross receipts taxes for residential and commercial customers utilizing net billing (Can the distribution cooperative apply the Net Billing Credit before the sales taxes are calculated and should it offset the distribution cooperative's revenues for calculating its gross receipts tax)?

Response: Florida Gross Receipts Tax is levied against the total amount of gross receipts received by a distribution company. [emphasis supplied] See Section 203 01(1)(c), F.S. The cooperatives should remit Gross Receipts Tax based on what they actually receive (and bill for what they will actually be receiving). In other words, if the bill to the customer is initially \$100.00 but after credits is \$75.00, Gross Receipts Tax would be due on the \$75.00 because that is the total amount that is (or will be) received by the cooperatives.

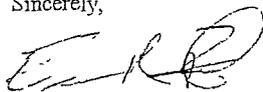
Sales of electricity to residential households are exempt from Florida Sales Tax. Likewise, as discussed above, a "sale for resale" is exempt from Florida Sales Tax. So for Florida Sales Tax purposes, how the customer is billed (in situations like the ones presented in your letter) is of no real consequence because no Florida Sales Tax is due on either of the transactions (the cooperative to customer sale and subsequently, the customer to cooperative sale).

As noted in the first paragraph of this letter, this LTA is being issued in response to the disclosed facts and circumstances of your specific situation, and it does not constitute the official position of the Department. Rather, this letter represents the opinion of the writer only. If you wish an official binding statement, you may file a written request for a Technical Assistance Advisement Rule Chapter 12-11, F.A.C., outlines the procedure to follow in making this request. This rule chapter of the Florida Administrative Code can be found at <http://www.myflorida.com/dor/law/>. Any request for a Technical Assistance Advisement should be sent to Technical Assistance and Dispute Resolution, Department of Revenue, P.O. Box 7443, Tallahassee, Florida, 32314-7443.

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If you have any further questions with regard to this matter and wish to discuss them, you may contact me directly at (850) 922-4714.

Sincerely,



Eric Russell Peate
Senior Attorney
Technical Assistance & Dispute Resolution

Record ID 34460

533 So.2d 281 (1988)

**PW VENTURES, INC., Appellant,
v.
Katie NICHOLS, Chairman of Florida Public Service Commission, and
Florida Public Service Commission, Appellees.**

No. 71462.

Supreme Court of Florida.

October 27, 1988.

282*282 Richard D. Melson of Hopping, Boyd, Green & Sams, Tallahassee, for appellant.

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GRIMES, Justice.

PW Ventures, Inc. (PW Ventures) appeals from an adverse ruling of the Florida Public Service Commission (PSC). We have jurisdiction. Art. V, § 3(b)(2), Fla. Const.

PW Ventures^[1] signed a letter of intent with Pratt and Whitney (Pratt) to provide electric and thermal power at Pratt's industrial complex in Palm Beach County. PW Ventures proposes to construct, own, and operate a cogeneration^[2] project on land leased from Pratt and to sell its output to Pratt under a long-term take or pay contract.^[3] Before proceeding with construction of the facility that would provide the power, PW Ventures sought a declaratory statement from the PSC that it would not be a public utility subject to PSC regulation. After a hearing, the PSC ruled that PW Ventures proposed transaction with Pratt fell within its regulatory jurisdiction.

At issue here is whether the sale of electricity to a single customer^[4] makes the provider a public utility. The decision hinges on the phrase "to the public," as it is used in section 366.02(1), Florida Statutes (1985). In pertinent part that subsection provides:

"Public utility" means every person, corporation, partnership, association, or other 283*283 legal entity and their lessees, trustees, or receivers supplying electricity or gas (natural, manufactured, or similar gaseous substance) to or for the public within this state... .

Distilled to their essence, the parties' views are as follows: PW Ventures says the phrase "to the public" means to the general public and was not meant to apply to a bargained-for transaction between two businesses. The PSC says the phrase means "to any member of the public." While the issue is not without doubt, we are inclined to the position of the PSC.

At the outset, we note the well established principle that the contemporaneous construction of a statute by the agency charged with its enforcement and interpretation is entitled to great weight. [Warnock v. Florida Hotel & Restaurant Comm'n, 178 So.2d 917 \(Fla. 3d DCA 1965\)](#), *appeal dismissed*, [188 So.2d 811 \(Fla. 1966\)](#). The courts will not depart from such a construction unless it is clearly unauthorized or erroneous. [Gay v. Canada Dry Bottling Co., 59 So.2d 788 \(Fla. 1952\)](#).

Also, it is significant that the statute itself would permit the type of transaction proposed by PW Ventures and Pratt to be unregulated if it were for natural gas services. Section 366.02(1) provides the following exemption: "[T]he term 'public utility' as used herein does not include ... any natural gas pipeline transmission company making only sales of natural gas at wholesale and to direct industrial consumers... ." The legislature did not provide a similar exemption for electricity. The express mention of one thing implies the exclusion of another. [Thayer v. State, 335 So.2d 815 \(Fla. 1976\)](#).

This rationale is further illustrated in the statutory regulation of water and sewer utilities. As explained in the PSC order:

In parallel with Section 366.02(1), Section 367.021, Florida Statutes (1985), defines a water or sewer utility as every person "providing, or who proposes to provide, water or sewer service to the public for compensation." Section 367.022(6), Florida Statutes, expressly exempts from this definition "systems with the capacity or proposed capacity to serve 100 or fewer persons". There is not a parallel numerical exemption to the statutory definition of a public utility supplying electricity. Yet the statutory interpretation advocated by PW Ventures would require a line to be drawn somewhere between sales to some members of the public, as a presumably nonjurisdictional activity, and sales to the public generally and indiscriminately, an admittedly jurisdictional activity.

Moreover, the PSC's interpretation is consistent with the legislative scheme of chapter 366. The regulation of the production and sale of electricity necessarily contemplates the granting of monopolies in the public interest. [Storey v. Mayo, 217 So.2d 304 \(Fla. 1968\)](#), *cert. denied*, [395 U.S. 909, 89 S.Ct. 1751, 23 L.Ed.2d 222 \(1969\)](#). Section 366.04(3), Florida Statutes (1985), directs the PSC to exercise its powers to avoid "uneconomic duplication of generation, transmission, and distribution facilities." If the proposed sale of electricity by PW Ventures is outside of PSC jurisdiction, the duplication of facilities could occur. What PW Ventures proposes is to go into an area served by a utility and take one of its major customers.¹⁵ Under PW Ventures' interpretation, other ventures could enter into similar contracts with other high use industrial complexes on a one-to-one basis and drastically change the regulatory scheme in this state. The effect of this practice would be that revenue that otherwise would have gone to the regulated utilities which serve the affected areas would be diverted to unregulated producers. This revenue would have to be made up by the remaining customers of the regulated utilities since the fixed costs of the regulated systems would not have been reduced.

^{284*284} We do not believe that [Fletcher Properties v. Florida Public Service Commission, 356 So.2d 289 \(Fla. 1978\)](#), mandates a different result. In that case, we did approve a PSC order which included reasoning to the effect that service to the public meant service to the indefinite public or to all individuals within a given area. However, the case did

not arise in the context of a sale to a single customer. We simply affirmed the PSC's determination that the developer and owner of lines and lift stations who proposed to furnish water and sewer service to single family homes at the same rate as it was charged by the area water and sewer utility occupied the status of a public utility.^[6]

The fact that the PSC would have no jurisdiction over the proposed generating facility if Pratt exercised its option under the letter of intent to buy the facility and elected to furnish its own power is irrelevant. The expertise and investment needed to build a power plant, coupled with economies of scale, would deter many individuals from producing power for themselves rather than simply purchasing it. The legislature determined that the protection of the public interest required only limiting competition in the sale of electric service, not a prohibition against self-generation.

We approve the decision of the Public Service Commission.

It is so ordered.

EHRlich, C.J., and OVERTON, SHAW, BARKETT and KOGAN, JJ., concur.

McDONALD, J., dissents with an opinion.

McDONALD, Justice, dissenting.

I dissent. In doing so, I accept the argument of PW Ventures, Inc. as set forth in its brief where it urges:

The cornerstone of "public utility" status and Commission jurisdiction under Chapter 366 is the provision of electric service "to the public". This phrase is not defined in Chapter 366, nor in any of the Commission's other jurisdictional statutes. Under Florida's rules of statutory construction, the phrase "to the public" must therefore be given either its plain and ordinary meaning or, if it is a legal term of art, its legal meaning. [City of Tampa v. Thatcher Glass Corporation, 445 So.2d 578 \(Fla. 1984\)](#); [Citizens v. Florida Public Service Commission, 425 So.2d 534 \(Fla. 1982\)](#); [Tatzel v. State, 356 So.2d 787 \(Fla. 1978\)](#); [Ocasio v. Bureau of Crimes Compensation, 408 So.2d 751 \(Fla. 3d DCA 1982\)](#). Under either test, a sale to a single industrial host in the circumstances of this case is not a sale "to the public."

* * * * *

The phrase "to the public" commonly connotes the people as a whole, or at least a group of people. Webster's Ninth New Collegiate Dictionary (1983) gives two relevant definitions for "public":

2: the people as a whole: POPULACE

3: a group of people having common interests or characteristics: *specif*:the group at which a particular activity or enterprise aims

Black's Law Dictionary (Revised 4th ed.) similarly defines "public" to mean:

The whole body politic, or the aggregate of the citizens of a state, district, or municipality.... In one sense, everybody; and accordingly the body of the people at large; the community at large, without reference to the geographical limits of any corporation like a city, town, or county; the people. In another sense the word does not mean all the people, nor most of the people, nor very many of the people of a place, but so many as contradistinguishes them from a few.

Thus if Section 366.02(1) is given its plain and ordinary meaning, a person is not supplying electricity "to the public," if it supplies electricity only to a single 285*285 industrial customer on whose property the electric generating facility is located.

[1] PW Ventures is a Florida corporation which was originally owned by FPL Energy Services, Inc. (a wholly owned subsidiary of FPL Group, Inc.) and Impell Corporation (a wholly owned subsidiary of Combustion Engineering, Inc.). After the entry of the PSC order, FPL Energy Services, Inc. transferred its 50% interest to Combustion Engineering, Inc.

[2] Cogeneration involves the use of steam power to produce electricity, with some of the energy from the steam being recaptured for further use. The PSC seeks only to regulate the sale of electrical power.

[3] The power would be used by Pratt and several affiliated corporate entities and by the Federal Aircraft Credit Union which is also located on the property.

[4] While the PSC reminds us that the power generated by the project will actually be passed on to several entities, we prefer to address the issue in the context argued by PW Ventures.

[5] Initially, Florida Power and Light had an interest in PW Ventures and would, in effect, transfer its own client to a subsidiary. FP & L is not now involved. Yet, if the argument of PW Ventures is accepted, there might be nothing to prevent one utility company from forming a subsidiary and raiding large industrial clients within areas served by another utility.

[6] The holding of that case actually supports the PSC's alternative position that PW Ventures will actually serve several customers at the Pratt facility.

Florida Department of Revenue participation at the April 24, 2015, workshop of
The Financial Impact Estimating Conference

Introduction

The FIEC has invited the Florida Department of Revenue to attend its April 24, 2015, workshop in order to assist the FIEC on certain State tax questions it had. The Department is glad to assist and submits this written document in the spirit of fostering discussion regarding the State tax issues presented. This document and the anticipated dialogue at the April 24, 2015, workshop are meant for discussion purposes only and should not be relied on as policy statements of the Department. Those seeking a binding opinion from the Department should request a Technical Assistance Advisement from the Department.

Amendment Language – Ballot Summary:

Limits or Prevents Barriers to Local Solar Electricity Supply

Limits or prevents government and electric utility imposed barriers to supplying local solar electricity. Local solar electricity supply is the non-utility supply of solar generated electricity from a facility rated up to 2 megawatts to customers at the same or contiguous property as the facility. Barriers include government regulation of local solar electricity suppliers' rates, service and territory, and unfavorable electric utility rates, charges, or terms of service imposed on local solar electricity customers.

Specific request of the Department of Revenue

We have been advised that the FIEC's review is limited solely to the estimated increase or decrease in revenues or costs to state or local governments. The FIEC has already met once in a Public Workshop. At the end of that meeting, the principals requested assistance from the Department of Revenue in better understanding the current operation of law or administration in regard to purchases or sales of solar equipment or energy. From a state perspective, the FIEC has identified several tax sources of interest:

- Sales and Use Taxes
- Gross Receipts Tax (especially the Use Tax provisions)
- Ad Valorem Taxes

We have been advised that, unlike a typical Impact Conference hosted by the Revenue Estimating Conference, the FIEC is looking for subject matter expertise from the Department rather than specific impacts.

Applicable statutory, judicial, rule or administrative provisions¹

1) Statutory, judicial, rule or administrative provisions that are relevant to the purchase of solar equipment.

- s. 212.08(7)(hh), F.S. – Sales Tax exemption for purchase of solar energy systems
- s. 212.02(26), F.S. – “solar energy system” defined

2) Statutory, judicial, rule or administrative provisions that are relevant to a utility’s sales of electricity or to their revenues, especially in regard to the treatment of solar energy.

- Ch. 203, F.S. – Gross Receipts tax
 - s. 203.01(1)(a)1., F.S. – tax is imposed on the gross receipts from utility services that are delivered to a retail customer
 - s. 203.01(1)(c)1., F.S. – tax is levied against the total amount of gross receipts received by a distribution company
 - s. 203.01(1)(h) and (i), F.S. – gross receipts “use tax”
 - s. 203.01(3)(a)1., F.S. – sales for resale are exempt
 - s. 203.012, F.S. – “distribution company” and “utility service” defined
- Rule Chapter 12B-6, Florida Administrative Code

¹ We limited our response to relevant State tax provisions

- Ch. 212, F.S. – Sales and Use Tax
 - s. 212.02(4), F.S. – “cost price” defined
 - s. 212.05, F.S. -- Sales Tax on electricity
 - s. 212.07(1)(b), F.S. – sales for resale are exempt
 - s. 212.08(7)(j), F.S. – sales of electricity to residential households by utility companies who pay the gross receipts tax imposed under s. 203.01, F.S. are exempt from sales tax
 - s. 212.06(1)(b), F.S. – Use Tax on electricity

3) Statutory, judicial, rule or administrative provisions that are relevant to sales of electricity by a person or entity that is not a utility.

Please see listing, above.

4) Statutory, judicial, rule or administrative provisions that are relevant to the valuation of solar equipment, whether as real property or tangible personal property.

- s. 192.001(11)(d), F.S. – definition of “tangible personal property”
- s. 193.624, F.S. – assessment of residential property; renewable energy source device exempt from increase in just value
- Rule 12A-1.051(17)(ii), F.A.C. – generally speaking, solar systems are considered real property contracts unless the facts demonstrate otherwise

As to Specific Transactions:

We have been advised that the FIEC is also interested in how the above provisions are applied in practice to specific transactions and situations. For example, how are the Sales and Use Tax and the Gross Receipts Tax applied to:

a) Transactions between a utility and a customer involving net-metering;

The sale of excess electricity by a customer to a utility – Exempt from both gross receipts tax and sales tax because the electricity is a sale for resale.

The sale of electricity by a utility to a customer – A utility would remit the gross receipt tax based on the amount of money received from its customers for charges for utility services. This would be the net amount of electricity billed to the customer after allowing a credit for the excess electricity generated by the customer and returned to the utility. In other words, if the bill from the utility shows electricity consumed by the customer in the amount of \$100 and a credit for excess customer-generated electricity in the amount \$25, resulting in a balance due of \$75, gross receipts tax is calculated on the net amount or \$75. The same analysis holds true for Sales Tax (i.e., Sales Tax in this example would be due on the \$75)

b) Persons or entities that produce electricity for their own use;

With certain exemptions and exceptions, both gross receipts tax and Chapter 212 tax have “use tax” elements. Persons or entities that produce electricity for their own use would need to file and remit. Existing Department forms and filing procedures would be used.

c) Purchases of electricity by a customer of a “local solar energy supplier,” as contemplated by the proposed constitutional amendment.

Please refer to the other parts of this document that focus on the particulars of this question.

d) Can the Department also be prepared to discuss the tax treatment of third-party-ownership (TPO) structures for photovoltaic (PV) systems—whether lease or power-purchase agreement (PPA)?

As we understand them, TPOs (a.k.a, PPAs) in this context generally involve a third-party who installs and operates a PV system on a customer’s property (or contiguous property). The TPO provides electricity to the customer (and possibly other contiguous persons). The customer pays the TPO only for the electricity it uses. The cost of installing and maintaining the PV system is shouldered by the TPO.

Gross Receipts tax – the heart of this issue goes to the term “distribution company” because Gross Receipts tax is imposed on “distribution companies.” Under current statute, arguments both for and against TPOs being considered “distribution companies” could be made. In the end, however, Gross Receipts tax is due – whether it will be from the TPO or its customer (under the Gross Receipts “use tax”). Unlike Chapter 212 tax, Gross Receipts tax is applicable in both residential and non-residential situations.

Chapter 212 tax – This tax, whether sales or use tax, will only be due on sales to non-residential customers. It appears clear that the TPOs will be selling electricity, therefore, they would need to register with the Department for sales tax and then collect it from its customers and remit the tax to the State. If one were to argue TPOs are not selling electricity (hypothetically TPOs may assert they are assisting customers in the customer’s production of their own electricity), then Use Tax would be due from the customer.

Net-metering –State tax would likely be handled the same way when TPOs are involved as is being handled today (see discussion elsewhere in this document).

Voluntary compliance is the key to efficient tax administration. Certainly, working with a handful of persons in an industry who collect tax from tens (and maybe hundreds) of thousands of customers is more efficient than working with tens (and maybe hundreds) of thousands of individual taxpayers. The Department would strive to work with the TPO industry, their customers, regulated utilities, sister agencies, tax practitioners and other interested persons in finding the least burdensome and most efficient way to administer State tax in this evolving area.

Examples:

I. A residential household buys or leases a solar system then sells excess electricity directly to a neighbor without going through the local utility/grid.

- a. Purchase or lease of solar system: exempt under s. 212.08(7)(hh), F.S.
- b. Use of self-generated electricity
 - i. Sales and Use Tax²: exempt as residential use under s. 212.08(7)(j), F.S.
 - ii. Gross receipts tax (the “use tax” component)³: taxable under s. 203.01(1)(h) or (i), F.S., based on s. 212.02, F.S., cost price
- c. Sale of excess electricity to neighbor
 - i. Sales and use tax: exempt if neighbor is residential; taxable if neighbor is commercial and does not otherwise qualify for exemption.⁴
 - ii. Gross receipts tax: arguably taxable under s. 203.01(1)(a)1., F.S.

² For these purposes, “sales and use tax” means both the 4.35% sales tax rate and the 2.6% gross receipts tax rate that is administered as a sales tax.

³ For these purposes, “gross receipts tax” means only the 2.5% gross receipts tax rate.

⁴ Types of exemption are: 1) use of electricity to operate machinery and equipment under s. 212.08(7)(ff), F.S.; 2) agricultural use under s. 212.08(5)(a), F.S.; 3) sale to entity holding Consumer’s Certificate of Exemption (such as religious organizations or 501(c)(3) nonprofits); 4) sale to federal government. Note that, with the exception of the manufacturing exemption, these exemptions do not apply to the 2.5% gross receipts tax.

II. A residential household buys or leases a solar system then sells excess electricity directly to a neighbor and sells the electricity to the neighbor using another entity's distribution system.

- a. Purchase or lease of solar system: exempt under s. 212.08(7)(hh), F.S.
- b. Use of self-generated electricity
 - i. Sales and Use tax: exempt as residential use under s. 212.08(7)(j), F.S.
 - ii. Gross receipts tax (the "use tax" component): taxable under s. 203.01(1)(h) or (i), F.S., based on s. 212.02, F.S., cost price
- c. Sale of excess electricity to neighbor
 - i. Sales and use tax: exempt if neighbor is residential; taxable if neighbor is commercial and does not otherwise qualify for exemption.⁵
 - ii. Gross receipts tax: arguably not taxable because selling household is not a distribution company.

III. A residential household buys or leases a solar system, sells the excess electricity to the local utility under a net-metering agreement. The local utility then sells the electricity to the household's neighbor.

- a. Purchase or lease of solar system: exempt under s. 212.08(7)(hh), F.S.
- b. Use of self-generated electricity
 - i. Sales and Use tax: exempt as residential use under s. 212.08(7)(j), F.S.
 - ii. Gross receipts tax (the "use tax" component): taxable under s. 203.01(1)(h) or (i), F.S., based on s. 212.02, F.S., cost price

⁵ Same as footnote 3.

- c. Sale of excess electricity to utility
 - i. Sales and use tax: exempt as sale for resale under s. 212.07(1)(b), F.S.
 - ii. Gross receipts tax: exempt as sale for resale under s. 203.01(3)(a)1., F.S.

IV. A commercial business buys or leases a solar system, then sells the excess electricity directly to a neighbor without going through the local utility/grid.

- a. Purchase or lease of solar system: exempt under s. 212.08(7)(hh), F.S.
- b. Use of self-generated electricity
 - i. Use tax: taxable under s. 212.06(1)(b), F.S., based on cost price unless the business qualifies for an exemption.⁶
 - ii. Gross receipts tax (the “use tax” component): taxable under s. 203.01(1)(h) or (i), F.S., based on s. 212.02, F.S., cost price
- c. Sale of excess electricity to neighbor
 - i. Sales and Use tax: exempt if the neighbor is residential; taxable if neighbor is commercial and does not otherwise qualify for exemption.⁷
 - ii. Gross receipts tax: arguably taxable under s. 203.01(1)(a)1., F.S.

V. A commercial business buys or leases a solar system, then sells the excess electricity directly to a neighbor and sells the electricity using another entity’s distribution system.

- a. Purchase or lease of solar system: exempt under s. 212.08(7)(hh), F.S.
- b. Use of self-generated electricity
 - i. Use tax: taxable under s. 212.06(1)(b), F.S., based on cost price unless the business qualifies for an exemption.⁸

⁶ Same as footnote 3.

⁷ Same as footnote 3.

- ii. Gross receipts tax (the “use tax” component): taxable under s. 203.01(1)(h) or (i), F.S., based on s. 212.02, F.S., cost price
- c. Sale of excess electricity to neighbor
 - i. Sales and Use tax: exempt if neighbor is residential; taxable if neighbor is commercial and does not otherwise qualify for exemption.⁹
 - ii. Gross receipts tax: arguably not taxable because the business is not a distribution company.

VI. A commercial business buys or leases a solar system, then sells the excess electricity to a local utility under a net-metering agreement. The local utility sells the electricity to the commercial business’s neighbor.

- a. Purchase or lease of solar system: exempt under s. 212.08(7)(hh), F.S.
- b. Use of self-generated electricity
 - i. Use Tax: taxable under s. 212.06(1)(b), F.S., based on cost price unless the business qualifies for an exemption.¹⁰
 - ii. Gross receipts tax (the “use tax” component): taxable under s. 203.01(1)(h) or (i), F.S., based on s. 212.02, F.S., cost price
- c. Sale of excess electricity to utility
 - i. Sales and Use tax: exempt as sale for resale under s. 212.07(1)(b), F.S.
 - ii. Gross receipts tax: exempt as sale for resale under s. 203.01(3)(a)1., F.S.

⁸ Same as footnote 3.

⁹ Same as footnote 3.

¹⁰ Same as footnote 3.

Miscellaneous:**How does DOR envision the future?**

Anytime we are presented with new technologies, business models or other market changes, we solicit the input of taxpayers, industry, tax practitioners and others in order to try to learn as much as we can. Our goal is to arrive at the most efficient and least burdensome way to fairly and accurately administer State tax law. We would likely do the same in this evolving area.

Is DOR auditing for use tax?

In trying to be good stewards of the resources we are given, the Department deploys resources in areas where there may be the greatest need and where the resources will be most efficiently used. The Department routinely audits various industries and businesses for use tax. As the area of solar power generation evolves and expands, the Department anticipates that it would work with industry and others to maximize voluntary compliance and to use its resources appropriately.

Tab 4

Reports

Diffusion of environmentally-friendly energy technologies: buy versus lease differences in residential PV markets

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Received 20 October 2012

Accepted for publication 23 January 2013

Published 19 February 2013

Online at stacks.iop.org/ERL/8/014022

Abstract

Diffusion of microgeneration technologies, particularly rooftop photovoltaic (PV), represents a key option in reducing emissions in the residential sector. We use a uniquely rich dataset from the burgeoning residential PV market in Texas to study the nature of the consumer's decision-making process in the adoption of these technologies. In particular, focusing on the financial metrics and the information decision-makers use to base their decisions upon, we study how the leasing and buying models affect individual choices and, thereby, the adoption of capital-intensive energy technologies. Overall, our findings suggest that the leasing model more effectively addresses consumers' informational requirements and that, contrary to some other studies, buyers and lessees of PV do not necessarily differ significantly along socio-demographic variables. Instead, we find that the leasing model has opened up the residential PV market to a new, and potentially very large, consumer segment—those with a tight cash-flow situation.

Keywords: residential solar PV, discount rates, solar business models, individual decision-making

 Online supplementary data available from stacks.iop.org/ERL/8/014022/mmedia

1. Introduction

Two questions prompted the work in this paper. First, what can be learned from the diffusion of solar photovoltaics (PV) for improving existing solar programs and the design of others in newer markets? As policy support for these technologies is waning, this increases the pressure for incentive programs to become more efficient (US DOE 2008, 2012). Second, what lessons can the residential PV market shed on the individual decision-making process? The scale of capital investment for solar PV is quite high relative to most other household investments. So, presumably, the choice to adopt PV forces individuals to consider the (alternative) options more carefully

than most investment decisions (Jager 2006). Unpacking the decision to adopt PV, then, might provide insights into the nature of the individual decision-making process.

Understanding the nature of the decision-making process has important practical implications for the design of mechanisms that incentivize reduction of greenhouse gas (GHG) emissions from energy use. With 22.2% consumption of primary energy and 21.4% of the total GHG emissions (EIA 2010) the residential sector is a key target for reducing energy demand and GHG emissions. Diffusion of microgeneration technologies, particularly rooftop PV, represents a key option in meeting demand and emissions reductions in the residential sector (US DOE 2012). As different actors have tried to design programs and incentives to spread the adoption of more efficient and environmentally-friendly consumption and generation devices (Taylor 2008), the nature of the individual's decision-making process has come to sharper focus (Allcott and Mullainathan 2010, Dietz 2010, Drury *et al* 2011, Jager 2006, Keirstead 2007, Bollinger and Gillingham 2012). Therefore, the last few years of experience with



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residential PV provides an early and unique opportunity to refine our understanding of how individual decision-making impacts technology diffusion.

Three lines of theory are relevant to this work. First, decision-making at the individual level. While the neoclassical microeconomic theory presumes that individual decision-makers are rational and information-prescient, there is increasing evidence that individual decision-makers depart significantly from the neoclassical model (Camerer *et al* 2004, Frederick *et al* 2002, Gintis 2000, Todd and Gigerenzer 2003, Wilson and Dowlatabadi 2007).

Second, empirical evidence of the use of high discount rates for future returns from energy-saving technologies (Gately 1980, Hausman 1979, Meier and Whittier 1983, Ruderman *et al* 1987). Expectations of rapid technological change, information barriers, and other non-monetary costs are some of the factors that give rise to the use of high implicit discount rates (Hassett and Metcalft 1993, Howarth and Sanstad 1995). In general, this phenomenon discourages the adoption of technologies whose benefits are spread over a long time horizon. The use of upfront capital subsidies have been proposed as a way to overcome this adoption barrier (Guidolin and Mortarino 2009, Hart 2010, Jager 2006, Johnson *et al* 2012, Timilsina *et al* 2011).

Third, business models for accelerating the deployment of technologies by addressing market barriers (Gallagher and Muehlegger 2011, Margolis and Zuboy 2006, Sidiras and Koukios 2004) facing individual decision makers—in particular the leasing model. Several researchers suggest that the option to lease a technology effectively addresses the high discount rate problem (Coughlin and Cory 2009, Drury *et al* 2011)—as well as some of the information failures associated with new technologies (Faiers and Neame 2006, Shih and Chou 2011).

2. Data

Our analysis uses a new household-level dataset built through two complementary data streams: (i) a survey of residents who have adopted PV and (ii) program data for the *same* adopters obtained from utilities that administer PV rebate programs. The survey, among other factors, explores *why* PV adopters made the financial choices they did (say, buy versus lease), and their own assessment of the attractiveness of their investment (Rai and McAndrews 2012). The survey was administered electronically in Texas during August–November 2011 and received 365 responses from the 922 PV owners contacted.

All survey respondents reported residing in areas of retail electricity choice in Texas (see supplementary information for spatial distribution available at stacks.iop.org/ERL/8/014022/mmedia). The mean size of the PV system installed was 5.85 kW-DC and the average age of respondents was 52 yr old. The mean household income was between \$85 000 and \$149 999 and 84.9% reported that at least one member of the household had achieved a college degree or higher level of education. Each of the prior demographics is significantly different from state-wide averages. That is, the survey population was wealthier, older, and better-educated than the average Texas

resident. No significant difference was found between lessees and buyers of PV on any demographic variable.

Of the 365 responses, we matched complementary program data for 210 respondents. The program data provides several data points, including (i) installed cost of the system, (ii) price and structure of lease payments if the system was leased, (iii) system capacity (kW, DC and AC), (iv) amount of rebates disbursed, (v) aggregate household electricity consumption from the prior year, (vi) retail electricity provider (REP), electric plan, and marginal cost of electricity consumption just prior to PV installation, and (vii) projected annual electricity generated by the system based on orientation, derating factor, and geography.

3. Methodology

Our strategy is to compare the financial metrics that PV adopters used to evaluate their investment decision (*reported metrics*) obtained through survey (above) with an ‘objective’ assessment of those same metrics (*modeled metrics*). To enable the comparison, we built a financial model that calculates the expected lifecycle costs and revenues of PV system ownership for the residential buying and leasing business models (NREL 2009, Kollins *et al* 2010). Our model is distinct in two ways. First, our uniquely comprehensive dataset allows detailed cost and revenue calculations for *each* respondent (decision maker). Second, it includes detailed features of *household-level* electricity consumption, electricity rates, and PV-based electricity generation, including time-of-day and monthly variations. Next, we provide an overview of our methodology; however a more thorough description is provided in the supplemental information.

3.1. Cash-flow model

For each PV adopter we calculate a series of monthly expected costs (C_k) and revenues (R_k) accrued over the lifetime of the PV system, where k is the number of months since the PV system was installed. Therefore, cash flows (CF_k) of the investment are:

$$CF_k = R_k - C_k. \quad (1)$$

Using these cash flows we calculate the net present value (NPV) using a 10% annual discount rate, NPV per DC-kW, payback period for each household’s investment, and estimate each individual’s implicit discount rate.

3.2. System costs

Costs (C_k) have three monthly components: (a) system payments (C_{system_k})—either lease payments or loan payments when financed and a down payment as appropriate, (b) operations and maintenance costs ($C_{O\&M_k}$), and (c) cost of inverter replacement (C_{Inverter_k}) where:

$$C_k = C_{\text{system}_k} + C_{O\&M_k} + C_{\text{Inverter}_k}. \quad (2)$$

System payments for *buyers* comprise a down payment in the first period and loan payments if the system was financed. The net system cost is the installed cost less the

utility rebate reported in the program data less applicable federal tax credits. We assume that: (i) buyers will make periodic operation and maintenance-related (O & M) expenses equivalent to 0–0.75% yr⁻¹ of the system's installed cost; these O&M costs are expensed equally each month, and (ii) inverters require replacement after 15 yr of use and cost \$0.7–0.95 per DC-Watt. In section 3.4 we present a set of scenarios that systematically vary these parameters.

Lessees are not obligated to pay O&M or inverter replacement costs as this is a value-adding service provided by the lessor (Mont 2004). Therefore, the only costs of ownership incurred are lease payments (upfront payment and monthly lease payments). Within the sample, 69% of lessees paid for their lease entirely through a 'prepaid' down payment, 26% through only monthly payments, and 4% through a combination of monthly payments and a down payment. For all leased systems analyzed, we use the actual lease payments being made by the lessees.

3.3. System revenue

PV systems generate value by reducing owners' electricity-bill expenses during the life of the system. Therefore, the difference between electric bills the owner would have incurred without the system (BAU bill) and those with the PV system (PV bill) is effectively a monthly stream of revenues (R_k). The value of these revenues depends on the structure and rates of both bills. Our model forecasts these revenues over the system's lifetime.

3.3.1. Electricity consumption and generation profiles. Two central factors in the PV value proposition are seasonal and hourly variations in the system's generation and the household's consumption of electricity. For both factors, we use each respondent's historic annual consumption and expected annual system production (kWh) as reported in the program data, but not individual consumption or generation patterns. To simulate these hourly and seasonal variations we used load profiles published by the Electricity Reliability Council of Texas (ERCOT) of average residential consumption patterns in north-central Texas in 2010 (ERCOT 2010) and a PV generation profile for the Dallas-Ft. Worth area taken from the PVWATTS model created by the US National Renewable Energy Laboratory (NREL 2011).

Furthermore, we assume that patterns and quantities of electricity consumption are invariant over the lifetime of the PV system. This is not a robust assumption per se, since we do not capture household-level patterns of consumption that differ from the ERCOT profile or that evolve over time. But, since the goal is to *compare* the objective and reported financial metrics, this assumption is robust enough for our analysis because any variations in consumption profiles will largely cancel out in the revenue calculations.

3.3.2. Electricity rates. Within the ERCOT deregulated electricity market customers freely choose retail electricity service among providers with varying rates and bill structures (TECEP 2012). An important factor is whether their Retail Electricity Provider (REP) offers a plan that credits

any moment-to-moment excesses of PV generation over consumption outflowed to the grid (Darghouth *et al* 2011, Mills *et al* 2008). Unlike many retail choice states, the ERCOT market does not mandate that REPs provide credits for these 'outflows' (PUCT 2012). Current practice is for REPs to credit outflows at a rate below the marginal price of electricity.

While it is tempting to assume that consumers will select electricity plans which offer the highest value for their PV system, it is not obvious what depth of information finding and analysis decision-makers go through to determine which REP provides this greatest value (Conlisk 1996, Fuchs and Arentsen 2002, Gigerenzer and Todd 1999, Goett *et al* 2000, Roe *et al* 2001, Tversky and Kahneman 1974). We account for this dilemma through a set of scenarios, discussed next.

3.4. Scenarios

To account for uncertainty in the model's parameters (Bergmann *et al* 2006, Laitner *et al* 2003), calculations are structured as a series of five scenarios—*Very Conservative*, *Conservative*, *Baseline*, *Optimistic*, and *Very Optimistic* (table 1). Scenarios employ progressively more optimistic assumptions that increase the value of solar to the consumer. Parameters varied were: (i) the annual growth rate in nominal retail electricity price (0–5%) (ii) if bought, lifetime of the system (20 or 25 yr) (iii) system loss rate (0.75–0.25% yr⁻¹) (iii) O&M costs as a percentage of installed costs incurred per year (0.5–0% yr⁻¹), and (iv) inverter replacement cost (\$0.95 W⁻¹–\$0 W⁻¹). Note that these scenarios are not intended to represent likely or unlikely outcomes, but to explore how consumers' differing assumptions would affect their evaluation of PV's value.

Scenarios also vary the customer's retail electricity plan *post-installation*. The most conservative scenario (scenario 1) assumes that consumers remain on their pre-PV plan for the lifetime of the system, whereas the most optimistic scenario (scenarios 4 and 5) assumes that the consumer actively researches and selects plans that minimize their electricity bill. The baseline scenario (scenario 3) assumes that consumers will adopt a 'solar' plan if offered by their REP, but will not transfer REPs. In addition, the consumer is credited 7.5 ¢ kWh⁻¹ for outflows if their current REP does not offer a solar plan—since we believe that nearly all REPs will offer an outflow credit in the future. Indeed, most major REPs do so already.

4. Results

We present here the results of our analysis. Framing this analysis are the differences between buying and leasing consumers. Contrary to Drury *et al* (2011), we found no statistically significant differences between the two groups on demographic factors including income, age, education, and race as well as contextual factors such as the size of their system, annual electricity consumed, or electricity rates. Based on these results and those that follow, our conclusion is that at this stage in the diffusion of residential PV buyers and leasers *do not* represent different demographic groups, but rather *different consumer segments* within the residential PV market.

Table 1. Description of the scenarios.

Scenario	(1) V. Conservative	(2) Conservative	(3) Baseline	(4) Optimistic	(5) V. Optimistic
Elec. cost growth	0.0% yr ⁻¹	2.6% yr ⁻¹	2.6% yr ⁻¹	3.3% yr ⁻¹	5.0% yr ⁻¹
System life	20 yr	20 yr	25 yr	25 yr	25 yr
System loss rate	0.75% yr ⁻¹	0.5% yr ⁻¹	0.5% yr ⁻¹	0.5% yr ⁻¹	0.25% yr ⁻¹
Maintenance costs	0.5% yr ⁻¹	0.25%	0.25% yr ⁻¹	0.15% yr ⁻¹	0% yr ⁻¹
Inv. replace. cost	\$0.95 W ⁻¹	\$0.95 W ⁻¹	\$0.7 W ⁻¹	\$0.7 W ⁻¹	None
Electricity plan after PV adoption	Keeps same REP and plan post-installation; no outflows	Adopts solar plan if offered by current REP	Adopts solar plan if offered by current REP; min. 7.5 ¢ kWh ⁻¹ outflow	Adopts plan with max. value among current market solar plans or BAU plan	Same as scenario 4

4.1. Installed cost and cost of ownership

Installed costs (\$W⁻¹) of leased systems (Mean = 8.3, Std. dev. = 0.53) were significantly more than those of bought systems (Mean = 6.2, Std. dev. = 1.4) and the mean differences were highly significant ($t(201) = 16.08$; $p < 0.001$). This corroborates similar installed cost differences for bought and leased systems nationally (Barbose *et al* 2012). As discussed in section 3.2, recall that while buyers' cost of ownership is the installed cost less applicable rebates, the installed cost is generally *not* reflective of the lessees' cost of ownership, which are only their lease payments. Surprisingly, the mean lessees' cost of ownership (\$0.70 W⁻¹) were substantially less than those of buyers (\$2.64 W⁻¹)⁴. Accordingly, we found that lessees had a statistically significant greater NPV per capacity ratio (NPV/DC-kW) than buyers in all but scenario 5 (figure 1; only baseline scenario shown).

How is it possible that leased systems are installed at higher costs than bought systems, but that lessees face a lower cost of ownership than the equivalent bought system? As others have noted (for example see, Barbose *et al* 2012), the installed cost reported to state and utility PV incentive programs is often the 'fair market value', or the appraised value, reported when applying for the 1603 Treasury Cash Grant or Federal ITC. Since the benefits of both the 1603 Treasury Cash Grant and tax benefits from MACRS increase with the appraised value of the system, it is plausible that some leasing companies might be inflating the appraised value—at least the incentive to do so clearly exists. Indeed the SEC and IRS recently began an investigation of several leading leasing firms to determine if the true fair market value of installed PV systems were materially lower than what the firms had historically claimed (SEC 2012). If proven true, one implication of this financial strategy would be that since additional system costs and company profits are recouped through the tax structure, leasing companies adopting such strategies would be able to offer lower rates to their customers

⁴ Note that the upfront cost of ownership does not reflect the operational life of PV systems or their performance over that lifetime. In general, most analyses assume an operational life for PV systems of 20–25 yr, which is applicable to buyers of PV systems. Lease contracts typically terminate after 15–20 yr. So the difference in the upfront cost of ownership of bought versus leased systems should be put in this context. However, as discussed below, NPV calculations incorporate this difference in the length of cash flows.

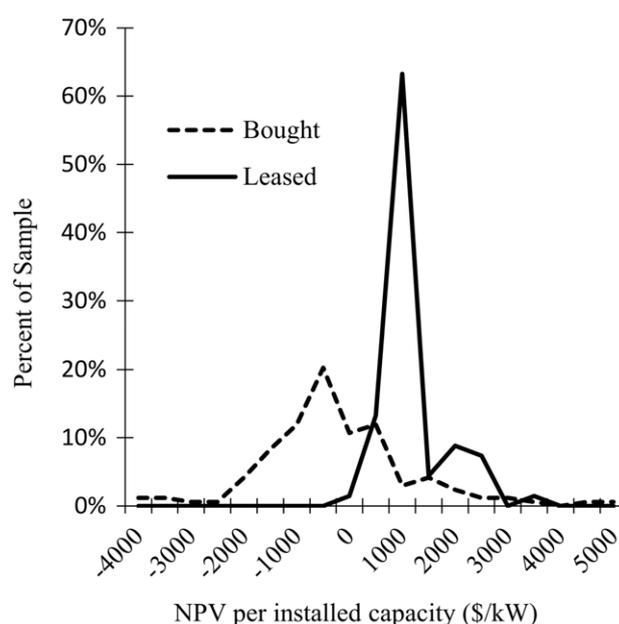


Figure 1. Distribution of modeled NPV kW⁻¹ assuming *baseline* model parameters.

(the lessees). The fact that we indeed find the cost of leasing PV systems (by the lessees) to be much lower than the cost of buying PV systems lends some support to the hypothesis that some leasing companies might be employing such financial strategies.

Therefore, we tentatively explain lower lessees' costs of ownership through the following mechanisms: (i) maximization of federal tax benefits by leasing companies (lessors) through the financial strategy described above; (ii) in the current policy environment, lessors are able to access additional financial incentives that buyers cannot access, particularly, accelerated depreciation (Bolinger 2009, Coughlin and Cory 2009); (iii) economies of scale present in the operation of a larger fleet of leased systems; (iv) ability for lessors to raise capital at a lower cost, which would increase their leveraged return on capital; and (v) since the lease contracts are typically only 15–20 yr as compared to the generally reported lifetime of PV panels of 20–25 yr, leased systems will likely have some residual value; in theory, the lessors could recoup the residual value at a later date, which

would allow them to offer the leased systems at lower rates today. All of these mechanisms would lower costs faced by lessors, and therefore reduce the size of the lease payments required to achieve a given rate of return. In a competitive leasing market, then, these mechanisms would translate into lower costs faced by lessees—just as we find. A deeper explanation of these aspects would require financial analysis of the leasing companies' balance sheets, which is beyond the scope of this paper.

If leasing is financially more attractive, why don't more adopters choose to lease? For many the option did not exist—73% of buyers reported not having the option to lease when making their decision. There is also evidence in the literature of conspicuous consumption for novel 'green' technologies (Dastrop *et al* 2011, Sexton 2011); under this paradigm, consumers could derive additional utility from the status gained by owning, rather than leasing, their system. Residence uncertainty was not a factor, as each group reported a similar (10–15 yr) period that they expected to continue living in their homes. Finally, a majority of PV adopters who had the option to either buy or lease a PV system, but chose to buy report concerns about potential difficulties with the leasing contract as a factor in their decision to buy⁵. Considering all these factors, we conclude that buyers who did have the option to lease, but chose to buy, had adequate cash-flow such that they preferred the contractually simple buying option, even though the leasing option is nominally cheaper.

4.2. Payback period comparison

Consistent with previous research (Camerer *et al* 2004, Kempton and Montgomery 1982, Kirchler *et al* 2008), the majority of respondents (66%) reported using payback period to evaluate the financial attractiveness of their investment as opposed to NPV (7%), internal rate of return (27%), net monthly savings (25%), or other metrics (6%). 10% made no estimate of the financial attractiveness. Respondents also reported the values of the metrics they used. These responses allow us to compare reported metric values (*reported*) to the values individually generated from the financial model (*modeled*) (figure 2; only baseline scenario shown).

For buyers, scenario 4 minimized the average absolute difference between reported and modeled payback period ($M = 2.6$ yr, $SD = 2.4$), followed by scenario 5 ($M = 3.1$, $SD = 1.9$). For lessees, scenario 3 ($M = 1.1$, $SD = 0.7$) was the best fit, followed by scenario 2 ($M = 1.296$, $SD = 0.704$). Scenario 1 was a poor fit overall. This suggests that buyers assumed parameters similar to those of scenario 4 when evaluating their investment. That is, buyers were optimistic when assessing the likely revenues and costs associated with their investment decision. By the same argument, lessees were more realistic and precise

⁵ There were 44 respondents in our sample who had the option to either lease or buy a PV system, but chose to buy. Of those 24 responded to a 5-point Likert-scale question on how strongly they agreed with the statement, 'I was concerned about potential difficulties related to the leasing contract'. 50% agreed or strongly agreed with the statement, while only 8.5% disagreed or strongly disagreed with the statement.

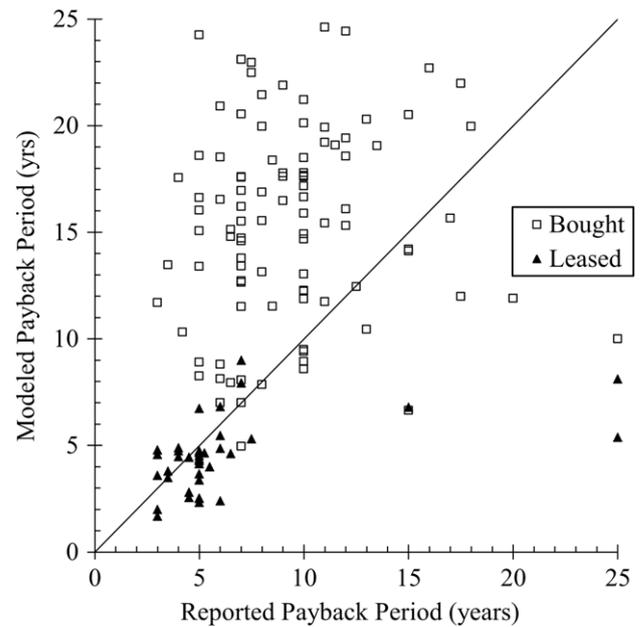


Figure 2. Comparison of reported and modeled payback period in scenario 3. Mean difference between modeled and consumer payback period: buyers = 7.1 yr⁻¹; leasers = 1.1 yr.

when making their investment decision. This is consistent with the fact that lessees receive much of this financial information from leasing companies, who use very detailed and sophisticated financial models.

4.3. Implied discount rate

For all calculations of NPV reported above a 10% annual discount rate was assumed. In this section we present discount rates calculated separately for each individual respondent. Specifically, we first determine each respondent's *implied NPV* and then back-calculate their discount rate using the implied NPV and their modeled cash flows. To determine the implied NPV, respondents were asked on a 5-point Likert-scale how strongly they agreed with the following five statements: (i) 'I would not have installed the PV system if it had cost me \$1000 more'... (v) 'I would not have installed the PV system if it had cost me \$5000 more'. One expects respondents to increasingly *agree* that they would *not* have installed the PV system as the price increased. The above question estimates the respondent's implied NPV by extrapolating how much more the respondent would have paid before becoming indifferent to purchasing the system or forgoing the investment (figure 3).

Of the 210 respondents in our dataset, 92 responses were excluded from these calculations—69 whose implied NPV was outside the range tested (\$0–\$5000), 7 responses which implied an increasing willingness to pay, and 16 non-responses. Of the excluded respondents, 55 respondents indicated they would have been willing to pay at least \$5000 more for their system—of which 76% were buyers and 24% leasers. That is, a significant per cent of the sample (26.2%) did assign a positive value to their investment, yet were not captured within this calculation because of insufficient data.

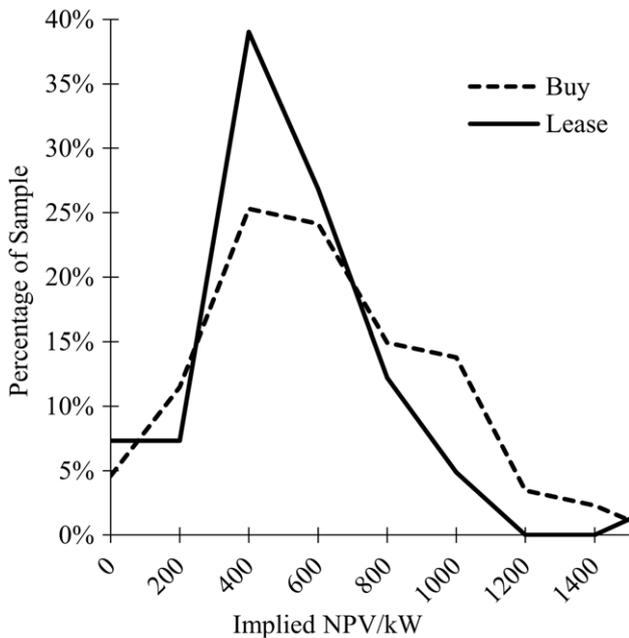


Figure 3. Distribution of implied NPV kW^{-1} for buyers and lessees; difference of mean is not significantly different than zero.

In the end, there are 81 buyers and 37 lessees remaining for the discount rate analysis reported in this section.

Using the implied NPV, we solve for the monthly discount rate (r_m), required to equate the respondent's implied NPV with the cash flows modeled earlier:

$$\text{NPV}_{\text{implied}} = \sum \text{CF}_k = \sum \frac{[R_k - C_k]}{(1 + r_m)^k}. \quad (3)$$

The monthly discount rate is then annualized using (4):

$$r = (1 + r_m)^{12} - 1. \quad (4)$$

Thus, r represents each respondent's discount rate implied by their willingness to pay and their modeled cash flows. As the cash flows vary with each scenario, implied discount rates also vary with scenarios.

Using baseline (scenario 3) parameters, the mean discount rate for buyers was $7 \pm 5\%$ and for lessees was $21 \pm 14\%$ ($\pm 1\sigma$) (tables 2 and 3). The calculated implied discount rates are higher in the optimistic scenarios since cash flows increase as the scenarios become more optimistic. Across all scenarios and income levels lessees' implied discount rates are significantly higher than buyers by 8–21%.

It is important to note a similarity in the timing of leased and bought payments—the majority (69%) of lessee respondents chose to structure their leases as a single 'prepaid' down payment, which is similar to the financial structure of a bought system, but significantly smaller in the scale of investment. After taking all incentives into account, for lessees the upfront payment is on the order of \$4000 and for buyers it is \$15 000 for a 6 kW-DC system. Yet, each group expects to receive a similar (normalized) NPV for their investment. That is possible only when these groups have differing cash urgencies. Indeed, in open-ended survey questions, 66.2% of

lessees agreed or strongly agreed that tight cash availability was one of the key factors in their decision to lease, whereas buyers generally did not have this problem. Given that there are little, if any, demographic differences between buyers and lessees, then, we infer that at this stage in the residential PV market buyers and lessees represent *different consumer segments* within a similar socio-demographic makeup. Put differently, compared to the average buyer the average lessee is not lower income *per se*—the majority of the lessees have some cash availability, just not enough to outright buy their PV system.

In general, our point is that within populations with similar demographics it is possible that there are variations in disposable income, and those variations are a key factor in ownership model choices⁶. Consistent with a large body of work in the diffusion of innovations tradition (Rogers 2003), our results suggest that there is a hierarchy within the population regarding the adoption of technologies. In early stages of technology diffusion, as is the case with PV now, information (awareness of products, interest in energy, etc) is the precursor, which is more likely to be found in higher income, more educated segments of the population. Within those segments, those with tighter cash flows opt for leasing, if that option is available. Thus, the leasing model appears to be especially effective in the early stages of a technology's diffusion, as it unlocks the cash-strapped but information-aware segments of the market. Put differently, the leasing model accelerates the early adoption stage of a technology's diffusion, thereby quickly establishing a wider base on which later adoption can build upon.

4.3.1. Discount rate and income. Previous literature starting with Hausman (1979) suggests that an inverse relationship exists between household income and consumer discount rate. That is, poorer consumers have more urgent needs for their cash than wealthy ones. At higher incomes, where one has a greater degree of spare income, the rate of return of investments (and hence, their discount rate) should converge to market returns. Our results are mixed in regard to these earlier findings.

A one-tailed t -test comparing the difference in mean discount rate among income groups for the baseline scenario was performed using the hypotheses $H_o: \text{DR}_1 = \text{DR}_2$, $H_a: \text{DR}_1 \geq \text{DR}_2$, and $H_o: \text{DR}_2 = \text{DR}_3$, $H_a: \text{DR}_2 \geq \text{DR}_3$, where DR_1 is the mean implied discount rate for income group 1 and so on⁷. This test was performed for both income pairs ($\text{DR}_1 \geq \text{DR}_2$, $\text{DR}_2 \geq \text{DR}_3$) since we expect the implied discount rate to monotonically decrease with income.

Even with a 90% confidence interval, we did not find a statistically significant relationship between income and discount rate for either buyers or lessees. We explain this discrepancy with two reasons. First, small sample size, particularly in the leasing sample, reduced our test's statistical

⁶ We note, however, there are several factors besides cash availability that can guide ownership choices—priority of environmental value over financial concerns, intended length of residence, financial security, and so on.

⁷ Income groups were: income 1: \$0–\$84 999 year^{-1} ; income 2: \$85 000–\$149 999 year^{-1} ; income 3: \$150 000 + year^{-1} .

Table 2. Mean implied discount rate for buyers along income and scenarios with $\pm 1\sigma$.

Buyers	All incomes	\$0–\$85k	\$85k–\$150k	\$150k+
<i>N</i>	81	22	37	22
Scen 2: conservative	6% ± 6%	6% ± 5%	6% ± 8%	7% ± 6%
Scen 3: baseline	7% ± 5%	7% ± 4%	6% ± 6%	7% ± 6%
Scen 4: optimistic	13% ± 6%	12% ± 5%	13% ± 6%	13% ± 7%
Scen 5: V. Optimistic	18% ± 7%	17% ± 5%	18% ± 7%	17% ± 8%

Table 3. Mean implied discount rate for lessees along income and scenarios with $\pm 1\sigma$.

Lessees	All incomes	\$0–\$85k	\$85k–\$150k	\$150k+
<i>N</i>	37	13	13	11
Scen 2: conservative	20% ± 15%	22% ± 19%	20% ± 14%	18% ± 12%
Scen 3: baseline	21% ± 14%	23% ± 18%	22% ± 13%	19% ± 12%
Scen 4: optimistic	32% ± 17%	33% ± 22%	35% ± 15%	30% ± 14%
Scen 5: V. Optimistic	35% ± 13%	29% ± 9%	38% ± 13%	36% ± 16%

power. Second, both groups exhibit characteristics typical of early adopters—wealthier, more educated, etc. These characteristics could negate the relationship between income and discount rate for products in settled markets as early adopters typically derive additional utility from adopting new technologies beyond financial benefits (Faiers *et al* 2007, Labay and Kinnear 1981, Rogers 2003). In agreement with previous literature, we do find that discount rates for buyers in the conservative, baseline, and optimistic scenarios (scenarios 2–4) ranges between 7 and 13%, which is close to market returns. This also supports our finding that buyers of PV systems are in a relatively comfortable cash-flow position.

5. Conclusion

We have studied the economics of the decision-process of individual consumers, particularly their decision to buy or lease a residential PV system. Consistent with several other studies, we find that a majority of PV adopters used payback period—not net present value (NPV)—as the decision-making criterion. We also find that owing to the peculiarities of financing and incentive mechanisms, the pre-rebate installed costs of leased PV systems are significantly higher than the bought systems, yet lessees end up paying nominally much lower amounts than buyers of PV. We calculate individual-level discount rates across a range of scenarios, finding that buyers employ discount rates 8–21% lower than lessees. Those who lease typically have a tighter cash-flow situation, which, in addition to less uncertainty about technological performance, are the main reasons for them to lease. As we do not find any significant variation between buyers and lessees on any socio-demographic dimension (income, age, etc) this suggests that the leasing model is making PV adoption possible for a new consumer segment—those with a tight cash-flow situation. As the diffusion of PV spreads to lower-income households, who generally experience tighter cash-flow than wealthier households, this implies that, *ceteris paribus*, moving forward the leasing model will likely be the predominant form of PV adoption. From this perspective, the leasing model has opened a new market segment at existing

prices and supply chain conditions—and represents a business model innovation.

Acknowledgments

VR would like to acknowledge support from the Elspeth Rostow Memorial Fellowship and from the Center for International Energy and Environmental Policy (CIEEP) at the University of Texas at Austin. BS would like to acknowledge support from the LBJ School of Public Affairs and the Energy & Earth Resources Program at UT Austin. The LBJ School of Public Affairs at UT Austin helped meet the publication charges for this letter. Any remaining errors are ours alone.

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VALUE OF THE GRID TO DG CUSTOMERS

IEE Issue Brief
September 2013
Updated October 2013



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Value of the Grid to DG Customers

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September 2013
Updated October 2013

Prepared by

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VALUE OF THE GRID TO DG CUSTOMERS

Some advocates of distributed generation (DG) claim that the DG customer derives no benefit from being connected to the host utility's distribution system.¹ While it is easy to say that a DG customer is “free from the grid,” that is simply not true – even for a DG customer (or a micro-grid) that produces the exact amount of energy that it consumes in any given day or other time interval.²

This paper describes how a DG customer (or a micro grid) that is connected to the host utility's distribution system 24/7 utilizes grid services on a continuous, ongoing basis. The point is to recognize the value of these grid services and to develop a methodology for the DG customer to pay for using the services. The utility's cost of providing grid services consists of at least four components – the typical fixed costs associated with: (i) transmission, (ii) distribution, (iii) generation capacity, and (iv) the costs of ancillary and balancing services that the grid provides throughout the day for the DG customer.

There is a related question about how much DG customers should be paid, or credited, for the excess electric energy they produce on-site and inject into the grid. This paper does not explicitly address this “value of on-site energy” issue.

THE BENEFITS OF REMAINING CONNECTED TO THE DISTRIBUTION SYSTEM

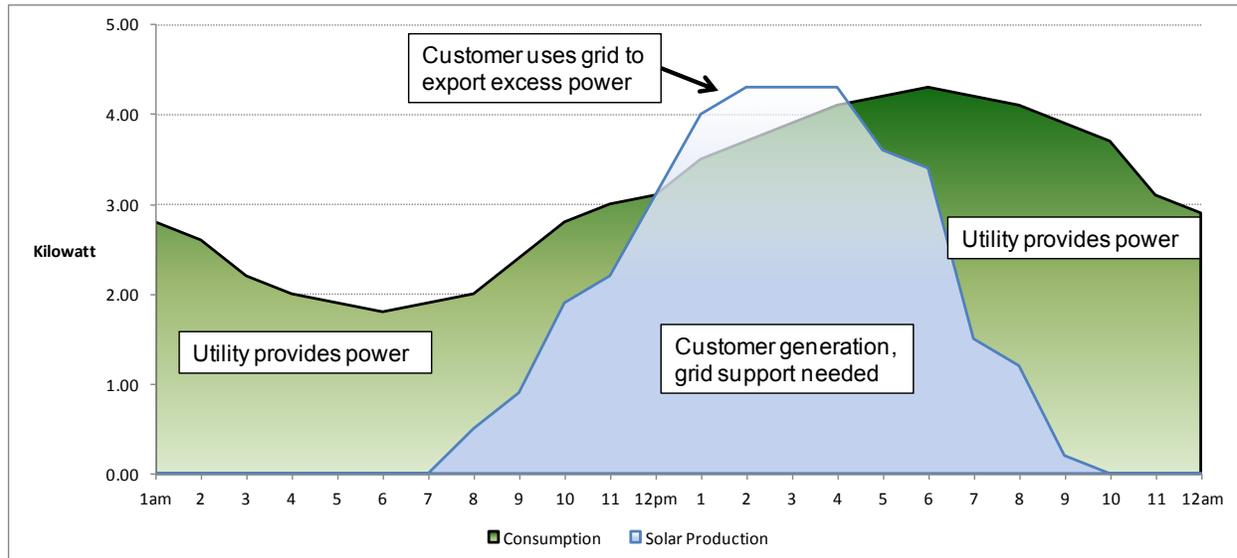
Consider a residential or small commercial customer with solar PV panels on its rooftop. Figure 1 displays a typical hourly pattern of energy production and consumption for such a customer. The green area is the energy delivered by the host utility and consumed by the customer. The area under the blue curve is the energy produced on-site by the solar panels. The area below the blue curve and above the green line is the excess energy injected into the utility's distribution system. The key take-away from this graphic is that the customer's consumption and generation are almost never equal; consequently, most of the time the customer is using the external power system to offset the difference between the customer's consumption of electric energy and its on-

1 A recent Forbes article, “Distributed Generation Grabs Power from Centralized Utilities,” August 8, 2013, ignores and fails to mention the grid services that are provided to DG customers continuously by the host utility.

2 The term, DG, refers to small retail customers with on-site generation that are net metered.

site production. In most cases the customer will be taking energy from the grid during many hours of the day. For example, the customer depicted in Figure 1 takes power from the grid in all hours except from noon to about 4:30 pm.

Figure 1: Typical Energy Production and Consumption for a Small Customer with Solar PV



Customers with any type of DG that are connected to the grid will be utilizing external grid services to:

- balance supply and demand in sub-second intervals to maintain a stable frequency (*i.e.*, regulation service);
- resell energy during hours of excess generation and deliver energy during hours of deficit generation;
- provide the energy needed to serve the customer's total load during times when on-site generation is inoperable due to equipment maintenance, unexpected physical failure, or prolonged overcast conditions (*i.e.*, backup service);
- provide voltage and frequency control services and maintain high AC waveform quality.

Clearly, even if the customer's total energy production over some time interval (*e.g.*, a monthly billing cycle) exactly equals its consumption over that same interval, that customer is still utilizing at least some, if not all, of the above grid services during that time interval.

So what value does a customer with solar PV generation derive from remaining connected to the grid? Let's begin by examining the charges that a typical residential customer consuming an average of about 1000 kilowatt-hours (kWh) per month [average consumption based on Energy Information Administration (EIA) data and rounded] will pay for grid services, excluding the charges for the electric energy itself. These charges are designed to allocate to the customer its fair share of the fixed costs associated with the transmission system, the distribution system, balancing and ancillary services, and the utility's (or the retail supplier's) investment in generation capacity.³ As stated earlier, the electric energy charges designed to recover the cost of the energy (kWh) consumed by the customer (including the associated transmission and distribution losses), are excluded here. Table 1 illustrates these charges for a typical residential customer.⁴

Table 1 – Non-Energy Charges Paid by a Typical Residential Customer on a Retail Tariff

Average Residential Customer: Non-Energy Charges as Percent of Typical Monthly Bill	
Average Monthly Usage (kWh)*	1000
Average Monthly Bill (\$)*	\$110
Typical Monthly Fixed Charges	
Ancillary/Balancing Services	\$1
Transmission Systems	\$10
Distribution Services	\$30
Generation Capacity ^	\$19
Total Fixed Charges for Customer	\$60
Fixed Charges as Percent of Monthly Bill	55%

*Based on Energy Information Administration (EIA) data, 2011

^The charge for capacity varies depending upon location. This is just an estimate.

In this example, the typical residential customer consumes, on average, about 1000 kWh per month and pays an average monthly bill of about \$110 (based on EIA data). About half of that bill (*i.e.*, \$60 per month) covers charges related to the non-energy services provided by the grid,

3 In “retail choice” states the retail customer can choose its energy supplier, which may not be the utility. In all other states the utility will be the retail supplier.

4 Other charges, such as sales and franchise taxes and environmental charges could be added to the table; however, the focus of this paper is on the grid services that are provided by the host utility.

including a charge for generation capacity. Because residential retail rates are almost always designed to recover most of the power system's fixed costs through kWh charges, a DG customer will avoid paying some or all of its fair share of the fixed costs of grid services. Ultimately the fixed costs that the DG customer does not pay, which are significant, will be shifted to other retail customers. In this example, each DG customer shifts up to \$720 per year in costs (*i.e.*, \$60 * 12 months) to other retail non-DG customers. To put this into context, if 50 percent of the residential customers in a given utility service territory had DG, the non-DG residential customers in that service territory could experience bill increases of up to 55 percent – from \$110 per month to \$170 per month. Clearly this cost shift is substantial and simply not fair.

IEE submits that DG customers should pay their fair share of the cost of the grid because pushing any of this cost onto non-DG customers raises serious economic efficiency and fairness issues. Indeed this is one of the key issues in the current debate over net metering.

To illustrate the value provided by the grid for a solar PV customer, consider what it would cost that customer to self-provide the technical equivalent of these services through some combination of energy storage and/or thermal generation (*e.g.*, a Generac home generator).

Preliminary estimates of the monthly costs that a typical residential customer would have to incur to self-provide the balancing and backup services that the grid currently provides are substantially higher than the \$60 charge shown in Table 1.⁵ Furthermore, this cost estimate of self-provision excludes the additional cost of maintaining the level of voltage and frequency control and AC waveform quality currently provided by the grid. An off-the-grid DG customer (or micro-grid) simply cannot provide, at reasonable cost, the same quality of service that a large power system provides. So, in fact, most DG customers remain connected to the grid today and utilize grid services.

This straightforward cost comparison to “self providing” grid services reveals three things. First, the balancing and backup services that the grid provides to DG customers are needed and have substantial value. Second, it does not make economic sense for a DG customer to self-provide these services. Third, it is unfair for DG customers to avoid paying for these grid services,

⁵ The Electric Power Research Institute (EPRI) is developing estimates of the cost of self-providing grid services and expects to release its results in 2014.

thereby shifting the cost burden to non-DG customers. Obviously, DG customers should pay their fair share of the cost of the grid services that the host utility provides.

ECONOMIES OF SCALE ASSOCIATED WITH POWER SYSTEMS

In many ways, the growth of DG and micro grids today goes full circle back to the early days of the electric power industry. Initially power systems were isolated and each served its own service area. As service areas expanded, utilities began to interconnect. PJM was the first entity to interconnect utilities for reliability purposes and to centrally provide balancing services. This evolution was driven by the substantial economies of scale that still exist today as ISO/RTO markets continue to grow and expand.⁶

These interconnection entities developed for good reasons. When a small power system interconnects with a larger one, all members of the resulting combined entity benefit. However, it has been observed that the small system benefits disproportionately more than the incumbent members. For example, the small system's operating reserve margin will decrease substantially. This phenomenon is even more pronounced when a micro-grid interconnects with a power system.

DG MARKET IS GROWING, PRICING IT RIGHT IS KEY

Although net metering was a convenient vehicle for kick-starting the DG market, there are now serious questions among state policymakers regarding its continuation and needed reforms. *One main concern, addressed by this paper, is that net-metered customers are avoiding payment of their fair share of the grid services described earlier, thereby causing those lost revenues to be recovered from other customers.* As also demonstrated in this paper, these “grid” costs are quite significant – about 55 percent of the monthly electric bill for a residential customer as demonstrated in Table 1. Although this may not have been a major problem when the DG market was in its infancy, sending the wrong price signals to both customers and to the DG industry is a major problem as the DG market rapidly grows and develops.

⁶ Entergy's decision to join MISO is a recent example.

REVENUE DECOUPLING WILL NOT RESOLVE THE DG COST-SHIFTING ISSUE

Revenue decoupling is currently being used to promptly restore utility net revenues that would otherwise be lost due to declining electricity sales resulting from utility investments in energy efficiency (EE). Although revenue decoupling makes the utility whole, it does so by explicitly shifting costs from participating EE customers to nonparticipating EE customers using a public or system benefits charge (which is typically visible and transparent to all customers as a charge on their utility bills). Decoupling causes the same cost shifting problem that is created by DG with net metering. However, a fundamental difference is that the magnitude of the “cost shifting” to non DG customers is on a much larger scale than the cost shifting due to energy efficiency. A recent study revealed that decoupling rate adjustments for energy efficiency are quite small – about 2 to 3 percent of the retail rate.⁷ In contrast, as described earlier in this paper, a DG customer could shift up to 55 percent of the retail rate onto non-DG customers (and, unlike efficiency charges, which are transparent, the DG cost shifting is essentially invisible to customers).

The amount of cost-beneficial energy efficiency is limited because the more you achieve, the less cost-beneficial the next increment of energy savings becomes. This “diminishing return” aspect means that energy efficiency increases only when it makes economic sense. In contrast, no such economic limit applies to DG. In fact, costs – particularly for rooftop solar PV – are expected to decline over time. *Although regulators have been willing to accept a relatively limited amount of cost shifting to promote utility investments in energy efficiency (about 2-3 percent of rates, on average), they are unlikely to accept the magnitude of cost shifting that will accompany the rapid expansion in net-metered DG unless some reforms to net metering are put into place.*⁸

ALTERNATIVE APPROACHES TO END COST SHIFTING DUE TO NET METERING

Three basic approaches to net metering are under examination across the nation, each of which seeks to ensure that a DG customer using grid services pays its fair share of the costs of those services while still receiving fair compensation for the excess energy that it produces:

⁷ “A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations.” Pamela Morgan, Graceful Systems LLC. February 2013.

⁸ Distributed generation and net metering were very hot topics at the Summer 2013 NARUC meetings with at least five panel discussions addressing them.

- Redesign retail tariffs such that they are more cost-reflective (including adoption of one or more demand charges);
- Charge the DG customer for its gross consumption under its current retail tariff and separately compensate the customer for its gross (*i.e.*, total on-site) generation; and
- Impose transmission and distribution (T&D) “standby” charges on DG customers.

These three approaches are illustrative and are further described below.

Redesign Retail Tariffs (APS Proposal). To address the fundamental issue that a residential customer with rooftop solar should be compensated at a fair rate for the power it exports (sells) to the grid and also pay a fair price for its use of grid services, APS is proposing two options.⁹ The first option requires the customer to take service under an existing demand-based rate schedule. The demand charge would cover a reasonable portion of the cost of grid services.

The second option allows the customer to choose an existing APS rate schedule for its total electric consumption and APS will purchase all of the customer’s rooftop solar generation at market-based wholesale rates. This option ensures recovery of grid services and sends more accurate price signals to DG customers. It is also conceptually very close to what Austin Energy has already put in place.

Treat On-site Generation and Consumption Separately (Austin Energy Tariff). Austin Energy has implemented a solar tariff that fully compensates its DG customers for their gross on-site generation while separately charging them for their gross consumption under its existing retail tariff.¹⁰ This approach effectively ensures that the cost of grid services are recovered from DG customers while also compensating DG customers for their generation at the utility’s full avoided cost of procuring energy. The Public Utility Regulatory Policies Act (PURPA), under Title II, provides an established precedent for such compensation.¹¹ This approach requires a separate meter for on-site generation.

⁹ APS conversation, July 2013.

¹⁰ Rabago, K.R., *The ‘Value Of Solar’ Rate: Designing An Improved Residential Solar Tariff*, Solar Industry, February, 2013. Available at www.solarindustrymag.com.

¹¹ Although PURPA only applies to generating resources that are Qualified Facilities (QFs), this condition has not been applied if the customer receives a credit on its electric bill, rather than a monetary payment for its generated energy.

Implement T&D Standby Charges for DG Customers (Dominion Tariff). Dominion requires a residential net-metered DG customer with a solar installation whose rated output is greater than 10kW and up to 20kW, to pay a monthly transmission standby charge of \$1.40 per kW and a monthly distribution standby charge of \$2.79 per kW. However, these standby charges are respectively reduced, dollar for dollar, by the customer's transmission and distribution charges that are recovered through kWh charges applied to the customer's monthly electricity consumption up to the point where each standby charge is fully phased out. This became effective on April 1, 2012. Dominion also proposed a placeholder for a future generation standby charge, but it was not approved. The Commission ruled that a generation standby charge should be studied and filed in a future proceeding.

A FINAL THOUGHT

In light of the rapid growth in net-metered DG, it is critical that these customers pay their fair share of the cost of grid services provided to them – and sooner rather than later. Updating net metering policies to put an end to the cost shifting that is occurring today should be done now.

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IEE is an Institute of The Edison Foundation focused on advancing the adoption of innovative and efficient technologies among electric utilities and their technology partners that will transform the power grid. IEE promotes the sharing of information, ideas, and experiences among regulators, policymakers, technology companies, thought leaders, and the electric power industry. IEE also identifies policies that support the business case for adoption of cost-effective technologies. IEE's members are committed to an affordable, reliable, secure, and clean energy future.

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A GENERALIZED APPROACH TO ASSESSING THE RATE IMPACTS OF NET ENERGY METERING

Prepared by

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Solar America Board for Codes and Standards Report

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January 2012

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EXECUTIVE SUMMARY

Net energy metering (NEM) is a state-level policy that permits a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. Forty-three states, the District of Columbia, and Puerto Rico have instituted NEM in some form to permit self-generation, typically at the urging of customers seeking to use solar, wind, and other renewable energy facilities. These NEM policies vary from state to state, particularly regarding how large an individual installation can be and how much NEM will be allowed in the aggregate. Restrictions on NEM are almost always driven by utility concerns that lower utility bills for NEM customers will lead to higher utility bills for customers who do not have NEM.

The intent of this report is to provide a consistent methodology to analyze the potential rate impacts of NEM. With reliable estimates of rate impacts, regulators can make informed decisions regarding modification of NEM rules, and our intent here is to provide a methodology for more reliable estimates. In this report, we review and synthesize three studies performed for major utilities in Arizona, California, and Texas during the past decade. All three were on a scale far beyond the scope of this report, but the broad categories of costs and benefits identified in the studies are not specific to a given utility.

Based on this review, we provide a generalized approach for any state or utility to analyze the potential rate impact of NEM in its area. The analysis and results of such studies are utility-specific, but the methodology should not be. If benefits exceed costs, then regulators may want to consider lifting restrictions on NEM and crediting NEM customers for the net benefits they provide. If costs exceed benefits, then other ratepayers are subsidizing NEM customers, and regulators must decide whether externalities such as reduced pollution, job creation, and resource diversity justify the subsidy.

Costs of NEM are often argued to be the utility's lost revenue and any associated administrative costs. Every kilowatt-hour (kWh) generated by an NEM customer means one less kWh sold by the utility at retail rates. The retail rate in question depends on the type of customer. Most residential and small commercial customers have a bundled rate that covers both their utility's fixed and variable costs, while large commercial customers typically have an "energy" charge based on kWh for variable costs and a "demand" charge based on the customer's peak usage, measured in kW, for fixed costs.

Typically, an NEM solar facility has minimal impact on the demand component of the demand-metered customer's bill. Even if the customer would have experienced peak demand coincident with sunshine without a solar array, and a solar array significantly lowered demand at that time, demand near that peak level after sunset or when the system is not operating will be unchanged. Thus, typically, demand-metered customers with an NEM solar facility primarily offset energy charges, which are much lower than the bundled rates for residential and small commercial customers. As the energy charge is based on variable costs that the utility no longer has to incur, the impact of NEM for these customers should be negligible. At present, roughly two-thirds of the installed capacity of all NEM solar facilities is located on commercial customer property, with much of that sized over 100 kW and likely to be offsetting the energy charges of demand-metered customers.

The other aspect of NEM costs is the utility's administrative expense. Most utilities use proprietary billing software that is costly to adapt for NEM. Therefore, in the short term many utilities use hand billing for NEM customers to avoid incurring a large cost for a



relatively small group of customers. However, over the medium to long term, changes to a utility's billing software to support evolving energy use patterns—dynamic rates, advanced metering, plug-in electric vehicles, etc.—will occur in the ordinary course of business. Logically, updating billing software to handle NEM program participants can occur as part of this longer-term evolution. Accordingly, we believe that the anticipated long-term administrative costs of a NEM program should be used in any rate impact analysis, on the reasonable presumption that billing of NEM customers will be automated.

On the benefits side of the rate impact calculation, the three studies we reviewed indicate that NEM allows utilities to save fuel expenses, avoid line losses, and realize at least some capacity benefit, while also suggesting various secondary benefits. An important component to the benefit calculation is determining what generation will be offset. Utility variable rates are based on average operating costs, and more than two-thirds of utility generation is from high capital cost/low operating cost coal, nuclear, and hydropower facilities. NEM solar facilities generally do not offset these baseload generators. Rather, they offset the lower capital cost/higher operating cost natural gas-fired facilities that operate during business hours and other periods of above-average demand to supplement baseload generation.

No matter which type of generation is offset, line loss savings are an important benefit of NEM. For every kWh generated by a utility-scale generator, five to ten percent of the electricity will be lost on the way to customers in the form of transmission and distribution losses. In contrast, NEM generation occurs at the customer's site, with almost no line loss. Neighbors typically use excess generation from a NEM facility, with negligible line losses. The demand on the distribution circuit serving the NEM customer drops by the full amount of the facility's generation at any given moment. Any line losses are utility- and time-specific, but for many utilities, higher losses occur during hot, sunny conditions. To calculate line loss savings associated with NEM solar facilities requires a reasonable estimate of average daytime line losses for that utility.

The most contentious element of the benefits calculation relates to capacity benefits. To the extent that NEM facilities allow a utility to delay or avoid construction of the next generator, transmission line, substation, or distribution line, there are clearly associated savings enjoyed by the utility and its customers. The studies we reviewed differed in their treatment of capacity benefits. We conclude that capacity benefits are real and incremental, with aggregate distributed solar generation far more stable and predictable than the obviously intermittent nature of individual solar facilities. We also include information about the potential for combining solar energy with demand response or energy storage programs to assure capacity benefits. While solar energy facilities are typically available during high demand periods, utility planners are hesitant to attribute capacity values to them because of the perception that they are not as reliable as traditional resources. Firming the output of solar energy generation with demand response or energy storage will allow utility planners to confidently rely on solar energy, particularly as new smart grid capabilities come online that allow grid operators to balance supply and demand at local levels in real time.



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The Solar America Board for Codes and Standards (Solar ABCs) is a collaborative effort among experts to formally gather and prioritize input from the broad spectrum of solar photovoltaic stakeholders including policy makers, manufacturers, installers, and consumers resulting in coordinated recommendations to codes and standards making bodies for existing and new solar technologies. The U.S. Department of Energy funds the Solar ABCs as part of its commitment to facilitate widespread adoption of safe, reliable, and cost-effective solar technologies.

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ACKNOWLEDGEMENTS

The authors gratefully acknowledge the comments of the following reviewers: Galen Barbose, Lawrence Berkeley National Laboratory; Michael Coddington, National Renewable Energy Laboratory; Jennifer DeCesaro, U.S. Department of Energy; and Sarah Wright, Utah Clean Energy.

This material is based upon work supported by the U.S. Department of Energy under Award Number DE-FC36-07GO17034.



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INTRODUCTION

Net energy metering (NEM) is critical to supporting customer investment in renewable distributed generation (DG). Although there are various policy options related to NEM, the basic structure allows a utility customer to generate electricity on site to offset the customer's load and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. To facilitate the expansion of opportunities for customers to invest in DG, 43 states, the District of Columbia, and Puerto Rico have implemented NEM programs. Increasing interest in NEM programs has come at a particularly important juncture in the development of the solar industry as module prices declined markedly in 2009-2010. This decline in prices resulted in increased consumer interest in solar energy despite the economic climate. However, while many NEM programs in this two-year period broadened in scope, the quality of programs continued to vary widely between the states.

NEM programs have met with resistance, notably from utilities concerned that a robust NEM program in their service territory would result in significant rate impacts for nonparticipating customers and—in the case of an investor owned utility (IOU)—a loss of profit. Unfortunately, a detailed analysis of potential NEM rate impacts has only recently begun, so potential rate impacts are not well understood and there continues to be disagreement about the appropriate inputs for such analysis.

Despite this disagreement, efforts have moved forward, particularly in Arizona, California, and Texas, to more rigorously quantify the rate impacts of NEM programs. Together, these efforts facilitate the development of a consensus view of the most important considerations in the valuation of renewable energy resources, particularly distributed solar energy systems.

To assist state policy makers, utilities, utility regulators, renewables advocates, and other stakeholders in their efforts to evaluate the potential rate impacts of NEM in their states, we suggest a methodology based on standard NEM provisions in states with the highest levels of program participation. Because solar facilities make up the majority of net-metered facilities participating in state NEM programs, we focus on the impact of net-metered solar facilities. We analyze the methodology for determining rate impacts, and do not undertake a review of any particular state renewable energy program. In addition, we consider only the impact of net-metered solar facilities on non-participating customers' rates, not economic impacts, environmental impacts, or impacts on participating customers investing in DG resources.

The "Present Status of Net Energy Metering" section provides a background discussion focusing on the key NEM program variables that can impact rates. The "Relevant Studies for Evaluating Net Energy Metering Rate Impacts" section discusses the costs and benefits of NEM that should be considered in a rate impact analysis. The "Best Practices in Valuing Net Energy Metering" section reviews California's efforts to assess the rate impacts of NEM, which constitute the most thorough analysis to date. Finally, we present conclusions and recommendations. We cite references within the text by title or author, and include full citations in the "References" section at the end of the report.

PRESENT STATUS OF NET ENERGY METERING

NEM as a policy choice for supporting customer investment in renewable energy resources is thriving. According to the Database for State Incentives for Renewables & Efficiency (<http://www.dsireusa.org>), 43 states, the District of Columbia, and Puerto Rico have adopted an NEM policy, as shown in Figure 1. Many states have adopted a policy that applies only to IOUs. However, some statewide policies also apply to municipal and cooperative utilities. Program rules vary widely among states on such crucial issues as overall NEM program size, facility size, allowance of third party ownership, and the ability to roll over excess generation from one month to the next.

Details on state NEM policies are thoroughly documented in an annual publication by the Network for New Energy Choices (NNEC) entitled *Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures* (Network for New Energy Choices, 2011). The document provides side-by-side comparison of state policies in 11 areas related to facility size, program size, eligibility, metering, treatment of excess generation, allowance of third party ownership, and protection from standby charges and other fees that nonparticipating customers do not face. Within those policy areas, NNEC awards a sliding scale of points based on the policy choices each state has made with the most points going to states with policies that accommodate more distributed generation.

For purposes of reviewing rate impacts of NEM programs, system size limitations, program size limitations, rollover of excess generation, and standby charges are discussed here. Policy choices in these areas directly affect rate impacts. These restrictions are often undertaken in an effort to address concerns about rate impacts on non-participating customers, with the intent of mitigating the perceived rate impacts of a NEM program. And yet, expansive NEM policies are an important element in state efforts to promote customer-sited renewable generation. (Itron, 2010; Doris, McLaren, Healey, & Hockett, 2009; Paidipati, Frantzis, Sawyer, & Kurrasch, 2008)

System Size Limitations

Figure 1 shows that eligible system size ranges from 20 kilowatts (kW) in Wisconsin—to the size of a very large residential system—to two megawatts (MW) or more in 14 states.

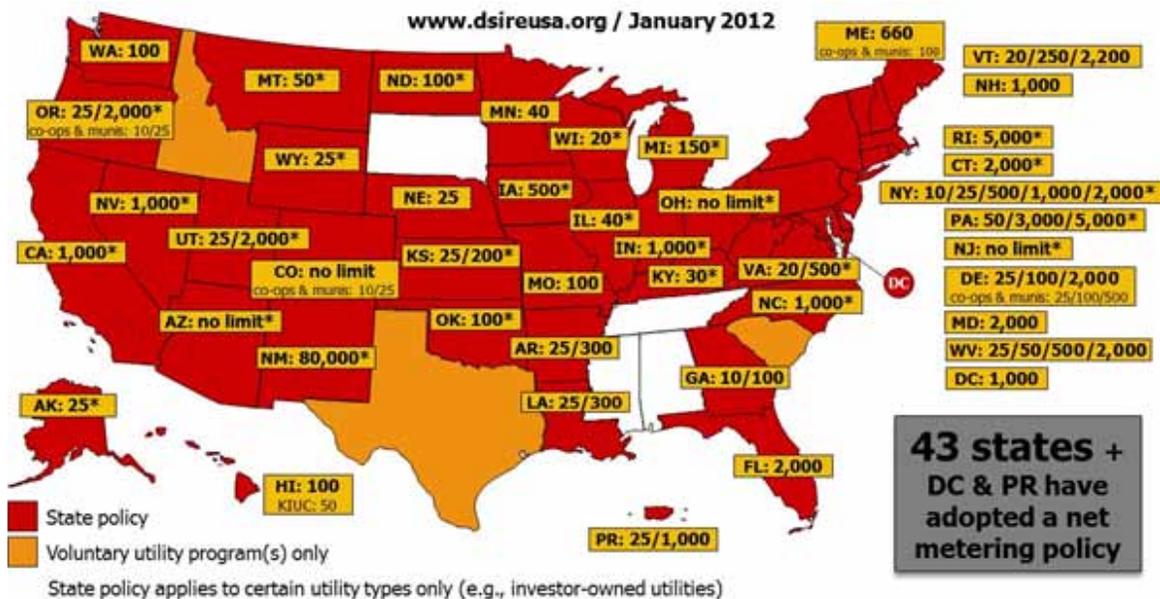


Figure 1. State net energy metering (January 2012, <http://www.dsireusa.org>). Numbers indicate residential/commercial individual system capacity limits.



As Table 1 shows, the top ten states for customer-sited solar energy share the attribute of allowing NEM facilities of at least one MW, with the exception of Hawaii, which has unique characteristics.

TABLE 1
Top 10 States by Installed Capacity and Their NEM System Size Cap

2010 Rank by State	2010 Market Share	Cumulative MWDC	NEM System Size Cap
1. California	48 %	1,022	1,000 kW
2. New Jersey	12 %	260	no limit
3. Colorado	5 %	117	no limit
4. Arizona	5 %	105	no limit
5. Nevada	5 %	102	1,000 kW
6. Florida	3 %	73	2,000 kW
7. New York	3 %	56	2,000 kW
8. Pennsylvania	3 %	55	5,000 kW
9. Hawaii	2 %	45	100 kW
10. New Mexico	2 %	43	80,000 kW
All Other States	12 %	261	

Source: Sherwood, L., *U.S. Solar Market Trends 2010*, Interstate Renewable Energy Council, June 2011. (Total of 2,139 MW_{DC})

Program Size Limitations

Limitations on program size and the size of eligible systems often go hand in hand. These policies appeal to those who believe that NEM programs are a subsidy, but this position is widely debated. A December 2009 report by the National Renewable Energy Laboratory reviewed how states have considered the rate impacts issue, with no example of a state finding that subsidization exists (Doris, Busche, & Hockett, p. 15). The report notes that North Carolina and Maryland looked into the issue and decided not to attempt studies because the experience in other states “had not shown a negative rate impact.” The report notes that in New York, an attempt at quantification was underway, but “the impacts have not been large enough to measure under the current data collection scheme.” Having surveyed states on the issue, the report concludes that “[t]he states that have increased the net metering system size cap generally cited the limited impacts of net metering on ratepayers in other states.”

These policy choices also hinder the development of renewable energy markets in two ways. First, program capacity caps signal to potential new energy developers that their efforts will ultimately be thwarted, not by a lack of customer interest, but by regulatory restrictions. At the same time, a cap on DG system size to less than one MW precludes development of economical systems above the size cap, and those larger systems have been an important driving force in market growth during the past few years. In the end, both policy choices signal to developers that their investments in building solar businesses are best made elsewhere.

Rollover of Excess Generation

At the heart of any NEM program is the treatment of generation in excess of a customer's needs. When implemented properly, NEM has nearly the same impact on a participating customer's utility bill as would occur if the customer-generator used a bank of batteries to store energy until the customer's demand exceeded his or her generation (batteries have modest losses, so NEM has a slightly greater utility bill impact). At its most basic, NEM allows a customer's meter to run backwards when the customer produces more power than the customer can use. (Note that most mechanical meters can actually run backwards, but for newer digital meters, "running backwards" is figurative.) States that do not allow this basic aspect of NEM simply do not "net meter" in the widely accepted understanding of the concept.

Once treatment of instantaneous excess generation is addressed, policy makers must consider the treatment of generation at the end of a particular billing period as they develop program rules. The most expansive net metering policy is to allow for indefinite rollover of net excess generation from billing period to billing period until it is used by the customer-generator. This policy choice provides the greatest flexibility in allowing customers to design a renewable energy system to meet their individualized needs, given the variations in output from a system over the course of the year and a customer's yearly consumption pattern. For many homeowners seeking to meet their entire annual load, solar energy generation in the sunny summer months exceeds their summer loads, with the excess offsetting loads in the winter.

Perpetual rollover of excess generation also avoids possible federal regulatory issues related to wholesale sales and addresses concerns that NEM might produce incentives for customers to oversize their systems. As well, the Internal Revenue Service has indicated in at least one private letter ruling that payment for excess generation is taxable income.

Stakeholders with concerns over the rate impacts of NEM often attempt to limit possible rate impacts by requiring the customer-generator to donate net excess generation at the end of a calendar year or some other twelve month period to the utility or to accept payment for the net excess generation at the utility's average avoided cost. Both of these program choices undervalue the net excess generation a customer provides to a utility by providing no value or valuing the on-site, customer-owned renewable energy generation at the cost of fossil fuel generation. NEM programs almost always have a requirement that systems be sized to meet no more than the customer's expected consumption, so substantially oversized systems are not built. Treatment of annual excess generation is an issue for the odd year when generation was higher than expected or consumption was lower than expected. Perpetual rollover of excess generation avoids the administrative burden of an annual reconciliation and gives the customer an assurance of credit for all energy delivered to the utility.

Standby Charges

There have been many instances of utilities proposing special tariffs for customer-generators structured as standby charges or other fees to compensate the utility for possible services that the utility provides. A utility's regulator—the state public utilities commission for IOUs, the city council for many municipal utilities, and other boards for various co-ops and public utility commissions—must approve such tariffs. From



another angle, some utilities have argued that any requirement that standby charges or fees may not be imposed is an unwarranted subsidy by nonparticipating ratepayers. Unfortunately, this argument does not account for the fact that standby charges were generally developed as a rate option for much larger cogeneration or combined heat and power facilities that supply energy on a steady 24/7 basis. These generators lower a customer's peak demand, and therefore the customer's demand charge, while their utility stands by to meet the customer's entire load if the generator fails. Solar energy generation ceases every night and dips during daytime due to cloud cover. For most commercial customers, this means that the utility will impose a demand charge based on peak demand that is nearly what the customer would pay without a solar generation facility. While residential customers typically do not have demand charges and can reduce their utility bills to nothing with NEM depending on facility size, the utility is still in the favorable position of receiving daytime energy that is more valuable than nighttime energy, and typically at least as valuable as early evening energy.

Because of these concerns, Freeing the Grid gives state programs that institute standby charges and other fees for net-metered systems fewer or even negative points. To the extent that proposed standby charges are based on actual rate impacts for a particular utility, institution of the charges is a policy choice available to regulators, but an NEM policy should be reviewed without standby charges to determine what rate impacts exist.

RELEVANT STUDIES FOR EVALUATING NET ENERGY METERING RATE IMPACT

As solar has become a viable option for increasing numbers of consumers, considerable federal, state, and utility attention has begun to focus on valuation of solar energy from DG resources. The following three sections offer a review of recent solar valuation studies, recent efforts in California to develop a methodology for valuing demand-side resources including solar energy systems, and recent efforts to value the capacity benefits provided by solar energy systems. Synthesis of these efforts will provide insight into areas of consensus on the valuation of solar and, therefore, form the foundation of best practices for assessing the rate impacts of NEM.

Studies Valuing the Benefits of Solar Resources

There have been several efforts to value solar energy generation in specific locales, of which three stand out as particularly comprehensive. The first two are discussed in this section: The Value of Distributed Photovoltaics to Austin Energy and the City of Austin (Hoff et al., 2006, followed by a 2008 revision) (AE study) and Distributed Renewable Energy Operating Impacts and Valuation Study (R.W. Beck, Inc., 2009) (APS study). The third comprehensive study of solar energy valuation is incorporated within a broader review of the costs and benefits of net metering for California's largest IOUs. We review that study in the "California's Cost-Benefit Methodology for Distributed Energy Resources" section.

The Austin Energy (AE) and Arizona Public Service (APS) studies discussed below provide an in-depth look at the value solar photovoltaic (PV) generation can bring to the grid for a specific utility. Moreover, each study was subject to scrutiny from many perspectives and stakeholders, and, taken together, they represent a good starting point for identifying consensus elements of the value solar PV can bring to the grid.

Austin Energy Study

To support its determination to move forward with a goal of installing 100 MW of solar generation by 2020, Austin Energy commissioned Clean Power Research to quantify the benefits of solar generation to the utility. At the onset, the authors identified two perspectives as forming the core of the AE study—the “utility” perspective and the “all ratepayer” perspective—and the study’s authors used these perspectives to inform the development of a methodology for valuing the benefits of distributed PV.

Based on the various perspectives, the AE study authors presented a comprehensive list of benefits stemming from distributed PV based on research performed by the National Renewable Energy Laboratory, and including the value of energy production, generation capacity value, transmission and distribution (T&D) deferrals, reduced transformer and line losses, environmental benefits, natural gas price hedge, disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control. Ultimately, the last four potential benefits listed here were not included in the AE study for various reasons, and the benefits associated with disaster recovery were studied, but not included in the primary analysis. (Hoff et al., 2006, p. 12).

The AE study found that PV offered a present value of \$1,983 to \$2,938/kW or on a levelized basis between 10.9¢ and 11.8¢ per kilowatt-hour (kWh) in 2006 dollars. In a 2008 recalculation, Austin Energy found substantially higher average values of \$3,139/kW and 16.4¢/kWh in 2008 dollars.

From the standpoint of NEM, when a customer receives a credit for excess generation that can be used when consumption exceeds generation, Austin Energy’s residential retail rate as of December 2010 on tariff E01 (the standard residential tariff), including a fuel adjustment of 3.65¢/kWh, is approximately 7.2¢/kWh for less than 500 kWh of consumption per month, 9.67¢/kWh for consumption of more than 500 kWh/month from November through April, and 11.47¢/kWh for consumption of more than 500 kWh/month from May through October. All of these rates are well below the 16.4¢/kWh unadjusted value of the benefits PV brings to Austin Energy.

Discussion of AE Study

In reaching these figures, it is important to note that ultimately, two important benefits were not included in the final valuation—disaster recovery and reactive power control.

Disaster recovery benefits were not included because the quantification of this benefit was the first known attempt to do so by the authors and, therefore, the results did not have the level of certainty desired. Ultimately, the authors of the study recommended further study of the issue by Austin Energy in combination with battery storage especially in the context of a hybrid electric vehicle program. Disaster recovery benefits were estimated to be \$2,701/kW for capacity and for energy generation to range from \$1,121 to \$1,578/kW. These numbers would almost double the overall value of PV generation to Austin Energy.

Voltage support and reactive power control had a value of \$0/kW in the final model because current technical standards do not allow for this benefit to be provided by inverters for the benefit of utility operators. The study estimated the value of this benefit at up to \$20/kW, but the figure could be much higher, and the technology to provide this benefit is available. At present, the technology may not be incorporated into inverters



pursuant to IEEE Standard 1547, the existing technical standard for interconnections. A working group of electrical engineers is developing a standard for interconnection of generation with inverters that provide reactive power and voltage support, which will become IEEE Standard 1547.8.

A recent study by the Electric Power Research Institute includes the graphic in Figure 2, displaying how voltage is less variable on a typical 12 kV circuit with solar energy and voltage control than it would be with no solar energy facilities at all. Already, New Jersey utility PSE&G (Public Service Electric & Gas Company) has mounted tens of thousands of individual solar modules on its power poles and is using the available voltage and reactive power support (as a utility, it does not need to wait for completion of IEEE 1547.8). Because of these developments, in any valuation of solar energy generation, it now seems reasonable to consider the value of voltage and reactive power support.

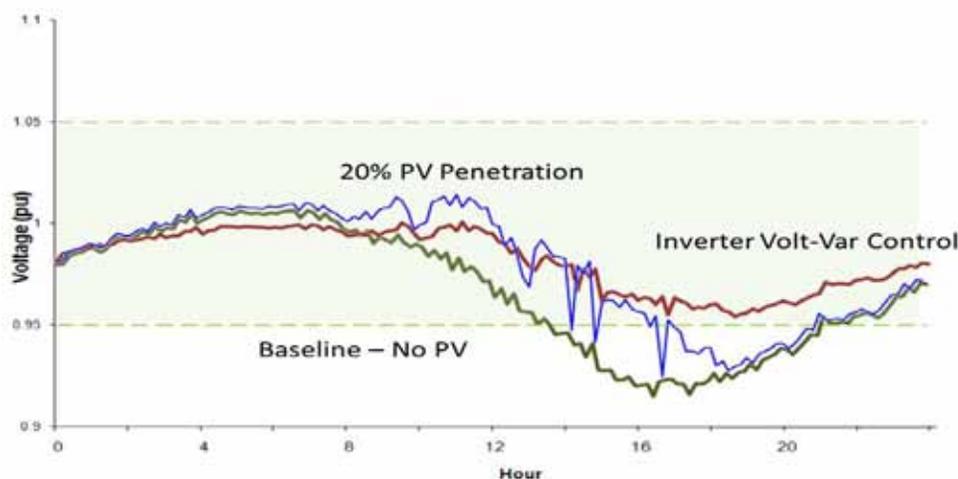


Figure 2. Percentage variation from rated voltage on a typical 12 kV line without PV (the green line, with lowest point), with 20% PV penetration without voltage and reactive power control (the jagged blue line), and with “Inverter Volt-Var Control” (the brown line, with the least voltage variability). Source: Seal, B., *Monitoring, Information, and Control: Management for Tomorrow’s PV* (PowerPoint), May 2010 (reprinted with permission).

Arizona Public Service Study

In early 2008, Arizona Public Service (APS) commissioned R.W. Beck, Inc., Energized Solutions, LLC, Phasor Energy Company, LLC, and Summit Blue Consulting, LLC to assess the impact of wide-scale deployment of distributed PV along with solar hot water systems and commercial daylighting systems on the APS system. Among the specific objectives of the study was an assessment of the benefits wide-scale deployment of these technologies could have for the APS system. In this sense, the APS study views the potential benefits of deployment of distributed solar from the utility perspective. The APS study was conducted in an open process with the participation of many stakeholders from within the solar industry, the business community, advocates, and the regulatory community.

In constructing the methodology for reviewing the benefits of the three distributed solar technologies discussed above, the study’s authors focused on low, medium, and high penetration scenarios, with generating capacity as a percent of peak demand reaching 0.5%, 6.4%, and 14% respectively by 2025 (Arizona Public Service, 2010, Tables 5-3 and 5-4). Within these scenarios, the authors made a number of assumptions about PV



capital cost reductions, the availability of federal tax credits, and the make-up of APS tariffs. The APS study also developed a target scenario that assumed APS would deploy solar technologies to achieve the greatest possible benefits. The target scenario included a general scenario and one in which all commercial PV used single-axis tracking.

The benefits identified in the APS study included reduction in T&D line losses, deferment of T&D capacity upgrades and additions, reduction in necessary equipment size within the distribution system, avoided electric generation capacity costs, avoided fixed operating costs, avoided energy purchases, and avoided fuel purchases. While labeled differently, this is a subset of the list used by the AE study, leaving off environmental benefits and the ability to provide a hedge on natural gas prices, as well as the four factors ultimately left out of the primary AE analysis (disaster recovery, blackout prevention and emergency utility dispatch, managing load uncertainty, retail price hedge, and reactive power control).

After detailed modeling, the APS study found a range of benefits across the various penetration and target scenarios of approximately 7.9¢ to 14.1¢/kWh in 2008 dollars, without reference to a particular scenario (Arizona Public Service, 2010, p. xxii). Residential rates for APS customers as of December 2010 were just under 9.4¢/kWh, ramping up in stages during summer months to 17.4¢/kWh for higher energy usage. Assuming benefits have increased with inflation, the APS study appears to be inconclusive regarding whether there is a subsidy flowing from residential ratepayers to NEM participants (calculated benefits at the lower end of the reported range are less than costs). For demand-metered customers, it seems that benefits exceed costs substantially.

An APS review of this report stated that benefits identified in the APS study were based on locating facilities optimally and maintaining utility ownership and control of the installations, although the benefits of optimal siting are not broken out separately in the APS study. The most likely benefit of selective siting would be for individual distribution circuits. Most transmission and generation benefits would accrue regardless of the location of NEM systems. Reported distribution system benefits are only 0 to 0.31¢/kWh, implying that the impact of selective siting is relatively modest.

Discussion of APS Study

Two important aspects of the APS study directly affect the extent of the benefits it found, and explain the substantial difference from the AE study results.

First, virtually no capacity benefits were identified for the years prior to 2025 and even then, the capacity benefits were only significant in the high penetration case. The study notes that capacity pricing is rolled into energy prices used to calculate the energy benefit, and in that sense, there is a capacity value. However, by “capacity benefit” we are only referring to deferral or avoidance of new utility-built generation and T&D. The APS study’s rationale for not attributing capacity benefits was that T&D and utility generation investments are “lumpy” so it would take a great deal of DG to have an impact on those investment decisions. (Arizona Public Service, 2010, p. 6-9). This view takes a primary advantage of PV—the ability to be installed incrementally—and gives it no value until output from the PV installation fully displaces a new utility generator. APS notes that its Integrated Resource Plan calls for no new construction for the next seven to eight years because it has sufficient capacity at present, but the PV installed over the next eight years could push the need for new construction out further and should be attributed some value. APS expects that peak demand will grow by 4,170 MW from 2010 to 2025. (Arizona Public Service, 2010, Table 5-6) and it is reasonable to assume that even a modest level of DG would defer some quantity of system level



utility investments by a year or more, thereby saving ratepayers money by deferring investment in these lumpy assets. In conjunction with modest levels of demand response, as discussed later in this report, installed solar facilities could also provide APS with firm power, eliminating the need for at least some portion of its contemplated generation and T&D investments.

The APS study makes a jump from modest penetration levels in 2015 to high penetration in 2025 without analyzing impacts in between. Even the high scenario assumes only 63 MW of DG by 2015 (Arizona Public Service, 2010, Table 5-3), or roughly 0.7 % of anticipated peak demand for APS in 2015 (Arizona Public Service, 2010, Table 5-4). By comparison, DG capacity in PG&E's service territory in California is more than 2 % of PG&E's peak demand as of early 2011. While the APS study looks at 6.4 % and 14 % penetrations in 2025, it would have been interesting to present capacity benefits in the 2 % to 5 % range that are likely in earlier years.

The second significant deficiency in the APS study is that it does not consider the benefits at the optimal penetration level using the optimal orientation. Because the study is "forward looking" in so far as it is not assessing the impacts of a program as currently implemented, it would seem logical to have performed this analysis. Indeed, the study acknowledges that southwest facing modules or solar tracking will increase production per MW in the late afternoon, when APS experiences peak demand, and have a greater capacity benefit than a south facing array of the same size. However, the scenarios describing the benefits of DG under the low and medium penetrations do not appear to take the capacity benefits of deploying these optimally oriented arrays into consideration.

Interestingly, in the high penetration case, a solar tracking sensitivity analysis concludes that in 2025, tracking would shift the APS peak to a later hour, at which time the capacity benefit would be little more than it would be with a fixed array pointed south. However, this case envisions generating capacity of 1,677 MW (Arizona Public Service, 2010, Table 5-3), which would be 14.6 % of peak demand. The analysis has thus skipped from a modest penetration of 0.7 % (63 MW) in 2015 to a penetration of 14.6 % in 2025 without looking at the optimal penetration that would occur in between. To its credit, the APS study does acknowledge that energy storage would increase the capacity value of solar energy systems, but it does not attempt to quantify the benefit.

Finally, the APS study did not attribute any environmental benefits to the utility or quantify natural gas hedging benefits as the AE study did. Inclusion of these benefits would have contributed to an overall valuation of the benefits to utility ratepayers from the solar resources modeled in the study. And like the AE study, the APS study did not attribute any value to the ability of solar generation to provide voltage and reactive power support or to provide disaster recovery benefits.

California's Cost-Benefit Methodology for Distributed Energy Resources

Starting in 2004 in Rulemaking (R.) 04-03-017, the California Public Utilities Commission (CPUC) embarked on an effort to develop a framework for valuing distributed energy resources. The overarching goal of the proceeding was to develop a methodology planners could use to compare demand-side resources in a consistent fashion across all resources—energy efficiency, renewable distributed generation, combined heat and power, etc. Efforts by numerous parties including renewable energy and combined heat and power advocates, CPUC staff, ratepayer advocates, and utilities to develop this methodology went on for a number of years and into successor distributed generation dockets R.06-03-008 and R.08-03-008. Stakeholders' efforts culminated in the issuance of Decision (D.) 09-08-026 on August 20, 2009.

In D.09-08-026, the CPUC established a methodology for valuing a wide range of distributed energy resources based on the approach used to value energy efficiency in California's Standard Practice Manual (SPM). In that vein, D.09-08-026 considers four tests described in the SPM for use in evaluating DG resources—the participant test, the rate payer impact (RIM) test, the program administrator (PA) test, and the total resource cost (TRC) test. Ultimately, the CPUC chose to use four tests—the participant test, the PA test, the TRC test, and the societal test—in evaluating DG resources. The societal test is very similar to the TRC test, but includes the impacts of externalities such as environmental costs/benefits, excludes tax benefits, and uses a different discount rate. Each of these tests views the costs and benefits of DG resources from different perspectives—the participating customer-generator (participant test), ratepayers generally (the RIM test), society (TRC and societal tests), and the program administrator, which in California is often the utility (the PA test).

Although D.09-08-026 does not require the use of the RIM test for a general evaluation of DG resources, the test is relevant to a discussion of the rate impacts of NEM because the RIM test attempts to compute bill and rate impacts due to changes in utility revenues and costs. D.09-08-026 identifies the following benefits within the RIM test—avoided T&D line losses, avoided energy and resource adequacy costs, T&D investment deferrals, environmental benefits, increased revenue from fuel transportation for natural gas-fired DG (not relevant for solar energy), and reliability benefits (ancillary benefits and volt-ampere reactive [var] support).

Unlike the AE and APS studies, the CPUC decision also identified costs, including net metering bill credits, program administration, reduced revenue from standby charge exemptions, lost revenue from non-bypassable charges, reduced T&D and non-fuel generation revenues, increased reliability costs for ancillary services and var support, cost of utility rebates or incentives, the cost of utility interconnection not charged to customer-generators, and increased utility fuel transportation costs for gas-fired DG (not relevant for solar energy).

Discussion of D.09-08-026

Inclusion of lost revenues must be handled very carefully in the context of NEM of intermittent resources such as solar and wind. In theory, the utility has a right to recover certain fixed costs under its standard tariffs, and NEM cuts into that expected recovery. However, great care must be taken to avoid double counting of costs. For instance, D.09-08-026 recognized that inclusion of lost standby charge revenue could result in double counting of lost T&D revenues, because standby charges developed in California were also designed to recover T&D expenses. Because both revenue streams would be recovering the same T&D expense, recovery of lost standby charge revenue along with recovery of lost T&D revenues could result in double counting of lost T&D revenues.

Additionally, practitioners must consider other factors when addressing lost revenue claims. First, utility standby charges are designed to recover the utility's cost of being constantly prepared to meet a customer's peak demand in the event that on-site generation is not functioning at the time of that peak demand. In the case of intermittent resources, it is a near certainty that generation will not be effective at some time during each billing cycle when the customer's demand nears the customer's peak demand. In other words, at those times, the customer's solar array is providing minimal generation to offset the customer's electricity consumption, and the customer will pay a demand charge based on almost all of the customer's peak consumption. For demand-metered customers in this situation, the demand charge resulting from their peak demand is



already at or very close to their peak consumption, so the utility is not standing by, it is providing the necessary power and charging for it already. Claiming that preclusion from billing standby charges is a utility cost is effectively claiming that the utility can bill the customer twice for fixed costs, which obviously is not correct. Double counting would almost certainly occur if potential lost standby charge revenue is included as an additional cost of the NEM of intermittent resources.

Moreover, although residential and small commercial customers do not face demand charges, the variability in their relatively small loads due to renewable generation has not been shown to have any significant impacts on the grid or been shown to be potentially any different than customers without renewable generation who have significantly varying loads from one moment to the next. Accordingly, requiring that these customers pay standby charges would be discriminatory in the absence of a cost of service study showing a clear justification for such charges.

These are not abstract concerns. For example, when Southern California Edison (SCE) undertook a more detailed review of its standby charges in light of the diversity of standby customer load compared to regular retail load, SCE found that the diversity of standby customer load was imposing significantly less cost on the distribution system than its regular tariffed customers. Accordingly, SCE redesigned its standby charge rates by reducing demand charges when compared to regular tariff services. Looking at this change in reverse, prior to the change in demand charges, standby customers were significantly overcompensating SCE under its prior standby charges. It would be useful to see whether customer investment in renewable energy similarly results in a greater diversity in their load when compared to typical retail customers, and has a similarly less taxing impact on the grid.

In sum, inclusion of lost utility revenue related to standby charges has some logical appeal and merit, but care must be taken to avoid double counting. Moreover, standby charges and T&D charges designed to recover costs from ratepayers who have not invested in DG resources may overcompensate the utility in the absence of cost of service studies specific to DG customers, which would set these fees in that context. That is, calculating lost revenues based on these tariffs could overstate the amount of the utility's lost revenue.

California's Net Energy Metering Cost Effectiveness Evaluation

In late 2008, the CPUC commissioned Energy and Environmental Economics, Inc. to value the excess generation produced by net-metered systems for the state's three largest IOUs—Pacific Gas & Electric (PG&E), SCE, and San Diego Gas & Electric (SDG&E). The resulting study, *Net Energy Metering (NEM) Cost Effectiveness Evaluation* (Energy and Environmental Economics, Inc., 2010) (E3 study), was publicly issued in March 2010 (dated January 2010). The study delves into detail by utility, customer class, customer size, and location not seen in any other study.

E3 Study Overview

As part of its focus on the costs and benefits of net-metered solar generation from the utility perspective, the E3 study provides the country's first comprehensive look at the rate impacts of NEM, making it uniquely important in this report. Although it does not reference the RIM test discussed above, the E3 study relies heavily on the analysis performed in D.09-08-026. Because of that fact, despite the groundbreaking nature of the E3 study, many of the flaws and concerns discussed above are present in the E3 study.

The benefits of NEM provided in the E3 study are similar to those in the AE and APS studies. For the E3 study, they include avoided costs from avoided energy purchases, avoided generation capacity or resource adequacy, avoided line losses, avoided T&D capacity, avoided environmental compliance, avoided ancillary services, and avoided renewable energy purchases by the utilities under California's Renewable Portfolio Standard.

On the cost side of the equation, the study evaluated the cost of bill credits provided to NEM participants, administrative costs, and interconnection costs (under California law interconnection costs are not billed to NEM customers).

While the complexity of the analysis in the E3 study precludes a detailed discussion of the methodology here, one example highlights the comprehensive nature of the study. Recognizing that the impact of NEM will not be uniform for all customer-generators, the E3 study models the impacts in 1,253 distinct customer-groupings based on utility, customer type, facility sizing in relation to customer load, and location. (Energy and Environmental Economics, Inc., 2010, p. 29) The complexity of such an undertaking is daunting, but it is important to accurately reflect the timing, size, cost, and benefits of exported energy. Additionally, to further explore the impact of certain cost assumptions on the analysis, the E3 study includes a sensitivity analysis related to billing costs, T&D avoided costs, standby charges, and interconnection costs.

Overall, the E3 study finds that current rate impacts average just over a hundredth of a cent for every kWh purchased (0.011 ¢/kWh, Energy and Environmental Economics, Inc., 2010, Table 4). Delving more deeply into the average figure, the results for each utility were 0.018¢/kWh for PG&E, 0.0005¢/kWh for SCE, and 0.0009¢/kWh for SDG&E. These are truly small figures; utility rates often rise by a penny or more per kWh in a utility rate case, and the figures here are all less than a fiftieth of a cent.

Looking to the future, the E3 study finds that by 2020, 2,550 MW of net-metered solar generation will result in a 0.38% increase in utility rates or 0.064¢/kWh (Energy and Environmental Economics, Inc., 2010, Table 5). In 2020, 2,550 MW of generation would be 3.7% of forecast peak load of just over 60,898 MW for the three utilities. (California Energy Commission, December 2009, p. 51—adding coincident peak demands for PG&E, SCE, and SDG&E). Taking the facts provided here, for every 1% of solar generation, as a percentage of utility peak demand, the E3 study indicates a 0.1% impact on utility rates.

Discussion of the E3 Study

Although the E3 study concludes that NEM at the California IOUs entails a modest subsidy of customer-generators by other ratepayers, several assumptions drive that conclusion.

First, an important assumption made in the E3 study is that the rate impact of NEM is limited to the impact of exported energy. The study notes that customers can generate electricity without NEM, but would not be able to export. With this approach, rate impacts related to energy used on site at the time of generation are not impacts of NEM, they are impacts related to solar generation generally. The study notes that 243 customer-generators with a total of 43 MW of generating capacity do not export at all, and are excluded from the impact analysis entirely. (Energy and Environmental Economics, Inc., 2010, p. 14). While the E3 study does not say it, this approach implicitly assumes that without NEM in place to support customer-generators, customer-generators would have installed the same amount and type of generation, would not have changed





their consumption patterns to make better use of their renewable energy investments, and, finally, that excess generation would be delivered to utilities for minimal compensation. This is not a likely outcome.

In the absence of NEM, there would still be federal and state incentives to install solar energy facilities along with the incentive of offsetting coincident customer load, but customer-generators would likely behave differently. On the one hand, some facilities might be sized smaller to reduce the amount of excess generation. Exported energy could still be sold at the utility's avoided cost in accordance with federal law, but that is less than retail rates, and customers could be expected to react to that lower payment. On the other hand, customers would be likely to try to better coordinate generation and consumption in the absence of NEM, to increase the percentage of generation used on site. For example, air conditioning equipment could be operated in conjunction with generation, cooling more at mid-day and less in the late afternoon. As well, customer-sited batteries could allow customers to synchronize inter-day generation and load for a modest additional investment.

It would be difficult to model generation and load in the absence of NEM, and it is understandable that the E3 study made the simplifying assumption that customers with solar energy facilities would not attempt to match generation and load in the absence of net metering. However, as a practical matter, the reported rate impact of NEM is probably overstated, because customer-generators would modify their behavior in the absence of an NEM program.

Second, it is important to recognize that the E3 study bases costs on the rates that utilities would have charged customer-generators, and California's IOUs have some of the highest residential rates in the country. For example, a residential customer exporting 1,000 kWh in a year will get a credit for 1,000 kWh from the customer's utility, which means the utility did not have the opportunity to sell that amount of energy to the customer for as much as 40¢/kWh. In many parts of the country, top residential rates are less than 10¢/kWh, and utilities' lost revenue from NEM is therefore much lower.

Additionally, the E3 study suffers from several deficiencies that, when looked at cumulatively, greatly decrease the value of the benefits from the energy provided by net-metered customers. Most importantly, the study finds that the utilities have limited need for additional capacity until 2015, so the study provides customer generation with limited credit for capacity value until after 2015. The E3 study values capacity starting at \$28/kW/yr in 2008 and increases linearly to \$141/kW/yr in 2015, then increases at a more modest pace to more than \$200/kW/yr by 2036 (Energy and Environmental Economics, Inc., 2010, Appendix A, p. 15-16).

Broadly, this assumption implies that utility planning occurs without consideration of customer generation, and accordingly assigns a limited capacity value for customer-sited generation. This assumption simply does not square with current practice in California for a number of reasons. First, long-term resource planning in California does include customer-sited generation because the utilities' long-term resource acquisition plans rely on load forecasts based on historical loads that include customer-sited generation and anticipated future customer-sited generation. Second, the California Energy Commission recently denied an application to build the natural gas fired Chula Vista plant based partly on the fact that significant solar DG would be coming online. So both in theory and practice, customer-sited DG is being taken into account in long-term decision-making on the need for generating capacity.

Interestingly, the E3 study's valuation of the capacity benefit of NEM solar generation is considerably lower than the likely valuation of capacity for solar energy purchased by California utilities under long-term contracts. While still under consideration, it appears that the market price referent (MPR) will be used for these contracts (other than the contracts under the Renewable Auction Mechanism). The MPR is based on the total cost of generation for a natural gas combustion turbine, including capital costs, and thus incorporates capacity value. It has been argued that solar energy under contract has more value than NEM solar energy because there is no assurance that the latter will continue to operate. However, there is no reason to expect widespread decommissioning of NEM systems. Having paid to install their systems, NEM customers are unlikely to remove them and forgo utility bill savings, and there are very few instances of such actions to date. It seems reasonable to give NEM generation the same capacity credit accorded to solar energy purchased under long-term contracts.

To highlight the significance of this flaw in the study's methodology, an added capacity value of even a \$20/kW/yr increase, applied to 2,550 MW of solar generation, is \$51,000,000 per year—a significant added benefit that would negate much of the net cost per year of NEM in the E3 study. For other states and utilities attempting to value capacity, the lesson is that to properly determine capacity value, a base assumption should be that the generation was anticipated, or should have been anticipated, and its value should not be assessed after the utility has made its generation choices and has sufficient generation. At the margin, a prudent utility has sufficient capacity and there is limited value to adding more capacity.

The other important factor not considered in the E3 study is reactive power and voltage support, as discussed earlier in this report. D.09-08-026, identified var support as an NEM cost, presumably based on the assumption that fixed-voltage inverters on solar energy facilities might cause greater voltage fluctuations on the circuit. As discussed earlier, new technology and revised standards will allow inverters to provide adjustable voltage support and var control. While current utility infrastructure does not enable utilities' use of these functions, the implementation of smart grid with associated communications and controls enhancements offers the strong potential to turn this presently deemed cost into a future benefit.

Administrative costs are identified in the E3 study as well, based on reported utility costs. Monthly incremental administrative costs for residential net-metered customers are a reported \$18.31 for PG&E, but only \$3.02 for SCE and \$5.96 for SDG&E. (Energy and Environmental Economics, Inc., 2010, p. 40) As noted above, to further explore the impact certain cost assumptions have on the results, the study performed sensitivity analysis. As part of that analysis, the study took a closer look at administrative costs, including a sensitivity analysis based on no administrative cost (the base case accepts the PG&E cost). This sensitivity analysis resulted in a 27% decrease from the base case. This sensitivity analysis is reasonable to consider because, while in practice there is some minor administrative cost per customer, that cost is likely to drop with automation and high volume. An overstatement of \$12/mo for systems averaging 6 kW in PG&E's service territory is equivalent to roughly \$24/kW/yr, implying an added cost of roughly \$24,000,000 per year, which seems unreasonable.

Automation of billing to handle NEM over the long term is sensible as part of an overall update of utility billing software to support the move to a smart grid that supports distributed generation. A holistic view of the necessary changes to utility billing practices is also required to support investment in the smart grid. These changes include the need to accommodate NEM, demand response, advanced energy storage, vehicle





electrification, and other necessary initiatives. All of these long-term policies have been identified as necessary to meet climate and environmental goals and therefore should not be viewed in isolation. In particular, smart metering has been justified based on traditional utility cost savings, and should allow administrative costs for NEM and other programs to drop to very low levels.

As noted earlier, it is critical to recognize that California IOUs have tiered rates as high as 40¢/kWh, so the lost-revenue cost to the California IOUs is two to five times higher than most utilities in the United States. In fact, the top rate at PG&E contemplated in the E3 study was 50¢/kWh, although that tier has since been eliminated.

Quantifying the Capacity Value of Solar

Because the capacity value for PV has been a particularly thorny issue in determining the value of solar resources for utilities, it is worthwhile to provide more discussion on this topic. For many utilities, peak demand typically occurs in the late afternoon. This fact is often cited as a key reason to dismiss the ability of solar to provide significant capacity benefits. However, depending on the actual hour of peak demand, modules can be oriented to the southwest to enable them to operate near their rated capacity in the late afternoon. Careful program design that encourages customers to orient their solar resources to meet a later system peak can address this concern. As discussed in the APS study, southwesterly oriented modules operate at more than two-thirds of rated capacity from 5:00 to 6:00 pm on a sunny summer day and at half of rated capacity from 6:00 to 7:00 pm. Moreover, modules pointed southwest are operating at only slightly less than their rated output between 3:00 and 4:00 pm, which was the peak load in California for 2008 (Self Generation Incentive Program Impact Report, 2008 revised).

The second challenge to solar energy's ability to provide capacity reliably is that cloud cover can dramatically impact an individual system's performance on short notice. In practice, the effect of cloud cover on a single solar energy system is not simultaneously felt across a whole region, and much of the variability is not even seen across a distribution circuit with multiple MW of interconnected generation. Perez et al. showed that just twenty systems over a limited service area will have a collective output with almost no variability on a partially cloudy day, despite the variability of each one of the systems individually (Perez et al., 2006). Likewise, researchers at Lawrence Berkeley National Laboratory recently calculated the smoothing effect of distributed solar power, finding that the relative aggregate variability of PV systems decreases with increased geographic diversity. That study showed aggregate variability over a 15-minute period is one-sixth of the variability of a single PV system, and over a one-hour period, it is one-third of the variability of a single PV system (Mills & Wiser, 2010).

Demand response or energy storage coupled with PV can play a role in meeting peak demand if peaking generation is not available at lesser cost. In a 2006 study, Perez et al. (Perez et al., 2006) analyzed the peak-month loads for three utilities and the coincidence of available solar generation. Stuningly, almost all of the loads above 90% of the utilities' peak load could be met with solar energy, with a minimal contribution provided by demand side management to fill in the gaps, as shown in Figure 3. In practical terms, these results show that solar energy is able to provide reliable energy peaking generation as needed with only a modest addition of demand side management.



Figure 3. Integration of PV in demand response programs, using PV rated capacity of 20% of utility peak demand and showing the peak line at 90% of utility peak. Solid shading indicates periods of demand side management. Source: Perez et al., 2006.

In sum, research has demonstrated that many of the concerns that lead utility planners to discount the capacity value of PV can be addressed through program design, careful analysis of potential benefits from diffusion of solar resources, and coupling PV with demand response and energy storage. Based on these points, it is unreasonable to dismiss any capacity value to solar energy for a particular utility without considering these issues.

BEST PRACTICES IN VALUING NET ENERGY METERING

Given the recent efforts to value solar resources discussed in the “Relevant Studies” section, one can begin to see a relatively clear picture of the necessary inputs in a methodology to value solar resources.

Costs of Net Energy Metering from a Rate Impacts Perspective

On the cost side of the methodology, although the AE and APS studies did not attempt to develop a methodology for consideration of NEM costs, the two main inputs developed in D.09-08-026 for the RIM Test—NEM bill credits and program administration costs—are unsurprising and could be relatively noncontroversial if they are carefully developed.

As we have noted, careful calculation of NEM bill credits is important to avoid double counting of costs. CPUC D.09-08-026 suggests that costs should include reduced T&D and non-fuel generation revenues and lost potential revenues from a standby charge exemption. If NEM bill credits are determined by comparison of estimated bills before and after renewable resources are installed, “revenue losses” related to T&D charges and non-fuel generation revenues are already included. Moreover, customers who face demand charges based on maximum demand during the billing period could see little or no change in their demand charges, and thus would still be paying the T&D and non-



fuel generation costs. For these reasons, inclusion of an additional input to measure T&D and non-fuel generation charges not collected by the utility due to NEM of solar and wind facilities is almost certainly double counting of this potential “lost revenue.”

Depending on how standby charge tariffs are actually implemented by a particular utility, calculating the potential lost revenues from a standby charge exemption would double count T&D charges again. Inclusion of lost standby charges is also troublesome because standby charges have usually not been developed for intermittent DG resources and, therefore, are not based on the cost of serving these particular customers. To its credit, the E3 study considered this “lost revenue” in a sensitivity analysis, but did not consider it in the base case.

Caution concerning program administration costs is also warranted. While it might be intuitive to include the actual costs the utility estimates it has incurred in administering its NEM program, it is clear from the E3 study that critical review is necessary. As discussed in the prior section, self-reported administrative costs at PG&E were nearly quintuple the costs reported by SCE and SDG&E with no explanation for this disparity. While some variation in costs is reasonable, a cost spread of this magnitude should raise concern and be justified before inclusion in any cost-benefit analysis. Moreover, as utilities begin to implement billing system updates to handle smart meters, demand response/control functions, and other emerging policies, those systems should be designed to handle NEM more efficiently, and the incremental costs of NEM should decline to slightly more than zero.

Benefits of Net Energy Metering from a Rate Impacts Perspective

On the benefits side of the equation, each study discussed in this report finds that avoided T&D line losses, avoided capacity and energy purchase costs, and avoided T&D investment deferrals should be included as benefits (though the studies did not agree on how to account for the benefits). Inclusion of these benefits in a methodology to assess the possible rate impacts of NEM should be relatively noncontroversial given their consistent identification as benefits of customer investment in renewable energy resources. Avoided line losses stem from locating the generation source on site, which allows line losses due to transmission from distant generation sources to load to be almost completely avoided (there are very modest losses associated with excess generation stepping up to utility line voltage then back down when used nearby on the same circuit). Avoided capacity and energy purchase costs stem from the reduction in on-site customer load and export of excess energy. T&D investment deferrals stem from decreased customer load at the feeder, substation, and transmission levels, and can include deferrals of investment and postponing of investment in T&D upgrades. Care should be taken to ensure evaluation of T&D investment deferrals includes not only the deferral of capacity investment but also equipment and operations and maintenance, as both the APS study and D.09-08-026 recognize these value streams.

Moreover, both the AE study and the E3 study recognize that renewable resources can provide environmental benefits due to avoided emissions from non-renewable energy sources. These benefits are a direct consequence of the investment by customers in generation sources that emit few or no pollutants during their production of energy. While the AE study and E3 study took different approaches to valuing this benefit, given regulatory frameworks in place for the measurement of NO_x, SO_x, and particulate matter, and efforts to regulate CO₂, assessment of the environmental benefits of renewable resources should not be excluded as a benefit. The ability to mitigate carbon regulatory risk is particularly valuable. The CPUC Self Generation Incentive Program Eight-Year Impact Evaluation Revised Final Report (Itron, Inc., 2009) finds that PV was able to

mitigate approximately 0.58 tons CO₂ per MWh. Given forecasts of future carbon prices in the range of \$15 to \$45 per ton on a levelized basis between 2013 and 2030, this would suggest a value of approximately \$9 to 26/MWh in avoided carbon on a levelized basis. (Schlissel et al., 2008)

Additionally, consideration should be given to the possible benefits customer-sited renewable resources will have on a utility's obligations to purchase renewable energy to meet state mandates as discussed in D.09-08-026. For example, because the California Renewable Portfolio Standard bases each utility's compliance obligation on retail sales, utilities will be able to avoid purchases of renewable generation they might have otherwise been required to purchase because customer-sited generation lowers a utility's retail sales. For this reason, D.09-08-026 finds that a typical avoided cost methodology might not fully capture the benefits of customer-sited renewable resources in avoiding renewable generation additions by utilities to meet their RPS obligations. States like Arizona and Colorado with similar RPS obligations should take care to ensure this benefit is appropriately assessed in their cost benefit methodology.

The AE study and D.09-08-026 also recognized that customer investment in renewable energy resources could have significant impacts on the natural gas market. The AE study identified the ability of PV to act as a hedge on natural gas price increases, and D.09-08-026 recognized that customer investment in renewable energy could decrease the demand for natural gas and thereby lower the market price of natural gas for all participants. Unfortunately, it concluded that the impact is too small and too difficult to discern at current DG penetration levels.

The conclusion that renewable energy has no impact on natural gas prices is not supported by research. A Lawrence Berkeley National Laboratory study (Wiser, Bolinger, & St. Clair, 2005) provides a detailed review of studies assessing this benefit. These studies show that the price impacts in terms of \$/MWh of renewable energy additions are significant, ranging from \$10/MWh to \$65/MWh nationally. Regional impacts were also evaluated. For example, the Lawrence Berkeley study found the impact of approximately \$5/MWh within California. Similarly, the price hedge for natural gas was estimated in the California Energy Commission's 2007 Integrated Energy Policy Report at approximately \$12/MWh. Given many utilities' substantial and increasing reliance on natural gas fired generation and consumer level consumption of natural gas, natural gas price impacts should not be ignored when estimating the rate impacts of NEM. Each of these benefits are significant and well documented and, therefore, worthy of inclusion as a benefit of customer-sited investment in renewable energy.

Regarding reliability, D.09-08-026 addressed only one part of the likely benefit of DG and arbitrarily set the value of other reliability benefits at zero. The decision concluded that demand reductions due to DG resources are likely to lead to the same reliability benefits that result from energy efficiency measures and the existing methodology to calculate that impact should be used for the present time. However, it only acknowledged that DG has the potential to provide ancillary services and var support. This ability has been widely acknowledged for inverter-based systems, although output voltage is typically preset rather than being reactive to utility grid voltage, so the ability to provide support is not used at present. However, this ability is very likely to be tapped, at least for larger solar facilities, and could add significant value. Even more importantly, the AE study properly noted that DG has the potential to provide backup power to both critical need customers and typical utility customers. The AE study placed a very high value on this functionality and it seems that some estimate should be made of this value. D.09-08-026 simply set var support and backup power values at zero, but properly directed that those values should be estimated.





Based on the three solar valuation studies reported here, best practices in developing a methodology for evaluating the rate impacts of net metering counsel for including the inputs noted in Table 2.

TABLE 2
Necessary Costs and Benefits Inputs in a Methodology for Evaluating the
Rate Impacts of Net Energy Metering

Benefits to the Utility	Costs to the Utility
Avoided Energy Purchases	NEM Bill Credits
Avoided T&D Line Losses	Program Administration
Avoided Capacity Purchases	
Avoided T&D Investments and O&M	
Environmental Benefits—NO _x , SO _x , PM, & CO ₂	
Natural Gas Market Price Impacts	
Avoided RPS Generation Purchases	
Reliability Benefits	

CONCLUSION

To date, views concerning the possible rate impacts of NEM programs have driven many of the policy deviations from best practices in NEM in many states. However, very little rigorous analysis of the relative costs and benefits of NEM has been done. In reviewing the major net metering and PV cost-benefit studies performed to date, we identified the benefits noted at the end of the previous section as essential for inclusion in any study of the possible NEM rate impacts.

On the cost side of the analysis, the three studies provide guidance as well. The primary cost of NEM is the utility's lost revenue from utility ratepayers, equal to what ratepayers would have paid had NEM not been available. As the E3 study did, we recommend that the lost ratepayer revenue only focus on the bill impacts directly attributable to NEM (i.e. directly attributable to providing value to excess generation). The lost revenue due to NEM should not be based on all production from customer-sited generation, because a customer can install a system to offset their energy needs without an NEM program in place. While simplifying assumptions—that the amount of generation installed would not change or other measures would not be taken to store excess energy for later consumption, for example—are necessary, given the relatively small percentage of generation that is actually net metered, such simplifications seem reasonable.



In addition, utility administrative costs should be included, as discussed in the E3 study. However, the variance in administrative costs among the three California utilities surveyed indicates a need to review cost claims carefully. An assumption regarding future administrative cost reductions per kWh should be included to account for automation of processes. Other costs can be considered based on any unique features of a state's net metering program, but they should be carefully considered to ensure they actually stem from a state's decision to allow net metering versus a decision to allow customer-sited generation as a general matter.

E3's pioneering work quantifying the benefits and costs of California's NEM program highlights the fact that further research is necessary to arrive at consensus on the appropriate methodology for quantifying these benefits and costs. However, the inclusion of the benefits listed at the end of the prior section should be relatively noncontroversial in most instances. As noted earlier, the cost-benefit analysis is utility-specific, and some utilities may realize little benefit from one or more of the items noted in Table 2. A utility in a state without an RPS will not have any savings associated with avoided RPS purchases. A winter-peaking utility will not have a substantial capacity benefit.

Based on the review undertaken in this report, it would be difficult to conclude that nonparticipating customers subsidize demand-metered customers with NEM facilities. The cost to the utility of demand-metered customers deploying NEM is the loss of energy charges, but those energy charges are based on the variable costs that the utility avoids by not having to provide the energy that is instead generated on site. The administrative cost in the long run should drop to almost nothing per kWh, and the non-energy benefits discussed here will still be provided. It appears that demand-metered customers with NEM facilities will typically provide a net benefit to nonparticipating customers.

For customers with bundled rates, such as residential customers, whether or not there is a net benefit will depend on utility-specific costs and benefits.

RECOMMENDATIONS

We recommend that utility regulators wishing to determine the NEM rate impact for specific utilities use the guidelines provided in this report. In particular, we recommend that:

- Studies comparing the costs and benefits of NEM include the costs and benefit inputs identified in Table 2 above.
- As part of this effort, none of the benefits identified in Table 2 should arbitrarily be set to zero based on unsupported assumptions.
- Capacity benefits associated with deferral of utility generation and T&D facilities should be modeled under a long-term framework to ensure that the value of PV to defer these resources under a long-term planning framework is properly captured.
- Assessment of the costs and benefits of net metering should be based only on exported energy, not the entire production of the facility.
- Program administrative costs should be based on a long-term assessment of costs based on the expectation that updating utility billing software to accommodate and support grid-modernization efforts, which include net metering, will be necessary.

At the earliest stages of a NEM program, the cost of such studies may be greater than any net costs or net benefits themselves, and regulators may understandably be hesitant to undertake studies prior to significant NEM deployment. The results discussed in this report should give regulators confidence that rate impacts at the earliest stages will be negligible and need not be a concern that leads to restrictive NEM policy.



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APPENDIX A

Summary of Costs and Benefits Inputs Used in Three Solar Valuation Studies

	Austin Energy Study	APS Study	CPUC E3 NEM Study
BENEFITS			
Energy production value	X	X	X
Generation capacity value	X	X	X
T&D deferrals	X	X	X
Reduced transformer losses	X	X	X
Reduced line losses	X	X	X
Environmental benefits	X		
Natural gas price hedge*	X	X	
Blackout prevention*	X		
Emergency utility dispatch*	X		
Managing load uncertainty*	X		
Retail price hedge*	X		
Reactive power control*	X		
Reduced distribution system size		X	
Avoided fixed operating costs		X	
Avoided environmental compliance			X
Avoided ancillary services			X
COSTS			
Net metering bill credits			X
Program administration**			X
Reduced standby charge revenue***			X
Costs of interconnection not charged***			X

* These benefits were not quantified in the Austin study. The study found that the benefits were real and quantifiable, but there was insufficient data to assign them a value for Austin Energy.

** Because of data problems with utility reported billing costs, these costs were also included in a sensitivity analysis.

*** These benefits were included as sensitivity analysis.

ACRONYMS

AE	Austin Energy
APS	Arizona Public Service
CPUC	California Public Utilities Commission
D.	decision
DG	distributed generation
IOU	investor owned utility
kW	kilowatt
kWh	kilowatt-hour
MPR	market price referent
MW	megawatt
NEM	net energy metering
NNEC	Network for New Energy Choices
PG&E	Pacific Gas & Electric
PA	program administrator
PV	photovoltaic
R.	rulemaking
RIM	ratepayer impact
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SPM	California's Standard Practice Manual
TRC	total resource cost
T&D	transmission and distribution
var	volt-ampere reactive



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Environmental Research Letters



LETTER

Exploring the market for third-party-owned residential photovoltaic systems: insights from lease and power-purchase agreement contract structures and costs in California

OPEN ACCESS

RECEIVED
1 October 2014ACCEPTED FOR PUBLICATION
19 December 2014PUBLISHED
4 February 2015

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E-mail: carolyn.davidson@nrel.gov**Keywords:** residential solar, third-party ownership, lease cost**Abstract**

Over the past several years, third-party-ownership (TPO) structures for residential photovoltaic (PV) systems have become the predominant ownership model in the US residential market. Under a TPO contract, the PV system host typically makes payments to the third-party owner of the system. Anecdotal evidence suggests that the total TPO contract payments made by the customer can differ significantly from payments in which the system host directly purchases the system. Furthermore, payments can vary depending on TPO contract structure. To date, a paucity of data on TPO contracts has precluded studies evaluating trends in TPO contract cost. This study relies on a sample of 1113 contracts for residential PV systems installed in 2010–2012 under the California Solar Initiative to evaluate how the timing of payments under a TPO contract impacts the ultimate cost of the system to the customer. Furthermore, we evaluate how the total cost of TPO systems to customers has changed through time, and the degree to which contract costs have tracked trends in the installed costs of a PV system. We find that the structure of the contract and the timing of the payments have financial implications for the customer: (1) power-purchase contracts, on average, cost more than leases, (2) no-money-down contracts are more costly than prepaid contracts, assuming a customer's discount rate is lower than 17% and (3) contracts that include escalator clauses cost more, for both power-purchase agreements and leases, at most plausible discount rates. In addition, all contract costs exhibit a wide range, and do not parallel trends in installed costs over time.

Introduction

Residential solar photovoltaic (PV) systems constituted roughly one quarter of the PV capacity installed in the United States in 2013—an estimated 792 MW (GTM Research 2013). While the PV market has been growing rapidly, PV still makes up a very small portion of the total US energy mix. As costs continue to decline and the industry continues to grow, PV could begin to make a substantial contribution to the US energy mix over the next couple of decades (DOE 2012). PV costs have witnessed steady declines over the past several decades, and in the past four years, have nearly halved (Feldman and Friedman 2013). At the same time, PV incentives—including the federal investment tax credit (ITC) and various state, municipal, and utility rebates and tax credits—have substantially reduced

the capital requirements to install solar. However, achieving grid parity (the ability to generate electricity at a cost that is less than or equal to the price of purchasing power from the electricity grid) will require additional cost reductions, and these cost reductions will need to be passed on to consumers.

The use of third-party-ownership (TPO) structures for PV has increased considerably over the past several years—from an estimated 10–20% in large US markets in 2009, to an estimated 65% of the US market in 2013 (GTM Research 2013, GTM Research 2014). TPO provides an attractive alternative for consumers who either do not want to assume risks associated with ownership or prefer a low money down payment option. Further, a TPO structure can make financial sense due to the challenges individual homeowners face in monetizing the ITC and modified

accelerated cost recovery system (MACRS) depreciation¹. Under a TPO contract, the contract type and payment structure between the solar customer (homeowner) and the system owner (solar integrator or third-party financier) can take the contractual form of a solar lease or a solar power-purchase agreement (PPA). In a solar lease, the customer pays a specified amount (agreed upon at the outset of the contract) every month, regardless of the system's energy production. In a solar PPA, the customer pays a specified amount per kilowatt-hour (kWh) of generation, so the amount paid varies monthly as a function of generation. Regardless of the type of contract (lease or PPA), customers typically pay a one-time, upfront down payment and monthly payments. The monthly payments can be flat, but in some cases, monthly payments may escalate at a flat rate through time. As a result, the timing of the payments by the homeowner varies by the magnitude of the down payment and monthly payments and the rate at which the payments escalate. Often the installer will provide the homeowner a menu of contract options by varying these parameters, with implied financial tradeoffs. Contract prices can be objectively compared and evaluated by aggregating the sum of down payments and the monthly payments over the duration of the contract and discounting. This total contract price—the real (i.e. 2012 dollars) out-of-pocket cost the customer is contractually obligated to pay—is the key economic measure for residential customers evaluating different TPO PV lease/PPA contracts.

While several current sources track installed PV prices via incentive program data and other market data sources (GTM Research 2013, Barbose et al 2014), there is little data on the out-of-pocket cost to the customer over the duration of the contract, which will be substantially reduced by available incentives. Further, while a few studies have evaluated the financial implications of buying versus leasing solar (Rai and Sigrin (2013), Navigant Consulting 2014), to date, no study has focused exclusively on comparing contract costs across the myriad TPO options offered to customers. In both of the above studies, results suggested that leasing provided a higher net present value than ownership—though the difference was more drastic in Rai and Sigrin (2013).

In this study, we use third-party contract data from the California Solar Initiative (CSI) to examine California's residential TPO market during 2010–2012². We use a sample of 1113 contracts to

evaluate how TPO contract structures vary and how this translates into a final TPO contract price. We use this data to evaluate the effect of contract structure, magnitude of down payment, and escalation clauses on the total contract price.

The remainder of this article is organized as follows. First, we discuss the study data, our sampling procedure and the method to convert contract terms into a total contract price (2012 dollars). Second, we evaluate contract characteristics: distribution of lease versus PPA and various payment structures (timing of payments and existence of escalation rates). Third, we evaluate TPO contract prices according to the structure and terms in the contract, as well as trends over time and by size. Finally, we assess whether customers appear to be selecting optimal contract structures.

Methodology

The California Public Utilities Commission (CPUC) oversees the CSI, a solar incentive program available to customers of the state's three investor-owned utilities: Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The CSI has a \$2.4 billion budget to stimulate the deployment of approximately 1940 MW of new solar capacity between 2007 and 2016 via solar rebates for residential, commercial, and utility-scale systems, including systems for low-income residents and multifamily affordable housing. To drive continual PV price reductions, the CSI incentive amount declines incrementally as the program reaches specific levels of cumulative installed capacity (separately specified in each of the three utility areas).

In this analysis, we focus on the residential sector during 2010–2012. During this period, systems in the CSI database represented about 45% of the residential PV installed nationwide (GTM Research 2013, California Solar Statistics 2014). The initial residential customer rebate was \$2.50/W in January 2007, and this declined to a final rebate of \$0.10/W in 2013³. During 2010–2012, incentives for residential systems ranged from roughly \$1.50/W–\$0.20/W, depending on the utility.

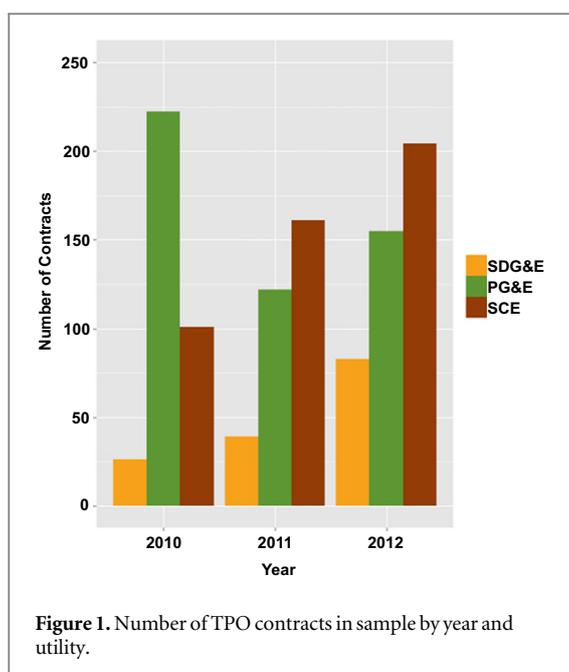
The CPUC requires incentive applicants to submit the installed system cost and documentation supporting that cost. For TPO systems, the CPUC requires installers to submit signed system contracts, which in many cases include the terms of the lease arrangement between the solar customer and the system owner.

The CPUC provided NREL with access to more than 50 000 residential third-party contracts signed

¹ MACRS is the tax depreciation system that allows businesses to recover the cost basis of an asset via annual tax deductions for depreciation, for commercial entities. In contrast to straight-line depreciation, where an asset is depreciated in equal increments annual over the useful life of the asset, MACRS in the case of a solar asset specifies the following 5-year depreciation schedule (20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76%).

² Over this period, residential third party ownership in California increased from 22% to 69% of new installations (CSI 2014).

³ The CSI program pays an expected performance-based buydown (EPBB)—a capacity-based incentive that is adjusted based on expected system performance that considers major design characteristics of the system, such as panel type, installation tilt, shading, orientation, and solar insolation available by location. By the end of 2013, CSI rebates had been exhausted in PG&E territory.



during 2010–2012⁴. We sampled 2400 residential contracts, with a mean system size of 6.04 W_{DC}⁵. To maximize our ability to make inferences about changes over time, we stratified our sample by quarter, selecting 200 contracts for each quarter from the first quarter of 2010 to the last quarter of 2012, based on the ‘completed date’ as recorded in the CSI database⁶. This resulted in a sample of 1113 contracts with usable data (the remaining contracts simply provide the signed contract, without down payments or monthly payments), from 162 installers. The distribution of the contracts that did not include usable price terms closely matched the distribution of the contracts with usable price terms by utility and quarter, reducing concerns about selection bias. As a result, this sample can be considered representative of the geography and installation timeframe of the IOUs in California. The distribution of the final dataset by year and utility is displayed in figure 1.

To evaluate contract prices across leases and PPAs with varying payment horizons and escalators, we rely on a discounted cash flow (DCF) methodology. The DCF aggregates all payments, present and future, to assign a total present value to each contract in 2012 dollars, which enables us to compare contracts with different structures. For the rest of the article, we refer to this figure as the ‘real contract price’ or the ‘TPO contract price’. This implies the real (2012 dollars) price of a lease or PPA contract to the homeowner. Future payments are discounted according to a

selected discount rate intended to reflect the ‘typical’ consumer’s tradeoff between present and future expenditures. In reality, each consumer will have a unique discount rate which will vary as a function of the opportunity cost of investing capital—i.e., what rate of return a consumer can expect from investing their money elsewhere. The cost of homeowner borrowing provides a reasonable proxy, which can range from low-rate home-equity lines of credit, to high-rate credit cards. However, additional factors present in a new market such as informational deficits, outsized perceptions of risk, aversion to sizable investments and other factors could increase a consumer’s discount rate. Further, research has found that discount rates for energy conservation investments are higher than for other investment decisions (Meier and Whittier 1983, Train 1985), perhaps because of higher uncertainty over future conservation savings (Hassett and Metcalf 1993). Less research has evaluated the discount rate for green energy generation investments, but there may be a similar degree of uncertainty. Rai and Sigrin (2013) found implied discount rates as high as 60% for PV adopters in Texas.

Owing to the wide range of theoretically plausible discount rates, we evaluate contracts over a range of discount rates when possible. For figures or calculations relying on one discount rate, we use 7% as a default nominal discount rate. Equation (1) presents the formula used to calculate the price of each contract.

$$\begin{aligned} \text{Real contract price} (\$2012)_i &= \text{Upfront payment} \\ &+ \sum_{y=1}^t \left(\left[\text{monthly payment} \times (1 + e)^{y \times 12} \right] / \right. \\ &\left. \left[(1 + d)^{y-1} \right] \right), \end{aligned} \quad (1)$$

where i is the individual contract, t is the term length, y is the contract year, e is the escalation rate, d is the discount rate.

In the case of a PPA, the monthly payment is estimated based on assessed average monthly production stipulated in the contract⁷. We assume system production declines of 0.05% per year (Jordan and Kurtz 2011) and calculate the estimated monthly payment as follows:

$$\begin{aligned} \text{Estimated monthly payment} &= \text{estimated monthly production} \times (0.995)^{y-1} \\ &\times \text{PPA rate}. \end{aligned} \quad (2)$$

Based on these calculations, we assign a real contract price to each contract.

⁴ The CPUC only began storing digital versions of contracts beginning in 2010, so contract data were not readily available for previous years.

⁵ All system sizes are reported in Watts-direct current.

⁶ The ‘completed date’ is the date when the final incentive check was created and sent to the payee. This date may be several months after the contract terms were quoted to the customer.

⁷ Companies likely rely on varying methods to estimate the average monthly production. We have no way to validate estimated monthly production or evaluate whether estimates are biased upwards or downwards as this depends on exact location, system design parameters, roof features and shading.

Table 1. Number of TPO contracts by year and type.

	2010	2011	2012
Lease	236	239	299
PPA	113	83	143

Results

Contract-type trends

Within our sample, nearly 69% of third-party contracts were structured as leases, with the remaining structured as PPAs (table 1). This proportion does not change substantially from 2010 to 2012. In our sample, most installers and integrators offered one structure exclusively (or nearly exclusively), although 10 of the 162 installers in our sample offered both leases and PPAs.

Whether a lease or a PPA, some contracts included an escalator clause, in which the base payment escalates at a given rate annually. Escalators are often included to allow revenue to keep pace with inflation⁸. In our sample, PPAs more consistently contained escalator clauses; 53% included an escalator of 3.0% (the most common level) or 3.9% per year. On the other hand, most leases in our sample data did not contain an escalator clause; among those that did, most had a relatively high escalator of 3.9% per year (figure 2). A smaller proportion of leases included escalators in 2012 than in 2010 or 2011, while the proportion of PPAs including escalators increased during our study period.

Contracts also varied in the timing of payments. The amount customers paid up front varied from zero (no-money-down) to the complete contract value (prepaid contract). Some contracts required partial payment up front, with the remaining contract price paid over time. With few exceptions, customers signed 20 year contracts.

Figure 2 shows the payment timing by contract type and year. The timing of PPA payments was weighted more toward the future compared with the timing of lease payments during each of the three years studied, with most PPAs structured as no-money-down contracts. However, the proportion of no-money-down leases increased substantially over the period. It is unclear whether this shift resulted from customer preferences or financier/integrator preferences.

Overall, the lease data suggests consolidation of preferences over time, with a trend towards an increasing percentage of no-money-down lease contracts. A recent trend towards securitization of solar leases and

PPAs may play a role in this shift as a contract that is fully prepaid cannot be securitized. However, without additional data, it is not clear whether this shift is a result of customer preferences or financier/integrator preferences.

Contract price analysis

In this section, we evaluate the full price of the TPO system to the end-consumer based on aggregating down payments and monthly payments from each contract to derive a real contract price. We provide an overview of the distribution of these prices, evaluating the value proposition provided by: (1) PPAs versus leases, (2) contracts with varying levels of upfront payments, and (3) contracts with and without escalators. Given that discount rates vary among consumers, we evaluate the contract price over discount rates of 0%–20%. Next, we evaluate effects of system installation year and system capacity on TPO contract price.

Impact of contract structure on contract price

Figure 4 shows the variation in contract price over the range of contracts sampled, assuming a 7% real discount rate. Both leases and PPAs exhibit a wide range. The mean contract price is \$3.04/W for leases and \$4.26/W for PPAs, with standard deviations of \$1.28 and \$1.08, respectively.

Figure 5 provides the distribution based on monthly lease payments per kilowatt and PPA rates per kilowatt-hour in order to provide a metric more comparable to terms found in TPO contracts. This is illustrated for no-money down contracts only. Monthly payments to lease a PV system range from \$12/kW to \$51/kW per month (sample mean \$24.30/kW per month), and PPA rates range from \$0.12/kWh to \$0.35/kWh (sample mean \$0.23/kWh).

PPA versus lease

Figure 6 illustrates the mean contract price, as well as the distribution of prices, for contracts with differing payment schedules. PPAs are consistently higher priced than leases, though much of this difference may be explained by the structure of the contracts; as a sample, leases are comprised of many more prepaid contracts. When comparing across similar payment structures, the difference between PPAs and leases declines as the amount of down payment declines. For the only category in which payment timing is exactly the same—0 down—the difference between PPAs and leases declines to \$0.52/W. Price differences between PPAs and leases, in all cases, are statistically significant. In the discussion section, we explore several hypotheses for this persistent pricing difference.

Contract payment timing: 'no-money-down' versus prepaid

Figure 7 illustrates the price differences in contract payment timing—focusing on leasing, which provides

⁸ Nationally, nominal residential electricity prices, on average, have increased by 2.01% annually in the last 20 years (U.S. Energy Information Administration 2011) and are forecasted to increase, on average, 2.20% annually from 2014–2040 (U.S. Energy Information Administration 2014).

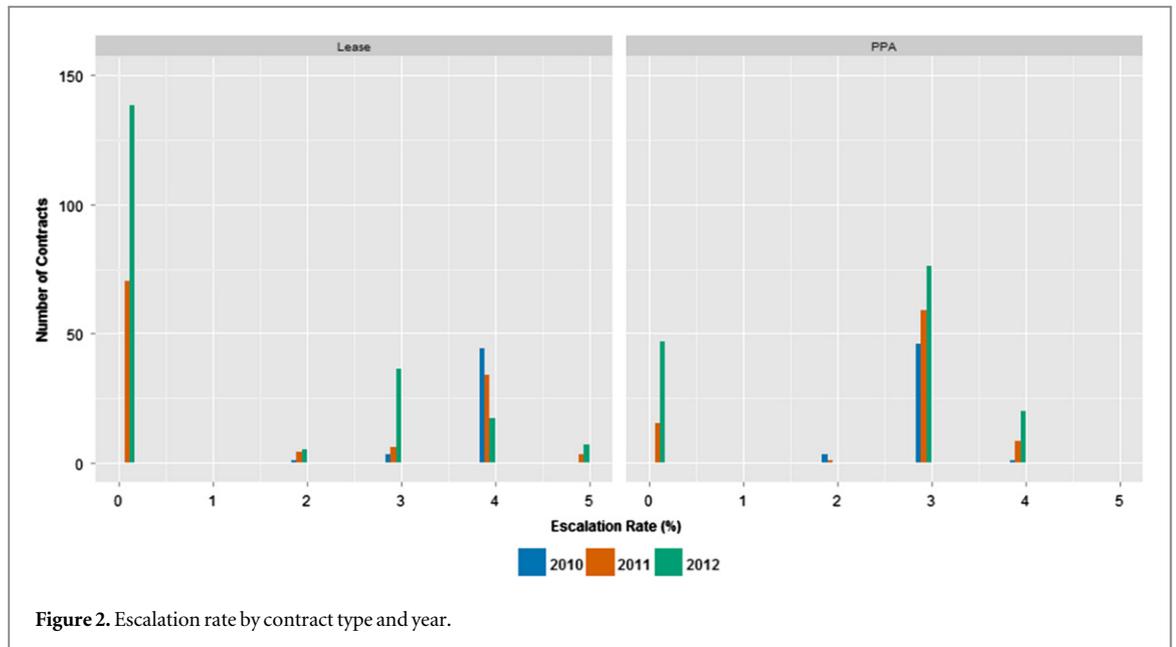


Figure 2. Escalation rate by contract type and year.

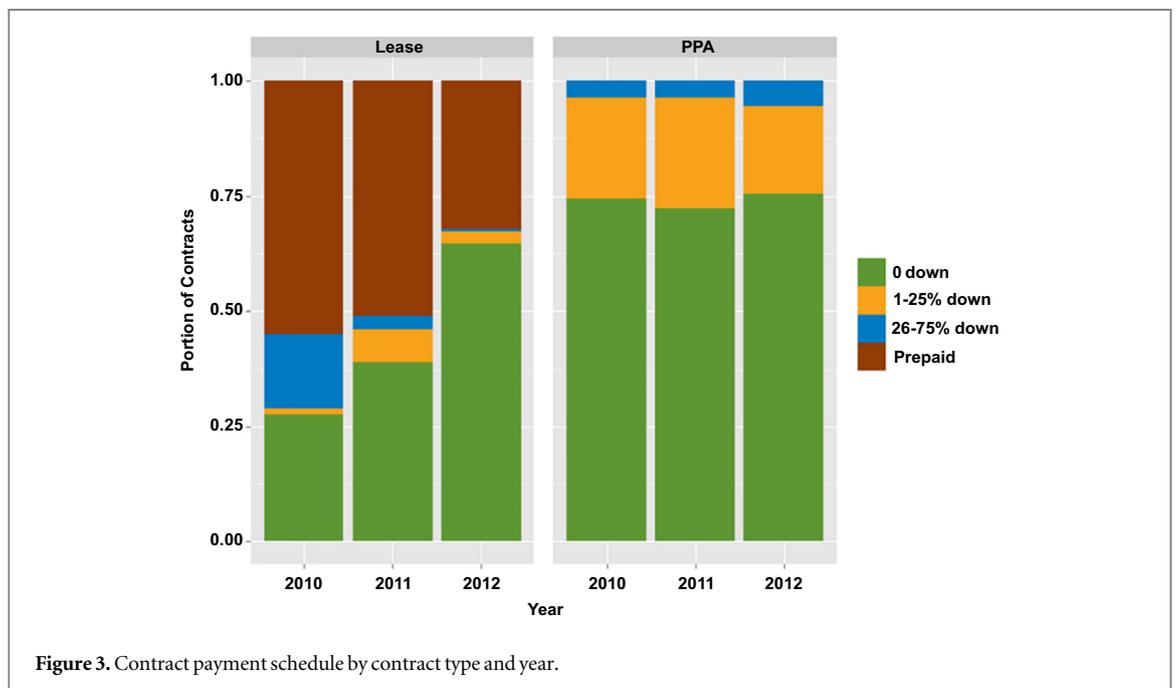


Figure 3. Contract payment schedule by contract type and year.

examples of both ‘no money down’ and fully prepaid contracts, at varying discount rates. As expected, no-money-down contracts cost more over the life of the contract in the lower range of discount rates. The two contract structures equate in price at a discount rate of approximately 17% as illustrated in figure 7.

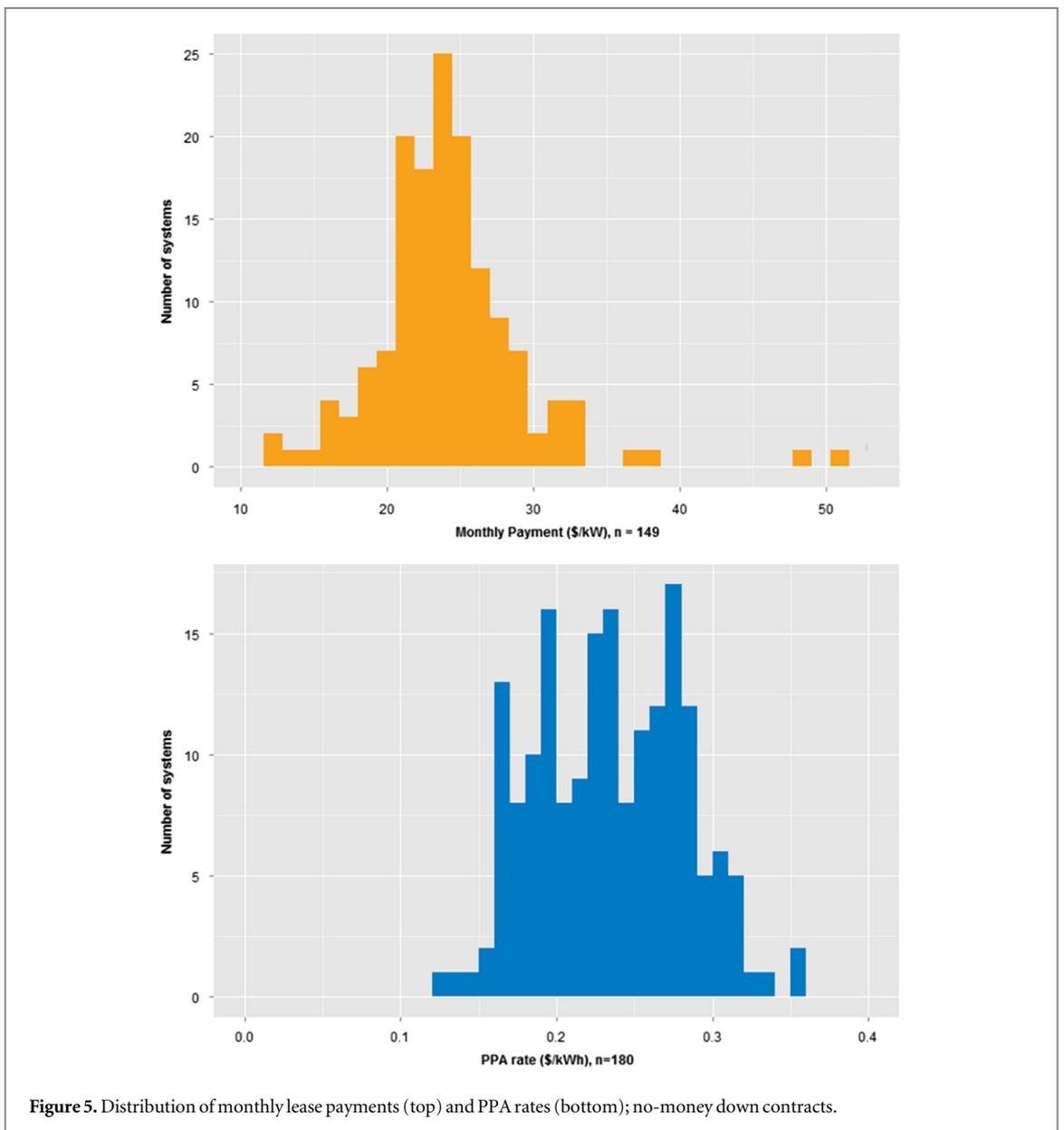
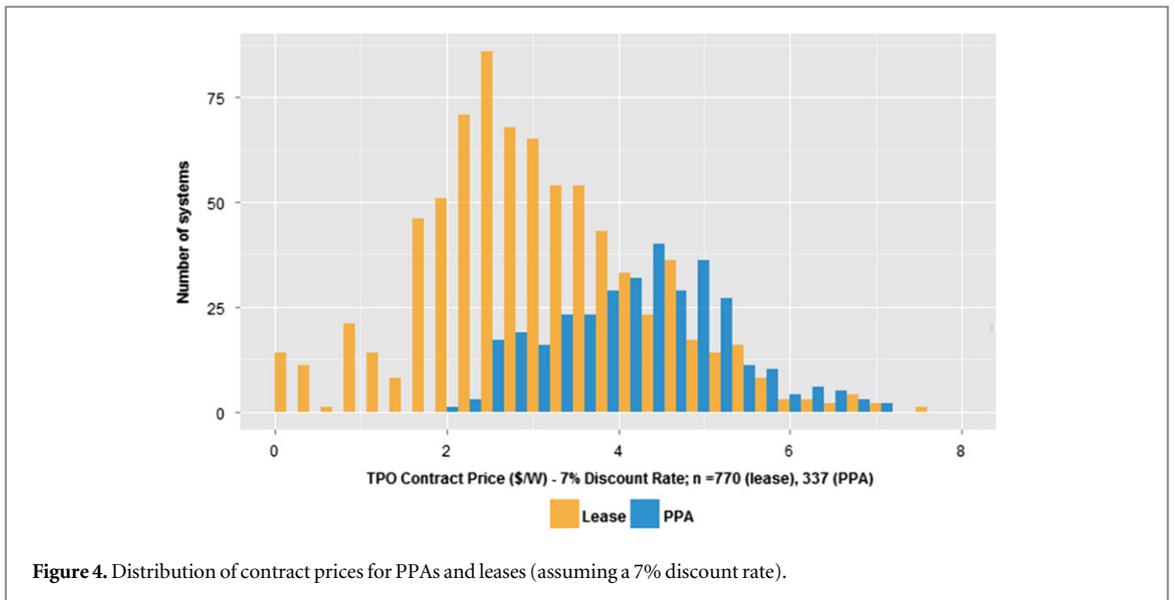
These data suggest that, on average, a prepaid contract is financially preferable to a no-money-down contract if the consumer’s expected rate of return on a competing investment is equal to or lower than 17%⁹.

⁹ This omits the additional option of paying a portion of the contract upfront and paying the remainder through monthly payments over a 20-year period. However, focusing on these two categories enables comparison across contracts that have identical payment timing within the two categories—payments are either fully paid upfront, or paid in equal increments over (typically) 20 years.

Escalators

As illustrated in figure 3, contracts commonly include payment escalators, although escalators are more common in PPAs than in leases. Figure 8 illustrates the real contract price of PPAs and leases with and without escalators¹⁰. It suggests that a contract with an escalator costs a consumer more than a contract without an escalator at nearly all plausible discount rates. At a discount rate just under 16%, leases with escalators approximately equate with leases without escalators. On average, PPAs with escalator clauses, at

¹⁰ We combine all contracts with escalators over 2.9% and exclude seven contracts with 1.9% escalators. For both leases and PPAs, this results in a blending of escalation rates, although 94% of escalation rates are 3.9% and 2.9%.



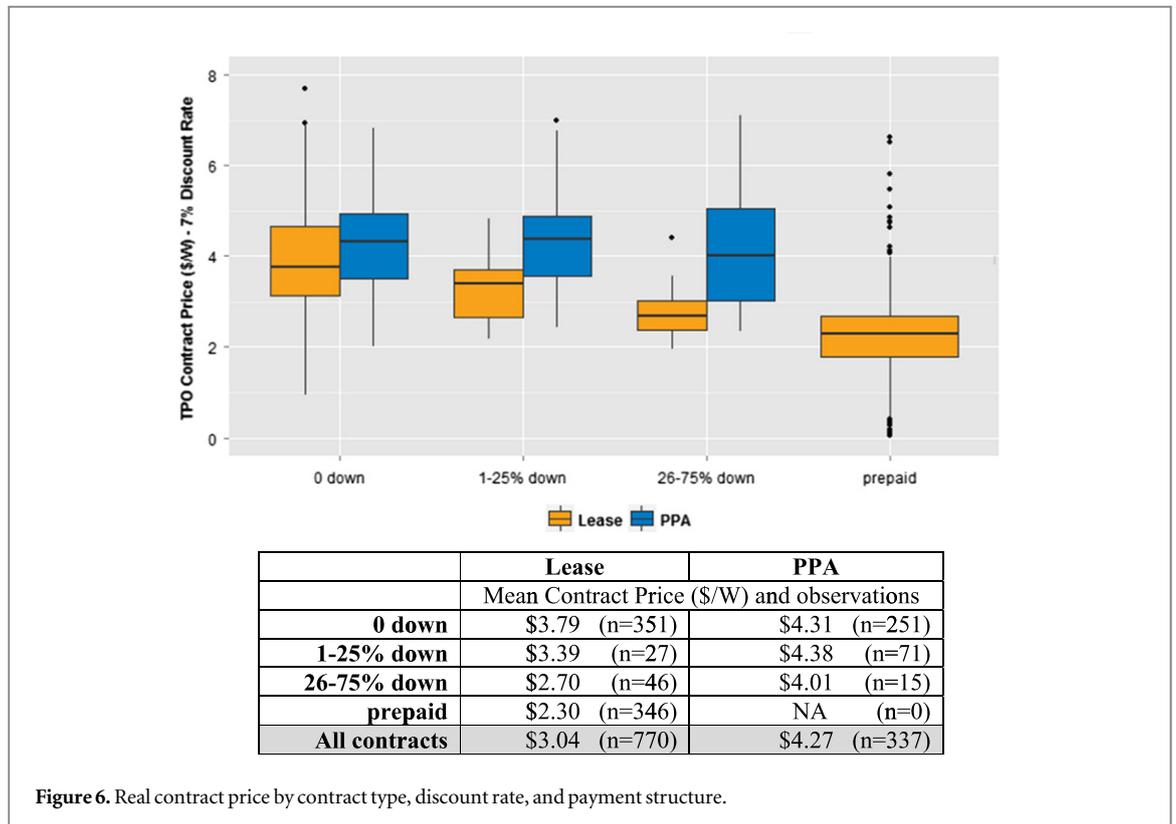


Figure 6. Real contract price by contract type, discount rate, and payment structure.

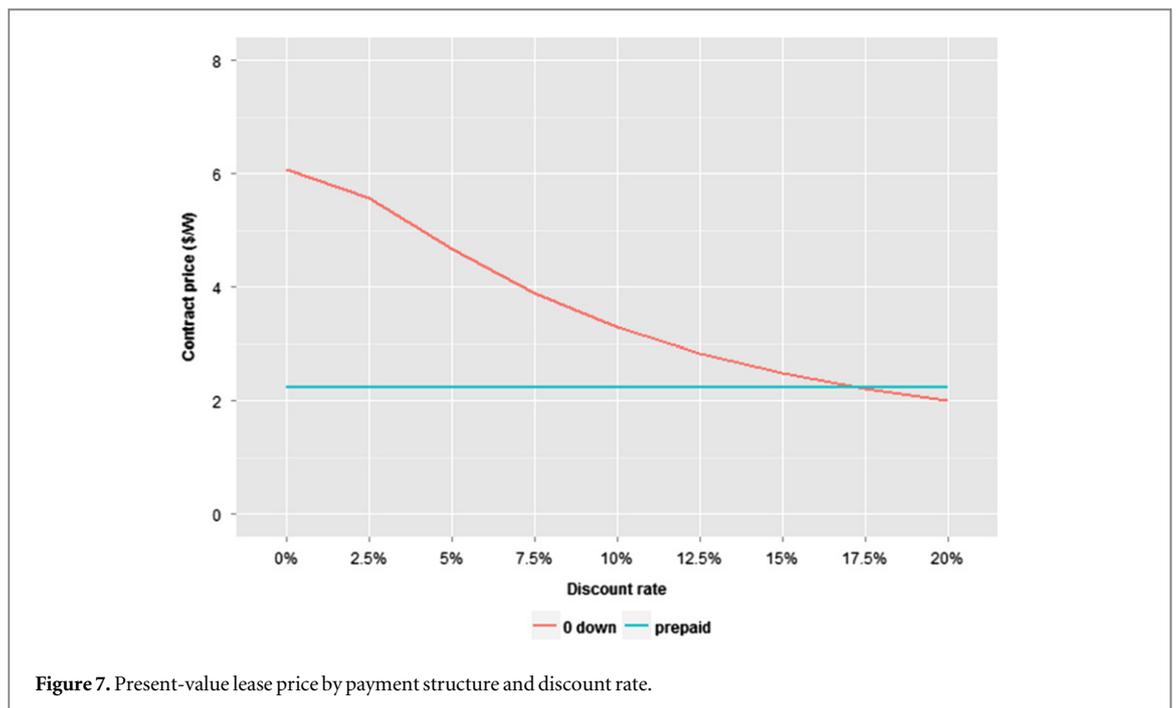


Figure 7. Present-value lease price by payment structure and discount rate.

every discount rate, cost more than PPAs without escalator clauses.

Contract price by reported price, installation year, and system capacity

In this section, we evaluate contract prices in relation to reported PV system prices, year of system installation, and system capacity.

As installed costs decline, we would expect installers to pass a portion of the cost declines along to

TPO contracts and reduce prices. Installed prices reported to the CSI program declined by roughly \$2.00/W during 2010–2012. Over this same period, the CSI incentive declined by \$0.87/W, from a median of \$2.40/W in the first quarter of 2010 to \$1.53/W in the last quarter of 2012. That is, reported prices declined more rapidly than did incentives. However, the average price of contracts changed less over this period, with both lease and PPA prices increasing in 2010–2011, and then PPA prices decreasing in 2012,

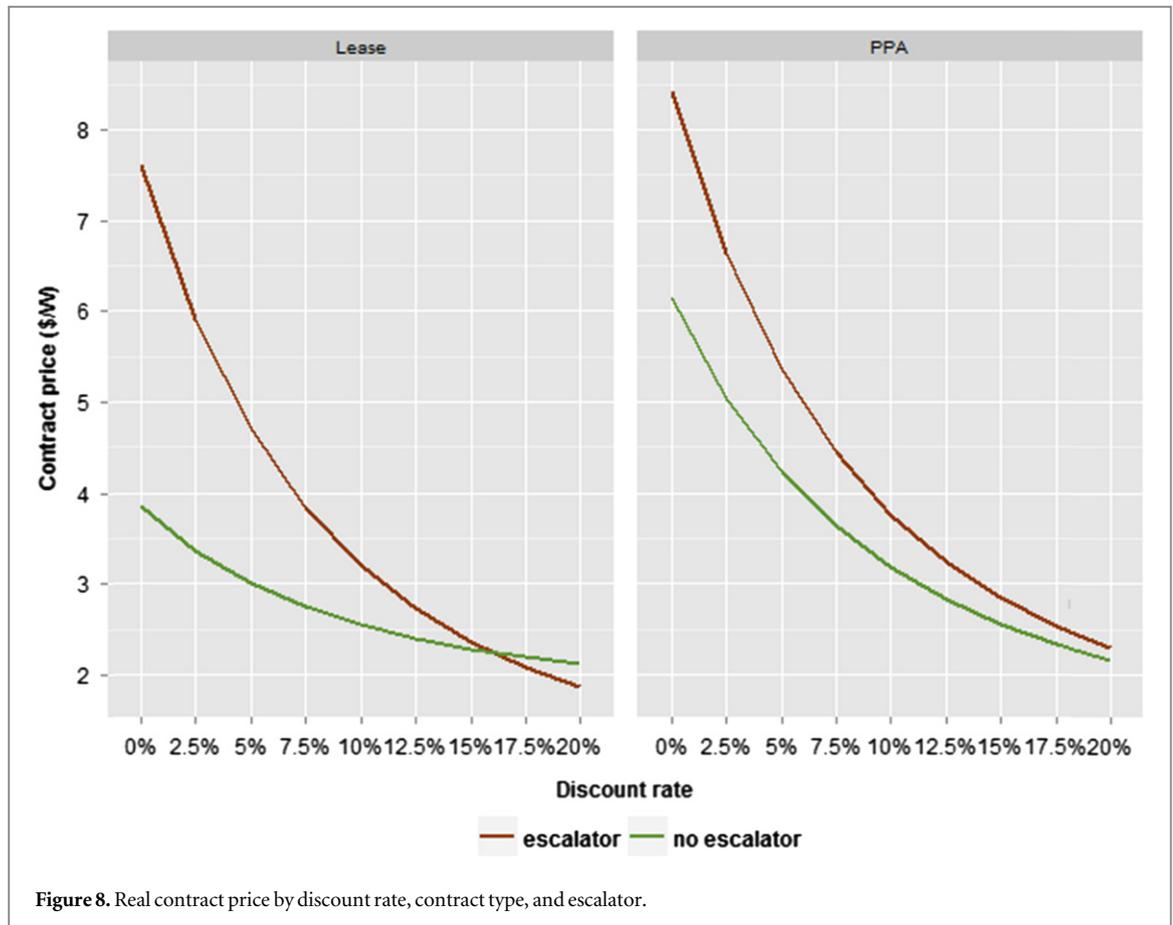


Figure 8. Real contract price by discount rate, contract type, and escalator.

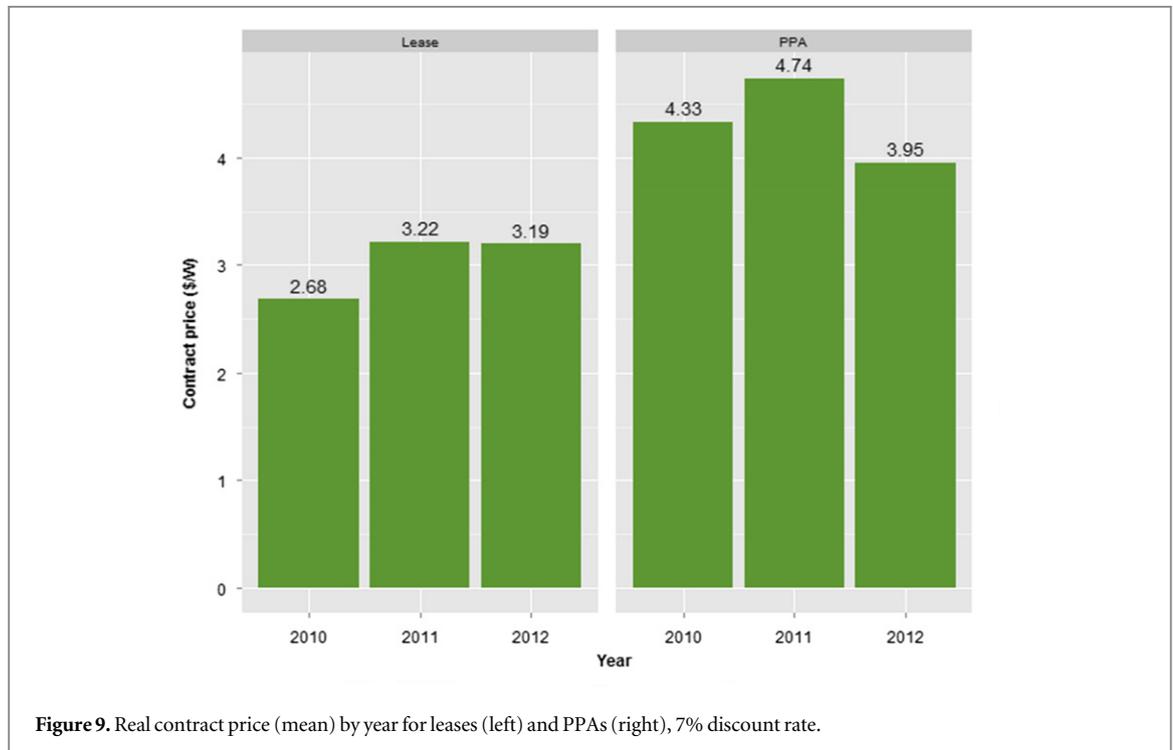


Figure 9. Real contract price (mean) by year for leases (left) and PPAs (right), 7% discount rate.

while lease prices remained flat (figure 9)¹¹. While

¹¹ The increase in lease prices between 2010 and 2011 was found to be statistically significant at <1%, however the difference between lease prices in 2011 and 2012 was statistically insignificant. The increase and subsequent decrease in PPA prices in 2010, 2011 and 2011, 2012, respectively, are both significant at <1%.

difficult to isolate the cause of these changes without further data, this suggests that factors beyond the installed cost of systems drive trends in contract prices. This may reflect costs associated with the TPO model (acquiring financing, operations and maintenance, system monitoring), outlined in Feldman

and Friedman (2013), but also likely reflects consumer demand dynamics.

We would also expect to observe economies of scale based on system size in contract prices, because larger systems enable the installer to spread certain fixed or lumpy costs (system permitting, business overhead) over a larger installed system. Barbose *et al* (2014) found that the mean installed reported price, nationwide, for systems of 5–10 kW was approximately \$0.50/W lower than for systems of 2–5 kW in 2012¹². Similarly, Davidson and Steinberg (2013) found a difference of approximately \$0.70/W, focusing on host-owned systems in California. Our data suggests that contract prices (for leases and PPAs) are higher for small systems (2–5 kW)—statistically significant at <5%, but exhibit no statistically significant difference in price between 5 and 15 kW (figure 10)¹³. There is no notable difference in the distribution of leases and PPAs across the difference size categories—70–75% are between 2 and 7 kW, and ~25% are 7–10 kW for both contract types,

Each of these systems is associated with a corollary publically-reported price. While in the case of host-owned systems, this represents the transaction between the system owner (homeowner) and the installer, in the case of TPO systems, this can represent either the appraised value of the system (by an independent third-party), or the price of an intermediate transaction between the installer and the financier. We would expect reported prices to be higher than the end customers' price as lease/PPA prices net incentives (in this case, the CSI rebate, ITC and MACRS depreciation). The reported prices for the systems in our sample exhibit a wide range from \$5.10/W to \$7.98/W (20th and 80th percentile), with a mean of \$6.38/W. Figure 11 illustrates the distribution of differences between prices reported to the CSI and the calculated contract price for each system in our sample. This illustrates a \$2.96/W difference, on average, though the distribution shows two peaks. While reported price and contract price are distinct metrics, they may be assumed to be strongly correlated given that they represent different transactions for the same system—but this is not the case in our sample. The Pearson correlation coefficient between the two metrics is 0.08.

Discussion and implications

The real contract price (discounted sum of all lease/PPA payments) of both leases and PPAs exhibit a range

¹² This excluded systems categorized as providing an appraised value, rather than a system cost.

¹³ For this study, we did not have access to detailed system cost information that would fully characterize the costs of a given system. The cost—particularly the labor requirements—will vary by house based on factors such as system layout and roof structure/obstructions.

of over \$7/W based on a 7% discount rate. Our findings suggest that differences in total contract price are partially driven by differences in contract structure and timing, although we note that a number of other factors may be contributing to these differences as well, not least of which is consumer willingness to pay, and price discrimination by installers.

First, we find that, on average, PPAs cost \$1.23/W more than leases assuming a 7% real discount rate—though this difference declines to \$0.52 when evaluating no-money-down contracts (the majority for the most recent year of data)¹⁴. Absent differences in payment timing, a number of potential reasons explain why a contract structured as a PPA costs the customer more than a lease, on average. The following are three potential factors:

- (a) A PPA, relative to a lease implies two risks to the owner/financer: (1) seasonal revenue difference—lower revenue in winter months when systems are producing less; (2) ongoing production variance. The downside risk of system underproduction (due to cloud cover, low insolation, soiling, malfunction) is transferred from the host to the owner/financer since the host pays only for actual electricity generated. The owner/financer can be expected to be compensated for bearing this risk, and the host customer may be willing to pay a premium to reduce this risk. Further, PPAs typically stipulate a payment cap, regardless of production. The potential to receive 'free' energy if the system produces more than estimated in the contract may increase the host customer's perceived value.
- (b) Due to this payment cap, system production may be overestimated (in the contracts) by the owner/financer in order to minimize the likelihood that 'free' energy is delivered to the customer above the cap. Estimates of monthly payments rely on production estimates, so if a system produces less than the amount estimated in the contract, the customer ultimately pays less than anticipated. Without system design parameters, there is no way to validate estimates of system production.
- (c) Most companies that provided PPAs did not provide leases, so this could reflect installer-specific practices.

Second, we find that prepaid contracts, on average, cost less than no-money-down contracts at discount rates up to 17%—suggesting that consumers may have very high discount rates. This figure is consistent with the low end of implied discount rates for PV lessors in Rai and Sigrin (2013). Further, since a prepaid contract is analogous to purchasing a system in terms of payment timing, insights can be applied from research on the financial tradeoffs of buying versus leasing in other

¹⁴ This difference is found to be statistically significant at >0.1%.

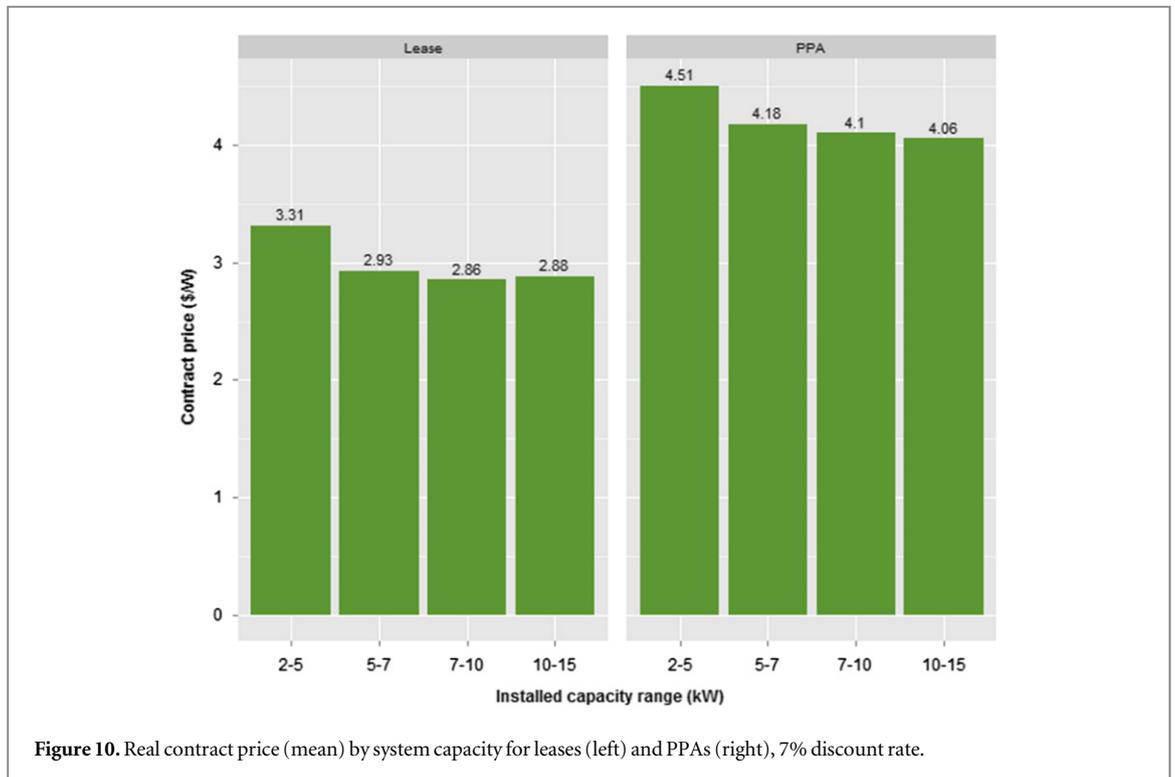


Figure 10. Real contract price (mean) by system capacity for leases (left) and PPAs (right), 7% discount rate.

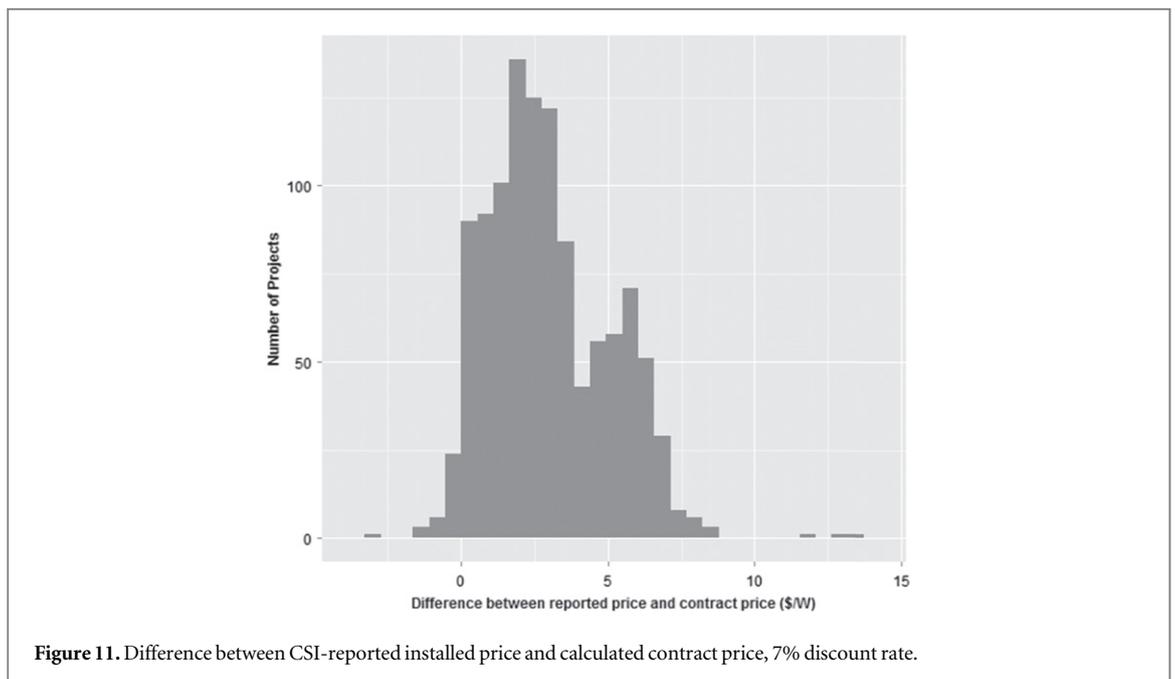


Figure 11. Difference between CSI-reported installed price and calculated contract price, 7% discount rate.

consumer durables. Typically, financial analysis suggests that monthly leasing provides a greater benefit than prepaying a lease (assuming this is analogous to a purchase) when the discount rate that equates the two cash flows is less than the after-tax rate of return that the lessee can obtain on invested capital. Although the implied discount rate in consumer durable markets sometimes appears high, this may be attributed to other consumer values. For example, Dasgupta *et al* (2007) and Nunnally and Plath (1989) found that the implied discount rate for automobile leases were higher

than available returns on capital, but Mannering identified frequency of vehicle upgrades as a consumer value that could explain this consumer behavior¹⁵.

However, analogies to other consumer durables are limited in that the adoption decision of a typical consumer durable does not directly offset another

¹⁵ It is possible that some customers may not have the access to inexpensive capital to prepay a lease (savings, home equity lines of credit, etc)—but unlikely, as financiers typically require a FICO score >700 to qualify for a lease or a PPA.

substantial household cost. Given a sufficiently high monthly savings on electricity costs, a homeowner may prefer to save their cash or divert it to other purposes, and opt for a monthly lease/PPA, foregoing the relatively higher return by not prepaying the lease¹⁶.

Third, we find that changes in key drivers of installed costs do not necessarily impact the price of a TPO contract to the customer. This is reflected in the fact that TPO contract prices do not consistently decline over the period of analysis, though we do see modest evidence of economies of scale based on system size. In the absence of sufficiently informed customers, firms can price discriminate, selling systems above their marginal cost at prices influenced by consumers' willingness-to-pay. A consumer's willingness-to-pay for PV is, in part, a function of the savings produced by offsetting purchased electricity. However, without access to pre-solar electric bills, we cannot test whether this drives contract prices. As a relatively nascent market, several factors likely preclude competitive TPO pricing, including asymmetric information regarding attributes of PV systems and high search and cognitive costs to seek and compare quotes.

Conclusion

This analysis indicates that the choice of contract type and payment structure may have implications for the total cost to the customer over the lifetime of the contract. Our sample data suggest the following findings:

1. PPA contracts appear to cost more than leases, and this trend persists when contracts are categorized by the amount of upfront payment. This could be driven by several factors, including higher perceived value/lower risk of the PPA contract structure to the customer, company-specific pricing for companies that only offer PPAs, and/or overestimating system production resulting in higher *apparent* PPA payments per watt¹⁷.
2. Delaying lease payment increases the total price to the customer at most plausible discount rates. Specifically, no-money-down contracts are more costly than pre-paid lease contracts assuming a customer's rate of return is lower than 17%.
3. Contracts that include escalator clauses cost more over the lifetime of the contract, for both PPAs and leases, at most plausible discount rates.

¹⁶ However, in these cases, assuming a homeowner can access a sufficiently low interest rate home equity loan, it would be advantageous to prepay a system with a home equity loan.

¹⁷ PPA contract costs are estimated based on assumed production—and may be ultimately be higher or lower depending on realized system production.

Variation in contract prices across different contract structures suggests insufficient customer information and/or very strong customer preferences for certain contract structures. There are likely high search costs and high cognitive costs involved in obtaining multiple bids and comparing bids that might vary by factors such as system size/configuration and perceived quality in addition to variations in contract structure. Future research could better evaluate the degree to which customers are electing the optimal choice by evaluating quotes to the same homeowner, and accounting for the full economic value of the system by understanding a homeowner's pre-solar electricity expenditure.

However, as the market continues to develop, increased competition, particularly in regions with an active solar market, will likely put downward pressure on TPO prices. Tools and resources that facilitate sharing contract bids and/or comparing multiple bids can reduce information asymmetry by reducing the search cost for consumers and providing data on prices for similarly sized systems.

Our study indicates that, while installed PV costs have declined rapidly, the real contract price to the customer has remained largely unchanged. Appealing to a broader market, particularly homeowners with lower electricity expenditure and/or in areas with less abundant sunlight may require offering lower-cost contracts to homeowners.

Acknowledgments

The authors would like to thank Camron Barati for his diligent data collection, without which this report would not be possible. The authors would also like to thank James Loewen, Ben Sigrin, Galen Barbose, Ted James and Laura Vimmerstedt for their support and input.

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Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners

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Technical Report
NREL/TP-6A2-46723
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Prepared under Task No. PVB9.4210

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Acknowledgements

The U.S. Department of Energy's (DOE) Solar Energy Technologies Program funded this work. The authors wish to thank participating DOE staff—Tom Kimbis and Charles Hemmeline—for providing useful insights and overall direction to this project. The authors are also grateful for the guidance and helpful input of the project managers, Robert Margolis and Selya Price of the National Renewable Energy Laboratory (NREL). We would also like to thank the individuals, who reviewed drafts of this report, including James Newcomb, Paul Denholm, and Jason Coughlin of NREL; Sarah Truitt, Sentech Inc.; Rick Gillman, SunEdison; and Lincoln Pratson, Duke University. Also, a special thank you goes to Jason Keyes and Kevin Fox of Keyes and Fox, LLP for providing ongoing support and expertise for this project.

The authors are also grateful to the interviewees for reviewing our descriptions of their programs and activities in the market and for providing additional clarifications. Thank you to Rusty Haynes, North Carolina Solar Center/Database of State Incentives for Renewables and Efficiency (DSIRE); Kathe Doran, CPS Energy; Renee Guild, formerly the Public Utilities Commission of Nevada; Michael Niver, SolarCity; Tammy Cordova, Public Utilities Commission of Nevada; Paul Danielsen, Mark Kapner, Austin Energy; Richard Mignogna, Colorado Public Utilities Commission; Cindy Miller, Florida Public Service Commission; and Ray Williamson, Arizona Corporation Commission.

Finally, the authors also offer their gratitude to Mike Meshek and Jim Leyshon of the NREL communications department for providing editorial support and graphics respectively.

A Note on the Revisions

This report, as originally published, contained editorial errors that have been corrected in this revision. No changes, except those noted here, changed the authors' intent.

- Page 8, last paragraph: Like the CPUC-recommended decision, SB 51 confirmed that third-party owned systems of any size are not subject to regulation by the CPUC providing they do not generate more than 120% of the customer's average annual consumption.
- Page 25, last paragraph: Under the most common of these, the solar lease, the customer does not pay for the equipment but receives the electricity generated from that equipment.
- Page 34, paragraph 5: However, if the utility contributes financial incentives or rebates to a project, the utility or their regulator might require the RECs to be transferred to the utility.

List of Acronyms and Abbreviations

C&I	commercial and industrial
CPUC	Colorado Public Utilities Commission
CREB	clean renewable energy bond
CSI	California Solar Initiative
dba	doing business as
DG	distributed generation
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables and Efficiency
EIA	Energy Information Administration
ESS	electrical service supplier
FERC	Federal Energy Regulatory Commission
IOU	investor owned utility
IREC	Interstate Renewable Energy Council
IRS	Internal Revenue Service
ITC	investment tax credit
kWh	kilowatt-hour
LLC	limited liability company
LSE	load serving entity
MACRS	Modified Accelerated Cost Recovery System
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
OPUC	Oregon Public Utilities Commission
PPA	power purchase agreement
PUCN	Public Utilities Commission of Nevada
PURPA	Public Utility Regulatory Policy Act
PV	photovoltaic
QF	qualifying facility
REC	renewable energy certificate
RES	renewable electricity standard
RPS	renewable portfolio standard
SREC	solar renewable energy certificate
SSA	solar services agreement
WAPA	Western Area Power Association

Executive Summary

Many end users of electricity would like to use on-site photovoltaic (PV) generation to hedge against volatile electric utility bills and reduce climate change impacts. However, PV systems have high initial costs, and they must be properly operated and maintained to deliver expected benefits.

Providing a potential solution to these cost challenges is a model in which a third-party owner uses a power purchase agreement (PPA) to finance an on-site PV system. This model—the third-party PPA model—allows a developer to build and own a PV system on the customer’s property and sell the power back to the customer. In addition, the third-party PPA model enables the customer to support solar power while avoiding most or all initial costs as well as responsibilities for operations and maintenance, both of which typically transfer to the developer. These advantages appeal to owners of residential and commercial buildings who would like to obtain solar PV systems.

However, third-party electricity sales face regulatory and legislative challenges in some states and jurisdictions. Several of these challenges pertain to whether third-party owners are deemed to act as monopoly utilities, competitive service suppliers (competitive suppliers), or both depending on the degree of retail electricity market deregulation. If third-party owners are deemed to act similarly, according to state definitions or state public utility commission (PUC) definitions, the third-party owners may also need to be regulated by the state PUC. Third-party owners of solar PV systems face an additional challenge if they are not allowed to net meter,¹ as this is a significant financial incentive to owning these systems.

Legislative and Regulatory Challenges with Third-Party PPA Model

Five legislative and regulatory issues that challenge the third-party PPA model—and the solutions that several states have applied to them—are summarized below and in Table ES-1.

- **Challenge 1—Definition of Electric Utility as Seller of Electricity:** Because third-party owners sell electricity to site hosts or end users, their systems may require PUC regulation when the state defines a public electric utility (or electrical corporation in California) as a retail seller of electricity. Also, some municipal utilities prohibit others from selling power to their customers and require their customers to buy power exclusively from them.

State Solutions: Colorado, New Mexico, and California determined that third-party owned systems are not utilities or electrical corporations and non-traditional power generators are not utilities, and are therefore exempt from PUC regulation.

¹ With net metering, an electric meter tracks net power usage—the difference in the amount of electricity provided by the utility and the amount generated by the PV system.

- **Challenge 2—Power Generation Equipment Included in Definition of Electric Utility:** When the definition of electric utilities includes power generation equipment (such as solar PV equipment), third-party owned systems may face regulatory challenges.

State Solutions: Nevada and Oregon excluded third-party owned renewable energy systems (specifically solar and wind power in Oregon) from the definition of a public utility in PUC regulations.

- **Challenge 3—Definition of Provider of Electric Services:** Third-party owned systems in regulated or partially restructured (“hybrid”) states may encounter challenges when legislation or regulation defines utilities or competitive suppliers in a way that includes those providing electric services. This is problematic for third-party owners who provide services to site hosts or end users.

State Solutions: Oregon decided that third-party owned systems are not competitive suppliers (known as electricity service suppliers in Oregon) because they do not provide ancillary services.

- **Challenge 4—Muni and Co-op Concern over Opting into Deregulation of Electricity Generation:** Third-party ownership of systems is still an issue in Texas within municipal and co-op jurisdictions. Municipal utilities (munis) and rural cooperatives (co-ops) are concerned that by allowing a third party to sell power to customers within their service territory, the public utility commission would force them to allow customers to choose retail electricity service suppliers.

State Solutions: Third-party ownership of systems remains an open issue in Texas within municipal and co-op jurisdictions.

- **Challenge 5—Determining Whether Third-Party Owned Systems May Net Meter:** Although net metering provides a significant financial incentive, it is not available in all states.

State Solutions: According to legislation in New Jersey, qualifying facilities include customer-generators that use power from solar PV systems sited on their property (i.e., customer-generators do not have to own the solar PV system). However, this issue remains unresolved in Texas where there are no plans to address it via regulatory or legislative changes.

Alternatives to Third-Party PPA model

Although third-party owned systems have faced regulatory and legislative obstacles in several states, all states that have tried recently have overcome these challenges. Florida examined this situation in the late 1980s and did not develop a solution; but the issue has not been addressed recently. And, while the potential solutions described in this report are state-specific, they likely could be applied in other states that want to encourage solar PV deployment by allowing third-party owned systems. When legislative or regulatory solutions cannot be found, end-use electricity customers may pursue alternatives to the third-party PPA model, including:

- **Solar leases:** Under a solar lease, the customer does not purchase power from a third party but simply leases equipment and receives the power generated by that equipment. This solution has been used in Florida, which does not allow the third-party PPA model. Although it avoids the retail sale of electricity, the solar lease model creates challenges for the use of the federal tax credit and accelerated depreciation.
- **Utilities as Contractual Intermediaries:** A utility may act as a contractual intermediary. Under this arrangement, the third-party owner sells power from the solar PV system to the utility, which, in turn, sells the power back to the site host/end-user.
- **Standardized Contract Language:** Standardized third-party PPA contract language protects customers and reduces the likelihood the PUC will disallow the third-party PPA model or require future regulation.
- **Utility Ownership:** Utilities that own solar PV systems sited on customers' properties could take the federal investment tax credit (ITC) to reduce the capital costs of owning solar PV. However, this model is not as market oriented as others and could exclude third-party solar developers from the utility service territory.
- **CREBs:** For states and municipalities that want to install solar PV on government property, clean renewable energy bonds (CREBs)² offer an alternative financing mechanism to the third-party PPA model. However, some projects may be too large to qualify and project owners had to apply by August 2009 to secure a CREBs allocation.
- **Waived Monopoly Powers:** The state PUC and utility may work together to jointly waive the monopoly power rights of the incumbent utility. While this solution is not typical and less feasible than other alternatives, it was applied in Colorado until legislation was passed that replaced this arrangement. With consent from the PUC, the monopoly utility allowed projects financed under the third-party PPA model only when the projects provided renewable energy certificates (RECs) to the utility.

² The Internal Revenue Service (IRS) issues CREBs. They are an alternative to tax-exempt bonds that pay out as tax credits instead of interest payments. For more information, see Appendix D.

Table ES-1. Summary of Solutions to Third-Party PPA Model Regulatory Challenges

Challenge	1. Definition of Electric Utility Includes Seller of Electricity	2. Definition of Electric Utility Includes Power Generation Equipment	3. Definition of Competitive Supplier or Utility Includes Provider of Electric Services	4. Munis and Co-ops Concerned with Opting into Deregulation of Retail Electricity Generation Markets	5. Third-Party Owned Systems May Not Net Meter
Solution					
<u>PPA Solutions</u>					
Clarify third-party owned systems are <i>not</i> utilities or competitive service suppliers	CO	NV		**	
Exempt non-conventional generation (including solar) from definition of electrical corporation or public utility	CA	OR (solar and wind only)			
Rule third-party owned systems are legal and do not require PUC regulation	CO	NV		**	
Decide third-party owned systems do not provide direct ancillary services			OR		
Allow net metering for systems <i>used</i> by customer-generators					NJ
<u>Alternative Solutions</u>					
Solar Lease (except for government or non-profit entities)	*	*	*	*	*
Developer Sells Power to Utility	*			*	*
Utility Owns Customer Sited Assets	*	*	*	*	*
Clean Renewable Energy Bonds ^a	*	*	*	*	
Utility and PUC Waive Monopoly Rights ^b	*	*	*		
Waiving of DG registration	*	*	*	*	

State abbreviations indicate that this solution has been applied there.

* Indicates a probable solution with no barriers identified.

** Indicates a possible solution that requires further investigation

^a This solution is only applicable for state and municipal solar PV installations that apply to the IRS for an allocation.

^b This solution, which requires PUC and utility approval, is possible but not as feasible as other alternatives.

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1 Introduction

The third-party PPA model is quickly becoming the financing method of choice across a wide range of PV generation market segments (Frantzis et al. 2008) and is even finding a niche in the residential and federal markets. However, use of this finance model may be inhibited if it conflicts with state legislation and regulation that was established before third-party ownership was used to finance renewable energy projects.

State regulations and legislation concerning the electric generation sector often define utilities and competitive service suppliers (competitive suppliers), and these definitions often become the starting points for determining which entities require regulation by the state PUC.³ However, many of these regulations were written when monopoly utilities or competitive electricity suppliers were the main providers in electricity markets. Thus, the regulations do not account for a finance model in which a non-utility entity owns power generation equipment and sells the power generated by this system to a customer. Therefore, in states where utilities or competitive suppliers are defined (a) as sellers of electricity, (b) owners of power generation equipment, or (c) providers of electricity services, the third-party owners that meet the State or PUC definition of utilities or electricity service suppliers may be interpreted as such. If third-party owners are interpreted as meeting these definitions, they might face regulation as a utility. In deregulated retail electricity markets where only munis and co-ops maintain monopoly rights over their service territories, these entities may not allow third-party owned systems if regulation does not clarify whether they would be opening themselves up to customer choice.

In addition to facing regulatory uncertainty, developers using the third-party PPA model may be disincentivized to install solar PV in states where systems using this finance model are not allowed to net meter. Thus, the deployment of solar PV may be hindered in states where third-party owners are uncertain if they will be regulated or allowed to net meter. This paper explores these regulatory conflicts between third-party ownership, state laws, and PUC decisions. It also looks at how particular states have dealt with these challenging issues and explores existing and potential ways to address them.

Section 1 introduces the third-party PPA model, regulation of electric markets, and the related legislative and regulatory challenges. Section 2 describes the third-party PPA model for financing PV projects at customer sites. Section 3 summarizes electricity markets in the United States and explains why markets are regulated and related issues. Section 4 explores in depth several legislative and regulatory challenges to using the third-party PPA model, using California, Colorado, Florida, Arizona, Nevada, New Jersey, Oregon, and Texas as examples. This section also details solutions or answers to these challenges, including legislative and regulatory solutions, and suggests other situations in which these solutions could be applied. Additional solutions, including variations of the third-party PPA model and alternatives to the third-party PPA model, are given in section 5.

³ In addition to facing state regulation, the third party PPA model could be subject to regulation by the Federal Energy Regulatory Commission (FERC). However, in a recent declaratory order, FERC ruled that they do not have jurisdiction over behind-the-meter third-party PPA solar generating systems (FERC 2009a).

2 The Power Purchase Agreement (PPA)

Traditionally, the PPA was a vehicle for utilities to purchase energy from each other. With the dawn of the Public Utility Regulatory Policy Act (PURPA) in 1978, utilities were required to purchase all of the power from qualifying facilities (QFs) generating renewable assets under 80 MW (FERC 2009b). Utilities used the PPA to purchase from independent generators (the QFs) under long-term stable-priced contracts. PPAs involving QFs are not as common with recent Federal Energy Regulatory Commission (FERC) Orders weakening the utilities' mandate to buy power from QFs and promoting wholesale electricity competition through the opening of transmission access.⁴ However, today utilities are signing PPAs with independent power producers for non-utility owned generating plants, for example to meet state renewable portfolio standards (RPS).

2.1 History and Explanation of the Third-Party PPA Model

While the traditional PPA is still the mechanism of choice for utility power purchases, in 2006 a new structure developed that uses a PPA to cater to the distributed generation (DG) markets.⁵ SunEdison and Renewable Ventures (formerly MMA Renewable Ventures) pioneered this financing model (Johnson 2008; Renewable Ventures 2009), which was quickly employed by others developers. As Figure 1 indicates, the use of PPAs as a financing model for non-residential solar PV installations has grown rapidly since 2006, taking over other financing models in 2008; this trend is expected to continue through 2009 (Guice and King 2008).

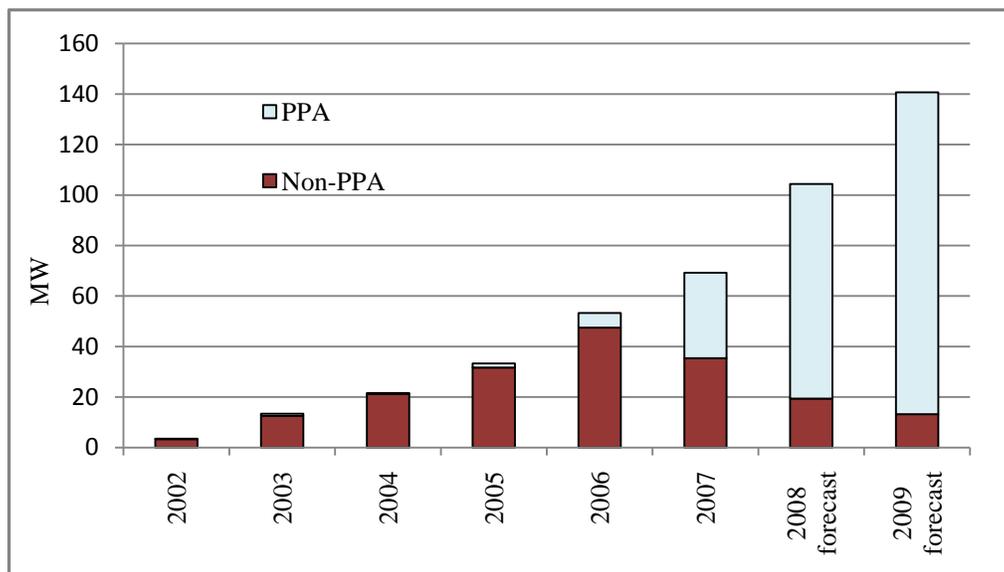


Figure 1. Use of PPAs for U.S. non-residential solar PV installations

⁴ The goals of FERC Order 888, issued in 1996, were “promoting wholesale competition through open access non-discriminatory transmission services by public utilities” and the “recovery of stranded costs by public utilities and transmitting utilities” (FERC 2006). These changes led to fewer PPAs (Stoel Rives 2006). FERC Order 688 also removed the mandate that utilities “must buy” the power from QFs if they were greater than 20 MW and have access to one of three major wholesale markets (Stoel Rives 2006).

⁵ DG is meant to encompass a variety of sizes of projects located behind customer meters. The larger the customer and the more electricity demanded, the larger the DG system can be. While this can be as small as 2 kW for residential systems, it can be up to 2 MW for large commercial and industrial customers.

Figure 2 details the third-party PPA model where a customer interested in hosting solar panels signs a PPA with a project developer who builds, owns, and operates a solar energy system on the customer's site, also known as the host site. The developer then sells the electricity back to the customer via the long-term PPA. In effect, this allows the customer to have the benefits of solar power while transferring the up-front capital costs to an entity designed to capture available tax benefits (with a potentially lower cost of capital) and foregoing the logistics of financing, building, and maintaining the system. The third-party PPA model is depicted in Figure 2 and is described in detail in Appendix A.

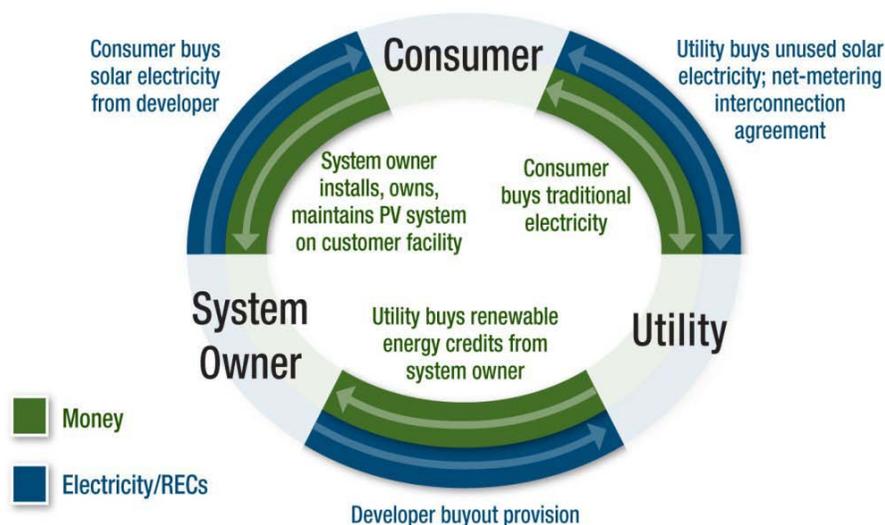


Figure 2. Third-party PPA model
(DOE Solar Energy Technologies Program)

In the PPA contract, a developer receives a combination of revenues and incentives that include electricity sales, sales of environmental attributes (RECs), cash incentives, and state and federal tax incentives in return for paying for the project up front. The customer and developer determine the right mix of up-front cost and payment for electricity sales to meet the developer's required rate of return. This means that customers who want to avoid paying any up-front costs will typically pay more for electricity.

2.2 The Benefits of the Third-Party PPA Model

One of the largest barriers to the deployment of solar energy systems is the high up-front cost. The recent emergences of financing structures that address this challenge have helped spur a significant increase in solar PV installations in the United States. In 2008, over 18,000 new PV systems were installed in the United States that generated 292 MW of the total 342 MW connected to the grid (SEIA 2009). The transfer of the up-front capital costs to an entity with greater access to capital, lower cost of capital, or greater ability to utilize tax specific incentives has been critical to commercial and industrial (C&I) customers adopting the technology. Although this financing model could be used for other installation types, it is primarily used for behind-the-meter installations (i.e., installations that affect only the use of the customer who hosts the installation) (Cory, Coughlin, and Coggeshall 2008).

3 U.S. Retail Electricity Markets and Third-Party PPA Model Interactions

Before examining the regulatory issues (Section 4), the context of state attempts to deregulate retail electricity generation markets must be understood. The level of restructuring in state retail electricity markets varies along a wide spectrum. While some states may be clearly defined as having traditionally regulated retail markets, other states may have “hybrid” markets that have characteristics of both regulated and deregulated electricity markets.⁶ Examples of hybrid markets include California, New Jersey, and Oregon.

In states with regulated, vertically integrated utilities, third-party owners of PV must understand the regulatory framework within which they operate. First, the state’s definition of a utility may be problematic. In some states, selling power to an end-use customer may mean that the third-party provider would be considered a utility and therefore need to be regulated by the utility regulators. In a few states with ample incentives or REC markets, the third-party owners have tried to get the regulations or laws changed (examples are discussed below).

In states with deregulated retail electricity markets, third-party owners must be aware of the regulations faced by competitive suppliers. And where hybrid markets exist, third-party owners need to be knowledgeable of how utilities and competitive suppliers are defined and where they are active. Developers using the third-party model in hybrid states should investigate whether munis and co-ops will allow these systems, especially in states like Texas where these utilities are concerned that this could open their territories to deregulation of the generation market. Lastly and in all types of markets, states must address whether third-party owned systems are allowed to net meter if they want to encourage the deployment of solar PV projects using the third-party PPA model.

When assessing the feasibility of third-party ownership, PUCs must consider consumer protection and grid safety. PUCs must also consider the degree to which third-party PPA models should be regulated, if at all. This section looks at the pros and cons of allowing third-party ownership in regulated and hybrid retail electricity markets, and it details some state positions on this issue.

3.1 Why Retail Electricity Markets are Regulated

Retail electricity markets in the United States remain regulated in most states in part to protect consumers (rates and reliability) and to ensure a highly functioning electric grid. If anyone could freely connect a generator to the existing grid, the electricity supply could become volatile and unsafe, which could cause congestion, blackouts, and maintenance concerns. Additionally, regulation of these markets prevents unnecessary duplication of assets such as transmission and distribution facilities. Regulated investor-owned utilities are given monopoly status in most service territories to prevent such problems. By having a single entity control the system, a utility can balance constantly changing supply and demand to ensure reliability and keep the electricity flow on the grid optimized and safe.

⁶ This is a simplifying assumption—that no market has fully achieved competition in the retail electricity generation markets—that could be debated. However, in many states, the default utilities are still serving substantial portions of the load, so it is difficult to say that any retail electricity generation market is truly deregulated.

States dealing with high power prices in the 1990s began considering deregulating retail electricity markets to lower prices by creating competition among generators supplying electricity (Borenstein 2000). With the relative success of deregulation in the wholesale electricity market, several states began to deregulate retail sales and allow customers to choose where and how they purchased their power. Throughout this electric system restructuring process, most municipal utilities (munis) and rural cooperatives (co-ops) remained regulated by their cities (i.e., by city council members) rather than opening up their territory to competition. Therefore, in most states that restructured, munis and co-ops continue to operate under different rules and regulations than do investor owned utilities (IOUs). Although views on the effectiveness of restructuring vary—and some states are taking steps to re-regulate generation—there are a number of states where customers (sometimes just non-residential customers) continue to choose their power providers.

3.2 Legislative Issues and Challenges with Regulated Retail Electricity Generation Markets

Generation deregulation can affect whether third-party owners are regulated. In electricity markets where the retail customer has consumer choice of their power provider, the third-party PPA model may pose fewer legislative issues. If the utility does not have monopoly power over a given customer base, the customer can choose to purchase power from a company that has placed a solar PV system on its roof or from a competitive supplier, or from both. However, even in a deregulated market, customers may not be incentivized to use the third-party PPA.

Notably, not all states have clearly regulated or deregulated retail electricity generation markets. In fact, some could be said to have “hybrid” markets with characteristics similar to both regulated and deregulated markets. Oregon is an example of a hybrid electricity market where third-party ownership is allowed and where a combination of IOUs, munis, and co-ops provide electricity to customers (State of Oregon 2007); the case of Oregon is discussed in further detail later. However, since most electricity markets in the United States have not restructured to allow customer choice (Showalter 2008; EIA 2008), any model in which an entity other than the monopoly utility sells electricity directly to customers may be prohibited. This legislative issue could significantly challenge third-party owned models.

3.3 Consumer Protection

Some state PUCs are asking if a third party owns a system and sells the power to a retail customer in the service territory of a regulated utility, does the utility commission need to regulate that entity to protect customers from fraud and to protect the security of the electric system? The same question could be posed if the third party owns a system and sells the power to a retail customer where markets are deregulated. In that case, the third-party owner may be considered a competitive supplier.

The utility commissions serve to protect consumers' interests by regulating rates and service quality. Additionally, they serve as a clearinghouse for customer complaints and are charged with dealing effectively with these matters. However, in the case of third-party owners, the PUCs may have no oversight or control over these competitive suppliers. This lack of oversight may pose a challenge for customers. Developers maintain they must provide a quality product to retain customers and remain competitive, and that detailed contract language assures the customer of what can be expected from the system and its owner (Danielson 2008). Moreover, the third-party model aligns the interests of the customer and developer as the project is paid for performance and will not be successful if it underperforms. At a minimum, the customer is usually protected by state consumer protection laws.

3.4 Interconnection Standards

Utilities may use interconnection standards, which provide safety provisions to protect the grid and utility workers, to integrate non-utility owned DG systems. Best practice interconnection standards follow engineering standards and FERC technical screens that maintain the safety of the grid and give DG customers stable policies for interconnection (NNEC 2008).

Interconnection standards consider the effects of size and location of distributed resources on the electric grid. In addition, interconnection standards include provisions about maintenance and the utility's right to disconnect the system if it identifies a problem. Interconnection standards, net metering policies, and other incentives are discussed in detail in Appendix B.

4 Regulatory and Legislative Issues and Challenges to the Third-Party PPA Model

Most state laws and regulations that complicate third-party ownership in monopoly territories have been in place for decades and did not originate specifically to prevent the third-party PPA model. In general, the third-party PPA model is not specifically outlawed. Rather, any entity that sells power to retail customers has to be regulated by the utility commission. Because regulation adds substantial cost and delay, it effectively removes a developer's incentive to offer services in a state. The regulatory language, which is different in each state, gives an idea of the prohibitions on third-party ownership in these markets. This issue is not limited to regulated or hybrid states as some states that have deregulated with respect to customer choice still have sub-markets that remain monopoly utilities (such as the previously mentioned munis and co-ops). The challenge in this case is third-party owners who are allowed to sell retail power to customers might open municipal utilities and rural electric cooperatives up to competition, thereby subjecting them to regulation by the PUC, which these small utilities may not desire (Cory, Coggeshall, and Kollins 2008). Additionally, some munis and co-ops have ordinances that protect their monopoly and do not allow for third-party developers in their territory. Also, there may be regulatory issues for third-party owned systems within deregulated electricity markets where systems using this finance model must abide by the same legal and public utility commission regulation as competitive suppliers.

Interviews with PUC officials across the country were conducted to determine the third-party PPA legislative issues that challenge states, the arguments being presented, and the solutions that may exist. The following describes five legislative and regulatory issues that several states have recently addressed. A few of these challenges have subtleties that depend on state or PUC definitions of utilities or competitive suppliers. All regulatory challenges and their possible solutions, as well as alternative solutions, are summarized in Table 1. Appendix C summarizes the language surrounding third-party ownership, and the status of third-party PPA models, in California, Colorado, Florida, Arizona, Nevada, New Jersey, Oregon, and Texas.

4.1 Challenge 1: Definition of Electric Utility as Seller of Electricity

In regulated markets where utilities are granted monopoly rights for selling electricity, definitions of utilities in PUC regulations or state legislation may prohibit third-party owned solar power generation systems. Because third-party owners of PV systems sell power to the hosts/end-users via the power purchase agreement, the owners could be considered sellers of electricity and thus utilities. Being considered a utility presents a challenge for developers wanting to use the third-party PPA model, as it would require that they be regulated by the state PUC. Regulation of third-party owned systems would add administrative costs and development time to projects, making this finance model less economically appealing.

In California, Colorado, Florida, and Arizona, utilities were defined as sellers of electricity, which created regulatory uncertainty for developers using the third-party PPA model. Colorado and California found legislative solutions for excluding third-party owned systems from being considered utilities; Colorado codified a previous regulatory solution and California addressed regulation of third-party owned systems several years ago.

4.1.1 California—Legislative Solution

California allowed the third-party PPA model for a number of years via a legislative decision. California Public Utilities Code 218 specifically allows certain ownership and technologies, and it promotes a clear path for long-term, customer-sited energy development. In fact, the code's definition specifically exempts an "Electrical Corporation" from regulation:

...a corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity solely for... the use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.

This language first establishes solar as an option by stating that non-conventional power sources are exempt. The key for the third-party ownership model is that a corporation can sell electricity if it is used solely on the property where it is generated. In fact, the electricity can even be sold to two other corporations or persons who are also on that property, according to the legislation.

California's language has several interesting implications. First, it allows third-party owners to sell to residential customers on an individual basis. Also, the exemption presents the possibility of selling power to multi-family housing units, as well as multi-tenant commercial and industrial buildings that are net-metered (with restrictions on the pricing of the power). However, the issue of selling power to tenants when the system is not net-metered remains unsettled. The state requires third-party owners to set up new independent business units (such as LLCs, or limited liability companies) for each commercial system they install in order to comply with the rules and use/employ the third-party PPA model.

When deciding whether a competitive supplier is subject to regulation as a public utility, California applies a standard of "dedication to public service." While states have interpreted differently what it means to offer service "to or for the public," California has interpreted their statutes in a way that provides an exception for the provision of power sales to a subset of customers such as tenants. Although California has consistently used this standard when interpreting the intention of power providers, the issue is still officially open.

4.1.2 Colorado—Legislative and Regulatory Solutions

Unlike California, Colorado did not allow third-party owned solar PV systems until very recently, at least not without the threat of PUC regulation. It was not clear if systems under 10 kW that were owned by third parties on a customer site would require regulation. In fact, the temporary response to this challenge was to allow Xcel Energy (Xcel), the state's largest utility, to waive monopoly rights for these smaller systems. That was until a challenge surrounding the regulatory uncertainty of third-owned systems was brought to the Colorado Public Utilities Commission (CPUC) at the request of SunRun, a residential solar developer that uses the third-party PPA finance model. SunRun wanted clarification on whether third-party owned systems smaller than 10 kW would be allowed. In February 2009, the PUC released a recommended decision (08-R-424E) in regard to changes to the renewable electricity standard (RES) confirming that systems less than 10kW are allowed, are not defined as utilities, and therefore, do not require CPUC regulation.

In addition, Colorado Senate Bill 51, which outlined the State's Renewable Electricity Standard, passed in April 2009, clarified whether third-party owned systems should be regulated (State of

Colorado 2009). Like the CPUC-recommended decision, SB 51 confirmed that third-party owned systems of any size are not subject to regulation by the CPUC providing they do not generate more than 120% of the customer's average annual consumption. The bill's specific language is:

The supply of electricity or heat to a consumer of the electricity or heat from solar generating equipment located on the site of the consumer's property, which equipment is owned or operated by an entity other than the consumer, shall not subject the owner or operator of the on-site solar generating equipment to regulation as a public utility by the commissions if the solar generating equipment is sized to supply no more than one hundred twenty percent of the average annual consumption of electricity by the consumer of that site.

Prior to the recent legislative and regulatory solutions, Xcel and the CPUC agreed to waive Xcel's monopoly rights on specific projects that provided it with RECs, thereby allowing it to comply with Colorado's RPS requirements, including a 4% solar set-aside. For systems over 100 kW, Xcel held a competitive solicitation for RECs generated from third-party owned PPA projects as well as selected winning proposals in order to meet Colorado's RPS solar set-aside mandate. Colorado also requires that 50% of the solar set-aside be customer-sited (DSIRE 2008a), and Xcel found the third-party ownership structure to provide an effective way of meeting that goal. However, Xcel provided this waiver only for those projects selected in its solicitation.⁷ This allowed the utility to decide which providers were allowed to serve the market for commercial-scale systems using the third-party PPA model. The recent state legislation and CPUC ruling provides stronger regulatory clarification, which is needed for the long-term development of third-party owned systems.

4.1.3 Florida—No Solution

Unlike Colorado and California, the third-party PPA model has not recently been debated formally in Florida. However, in 1987, the Florida Public Service Commission (FPSC) considered a proposed cogeneration project for which PW Ventures, Inc. (PW Ventures) would have sold electricity from their plant exclusively to Pratt and Whitney (the customer) to provide most of their power needs (*PW Ventures v. Nichols*, 533 So. 2d 281). Supplementary power needs and emergency backup power would have come from the local utility, Florida Power & Light. The definition of a "Public utility" as defined by Florida Statute 366.02 is:

Every person, corporation, partnership, association, or other legal entity and their lessees, trustees, or receivers supplying electricity or gas...to or for the public within this state.

In their ruling on the issue, the FPSC focused on the definition of "to or for the public." PW Ventures argued that to be considered a utility they would have to sell their power to the general public to be considered a utility. However, the Commission determined that the definition of "to or for the public" could mean *one* customer, meaning that by selling only to Pratt and Whitney, PW Ventures was selling to the public and would be deemed a public utility. Without a change in

⁷ Telephone conversation with Richard Mignogna, Professional Engineer, Colorado Public Utilities Commission, September 24, 2008.

statute, this ruling appears to eliminate the possibility of using the third-party PPA model in Florida without PUC regulation (FPSC 1987).

4.1.4 Arizona—No Solution

Arizona has not addressed the regulatory uncertainty about the third-party PPA model. As in Oregon, the retail electricity generation market in Arizona is a hybrid market where competitive suppliers are allowed to register and sell electricity within the utility's exclusive service territory, although no competitive suppliers are currently registered. However, according to the Arizona Corporation Commission, there are several solar PV projects that plan to use the third-party PPA model even though these project arrangements are not allowed.⁸ Article 15 Section 2 of Arizona's Constitution defines a public utility as a corporation that "furnishes" electricity or power, requiring that any entity furnishing electricity be regulated in Arizona. Because the definition is part of the constitution, the issue would likely require a legislative solution rather than a regulatory one.

The Solar Alliance, a consortium of solar manufacturers, integrators, and financiers, in 2008 appealed to the Arizona Corporation Commission for a declaratory order in an attempt to resolve the third-party PPA model matter in the state. The Solar Alliance requested that providers of certain solar service agreements not be considered public service corporations (and therefore not be regulated by the Commission). The docket outlines the characteristics of these solar service agreements and argues they are not public service corporations because they are not "clothed with the public interest," which legal precedent has determined is a characteristic of an entity that requires regulation. The Solar Alliance argues that they therefore, do not require the Commission's economic regulation (Arizona Corporation Commission 2008).

Interestingly, in 2007 the Arizona legislature passed HB 2491 to make third-party financiers eligible for the Arizona corporate solar tax credits (State of Arizona 2007). It is to be determined whether the third-party owners will be able to take advantage of this legislation.

4.1.5 Applicability Elsewhere

California's legislative solution is applicable in fully regulated, hybrid, or deregulated power generation and supplier markets where third-party power suppliers are considered by definition to be electrical corporations. Of course, this type of legislative solution, in which renewable energy power suppliers are exempt from being regulated, requires the support of state lawmakers and their willingness to change state laws.

The recent solution applied in Colorado—clarifying in an RES bill that third-party owned systems are legal—could also be applied in other states with fully regulated electricity markets. This type of solution makes sense in states passing new RES legislation as both RESs and the allowance of third-party owned solar PV systems support renewable energy deployment.

The prior solution used in Colorado—allowing a utility to waive its monopoly rights—could be applied in other fully regulated or hybrid electricity markets. However, this solution is less feasible because a public utility commission may not always allow a utility simply to decide

⁸ Telephone conversation with Ray Williamson, utilities division, Arizona Corporation Commission, September 23, 2008.

whether third-party owned systems should be allowed, and the utility may not agree to this policy. Nonetheless, this might be a solution in a state where the public utility commission or legislature has not established rules that clearly allow for third-party owned systems, but the utility and its regulators desire this option to meet an RPS requirement.

4.2 Challenge 2: Power Generation Equipment Included in Definition of Electric Utility

Third-party owned systems may fit the definition of a utility in states where regulations or legislation defines electric utilities as those that use power generation equipment for purposes other than personal use. This is because third-party developers own solar PV equipment that generates power sold to the site host. Developers who worry that third-party owned systems could be interpreted as utilities may choose not to install projects in these states.

Both Nevada and Oregon have dealt with the issue of third-party owned systems meeting the definition of public electric utilities, which included power generation equipment.

4.2.1 Oregon—Regulatory Solution

In Oregon, whether third-party owned systems should be considered public utilities came into question when third-party PPA model developers approached the PUC about net metering. The issue was brought to the Oregon Public Utilities Commission (OPUC) via a Petition for Declaratory Ruling pursuant to ORS 756.450 by Honeywell and PacifiCorp seeking clarity on Honeywell's use of the third-party PPA model. To clarify whether third-party owned systems could net meter, the OPUC considered the definition of public utilities. According to Oregon's net metering law, ORS 757.00, public utilities are defined as:

any corporation, company, individual, association of individuals, or its lessees, trustees or receivers, that owns, operates, manages or controls all or a part of any plant or equipment in this state for the production, transmission, delivery or furnishing of heat, light, water or power, directly or indirectly to or for the public, whether or not such plant or equipment or part thereof is wholly within any town or city.

Because third-party owned solar PV systems consist of equipment used within the state for the production of power, they may have to be considered as a utility in Oregon. However, whether third-party owned systems provide power "to or for the public" in Oregon is debatable because they would likely only provide power to one or two other users.

The Oregon legislature determined a solution prior to any PUC decision. PUC Order 08-388 found that according to ORS 757.005 a public utility does not include:

...any corporation, company, individual or association of individuals providing heat, light or power...*from solar or wind resources* to any number of customers (Emphasis added).

Thus, a third-party owned solar PV systems may not be considered a public utility because solar and wind power generation systems are specifically exempt from the definition even though the definition of a utility includes generation equipment.

The OPUC also considered whether third-party owned systems may be considered competitive suppliers. This is discussed in section 4.3.

4.2.2 Nevada—Regulatory and Legislative Solutions

In Nevada, the question of whether third-party owned systems should be regulated came about because they fit the definition of an electric utility, according to Nevada Statute 704-020, which defined a utility as:

any plant or equipment, or any part of a plant or equipment, within this State for the production, delivery or furnishing for or to other persons.... power in any form.

Thus, a third-party owned system could be deemed a utility because the equipment used to produce power is ultimately furnished “for or to other persons.”

On November 20, 2008, the Public Utilities Commission of Nevada (PUCN) formally addressed the issue of third-party owned systems, ruling in favor of third-party ownership (IREC 2008a). According to the findings, which were a result of a PUCN vote to expand a net metering docket to include the issue of third-party ownership, third-party owned systems are not utilities even though they use power generation equipment. In addition, the PUCN found in their Report on Third Party Ownership of Net Metering Systems in Nevada, that third party owners of net-metered renewable energy systems are not public utilities and beyond the jurisdiction of the Commission. The PUCN noted in its comments that allowing third-party ownership of net-metered systems is consistent with state policy goals to encourage the development of, and private investment in, renewable energy resources, stimulate economic growth in Nevada, and enhance the diversification of energy resources (IREC 2008a).

Notably, Nellis Air Force Base in Nevada had the largest U.S. solar PV system to use a third-party PPA model even before third-party ownership was allowed without regulation in the state. Nellis contracted with MMA Renewable Ventures to provide a third-party PPA for a 14-MW solar PV array (WAPA 2008). According to conversations with the PUCN,⁹ Nellis accomplished this because it is operated by a federal agency that has special exclusions in the state and as such can choose where to purchase electricity.

Finally, the 2009 Nevada legislature passed, and the Governor signed Assembly Bill 186, which, like Colorado’s legislative regulatory solutions, codifies the exemption of third party developers from regulation. The pertinent language is as follows:

Persons who for compensation own or operate individual systems which use renewable energy to generate electricity and sell the electricity generated from those systems to not more than one customer of a public utility per system if each individual system is:

(a) Located on the premises of another person;

⁹ Telephone conversation with Tammy Cordova, Assistant General Counsel, Public Utilities Commission of Nevada, September 23, 2008.

(b) Used to produce not more than 150 percent of that other person’s requirements for electricity on an annual basis for the premises on which the individual system is located; and

(c) Not part of a larger system that aggregates electricity generated from renewable energy for resale or use on premises other than the premises on which the individual system is located As used in this subsection, “renewable energy” has the meaning ascribed to it in NRS 704.7811.

4.2.3 Applicability Elsewhere

Nevada’s regulatory solution could be applied in states in which the definition of utility includes the use of power generation equipment to supply electricity to other persons or entities. Similar to Oregon’s solution (discussed in section 4.4), Nevada also looked to state policy goals, which support renewable energy deployment, to guide their own regulatory decisions.

4.3 Challenge 3: Definitions and “Competitive Service Suppliers”

Regulatory uncertainty for third-party owned systems may arise when the definition of either “provider of electric services” or “public utility” does not explicitly exempt third-party owned PV systems. Competitive suppliers provide electricity to customers within deregulated or hybrid electricity markets, where customers can choose their electricity supplier. However, a vague definition of a competitive supplier may lead to confusion about whether third-party owned systems require regulation as they too provide some degree of service to the site host, usually in the form of operations and maintenance. Also, in regulated markets, the definition of public utility might not clearly exempt third-party owned systems. This is the case in New Mexico, which is examining the issue.

4.3.1 Oregon—Regulatory Solution

Oregon, which has a semi-regulated retail electricity market, addressed the issue of the regulatory uncertainty surrounding the use of third-party owned systems via a PUC decision. The question for Oregon was whether a third-party provider qualified as an electrical service supplier—Oregon’s term for a competitive supplier. Oregon Legislative Statute 757.600 defines an “ESS” as:

A person or entity that offers to sell electricity services available pursuant to direct access to more than one retail electricity consumer.

“Direct access” is defined as:

The ability of a retail electricity consumer to purchase electricity and certain ancillary services, as determined by the commission . . . directly from an entity other than the distribution utility. (OPUC 2008)

Because third-party owners—who do sell electricity to hosts of solar PV systems and may sell to more than one retail electricity customer—would be considered electrical service suppliers under Oregon legislation and would need to be regulated by the state’s public utilities commission. As discussed previously, the regulation as an ESS (or utility) is a disincentive to develop third-party owned systems.

In Order 08-338 entered on July 31, 2008, the OPUC interpreted the definitions and statutes in a manner they felt met the legislation's intent (OPUC 2008), especially because the legislation was designed to increase renewable energy generation. To be considered an ESS in Oregon, the entity must provide "direct access" and use the utilities' distribution system. Entities are considered to provide "direct access" if they provide both electricity *and* "ancillary services," which are defined as:

Services necessary or incidental to the transmission and delivery of electricity from generating facilities to retail electricity consumers, including but not limited to scheduling, load shaping, reactive power, voltage control and energy balancing services. (OPUC 2008)

The OPUC recognized that ancillary services—which relate to the management of electric power delivered through the transmission and distribution grid—did not apply to the third-party owners who generated power on the customer's side of the meter and did not use the distribution system (OPUC 2008).

Even though most third-party owned PV systems participate in net metering in Oregon, DG systems there usually generate between 0.05% and 18% of the total electricity used in the state (OPUC 2008).¹⁷ As such, the third-party owned PV systems are not intended to be annual net generators and are thus not considered energy wholesalers, which would require the ancillary services of the distribution system (OPUC 2008). Systems typically produce less than the customer's annual electricity use because any net excess generation will not be credited to the site host. Rather, it is credited to the utility's low-income assistance program. In addition, the net metering limit on a project is 25kW for residential systems and 2MW for commercial systems.

4.3.2 Applicability Elsewhere

Oregon's solution has the potential to be applied in other electricity generator and supplier markets in which third-party owned systems are in conflict with the definition of a competitive supplier or public utility. Clarification that third-party owned systems are not considered competitive suppliers or utilities is important as both are regulated by the state PUC making doing business too difficult for third-party providers. In Oregon, public utility officials were supported by legislation that guided state policy on renewable energy generation. Having state legislation that explicitly encourages the deployment of renewable energy could help steer regulatory decisions made by utility commissions.

4.4 Challenge 4: Munis and Co-ops Resisting Opting into Deregulation of Electricity Generation

As discussed earlier, many of the challenging issues surrounding the regulation of third-party owned systems arises in regulated retail electricity markets, where they could be viewed as being in competition with monopoly utilities. However, in some deregulated retail electricity markets, municipal utilities and cooperatives were not required to deregulate. Thus, within the service districts of those munis and co-ops, third-party owned systems could be seen as being in competition with these local, smaller utilities. This is the case in Texas, which has not attempted to address the issue.

4.4.1 Texas—No Solution

Texas presents an interesting case regarding the regulation of third-party owned systems within the jurisdiction of municipal utilities and co-ops that, per usual, were not required to deregulate. Thus, in most of Texas, the third-party PPA model can be used as a financing mechanism. However, this financing mechanism only makes sense when the third-party PPA owner is not producing more electricity than it consumes, as net metering is not allowed anywhere in the state. In addition, in jurisdictions such as Austin and San Antonio where municipal utilities supply the electricity, third-party PPAs may not be an option (Cory, Coggeshall, and Kollins 2008).

The Texas Utilities Code Section 40.053(a) says:

If a municipally owned utility chooses to participate in consumer choice, after that choice all retail customers served by the municipally owned utility within the certificated retail service area of the municipally owned utility shall have the right of customer choice ..., and the municipally owned utility shall provide open access for retail service.

Though the Texas PUC has made no formal statement on the matter, municipal utilities are concerned they might open themselves to competition if they allow generators to sell electricity to their customers. Even though these utilities may want to allow the third-party PPA model to facilitate the adoption of solar power, they will not risk inadvertently exposing themselves to deregulation and competition in their service territory.

However, the third-party PPA developer could create a contract with the utility that would effectively allow the utility to buy the electricity and resell it to the site host. This solution, which is described in detail in section 5.2.1, requires that utilities work with customers and developers on a project basis. It also requires that utilities act as silent intermediaries and do not create administrative or cost barriers that might reduce the appeal of using the third-party model.

4.4.2 Applicability Elsewhere

Although no solution has been found, this challenge could arise in other states that have fully or partially deregulated electricity markets and where munis and co-ops worry that by allowing for third-party owned systems, they will open themselves up to competitive suppliers. However, the municipal utility regulators (usually the city council, which is often also the utility's board of directors), state regulators, or state legislators could make a regulatory or legal exception for using the third-party PPA model. And as discussed previously, alternative solutions such as using the utility as a contractual intermediary might be an option for developers wanting to use the third-party PPA model in Texas or other states in similar situations.

4.5 Challenge 5: Net Metering

Allowing third-party owned systems to net meter could facilitate the deployment of solar PV systems because the on-site generation reduces electricity purchased from the utility and any excess is credited to the customer bill. However, in some states, third-party owned systems may not meet the definition of facilities or customers that are allowed to net meter. Net metering has been problematic for third-party owned systems in at least two states, New Jersey and Texas, and only New Jersey offers a (somewhat vague) solution.

Neither New Jersey nor Texas has explicitly addressed whether third-party owned systems are allowed to net meter; however, both states demonstrate how the interpretation of regulations or legislation can alter whether third-party owned systems are allowed to net meter.

4.5.1 New Jersey—Legislative Solution

New Jersey does not have legislative or regulatory language that determines whether third-party owned systems are allowed to net meter. However, New Jersey Administrative Code 14:8-4.2 and 4.3, which outline changes to net metering and interconnection rules, (Docket #: EX08070548) define a “customer-generator facility” as:

...the equipment *used* [italics added] by a customer-generator to generate, manage, and/or monitor electricity. A customer-generator facility typically includes an electric generator and/or an equipment package.

New Jersey’s definition stipulates that the equipment need only be used by the customer; i.e., a customer-generator allowed to net meter is not required to own the generation equipment, and third-party owners are allowed to net meter (Keyes 2008).

4.5.2 Texas—No Solution

In Texas, where the retail electricity generation market is deregulated, the PUC claimed that *requiring* net metering is incompatible with deregulation, thus making the third-party PPA model financially less attractive as carrying excess generation forward would not be possible.

4.5.3 Applicability Elsewhere

New Jersey’s regulatory solution in which the PUC determined eligible customers only need to use the power generated by the facilities (regardless of ownership) could be applied in any state determining which kind of facilities are eligible to net meter. However, as noted previously, New Jersey was able to look to state legislation that clearly supports renewable energy deployment and make decisions in a consistent manner with the legislation. Thus, having state legislation that can serve as a guideline for PUC officials may help to create state regulations that support net metering for third-party owned/PPA financed systems.

Overall, implementing third-party PPA model financing is difficult in states where unclear legislation or regulations could result in the regulation of third-party PPA owners. Munis and co-ops might be concerned that allowing third-party owned systems to sell power to their customers will open their service territories to deregulation. The third-party PPA model is also problematic in states that do not explicitly allow net metering of third-party owned systems. Finding a one-size-fits-all policy solution is not possible when states not only define differently utilities and other competitive supplier, but also put in place different rules about what they can legally supply or how many customers they can serve. However, more parties are seeking resolution to these issues as evidenced by recent rulings in Colorado and Nevada, and a docket filing in Arizona.

See Appendix C for a summary of all the language variations explored in this section.

5 Alternatives to the Third-Party PPA Model

In cases where states have ruled against the third-party PPA model or where legislative change or PUC decisions are not feasible, the following alternative solutions may be applicable. Additionally, Clean Renewable Energy Bonds (CREBs) provide a potential alternative for munis and co-ops and are discussed in Appendix D.

5.1 Third-Party Ownership Solar Leases

The third-party solar lease model is sometimes called the solar services agreement (SSA) model. Like the third-party PPA model, it benefits from having a third party finance and own the solar energy system.

The solar lease is a relatively new way to provide customers access to on-site solar energy systems, however, the concept is the same as traditional equipment leases. Instead of purchasing a PV system, the customer enters into a service contract with a lessor (the owner) of a PV system and agrees to make fixed monthly lease payments (regardless of system generation) over time (Coughlin and Cory 2009). The customer consumes whatever electricity the leased system generates, net meters any excess or pays the utility rate for any additional electricity it requires.

5.1.1 *Benefits of the Solar Lease*

The benefits of the solar lease mirror most of those associated with the third-party PPA model, including transferring most or all of the up-front cost, using a developer who can partner with a tax equity investor to take advantage of federal tax incentives, and if indicated in the contract, transferring maintenance responsibilities to a qualified party. However, the price of electricity will differ somewhat because the customer effectively pays a set price for the equipment (and sometimes maintenance) and not the electricity itself. Ideally, monthly electric bill savings will equal, if not exceed the lease payments (which take into account available state and federal incentives) to create a cash neutral or cash positive transaction. Figure 3 presents the parties involved in the solar lease.

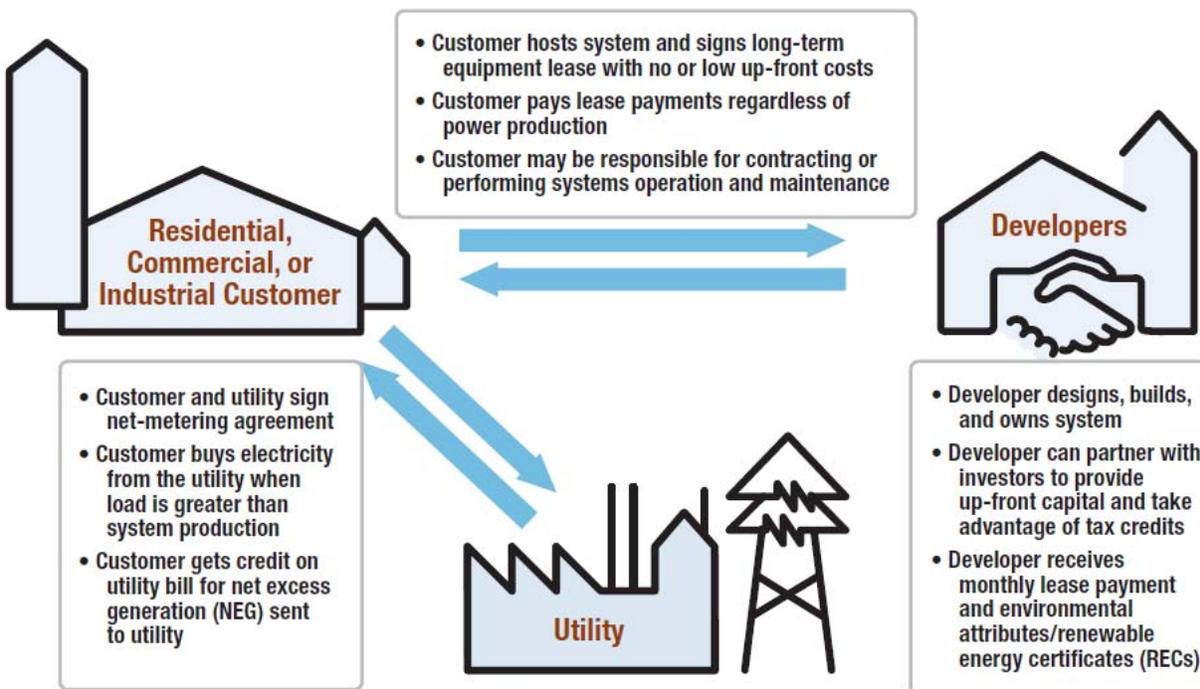


Figure 3. Solar lease structure (aka solar services agreement)

If the customer purchases a maintenance package, the solar leasing company may monitor the systems in real-time to detect issues and provide prompt resolution. Additionally, a solar lease may come with a performance guarantee to make the customer more comfortable with the arrangement (SolarCity 2008).

To make the projects economic (with lease payment levels close to the customer's retail utility rate), developers typically require that either they receive the RECs or that the RECs are sold to the utility (which may have an RPS requirement). As previously mentioned, many utilities mandate that they receive the RECs from those projects where they have contributed rebates and financial incentives (Holt et al. 2006). These up-front cash incentives exchanged for the environmental attributes generated by the PV system can be an important revenue stream to make the project economic. This is especially true with smaller residential projects.

5.1.2 Challenges with the Solar Lease

Under the solar lease model, more risk may be transferred to the customer and away from the developer compared to the third-party PPA model. The developer receives a fixed lease payment regardless of whether the system is operational and independent of the electricity produced. Operations and maintenance risks are therefore transferred to the customer unless maintenance services or operational guarantees can be procured from the developer or another provider. The customer may be responsible for property insurance for the system, which could be added to homeowner's insurance or an existing property policy. The developer, on the other hand, is responsible for insuring the construction and operation of the system; their policies may include workers' compensation and auto, business interruption, and liability insurance. Because large developers have established insurance relationships, they receive more favorable rates than do onetime residential or commercial customers looking for solar PV insurance.

In addition to taking on the previously mentioned risks, some types of customers also face more financial challenges with solar leases than they do with the third-party PPA model. Owners of systems sited on property owned by governmental entities or non-profits, including schools, are not eligible for the ITC (SEIA 2008). This removes a large incentive to the developer and in turn raises required lease payments for the customer. Another important financial challenge for the solar lease model regards the estimation of a system's electricity production. If estimates of solar PV system production are not accurate, the customer may pay more for the electricity on a levelized basis (\$/kWh) than if had they entered into a PPA.

Notably, the solar lease (solar services agreement) model involves a traditional sale/leaseback arrangement between the developer/operator of the system and the tax equity partnership established to monetize the federal tax credits and use the accelerated depreciation. For the investor to receive the tax benefits, the agreement between its lessee and the host customer must be a *service* agreement (hence, the SSA), and the recipient of the service agreement cannot operate the system or stand to face significant financial loss or gain in case the system does not perform as predicted. Were the host customer to sublease the system, it would arguably be taking on the operation of the system (the definition of lease tends to include the lessee's "control" of the leased asset). Moreover, because lease payments are typically fixed, the host would either gain if the system overproduced or lose if the system under produced.

A direct lease—under which the solar developer owns the system and leases it to the host customer—is not feasible for most developers because neither the developer nor the host/lessee would be able to fully realize the benefits of the federal incentives. Solar developers, as system owners, typically do not have the tax appetite to realize the benefit of either the ITC or accelerated depreciation. The solar developer could pass the ITC (but not the accelerated depreciation) through to the host/lessee, but one-half of the ITC would be treated as taxable income to the host. Even in this pass-through scenario, the developer still holds the essentially worthless depreciation benefit. Thus, most of the benefit of the incentives would be lost making the project more costly or economically unreasonable.

It should be noted that, like the third-party ownership/PPA model, the solar lease could also face regulatory challenges. However, this appears not to be as common of a challenge as it is for the third-party PPA model. An example of the solar lease facing regulatory changes occurred in Nevada, where the Public Utility Commission of Nevada did not believe that the third-party PPA model or the solar lease structures are legal under Nevada law. The staff was also concerned with consumer protection if these third parties were not regulated. Further, they felt the Commission should implement rules that govern rates and fees as well as contractual obligations (PUCN 2008).

5.1.3 Applicability of the Solar Lease: Florida and Texas

The solar lease appears to be acceptable in those states that define a utility or load serving entity (LSE) as an entity that sells "electricity." With a solar lease, the owner leases the equipment and does not sell the electricity, which most states find to be an acceptable arrangement.

In Florida, the FPSC went so far as to rule in favor of a solar lease structure in the Monsanto case of 1987 (FPSC 1987). In that case, the Commission stated that there was no *sale of electricity* because Monsanto was leasing equipment that produced electricity rather than buying electricity

that the equipment generated. The terms of the lease were the most important factor in this ruling:

The lease payments would be fixed throughout the term of the lease. These payments, based on a negotiated rate of return on the lessor's investment, would be independent of electric generation, production rates, or any other operational variable of the facility. Thus, lease payments would continue to be due during either planned or unplanned outages of the facility.

This puts the operating risk on the customer instead of the third party, which the FPSC found to be a completely different transaction than the third-party PPA model where the risk was born by the third-party. Although this operational risk requirement is applicable in Florida, other states do not carry this stipulation, and O&M can be performed by the third-party owner, often with some sort of performance guarantee.

For the financial challenges with the federal tax credit and accelerated depreciation, the solar lease may be a good option in electricity markets where the legality of third-party owned systems is uncertain. However, it is not an option for projects on government or non-profit property (including schools) as the benefits of the ITC cannot be realized. In places such as Florida and possibly Texas where the third-party owned systems are not legal or cannot net meter, the solar lease may be a good financial alternative because the lease finance structure does not appear to face the same legislative barriers (specific situations should be checked with legal counsel). Because the solar lease is competitive cost-wise with the third-party model, it does not pose a real loss to those looking to install solar PV systems on property located in electricity markets where the third-party PPA model cannot be used.

Table 1. Incentives and Project Responsibilities for Solar Financing Mechanisms

Financing Mechanisms	Self-Financing	Third-Party Ownership PPA	Solar Lease
<u>Incentives</u>			
State Cash Incentive (production-based or upfront)	Yes	Yes	Yes
Use of Federal ITC	Requires large tax liability	Yes	Yes, except on government or non-profit property
Accelerated Depreciation	Yes	Yes	Yes, except on government or non-profit property
State Tax Credits	Yes**	Yes**	Yes**
<u>Responsibilities</u>			
Upfront Costs	Yes	No*	No
O&M	Yes	No	Yes, unless contracted to the developer

* The lower the up-front costs, the higher the price of electricity, therefore up-front costs depend on the contract arrangement between the third-party owner and the customer to meet the goals of both parties.

** Requires a larger tax liability within the state the system is located.

5.2 Other Alternative Solutions

When statutory interpretation is unclear with regard to third-party PPA models, it might make sense to consider variations of this model or alternative arrangements. Customers interested in solar PV systems and developers looking to enter new markets can explore the following alternatives to the standard third-party PPA model.¹⁰

5.2.1 Utilities as Silent Contractual Intermediaries:

If the utility is willing to work with customers and developers on a project-by-project basis, the project developer may sign a PPA with the customer's utility then have the utility sell the electricity back to the customer. With this potential solution, the utility is a silent intermediary in the third-party PPA model and only transfers the sales and purchases on paper, while the actual electricity is used directly by the customer. This process would likely require some standardization within the utility if it were to be deployed for more than a few projects. One potential concern with this model is that it turns the developer into the wholesaler of electricity, which could subject the developer to FERC regulation. While this regulation is workable and

¹⁰ This does not constitute legal advice, and it should not be considered as such; a full legal opinion from your attorney, specific to your situation, should be obtained.

common in many states, it puts additional responsibility on the developer. Moreover, the retail transaction between the utility and the customer could be subject to regulation.

This solution, which clearly requires that the utility be interested in promoting solar resource development, is an important potential option for a regulated utility concerned about opening themselves to competition, as is the case for municipal utilities in Texas. Because of increased transaction costs, the structure may not come with pricing as favorable as the third party PPA model, but it could be an important solution when legal questions surround the third-party PPA model.

5.2.2 Standardized Third-Party PPA Contract Language

Many states noted that it would be in the customer's best interest to have standard rules and contract clauses in place that must be part of the third-party PPA. This would help ensure that customers receive a fair deal and are not paying hidden fees or signing up for services of which they are not aware. A standard contract approved by the PUC would leave less room for interpretation of legality down the road, but developers and their bankers might view it as a form of regulation.

5.2.3 Utility Owns Customer Sited Generation Assets

With the recent change to the federal ITC that allow utilities to take the 30% up-front PV tax credit (H.R. 2008), more tax-paying utilities may choose to own PV. Although these utilities may choose to build and own large-scale solar plants, they can also finance customer-sited DG and sell the power back to host customers. In this instance, the utility effectively takes the place of the third party in the third-party owned PPA model. If the model is properly structured, the customer can enjoy the same benefits of fixed-price power at or below utility retail rates, and the utility can take advantage of the tax credits. However, some argue that utility costs of developing customer-sited solar projects could be higher than costs available in the competitive marketplace. In addition, some suggest it is not fair or efficient to allow a utility to be the sole provider of a service that is a competitive offering in many states.

5.2.4 Utility- and PUC-Waived Monopoly Rights for Distributed Generation (DG)

Although not typical, monopoly utilities might be able to waive their monopoly rights and allow third-party owners to participate in their service territories if their regulators support this structure. Xcel Energy and their regulators in Colorado used this as an interim measure before the legislature passed a law allowing the third-party PPA ownership model.

To meet Colorado's RPS requirements, including the 4% solar set-aside, Xcel Energy (in agreement with their regulators) waived their monopoly rights on specific projects that provide it with RECs for compliance. For systems over 100 kW, Xcel holds a competitive solicitation and selects winning proposals in order to comply with the Colorado RPS solar set-aside. Colorado also requires that 50% of the solar set-aside be customer-sited (DSIRE 2008a), and Xcel has found the third-party ownership structure to be an effective way of meeting that goal. However, Xcel provides this waiver for only those projects that are selected in its solicitation and that provide it with RECs for its compliance obligations (Mignogna 2008). This makes the utility the absolute power and "sole arbiter" of which providers are allowed to serve the market for commercial-scale systems using the third-party PPA model. For projects from 10kW to 100kW, Xcel has a standard rebate offer but only for projects that supply it with RECs. For the under 10-

kW “residential” segment, Xcel runs another standard rebate offer but requires that the customer own the system.

Table 2 illustrates the wide range of solutions previously discussed. Legislative or regulatory changes to allow the third-party PPA model might be out of the control of third-party developers or the customers who desire their services, but both variations to the traditional model or entirely different alternatives are possible. Some of the variations will require a ruling by a governing body (registration of DG service providers and standardized third-party PPA contracts), while others can be implemented in many jurisdictions without any legal issues.

Table 2. Summary of Attributes of Alternative Solutions to Third-Party PPAs

Attributes of Alternative Solutions	PPA Parties	Low/No Up-front Costs	System Maintenance Responsibilities	Monthly Payments
Solar Lease	No PPA, just flat lease fee	Yes	Customer, unless contracted to the developer	Fixed
Developer Sells Power to Utility	Third-party sells to the utility, which sells to the end-use customer	Yes	Third party	Based on electricity usage
Utility Owns Customer Sited Assets	Utility sells to end-use customer	Yes	Utility	Based on electricity usage
Standardized Third-Party PPA Contracts	Third-party sells to end-use customer	Yes	Third party	Based on electricity generated
Clean Renewable Energy Bonds (Municipal utilities)	Customer (govt. entity) owns the system	Must pay issuing costs	Customer, unless contracted	None *

* Annual principal payments were required for CREBs before 2009.

Table 3 indicates in which states the five major regulatory challenges to the third-party ownership/PPA model have occurred, as discussed in Section 4, and the solutions that have been applied or are possible.

Table 3: Summary of Solutions to Third-Party Ownership Regulatory Challenges

Challenge Solutions	1. Definition of Electric Utility Includes Seller of Electricity	2. Definition of Electric Utility Includes Power Generation Equipment	3. Definition of Competitive Supplier or Utility Includes Provider of Electric Services	4. Munis and Co-ops Concerned with Opting into Deregulation of Retail Electricity Generation Markets	5. Third-Party Owned Systems May Not Net Meter
<u>PPA Solutions</u>					
Clarify third-party owned systems are <i>not</i> utilities or competitive service suppliers	CO	NV		**	
Exempt non-conventional generation (including solar) from definition of electrical corporation or public utility	CA	OR (solar and wind only)			
Rule third-party owned systems are legal and do not require PUC regulation	CO	NV		**	
Decide third-party owned systems do not provide direct ancillary services			OR		
Allow net metering for systems <i>used</i> by customer-generators					NJ
<u>Alternative Solutions</u>					
Solar Lease (except for government or non-profit entities)	*	*	*	*	*
Developer Sells Power to Utility	*			*	*
Utility Owns Customer Sited Assets	*	*	*	*	*
Clean Renewable Energy Bonds ^a	*	*	*	*	
Utility and PUC Waive Monopoly Rights ^b	*	*	*		
Waiving of DG registration	*	*	*	*	

State abbreviations indicate that this solution has been applied there.

* Indicates a probable solution with no barriers identified.

** Indicates a possible solution that requires further investigation

^a This solution is only applicable for state and municipal solar PV installations that apply to the IRS for an allocation.

^b This solution, which requires PUC and utility approval, is possible but not as feasible as other alternatives.

6 Summary

Of the states that have examined the legislative and regulatory issues with the third-party PPA model in recent years, most have accepted the structure as sound and clear of conflict with utility rights. This is true whether states deregulated their retail electric generation market or not. However, most states have not clarified the use of this model, and therefore it may not be clear whether this structure can be used. Of the cases investigated, no two states have had the same specific situation (language and regulating body, for example) regarding the regulation of third-party owners, which defies a single solution that will work everywhere. However, lessons from the examples in this report could be used in other states that wish to address the issue of regulation of the third-party PPA model.

Several regulatory challenges exist for the third-party PPA model. The first challenge occurred when state legislation or regulations defined electric utilities as sellers of electricity. Because the owners of third-party systems using a PPA sell their electricity to site hosts, these systems may be interpreted as being electric utilities and would therefore require PUC regulation. This issue has arisen in Colorado, Florida, and Arizona. However, Colorado and California determined that third-party owned systems using PPAs are not utilities or electrical corporations, and that non-traditional sources of power generation are exempt from being considered as utilities. Florida's ruling, which occurred in 1987, has not been revisited. The second challenge occurred when the definition of electric utilities included power generation equipment, such as solar PV, and thus required regulation. Solar developers in Nevada and Oregon who were using the third-party PPA model encountered this challenge, but PUC regulators in those states clarified that third-party owned renewable energy generation systems (solar and wind only, in the case of Oregon) using a PPA are not considered to be public utilities.

A third type of challenge occurred in Oregon, where the definition of competitive service suppliers (or ESS under Oregon's definition) and utilities came into conflict with third-party ownership. Oregon legislation defined an ESS as a seller of electricity that provides direct access and ancillary services. Nonetheless, the State of Oregon determined that third-party owned systems using a PPA are not electrical service suppliers because they do not provide ancillary services. The fourth challenge occurred when munis and co-ops were concerned they would open their service territories to deregulation of electricity markets if they allowed the third-party PPA model. This challenge has occurred only in Texas where the remainder of electricity markets is deregulated. Texas has not addressed this issue and has no plans to do so. The fifth and final challenge, which has been identified in New Jersey and Texas, occurred when third-party owned systems were not allowed to net meter. Texas has not resolved this issue, but New Jersey regulations allow net metering for all systems "used" by customer-generators, thus they do not have to be owned by the customers.

All of the solutions found here could be applied in regulated, hybrid, or deregulated markets. The solutions could be applied to a number of challenges. Lastly, in a few cases, PUC officials looked to their state's policies/goals for renewable energy deployment when making regulations favorable to third-party owned systems.

Other solutions include variations of the third-party PPA model, many of which also require legislative or regulatory approval. For example, states can allow a standardized third-party PPA

contract. Other variations of the third-party PPA model do not require legislative approval but focus on the utility. For example, a developer may sell power to the end user via the utility as a contractual intermediary, allowing the utility to remain the only seller of electricity. In addition to these other regulatory solutions, effective financing mechanisms can be employed in jurisdictions where the third-party PPA model is unavailable. Under the most common of these, the solar lease, the customer does not pay for the equipment but receives the electricity generated from that equipment. However, this option is not available to government or non-profit entities. CREBs are available to state and local governments including co-ops and munis, that apply for and receive an allocation from the IRS, which allows them to finance and own solar PV without major up-front costs.

States that want to support renewable energy—and feel that adequate consumer protection provisions are in place—might want to consider explicitly allowing third-party owners using PPAs to be unregulated. The third-party PPA model provides benefits to customers who are interested in solar PV but do not want the up-front costs or maintenance responsibilities. The third-party PPA model can be an attractive financing option, and it has spurred solar PV growth in states where it is available. It also promotes market discipline and is instrumental in driving the cost of solar energy down. For these reasons, states may consider allowing third-party electricity sales as one way to meet their renewable energy, solar, and distributed generation mandates and goals.

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Appendix A: Overview of Third-Party PPA Model

Recently, attributes of the third-party PPA have popularized this model for financing new PV installations. The benefits (and challenges) of this model, which are outlined below, apply to both residential and commercial customers. Implications of using the model vary and depend on customer type.

Minimal Up-Front Costs

A primary benefit of the third-party PPA is that it dramatically reduces or eliminates up-front costs for commercial, industrial, and residential customers by transferring the up-front capital costs of the solar PV system to entities set up to use numerous revenue streams from the system; and, the third-party PPA potentially does this with lower costs of capital. Developers can eliminate the need for customers to provide up-front capital by finding capital to buy the systems, by either purchasing them outright or securing financing for most of their capital costs. The PPA contract payment level established by the customer and developer determines the amount of up-front cost, if any to the customer.

Project Financing Expertise

Solar energy developers participate in the niche tax equity financing market and form relationships with banks that have tax equity financing divisions. Because this is the developer's line of business, they are well equipped to manage the process and can usually find capital at lower costs than homeowners can or businesses can. However, the recent financial crisis in the United States has consolidated or eliminated many participants in the tax equity market, while others have scaled back as they have less taxable income to offset. Therefore, there are fewer tax equity investors in renewable project financing than before. The remaining players in the tax equity market are increasing their return on capital requirements and focusing on projects with low counterparty risk (Chadbourne & Parke 2009).

Efficient Use of Tax Credits

As mentioned earlier, a number of available tax credits encourage the installation of solar PV. However, only certain entities can take advantage of these financial incentives, and commercial businesses with taxable profits often have the most to gain. Third-party developers are set up to allow investors in their business to take advantage of incentives in the form of tax credits, thereby allowing them to use both more and higher-value incentives than traditional businesses or homeowners are able to use.

The most salient examples, the ITC and the residential tax credit, are only available to a homeowner or business with taxable income. A homeowner or commercial entity whose tax bill is not large enough to absorb the entire tax credit—even with the credit carried forward—cannot take advantage of an incentive that potentially offsets 30% of the up-front capital cost. The residential and non-tax paying customers are at a disadvantage because neither can use the Modified Accelerated Cost-Recovery System (MACRS) depreciation tax benefit. This means that the project owner must have predictable profits large enough to offset the depreciation benefits (MACRS) and tax credits they receive from the project.

By contracting with developers who can take advantage of these incentives and credits, certain customers can now realize cost savings that would have not been possible had they themselves

purchased and owned the systems. The cost savings are subsequently passed from developers to customers in the form of lower electricity rates (equivalent to the system output).

Removal of Maintenance Responsibilities

For the most part, the businesses and residences that are installing PV do not have expertise in solar array maintenance and operations. With the third-party PPA model, the ownership and responsibility of the system is placed on the developer and not on the customer, who pays only for the electricity generated. If the system does not function properly, the customer does not pay for repairs or for the electricity. Ultimately, the customer just purchases more electricity from the utility. This arrangement provides a revenue incentive for developers to maintain their system because they are not paid unless the system produces power.

Predictable Costs in Volatile Electricity Markets

Both residential and business customers are looking at ways to reduce electricity costs and incorporate predictability in their future electricity expenditures. The third-party PPA model allows a customer to avoid some of the large rate increases seen across the nation in recent years (Smith 2008) by providing a contract with a pre-determined price for 20 to 25 years.

When businesses with large power needs are considering ways to reduce expenditure risk, locking in prices with suppliers via long-term contracts is an excellent way to manage this line item. Often these contracts start with electricity rates that are competitive with the utility retail rate for that customer and may remain constant or contain an annual escalation factor of 3 to 3.5% (Cory, Coughlin, and Coggeshall 2008). With this stability, businesses can plan a portion of their energy expenses with certainty, and project investors can count on a revenue stream as long as they maintain system performance.

The financial efficiency of the third-party model greatly increases opportunities for commercial, industrial, and government customers to use solar resources on-site. As a result of this expansive market, solar energy costs are driven down through volume purchases of equipment and efficient construction and installation methods.

Non-regulatory Challenges with the Third-Party PPA Model

Some challenges with the third-party PPA model are beyond the regulatory challenges examined in the body of this paper. One such challenge is determining whether the utility is entitled to the RECs. In net metering situations, some states have pre-determined whether the customer or the utility has rights to the RECs. The majority side in favor of the customer retaining the RECs, especially for generation associated with the customer's load (vs. net excess generation). However, if the utility contributes financial incentives or rebates to a project, the utility or their regulator might require the RECs to be transferred to the utility (Holt 2006). One exception is the California Solar Initiative (CSI), which does not require the surrendering of RECs as a condition for receiving financial incentives or rebates (California Public Utilities Commission 2009, DSIRE 2009).

In the case of the third-party PPA model, the developer typically sells the electricity to the customer and retains the RECs or more valuable solar RECs (SRECs) for sale into the REC market. The sale of SRECs helps the project make the necessary returns and allows the developer to offer the customer a price competitive with grid-supplied electricity. To claim they are "solar

powered,” customers must purchase all or a portion of the SRECs from developers. In states with an RPS with a solar set-aside, which usually significantly increases the value of SRECs, the removal of SRECs from the deal can make the project uneconomic. However, customers do have other options in some cases. For example, federal agencies in regions with active REC markets often buy wind or landfill gas RECs for less on the open market, which allows them to retain the renewable energy claim (just not a “solar” energy claim) while taking advantage of high SREC prices (Cory, Coughlin, and Coggeshall 2008).

The contract states the customer’s options in the event they sell their property. Because the third party has taken on the credit risk of the initial customer, the new occupant is not automatically entitled to assume the terms of the contract; the new occupant often must meet a credit check and other requirements. In addition, some contracts have buy-out clauses that allow the customer to buy the system and sell it with the building. Some jurisdictions, such as Colorado, are beginning to address these issues in their rules governing customer-sited solar resources.

Appendix B: Solar Laws, Financial Incentives, and Policy Background

A successful solar installation involves logistical and economic prerequisites, including net metering laws, interconnection standards, financial incentives, and federal and state policies requiring incremental renewable generation.¹¹ All these must come together to ensure an economically viable project.

Connecting Solar Energy Systems to the Grid

The financial incentives discussed in the body of this paper help only when the state where the solar energy system is installed has the appropriate net metering and interconnection standards. Net metering and interconnection, which ensure that systems are adequately sized, safe, and affordable, are discussed below and in detail in the Interstate Renewable Energy Council's (IREC) 2008 annual report and in "Freeing the Grid" (NNEC 2008).¹²

Interconnection Standards

Interconnection standards govern the technical and procedural process by which an electric customer connects an electric-generating system to the grid. Generally, the distribution utility assesses and approves the customer-generator within the rules established by the public utilities commission based on input from utilities and other stakeholders.

IREC also recommends eliminating any requirement for external disconnect switches because all modern grid-connected systems automatically shut down in the event of a grid failure (NNEC 2008). Such improvements to interconnection standards will remove logistical barriers for small systems and make larger systems operate safely within the grid.

Net Metering

Net metering is the billing arrangement between customer-generators and utilities whereby the customer is credited by the utility for excess electricity that the customer generates. Typically, net metering allows a customer to earn a credit for net excess generation (NEG) produced by the customer's system over a billing period at the utility's wholesale rate, the utility's avoided cost, or the customer's retail rate. Essentially, the customer can use credit obtained through past NEG in one billing period toward electricity consumed in future billing periods.

IREC's best practices with respect to net metering include (1) removing size limits and customer classes from net metering, (2) allowing monthly carryover of NEG credited at the utility's full retail rate, and (3) standardizing net metering standards across the state without regard to the type of utility to make rules simpler and clear to all market participants (NNEC 2008). These

¹¹ The quality of the solar resource (i.e., location) is another critical element to PV projects. However, even in a location with excellent resource, incentives are needed for the project to be economic under current conditions. In fact, incentives can compensate for the differential between poor and great resources to help spur new development. Germany is a world leader in PV despite having a solar resource on par with Alaska's; government incentives make the difference.

¹² *Freeing the Grid* rates and reports the effectiveness of state interconnection standards and net metering standards with the goal of displaying best practices and helping states make incremental improvements and facilitating additional grid-tied solar development.

practices are important as net metering rules can determine a project's size and economic feasibility in many cases.

States' rules and requirements for net metering differ based on whether the customer is a commercial or industrial customer versus a residential customer. The primary element in net metering rules is the allowable size of the systems, which dictate whether customers can install systems large enough to (approximately) meet their load and realize economies of scale. Allowable size varies greatly from state to state—the range stretches from six states that have no net metering laws to New Mexico, which allows up to 80MW, and Ohio, which does not have a limit (DSIRE 2008b). Arizona now allows net-metered systems sized to 125% of the customer's "connected load."¹³ The net metering limit in Colorado is 120% of consumption, for the first time breaking from a capacity-based limitation. Figure B_1 shows the states with net metering standards and the allowed system capacity in kilowatts.

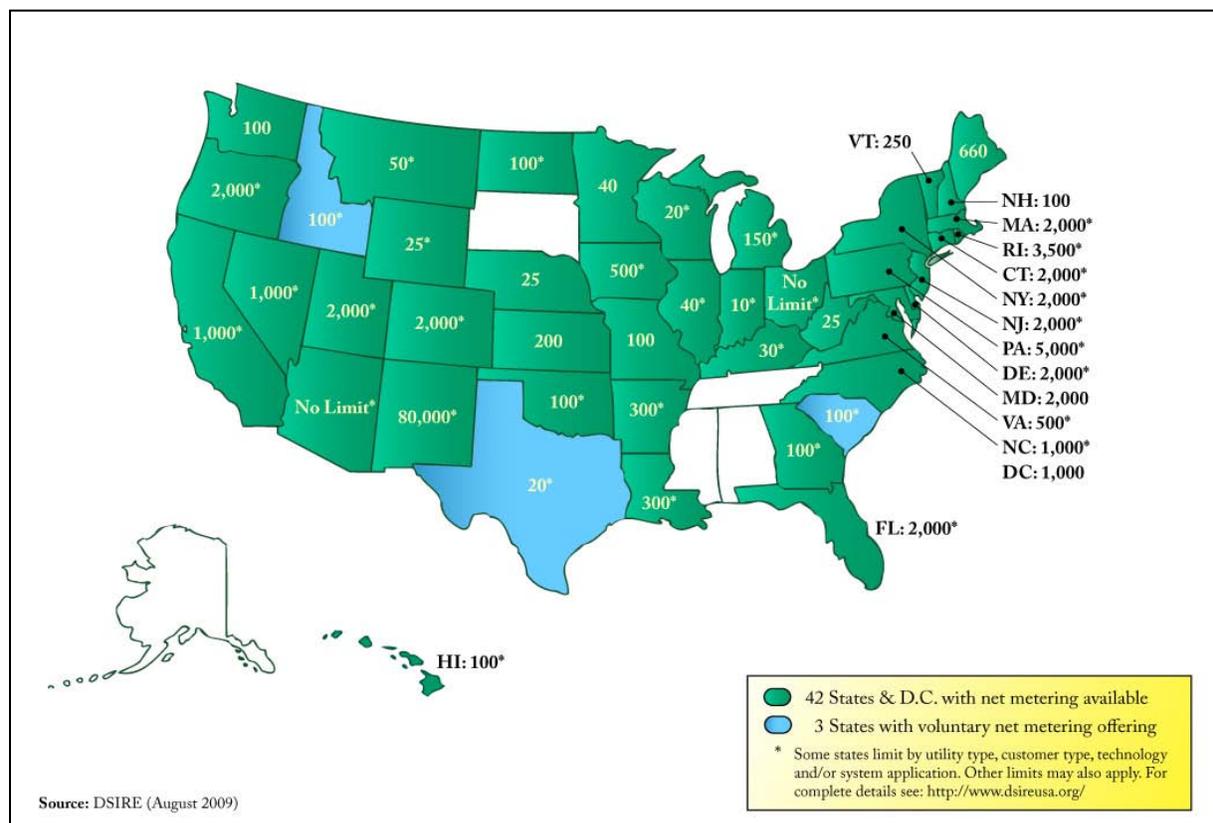


Figure B-1. Map of states with net metering standards (August 2009)

Although many states have net metering limits, they are generally unnecessary because financial mechanisms in most states discourage installation of systems larger than a customer's average load. For example, in many states, customer-generators are not paid for NEG held at the end of a 12-month period. This means that if a customer installs a system that produces more than their average load over the course of one year, they will not receive a financial benefit for overproduction (NNEC 2008).

¹³ Connected load means the theoretical maximum a customer could load if all electrical devices were operating concurrently.

Other net metering provisions can discourage solar installations altogether. Because solar energy production varies significantly based on the time of day and the season, a system can produce more than the host site uses—particularly during the day and in sunny months—thereby creating a need for the NEG to rollover into the next month to average out over the course of a year. However, some state’s net metering provisions do not allow rollover of NEG each month, thereby reducing the financial incentive to build a system sized to meet the customer’s average load over the course of a year (rather than building a system to meet just peak demand). In some states, the customer is forced to pay an overlaying premium on a retail tariff for electricity purchased.¹⁴ These charges can negate some or all of the financial benefit the customer would receive from the solar energy system even though the utility would benefit when the system’s peak generation coincided with the utility’s peak load.

Financial Incentives

With the proper net metering and interconnection standards in place, financial incentives from federal, state, and local governments, as well as utilities, can make solar power an economically attractive option.

Federal Investment Tax Credit

One of the most important incentives for solar PV is the federal investment tax credit (ITC). The ITC reduces federal income taxes for qualified tax-paying owners based on the capital investment of the solar project. The ITC is set at 30% of qualified expenses and was recently extended through December 31, 2016 (WRI 2008; H.R. 2008, Sec. 103). While the commercial ITC has never had a maximum amount, the 30% residential tax credit had a cap of \$2,000 until October 2008 when Congress removed the cap as of January 2009. Additionally, a limited number of entities can take full advantage of the 30% credit. Because the entities must pay federal taxes, not-for-profit businesses, state and federal government agencies, and any other business that do not earn accounting profits are not eligible.¹⁵ Finally, the October 2008 changes to the ITC now allow investor-owned utilities to use the tax credit starting in October 2008, which they were unable to do before.

Accelerated Depreciation

Another critical incentive for solar PV is the federal Modified Accelerated Cost-Recovery System (MACRS), which allows a business¹⁶ to recover investments in property through accelerated asset depreciation, effectively reducing its tax liability. A business can depreciate solar equipment over a five-year period and thereby use this deduction over a time span that is less than the economic life of the equipment (20-30 years) (DSIRE 2008c).

Accelerated tax depreciation provides an incremental benefit equal to about 12% of system cost on a present value basis (assuming a 40% combined effective state and federal tax bracket and a

¹⁴ This additional premium for net metering, which the state PUC must approve, goes to the utility because they must provide backup power when the customer generator’s system does not perform.

¹⁵ Accounting profits refer to the financial statements that companies submit to the IRS. These are different from the statements of cash transactions, which recognize revenue when the service is performed (not when the cash is obtained) and include non-cash expenses like depreciation. As a result, the business may earn a cash profit but have enough taxable expenses (such as depreciation) in a given year to offset taxable income, thereby eliminating profits on an accounting basis even though the business is cash positive.

¹⁶ MACRS is only available to businesses, not residential customers.

10% nominal discount rate). Together then, the 30% ITC and accelerated depreciation provide a combined tax benefit equal to about 42% of the installed cost of a commercial PV system (Bolinger 2009).

Cash Incentives

In addition to federal incentives, a large number of cash incentives are available to solar projects through state, local, and utility-specific financing programs. These programs can be very creative with their incentives, which include grants, loans, income tax and property tax incentives, sales-tax exemptions, and more. The incentives are detailed in the Database of State Incentives for Renewables and Efficiency (DSIRE) maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC), which can be found at <http://www.dsireusa.org/>. Some of these incentives are substantial enough to advance solar installations in their respective territories. Because state programs are the most widely available programs and tend to have the most funds available, a state-specific example is presented.

The California Solar Initiative (CSI) is a robust state incentive program. Adopted in January 2006 by the California Public Utilities Commission, the CSI is designed to provide more than \$3 billion in incentives for solar energy projects with the objective of providing 3,000 megawatts (MW) of solar capacity by 2016. The program initially offers higher incentive levels, which are reduced over 10 years as utility-specific capacity targets are met.

Incentives are based on project size. When the program began in 2007, “buy downs” (rebates) for systems less than 50 kW were \$2.50/W AC for residential and commercial systems, and \$3.25/W AC for government entities and nonprofits. Incentives are adjusted based on expected performance of the specific PV system at a particular site. For a system greater than 50 kW, performance-based incentives are paid for the first five years starting at \$0.39/kWh for taxable entities and \$0.50/kWh for government entities and nonprofits. These incentives ramp down as state-level PV capacity is reached in each California utility’s service territory.

On top of the generous state incentives, numerous utilities in the state offer grants, loans, and rebates to make solar PV even more financially attractive.

State Policies Encouraging Solar

State policies requiring renewable generation known as renewable portfolio standards (RPSs) play a major role in the development of new renewable energy generating assets. Most RPS policies mandate that utilities generate or purchase a certain percentage of electricity from new renewable energy sources on behalf of their customers. States looking specifically to encourage solar power can do so in a number of ways.

The most frequently implemented is a solar set-aside within the RPS (shown in Figure 3). The set-aside dictates the amount of power that must be generated from solar resources in particular. This solar-specific requirement fundamentally helps separate solar from less expensive forms of renewable generation, such as wind and landfill gas. Also, direct solar set-asides and set-asides for renewable DG are available and primarily fulfilled using customer-sited solar.

The “multiplier” is another mechanism to encourage specific types of generation. For each kWh of solar power generated, the utility gets bonus credit towards meeting the RPS requirement.

A number of states have tried multipliers, but they have not resulted in viable solar markets. In fact, many states that tried multipliers have switched to set-asides.

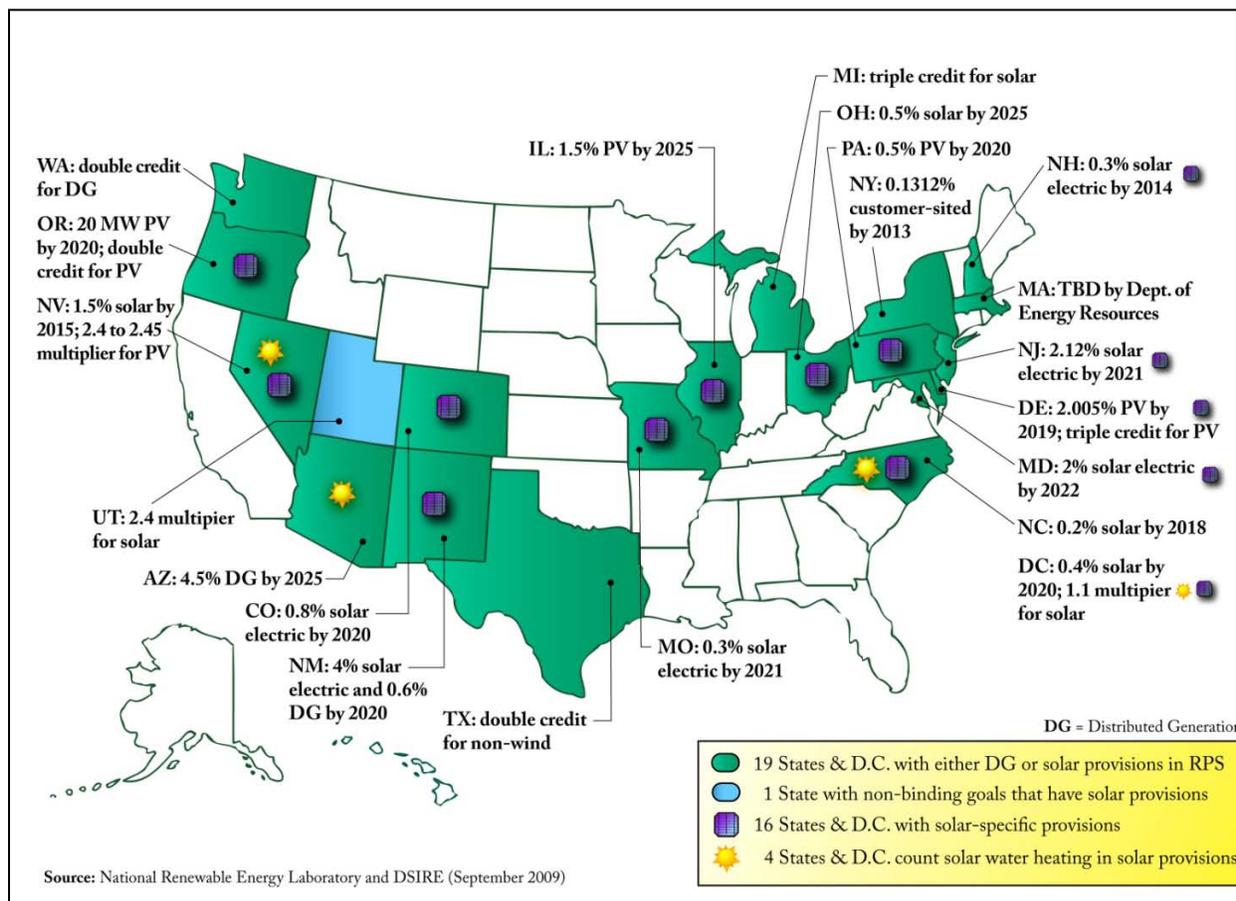


Figure C-1. Map of solar and DG provisions in RPS policies (August 2009)

Renewable energy certificates (RECs) have become the dominant mechanism for compliance with RPS policies.¹⁷ RECs are tradable commodities separate from the electricity produced, meaning that the non-electricity “attributes” of renewable electricity generation are not bundled or sold with the electricity (although they can be if a contract provides for this). Definitions of “attributes” vary across contracts but typically include future carbon trading credits, emission reduction credits, and emission allowances (Cory, Coughlin, and Coggeshall 2008).

Solar RECs (SRECs) are generated exclusively by solar projects and have the potential to demand higher prices in markets with solar set-asides or tiers in their RPSs. Several states have instituted penalty prices on utilities or load serving entities (LSE) for not meeting their specified share of the RPS. The penalties are designed to be high enough to encourage utilities to obtain generation from renewable energy sources. The penalties come in the form of alternative compliance payments, explicit financial penalties (can be on a per MWh basis or fixed), and discretionary financial penalties (Wiser and Barbose 2008). The more concrete the penalty, the more it helps encourage utilities and developers to meet the RPS by letting them know what the

¹⁷ RECs are not used for RPS compliance in Arizona, California, Hawaii, or Iowa (Wiser and Barbose 2008).

“alternative” payments will be if too few RECs or SRECs are generated or purchased. For example, New Jersey has a solar tier in its RPS and high penalties for non-compliance. Previously, New Jersey’s penalty price was set at \$300/MWh (Corbin Solar 2007), and SRECs for compliance year 2008 (July 2007–August 2008) traded at a weighted average monthly price between \$197 and \$246/MWh (NJ Clean Energy 2009). When the RPS compliance year 2009 started in July 2008, the penalty price was set to \$711/MWh (NJ Clean Energy 2007). As a result of the increase in penalty price, SREC prices traded at a weighted average monthly price between \$308 and \$513/MWh from July 2008 to June 2009 reaching a monthly high of \$695/MWh (NJ Clean Energy 2009).

Best practice interconnection and net metering standards—which allow DG technologies to connect to the grid, bring about a fair price for generators, and reduce barriers to installation—can make solar PV expansion viable. Federal incentives have boosted solar energy systems in recent years, but state financial incentives and state policies encouraging solar truly drive the adoption of solar PV as indicated by significant penetration levels in California, Colorado, and New Jersey.

Appendix C: State Third-Party Language Summaries

Table C-1. Summary of State Third-Party Language

State	Are 3 rd Party PPAs Allowed without Regulation?	Where is the Language?	What is the Language?	Status and Solutions
OR	Yes	PUC Decision: Order 08-388	Customer is not an Energy Services Supplier because they are not using the utility's distribution system (i.e., generation is less than load). Oregon Law exempts solar and wind from being "Public Utilities."	PUC made a Decision to allow the third-party PPA model.
NV	Yes	Legislation; Docket 07-06024	Third-party ownership of net-metered systems does not qualify as a utility, is legal, and is not under the jurisdiction of the Commission.	PUC found that the third-party PPA model should be allowed.
FL	No, except leases are okay	PUC Decision: Docket 860725-EU; Order 17009	Every legal entity supplying "electricity to or for the public" was determined by legal precedent that "to or for the public" could be just ONE customer	No current attempts to change
AZ	Yes, but must be regulated	State Constitution: Article 15 Section 2	Anyone who furnishes electricity shall be deemed a public service corporation.	Solar Alliance filed a Docket with the PUC to exempt third-party PPAs from regulation
CO	Yes	SB 51	Third-party owned systems are not subject to regulation so long as the solar generating equipment is sized to supply no more than one hundred twenty percent of the average annual consumption of electricity by the consumer of that site.	RES bill SB 51 passed with supporting PUC recommended decision 08-R-424E
TX – Munis	Unclear	Legislation: Texas Utilities Code Section 40.053	By allowing someone else to sell to muni customers, the muni could be opening themselves up to competition	Munis are exploring alternative solutions (e.g. solar leasing and utility as the intermediary)
CA	Yes	Legislation: California Public Utilities Code 218	Utility Code states that if the system generates non-conventional energy and if you serve two or fewer customers on that property, you are not considered an LSE or ESP	Legislation was used to make third-party PPAs allowable
NJ	Yes	BPU Docket EX08070548	Customer generators may "use" a "customer-generator facility" and are thus not required to own the facility.	No current attempts to change

Appendix D: Clean Renewable Energy Bonds

One major reason to consider the third-party PPA model is that it helps get projects financed economically without large up-front payments from the end-user. For munis and co-ops, customer-sited projects can be financed in another way as long as the projects are not too large to qualify.

Munis and co-ops may apply to the Internal Revenue Service (IRS) for clean renewable energy bonds (CREBs) to help finance renewable projects, which have traditionally been smaller projects. CREBs, an alternative to tax-exempt bonds, are a financing instrument with a structure similar to a tax-exempt bond except that the federal government provides the investor with a tax credit in lieu of an interest payment (Cory, Coughlin, and Coggeshall 2008). A recent allocation and authorization of \$800 million in CREBs funding (H.R. 2008) makes this option again available to state and local governments, co-ops, and munis, each of which receives one third of the allocation.¹⁸ While this structure has some challenges (Cory, Coughlin, and Coggeshall 2008), Congress updated the CREBs structure in October 2008 in an attempt to address a number of the drawbacks. More information about these updates is explained in the IRS guidance, which can be found at <http://www.irs.gov/taxexemptbond/article/0,,id=206034,00.html>.

¹⁸ Munis and co-ops are eligible for CREBs, but approved systems are likely to be small based on how the IRS has traditionally allocated CREBs (from smallest to largest). New CREBs allow municipal utilities to get a pro rata share of \$800M, which means that even large projects can take advantage of CREBs.

REPORT DOCUMENTATION PAGEForm Approved
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The public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to Department of Defense, Executive Services and Communications Directorate (0704-0188). Respondents should be aware that notwithstanding any other provision of law, no person shall be subject to any penalty for failing to comply with a collection of information if it does not display a currently valid OMB control number.

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1. REPORT DATE (DD-MM-YYYY) Revised February 2010		2. REPORT TYPE Technical Report		3. DATES COVERED (From - To)	
4. TITLE AND SUBTITLE Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners				5a. CONTRACT NUMBER DE-AC36-08-GO28308	
				5b. GRANT NUMBER	
				5c. PROGRAM ELEMENT NUMBER	
6. AUTHOR(S) K. Kollins (Duke University); B. Speer and K. Cory (NREL)				5d. PROJECT NUMBER NREL/TP-6A2-46723	
				5e. TASK NUMBER PVB9.4210	
				5f. WORK UNIT NUMBER	
7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES) National Renewable Energy Laboratory 1617 Cole Blvd. Golden, CO 80401-3393				8. PERFORMING ORGANIZATION REPORT NUMBER NREL/TP-6A2-46723	
9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)				10. SPONSOR/MONITOR'S ACRONYM(S) NREL	
				11. SPONSORING/MONITORING AGENCY REPORT NUMBER	
12. DISTRIBUTION AVAILABILITY STATEMENT National Technical Information Service U.S. Department of Commerce 5285 Port Royal Road Springfield, VA 22161					
13. SUPPLEMENTARY NOTES					
14. ABSTRACT (Maximum 200 Words) Residential and commercial end users of electricity who want to generate electricity using on-site solar photovoltaic (PV) systems face challenging initial and O&M costs. The third-party ownership power purchase agreement (PPA) finance model addresses these and other challenges. It allows developers to build and own PV systems on customers' properties and sell power back to customers. However, third-party electricity sales commonly face five regulatory challenges. The first three challenges involve legislative or regulatory definitions of electric utilities, power generation equipment, and providers of electric services. These definitions may compel third-party owners of solar PV systems to comply with regulations that may be cost prohibitive. Third-party owners face an additional challenge if they may not net meter, a practice that provides significant financial incentive to owning solar PV systems. Finally, municipalities and cooperatives worry about the regulatory implications of allowing an entity to sell electricity within their service territories. This paper summarizes these challenges, when they occur, and how they have been addressed in five states. This paper also presents alternative to the third-party ownership PPA finance model, including solar leases, contractual intermediaries, standardized contract language, federal investment tax credits, clean renewable energy bonds, and waived monopoly powers.					
15. SUBJECT TERMS solar PV systems; on-site; photovoltaic (PV); PV generation; PV-generating systems; site hosts; end users; solar developers; residential; commercial; electricity; electric utility; public utility; public utility commission; PUC definitions; PUC regulations; retail electricity markets; deregulation; power purchase agreements; PPA; third-party owners; third-party ownership; finance models; initial costs; O&M costs; legal definitions; regulatory definitions; legal problems;					

regulatory problems; regulated electricity providers; electric services providers; competitive electricity suppliers; power generation equipment; sellers of electricity; Colorado; Florida; New Mexico; Nevada; New Jersey; Oregon; Texas; net meter; net metering; contracts, contract language; financial incentives

16. SECURITY CLASSIFICATION OF:			17. LIMITATION OF ABSTRACT UL	18. NUMBER OF PAGES	19a. NAME OF RESPONSIBLE PERSON
a. REPORT Unclassified	b. ABSTRACT Unclassified	c. THIS PAGE Unclassified			19b. TELEPHONE NUMBER <i>(Include area code)</i>

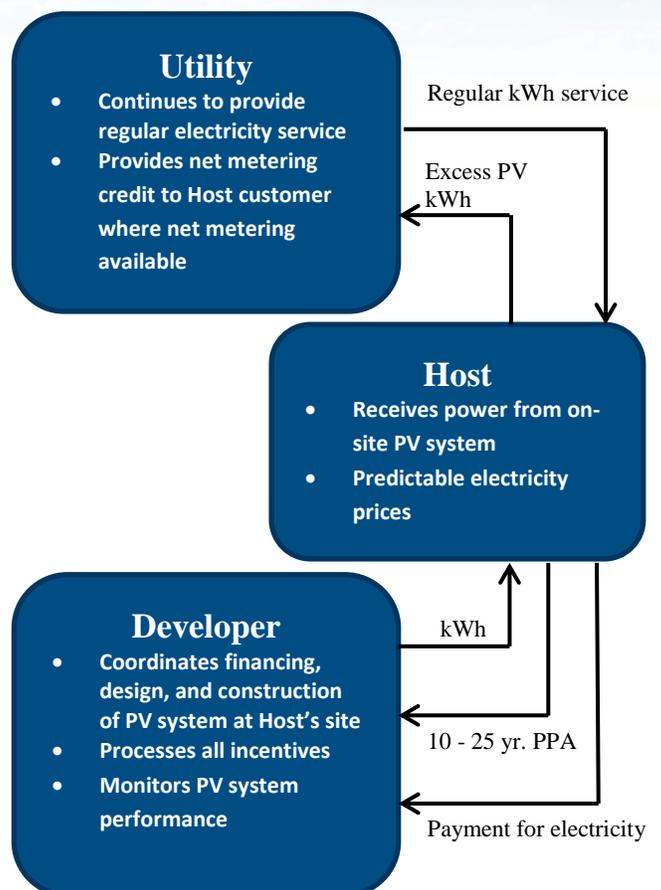
Solar Power Purchase Agreements (PPAs)

What is a solar power purchase agreement?

A solar power purchase agreement (PPA) is a financial agreement where a developer arranges for the design, permitting, financing and installation of a solar energy system on a customer's property at little to no cost. The developer sells the power generated to the host customer at a fixed rate that is typically lower than the local utility's retail rate. This lower electricity price serves to offset the customer's purchase of electricity from the grid while the developer receives the income from these sales of electricity as well as any tax credits and other incentives generated from the system. PPAs typically range from 10 to 25 years and the developer remains responsible for the operation and maintenance of the system for the duration of the agreement. At the end of the PPA contract term, a customer may be able to extend the PPA, have the developer remove the system or choose to buy the solar energy system from the developer.

Benefits of PPAs to Solar Customers

- **No or low upfront capital costs:** The developer handles the upfront costs of sizing, procuring and installing the solar PV system. Without any upfront investment, the host customer is able to adopt solar and begin saving money as soon as the system becomes operational.
- **Reduced energy costs:** Solar PPAs provide a fixed, predictable cost of electricity for the duration of the agreement and are structured in one of two ways. Under the fixed escalator plan, the price the customer pays rises at a predetermined rate, typically between 2% - 5%. This is often lower than projected utility price increases. The fixed price plan, on the other hand, maintains a constant price throughout the term of the PPA saving the customer more as utility prices rise over time.
- **Limited risk:** The developer is responsible for system performance and operating risk.
- **Better leverage of available tax credits:** Developers are typically better positioned to utilize available tax credits to reduce system costs. For example, municipal hosts and other public entities with no taxable income would not otherwise be able to take advantage of the Section 48 Investment Tax Credit.
- **Potential increase in property value:** A solar PV system has been shown to increase residential property values.ⁱ The long term nature of these agreements allows PPAs to be transferred with the property and thus provides customers a means to invest in their home at little or no cost.





Market Adoption and Policy

PPAs provide a means to avoid the upfront capital costs of installing a solar PV system as well as simplifying the process for the host customer. In some states, however, the PPA model faces regulatory and legislative challenges that would regulate developers as electric utilities. A solar lease is another form of third-party financing that is very similar to a PPA, but does not involve the sale of electric power. Instead, customers lease the system as they would an automobile. In both cases, the system is owned by a third party while the host customer receives the benefits of solar with little or no up-front costs. These third-party financing models have quickly become the most popular method for customers to realize the benefits of solar energy. Colorado, for example, first entered the market in 2010 and by mid-2011 third-party installations represented over 60% of all residential installations and continued to rise to 75% through the first half of 2012.ⁱⁱ This upward trend is evident throughout states that have introduced third-party financing models.

PPA Considerations

- **SRECs:** Solar renewable energy credits (SRECs) show that a certain amount of electricity was produced using solar energy. They are typically bought and sold by load serving entities (typically regulated utilities) to meet obligations associated with state-level renewable energy standards. SRECs are also used by consumers who voluntarily purchase them for marketing claims or other use. Most often in PPAs, SRECs are owned by the developer. When entering into a PPA, it will be important for a customer to clearly understand who owns and can sell the SRECs generated from the PV system, the risks attendant to SREC ownership, and the tradeoffs with respect to PPA price.
- **How to finance:** While both third-party financing models provide numerous benefits, purchasing a PV system outright has its own benefits. Anyone considering installing a solar PV system should consider each of the financing options available to find the best fit.
- **Site upgrades:** While the developer is responsible for installation, operation and maintenance of a solar PV system, the host customer may need to make investments in their property in order to support the installation of the system, lower the cost of installation or to comply with local ordinances. This might include, for example, rooftop repairs or trimming trees that shade the PV system.
- **Possible higher property taxes:** While a PV system may help to raise the site's property value, there is also a potential increase in property taxes when the property value is reassessed. Different states, however, have different policies in regards to these possible property tax increases.

ⁱ Berkeley National Laboratory report (2011) - <http://emp.lbl.gov/sites/all/files/REPORT%20bnl-4476e.pdf>

ⁱⁱ Solar Market Insight Q2 2012 – Executive Summary. <https://www.slideshare.net/SEIA/us-solar-market-insight-report-q2-2012>

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For more information, please visit www.seia.org.

The Grid of the Future

By Devon Manz,
Reigh Walling,
Nick Miller,
Beth LaRose,
Rob D'Aquila, and
Bahman Daryanian

FOR OVER A CENTURY, THE MISSION of the power industry has been to build and operate a reliable, affordable, and efficient grid. In the past few decades, developed regions have focused on increasing operational efficiency, while emerging economies have focused on attracting capital to grow their grids. Changing markets, new technologies, and an emerging societal focus on emissions have moved the industry in a new direction. The emergence of modern power electronics, widespread software development, and low-cost communications technologies creates opportunities. The cost-effective extraction of oil and gas in North America is expected to shift our generation mix away from coal and toward natural gas-fired generation. Wind and solar power have proliferated, creating new challenges and opportunities. Advancements in energy storage technologies have revolutionized the consumer electronics industry and paved the way for hybrid and electric vehicles (EVs). In parallel, the resiliency of the aging electric power infrastructure has been questioned in light of the increased frequency and severity of natural disasters, making a

Digital Object Identifier 10.1109/MPE.2014.2301516
Date of publication: 17 April 2014



- ✓ Coal plant retirements
- ✓ Wind and solar power
- ✓ Gas-fired generation
- ✓ Electric vehicles
- ✓ Energy storage
- ✓ Distributed generation
- ✓ Management of distributed solar power
- ✓ Dynamic reactive power sources
- ✓ Demand management
- ✓ Maintaining grid resiliency with microgrids

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Ten Trends That Will Shape the Grid Over the Next Decade

stronger case for a major investment to build a stronger, more resilient, and sustainable U.S. grid.

Ten Key Trends

Today's electric power industry also manages the interplay of many moving parts and stakeholders. Local, state, and federal policies, the emergence of power marketplaces, and competition drive a fundamental shift away from traditional planning and design disciplines. New evaluation methodologies and analytical tools are being developed to address these emerging needs. This article focuses on presenting the authors' views on ten key trends and their potential impact on shaping the grid of the future.

- ✓ *Coal plant retirements:* Pending regulations and potential greenhouse gas (GHG) policies could lead to a significant retirement of coal-fired generation in the United States. How will the U.S. grid cope with a significant loss of base-load power generation?
- ✓ *Wind and solar power:* Industry's confidence in reliably accommodating nondispatchable resources is increasing while technical advances reduce the cost of wind and solar power. Will we continue to see growth in wind and solar resources?
- ✓ *Gas-fired generation:* Flexible gas-fired generation offers rapid ramping, turn down, and short start times, ideally suited to accommodate more wind and solar generation additions and cope with the retirement of less flexible, aging base-load generation. How will market forces reward the flexibility that will reduce system-wide costs and emissions?
- ✓ *Electric vehicles:* Electric vehicles are increasingly entering the transportation sector. Significant infrastructure investments and policy support will be needed in the near term to accelerate EV adoption. How important is "smart vehicle charging" and economic incentives in this transformation?
- ✓ *Energy storage:* Energy storage faces a cost challenge relative to alternate solutions to the challenges that face the grid. Storage can be an alternative for frequency regulation or short-term reserves. What hurdles must be overcome to see more widespread storage projects? Can storage technologies play a major role in a resilient grid?
- ✓ *Distributed generation:* Distributed generation (DG) growth is being driven by policy [e.g., subsidies and incentives for rooftop solar photovoltaics (PVs)], but DG can provide efficient energy when both electricity and heat are needed in combined heat and power (CHP) applications. Are we going to see DG and microgrids displacing the need for a conventional grid?
- ✓ *Management of distributed solar power:* Rapid growth in distributed solar PVs could challenge the ability of the grid to manage voltage and loading in the distribution system and will create opportunities for new distribution management and voltage control solutions. How will integration challenges impact growth in PVs, and what types of solutions will emerge?
- ✓ *Dynamic reactive power sources:* The retirement of power plants situated near loads, the growth of asynchronous wind and solar power generators, and changing loads on the grid will challenge the grid's reactive power reserves and ability

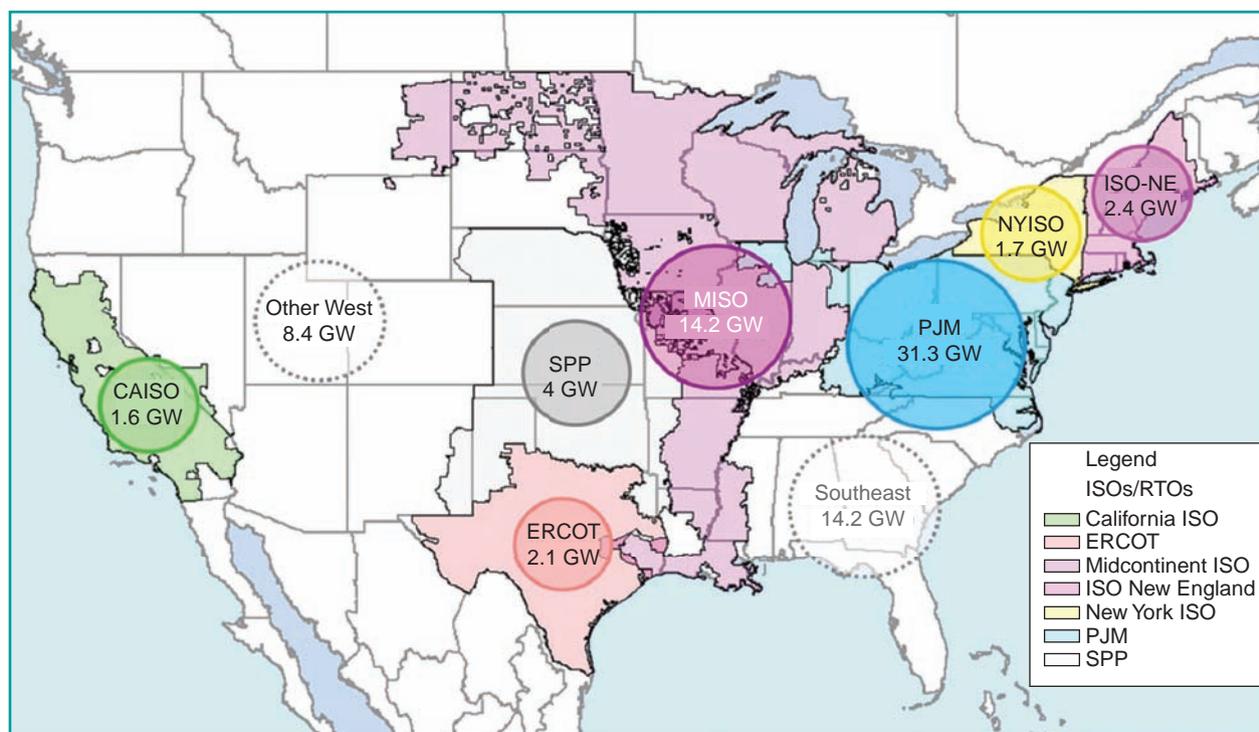


figure 1. Potential coal retirements (map created with Ventyx, an ABB Company, Energy Velocity Suite, Intelligent Map).

to maintain voltage stability. How will the grid maintain steady state and dynamic voltage support?

- ✓ *Demand management:* Generation resources were historically built to provide low-cost electricity and ancillary services and capacity to meet reliability at peak load. Today, demand management can provide these same services. What is the right mix and types of programs and incentives that can maximize the benefits of demand management?
- ✓ *Maintaining grid resiliency with microgrids:* Natural disasters, such as Hurricane Sandy, have registered strongly in the minds of policy makers and have motivated towns, cities, and electric utilities to provide greater operational resiliency for a wide range of critical infrastructure and services. What is the role of small microgrids in providing resiliency to the grid?

While there may be other trends driving the evolution of the grid, the authors expect these ten trends to be at the heart of the discussion in the coming years. The remainder of this article is devoted to more in-depth discussions of each trend.

Coal Plant Retirements

Coal plant owners face an important decision: Should they invest to comply with the proposed environmental regulations or retire their plants? The Environmental Protection Agency (EPA) has proposed a set of rules/standards to reduce air and water pollution: the Cross-State Air Pollution Rule (CSAPR), Clean Water Act Section 316(b), and regulations around hazardous air pollutants such as mercury and

air toxics standards, GHGs, and coal combustion residual disposal. In August 2012, CSAPR was vacated by the U.S. Court of Appeals and has reverted back to previous requirements, the Clean Air Interstate Rule, until a valid version of CSAPR can be proposed and implemented. To continue operating, EPA regulations will require coal plant owners to retrofit their plants with environmental control technology or retire the affected coal units altogether.

Based on the authors' estimates, 17 GW of coal capacity was retired from 2010 through September 2013, and about 69 GW more is likely to retire or mothball through 2021 for a total of ~86 GW of coal retirements. The majority of the remaining coal capacity is likely to be retrofitted with technology, such as flue gas desulfurization and baghouses, for a projected cost of approximately US\$90 billion expended in 2013 and beyond. Figure 1 shows the projected coal retirement capacity by NERC subregion.

To maintain reliability levels, it is estimated that about 40–50 GW of new capacity will be needed in the United States by 2020 to replace retirements, meet load growth, and maintain reliability. The price of natural gas, the cost of compliance, and the cost of gas-fired generation will affect the rate and amount of coal generation retired. With near-term gas prices around US\$4/mmBtu, a high retirement scenario is being born out as reflected in the current estimates of 86-GW total retirements.

The evolution of future EPA regulations is not known, but as it stands, the power industry has opened the door for new generation capacity. Historically, drivers for new

generation have hinged on economic growth and the associated load growth that follows. Today, the impact of policy and regulations for environmental sustainability and energy security are also drivers for growth. Historically low natural gas prices and the potential retirement of significant coal-fired generation suggest there could be a resurgence of development in new gas-fired generation over the coming decades.

Wind and Solar Generation

The United States has installed more than 50 GW of wind power, with the vast majority in under a decade. This growth, enabled by cost reductions, improvements in availability and reliability, and strong policy support, continues in the near term. Years in which the coveted wind energy production tax credit was available saw rapid growth in wind power, while years in which the tax credit did not exist saw a significant

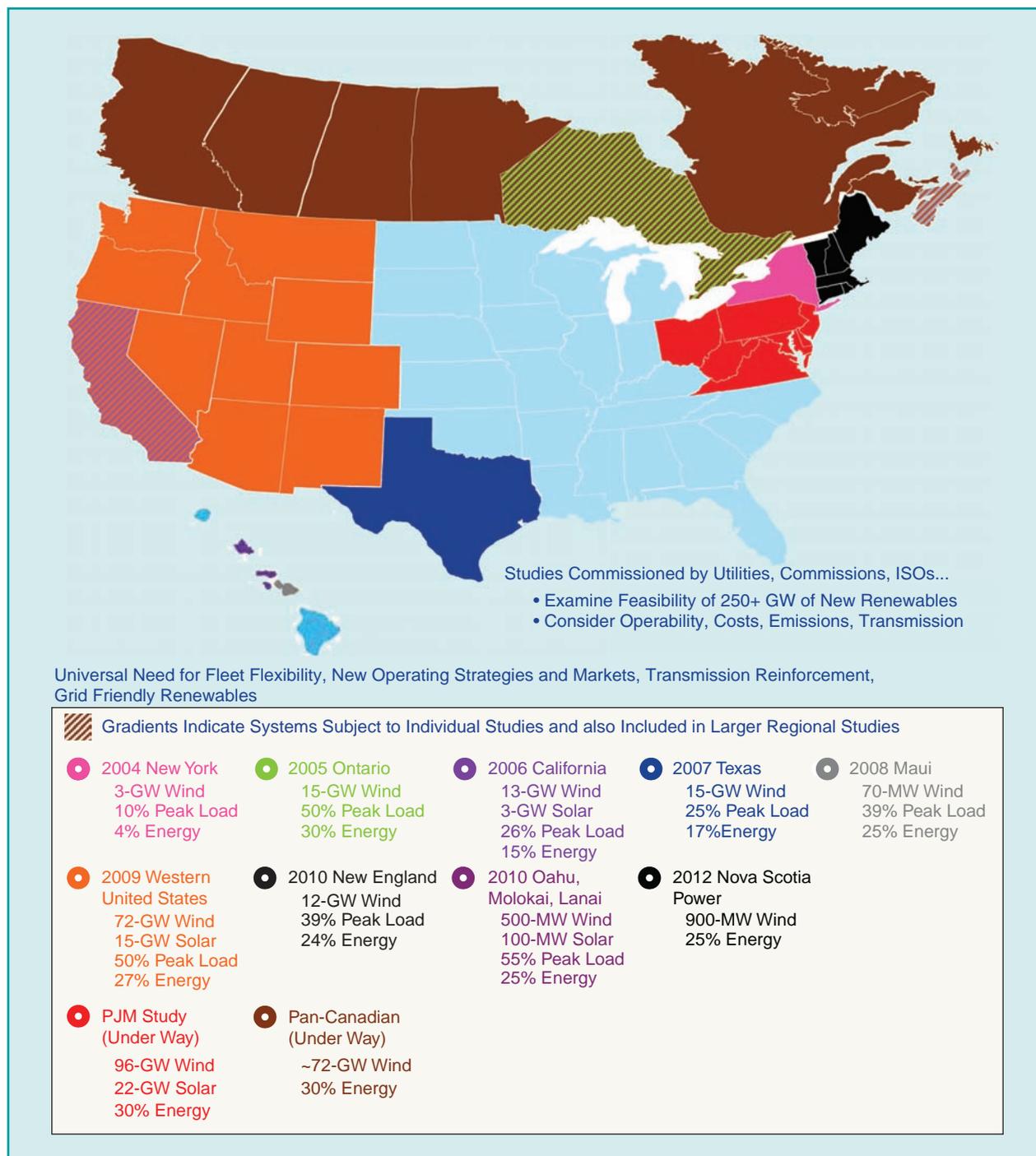


figure 2. Recent GE wind and solar integration studies.

Smart vehicle charging strategies will be critical to avoid potentially dramatic increases in generation, transmission, and distribution capacity requirements.

drop in new wind projects. While many states have renewable portfolio standards, it is not clear if the targets will suffice for continued wind power growth.

Like wind power, the value proposition for solar also relies on policy support in the form of feed-in tariffs in some European countries, an investment tax credit in the United States, and various state-by-state policies ranging from tax credits and renewable energy certificates to net metering policies to renewable portfolio standards. Each of these policies strengthens the value proposition for solar power. It is expected that strong policy support will continue to drive new wind and solar power in the United States. And as solar PV technology rapidly rides down the cost curve, solar power will continue to become more economical. Solar PVs have seen explosive growth in the United States over the past year or two, with PV capacity installations exceeding wind in 2012. In some parts of the United States, solar PVs are on a trajectory to become a significant resource in the generation mix. Wind and solar power continue to grow, even as load growth has slowed. Slow load growth in North America and Europe, and lower natural gas prices in North America, are challenging the economics of wind and solar

power. Also, the subsidy to retail PVs provided by net metering policies is under increasing challenge as it inherently involves the transfer of costs to non-PV customers. In the near term, policy support is needed to maintain growth for both wind and solar power.

Gas-Fired Generation

As both wind and solar resources increasingly constitute a significant portion of the generation mix, questions have been raised about the capabilities of the grid to manage the variability and uncertainty of wind and solar power. Numerous wind integration studies have been completed over the past decade, led by groups like the National Renewable Energy Laboratory, various utilities, state commissions, independent system operators, and regional transmission organizations, with each examining the performance and economic impact of integrating high levels of wind power in different regions of the world. A summary of the wind and solar integration studies that GE has led or contributed to is shown in Figure 2. These studies suggest that integrating enough wind power to generate more than 30% renewables by energy is possible, provided the system has adequate generation flexibility, transmission capacity, control area cooperation, and grid requirements for wind plants, to name a few. However, the capacity value of wind power remains relatively low, depending on the geographic diversity of the wind power plants, the size of the control area, and the strength and nature of the wind resources. The uncertainty and variability associated with wind and solar power demands flexibility from the rest of the generating fleet. Flexible generation will be needed as wind and solar plants are built out. Faster starting times, the capability to back plants down further, and higher unit ramping capabilities are emerging as key needs to support the build out of significant levels of wind and solar power.

As the economics for recovering unconventional natural gas improve, North American natural gas prices are expected to remain relatively low. The relatively low gas prices and the potential retirement of significant levels of coal-fired generation over the next decade will further promote the build out of new natural gas-fired generation. Wind, solar, and gas-fired generation will play a substantial role in the grid of the future.

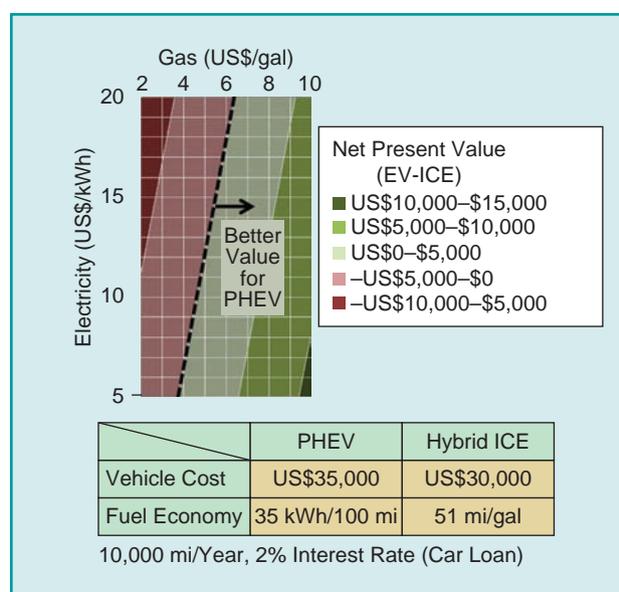


figure 3. Break-even economics for a hybrid ICE and a PHEV. The maintenance costs for each vehicle were assumed to be equal. (Used with permission from “Integrating Electric Vehicles into the Power System,” 2011 CIGRE Symposium).

Electric Vehicles

EVs and plug-in hybrid EVs (PHEVs) are slowly emerging as alternatives to conventional gasoline-fueled vehicles but will

Synchronous condensers are expected to re-emerge as a tried and tested approach to maintaining a stiff grid voltage for stable operation of the grid of the future.

continue to need strong incentives and a relatively high cost of gasoline to be viable. A key driver for these vehicles in the United States is the desire to reduce U.S. dependence on oil and reduce tailpipe emissions. Today there is strong policy support with a U.S. tax credit of up to US\$7,500 for new EVs and PHEVs, which substantially covers the cost of the battery system, estimated today to cost as much as US\$10,000 per vehicle, depending on the vehicles' range.

At today's gasoline and electricity prices, it will be some time before EVs are truly a cost-competitive alternative to conventional gas-fueled vehicles without policy support. If the cost of batteries is substantially reduced and a new car buyer, who drives 10,000 mi per year, is faced with a decision to buy a US\$35,000 PHEV or a US\$30,000 gas-fueled vehicle, the driver should still opt for a gas-fueled vehicle if economics are the determining criterion for the buyer. Today, a Toyota Prius achieves 51 mi/gal. A PHEV driving in all-electric mode is the favored alternative to a Prius only when gasoline prices exceed US\$6/gal, assuming that the PHEV is charged with US\$.18 per kWh electricity. Even if the price of electricity were US\$.07 per kWh, the price of gasoline would still need to exceed US\$4/gallon for the economic value of the PHEV to exceed that of the Prius. This is shown in Figure 3. At today's fuel prices, lower battery costs and stronger incentives are needed for these vehicles to make substantial inroads into the transportation sector. Even if the cost of the battery falls by 50%, incentives will still be needed to enable widespread growth of EVs and PHEVs. It took more than ten years for hybrid vehicles to constitute 2.5% of the U.S. vehicle market. It may take many years for EVs to reach a significant portion of the vehicle fleet.

If EVs are able to gain a substantial share of the automotive market, they will drive substantial load growth. A recent GE study showed that, for one region, transitioning 10% of the light-duty vehicle fleet to EVs would increase the load energy by ~5%. The implementation of a charging infrastructure for EVs and PHEVs offers a substantial new business opportunity. For the system studied, "smart" vehicle charging costs 19% less than serving uniform load growth, while completely uncontrolled charging costs 24% more (see Figure 4). These savings could be used to invest in the technologies needed to enable smart charging, provide customer incentives that promote controlled charging, and provide savings to customers. For the system examined, the difference in energy production cost between uncontrolled and smart charging equated to ~US\$300/year per PHEV

owner. In addition to the energy production cost savings, there are savings due to avoided power generation and delivery infrastructure otherwise needed to support increased peak demand driven by uncontrolled charging.

Uncontrolled EV charging can result in a substantial increase of peak load and a deterioration of system load factor. The peak-load increase could drive a substantial, and uneconomical, increase in generation, transmission, and distribution capacity to support this peak. Of these, the generation capacity costs to meet increased peak are typically dominant. If EV charging is appropriately controlled, the required energy can be supplied without an increase in peak system demand, and thus the high costs of incremental generation capacity to support EV charging can be avoided or deferred. Controlled EV charging could prove to be a significant beneficial asset for managing light load system operational challenges. However, even with the control of system peak demand, there may be the impact of EV charging on

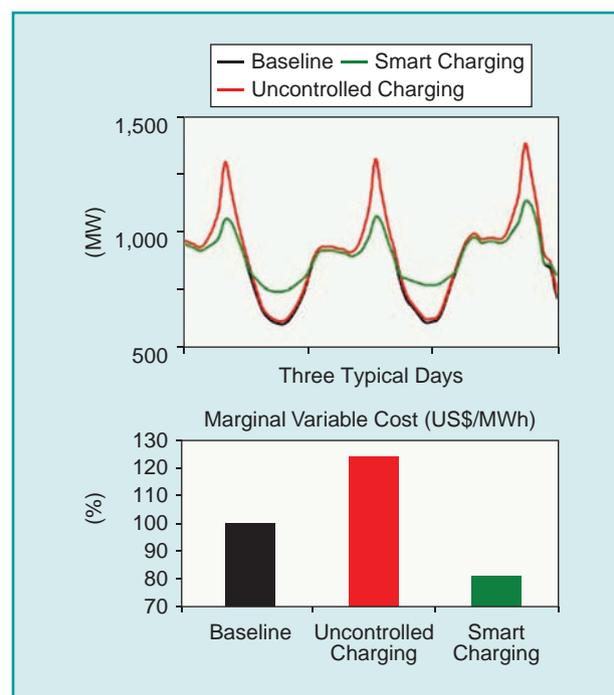


figure 4. Marginal variable cost of serving the EV load for two EV charging strategies, with respect to the marginal cost of serving uniform load growth. (Used with permission from "Integrating Electric Vehicles into the Power System," 2011 CIGRE Symposium.)



figure 5. GE/GNB and Metlatkla Power and Light battery energy storage system in Alaska. (Reprinted with permission from George Hunt, GNB/Exide.)

transmission and distribution assets due to localized EV concentration or loading factors not directly related to just peak demand, such as limiting transformer cool-down during off-peak periods. Replacing overloaded transformers, reconfiguring heavily loaded distribution circuits, and building new substations may be needed in areas that experience sudden increases in EV charging loads. These system modifications and equipment additions/upgrades are expected to be manageable and reasonably small relative to the cost of the EVs and the charging infrastructure if charging patterns are managed. Smart vehicle charging strategies will be critical to avoid potentially dramatic increases in generation, transmission, and distribution capacity requirements.

Energy Storage

The grid is the ultimate “just-in-time” system, instantaneously serving customer load with generation that is precisely dispatched and controlled to match the load. Energy storage presents the capability to relax this constraint. Historically, the power system has been designed and controlled to manage variability in load by increasing or decreasing the output of generation. Wind and solar power exacerbate the variable power needed from the rest of the generation. However, studies by the authors suggest that the variability of wind and solar power, when more than 30% of the annual energy is generated by these resources, can be managed by the grid. Generally, the significant wind and solar variability smoothing effect observed over large areas (similar to that of the load smoothing effect of a neighborhood relative to that of a single home) does not necessitate the *need* for energy storage. However, the grid is demanding more flexibility. This is manifesting in a greater need for frequency regulation and reserves. Wind turbine manufacturers have responded to this trend and advanced wind turbine technology to better manage variations in wind power output. For example, GE is currently offering a hybrid wind turbine with integrated battery energy storage that can competitively self-supply incremental ancillary services, given suitable power market structures.

While storage has not yet found widespread use in the grid, a long list of potential applications for storage has been cited. Applications that require substantial energy ratings range from capturing lower cost energy to displace higher

cost energy at a later time, price arbitrage, or shifting energy from one time to another to avoid overloading equipment. In general, these applications do not currently offer strong value propositions as the cost of energy-storage technologies is high relative to energy prices and conventional approaches for managing overloaded equipment. It is the applications that demand the sudden injection or removal of energy of short durations that seem to offer the greatest value. Niche applications already exist, and more are emerging. Isolated systems with very high electricity costs also tend to have relatively high regulation and reserve requirements. Meeting some of these ancillary service requirements with energy storage rather than high-cost fossil fuel generation has the potential to be highly economical. For utilities operating in regions of the United States where there are no organized power markets, the evaluation of energy storage versus other sources of operational flexibility needs to be done on a cost-avoidance basis, rather than from ancillary service market revenues. For example, in the 1990s, GE worked with GNB/Exide Technologies to build a battery storage system in Metlatkta, Alaska, to reduce the use of expensive diesel-fired generation. The system is shown in Figure 5. The roughly US\$2 million battery system reduced the diesel fuel bill by more than US\$6 million over its 12 years of operation.

Even in large grids, storage can be an alternative provider of regulation. The application of storage in this case is not driven by necessity but must be economically competitive with generation flexibility. Power market prices for frequency regulation vary daily and seasonally. During periods of scarcity, prices can be high. The cost of storage for frequency regulation is approaching the average current prices for regulation in some energy markets. It remains to be seen if energy storage, without subsidies, can be truly competitive in the regulation application.

More applications are also being observed. Urban centers experiencing line or transformer overloads, with no room available for new equipment, may benefit from storage located closer to the loads to avoid expanding the substation or reconfiguring the lines. In September 2013, the California Public Utilities Commission issued a proposed Decision Adopting Energy Storage Procurement Framework and Design Program to address the policies and mechanisms for the procurement of electric energy storage pursuant to California Assembly Bill (AB) 2514. One of the objectives is to employ storage technology to help maximize existing generation and transmission investment and operation, integrate renewables, and minimize GHG emissions. The framework sets forth the storage targets for the investor-owned utilities and the procurement requirements for other load-serving entities in California, the procurement mechanisms, and the program evaluation criteria.

Ultimately, storage is another resource that can provide the grid with flexibility. As the grid evolves, flexibility requirements are likely to increase, and traditional sources of flexibility may be displaced. As the cost of storage

decreases and more applications emerge, storage will contend with strong competitors in the form of demand response (DR), flexible fossil fuel-based generation, and other emerging technologies. While there are no challenges in the operation or performance of the grid for which storage is the only solution, applications where storage is the best technical and most cost-effective alternative do exist.

Distributed Generation

Electric power infrastructure originated over a century ago when isolated small generators supplied nearby loads. As the infrastructure rapidly evolved, the benefits of a system based on centralized generation emerged. Central generation within interconnected systems produced benefits of scale, diversification of loads, improved energy resource flexibility, and increased reliability. These outweighed the costs of the transmission and distribution infrastructure needed to connect the central generation with distributed loads and set a trend that evolved toward a large interconnected grid. More recently, regulatory changes, technical advancements, and environmental impacts have led to a significant increase in DG applications.

The definition of DG is somewhat ambiguous. There is presently no uniformly accepted industry definition, and definitions can vary from nondispatchable solar PVs located on the customer side of the meter to cogeneration facilities at large industrial sites with ratings of 100 MW or more. The drivers behind most customer-owned DG applications can be tied to one or more of the following:

- ✓ Utilize a locally available energy source that cannot be easily transported, such as biogas or sun.
- ✓ Increase efficiency by generating electricity and using exhaust for heating (CHP).
- ✓ Provide lower-cost electricity than that of the local utility. This may involve peak shaving for commercial facilities billed for demand charges.
- ✓ Take advantage of policy-driven economic incentives such as feed-in tariffs, net-metering rules, and rebates specific to DG.
- ✓ Increased reliability to a facility where the DG is located.
- ✓ Fulfill social and sustainability goals, including the desire to be independent from the utility, create microgrids for resiliency and security, and other similar values that cannot be measured purely in a pro-forma analysis.

Independent power producers and utilities may choose to connect at the distribution level when the scale of their development is small or when policy provides specific incentives for distribution interconnection. In general, generation built close to load, in locations that alleviate transmission congestion, will generate greater revenue in the wholesale market. Some utilities have also implemented strategies where DG is used to alleviate localized overloads of existing distribution substation capacity, where the cost of the next substation capacity step is excessive relative to the size of the overload.

The value of DG in offsetting transmission and distribution capacity requirements, however, is much less, and more indirect, than commonly perceived. To provide an effective substitute for transmission and distribution assets, DG output must be available at the time of system peak. This usually requires that the DG be dispatchable and contractually obligated to provide support when needed. Also, because individual generation equipment has a lower reliability and availability than the utility service we receive at our homes, DG redundancy needs to be considered. Where only a few DG units are involved, the costs to provide reliable capacity could be sizeable.

While wind generation and hydro power are presently the largest renewable energy sources in the grid, solar PVs represent the most rapidly growing DG segment. In general, the unsubsidized cost of PV is high relative to alternate forms of generation. When PVs are connected “behind the meter” on the roofs of customers, the electricity produced will displace the electricity typically provided by the utility. Where net metering tariffs are in place, the effective value to the owner of the generated energy is equal to the retail energy rate. Today, many utilities recover their fixed service costs through retail rates based entirely on the energy provided to the customer. Since the grid service will still be needed on the cloudy days when PVs are unable to entirely displace the utility electricity supply, much of the fixed service costs remain unchanged. Thus, utilities may need to consider alternative tariff structures to adequately recover these fixed costs without placing undue burden on the customers who are not self-generating. These alternatives could include demand charges, similar to those experienced by industrial customers, or larger fixed service charges. Either will tend to decrease the energy-based electricity rates. While PVs are approaching grid parity relative to conventional volumetric (kWh-based) retail electricity rates in some regions of the country, pricing mechanisms may change to ensure that the true cost of electric service is properly reflected in its price.

The aforementioned drivers for DG will continue to increase their presence in the grid of the future. The dominant driver for DG in North America will be policy, particularly those that promote renewable generation and grid resiliency. Distributed solar PVs and CHP will likely be the most pervasive form of DG. While growth in DG will continue, there is a long-term cost savings driver toward a grid comprised of centralized generation.

Managing Distributed Solar PV

Solar PVs have historically been applied as a small-scale distributed resource. However, in recent years, there has been explosive growth in large utility-scale PV power plants, with some facilities currently planned to exceed several hundred megawatts of capacity. Unlike wind, solar PVs do not suffer a large cost penalty when scaled to a small size. Thus, PV installations in the future are expected to be well divided

Solutions for intelligent distribution controls that provide necessary coordination between many devices, including distributed PV, are evolving.

between small distributed applications and large utility-scale plants.

The integration of large-scale PV plants in the transmission system can follow the successful model already established by wind integration, with the consequential impact of variability treated in the same manner. At the distribution level, locally high penetrations of connected PV capacity can be very disruptive to operations. Power variability due to intermittent cloud shading of PVs, in itself, is not of concern at the distribution level because energy balance is achieved on a much wider basis at the transmission level. However, the consequential impact of power variability is voltage variation that can cause premature failure of utility voltage-regulating equipment and power quality degradation for all customers served by the distribution system.

While energy storage is often discussed as a mitigating approach, voltage variations can, in most cases, be much more economically addressed using reactive power. Dynamic reactive devices, such as static synchronous compensators (STATCOM) and static var compensators (SVCs) can be applied to mitigate voltage variations at the feeder level and cover the temporal range of PV variability that cannot be mitigated by mechanically switched voltage regulators. IEEE Standard 1547 has until recently prevented PVs from participating in providing mitigation of these problems. Recent modifications to the standard have opened the door for advanced inverters to use their reactive power capability to help mitigate voltage variations caused by PVs. Solutions for intelligent distribution controls that provide necessary coordination between many devices, including distributed PVs, are evolving and are expected to help manage this emerging challenge that faces the grid.

Dynamic Reactive Power Sources

The growth in wind and solar power and DG and the retirement of coal plants and other large aging central-station generation plants will have an unintended consequence on the performance of the transmission system. Today, many of the oldest thermal units are located near large urban load centers. These units, which may be retired or displaced in the near future, often provide essential voltage support and needed short-circuit strength. This dynamic support is critical to maintain a strong and stiff voltage for the stability of the grid during and after disturbances such as the loss of a major transmission line. Unlike active power (watts), the need for and the provision of reactive power (vars) is highly

locational. Since utility-scale wind and solar plants tend to be built far from load centers, the reactive power produced on a remote windy plain or out in the sunny desert is of little value to maintaining voltage in urban load centers.

Historically, nearly all electricity transmitted through the grid was delivered via synchronous generators equipped with excitation systems. In contrast, wind and solar use asynchronous generating technologies that contribute little to short-circuit strength. Wind and solar energy can provide the necessary dynamic reactive power to the grid to support voltage for normal operating conditions, but these asynchronous generators do not create the same level of voltage stiffness during deep grid disturbances as conventional synchronous generators. In addition to loss of dynamic reactive capability near load centers, there is growing evidence that the aggregate load on the grid is becoming less “grid friendly.” Modern electronic loads, air conditioning, and computers can all increase the requirement for dynamic reactive support. The retirement of conventional generators and the displacement of remaining generators with wind and solar power could alter the present systems’ capabilities to manage disturbances on the grid.

Generation retirements are typically announced fewer than two years before the planned retirement date, making the lead time for needed grid reinforcements short and transmission solutions impractical. For many voltage problems, shunt capacitors are a relatively inexpensive approach and can be installed quickly. However, shunt capacitors cannot regulate voltage dynamically due to the discrete switching necessary for operation. Power electronics, such as SVCs, have been used successfully for many years to meet dynamic voltage regulation requirements but require a stiff grid voltage that is created by nearby generation. More advanced power electronic devices such as STATCOM can provide improved performance in a weaker grid, but in a very weak grid they still have limited ability to stabilize voltage during a disturbance. The most robust and often the only viable option is synchronous condensers, which replicate the dynamic reactive power capability of a conventional power plant without the capability of generating power for the grid. An emerging trend in North America is the conversion of retired generation to synchronous condensers. This involves removing the turbine and operating the synchronous generator to produce only reactive power. This is often a very attractive approach from both a system performance and economic perspective.

Wind, solar, and gas-fired generation will play a substantial role in the grid of the future.

As loads become less grid friendly, as more wind, solar, and other asynchronous forms of power generation displace conventional power plants, and as older plants are retired, the grid will need both local dynamic reactive power sources and the means to maintain adequate short-circuit strength. Synchronous condensers are expected to re-emerge as a tried and tested approach to maintaining a stiff grid voltage for stable operation of the grid of the future.

Demand Management

Demand management or DR covers the whole range of demand-side resources from direct load control (operators disconnect load on demand) to responsive demand based on dynamic pricing and other control signals (price schedules or signals are passed to customers to incent load reduction). The advent of new technology is enabling more sophisticated and engaging DR options that, coupled with dynamic pricing, are making possible more flexible and robust customer response behavior. Smart grid innovations in advanced metering infrastructures, communications, home emergency management systems, and smart appliances are making DR both technologically feasible and economically viable, enabling a wider deployment.

Despite the relatively slow economy, utility and retail DR programs are being driven by state regulatory commissions and by utilities in need of managing their peak demand and reducing long-term capacity costs. Furthermore, FERC orders #719 and #745 are opening up opportunities for the participation of DRs in wholesale markets, with DR to be paid ISO locational marginal prices and to be treated similarly to supply-side resources in energy, capacity, and ancillary services markets. DR benefits utilities, customers, and the power system in a number of ways, including deferring the need for new investment in generation and transmission, increased reliability, and increased economic efficiency by price responsive (and price-elastic) demand.

FERC estimates that, if the current level of DR is preserved through the next decade, DR would shave 38 GW off U.S. peak demand in the year 2019, and, with dynamic pricing, the total potential could range between 14 and 20% of peak demand or 138–188 GW depending on whether dynamic pricing is deployed on an opt-in or opt-out basis. The Brattle Group estimates US\$65 billion in cost avoidance in the United States through 2030 from DR. With the proper alignment of technology, pricing, and incentives, DR is expected to play a key role in the value proposition for the grid of the future.

Grid Resiliency

Recent disasters in the United States, such as the 9/11 terrorist attack in 2001 and Hurricane Sandy in 2012, have highlighted a vital need for preventing power disruptions and blackouts that paralyze the operations of essential services and disrupt the provision of key necessities to the population at large. These include such services as those provided by the first responders, police departments, fire houses, hospitals, emergency shelters, elderly care facilities, water utilities, sewage treatment facilities, public transit systems, and other essential government and business operations.

According to the U.S. Department of Energy, outages caused by severe weather such as thunderstorms, hurricanes, and blizzards account for 58% of outages observed since 2002 and 87% of outages affecting 50,000 or more customers.

In June 2011, President Obama released “A Policy Framework for the 21st Century Grid,” which set out a four-pillared strategy for modernizing the electric grid. The initiative directed billions of dollars toward investments in 21st century smart grid technologies focused on increasing the grid’s efficiency, reliability, and resilience, thereby making it less vulnerable to weather-related outages and reducing the time it takes to restore power after an outage. Recently, in August 2013, the Executive Office of the President issued the report “Economic Benefits of Increasing Electric Grid Resilience to Weather Outages,” which estimates the annual cost of power outages caused by severe weather between 2003 and 2012 and describes various strategies for modernizing the grid and increasing grid resilience.

One such strategy to make certain critical areas of the system more robust is by employing microgrids. Microgrids can be a useful means of providing electric service resiliency to certain areas by enabling sustainable operations and uninterrupted functioning of critical load in islanded mode in the event of widespread disruptions in electric utility services. The U.S. Department of Energy defines the term “microgrid” to mean “a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode.” Well-designed microgrid systems, which may include a combination of DG, energy storage, and DR, with an intelligent system platform that enables system integration, communication, monitoring, and smart control, would function

seamlessly in a sustainable manner during contingency periods and judiciously utilize available resources on a selective manner to ensure continued operation of the critical loads.

Microgrids are particularly applicable when a facility or condensed load area has relatively secure intrafacility interconnections (e.g., underground distribution) but is supplied by relatively vulnerable connections to the grid. In the more general situation of entirely overhead supply and local distribution lines, the distribution secondaries and laterals tend to be more vulnerable to storm damage than the trunk feeders and subtransmission lines. With the likely unavailability of local interconnections following a storm or disaster, the microgrid model is less applicable in this more general situation.

Microgrids are just one potential approach to improving resiliency. A comprehensive strategy considers all the measures available, including intelligent approaches such as automated distribution reconfiguration, as well as lower-technology approaches such as moving distribution underground and increasing tree trimming.

Moving forward, a necessary step is the development of national and regional policies that place value on a resilient energy supply. These policies should focus on the definition and achievement of desired outcomes, such as the preservation of power supply to critical loads. Policies should be technology neutral, allowing existing and new strategies, including microgrids, to meet their objectives. In any event, all future systems designed for resiliency may have to be custom designed and implemented on a case-by-case basis to be suitable for their intended settings (e.g., urban, suburban, and rural) and appropriate for a different mix of government, civic, and business entities within each setting. The grid of the future will employ a spectrum of existing and new technologies to ensure grid resiliency during and following disasters.

Conclusions

New technologies, changing market conditions, more frequent extreme weather events, and new regulations and policies all shape the future of the grid. This is true for both the emerging and developed economies of the world. The many moving parts of policy, regulations, and market conditions and the cost and performance of new and existing technology makes it difficult to place bets as a product vendor, utility planner, or investor. While many factors will shape the future of the grid and many others can alter its course, the ten trends described in this article are some of the key drivers that will shape the grid over the next decade.

For Further Reading

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Acknowledgments

Parts of this article are updated from earlier versions that have been published by B. Daryanian, H. Elahi, E. LaRose, R. Walling, "Trends for the Grid of the Future," CIGRE U.S. National Committee, 2012 Grid of the Future Symposium, Kansas City, Missouri, USA. Section 4 contains material presented at the 2011 CIGRE Symposium by D. Manz, N. Miller, and G. Hinkle, "Integrating Electric Vehicles into the Power System."

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Selling Into the Sun:

Price Premium Analysis of a Multi-State Dataset of Solar Homes

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**SELLING INTO THE SUN:
PRICE PREMIUM ANALYSIS OF A
MULTI-STATE DATASET OF SOLAR HOMES**

Prepared for the
Office of Energy Efficiency and Renewable Energy
Solar Energy Technologies Office
U.S. Department of Energy

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January 19, 2015

This work was supported by the Office of Energy Efficiency and Renewable Energy (Solar Energy Technologies Office) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

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Acknowledgements

This work was supported by the Office of Energy Efficiency and Renewable Energy (Solar Energy Technologies Office) of the U.S. Department of Energy (DOE) SunShot Initiative under Contract No. DE-AC02-05CH11231. For funding and supporting this work, we especially thank Minh Le, Kelly Knutsen, Elaine Ulrich, Christina Nichols, and Ammar Qusaibaty (DOE). For providing the data that were central to the analysis contained herein, we thank Joshua Tretter and Debra Sinclair (CoreLogic Inc.) as well as the many individuals involved in providing us address data, especially James Loewen of the California Public Utilities Commission. Additionally we thank Cassandra May of SUNY Ulster in New York for her help in exploring pool prevalence among PV homes. Finally, we would like to thank the many external reviewers for providing valuable comments on an earlier draft version of the report, including Matt Brost (SunPower), Lisa Desmarais (Peak to Peak Appraising, LLC), Mari Hernandez (SolarCity), Robert Dietz (National Association of Homebuilders), Timothy Treadwell (California Center for Sustainable Energy), Laura Reedy Stukel (Elevate Energy), Greg Lampman (New York State Energy Research and Development Authority), and Le-Quyen Nguyen (California Energy Commission). Of course, any remaining errors or omissions are our own.

Abstract

Capturing the value that solar photovoltaic (PV) systems may add to home sales transactions is increasingly important. Our study enhances the PV-home-valuation literature by more than doubling the number of PV home sales analyzed (22,822 homes in total, 3,951 of which are PV) and examining transactions in eight states that span the years 2002–2013. We find that home buyers are consistently willing to pay PV home premiums across various states, housing and PV markets, and home types; average premiums across the full sample equate to approximately \$4/W or \$15,000 for an average-sized 3.6-kW PV system. Only a small and non-statistically significant difference exists between PV premiums for new and existing homes, though some evidence exists of new home PV system discounting. A PV green cachet might exist, i.e., home buyers might pay a certain amount for any size of PV system and some increment more depending on system size. The market appears to depreciate the value of PV systems in their first 10 years at a rate exceeding the rate of PV efficiency losses and the rate of straight-line depreciation over the asset's useful life. Net cost estimates—which account for government and utility PV incentives—may be the best proxy for market premiums, but income-based estimates may perform equally well if they accurately account for the complicated retail rate structures that exist in some states. Although this study focuses only on host-owned PV systems, future analysis should focus on homes with third-party-owned PV systems.

Key words: photovoltaic, PV, solar, homes, residential, property value, selling price, premium, hedonic, California, new homes, existing homes, host-owned

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1. Introduction

As of the second quarter (Q2) of 2014, solar photovoltaic (PV) energy systems have been installed on more than a half million homes in the United States; more than 42,000 systems were installed in Q2 alone, roughly four times the number installed in the same quarter in 2010 (SEIA & GTM, 2014). This growth is in part related to the dramatic decrease in installed PV costs over the last 10 years (Barbose et al., 2014) as well as the increase in financing options for property owners installing PV, such as leased PV systems and other zero-money-down purchase options (SEIA & GTM, 2014).

As PV installations have proliferated, so has the number of transactions involving homes with PV (Hoen et al., 2013b). Because of this, the real estate sales and valuation communities have been working to enable a better understanding of the valuation of PV systems and green features more generally (Adomatis, 2014). For example, courses on the marketing and valuation of green features are available through the Appraisal Institute and the NATIONAL ASSOCIATION OF REALTORS® (NAR)¹; green attributes for a multiple listing services data dictionary have been recommended by a working group of the NAR (2014); the Appraisal Institute has developed a “Residential Green & Energy Efficient Addendum” to capture green attributes during an appraisal²; PV Value®, a web-based tool specifically designed for the valuation of PV systems, has been developed (Klise et al., 2013); the National Home Performance Council and CNT Energy developed a blueprint to make energy improvements more visible in the real estate market (CNT Energy & NHPC, 2014); Fannie Mae, in its updated standards for conforming loans it will repurchase, now mentions homes with solar panels and the need to “adjust” the appraised value of the home if the market warrants it (Fannie Mae, 2014); and, finally, the Federal Housing Administration has proposed requirements for valuing “Special Energy Related Building Components” in its *Draft Single Family Housing Handbook*, which governs conforming loans for homes with PV systems (FHA, 2014).

Despite the activity around valuing (and marketing) PV homes, little research documents the premiums for these homes. Farhar and Coburn (2008) first documented the apparent increase in values for 15 PV homes inside a San Diego subdivision. This was later corroborated by strong empirical evidence from greater San Diego and Sacramento (Dastrup et al., 2012) and from a relatively large dataset of approximately 1,900 California PV homes (Hoen et al., 2011; 2013a; 2013b); these studies employed hedonic pricing models to estimate premiums. Finally, a case study of 30 PV homes that sold in the Denver metro area found evidence of premiums (Desmarais, 2013). Because the evidence that PV homes garner a premium has focused on a relatively small number of California homes and a few in Colorado, there is need for further evidence of premiums outside of California and even inside California. There is also a need to analyze transactions that occurred after the recent housing bubble, the period from which most previous data had been collected and analyzed (Hoen et al., 2011; 2013a; 2013b).

In most local markets, few PV home sales occur, thus appraisers and other real estate professionals (real estate agents, lenders, underwriters, etc.) often cannot compare similar PV and non-PV home sales to derive a PV premium. Because of this, valuation professionals often use other methods to value PV systems, including the income and cost methods (Adomatis, 2014; FHA, 2014). Hoen et al. (2013b) used hedonic (regression) modeling, employing similar methods as the sales-comparison approach, and found premiums larger than the contributory values generated with the cost and income approaches—a counterintuitive result. Possible reasons for this result include issues with the underlying dataset, which

¹ See, e.g., <http://www.appraisalinstitute.org/education/education-resources/green-building-resources/> and <http://www.greenresourcecouncil.org/>.

² See <http://www.appraisalinstitute.org/professional-practice/professional-practice-documents/new-residential-green-energy-efficient-addendum/>.

included sales from homes with a very wide range of prices and sales that occurred largely during the housing boom. In addition to that California-based study, Desmarais (2013) compared the three methods in her analysis of 30 Colorado sales but did not use statistical tests. Therefore, additional comparison of the various methods—using a more recent dataset, statistical methods, and a broader group of transactions—would be a valuable contribution to the literature.

Other considerations are important as well. The gross installed costs (i.e., costs before state and federal incentives) of PV systems have declined steadily in recent years, while net costs (i.e., with incentives included) have remained fairly stable (Barbose et al., 2014). Examining premium changes over this period might indicate how the market responds to signals from gross and net costs. Moreover, over the same period, the housing market saw significant swings: the housing bubble, the subsequent crash, and then the recovery. Understanding whether observed PV premiums varied over this period would help illuminate how enduring these premiums might be. There also has been evidence that the new home market in California heavily discounted PV homes during the housing boom and bust (through 2009) in comparison to the premiums garnered by existing home sellers (Hoen et al., 2011; 2013a).³ Therefore, examining how new home PV premiums fared in relation to existing home premiums within an expanded dataset would be of interest.

In addition, others have explored the existence of a green cachet, such as the “Prius effect” and other forms of “conspicuous (non)consumption,” where buyers appear to pay more for a “green” item than they will save over its life in decreased energy costs (White, 1978; Kahn, 2007; Sexton, 2011). Dastrup et al. (2012) find larger PV premiums where more Prius hybrid vehicles are registered, which they use as a proxy for environmental leanings. This analysis concentrated on only the San Diego and Sacramento areas, thus analysis of a broader dataset is warranted.

Finally, previous literature suggests the need for more research on the market’s depreciation of aging PV systems, especially for systems greater than 6 years old, which have not been well studied because of the immaturity of the PV market (Hoen et al., 2011; 2013a; 2013b). A clearer understanding of how the market depreciates PV systems would likely enhance appraisal techniques.

In summary, there are a number of gaps in the literature, each of which the present research seeks to address:

1. Are PV home premiums evident for a broader group of PV homes than has been studied previously both inside and outside of California and through 2013?
2. Are PV home premiums outside of California similar to those within California?
3. How do PV home premiums compare to contributory values estimated using cost and income methods?
4. How did the size of the premium change over the study period, as gross PV system prices decreased and during housing market swings?
5. Are premiums for new PV homes similar to existing PV home premiums?
6. Is there evidence of a “green cachet” for PV homes above the amount paid for each additional watt added?
7. How does the age of the PV system influence the size of the PV premium?

³ These discounts, it was assumed, were offset by decreased marketing times (i.e., “sales velocity”) for these homes, a priority for home builders as the market for new homes slowed and inventories increased (Dakin et al., 2008; Farhar and Coburn, 2008; SunPower, 2008).

It is important to clarify that this research focuses on only host-owned PV systems and therefore excludes third-party-owned systems, which, we recommend, should be the focus of future research.

The remainder of this report is organized as follows: Section 2 discusses our methodological approach; Section 3 details the data used for the analysis; and Section 4 presents the results, followed by a discussion of the results in Section 5 and conclusions in Section 6. An appendix detailing cost estimate preparation follows the references.

2. Methodological Approach

To examine the questions above, this research relies on a hedonic pricing model—the “Base Model”—against which a series of other models are compared. Those other models use a subset of the data (e.g., new or existing homes), an interaction term(s) (e.g., age of the PV system), or other variants to examine the various research questions and test the overall robustness of the results.

The basic theory behind the hedonic pricing model starts with the concept that a house can be thought of as a bundle of characteristics. When a price is agreed upon between a buyer and seller, there is an implicit understanding that those characteristics have value. When data from a number of sales are available, the average marginal contribution to the sales price of each characteristic can be estimated with a hedonic regression model (Rosen, 1974; Freeman, 1979; Sirmans et al., 2005). This relationship takes the basic form:

Sales price = f (home and site, neighborhood, and market characteristics)

“Home and site characteristics” might include, but are not limited to, the number of square feet of living area and the presence of a PV system. “Neighborhood” characteristics might include such variables as the crime rate and the distance to a central business district. Finally, “market characteristics” might include, but are not limited to, temporal effects such as housing market inflation/deflation.

2.1 Base Model

The “Base Model” to which other models are compared uses a relatively simple set of home and site characteristics: size of the home (i.e., square feet of living area); age of the home at the time of sale (in years); age of the home squared (in years); size of the parcel (in acres) up to 1 acre; and any additional acres more than 1 (in acres).⁴ It also includes the presence and size of the PV systems. To control for neighborhood, we include a census block group fixed effect, which, in all cases, includes at least one PV home and one non-PV home.⁵ Finally, market characteristics are accounted for by including a dummy variable for the quarter and year (e.g., 2013 Q2, 2009 Q1, etc.) in which the sale occurred. This model form was chosen for its relative parsimony, its high adjusted R², and its transparency.⁶ It is estimated as follows:

$$\ln(P_{itk}) = \alpha + \beta_1 (T_i) + \beta_2 (K_i) + \sum_a \beta_3 (X_i) + \beta_4 (PV_i \cdot SIZE_i) + \varepsilon_{itk} \quad (1)$$

⁴ Acres is entered into the model as a spline function using two variables, up to 1 acre (*acreslt1*) and any additional acres above 1 (*acresgt1*), to capture the different values of up to the first and additional acres of parcels in the sample. Therefore *acreslt1* = *acres* if *acres* ≤ 1 and 1 otherwise, while *acresgt1* = *acres* - 1 if *acres* > 1 and 0 otherwise. Additionally, square feet and age squared are entered into the model in 1,000s to allow for easier interpretation of the coefficients.

⁵ A census block group contains approximately 600 to 3,000 people. By including this fixed effect, and requiring each to contain at least one PV and one non-PV home, the PV estimates are, therefore, essentially a comparison of those two home types within the block group, while controlling for temporal and characteristic differences between them.

⁶ Model choice for this work was based on extensive robustness model exploration in previous analysis (Hoen et al., 2011; 2013a; 2013b). Other models were explored but are not presented here. They include adding other home and site parameters such as number of bathrooms, condition of the home, and if a pool is present, all of which further limited the dataset but did not substantively affect the results. Similarly, instead of using a fixed effect for sale year and quarter, interacting sale year and, separately, sale quarter, with a geographic variable, such as county, to control for geographic variation in market inflation/deflation was explored with no change to the results.

where

P_{itk} represents the sale price for transaction i , in quarter t , in block group k ,

α is the constant or intercept across the full sample,

T_i is the quarter t in which transaction i occurred,

K_i is the census block group k in which transaction i occurred,

X_i is a vector of a home and site characteristics for transaction i ,

PV_i is a fixed-effect variable indicating a PV system is installed on the home in transaction i ,

$SIZE_i$ is a continuous variable for the size (in kW) of the PV system installed on the home prior to transaction i ,⁷

β_1 is a parameter estimate for the quarter in which transaction i occurred,

β_2 is a parameter estimate for the census block group in which transaction i occurred,

β_3 is a vector of parameter estimates for home and site characteristics a ,

β_4 is a parameter estimate for the change in sale price for each kilowatt added to a PV system, and

ε_{itk} is a random disturbance term for transaction i , in quarter t , in block group k .

The parameter estimate of primary interest in this model is β_4 , which represents approximately the marginal percentage change in sale price over the average sale price of the comparable set of non-PV homes within the same census block group, with the addition of each kilowatt of PV.⁸ If differences in selling prices exist between PV and non-PV homes, we would expect the coefficient to be positive and statistically significant.

This model allows an examination of many of the research questions depending on the dataset that is used. If the full dataset is used, the first question can be answered. If a subset of the dataset is used, many of the other questions can be answered. For example, if homes within and outside California are used, the second question can be explored. Similarly, if the data are restricted to particular subsets of the study period (e.g., 2002–2007, 2008–2009, 2010–2011, or 2012–2013), the fourth research question could be examined. To explore if new or existing homes had similar premiums (the fifth question), the data could be restricted to those subsets. Finally, if only PV systems of particular ages were used, the seventh question could be answered. Therefore, almost all of the research questions can be answered using subsets of the data, leaving only the sixth question regarding green cachet, which requires a slightly altered model and will be discussed next, and the third question, which can use either the full dataset or subsets of the data but also requires calculations of comparison valuation estimates using the cost or income method.⁹

⁷ All references to the size of PV systems in this paper, unless otherwise noted, are reported in terms of direct-current watts or kilowatts under standard test conditions. A discussion of this convention is offered in Appendix A of Barbose et al. (2014).

⁸ To be exact, the conversion to percent is actually $\text{EXP}(\beta_4)-1$, but the differences are often *de minimis*.

⁹ Although the preferred method is to estimate a separate model using a subset of the data, which allows all of the controlling parameters to take different values for each subset, we also explored estimating models with a categorical variable for each of the subsets interacted with either the variable of interest only or both the variable of interest and the other controlling parameters, with no substantive change in the results.

2.2 Base Model Variation: Size of PV System Model

Although the Base Model and variations to the subsets of data allow examination of almost all the research questions, the sixth question requires a slightly altered model: the Size of PV System Model. If the market exhibits a green cachet, theoretically a fixed amount might be added to the value of a home with PV regardless of the size of that PV system. Therefore, for smaller systems, a premium expressed in dollars per installed watt would be larger than it would be for larger systems, representing a decreasing marginal premium for each watt added to a PV system. To examine decreasing marginal returns, a second-order polynomial is added, and therefore we estimate the following model:

$$\ln(P_{itk}) = \alpha + \beta_1(T_i) + \beta_2(K_i) + \sum_a \beta_3(X_i) + \beta_4(PV_i \cdot SIZE_i) + \beta_5(PV_i \cdot SIZE_i^2) + \varepsilon_{itk} \quad (2)$$

where

$SIZE_i^2$ is a continuous variable for the squared size (in kilowatts) of the PV system installed on the home prior to transaction i , and

β_5 is a parameter estimate for the change in sale price for each additional squared kilowatt added to a PV system, and all other variables are as shown in Equation (1).

The parameter estimates of primary interest in this model are β_4 and β_5 . If decreasing marginal returns exist for increasing sizes of PV systems, we would expect the β_4 coefficient to be positive and larger and the β_5 coefficient to be negative and smaller.

2.3 Model Summary

Combining the Base Model, the use of various subsets of data, and the Size of PV System Model allows examination of the seven research questions listed in Section 1. The full set of research questions, models, and sample sets are described in Table 1.

Table 1: Summary of Research Questions, Models, and Sample Sets

Research Question	Equation	Model Name	Sample Set(s)
1. Are PV home premiums evident for a broader group of PV homes than has been studied previously both inside and outside of California and through 2013?	Equation (1)	Base Model	All Data
2. Are PV home premiums outside of California similar to those within California?	Equation (1)	Location Models	CA vs. Non-CA Homes
3. How do PV home premiums compare to contributory values estimated using the cost and income methods?	Equation (1)	Various Models	All Data, or Subsets of Data, But Compare Results To Income and Cost Methods
4. How did the size of the premium change over the study period, as gross PV system prices decreased and during housing market swings?	Equation (1)	Year of Sale Models	Subsets of Years in Sample Period (e.g., Pre-'08; 08-09, 10-11, Post 11)
5. Are premiums for new PV homes similar to existing PV home premiums?	Equation (1)	Home Type Models	New vs. Existing Homes
6. Is there evidence that there is a "green cachet" for PV homes over and above the amount paid for each additional watt added?	Equation (2)	Size of PV System Model	All Data
7. How does the age of the PV system influence the size of the PV premium?	Equation (1)	Age of PV System Models	Subsets of PV System Ages (e.g., < 2 years; 2-4; 5-6; 7-14 years)

2.4 Robustness Models

We also explore the robustness of our results with two alternative model specifications.

2.4.1 PV Only Model

It has been well documented that PV homes often have a suite of additional energy-efficiency (EE) features (CPUC, 2010; Hee et al., 2013; Langheim et al., 2014). Further, it has been theorized that PV home owners, who have the financial resources to install a PV system, might also make other (non-EE) upgrades, such as a new kitchen or bathroom, or may alternatively replace their roof contemporaneously with PV system installation. Therefore, the premium estimated from Equation (1) could also include effects of EE and other features and therefore overestimate the effect related to PV alone.

To test this, PV homes are compared to other PV homes based on system size. While the Base Model estimates a difference in sales prices between PV and non-PV homes, all else being equal, the PV Only Model compares the difference between PV homes and PV homes based on differences in their PV system size, all else being equal. Assuming all PV homes have the same frequency of EE and other features among them, an effect free of those influences can be estimated and then compared to the results in Equation (1).¹⁰

One complication of this model concerns possible collinearities of the block group fixed effects and PV when a single or small number of PV homes exist within a single block group. While in the Base Model the use of the block group fixed effect is appropriate, because each contains at least one PV and one non-PV home, in the PV Only Model collinearities might exist for block groups with only one or a few PV homes, or those that might have only similarly sized PV systems. In those block groups, the fixed effect might absorb the contributory effect of the PV variable. Therefore, this model uses the county as the fixed effect and is restricted to counties that have two or more PV homes, to allow more heterogeneity between the PV homes within the fixed effect delineation and therefore less collinearity between them and the PV variable; otherwise the model is identical to Equation (1).¹¹

2.4.2 Repeat PV Home Model

A common concern with hedonic modeling, such as the Base Model, is that a suite of home and site characteristics are not controlled for, which could be driving the results. These omitted variables could include any manner of home features, such as granite countertops, a newly renovated basement, and Jacuzzi, as well as neighborhood features, such as location on a cul-de-sac, a scenic vista, or location next to a major road. These variables could be present for PV and non-PV homes. Although the assumption is that these unobserved features are randomly distributed among PV and non-PV homes, and therefore are not correlated with the presence of PV, this might not be the case. This can be tested using the Repeat PV Home Model.

The Base Model estimates a difference in sales prices between PV and non-PV homes all else being equal, but the Repeat PV Home Model compares sales prices of homes before they had PV installed to prices of the same homes after they had PV installed. Because many of the characteristics controlled for

¹⁰ It is at least conceivable that EE and other features are correlated with PV system size, with a larger PV system correlated with more EE and other features. We expect, however, that this would likely be more correlated with the size of the home, which is controlled for in this and the Base Model.

¹¹ Although not shown here, using county fixed effects in the Base Model in place of block group fixed effects has no apparent effect on the premium estimate, and therefore this PV Only Model can be compared directly to the Base Model results. Also, this model assumes a tradeoff with being able to compare PV homes to PV homes, and therefore controlling for the unobservables associated with PV, versus controlling for the unobservables associated with the localized neighborhood effects that the block group fixed effect controls for.

in the Base Model are held constant in the Repeat PV Home Model, such as block group and size of the home and parcel, they do not need to be controlled for.¹² Therefore, the following greatly simplified model can be estimated:

$$\ln(P_{itk}) = \alpha + \beta_1(T_i) + \sum_a \beta_2(X_i) + \beta_3(PV_i \cdot SIZE_i) + \varepsilon_{itk} \quad (3)$$

where

X_i is a vector of age of the home and age squared for transaction i ,

β_2 is a vector of parameter estimates for age and age squared,

β_3 is a parameter estimate for the change in sale price for each additional kilowatt added to a PV system, and all other variables are as defined in Equation (1).

¹² Ideally we would have information on the size of the home as of the first sale and the second sale, but we only have information from the most recent assessment and therefore can only assume that it has not changed between sales. If it has changed, however, it would have likely increased the home's value, thus the second sale would include the increase in related value. If this were the case, the PV premium would capture this increase. Our results do not exhibit this increase, so it is assumed that the Repeat PV Home Model results are free of this influence.

3. Data Preparation and Summary

This section describes the underlying data used for this analysis—including PV home and non-PV home data, cost estimates, and income estimates—followed by a data summary.

3.1 PV and Non-PV Home Data

For the Tracking the Sun (TTS) report series (e.g., Barbose et al., 2013), Lawrence Berkeley National Laboratory was provided a set of approximately 150,000 host-owned (i.e., not third-party-owned) PV home addresses by various state and utility incentive providers, along with information on PV system size, date the incentive was applied for, date the system was put into service, and the average tilt and azimuth of the PV system, where available.¹³ These data span the years 2002–2012 and stretch across eight states: California, Connecticut, Florida, Massachusetts, Maryland, North Carolina, New York, and Pennsylvania.¹⁴

These PV home addresses were matched to addresses maintained by CoreLogic,¹⁵ which CoreLogic aggregates from county-level assessment and deed recorder offices. Once the addresses were matched, CoreLogic provided, when available, real estate information on each of the PV homes as well as similar information on approximately 200,000 non-PV homes located in the same (census) block group as the PV homes. The data for both of these sets of homes included, but were not limited to:

- address (e.g., street, street number, city, state and zip+4 code);
- most recent and previous (if applicable) sale date and amount;
- home characteristics (e.g., acres, square feet of living area, bathrooms, pool, and year built¹⁶);
- assessed value of land and improvements;
- parcel land use (e.g., commercial, residential);
- structure type (e.g., single-family residence, condominium, duplex); and,
- x/y coordinates.

These data were cleaned to ensure all data were populated and appropriately valued.¹⁷ Using these data, along with the PV incentive provider data, we determined if a home sold after a PV system was installed, significantly reducing the usable sample because the majority of PV homes have not yet sold. We also culled a subset of these data for which previous sale information was available and for which a PV system

¹³ For a full discussion of how these data are obtained, cleaned, and prepared, see Barbose et al. (2013).

¹⁴ The TTS dataset also included data on PV homes from other states, including Illinois, New Mexico, New Hampshire, Oregon, Texas, and Vermont. However, after matching to the CoreLogic sales transaction dataset and cleaning to ensure all the homes that did sell had data that were fully populated and appropriately signed, no PV home sales existed from these states.

¹⁵ More information about this product can be obtained from <http://www.corelogic.com/>.

¹⁶ Year built, along with previous sales information and a CoreLogic-provided flag on new homes, allowed for a determination of whether the home was newly built or existing at the time of sale.

¹⁷ Because the CoreLogic data sometimes are missing or miscoded, the cleaning and preparation of these data were extensive and therefore not detailed here, but the process included the following screens: sale price greater than \$165,000 and less than \$900,000, size of the home between 1,000 and 5,000 square feet, sale price per square foot between \$8 and \$800, sale year after 2001, and size of the parcel between 0.05 and 10 acres.

had not yet been installed as of this previous sale. These “repeat sales” were used in the Repeat PV Home Model described in Section 2.4.2 .

Ideally, for each PV home transaction, we would have a set of identical (i.e., all else being equal) non-PV home transactions for comparison. This theory underlies the comparable-sales method used by appraisers and other valuation professionals (Adomatis, 2014), where comparable homes are chosen that are as similar as possible, and then adjustments are made to account for the observable differences.

To emulate the comparable-sales method, we employed the Coarsened Exact Matching (CEM) process (King et al., 2010), which finds a matched sample of PV and non-PV homes that are statistically equal on their covariates.¹⁸ The covariates include being within the same block group, selling in the same year, and having similar values for size of the home, age of the home, size of the parcel, and ratio of assessed value of land to total assessed value.¹⁹ This procedure results in a reduced sample of homes to analyze, but biases related to the selection of PV and non-PV homes are minimized.²⁰ The unmatched dataset has 173,982 non-PV homes and 5,373 PV homes, while the matched dataset—the one used for the analysis—has 18,871 non-PV homes and 3,951 PV homes. Various models, as described above, use subsets of the PV homes and therefore will need matching non-PV homes. For most of the subsets this is straightforward, because we divide the PV and non-PV homes along the same lines used for the CEM matching, such as whether the homes are located in California or the rest of the United States, or if they are newly built homes or existing. For the Age of PV Systems models, though, there is not an intuitive division for the non-PV homes, because age of the PV system was not used for matching. Therefore, for these models the CEM process was employed again for each set of PV homes. The resulting matched non-PV homes were not necessarily mutually exclusive between the sets of PV homes, but most importantly each block group contained at least one PV home and one non-PV home.

3.2 Cost Estimates

In this analysis, as in previous studies (Hoen et al., 2011; 2013a; 2013b), we compare the market premiums we find using our Base Model and alternative models to cost and income contributory-value estimates to illuminate how the market might be reacting to various signals. A cost estimate refers to the cost to replace an asset with a new equivalent. Appraisal theory posits that cost estimates are likely important price signals in the marketplace, and market values normally should not exceed the replacement cost of an asset. This might mean, for example, that a buyer of a PV system already installed on a home is not willing to pay more for it than the cost of a new system (i.e., its replacement cost).

For this analysis, we prepared two sets of cost estimates: gross costs and net costs, the detailed preparation of which is described in Appendix A. In this context “net” implies a cost after federal and state tax incentives and state rebates are factored in, while “gross” estimates do not factor these incentives

¹⁸ The procedure used, as described in the referenced paper, is CEM in Stata, available at: <http://ideas.repec.org/c/boc/bocode/s457127.html>. Because this matching process excludes non-PV homes that are without a statistically similar PV match (and vice versa), a large percentage of homes (approximately 90% of non-PV and 33% of PV) are *not* included in the resulting dataset. Pre-matching Multivariate Distance (0.95) compares favorably to post-matching Distance (0.82).

¹⁹ The assessed value of land to total value ratio is expected to capture the unexplained within-block group locational variation that often is present, for example, due to being on a quiet road, abutting a park, or being on the waterfront. Assessed values, it is assumed, are consistently applied within the block group.

²⁰ Although the preferred model is one with a matched dataset, the Base Model was also estimated using the unmatched dataset, which results in a slightly higher estimated premium. We attribute this change to the heterogeneity of the unmatched PV and non-PV homes and the fact that the unmatched non-PV homes have lower-valued unobserved characteristics.

in.²¹ We distinguish between the two because the ability of the homeowner to benefit from the incentives depends somewhat on their tax obligations. For example, the federal incentive for PV comes in the form of a reduced federal tax obligation (formally known as the Internal Revenue Code Section 25D: Residential Energy Efficient Property Credit). If a homeowner expects to pay very little in taxes (e.g., because they have a mortgage and very little taxable income), then the federal tax incentive might not be realized immediately (it can be carried over year to year). A similar scenario exists if state tax incentives are present. More generally, incentive availability changes with time, so home buyers may have some uncertainty about what incentives might be available, and their value. Because of these different scenarios, it is not immediately clear if the market would fully capitalize the incentives calculated as part of the net cost, thus net cost can serve as the low cost estimate for our purposes. Similarly, we expect that buyers would not be willing to pay more than the gross cost, which thereby serves as the high cost estimate.

Finally, in previous analyses, we prepared cost estimates depreciated using a straight-line 20-year depreciation schedule, assuming this would be roughly equivalent to the usable life of a PV system (Hoen et al., 2011; 2013a; 2013b). For the present analysis we use, instead, the un-depreciated amount. In doing so, we do not presuppose how the market depreciates PV systems and/or the replacement costs of those systems; rather, we allow the market to dictate how best to depreciate their values, if at all. This is the customary approach of appraisers (Adomatis, 2014).

3.3 Income Estimates Using the PV Value Algorithm

As with cost estimates, appraisal theory posits that income estimates—a discounted stream of income derived from an asset over time, such as rent—are likely important price signals in the marketplace. For example, an apartment seller might not be willing to sell a property for significantly less than the present value of rent (minus costs) it receives for that property. Similarly, the buyer and seller of a home with a PV system might use the discounted value of the system's energy cost savings as a key factor in determining any PV premium.

For each of the PV homes in our sample, we prepared data to estimate the present value of energy bill savings (income estimates) using the size and age of the system, the zip code of the home, and the estimated tilt and azimuth of the system.²² These inputs were fed through the PV Value algorithm (Klise et al., 2013) to produce estimates for utility bill savings for a similarly sized system as of the time of sale.²³

The algorithm is outlined by Klise and Johnson (2012), and the inputs for our current research effort are based on the following: the expected energy output of the PV system after the sale date and assuming a life span not greater than the warranty life of the panels (usually 25 years); an electricity retail rate at the time of sale and an escalation of the rate similar to the historical escalation over the previous years; discount rates as of the time of sale, which, for the purposes of this study, are equivalent to 100 basis points above the 30-year, fixed mortgage, 60-day Fannie Mae lock-in rate at the time of sale; a system

²¹ Other incentives exist, such as state renewable energy credits, feed-in tariffs, and performance-based incentives, but these are rare throughout the analysis dataset and therefore are not considered. Understanding how to value them appropriately should be the subject of future research, however, because their value can be significant in certain circumstances.

²² Because tilt and azimuth were not available for all PV systems (the data were not provided during the TTS data-collection effort), they were estimated via a cascading approach, based on systems with those data in the same census block group if available, then, if not available, census tract or, finally, county when needed.

²³ The estimation procedure produces a set of low, average, and high estimates of the present value of the expected energy output, based on a risk premium of 50, 100, and 200 basis points, respectively. Only the average value was used for this analysis.

direct current-to-alternating current derate factor of 0.77%; a module degradation factor of 0.5% per year; and an expected inverter replacement at 15 years. Tiered rates, which are prevalent in California, are not considered here, but instead an average zip-code level rate is used, as is the default for PV Value. We return to this issue in Section 5, where we discuss results from the model estimation in comparison to the income estimates.

The descriptions of the income estimation procedure are contained elsewhere (Klise and Johnson, 2012; Appendix A in Hoen et al., 2013b; Klise et al., 2013) and therefore are not detailed here.

3.4 Data Summary

The final dataset includes 22,822 transactions, consisting of matched PV ($n = 3,951$) and non-PV ($n = 18,871$) homes. This full matched dataset is composed of transactions occurring across eight states (Table 2) from 2002 to 2013 (Table 3), with the vast majority in California. All PV systems in this dataset are homeowner owned as opposed to third-party owned (leased or under a power-purchase agreement).

Table 2: Frequency Summary of PV and Non-PV Homes by State

State	Non-PV Homes	PV Homes	Total
CA	18,207	3,828	22,035
FL	317	25	342
Mid-Atlantic Region: MD, NC, PA	288	77	365
Northeast Region: CT, MA, NY	59	21	80
Total	18,871	3,951	22,822

Table 3: Frequency Summary of PV and Non-PV Homes by Sale Year

Sale Year	Non-PV Homes	PV Homes	Total
2002	107	18	125
2003	196	31	227
2004	238	53	291
2005	197	56	253
2006	348	64	412
2007	818	242	1,060
2008	1,251	453	1,704
2009	1,762	429	2,191
2010	2,751	504	3,255
2011	3,341	642	3,983
2012	3,928	694	4,622
2013	3,934	765	4,699
Total	18,871	3,951	22,822

Summary statistics for the PV and non-PV homes are shown, respectively, in Table 4 and Table 5. The mean sale price (sp) of the PV homes in the sample is \$473,373 and ranges from a minimum of \$165,500 to a maximum of \$899,500. The average PV home in the sample has 2,334 square feet of living area

(*sfla*), is located on a parcel of 0.45 acres (*acres*), and was 17 years old (*age*) when it sold in 2010 (*sy*).²⁴ It has a 3.6-kW PV system (*size*), which was installed 2.7 years before the home was sold (*pvage*). The gross installed cost for a similarly sized PV system in the same county at the time of sale was \$6.90/W (*grosscost*), while the net cost (after incentives) was \$4.14/W (*netcost*). The present value of the stream of energy produced by the PV system, as calculated by the PV Value algorithm, is \$2.93/W (*income*). PV systems in the sample range in size from 0.1 kW to 14.9 kW, with a median of 2.8 kW (*size*). The age of the PV systems at the time of sale ranges from new to more than 13 years, with a median of 2.2 years (*pvage*). For the 18,871 non-PV homes, we find a mean sale price of \$456,378, which is \$16,995 lower than that of the matching PV homes. The average non-PV home is slightly smaller than the average PV home (2,319 square feet), occupies a smaller parcel (0.41 acres), and is equivalent in age. The dataset contains 7,480 newly built homes and 15,342 existing homes, of which 1,444 and 2,507, respectively, are PV homes.

Table 4: Summary Statistics for All PV Homes

variable	description	N	mean	sd	min	median	max
sy	year of sale	3951	2010	2	2002	2011	2013
syq	year and quarter of sale (yyyyq)	3951	20103	23	20021	20111	20134
sp	price of sale (dollars)	3951	\$ 473,373	\$ 196,451	\$ 165,500	\$ 433,000	\$ 899,500
lnsp	natural log of sale price	3951	12.98	0.43	12.02	12.98	13.71
sfla	living area (square feet)	3951	2,334	702	1,006	2,244	4,981
sfla1000	living area (in 1000s of square feet)	3951	2.3	0.7	1.0	2.2	5.0
acres	size of parcel (in acres)	3951	0.45	0.95	0.05	0.18	9.99
age	age of the home at time of sale (years)	3951	17	21	(2)	7	100
agesq1000	age of the home squared (in 1000s of years)	3951	0.7	1.3	0	0.0	10.0
pv	if the home has a PV system (1 if yes)	3951	1	-	1	1	1
size	size of the PV system (kilowatts)	3951	3.6	2.0	0.1	2.8	14.9
pvage	age of the PV system at time of sale (years)	3951	2.7	2.9	(0.5)	2.2	13.4
income	average PV Value estimate (\$/watt)	3951	\$ 2.93	\$ 0.57	\$ 1.18	\$ 2.92	\$ 4.98
netcost	net cost estimate (\$/watt)	3951	\$ 4.14	\$ 0.93	\$ 1.07	\$ 4.04	\$ 7.95
grosscost	gross cost estimate (\$/watt)	3951	\$ 6.90	\$ 1.50	\$ 3.15	\$ 6.92	\$ 11.83

Table 5: Summary Statistics for All Non-PV Homes

variable	description	N	mean	sd	min	median	max
sy	year of sale	18871	2010	2	2002	2011	2013
syq	year and quarter of sale	18871	20103	23	20021	20112	20134
sp	price of sale (dollars)	18871	\$ 456,378	\$ 197,004	\$ 165,500	\$ 413,000	\$ 899,500
lnsp	natural log of sale price	18871	12.94	0.44	12.02	12.93	13.71
sfla	living area (square feet)	18871	2,319	714	1,001	2,200	4,990
sfla1000	living area (in 1000s of square feet)	18871	2.3	0.7	1.0	2.2	5.0
acres	size of parcel (in acres)	18871	0.41	0.86	0.05	0.18	9.8
age	age of the home at time of sale (years)	18871	17	21	(2)	8	100
agesq1000	age of the home squared (in 1000s of years)	18871	0.7	1.3	0	0.1	10.0
pv	if the home has a PV system (1 if yes)	18871	0	0	0	0	0

²⁴ Negative values for the minimum age of a home (e.g., -2) apply to newly built homes in the sample and occur when the sale date is prior to the date of home completion, as might occur when a home is purchased on spec. Similarly, for PV system age, a negative minimum value occurs when the completion date of the PV system occurred before the home sale date, which happens sometimes for new homes. Additionally, although acres is shown in the tables, it is entered in the model as a spline function of up to 1 acre and any additional acres above 1 (see Section 2.1). Finally, age of the home squared is not shown in the tables.

4. Results

This section presents results, starting with the Base Model, which addresses the first research question: Are PV home premiums evident for a broader group of PV homes than has been studied previously? This is followed by results for the various other models, which explore the remainder of the research questions (Table 1 shows the full set of questions), and the two robustness models.

4.1 Base Model Results

The Base Model estimates, over the entire dataset, the marginal return to each kilowatt of PV installed on a home as defined in Equation (1). The model is summarized in Table 6, with full results shown in Table 7.²⁵ Overall the model performs well, with an adjusted R^2 of 0.92, indicating that it captures approximately 92% of the price variation within the 22,822 home sales located in the 1,830 census block groups that make up the sample.

Table 6: Base Model Results Summary

Total n	22,822
PV n	3,951
Non-PV n	18,871
Adjusted R^2	0.92
Dependent Variable	$\ln sp$
Block Group Fixed Effects	1,830

The full set of results is shown in Table 7. The controlling variables that account for size ($sfla1000$) and age of the home (age , $agesq1000$) and size of the parcel ($lt1acres$, for each acre up to 1, and $gt1acres$, for each acre over 1) are all highly statistically significant (i.e., p -value < 0.001). The model indicates that, in our sample, each additional 1,000 square feet adds approximately 21% to the selling price, while each acre up to 1 adds 39% and each additional acre beyond 1 adds 3%.²⁶ Each year a home ages initially takes approximately 0.7% off its value, but this annual value reduction declines with time, and homes over approximately 60 years in age appreciate in value as they age.²⁷ Using the fourth quarter of 2013 as the reference category, in our sample, prices start approximately 44% lower (Q1 2002) and then increase to approximately 20% higher (2005), before falling again to lows in early 2012 and then increasing to levels present in late 2013. This rise, fall, and eventual recovery are entirely consistent with the national trends in housing prices.²⁸ Combined, the various controlling characteristics are appropriately signed and leveled based on our expectations, giving us confidence that the model is acting appropriately and adequately capturing price differences across the sample.

Turning to the variable of interest, $pv*size$, the model estimates that, for each kilowatt of installed PV, sale prices increase by 0.91%, and this estimate is highly statistically significant (p -value < 0.001).

²⁵ All models are estimated in Stata using *areg*, with block groups as the absorbed fixed effect and with robust standard errors.

²⁶ The exact percentage interpretation of coefficients in a semi-log model is as follows: $\exp(\text{coefficient})-1$, but the differences in this context are *de minimis*.

²⁷ Approximately 60 years is determined by dividing the age coefficient by the first derivative of the square term's ($agesq$) coefficient.

²⁸ As noted previously, we also explored interacting the year of sale with the county, to capture regional price trends, with no substantive change to the results.

Accordingly, at the 95% confidence interval, average price increases are estimated to vary between approximately 0.78% and 1.05% per kilowatt, a relatively precise estimate. This sample of approximately 4,000 PV homes shows a clear premium for each kilowatt of PV installed above the sale prices of comparable non-PV homes.

By using the mean sale price (in dollars) for non-PV homes, we can convert this percentage estimate into dollars per watt.²⁹ Doing so leads to an estimated premium of \$4.18/W, with a 95% confidence interval of +/- \$0.62/W, which corresponds to a premium of approximately \$15,000 for an average-sized system of 3.6 kW. From Table 4, we see that, for these PV homes, the mean gross cost estimate is \$6.90/W, while the net cost estimate is \$4.14/W, and the average PV Value (income) estimate is \$2.93/W. Therefore, the premium in our sample is almost identical to the average net cost for a similarly sized system as of the time of sale, is approximately \$2.70/W less than the gross cost, and is \$1.25/W higher than the PV Value income estimate.

4.2 Base Model Variations Using Subsamples

As shown in Table 1, many of the research questions can be investigated using variations of the Base Model that use subsamples of the data in place of the full sample. The following sections describe those model sets and include: Location Models, for California and the rest of the United States; Home Type Models, for newly built and existing homes; Age of PV System Models; and Year of Sale Models.

4.2.1 Location Model Results

Our Location Models estimate premiums for either the subset of homes located in California or those located in the rest of the United States; Table 8 shows the results, along with results for the Home Type Models (which are discussed in the next subsection).³⁰ Also shown in the table, for reference purposes, are the results for the Base Model using the full sample. Results shown for each model include the *pv*size* coefficient, standard error, and *p*-value; the mean non-PV home sale price; the \$/W premium and its 95% confidence interval; and estimates for the net and gross costs and PV Value income. Finally, for each model, the table shows the total, PV, and non-PV sample sizes; the adjusted R²; and the number of block groups represented by the sample.

The coefficient for the variable of interest for the California subsample is 0.0091, which is highly statistically significant and equates to a \$4.21/W premium and a 95% confidence interval of +/- \$0.64/W. Not surprisingly, the PV premium is very close to the premium estimated for the full sample, because California PV homes make up 97% of that sample. The PV premium can be compared to the net, gross, and PV Value estimates of \$4.16/W, \$6.94/W, and \$2.95/W, respectively.

For homes outside of California where we have data (in Connecticut, Florida, Massachusetts, Maryland, North Carolina, New York, and Pennsylvania), the PV premium is estimated to be \$3.11/W and highly statistically significant (*p*-value < 0.01), but with a 95% confidence interval of \$2.33. This indicates that, in this broader sample of homes, a premium for PV homes is evident, but that the smaller sample of homes outside California does not allow for a very precise estimate of the effect size. The estimated premium is very similar to the net cost estimate for this subset of \$3.09/W, and it is not statistically different from the premium estimated for California homes.

²⁹ The formula for doing so is: \$/W premium = ((exp (*pv*size* coefficient)-1)* mean sale price in dollars for non-PV homes)/1,000.

³⁰ For brevity, only the variable of interest is shown for the remainder of the report. Results for the controlling variables were similarly signed and leveled across the various models as they are in the Base Model. The full set of results is available upon request.

Table 7: Base Model Results

Variable	Coefficient	Standard Error	t Statistic	p-value	- 95% CI	+ 95% CI
intercept	12.498	0.016	758.00	0.000	12.465	12.530
pv*size	0.0091	0.0007	13.12	0.000	0.0078	0.0105
sfla1000	0.213	0.004	51.70	0.000	0.205	0.221
lt1acre	0.386	0.028	13.73	0.000	0.331	0.441
gt1acre	0.029	0.006	5.08	0.000	0.018	0.040
age	-0.007	0.001	-7.86	0.000	-0.008	-0.005
agesq1000	0.056	0.009	6.63	0.000	0.040	0.073
syq						
20021	-0.441	0.034	-13.100	0.000	-0.507	-0.375
20022	-0.379	0.038	-10.060	0.000	-0.453	-0.305
20023	-0.375	0.036	-10.480	0.000	-0.446	-0.305
20024	-0.306	0.073	-4.220	0.000	-0.448	-0.164
20031	-0.087	0.056	-1.560	0.118	-0.196	0.022
20032	-0.077	0.037	-2.050	0.040	-0.150	-0.004
20033	-0.025	0.038	-0.670	0.505	-0.100	0.049
20034	-0.035	0.037	-0.950	0.343	-0.108	0.037
20041	0.001	0.031	0.040	0.972	-0.060	0.062
20042	0.095	0.021	4.430	0.000	0.053	0.137
20043	0.121	0.024	5.120	0.000	0.075	0.168
20044	0.124	0.028	4.340	0.000	0.068	0.179
20051	0.137	0.047	2.910	0.004	0.045	0.230
20052	0.204	0.039	5.170	0.000	0.127	0.281
20053	0.164	0.062	2.640	0.008	0.042	0.285
20054	0.202	0.038	5.340	0.000	0.128	0.276
20061	0.159	0.021	7.710	0.000	0.119	0.200
20062	0.163	0.021	7.900	0.000	0.123	0.204
20063	0.160	0.022	7.300	0.000	0.117	0.203
20064	0.071	0.022	3.240	0.001	0.028	0.114
20071	0.162	0.017	9.700	0.000	0.129	0.195
20072	0.124	0.020	6.170	0.000	0.085	0.163
20073	0.074	0.016	4.580	0.000	0.042	0.106
20074	0.002	0.018	0.100	0.919	-0.034	0.038
20081	0.022	0.016	1.360	0.175	-0.010	0.054
20082	-0.005	0.013	-0.380	0.707	-0.031	0.021
20083	-0.050	0.014	-3.690	0.000	-0.077	-0.023
20084	-0.066	0.014	-4.630	0.000	-0.094	-0.038
20091	-0.113	0.014	-8.070	0.000	-0.141	-0.086
20092	-0.116	0.012	-9.800	0.000	-0.139	-0.092
20093	-0.124	0.012	-10.610	0.000	-0.147	-0.101
20094	-0.120	0.012	-9.700	0.000	-0.144	-0.096
20101	-0.121	0.013	-9.030	0.000	-0.147	-0.095
20102	-0.124	0.012	-10.750	0.000	-0.147	-0.102
20103	-0.144	0.012	-11.660	0.000	-0.168	-0.120
20104	-0.171	0.012	-14.070	0.000	-0.194	-0.147
20111	-0.173	0.011	-15.170	0.000	-0.196	-0.151
20112	-0.189	0.011	-17.360	0.000	-0.211	-0.168
20113	-0.190	0.011	-17.040	0.000	-0.212	-0.168
20114	-0.205	0.011	-18.360	0.000	-0.227	-0.183
20121	-0.212	0.011	-19.000	0.000	-0.234	-0.190
20122	-0.176	0.012	-15.180	0.000	-0.199	-0.153
20123	-0.154	0.011	-13.660	0.000	-0.176	-0.132
20124	-0.123	0.012	-10.220	0.000	-0.147	-0.099
20131	-0.090	0.010	-9.480	0.000	-0.109	-0.072
20132	-0.038	0.009	-4.150	0.000	-0.056	-0.020
20133	-0.009	0.009	-1.000	0.317	-0.027	0.009
20134			---	omitted	---	

Table 8: Location and Home Type Model Results³¹

	All Homes	Location		Home Type	
		California	Rest of US	New Homes	Existing Homes
PV Premium Estimates					
PV*Size Coefficient	0.0091	0.0091	0.0085	0.0084	0.0094
PV*Size Standard Error	0.0007	0.0007	0.0032	0.0012	0.0008
PV*Size <i>p</i> -value	0.000	0.000	0.009	0.000	0.000
Mean Sale Price Non-PV (\$)	\$ 456,378	\$ 459,366	\$ 364,854	\$ 422,001	\$ 476,124
PV Premium (\$/watt)	\$ 4.18	\$ 4.21	\$ 3.11	\$ 3.58	\$ 4.51
95% CI (\$/watt)	\$ 0.62	\$ 0.64	\$ 2.33	\$ 1.00	\$ 0.71
Contributory Value Estimates					
PV Value - Income (\$/watt)	\$ 2.93	\$ 2.95	\$ 2.15	\$ 3.04	\$ 2.86
Net Cost (\$/watt)	\$ 4.14	\$ 4.16	\$ 3.09	\$ 3.85	\$ 4.29
Gross Cost (\$/watt)	\$ 6.90	\$ 6.94	\$ 5.64	\$ 7.34	\$ 6.65
Model Info					
Total <i>n</i>	22,822	22,035	787	7,480	15,342
PV <i>n</i>	3,951	3,828	123	1,444	2,507
Non-PV <i>n</i>	18,871	18,207	664	6,036	12,835
Adjusted R ²	0.92	0.93	0.88	0.97	0.91
Dependent Variable	lnsp	lnsp	lnsp	lnsp	lnsp
Block Group Fixed Effects <i>n</i>	1,830	1,721	109	155	1,766

4.2.2 Home Type Model Results

Dividing the data by the type of home, specifically whether the home was newly built or existing at the time of sale, allows examination of the differences between these subgroups. In previous analyses, premiums for existing homes were found to be significantly larger than those for newly built homes, but the sample used was smaller, only for homes in California, only extended through 2009, and included homes with sales prices up to almost \$3 million (Hoen et al., 2011; 2013a). The present analysis enables a reexamination of this question by using a sample that is larger, more broadly distributed geographically, has more recent data, and uses homes no more expensive than \$900,000.

The results from the Home Type Models that used the new and existing home subsamples are shown in Table 8. New homes have a premium of \$3.58/W, while existing homes have a premium of \$4.51/W, a difference of approximately \$1/W. Both estimates are highly statistically significant (*p*-values < 0.001) by themselves, but they are not statistically different from each other (difference in coefficients = 0.001, *p*-value = 0.46; not shown in table). Therefore, we are unable to uncover a difference in premiums between those subgroups with the larger, more geographically diverse and recent dataset. Nonetheless, the differences between these two sets of estimates mimic the different net costs, which are higher for existing homes than for newly built homes.

4.2.3 Age of PV System Model Results

Dividing the full sample into subsamples consisting of four quartiles based on PV system age (0.5–2.4 years, 2.4–3.8 years, 3.8–5.9 years, and 5.9–14 years) allows us to explore if the market accounts for PV system age when valuing PV systems. For this set of quartiles, only existing homes are used, because all

³¹ Here, as in other results tables, the numbers of block groups for subsets of data do not always sum to 1,830. This occurs when the block groups are not mutually exclusive between the subsets, e.g., with new or existing homes.

newly built homes have PV systems that are also new. Table 9 contains the results for the full set of existing homes and the four other quartile models. Each of the four quartile models uses a different set of PV homes and a set of non-mutually exclusive CEM matched non-PV homes, to which the PV homes are compared.³²

The coefficients for each progressively older subset of PV systems are monotonically ordered, going from 0.0123 for the systems 0.5–2.4 years old to 0.0055 for systems 5.9–14 years old. These translate into premiums of \$5.90/W for the newest systems and \$2.60/W for the oldest systems, with relatively stable 95% confidence intervals of approximately \$1.40/W and somewhat decreasing cost and income estimates. Clearly home buyers and sellers place greater value on newer systems than on older systems, all else being equal. Although not shown here, additional models were estimated with additional older age groups (e.g., 10–14 years), but the confidence intervals around those estimates increased such that the results were not any more revealing than what is presented here. In none of the models, however, did we find an estimate close to zero. This seems to indicate that, as systems age, their value flattens out, but additional analysis in future years is needed to understand this trend better.³³

Finally, it appears that the premiums, as systems age, start well above what would be predicted by the net cost estimates for young systems and then fall well below what would be predicted by the net cost estimates for older systems. This is an artifact of how the net cost estimates are calculated. As discussed in Section 3.2 the cost estimates are prepared without any depreciation and therefore are estimates of a new system. Of course new systems likely would not have the same value as otherwise identical older systems, but knowing the correct amount of depreciation to apply to these estimates is beyond the scope of this work.

³² As described above, because the characteristics on which the PV homes are matched to the non-PV homes are exclusive of PV system age, the set of non-PV homes (and the block groups in which they are located) are not mutually exclusive across the models, but the same rules apply to these subsets in that for each block group that contains a PV home at least one matched non-PV home is present.

³³ Additionally, we calculated a linear estimate of age of PV interacted with PV system size, which was, not surprisingly, negative and highly statistically significant. Although this reaffirms that increasing age of PV systems is highly correlated with lower premiums, by its very nature it implies that PV systems lose 100% of their value at some point in time. This was calculated to be about 13 years, but it is at the end of our dataset and is not borne out in other tests (e.g., bins shown above, polynomial interactions, and additional binning for older systems). Therefore, we conclude that older systems are of lower value, but not of no value, at least given the age distribution of 0 to 14 years contained in the sample.

Table 9: Age of PV System Model Results

	Existing Homes	Age of PV System Groups			
		0.5-2.4	2.4-3.8	3.8-5.9	5.9-14
PV Premium Estimates					
PV*Size Coefficient	0.0094	0.0123	0.0113	0.0076	0.0055
PV*Size Standard Error	0.0008	0.0014	0.0014	0.0015	0.0016
PV*Size <i>p</i> -value	0.000	0.000	0.000	0.000	0.001
Mean Sale Price Non-PV (\$)	\$ 476,124	\$ 477,737	\$ 474,560	\$ 478,634	\$ 474,476
PV Premium (\$/watt)	\$ 4.51	\$ 5.90	\$ 5.40	\$ 3.67	\$ 2.60
95% CI (\$/watt)	\$ 0.71	\$ 1.30	\$ 1.33	\$ 1.37	\$ 1.51
Contributory Value Estimates					
PV Value - Income (\$/watt)	\$ 2.86	\$ 3.06	\$ 3.03	\$ 2.83	\$ 2.52
Net Cost (\$/watt)	\$ 4.29	\$ 4.49	\$ 4.27	\$ 4.24	\$ 4.16
Gross Cost (\$/watt)	\$ 6.65	\$ 7.08	\$ 6.65	\$ 6.54	\$ 6.34
Model Info					
Total <i>n</i>	15,342	4,398	3,865	4,100	3,607
PV <i>n</i>	2,507	633	613	635	626
Non-PV <i>n</i>	12,835	3,765	3,252	3,465	2,981
Adjusted R ²	0.91	0.93	0.93	0.92	0.90
Dependent Variable	lnsp	lnsp	lnsp	lnsp	lnsp
Block Group Fixed Effects <i>n</i>	1,766	574	504	509	540

4.2.4 Year of Sale Model Results

Because the dataset spans the period from 2002 through 2013, we can examine how premiums change over time. This is especially interesting given that, in the same period, the costs for PV modules dropped (Barbose et al., 2013) and housing market prices saw a rapid rise, fall, and recovery. We break the data into four subsamples roughly consistent with these broad changes (2002–2007, 2008–2009, 2010–2011, and 2012–2013) and estimate the Base Model specification for each subsample.

Results from these models are contained in Table 10. The model results for the full dataset are also contained in Table 10 for reference. In each model, the coefficient of the variable of interest, *pv*size*, is highly statistically significant (*p*-value ≤ 0.001), with relatively stable standard errors ranging from 0.002 to 0.001, or a tenth of a percent. Despite varying levels of non-PV homes prices, which range from \$512,170 to \$440,495, premiums are relatively stable, ranging from \$3.41/W to \$4.54/W, with none being statistically different from each other over the various periods.

During this period, we see mean gross costs descend from a high of \$8.97/W in 2002–2007 to a low of \$5.45/W in 2012–2013. Net costs fall much less between these two periods, from \$5.39/W to \$3.58/W, while PV Value income estimates remain near, or slightly below, \$3/W. Despite falling gross costs, and shifts in the overall housing market, premiums remain fairly flat and not statistically different from the net costs in all periods and from the PV Value income estimates in two out of four periods.

Table 10: Year of Sale Model Results

	All Homes	Year of Sale Groups			
		2002-2007	2008-2009	2010-2011	2012-2013
PV Premium Estimates					
PV*Size Coefficient	0.0091	0.0066	0.0103	0.0083	0.0093
PV*Size Standard Error	0.0007	0.0020	0.0016	0.0011	0.0010
PV*Size <i>p</i> -value	0.000	0.001	0.000	0.000	0.000
Mean Sale Price Non-PV (\$)	\$ 456,378	\$ 512,170	\$ 440,495	\$ 448,976	\$ 453,988
PV Premium (\$/watt)	\$ 4.18	\$ 3.41	\$ 4.54	\$ 3.73	\$ 4.23
95% CI (\$/watt)	\$ 0.62	\$ 2.03	\$ 1.34	\$ 0.97	\$ 0.88
Contributory Value Estimates					
PV Value - Income (\$/watt)	\$ 2.93	\$ 2.79	\$ 2.73	\$ 3.00	\$ 3.02
Net Cost (\$/watt)	\$ 4.14	\$ 5.39	\$ 4.56	\$ 4.00	\$ 3.58
Gross Cost (\$/watt)	\$ 6.90	\$ 8.97	\$ 8.25	\$ 6.88	\$ 5.45
Model Info					
Total <i>n</i>	22,822	2,368	3,895	7,238	9,321
PV <i>n</i>	3,951	464	882	1,146	1,459
Non-PV <i>n</i>	18,871	1,904	3,013	6,092	7,862
Adjusted R ²	0.92	0.96	0.96	0.95	0.91
Dependent Variable	lnsp	lnsp	lnsp	lnsp	lnsp
Block Group Fixed Effects <i>n</i>	1,830	259	313	630	1,022

4.3 Size of PV System Model

To examine if larger PV systems garner an equal, lower, or higher marginal price premium than smaller systems, we estimate a polynomial model as described in Equation (2) with parameters for $pv*size$ and $pv*size^2$. Abbreviated results from this model are shown in Table 11. Coefficients for the first- and second-order polynomials are highly statistically significant (p -value < 0.02) and indicate decreasing marginal returns to increasing PV system size. The $pv*size$ coefficient equates to a premium of \$5.86/W, while the $pv*size^2$ coefficient corresponds to a decrease in value of \$0.53/W. Therefore, the model estimates that, up to approximately 10 kW, each increase in PV system size adds value to a home, but progressively less value for each addition. Beyond 10 kW, premium increases with increasing system size seem to flatten out, but we are less confident of the results because of the relatively few observations in this size range.³⁴

³⁴ We also estimated models using subsets of data, each containing progressively larger systems, and find a similar pattern, with decreasing \$/W premiums for increasing sizes.

Table 11: Size of PV System Model Results

	PV*Size	PV*Size ²
Coefficient	0.0128	-0.0006
Standard Error	0.0015	0.0002
<i>p</i> -value	0.0000	0.0130
Mean Sale Price Non-PV (\$)	\$ 456,377	\$ 456,377
PV Premium (\$/watt)	\$ 5.86	\$ (0.53)
95% CI (\$/watt)	\$ 1.35	\$ 0.42
Model Info		
Total <i>n</i>	22,822	
PV <i>n</i>	3,951	
Non-PV <i>n</i>	18,871	
Adjusted R ²	0.92	
Dependent Variable	lnsp	
Block Group Fixed Effects <i>n</i>	1,830	

4.4 Robustness Models

The various models estimated above, which mostly are based on the Base Model and subsets of the data, compare PV home prices to non-PV home prices. Here we estimate two Robustness Models, which allow us to examine the robustness of the results under alternative specifications: the PV Only Model and the Repeat Sales Model. The PV Only Model compares selling prices of only PV homes, while the Repeat Sales Model examines the selling prices of the same home for homes sold once before the PV system was installed and again after it was installed, as described by Equation (3). These models use both different sets or subsets of the data and different specifications of the model, which allows them to control for possible specification biases in the Base Model. They, therefore, serve as valuable comparisons to and, potentially, validations of the Base Model results.

4.4.1 PV Only Model

Results for the PV Only Model are shown in Table 12. The coefficient for *pv*size* is effectively identical to that estimated for the Base Model with the full dataset, and it is highly statistically significant (*p*-value ≤ 0.001). The fact that the coefficient is identical to the Base Model coefficient is remarkable given that it is derived from a model that uses county fixed effects, rather than the more geographically precise block group fixed effect used in the Base Model. The estimated premium is \$4.37/W, although the 95% confidence interval is considerably larger at \$2.62/W vs. the Base Model's \$0.62/W, indicating considerably less precision in the PV Only Model estimate.

4.4.2 Repeat PV Home Model

Results from the Repeat PV Home Model are also shown in Table 12. The coefficient for *pv*size* is very similar to that estimated for the Base Model with the full dataset, but it is not statistically significant (*p*-value = 0.113). The estimated premium is \$4.60/W, which is also very similar to that of the Base Model, although the 95% confidence interval, at \$5.69/W, is considerably larger than those for the Base and PV Only Models.

4.4.3 Summary of Robustness Checks

Because of the large margins of error, we cannot say the three estimates are statistically different from each other. Despite this, none of the results appear markedly different from that estimated using the Base

Model where PV homes are compared to non-PV homes. When comparing PV homes to other PV homes, as in the PV Only Model, or the same PV home to itself over multiple transactions, as in the Repeat PV Home Model, we find little evidence to support the claim that the Base Model PV premium estimate is biased. Therefore, there appears to be no evidence that the PV estimate also contains the effects of other omitted features such as EE upgrades.

Table 12: Robustness Model Results

<u>PV Premium Estimates</u>	All Homes	PV Only	Repeat
PV*Size Coefficient	0.0091	0.0092	0.0087
PV*Size Standard Error	0.0007	0.0028	0.0055
PV*Size <i>p</i> -value	<i>0.000</i>	<i>0.001</i>	<i>0.113</i>
Mean Sale Price Non-PV (\$)	\$ 456,377	\$ 474,529	\$ 528,368
PV Premium (\$/watt)	\$ 4.18	\$ 4.37	\$ 4.60
95% CI (\$/watt)	\$ 0.62	\$ 2.62	\$ 5.69
<u>Contributory Value Estimates</u>			
PV Value - Income (\$/watt)	\$ 2.93	\$ 2.93	\$ 2.15
Net Cost (\$/watt)	\$ 4.14	\$ 4.14	\$ 3.09
Gross Cost (\$/watt)	\$ 6.90	\$ 6.91	\$ 5.64
<u>Model Info</u>			
Total <i>n</i>	22,822	3,915	1,698
PV <i>n</i>	3,951	3,915	849
Non-PV <i>n</i>	18,871	-	849
Adjusted R ²	0.92	0.68	0.23
Dependent Variable	lnsp	lnsp	lnsp
Fixed Effects <i>n</i>	1,830	65	n/a

5. Discussion of Research Questions

This section explores in more detail the seven research questions listed in Table 1, building on the full set of results described above.

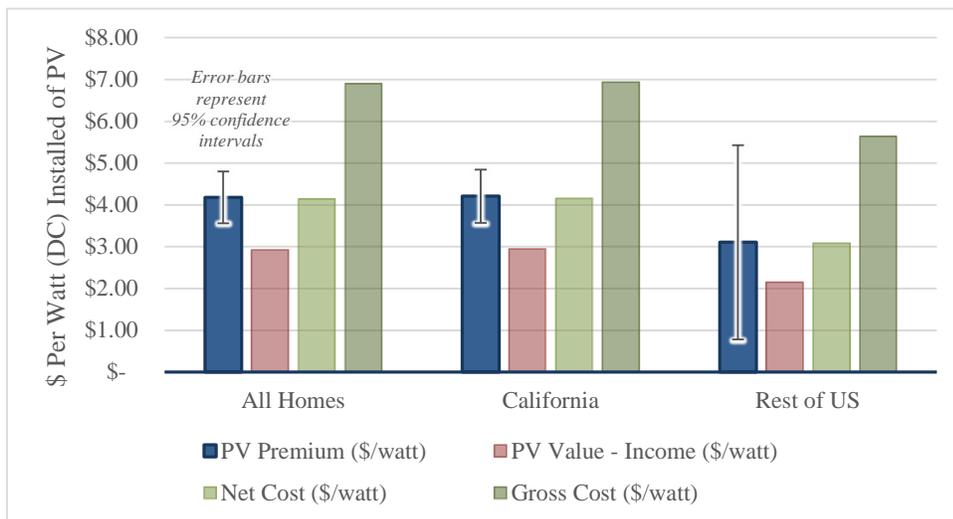
Are PV home premiums evident for a broader group of PV homes than has been studied previously both inside and outside of California and through 2013?

PV home premiums have been found by previous research of transactions of 15 PV homes in one California subdivision from 2001–2006 (Farhar and Coburn, 2008), of 594 PV homes in the San Diego and Sacramento metro areas between 1997–2010 (Dastrup et al., 2012), of approximately 1,900 PV homes in 31 California counties between 1999–2009 (Hoen et al., 2011; 2013a), and of 30 PV homes in the Denver metro area between 2011–2013 (Desmarais, 2013).

This analysis more than doubles the number of transactions analyzed, with data on almost 4,000 PV home transactions across 102 different counties in eight different states, including California, Connecticut, Florida, Massachusetts, Maryland, North Carolina, New York, and Pennsylvania. The data span the period from 2002 to 2013, with more than a third from 2012 and 2013 alone.

The Base Model and Location Models (Table 8 and Figure 1) show a consistent difference in PV home prices compared to matched non-PV homes across the dataset, with premiums ranging from a bit more than \$4/W in California to approximately \$3/W outside of California, both of which are highly statistically significant.³⁵ Moreover, this premium, as shown in the Year of Sale Models (Table 10 and Figure 2), survived both the dramatic decrease in installed costs over the study period as well as the market tumult which was the housing bubble, subsequent crash, and recovery. Clearly buyers of homes with PV are willing to pay a premium for PV, and this trend has continued despite dramatic changes in both the PV and housing markets. Finally, similarly sized premiums are found for the two robustness models—the PV Only Model and the Repeat PV Home Model—which further validates these results.

Figure 1: Base and Location Model Results



³⁵ The standard error for the Base Model of 0.0007 is 35% of the standard error found in the previous analysis of California PV homes of 0.0018 (Hoen et al. 2011; 2013a), indicating the increased precision of this estimate.

Are PV home premiums outside of California similar to those within California?

As shown in Table 8 and Figure 1, premiums for PV homes are estimated, on average, to be \$1.10/W larger in California than outside of California. However, this difference, given the relatively large margin of error around the Rest of U.S. estimate, is not statistically significant. That notwithstanding, the apparent difference seems to echo decreases in each of the three other contributory value estimates we derived. For example, the gross and net costs in California are \$1.30/W and \$1.07/W higher than outside of California. Similarly, the PV Value income estimate is \$0.80/W lower outside of California. In any case, these findings should give stakeholders outside of California greater confidence that PV adds value to homes in their markets.

How do PV home premiums compare to contributory values estimated using the cost and income methods?

The market premiums estimated from our suite of models seem to follow, at least to some degree, the contributory-value net cost estimates and, to a lesser degree, the PV Value estimates using the income approach, but not the gross cost estimates. For example, as shown in Figure 1, both the California and Rest of U.S. estimates are within a few pennies of the net cost estimates, but they are more than \$2.50/W less than the gross cost estimates. Similarly, the Year of Sale Model results show PV premiums that are not statistically different in any period from the net cost estimates (Table 10 and Figure 2) despite widely changing gross cost estimates and underlying housing market tumult. Therefore, the net cost estimates—which account for the federal, state, and local incentives available at the time of sale—seem reasonably related to the value added (PV premiums) at least among average PV systems in our sample. Since the data indicate that, for the average systems in our sample, the PV premium is similar to the net cost estimate, it is reasonable to conclude the incentives are offsetting the influence of depreciation for those systems. At the same time and as discussed in further detail later, net cost estimates diverge from the calculated market premiums for those PV systems that are considerably newer or considerably older at the time of home sale. Depreciation in PV premiums is therefore apparent when other PV system ages are considered. As such, adjustments to net cost estimates may be required to account for market-derived depreciation. In this instance, it may be necessary for appraisers to estimate physical deterioration and functional obsolescence in situations where replacement costs exceed the contributory market value of older systems.

Figure 2: Year of Sale Model Results

Curiously, the PV Value income estimates are consistently lower than the premiums found in the market, while theory holds that cost savings should be a strong price signal. One reason for this disparity, which is especially evident in the California subset, might be related to the PV Value inputs that we used in this study, which were based on the average retail electricity rate. In California, tiered volumetric rates, which are based on the customer's consumption, are normal for most of the state's residential PV customers (CPUC, 2013). If customers consume more than the average retail customer, then they will be moved into higher-priced tiers. These tiers can be dramatic, with a doubling or even tripling of rates, depending on which tier the consumer falls into (CPUC, 2013). PV customers tend to be larger consumers of electricity than the average retail customer in California, thus they often pay more than the average (Darghouth et al., 2011; CPUC, 2013) and, with a PV system, may avoid higher-cost tiers altogether, increasing the value of the avoided costs. We cannot determine the exact level of this increase for the specific PV homes in our sample, but even a \$0.05/kWh increase in the rate, which is well within the range proposed by others for PV customers (CPUC, 2013), would result in a substantial increase in the income estimate. The mean default electricity rate we entered into PV Value for the California portion of our sample is \$0.1543/kWh. If that rate increased by \$0.05/kWh, it would increase the PV Value estimate from \$2.93/W to almost \$4/W, within the margin of error of our premium estimate. Therefore, it seems possible that buyers and sellers might be using the cost savings as an important price signal, but they are estimating those savings at a slightly higher rate than the tool's default average retail rate. It is recommended that, when tiered rates are present that deviate substantially from the default average rate and normal consumption for a particular home would put the homeowner in higher tiers, users of the PV Value tool should input a custom rate that is more appropriate.³⁶

How did the size of the premium change over the study period, as gross PV system prices decreased and during housing market swings?

While gross costs decreased dramatically over the study period, dropping 40% from \$8.97/W in the 2002–2007 period to \$5.45/W in the 2012–2013 period, PV premiums remained fairly consistent around

³⁶ For example, for California customers where tiered rates are common, weighting based on the tiers and the usage within each tier for particular PV homes might result in a more appropriate input rate.

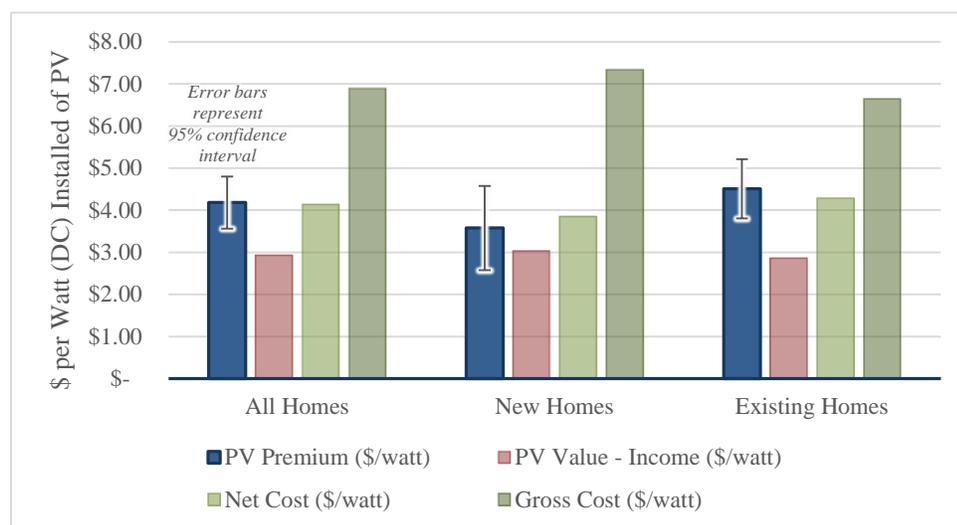
\$4/W (see Figure 2). During this same period, the housing market was in upheaval, with a sizable rise, a subsequent crash, and then a recovery. This seems to show, first, that the gross cost is not a strong market signal. Rather, net cost, which over all periods was not statistically different from the premium, seems to be the more significant price signal. Moreover, it shows that the PV premium has been reasonably consistent during widely varying housing market conditions.

Are premiums for new PV homes similar to existing PV home premiums?

The results from the Home Type Model, which explores differences between new and existing home premiums, are shown in Table 8 and Figure 3. The average new home premiums of \$3.58/W are lower than the existing home premiums of \$4.51/W, a non-statistically significant difference of \$0.93/W (p -value = 0.46). The net cost estimates for new homes are also lower (by \$0.44/W) than those of existing homes, potentially explaining some of the difference.

Previous analyses found large, statistically significant differences between new and existing home premiums (Hoen et al., 2011; 2013a; 2013b). These differences occurred because existing home estimates were larger (near \$6.50/W) and new home estimates were smaller (near \$2.5/W) than found in the present analysis. It appears, based on analysis not shown here, that high-priced homes (e.g., over \$1 million), which were included in the past analyses (up to \$3.3 million) but excluded from this analysis, might explain a large portion of the differences. Including those homes in our analysis increased the existing home premiums and lowered the new home premiums, although not to the extent found previously. Including these homes also increased the margin of error around the estimates, however, implying that our models did a poorer job of explaining price differences and that many home and site characteristics for these homes likely are not included in the models. Further, the previous analyses included home transactions only through 2009, but this analysis included transactions through 2013, with two thirds occurring after 2009. In summation, this analysis is likely a better representation of the current market for most PV homes because it included many more recent sales, had more sales in total, and excluded high-priced homes (over \$1 million) that were difficult to model, but it does not find a statistically significant difference between new and existing homes.

Figure 3: Home Type Model Results



One additional nuance to the present findings involves the new home premium and the net cost estimate. As discussed in Section 3.2, the net cost estimates (e.g., shown in Figure 3) represent the gross cost estimates less the appropriate federal and state incentives (and rebates where appropriate). The federal incentive, which normally comes in the form of an investment tax credit (ITC), is calculated as 30% of the gross cost of a PV system after state and utility incentives are applied. Interestingly, this incentive

cannot be claimed by new home builders but instead only by the buyer of the home.³⁷ Therefore, the new home buyer not only receives the PV system on the home, but will also be able to receive a tax credit. Correspondingly, the net cost of the builder should not include this federal ITC reduction and, therefore, should be approximately \$1.26/W higher and should affect the premium the buyer paid. This is interesting because we do not see a premium that reflects this incentive. If we did, the premium would be approximately \$1.26/W higher or \$4.84/W; instead we find a premium of \$3.58/W.³⁸ Understanding the exact reasons for this discounting is beyond the scope of this work, but several plausible explanations exist: home builder discounting—the builder discounts the home for other reasons, for example to sell the home more rapidly (e.g., Dakin et al., 2008; SunPower, 2008), which has the effect of obscuring the premium related to the federal ITC; buyer discounting—the buyer is not willing to pay the full cost of the tax credit because it cannot be claimed until the following year when taxes are filed and might not be able to be claimed fully because of a lack of tax appetite by the homeowner; and lack of market clarity—because tax rules related to the federal ITC only recently were clarified (US IRS, 2013), both the home builder and buyer might not have consistently known if the ITC could be claimed.

Is there evidence of a “green cachet” for PV homes above the amount paid for each additional watt added?

Results from the Size of PV System Model suggest that the systems with the highest marginal premiums, in terms of dollars per watt, were the smallest systems, and as system size increased the dollar-per-watt premium decreased (Table 11). This decreasing slope is estimated in Figure 4 for PV systems from 1 to 10 kW, which shows both the decreasing dollar-per-watt value of each additional kilowatt added (left axis) and the total PV system premium (right axis). This indicates, potentially, that there is a fixed component of PV home premiums that occurs regardless of system size. This might indicate that a green cachet exists for PV homes in our sample. In other words, buyers might be willing to pay something for having any size of PV system on their homes and then some increment more depending on the size of the system. These findings echo those found previously (Dastrup et al., 2012).

How does the age of the PV system influence the size of the PV premium?

The results from the Age of PV System Models, which explore how premiums change as PV systems age, are shown in Table 9 and Figure 5. For systems installed on homes just before they were resold, larger premiums were garnered, with premiums falling by almost 60% in the oldest age group compared with the newest group.³⁹ This indicates that the market quickly depreciates PV systems in their first 10 years at a rate exceeding an average rate of PV efficiency losses, e.g., 0.5%/year (Dobos, 2014), and also exceeding the depreciation expected were straight-line depreciation applied over the asset’s life; this might indicate functional obsolescence setting in. Because the mean age for the oldest quartile (5.9–14 years) is only 7.8 years (Figure 5), however, we cannot describe PV system values as they age into their second decade. Does their value level out and decrease at the rate of system degradation? Or do they lose 100% of their value before that? Those questions are recommended for future analyses.

³⁷ In this instance we are referring to the federal ITC under Title 26 Section 25D of the Internal Revenue code (see: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F).

³⁸ The portion of the difference between net and gross cost attributable to the federal ITC ranges from approximately \$0.80/W to as high as \$1.84/W, with a mean of \$1.26/W.

³⁹ Although not shown here, the average size of PV systems was very similar in all four age bins, at approximately 4.2 kW. We hypothesize that this larger premium for nearly new systems is related to additional nearly new features installed coincidentally or the homeowner not fully taking advantage of tax incentives if they had planned on selling the home soon after the installation.

Figure 4: Estimated Dollar Per Watt Premium for Increasingly Larger PV Systems

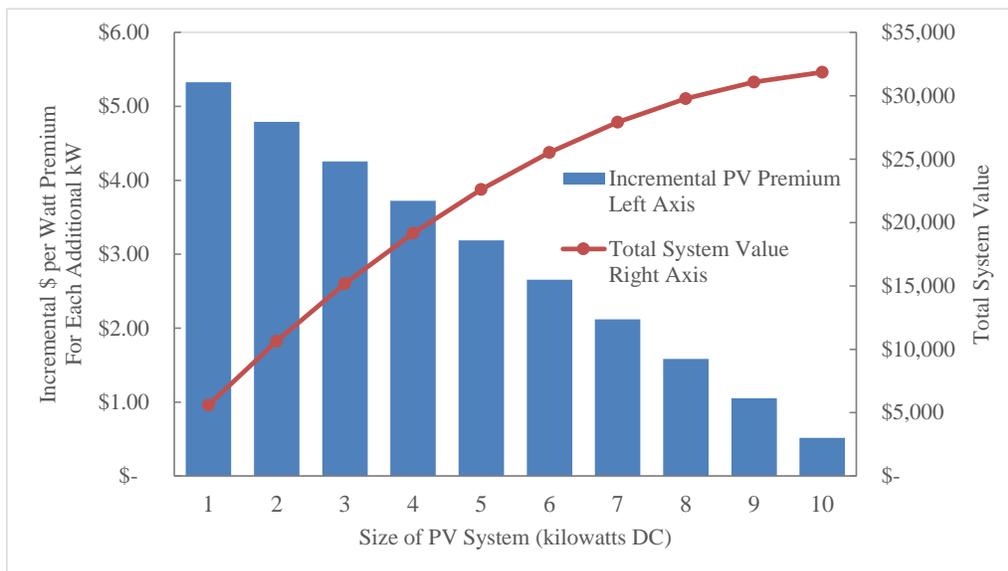
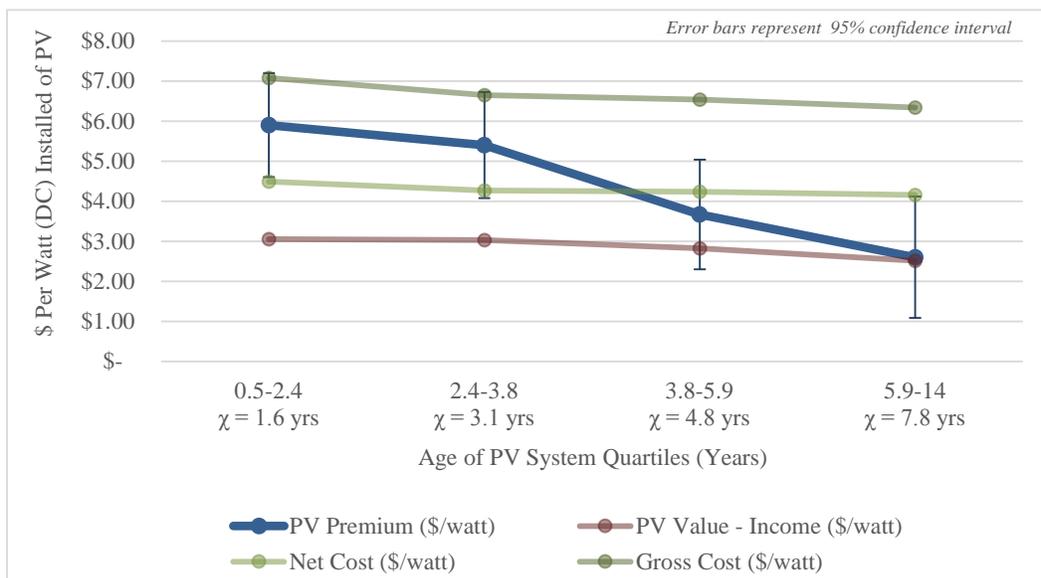


Figure 5: Age of PV System Model Results



6. Conclusion

As solar photovoltaic (PV) systems become an increasingly common feature of U.S. homes, the ability to value homes with these systems appropriately will become increasingly important. The U.S. Department of Energy estimates that achieving its SunShot PV system price-reduction targets could result in 108 GW of residential rooftop PV installed by 2050—equivalent to 30 million American homes with PV (US DOE, 2012).⁴⁰ Conversely, capturing the value of PV to residential properties is important for enabling a robust rooftop PV market.

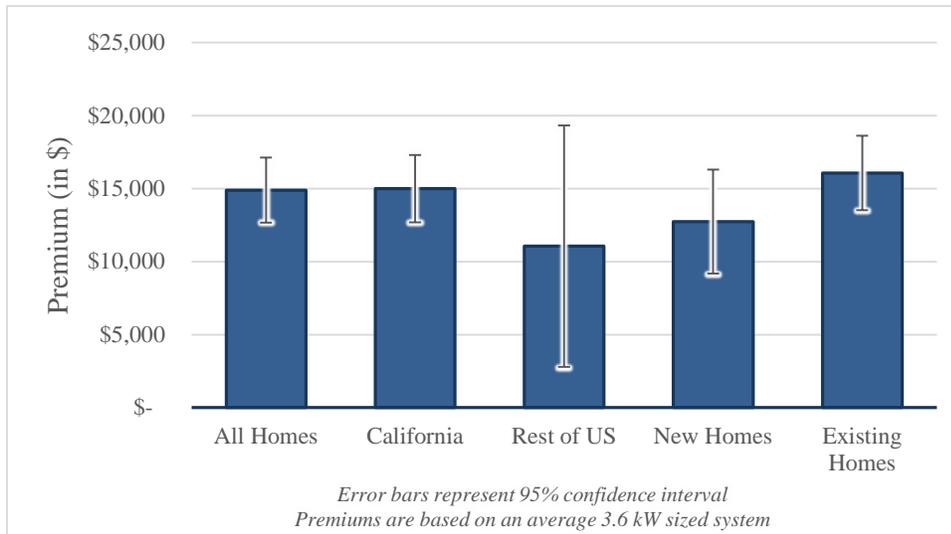
Appraisers, sales agents, and others tasked with property valuation have made strides toward valuing PV homes, and several limited studies suggest the presence of PV home premiums, particularly in California. Our study fills important gaps in this literature and illuminates various factors that might influence U.S. PV home premiums. The study more than doubles the number of PV home sales previously analyzed, examines transactions in eight different states, and spans the years 2002–2013, thus encompassing the recent housing boom, bust, and recovery. Based on our results, we draw the following major conclusions:

- Home buyers consistently have been willing to pay more for a property with PV across a variety of states, housing and PV markets, and home types. Average market premiums across the full sample of homes analyzed here are about \$4/W or \$15,000 for an average-sized 3.6-kW PV system (Figure 6).
- Our findings should provide greater confidence that PV adds value to non-California homes. Premiums for PV homes are \$1.10/W larger in California than outside of California (respectively equating to \$16,000 and \$12,700 for an average-sized system – Figure 6), but this difference is not statistically significant: somewhat lower premiums outside of California are consistent with lower net cost and income estimates.
- Net cost estimates—which account for government and utility PV incentives—seem to be generally consistent with incremental market value premiums for the average PV home in our sample, but they do not appear to account accurately for market-based depreciation (the difference between value and cost). PV Value income estimates—which for this study used the default average retail rates—were consistently lower than the calculated market premiums, which seems to indicate that a higher retail rate would be more appropriate for that portion of the sample where tiered rates were present.
- PV premiums remained fairly consistent even as PV gross costs decreased dramatically over the study period and the housing market went through upheaval. This suggests that net cost, rather than gross cost, may be the more dominant market signal. It also suggests that PV premiums are robust to housing market conditions.
- In contrast to previous studies, our study found a relatively small and non-statistically significant difference between PV premiums for new and existing homes (respectively equating to \$12,700 and \$16,000 for an average-sized system – Figure 6), likely because our study includes many more sales and recent sales while excluding very-high-priced homes. That notwithstanding, there might be some evidence of either home builder or buyer discounting of new home PV systems.
- A green cachet might exist for PV homes; that is, buyers might be willing to pay a certain amount for having any size of PV system on their homes and then some increment more depending on the size of the system.
- The market appears to depreciate PV systems in their first 10 years at a rate exceeding the rate of PV efficiency losses and of straight-line depreciation over the asset's life. Our data do not allow analysis

⁴⁰ Assuming the average PV system size of 3.6 kW found for all PV homes in this study.

of depreciation into the second decade of PV systems' operation—this is an area for future research.

Figure 6: Estimated Premiums Based on an Average-Sized 3.6 kW System



This study focuses only on homes with host-owned PV systems, as opposed to those with leased PV systems. Future analysis should focus on leased systems, because they are a growing portion of the PV home market and have not been studied. In addition, although our sample indicates that, as PV systems age, the size of the premium diminishes, our data are not robust to systems in their second decade; such older systems should be the focus of future study, as should the appropriate depreciation to place on PV systems throughout their lives.

Although this work allows for a robust analysis of average system premiums across the full dataset, and subsets of the data, the results are not necessarily applicable to individual markets and states that might have unique characteristics. Therefore, any market-specific (“small scale”) analysis, especially one that employs appraisers and other valuers in those local markets, would be beneficial. Similarly, collecting and analyzing more data in a wide variety of states individually would be useful.

Because premium differences related to the availability of PV homes are unclear, investigating both buyer’s markets (with many PV homes available) and seller’s markets (with few PV homes available) would add clarity to PV home valuation. Finally, very large PV systems and systems on commercial properties were not represented in our data; both could have unique valuation characteristics and are thus areas for further study.

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8. Appendix A: Cost Estimate Preparation

To calculate both the net and gross cost estimates for each of the PV home transactions at the time of sale, we estimate a two-stage regression as used previously (Hoen et al., 2011; 2013a; 2013b). This procedure starts with the extensive dataset of more than 150,000 PV homes collected for TTS VI and their respective gross installed costs as reported (Barbose et al., 2013), for which the respective net installed costs (i.e., net of federal and state incentives) are calculated using the procedure outlined in Appendix C of Barbose et al. (2010). The first stage uses the net costs as the dependent variable and county, year, system size, and home type (new or existing) as the independent variables, in the following model:

$$C_{itsc} = \alpha + \beta_1(T_i) + \beta_2(S_i) + \beta_3(N_i) + \beta_4(C_i) + \varepsilon_{itsc} \quad (4)$$

where

C_{itsc} is the “net installed cost” of PV system i after state and federal incentives from the full TTS dataset,

T_i is a vector of variables representing the year t in which the system was installed,

S_i is a vector of variables representing the size s of the system in rounded kilowatts (e.g., 1 kW, 2 kW, 3 kW...),

N_i is a fixed-effect variable indicating if the home was newly built when the system was installed,

C_i is a vector of variables representing the county c in which the system was installed,

α is the constant,

β_{1-4} are coefficients for the parameters, and

ε_{itsc} is the error term.

The model accounts for the different state incentives and system component prices over the study period (via T_i), economies of scale (via S_i), different installed costs between new and existing homes (N_i), and the variety of rate structures, installer competitive prices, and market development (via C_i).

Using the predicted coefficients from this model, the data for the set of PV home transactions (county in which the home is located, PV system size, if the home is newly built, and substituting the sale year for the installation year t) are fed into the model to produce predicted net cost estimates. These represent, as of the time of sale, the approximate cost to replace a similarly sized system new on the same home.

An identical procedure is followed for gross cost estimates, except, for the first stage, C_{itsc} is the “gross installed cost” of PV system i before state and federal incentives from the full TTS VI dataset.

Tab 5

Presentations



Floridians for Solar Choice

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Floridians for Solar Choice, Inc.

SUBJECT: Financial Impact Statement for the Amendment: Limits or Prevents Barriers to Local Solar Electricity Supply

DATE: April 8, 2015

The Financial Impact Estimating Conference (FIEC) is statutorily charged with the responsibility of preparing a financial impact statement to the public regarding the probable financial impact of any amendment proposed by initiative. *See, § 5, Art. XI, Fla. Const. and § 100.371, Fla. Stat.* This memorandum is intended to provide information to the FIEC regarding the initiative entitled, "Limits or Prevents Barriers to Local Solar Electricity Supply" (Solar Amendment) from Floridians for Solar Choice, Inc., the Sponsors of the Solar Amendment. To put the Solar Amendment in context, this memorandum describes solar energy business models and explains the current Florida regulatory system of electric utilities and solar generated electricity, including the net metering requirements. Also included is a statement of the impact of the Solar Amendment on state and local revenues and costs.

The Solar Amendment

BALLOT TITLE: Limits or Prevents Barriers to Local Solar Electricity Supply

BALLOT SUMMARY: Limits or prevents government and electric utility imposed barriers to supplying local solar electricity. Local solar electricity supply is the non-utility supply of solar generated electricity from a facility rated up to 2 megawatts to customers at the same or contiguous property as the facility. Barriers include government regulation of local solar electricity suppliers' rates, service and territory, and unfavorable electric utility rates, charges, or terms of service imposed on local solar electricity customers.

ARTICLE AND SECTION BEING CREATED OR AMENDED: Add new Section 29 to Article X

FULL TEXT OF PROPOSED AMENDMENT:

Section 29. Purchase and sale of solar electricity. –

(a) **PURPOSE AND INTENT.** It shall be the policy of the state to encourage and promote local small-scale solar-generated electricity production and to enhance the availability of solar power to customers. This section is intended to accomplish this purpose by limiting and preventing regulatory and economic barriers that discourage the supply of electricity generated from solar energy sources to customers who consume the electricity at the same or a contiguous property as the site of the solar electricity production. Regulatory and economic barriers include rate, service and territory regulations imposed by state or local government on those supplying such local solar electricity, and imposition by electric utilities of special rates, fees, charges, tariffs, or terms and conditions of service on their customers consuming local solar electricity supplied by a third party that are not imposed on their other customers of the same type or class who do not consume local solar electricity.

(b) **PURCHASE AND SALE OF LOCAL SMALL-SCALE SOLAR ELECTRICITY.**

(1) A local solar electricity supplier, as defined in this section, shall not be subject to state or local government regulation with respect to rates, service, or territory, or be subject to any assignment, reservation, or division of service territory between or among electric utilities.

(2) No electric utility shall impair any customer's purchase or consumption of solar electricity from a local solar electricity supplier through any special rate, charge, tariff, classification, term or condition of service, or utility rule or regulation, that is not also imposed on other customers of the same type or class that do not consume electricity from a local solar electricity supplier.

(3) An electric utility shall not be relieved of its obligation under law to furnish service to any customer within its service territory on the basis that such customer also purchases electricity from a local solar electricity supplier.

(4) Notwithstanding paragraph (1), nothing in this section shall prohibit reasonable health, safety and welfare regulations, including, but not limited to, building codes, electrical codes, safety codes and pollution control regulations, which do not prohibit or have the effect of

prohibiting the supply of solar-generated electricity by a local solar electricity supplier as defined in this section.

(c) DEFINITIONS. For the purposes of this section:

(1) "local solar electricity supplier" means any person who supplies electricity generated from a solar electricity generating facility with a maximum rated capacity of no more than 2 megawatts, that converts energy from the sun into thermal or electrical energy, to any other person located on the same property, or on separately owned but contiguous property, where the solar energy generating facility is located.

(2) "person" means any individual, firm, association, joint venture, partnership, estate, trust, business trust, syndicate, fiduciary, corporation, government entity, and any other group or combination.

(3) "electric utility" means every person, corporation, partnership, association, governmental entity, and their lessees, trustees, or receivers, other than a local solar electricity supplier, supplying electricity to ultimate consumers of electricity within this state.

(4) "local government" means any county, municipality, special district, district, authority, or any other subdivision of the state.

(d) ENFORCEMENT AND EFFECTIVE DATE. This amendment shall be effective on January 3, 2017.

Purpose of the Constitutional Amendment

The Solar Amendment is intended to limit or prevent barriers to local solar electricity supply by accomplishing the following:

1. Prohibit the Public Service Commission (PSC) from regulating small scale solar energy providers as an electric utility. This means that small scale solar providers cannot be subject to PSC rate regulation, service regulation, or territorial regulation.
2. Preserve the electric utility's current obligation to serve customers who use local solar generated electricity.
3. Prohibit an electric utility's impairment of its customers' ability to purchase electricity from third party local solar energy providers by imposing unique rates, fees, charges, or terms or rules of service for customers making this choice.

In short, the Solar Amendment prohibits PSC-type regulation of local solar electricity suppliers.

What the Solar Amendment does not do:

1. Require or prohibit a change in the law regarding state or local taxation of solar energy.
2. Remove the authority of the State and local governments to regulate local solar energy suppliers regarding health, safety and welfare. For example, the amendment does not prohibit the applicability of electrical codes, building codes, or environmental protection regulations, and the like.
3. Eliminate the PSC's ability to regulate a local solar electricity supplier's interconnection of its generation facility via a customer's net metering arrangement with the electric utility, as long as the regulation does not allow the electric utility to discriminate against its customers choosing to purchase electricity from a local solar electricity supplier.

The Solar Amendment does not eliminate the PSC's ability to regulate interconnection and net metering for a local solar electricity supplier's customer who is connected to the electric grid. Such regulations are not regulations of the local solar electricity supplier's service, which are prohibited by the Solar Amendment. Rather, such regulations are regulations governing the relationship between the electric utility and its customer, and are authorized under the Solar Amendment as long as the regulations do not require the electric utility to discriminate against the customer because of its purchase of electricity from a local solar electricity supplier.

Solar Business Models

1. A property owner contracts for the purchase and installation of solar equipment that provides energy to the property. This model is currently authorized outside of PSC jurisdiction.
2. A property owner enters into a lease for the installation of solar equipment on the property with the solar energy being consumed on the property. The property owner pays the company for the use and maintenance of the solar equipment. This model is currently authorized outside of PSC jurisdiction.
3. A property owner allows a company to install equipment on the property and purchases some, but not necessarily all of the solar energy from the company. The purchase may be financed through a Power Purchase

Agreement which requires the purchaser to pay a monthly charge to the solar supplier based on the amount of solar electricity used at the property. This model is currently prohibited unless subjected to PSC jurisdiction.

4. A property owner provides solar generated electricity to itself and sells it to contiguous property owners. This model is currently prohibited unless subjected to PSC jurisdiction.

PSC Rate and Territorial Regulation of Electric Utilities

The Florida PSC has broad supervisory authority over "public" electric utilities, defined in the statutes to include Florida's five investor-owned electric utilities and any other type of electric utility that is not municipally owned or a rural electric cooperative. This broad supervisory power includes authority over the rates the public utilities charge, the service they provide and the means they use to finance their operations. In addition to the supervisory authority the PSC exercises over public utilities, the agency exercises authority over all electric utilities, including municipally owned electric utilities and rural electric cooperatives, for the following purposes:

- To prescribe uniform accounting systems and classifications;
- To prescribe a rate structure which establishes how rates are charged to allocate the utility's costs among different classes of customers;
- To require electric power conservation and reliability within a coordinated grid, for operational as well as emergency purposes;
- To approve territorial agreements among all types of electric utilities;
- To resolve territorial disputes;
- To require the filing of periodic reports and other data the PSC needs to carry out its regulatory jurisdiction;
- To supervise the planning, development and maintenance of a coordinated electric power grid throughout the state to assure an adequate and reliable source of energy for operational and emergency purposes and the avoidance of uneconomic duplication of facilities; and
- To prescribe and enforce safety standards for transmission and distribution facilities.

In addition to rates and territory, the PSC also regulates the service of public electric utilities. "Service" regulation includes those relating to the quality, reliability, safety and availability of service. Some of the PSC service regulations include the following:

- Prescribing the preferred location of distribution facilities (Rule 25-6.034, F.A.C.);

- Prescribing standards for hardening against the impacts of hurricanes (Rule 25-6.0342, F.A.C.);
- Requiring the maintenance of a specified level of generating capacity above what is needed to meet reasonable load requirements (Rule 25-6.035, F.A.C.);
- Prescribing equipment standards (Rule 25-6.037, F.A.C.);
- Requiring the collecting and tracking and reporting of reliability and continuity of service data (Rule 25-6.044, F.A.C.);
- Prescribing standards for variances between current supplied and service demand ratings (Rule 25-6047, F.A.C.);
- Rules governing the extension of service to new customers (Rule 25-6.064, F.A.C.); and
- Regulation of construction practices (Rule 25-6.081, F.A.C.), among others.

Barriers to Local Solar Electricity Supply

A "public" electric utility is defined as any person or legal entity "supplying electricity ... to or for the public within this state" *See, § 366.02(1), Fla. Stat., attached as Appendix "A"*. The Florida Supreme Court has determined that any single person or entity supplying electricity to a single different person or entity, even pursuant to a private contract between them with no offer to sell or supply electricity to the general public, is a "public utility" for the purposes of the statute, and is under the full regulatory jurisdiction of the PSC. *See, PW Ventures, Inc. v. Katie Nichols, 533 So.2d 281 (Fla. 1988), attached as Appendix "B"*.

Therefore, under current law, any person or entity that owns a solar electric generating facility, such as an array of photo-voltaic solar panels, may not sell the electricity to another person, such as another homeowner, without coming under the full rate setting and service jurisdiction of the PSC and without being subject to existing PSC-enforced monopolies within established electric utility service territory. The exercise of rate, service, and territorial jurisdiction is intended to govern monopoly utilities with centralized power generation and sprawling networks of transmission and distribution power lines, and to prevent the uneconomic duplication of facilities. But the regulations also serve as a barrier in Florida to sales of locally generated solar electricity and to the use of Power Purchase Agreements, which are well-known small scale solar financing arrangements used in other states.

The Solar Amendment removes these regulatory barriers for the local sale of solar electricity generated on a limited scale. It prohibits rates, service and territorial regulation by the State and local governments except as otherwise provided in the Solar Amendment. The Solar Amendment's protection applies to local sales only: local sales include sales made to a customer on the same property as the facility generating the solar electricity, or sales made to a customer located on a property contiguous with the property where the facility generating the solar electricity is located. Further, it applies

to sales of solar electricity generated only on a limited scale: up to two megawatts (2 MW) which has the potential to service an estimated 714 residential customers.¹ The Solar Amendment's 2 MW limitation coincides with the current PSC net metering rule.

PSC Regulation of Net Metering

Net metering is a system of metering electricity that allows a customer who connects an eligible renewable generation system, such as solar panels, to the electric grid to buy electricity from, and sell excess electricity back to, the electric utility. When a customer generates electricity from a solar array (for example) for his or her home or business, the amount of energy purchased from the electric utility is reduced, lowering the customer's monthly electric bills. If the solar array (used in this example) generates more electricity than can be used on the premises, the excess electricity flows through the two-way net meter onto the electric utility's distribution grid and is sold to the electric utility at a PSC-regulated price.

This activity is governed by the PSC's Interconnection and Net Metering of Customer-Owned Renewable Generation Rule. *See, Rule 25-6.065, F.A.C., attached as Appendix "C"*. Under the Rule, the utility is authorized to charge the customer only for the amount of electricity used by the customer in excess of the amount of electricity the customer supplies to the grid. If at the end of the customer's billing cycle, he or she delivers more electricity to the grid than he or she consumes from it, the excess amount is credited to the customer's consumption for the next billing cycle. If consumption credits remain following a year of billing, the utility must pay the customer for the unused credits. The rate paid to the customer is the same rate paid to certain independent small power producers (also known as co-generators or Qualifying Facilities) which qualify under federal and state laws for a standardized wholesale payment rate.

In addition to authorizing the use of net metering and requiring payment of credits, the Rule establishes standards for the interconnection of the renewable generation facility to the grid, and prescribes what fees, if any, the electric utility can charge to the customer. The standards and fees may vary depending on the size of the facility; however, the Rule prohibits interconnection with the electric utility if the rated capacity of the renewable generation facility exceeds 90 percent of the customer's service rating established by the utility.

The Rule recognizes three Tiers. Tier 1 consists of facilities rated 10 kW or less. Tier 2 consists of facilities rated greater than 10 kW up to 100 kW. Tier 3 consists of facilities rated greater than 100 kW up to 2,000 kW (2 MW). A customer interconnecting a Tier 1 or 2 facility may do so without additional design or testing. Additional design

¹ 1 MW can serve the demand of 357 residential customers, based on an average demand of 2.8 kW, according to recent information provided by the PSC upon request of the Sponsor.

and testing standards to those included in the Rule may be imposed for a Tier 3 facility of sufficient size to require an interconnection study. The Rule also prohibits the utility from imposing any additional charge on a customer interconnecting a Tier 1 facility, but allows an application charge for Tiers 2 and 3 and an interconnection study charge for Tier 3.

Currently, a property owner who owns his own solar panels can net meter. A property owner who leases panels from a third party can net meter. These activities are permitted because the property owner is not purchasing solar electricity from a third party, but is instead purchasing or leasing the panels. A property owner who buys solar generated power from a company which has placed solar panels on his or her property cannot net meter.

Interconnection Regulation Under the Solar Amendment

Under the Solar Amendment, the PSC maintains the authority to regulate the interconnection between the customer who purchases electricity from a local solar electricity supplier and the customer's electric utility, as long as the regulations do not require the electric utility to impose any unique rules, rates, charges, or other conditions on the customer because of the customer's purchase of electricity from the local solar electricity supplier.

Effect on State and Local Revenues and Costs

The Solar Amendment's intent is to limit or prevent barriers to local solar electricity supply. It does not alter the current rates or the application of State and local government taxes and fees on solar generated energy. Thus, the Solar Amendment will have no direct impact on State and local government revenues.

It is currently unknown and speculative, how many, if any, businesses or households may avail themselves of any new solar business models that may enter the Florida market as a consequence of the Solar Amendment.

With regard to costs of the State and local government as a potential purchaser of solar generated electricity, it would be speculative to predict future policy and purchasing decisions of the State and local governments.

LIST OF APPENDICES

Section 366.02(1), Florida Statutes	A
<u>PW Ventures, Inc. v. Katie Nichols</u> , 533 So.2d 281 (Fla. 1988)	B
Rule 25-5.065, F.A.C.....	C

.

APPENDIX A

Select Year:

The 2014 Florida Statutes

[Title XXVII](#)

[Chapter 366](#)

[View Entire Chapter](#)

RAILROADS AND OTHER REGULATED UTILITIES

PUBLIC UTILITIES

366.02 Definitions.—As used in this chapter:

(1) “Public utility” means every person, corporation, partnership, association, or other legal entity and their lessees, trustees, or receivers supplying electricity or gas (natural, manufactured, or similar gaseous substance) to or for the public within this state; but the term “public utility” does not include either a cooperative now or hereafter organized and existing under the Rural Electric Cooperative Law of the state; a municipality or any agency thereof; any dependent or independent special natural gas district; any natural gas transmission pipeline company making only sales or transportation delivery of natural gas at wholesale and to direct industrial consumers; any entity selling or arranging for sales of natural gas which neither owns nor operates natural gas transmission or distribution facilities within the state; or a person supplying liquefied petroleum gas, in either liquid or gaseous form, irrespective of the method of distribution or delivery, or owning or operating facilities beyond the outlet of a meter through which natural gas is supplied for compression and delivery into motor vehicle fuel tanks or other transportation containers, unless such person also supplies electricity or manufactured or natural gas.

(2) “Electric utility” means any municipal electric utility, investor-owned electric utility, or rural electric cooperative which owns, maintains, or operates an electric generation, transmission, or distribution system within the state.

(3) “Commission” means the Florida Public Service Commission.

History.—s. 2, ch. 26545, 1951; s. 3, ch. 76-168; s. 1, ch. 77-457; ss. 2, 16, ch. 80-35; s. 2, ch. 81-318; ss. 1, 20, 22, ch. 89-292; s. 4, ch. 91-429; s. 14, ch. 92-284.

APPENDIX B



PW VENTURES, INC., Appellant, v. KATIE NICHOLS, Chairman of Florida Public Service Commission, and FLORIDA PUBLIC SERVICE COMMISSION, Appellees

No. 71,462

Supreme Court of Florida

533 So. 2d 281; 1988 Fla. LEXIS 1161; 13 Fla. L. Weekly 635

October 27, 1988

PRIOR HISTORY: [**1] An Appeal from the Public Service Commission.

COUNSEL: Richard D. Melson of Hopping, Boyd, Green & Sams, Tallahassee, Florida, for Appellant.

Susan F. Clark, General Counsel, Florida Public Service Commission, Tallahassee, Florida, for Appellees.

Richard A. Zambo and Paul Sexton of Richard A. Zambo, P.A., Brandon, Florida, for Amici Curiae: C.F. Industries, Inc., IMC Fertilizer, Inc., The Monsanto Company and W. R. Grace & Co.

JUDGES: Grimes, J. Ehrlich, C.J., and Overton, Shaw, Barkett and Kogan, JJ., concur. McDonald, J., dissents with an opinion.

OPINION BY: GRIMES

OPINION

[*282] PW Ventures, Inc. (PW Ventures) appeals from an adverse ruling of the Florida Public Service Commission (PSC). We have jurisdiction. *Art. V, § 3(b) (2), Fla. Const.*

PW Ventures¹ signed a letter of intent with Pratt and Whitney (Pratt) to provide electric and thermal power at Pratt's industrial complex in Palm Beach County. PW Ventures proposes to construct, own, and operate a cogeneration² project on land leased from Pratt and to sell its output to Pratt under a long-term take or pay contract.³ Before proceeding with construction of the facility that would provide the power, PW Ventures sought a declaratory statement from the PSC that it would [**2] not

be a public utility subject to PSC regulation. After a hearing, the PSC ruled that PW Ventures proposed transaction with Pratt fell within its regulatory jurisdiction.

1 PW Ventures is a Florida corporation which was originally owned by FPL Energy Services, Inc. (a wholly owned subsidiary of FPL Group, Inc.) and Impell Corporation (a wholly owned subsidiary of Combustion Engineering, Inc.). After the entry of the PSC order, FPL Energy Services, Inc. transferred its 50% interest to Combustion Engineering, Inc.

2 Cogeneration involves the use of steam power to produce electricity, with some of the energy from the steam being recaptured for further use. The PSC seeks only to regulate the sale of electrical power.

3 The power would be used by Pratt and several affiliated corporate entities and by the Federal Aircraft Credit Union which is also located on the property.

At issue here is whether the sale of electricity to a single customer⁴ makes the provider a public utility. The decision hinges on the phrase "to the public," as it is used in *section 366.02(1), Florida Statutes* (1985). In pertinent part that subsection provides:

"Public utility" means every person, [**3] corporation, partnership, association, or other [*283] legal entity and their lessees, trustees, or receivers supplying electricity or gas (natural, manufactured, or similar gaseous substance) to or for the public within this state

533 So. 2d 281, *; 1988 Fla. LEXIS 1161, **;
13 Fla. L. Weekly 635

4 While the PSC reminds us that the power generated by the project will actually be passed on to several entities, we prefer to address the issue in the context argued by PW Ventures.

Distilled to their essence, the parties' views are as follows: PW Ventures says the phrase "to the public" means to the general public and was not meant to apply to a bargained-for transaction between two businesses. The PSC says the phrase means "to any member of the public." While the issue is not without doubt, we are inclined to the position of the PSC.

At the outset, we note the well established principle that the contemporaneous construction of a statute by the agency charged with its enforcement and interpretation is entitled to great weight. *Warnock v. Florida Hotel & Restaurant Comm'n*, 178 So.2d 917 (Fla. 3d DCA 1965), appeal dismissed, 188 So.2d 811 (Fla. 1966). The courts will not depart from such a construction unless it is clearly unauthorized or erroneous. [**4] *Gay v. Canada Dry Bottling Co.*, 59 So.2d 788 (Fla. 1952).

Also, it is significant that the statute itself would permit the type of transaction proposed by PW Ventures and Pratt to be unregulated if it were for natural gas services. Section 366.02(1) provides the following exemption: "The term 'public utility' as used herein does not include . . . any natural gas pipeline transmission company making only sales of natural gas at wholesale and to direct industrial consumers. . . ." The legislature did not provide a similar exemption for electricity. The express mention of one thing implies the exclusion of another. *Thayer v. State*, 335 So.2d 815 (Fla. 1976).

This rationale is further illustrated in the statutory regulation of water and sewer utilities. As explained in the PSC order:

In parallel with Section 366.02(1), Section 367.021, Florida Statutes (1985), defines a water or sewer utility as every person "providing, or who proposes to provide, water or sewer service to the public for compensation." Section 367.022(6), Florida Statutes, expressly exempts from this definition "systems with the capacity or proposed capacity to serve 100 or fewer persons". There is not a parallel [**5] numerical exemption to the statutory definition of a public utility supplying electricity. Yet the statutory interpretation advocated by PW Ventures

would require a line to be drawn somewhere between sales to some members of the public, as a presumably nonjurisdictional activity, and sales to the public generally and indiscriminately, an admittedly jurisdictional activity.

Moreover, the PSC's interpretation is consistent with the legislative scheme of chapter 366. The regulation of the production and sale of electricity necessarily contemplates the granting of monopolies in the public interest. *Storey v. Mayo*, 217 So.2d 304 (Fla 1968), cert. denied, 395 U.S. 909, 89 S. Ct. 1751, 23 L. Ed. 2d 222 (1969). Section 366.04(3), Florida Statutes (1985), directs the PSC to exercise its powers to avoid "uneconomic duplication of generation, transmission, and distribution facilities." If the proposed sale of electricity by PW Ventures is outside of PSC jurisdiction, the duplication of facilities could occur. What PW Ventures proposes is to go into an area served by a utility and take one of its major customers. ⁵ Under PW Ventures' interpretation, other ventures could enter into similar contracts with other high use [**6] industrial complexes on a one-to-one basis and drastically change the regulatory scheme in this state. The effect of this practice would be that revenue that otherwise would have gone to the regulated utilities which serve the affected areas would be diverted to unregulated producers. This revenue would have to be made up by the remaining customers of the regulated utilities since the fixed costs of the regulated systems would not have been reduced.

5 Initially, Florida Power and Light had an interest in PW Ventures and would, in effect, transfer its own client to a subsidiary. FP & L is not now involved. Yet, if the argument of PW Ventures is accepted, there might be nothing to prevent one utility company from forming a subsidiary and raiding large industrial clients within areas served by another utility.

[*284] We do not believe that *Fletcher Properties v. Florida Public Service Commission*, 356 So.2d 289 (Fla. 1978), mandates a different result. In that case, we did approve a PSC order which included reasoning to the effect that service to the public meant service to the indefinite public or to all individuals within a given area. However, the case did not arise in the context [**7] of a sale to a single customer. We simply affirmed the PSC's determination that the developer and owner of lines and lift stations who proposed to furnish water and sewer service to single family homes at the same rate as it was charged by the area water and sewer utility occupied the status of a public utility. ⁶

6 The holding of that case actually supports the PSC's alternative position that PW Ventures will actually serve several customers at the Pratt facility.

The fact that the PSC would have no jurisdiction over the proposed generating facility if Pratt exercised its option under the letter of intent to buy the facility and elected to furnish its own power is irrelevant. The expertise and investment needed to build a power plant, coupled with economies of scale, would deter many individuals from producing power for themselves rather than simply purchasing it. The legislature determined that the protection of the public interest required only limiting competition in the sale of electric service, not a prohibition against self-generation.

We approve the decision of the Public Service Commission.

It is so ordered.

Ehrlich, C.J., and Overton, Shaw, Barkett and Kogan, JJ., concur. McDonald, J., dissents with an opinion.

DISSENT BY: McDONALD

DISSENT

McDONALD, J., dissenting.

I dissent. In doing so, [**8] I accept the argument of PW Ventures, Inc. as set forth in its brief where it urges:

The cornerstone of "public utility" status and Commission jurisdiction under Chapter 366 is the provision of electric service "to the public". This phrase is not defined in Chapter 366, nor in any of the Commission's other jurisdictional statutes. Under Florida's rules of statutory construction, the phrase "to the public" must therefore be given either its plain and ordinary meaning or, if it is a legal term of art, its legal meaning. *City of Tampa v. Thatcher Glass Corporation*, 445 So.2d 578 (Fla. 1984); *Citizens v. Florida Public Service Commission*, 425 So.2d 534 (Fla. 1982); *Tatzel v. State*, 356 So.2d 787 (Fla. 1978); *Ocasio v. Bureau of Crimes Compensation*, 408 So.2d 751 (Fla. 3d DCA 1982). Under either test, a sale to a

single industrial host in the circumstances of this case is not a sale "to the public."

* * *

The phrase "to the public" commonly connotes the people as a whole, or at least a group of people. Webster's Ninth New Collegiate Dictionary (1983) gives two relevant definitions for "public":

2: the people as a whole: POPULACE

3: a group of people having common interests or characteristics: [**9] *specif*: the group at which a particular activity or enterprise aims

Black's Law Dictionary (Revised 4th ed.) similarly defines "public" to mean:

The whole body politic, or the aggregate of the citizens of a state, district, or municipality. . . . In one sense, everybody; and accordingly the body of the people at large; the community at large, without reference to the geographical limits of any corporation like a city, town, or county; the people. In another sense the word does not mean all the people, nor most of the people, nor very many of the people of a place, but so many as contradistinguishes them from a few.

Thus if *Section 366.02(1)* is given its plain and ordinary meaning, a person is not supplying electricity "to the public," if it supplies electricity only to a single [**285] industrial customer on whose property the electric generating facility is located.

APPENDIX C

25-6.065 Interconnection and Net Metering of Customer-Owned Renewable Generation.

(1) Application and Scope. The purpose of this rule is to promote the development of small customer-owned renewable generation, particularly solar and wind energy systems; diversify the types of fuel used to generate electricity in Florida; lessen Florida's dependence on fossil fuels for the production of electricity; minimize the volatility of fuel costs; encourage investment in the state; improve environmental conditions; and, at the same time, minimize costs of power supply to investor-owned utilities and their customers. This rule applies to all investor-owned utilities, except as otherwise stated in subsection (10).

(2) Definitions. As used in this rule, the term.

(a) "Customer-owned renewable generation" means an electric generating system located on a customer's premises that is primarily intended to offset part or all of the customer's electricity requirements with renewable energy. The term "customer-owned renewable generation" does not preclude the customer of record from contracting for the purchase, lease, operation, or maintenance of an on-site renewable generation system with a third-party under terms and conditions that do not include the retail purchase of electricity from the third party.

(b) "Gross power rating" means the total manufacturer's AC nameplate generating capacity of an on-site customer-owned renewable generation system that will be interconnected to and operate in parallel with the investor-owned utility's distribution facilities. For inverter-based systems, the AC nameplate generating capacity shall be calculated by multiplying the total installed DC nameplate generating capacity by .85 in order to account for losses during the conversion from DC to AC.

(c) "Net metering" means a metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on-site.

(d) "Renewable energy," as defined in Section 377.803, F.S., means electrical, mechanical, or thermal energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen, biomass, solar energy, geothermal energy, wind energy, ocean energy, waste heat, or hydroelectric power.

(3) Standard Interconnection Agreements. Each investor-owned utility shall, within 30 days of the effective date of this rule, file for Commission approval a Standard Interconnection Agreement for expedited interconnection of customer-owned renewable generation, up to 2 MW, that complies with the following standards:

(a) IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems;

(b) IEEE 1547.1 (2005) Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems; and

(c) UL 1741 (2005) Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.

(d) A copy of IEEE 1547 (2003), ISBN number 0-7381-3720-0, and IEEE 1547.1 (2005), ISBN number 0-7381-4737-0, may be obtained from the Institute of Electric and Electronic Engineers, Inc. (IEEE), 3 Park Avenue, New York, NY, 10016-5997. A copy of UL 1741 (2005) may be obtained from COMM 2000, 1414 Brook Drive, Downers Grove, IL 60515.

(4) Customer Qualifications and Fees.

(a) To qualify for expedited interconnection under this rule, customer-owned renewable generation must have a gross power rating that:

1. Does not exceed 90% of the customer's utility distribution service rating; and

2. Falls within one of the following ranges:

Tier 1 – 10 kW or less;

Tier 2 – greater than 10 kW and less than or equal to 100 kW; or

Tier 3 – greater than 100 kW and less than or equal to 2 MW.

(b) Customer-owned renewable generation shall be considered certified for interconnected operation if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in subsection (3).

(c) Customer-owned renewable generation shall include a utility-interactive inverter, or other device certified pursuant to paragraph (4)(b) that performs the function of automatically isolating the customer-owned generation equipment from the electric grid in the event the electric grid loses power.

(d) For Tiers 1 and 2, provided the customer-owned renewable generation equipment complies with paragraphs (4)(a) and (b), the investor-owned utility shall not require further design review, testing, or additional equipment other than that provided for in

subsection (6). For Tier 3, if an interconnection study is necessary, further design review, testing and additional equipment as identified in the study may be required.

(e) Tier 1 customers who request interconnection of customer-owned renewable generation shall not be charged fees in addition to those charged to other retail customers without self-generation, including application fees.

(f) Along with the Standard Interconnection Agreement filed pursuant to subsection (3), each investor-owned utility may propose for Commission approval a standard application fee for Tiers 2 and 3, including itemized cost support for each cost contained within the fee.

(g) Each investor-owned utility may also propose for Commission approval an Interconnection Study Charge for Tier 3.

(h) Each investor-owned utility shall show that their fees and charges are cost-based and reasonable. No fees or charges shall be assessed for interconnecting customer-owned renewable generation without prior Commission approval.

(5) Contents of Standard Interconnection Agreement. Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement shall, at a minimum, contain the following:

(a) A requirement that customer-owned renewable generation must be inspected and approved by local code officials prior to its operation in parallel with the investor-owned utility to ensure compliance with applicable local codes.

(b) Provisions that permit the investor-owned utility to inspect customer-owned renewable generation and its component equipment, and the documents necessary to ensure compliance with subsections (2) through (4). The customer shall notify the investor-owned utility at least 10 days prior to initially placing customer equipment and protective apparatus in service, and the investor-owned utility shall have the right to have personnel present on the in-service date. If the customer-owned renewable generation system is subsequently modified in order to increase its gross power rating, the customer must notify the investor-owned utility by submitting a new application specifying the modifications at least 30 days prior to making the modifications.

(c) A provision that the customer is responsible for protecting the renewable generating equipment, inverters, protective devices, and other system components from damage from the normal and abnormal conditions and operations that occur on the investor-owned utility system in delivering and restoring power; and is responsible for ensuring that customer-owned renewable generation equipment is inspected, maintained, and tested in accordance with the manufacturer's instructions to ensure that it is operating correctly and safely.

(d) A provision that the customer shall hold harmless and indemnify the investor-owned utility for all loss to third parties resulting from the operation of the customer-owned renewable generation, except when the loss occurs due to the negligent actions of the investor-owned utility. A provision that the investor-owned utility shall hold harmless and indemnify the customer for all loss to third parties resulting from the operation of the investor-owned utility's system, except when the loss occurs due to the negligent actions of the customer.

(e) A requirement for general liability insurance for personal and property damage, or sufficient guarantee and proof of self-insurance, in the amount of no more than \$1 million for Tier 2, and no more than \$2 million for Tier 3. The investor-owned utility shall not require liability insurance for Tier 1. The investor-owned utility may include in the Interconnection Agreement a recommendation that Tier 1 customers carry an appropriate level of liability insurance.

(f) Identification of any fees or charges approved pursuant to subsection (4).

(6) Manual Disconnect Switch.

(a) Each investor-owned utility's customer-owned renewable generation Standard Interconnection Agreement may require customers to install, at the customer's expense, a manual disconnect switch of the visible load break type to provide a separation point between the AC power output of the customer-owned renewable generation and any customer wiring connected to the investor-owned utility's system. Inverter-based Tier 1 customer-owned renewable generation systems shall be exempt from this requirement, unless the manual disconnect switch is installed at the investor-owned utility's expense. The manual disconnect switch shall be mounted separate from, but adjacent to, the meter socket and shall be readily accessible to the investor-owned utility and capable of being locked in the open position with a single investor-owned utility padlock.

(b) The investor-owned utility may open the switch pursuant to the conditions set forth in paragraph (6)(c), isolating the customer-owned renewable generation, without prior notice to the customer. To the extent practicable, however, prior notice shall be given. If prior notice is not given, the utility shall at the time of disconnection leave a door hanger notifying the customer that their customer-owned renewable generation has been disconnected, including an explanation of the condition necessitating such action. The investor-owned utility shall reconnect the customer-owned renewable generation as soon as the condition necessitating disconnection is remedied.

(c) Any of the following conditions shall be cause for the investor-owned utility to disconnect customer-owned renewable generation from its system:

1. Emergencies or maintenance requirements on the investor-owned utility's electric system;
2. Hazardous conditions existing on the investor-owned utility system due to the operation of the customer's generating or protective equipment as determined by the investor-owned utility;
3. Adverse electrical effects, such as power quality problems, on the electrical equipment of the investor-owned utility's other electric consumers caused by the customer-owned renewable generation as determined by the investor-owned utility;
4. Failure of the customer to maintain the required insurance coverage.

(7) Administrative Requirements.

(a) Each investor-owned utility shall maintain on its website a downloadable application for interconnection of customer-owned renewable generation, detailing the information necessary to execute the Standard Interconnection Agreement. Upon request the investor-owned utility shall provide a hard copy of the application within 5 business days.

(b) Within 10 business days of receipt of the customer's application, the investor-owned utility shall provide written notice that it has received all documents required by the Standard Interconnection Agreement or indicate how the application is deficient. Within 10 business days of receipt of a completed application, the utility shall provide written notice verifying receipt of the completed application. The written notice shall also include dates for any physical inspection of the customer-owned renewable generation necessary for the investor-owned utility to confirm compliance with subsections (2) through (6), and confirmation of whether a Tier 3 interconnection study will be necessary.

(c) The Standard Interconnection Agreement shall be executed by the investor-owned utility within 30 calendar days of receipt of a completed application. If the investor-owned utility determines that an interconnection study is necessary for a Tier 3 customer, the investor-owned utility shall execute the Standard Interconnection Agreement within 90 days of a completed application.

(d) The customer must execute the Standard Interconnection Agreement and return it to the investor-owned utility at least 30 calendar days prior to beginning parallel operations and within one year after the utility executes the Agreement. All physical inspections must be completed by the utility within 30 calendar days of receipt of the customer's executed Standard Interconnection Agreement. If the inspection is delayed at the customer's request, the customer shall contact the utility to reschedule an inspection. The investor-owned utility shall reschedule the inspection within 10 business days of the customer's request.

(8) Net Metering.

(a) Each investor-owned utility shall enable each customer-owned renewable generation facility interconnected to the investor-owned utility's electrical grid pursuant to this rule to net meter.

(b) Each investor-owned utility shall install, at no additional cost to the customer, metering equipment at the point of delivery capable of measuring the difference between the electricity supplied to the customer from the investor-owned utility and the electricity generated by the customer and delivered to the investor-owned utility's electric grid.

(c) Meter readings shall be taken monthly on the same cycle as required under the otherwise applicable rate schedule.

(d) The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation in accordance with normal billing practices.

(e) During any billing cycle, excess customer-owned renewable generation delivered to the investor-owned utility's electric grid shall be credited to the customer's energy consumption for the next month's billing cycle.

(f) Energy credits produced pursuant to paragraph (8)(e) shall accumulate and be used to offset the customer's energy usage in subsequent months for a period of not more than twelve months. At the end of each calendar year, the investor-owned utility shall pay the customer for any unused energy credits at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(g) When a customer leaves the system, that customer's unused credits for excess kWh generated shall be paid to the customer at an average annual rate based on the investor-owned utility's COG-1, as-available energy tariff.

(h) Regardless of whether excess energy is delivered to the investor-owned utility's electric grid, the customer shall continue to pay the applicable customer charge and applicable demand charge for the maximum measured demand during the billing period. The investor-owned utility shall charge for electricity used by the customer in excess of the generation supplied by customer-owned renewable generation at the investor-owned utility's otherwise applicable rate schedule. The customer may at their sole discretion choose to take service under the investor-owned utility's standby or supplemental service rate, if available.

(9) Renewable Energy Certificates. Customers shall retain any Renewable Energy Certificates associated with the electricity

produced by their customer-owned renewable generation equipment. Any additional meters necessary for measuring the total renewable electricity generated for the purposes of receiving Renewable Energy Certificates shall be installed at the customer's expense, unless otherwise determined during negotiations for the sale of the customer's Renewable Energy Certificates to the investor-owned utility.

(10) Reporting Requirements. Each electric utility, as defined in Section 366.02(2), F.S., shall file with the Commission as part of its tariff a copy of its Standard Interconnection Agreement form for customer-owned renewable generation. In addition, each electric utility shall report the following, by April 1 of each year.

- (a) Total number of customer-owned renewable generation interconnections as of the end of the previous calendar year;
- (b) Total kW capacity of customer-owned renewable generation interconnected as of the end of the previous calendar year;
- (c) Total kWh received by interconnected customers from the electric utility, by month and by year for the previous calendar year;
- (d) Total kWh of customer-owned renewable generation delivered to the electric utility, by month and by year for the previous calendar year; and
- (e) Total energy payments made to interconnected customers for customer-owned renewable generation delivered to the electric utility for the previous calendar year, along with the total payments made since the implementation of this rule.
- (f) For each individual customer-owned renewable generation interconnection:
 1. Renewable technology utilized;
 2. Gross power rating;
 3. Geographic location by county; and
 4. Date interconnected.

(11) Dispute Resolution. Parties may seek resolution of disputes arising out of the interpretation of this rule pursuant to Rule 25-22.032, F.A.C, Customer Complaints, or Rule 25-22.036, F.A.C., Initiation of Formal Proceedings.

Rulemaking Authority 350.127(2), 366.05(1), 366.92 FS. Law Implemented 366.02(2), 366.04(2)(c), (5), (6), 366.041, 366.05(1), 366.81, 366.82(1), (2), 366.91(1), (2), 366.92 FS. History—New 2-11-02, Amended 4-7-08.



MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Floridians for Solar Choice, Inc.

SUBJECT: Financial Impact Statement for the Amendment: Limits or Prevents Barriers to Local Solar Electricity Supply

DATE: April 22, 2015

This second memorandum from the sponsors of the Solar Amendment to the FIEC is intended to provide additional information on issues raised at the FIEC public hearing on April 10, 2015. This memorandum discusses the Solar Amendment's implications for the wheeling of local solar energy on the electric grid, the electric utilities' recovery of sunk costs, and local government franchise agreements. The memorandum considers these issues within the context of the FIEC's duty to issue a statement on the Solar Amendment's probable financial impact on the revenues and costs to the state and local governments.

Wheeling

The Solar Amendment envisions a local solar electricity supplier directly providing electricity to its customer instead of using the electric utility's grid to transmit and distribute or "wheel" the electricity to its customer. The Solar Amendment neither prohibits nor requires wheeling through the electric grid to a customer the electricity generated by a local solar electricity supplier. In the event wheeling occurs, the Solar Amendment does not prohibit an electric utility from charging rates for such a service provided to a local solar electricity supplier or its customer when such rates are also charged for wheeling electricity generated by a source other than a local solar electricity supplier.

Restriction on Regulating Local Solar Electricity Suppliers

Paragraph (b)(1) of the Solar Amendment prohibits state or local government from regulating a local solar electricity supplier "with respect to its rates, service, or territory," and further provides that such a local solar electricity supplier may not be "subject to any assignment, reservation, or division of service territory between or

among electric utilities." In a scenario where a local solar electricity supplier desires to use the electric grid owned by an electric utility, nothing in paragraph (b)(1) prevents the electric utility from charging the local solar electricity supplier for the service of transporting the electricity on behalf of the local solar electricity supplier, and nothing prevents the entity regulating rates from approving any such rate or charge.

By its plain language, paragraph (b)(1) restricts government authority over rates and service of a local solar electricity supplier, but imposes no such restriction on regulation of rates and service of electric utilities. A state agency's or local government's requirement that the electric utility charge a particular rate or fee for "wheeling" services, and that such a rate or fee be established following prescribed procedures, is not a regulation of the local solar electricity supplier's rates, service or territory, because such requirements do not regulate the rates the solar electricity supplier charges to its customer, do not regulate the service that it provides to its customer, and do not enforce territorial boundaries in a way that restricts the local solar electricity supplier from providing service to its customer.

Impairment of Solar Electricity from a Local Solar Electricity Supplier

Paragraph (b)(2) of the Solar Amendment provides that "[n]o electric utility shall impair any customer's purchase or consumption of solar electricity from a local solar electricity supplier through any special rate, charge, tariff, classification, term or condition of service, or utility rule or regulation, that is not also imposed on other customers of the same type or class that do not consume electricity from a local solar electricity supplier." The Merriam-Webster Online dictionary defines the term "impair" to mean: "to damage or make worse by or as if by diminishing in some material respect." Additionally, Black's Law Dictionary, 6th Edition, defines the term "impair" to mean: "[t]o weaken, to make worse, to lessen in power, diminish, or relax, or otherwise affect in an injurious manner." Applying either definition, it is clear that an electric utility's term of service or rule requiring either the local solar electricity supplier or the ultimate customer to pay for wheeling services will diminish in some material respect or lessen in some way the customer's purchase or consumption of the electricity produced by the local solar electricity supplier by imposing additional costs on the customer, either through higher rates for the solar electricity or through utility charges, depending on how the wheeling charges are collected by the electric utility. However, such a wheeling charge is one that would be charged under current law to any producer of electricity seeking to wheel power over the electric utility's distribution or transmission system whether it would be to a separate customer or to itself at a facility remote from the self-generating facility. Thus, every customer who receives electricity wheeled over the grid is subject to such "impairment." As such, the rate or charge that creates the impairment is one that is "also imposed on other customers of the same type or class that do not consume electricity from a local solar electricity supplier."

An example in current law where wheeling is authorized can be found in Section 366.051, Fla. Stat. That statute provides in part:

Public utilities shall provide transmission or distribution service to enable a retail customer to transmit electrical power generated by the customer at one location to the customer's facilities at another location, if the commission finds that the provision of this service, and the charges, terms, and other conditions associated with the provision of this service, are not likely to result in higher cost electric service to the utility's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers

This statute authorizes a utility customer to use the utility's distribution or transmission system to transport self-generated electricity to its facilities at a different location, and authorizes the electric utility providing the transportation to charge for the service. Because those generating the electricity are charged by the utility for wheeling the power to their remote facilities, they are in the same position as a customer of the same utility who receives electricity wheeled from a local solar electricity supplier's facility. The charge would not constitute an unauthorized impairment in violation of the Solar Amendment because other customers of the same type (customer's receiving electricity "wheeled" to them by the electric utility) are similarly impaired by the same kind of rate or charge for the same kind of service.

Authority to Recover Fixed or "Sunk" Costs by Dedicated Fee or Charge, or Through Base Rates

What an electric utility charges its customer is set forth in a group of rate schedules, which each apply to a particular class of customer and set forth the charges that can appear on the customer's bill. For public utilities, these schedules are established by the utility, subject to review and approval by the Public Service Commission. For municipal electric utilities, these schedules are established by the utility, subject to review and approval by the authority with oversight responsibilities for the utility, usually the city governing body, but sometimes a separate board or authority answerable to the city governing body or residents. For rural electric cooperatives, these schedules are established by the utility and are subject to review and approval by a board of directors elected by the customer members of the cooperative.

The components of a customer's bill typically consist of several types of charges varying in amount depending on the class of customer. The first type of charge is called a customer charge. It is the minimum amount a customer is required to pay, regardless of the amount of electricity consumed. This charge is supposed to allow the utility to collect its fixed costs to serve a particular customer regardless of the amount of electricity consumed. These "fixed costs" typically include the costs to the utility of

maintaining and keeping the customer's account records active, such as data processing, meter reading, billing, and other administrative-type costs.

The second type of charge is a consumption (or energy) charge, which is a per kilowatt-hour rate that is charged to a customer depending on the amount of electricity consumed. This charge is designed to cover the customer's share of the utility's investment in the physical plant, the cost of maintenance and operations, and for an investor-owned public utility, the authorized shareholder return on investment (for a municipal utility some amount above actual utility costs may be charged to support general governmental operations).

These first two types of charges combine to make up what is referred to as the utility's "base rate." However, most utilities also charge one or more "additional charges" to cover either recurring operating costs that are outside of the utility's control, such as the cost of fuel to run generating plants, or temporary costs to the utility, such as the cost to pay for hurricane damages. Additional charges have historically been imposed for such things as fuel cost recovery, recovery of costs related to hurricane damage, and pass-through of franchise fees and taxes.

Assuming the Solar Amendment becomes law, and assuming for the sake of argument that electric utilities and their rate regulators determine that activities authorized by the Solar Amendment either inhibit cost recovery by utilities or shift too much of the cost burden to customers who do not consume electricity produced by a local solar electricity supplier, the Solar Amendment preserves sufficient flexibility for utilities and their rate regulators to address the matter.

The Solar Amendment does not prohibit imposition of utility rates, fees or charges that impair a customer's purchase or consumption of *solar electricity*. Rather, the amendment has a far narrower effect. It prohibits a utility from imposing a rate, fee or charge that impairs a customer's purchase or consumption of solar electricity *from a local solar electricity supplier*, and then, only if the rate, fee or charge is one that is not also imposed on other customers of the same type or class. The focus of the Amendment is to remove regulatory barriers inhibiting the third-party local solar supplier business model specifically, not to protect the use of distributed solar electricity generally.

To the extent that current law authorizes the imposition of a rate, fee or charge on a customer who uses solar electricity because such use reduces the revenue the electric utility anticipated collecting from that customer when it made its system investments, the Solar Amendment would allow the same rate, fee or charge to a customer purchasing or consuming electricity from a local solar electricity supplier. Such a rate, fee or charge imposed by the electric utility would not violate the Solar Amendment's "impairment" provision because it is likewise charged to customers of the same type (customers who consume solar electricity from a source other than the

regulated electric utility) who do not consume electricity from a local solar electricity supplier.

A utility may, for example, include a rider in its tariff (subject to approval of its rate regulator) allowing a surcharge or a rate adjustment for all customers of a certain class (such as residential, or commercial) who reduce their demand by using electricity produced from renewable generating equipment not owned by the utility. Such a rider does not violate the Solar Amendment because the rider does not impair the consumption or purchase of electricity solely for customers of a local solar supplier, but applies to others as well. If, however, the same utility attempts to impose a rider that applies the same surcharge or rate adjustment to customers of local solar electricity suppliers ONLY, such a rider would violate the impairment provisions of the Solar Amendment.

Revenue Requirement and Rates

Every electric utility has what is known as a "revenue requirement." The revenue requirement is the amount of revenue that the utility must collect through its rates, fees and charges to recover all of its reasonable costs and meet all of its legitimate and reasonable obligations. For an investor-owned public utility, the revenue requirement includes the amount of revenue the utility must collect from its established rates, fees and charges to meet all of its operating and maintenance expenses, recover the amount of capital invested in the physical plant, service its debt, and pay to shareholders a return on investment that has been approved by the Public Service Commission and determined to be adequate to fairly compensate the shareholders for their investment. The Florida Supreme Court has determined that a utility's return on its shareholder's equity may vary within a range above or below the percentage established by the PSC and remain fair to shareholders and reasonable to customers. Court opinions have established that a realized rate of return on equity that falls within one percentage point of the percentage established by the PSC is presumptively reasonable. Therefore, a utility will typically not seek a change in its rates unless the return on equity is anticipated to fall below or rise above the ends of this established range.

Similarly, a municipal utility establishes rates to cover its revenue requirement. While no municipal utility pays shareholders a fair return on investment, some use utility revenues to fund non-utility operations, and therefore have a revenue requirement in excess of the actual costs of financing, constructing, operating and maintaining the utility system.

Whether a policy change such as that proposed in the Solar Amendment alters an investor-owned public utility's revenues enough so that it would be compelled to amend its rates or to impose an additional charge in order to meet its revenue requirement would likely depend on whether revenues declined to a degree that the utility no longer earned a return on its investment falling within the range established by

the PSC. Whether passage and application of the Solar Amendment increases distributed solar generation enough to decrease revenues and trigger the need to raise rates so that the utility may continue to earn a rate of return within the authorized range is speculative and uncertain. Whether any potential decrease in revenue caused by activities authorized by the Solar Amendment may be offset by separate increases in revenues brought about by increased operating efficiencies, management cost cutting, and customer growth is also unknown.

Likewise, whether increases in distributed solar prompted by the Solar Amendment would decrease municipal utility revenues to a level that jeopardizes non-utility governmental funding is uncertain, and whether any revenue decreases, should they materialize, will be offset by separate increases in revenues from increased operating efficiencies, management cost cutting, and customer growth, is also uncertain.

The FIEC notebook distributed after the public hearing includes papers on a variety of solar topics, including reports on electric utility rate implications of local solar, particularly whether non-solar customers cross-subsidize the rates of local solar customers. Appendix "A" includes a concise yet scholarly analysis of the debate by immediate past Chair of the Federal Energy Regulatory Commission Jon Wellinghoff and James Tong: "A Common Confusion Over Net Metering is Undermining Utilities and the Grid" at: <http://www.utilitydive.com/news/wellinghoff-and-tong-a-common-confusion-over-net-metering-is-undermining-u/355388/> The article suggests cross-subsidization of rates regularly occurs in other contexts, such as the snowbird discount mentioned at the FIEC public hearing, and points to studies demonstrating that local solar customers contribute more than their fair share.

Will the Solar Amendment Cause Cancellation of Franchise Agreements?

Passage of the Solar Amendment will not result in the widespread cancellation of franchise agreements between cities and counties and the franchisee public electric utilities. Beginning in 1996, electric utilities began including within franchise agreements offered to local government provisions that could be exercised to cancel the agreement in the event that changes in state or federal law result in retail competition. These provisions typically state the following, or something substantially similar:

If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being

served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 90 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice.

This example is excerpted from the initial form agreement offered by FPL to the City of South Miami during its recent negotiation for a franchise agreement renewal and is identical to language found in numerous FPL franchise agreements entered after 1996.

First, under these provisions, termination of the agreement is not automatic. The right of the utility to terminate is not triggered by a change in the law, rather it is triggered when the utility determines that the existence of the franchise agreement has placed it at a competitive disadvantage with respect to the new service provider, and the local government has failed to provide a remedy acceptable to the utility. The language in these agreements is usually silent as to the nature of the remedy required to avoid termination. It is uncertain and speculative that any utility will be placed at a competitive disadvantage with respect to a local solar electricity supplier who operates as authorized under the Solar Amendment. It is also uncertain and speculative that any franchise agreement will be terminated if a utility actually determines that it is at a competitive disadvantage, because the local government has the opportunity to propose a remedy or negotiate revised terms, which may or may not involve the amount of revenue paid to the local government. In a review of nearly 190 such agreements only one turned up which contained this kind of termination provision did not also provide an express opportunity to remedy prior to termination.

Second, franchise agreements are not uniform throughout the state and across utilities. Each utility offers its own form agreement, and every local government to varying degrees, negotiates its own terms which deviate from the form agreement. Several current agreements are attached as Appendix "B" for comparison purposes. Consider that agreements entered between 1985 and 1996 (all of which remain in effect – the term is almost uniformly 30 years) contain no right of termination due to competitive disadvantage.

Third, a franchise agreement is more than just an agreement as to the electric utility's payment of a fee to the local government. Such agreements grant significant benefits to the utility franchisee, including the city or county's agreement, for a 30-year term, not to take over and operate the portions of the utility system located within the local government's jurisdictional boundaries. Additionally, such agreements provide a means for addressing the utilities' uses of the public rights of way and public easements within the jurisdiction, which may be more advantageous to the utility than terms provided in statutes. In short, there are compelling reasons for a utility to continue operating under a franchise agreement notwithstanding changes in the law that allow third parties to provide electric service in the jurisdiction without being subject to the same franchise terms.

Finally, it is unclear whether provisions like those excerpted above, which are intended to apply in the event of a restructured retail electricity market, would even apply in the event that the Solar Amendment is approved and becomes law. The Solar Amendment will not be likely to cause any electric utility to lose its customer because of retail competition. Indeed, the express language contained in paragraph (b)(3) of the Solar Amendment provides that the electric utility may not be relieved of its obligation under law to provide electric service to any customer in its service territory on the basis that the customer also purchases electricity from a local solar electricity supplier. A customer of a local solar electricity supplier, therefore, remains a customer of the electric utility. If the utility does not lose its customer, is it at a competitive disadvantage with respect to a local solar electricity supplier? To the extent that ambiguity exists in any such termination provision within a franchise agreement, the Florida Supreme Court requires that the ambiguity be resolved in favor of the government and against the franchisee. See, Tampa-Hillsborough County Expressway Authority v. K.E. Morris Alignment Service, Inc., 444 So.2d 926, 928 (Fla. 1983) (attached as Appendix "C").

Revenues and Costs to the State and Local Government

The foregoing discussion about the Solar Amendment's electric utility rate implications and the franchise agreement consequences inform the FIEC's consideration of the revenue and cost consequences of the Solar Amendment. Section 100.371(5)(a), Florida Statutes, requires the FIEC to "complete an analysis and financial impact statement to be placed on the ballot of the estimated increase or decrease in any revenues or costs to state or local governments resulting from the proposed initiative." With regard to revenues, the state and local governments impose a variety of

taxes and fees on electric utilities and can generate tax and fee revenues from local solar electricity suppliers and their customers. How much and whether the revenue amounts will vary from those received today depends on a variety of factors, including among others the extent to which customers choose to utilize local solar electricity suppliers and the state and local regulatory reaction to rate change requests, if any, from the electric utilities. Because the degree to which customers take advantage of new local solar authorized by the Amendment and the regulatory reactions are unknown, the state and local revenue effects are unknown. Likewise, those factors affect the analysis of the costs to state and local government as customers of electric utilities. There is no way to know whether the Solar Amendment will result in the state and local government becoming customers of local suppliers or will result in higher or lower costs for the purchase of electric utility power from rates adjusted upwards or downwards by state or local regulatory changes. Consequently, neither the revenue nor the cost impacts can be known with the degree of certainty constitutionally required for the FIEC to determine the "probable financial impact" of the Solar Amendment.

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APPENDIX A

Utility Dive

OPINION

Wellinghoff and Tong: A common confusion over net metering is undermining utilities and the grid

'Cost-shifting' and 'not paying your fair share' are not the same thing.

By Jon Wellinghoff and James Tong | January 22, 2015

Editor's Note: The following is a guest post written by Jon Wellinghoff and James Tong. Wellinghoff is the former chairman of the Federal Energy Regulatory Commission and is currently a partner at law firm Stoel Rives LLP. Tong is the vice president of strategy and government affairs for Clean Power Finance, a financial services and software firm in the residential solar market. This article is the first in a series from Tong and Wellinghoff looking at issues surrounding utilities, distributed energy resources, and the grid. Tong and Wellinghoff's joint proposal to create an independent distribution system operator was covered in Utility Dive [here](http://www.utilitydive.com/news/jon-wellinghoff-utilities-should-not-operate-the-distribution-grid/298286/) (<http://www.utilitydive.com/news/jon-wellinghoff-utilities-should-not-operate-the-distribution-grid/298286/>).

Correction: A previous version of this post said a report by the California Public Utilities Commission (CPUC) found that net energy metering (NEM) customers in the state were paying 106% of the full cost of service. The report was, in fact, a draft. The final report found California NEM customers were paying 103% of the full cost of service.

Public discussion on net energy metering (NEM) has gone from heated to downright nasty. It started as an arcane and seemingly innocuous policy: solar customers get a one-for-one bill credit from their utility for each kWh they produce and send to the grid. NEM has become a full-blown wedge issue.

Critics assert NEM customers use the grid but do not pay their fair share of the costs. They say that NEM shifts grid costs to non-solar ratepayers, especially lower-income households and minorities. They invoke phrases such as "regressive tax", "reverse Robin Hood," or even "robbin' (<http://www.fortnightly.com/fortnightly/2013/07/reverse-robin-hood>) the hood (<http://www.fortnightly.com/fortnightly/2013/07/reverse-robin-hood>)," to suggest that solar customers – purportedly far wealthier and whiter – are getting a free ride at everyone else's expense.

"Nonsense," reply NEM advocates. "NEM critics don't care about ratepayer fairness – they care about protecting profits and monopolies for utilities that have never faced competition." They contend that, far from shifting costs, NEM customers create net value to the grid and all grid users. One only need look to [a study commissioned by the neutral Nevada Public Utility Commission](http://puc.nv.gov/uploadedFiles/pucnv.gov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study) (http://puc.nv.gov/uploadedFiles/pucnv.gov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study) that shows NEM customers provide a net present value benefit of \$36M to non-NEM customers in Nevada.

However, both arguments miss the point. That is because both use "cost-shifting" and "not paying the fair share" interchangeably. This understanding is wrong – critically wrong. And it is resulting in needlessly fractious debates and bad policies, including arbitrary fixed fees on solar customers.

A telling example: In 2013, [the California Public Utilities Commission \(CPUC\) published a study](http://www.cpuc.ca.gov/NR/rdonlyres/75573B69-D5C8-45D3-BE22-3074EAB16D87/0/NEMReport.pdf) (<http://www.cpuc.ca.gov/NR/rdonlyres/75573B69-D5C8-45D3-BE22-3074EAB16D87/0/NEMReport.pdf>) that projected a cost shift of \$1.1 billion per year by 2020 due to NEM policy. NEM critics, including the [American Legislative Council](http://alec.org/docs/Net-Metering-reform-web.pdf) (<http://alec.org/docs/Net-Metering-reform-web.pdf>) (ALEC), [Americans for Prosperity](http://americansforprosperity.org/georgia/article/why-the-sun-isnt-free-by-joel-aaron-foster/) (<http://americansforprosperity.org/georgia/article/why-the-sun-isnt-free-by-joel-aaron-foster/>), and even some academics cited the study as proof that NEM customers were not paying their fair share. So they pushed harder for fixed fees for NEM customers, a policy that various states, including Wisconsin, Arizona, Kansas, and Oklahoma, have since either explored or enacted.

But critics (as well as NEM advocates) overlooked that the same CPUC report also found that NEM customers as a whole "appear to be paying slightly more than their full cost of service" – 103% of their costs, to be precise. In other words, NEM customers were not zeroing out their bills and "free-riding;" on average, they were paying more to utilities in fixed-cost recovery than non-NEM customers.

Why do so many policy wonks on both sides consistently conflate cost-shifting with not paying one's fair share? It could be that explaining these concepts is difficult and doesn't make for good sound bites. Or it could be that few people understand the arcane subject of utility rate design or are willing to admit that the [prevailing utility regulatory model is highly redistributive to begin with](http://www.utilitydive.com/news/why-the-net-metering-fight-is-a-red-herring-for-utilities/307061/) (<http://www.utilitydive.com/news/why-the-net-metering-fight-is-a-red-herring-for-utilities/307061/>).

According to the CPUC study, before going solar, all NEM customers (commercial and residential) had paid 133% of their full cost of service. The residential segment alone paid 154% of its cost. By going solar, NEM customers were mitigating or reversing the subsidies they had traditionally been paying to support the grid. This is the crux of what is called cost-shifting.

Cost-shifting should not be ignored. But the focus on NEM customers dangerously [obscures more critical problems with the utility model](http://www2.deloitte.com/us/en/pages/energy-and-resources/articles/the-math-series-solving-for-disruption-in-US-electric-power-industry.html) (<http://www2.deloitte.com/us/en/pages/energy-and-resources/articles/the-math-series-solving-for-disruption-in-US-electric-power-industry.html>), namely slowing demand, escalating costs, and disruptive innovations. In such an environment, any technology that reduces sales of electrons will challenge traditional practices of cross-subsidization.

For example, the energy economist Catherine Wolfram estimates that [adoption of LED lighting may shift costs as much as the adoption of distributed solar](https://energyathaas.wordpress.com/2014/03/17/why-arent-we-talking-about-net-energy-metering-for-leds/). (<https://energyathaas.wordpress.com/2014/03/17/why-arent-we-talking-about-net-energy-metering-for-leds/>) Does this mean we should condemn LED users for cheating the system, or charge them fixed fees? Or should we fix the system in which the mere adoption of LED lighting can hurt the poor?

Vulnerable customer segments should not bear more cost when others adopt [distributed energy resources \(DERs\)](http://www.epri.com/Our-Work/Pages/Distributed-Electricity-Resources.aspx) (<http://www.epri.com/Our-Work/Pages/Distributed-Electricity-Resources.aspx>), such as rooftop solar or efficiency technologies. But all customers – not just solar or DER customers – need to address the potential equity issues that new technologies, however promising, may raise. The [Regulatory Assistance Project's concept of a minimum bill](http://www.raponline.org/featured-work/the-minimum-bill-an-effective-alternative-to-high-customer) (<http://www.raponline.org/featured-work/the-minimum-bill-an-effective-alternative-to-high-customer>) – which [utilities and solar advocates in Massachusetts had agreed to](http://www.greentechmedia.com/articles/read/why-the-massachusetts-net-metering-compromise-could-be-a-model-for-other-st) (<http://www.greentechmedia.com/articles/read/why-the-massachusetts-net-metering-compromise-could-be-a-model-for-other-st>) before getting stuck in the legislature – can ensure that all grid users pay their fair share. While imperfect (we advocate for [more comprehensive reforms](http://www.fortnightly.com/fortnightly/2014/08/rooftop-parity?authkey=694f9b6d88b73bb34af7a1dfe32592897cf7300b810bfb7d7d2030eab37ffed0) (<http://www.fortnightly.com/fortnightly/2014/08/rooftop-parity?authkey=694f9b6d88b73bb34af7a1dfe32592897cf7300b810bfb7d7d2030eab37ffed0>)), the concept is more efficient and fairer than a sweeping fixed fee that singles out one technology with almost no regards of its benefits and costs to the grid.

The recent push for fixed fees is problematic for many reasons; for one, [it does not rely on actual data or results](http://www.utilitydive.com/news/utah-regulators-turn-down-rocky-mountain-powers-bid-for-solar-bill-charge/304455/) (<http://www.utilitydive.com/news/utah-regulators-turn-down-rocky-mountain-powers-bid-for-solar-bill-charge/304455/>), but rather on the faulty assumption that users of technologies that shift costs are necessarily not paying their fair share. This fallacy will handicap the deployment of all promising DERs, which, by virtue of being distributed, will necessarily create uneven benefits and costs. Even worse, it may ultimately harm those ratepayers that NEM critics are trying to protect.

Separate analyses from the [Rocky Mountain Institute](http://www.rmi.org/electricity_grid_defection) (http://www.rmi.org/electricity_grid_defection) and [Morgan Stanley](http://www.greentechmedia.com/articles/read/Solar-Fixed-Charges-May-Cause-Grid-Defection) (<http://www.greentechmedia.com/articles/read/Solar-Fixed-Charges-May-Cause-Grid-Defection>) show that grid defection will soon be economically viable, and that levying more fixed fees would accelerate defection. Even if “mass defection” is unlikely, defection by a small group will probably have an outsized impact. Utilities rely disproportionately on heavy users, who tend to be more affluent and thus more economically capable of going off-grid. If these users do start defecting en masse, then we really will have an unprecedented problem of cost-shifting from the “haves” to the “have-nots” – but we can't blame the “haves” for not paying their fair share for a grid they aren't using.

Let us hope that we never have to face this calamity to finally understand the distinction between cost-shifting and not paying one's fair share.

Top Image Credit: [San Jose Inside](http://www.sanjoseinside.com/news/entries/4_19_13_sustainable_energy_solar_utilities/) (http://www.sanjoseinside.com/news/entries/4_19_13_sustainable_energy_solar_utilities/)

Filed Under:

APPENDIX B

ORDINANCE NO. 19-14-2197

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF SOUTH MIAMI, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Commission of the City of South Miami, Florida recognizes that the City of South Miami (the "City") and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City does not desire to undertake to provide such services at this time; and

WHEREAS, Florida Power & Light Company ("FPL") is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, there is currently in effect a franchise agreement between the City and FPL, the terms of which are set forth in City Ordinance No. 7-84-1202, passed and adopted May 15, 1984, and FPL's written acceptance thereof dated May 18, 1984 granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"). As a result of short extensions passed and adopted by the City on May 14, 2014 and on August 19, 2014, respectively, and accepted by FPL, the Current Franchise Agreement expires on September 18, 2014; and

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WHEREAS, FPL and the City (collectively, the "Parties") desire to enter into a new agreement ("New Franchise Agreement") providing for the payment of fees to the City in exchange for the nonexclusive right and privilege of supplying electricity within the City free of competition from the City, pursuant to certain terms and conditions; and

WHEREAS, the City Commission deems it to be in the public interest to enter into this agreement addressing certain rights and responsibilities of the Parties as they relate to the use of the public rights-of-way within the City's jurisdiction.

NOW, THEREFORE, BE IT ORDAINED BY THE MAYOR AND CITY COMMISSION OF THE CITY OF SOUTH MIAMI, FLORIDA:

Section 1. The foregoing recitals are hereby found to be true and correct, and are incorporated herein and adopted and approved as if set out at length.

Section 2. There is hereby granted to FPL, its successors and assigns, for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, rights-of-way and other public places (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the City and its successors, in accordance with FPL's customary practices, and practices prescribed herein, with respect to construction and maintenance of the electrical light, power and related facilities, including, without limitation, conduits, underground conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with

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or ancillary to FPL's provision of electricity and other services (hereinafter called "facilities") to the City and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 3. (a) FPL's facilities shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transportation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(b) To minimize such conflicts with the standards set forth in subsection (a) above, the location, relocation, installation, construction or erection of all facilities shall be made as representatives of the City may prescribe in accordance with all applicable federal and state laws, and pursuant to the City's valid rules and regulations with respect to utilities' use of public rights-of-way relative to the placing and maintaining in, under, upon, along, over and across said public rights-of-way, provided such rules and regulations:

- (i) shall be for a valid municipal purpose;
- (ii) shall not prohibit the exercise of FPL's rights to use said public rights-of-way for reasons other than conflict with the standards set forth above;
- (iii) shall not unreasonably interfere with FPL's ability to furnish reasonably sufficient, adequate and efficient electric service to all its customers while not conflicting with the standards set forth above; or

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(iv) shall not require relocation of any of FPL's facilities installed, before or after the effective date hereof, in any public right-of-way, unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way causes the facilities to unreasonably interfere with the convenient, safe, or continuous use, or the maintenance, improvement, extension, or expansion of any such public "road," or unless such relocation is required by state or federal law.

(c) Such rules and regulations shall recognize that FPL's above-grade facilities installed after the effective date hereof should, unless otherwise permitted, be installed near the outer boundaries of the public rights-of-way to the extent possible.

(d) When any portion of a public right-of-way is excavated, damaged or impaired by FPL or any of its agents, contractors or subcontractors because of the installation, inspection, or repair of any of its facilities, the portion so excavated, damaged or impaired shall, within a reasonable time and as early as practicable after such excavation, be restored to a condition equal to or better than its original condition before such damage by FPL at its expense.

(e) The City shall not be liable to FPL for any cost or expense incurred in connection with the relocation of any of FPL's facilities required under this Section, except, however, that FPL may be entitled to reimbursement of its costs and expenses from others and as provided by law.

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Except as expressly provided, nothing herein shall limit or alter the City's existing rights with respect to the use or management of its rights-of-way that are not otherwise preempted by the state or federal government.

Section 4. The acceptance of this New Franchise Agreement shall be deemed an agreement on the part of FPL to the following: (a) to indemnify and save the City harmless from any and all damages, claims, liability, losses and causes of action of any kind or nature arising out of a negligent error, omission, or act of FPL, its Contractor or any of their agents, representatives, employees, or assigns, or anyone else acting by or through them, and arising out of or concerning the construction, operation or maintenance of its facilities hereunder; (b) to pay all damages, claims, liabilities and losses of any kind or nature whatsoever, in connection therewith, including the City's attorney's fees and expenses in the defense of any action in law or equity brought against the City, including appellate fees and costs and fees and expenses incurred to recover attorney's fees and expenses from FPL, arising from the negligent error, omission, or act of FPL, its Contractor or any of their agents, representatives, employees, or assigns, or anyone else acting by or through them, and arising out of or concerning the construction, operation or maintenance of its facilities hereunder.

Section 5. All rates and rules and regulations established by FPL from time to time shall be subject to such regulation as may be provided by law.

Section 6(a). As a consideration for this franchise, FPL shall pay to the City, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which added to the amount of

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all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the City against FPL's property, business or operations and those of its subsidiaries during FPL's monthly billing period ending 60 days prior to each such payment will equal six percent of FPL's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the City for the monthly billing period ending 60 days prior to each such payment. In no event shall payment for the rights and privileges granted herein exceed 6 percent of such revenues for any monthly billing period of FPL. For clarity, actual write-offs will be subtracted from FPL's billed revenues. In the event FPL subsequently collects previously written-off billed revenues from the sale of electrical energy to residential, commercial, and industrial customers, FPL shall pay to the City a franchise payment on such revenues in accordance with the formula set forth above in this Section 6(a). FPL shall continue to remit payment in a manner consistent with the Current Franchise Agreement until the first payment is due under this New Franchise Agreement.

The City understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 7-84-1202, to the precise revenues described therein, and that such revenues do not include, by way of example and not limited to: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility

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restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

(b) If during the term of this franchise FPL enters into a franchise agreement with any other municipality located in Miami-Dade County or Broward County, Florida, where the number of FPL's meters for active electrical customers does not exceed the number of meters for FPL's active electrical customers within the incorporated area of the City by more than one hundred and fifty (150) percent, the terms of which provide for the payment of franchise fees by FPL at a rate greater than 6 percent of FPL's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under substantially similar terms and conditions as specified in Section 6(a) hereof, FPL, upon written request of the City, shall negotiate and enter into a new franchise agreement with the City in which the percentage to be used in calculating monthly payments under Section 6(a) hereof shall be no greater than that percentage which FPL has agreed to use as a basis for the calculation of payments to the other municipality, provided however, that such new franchise agreement shall include additional benefits to FPL, in addition to all benefits provided herein, at least equal to those, if any, provided by its franchise agreement with the other municipality. Subject to all limitations, terms and conditions specified in the preceding sentence, the City shall have the sole discretion to determine the percentage to be used in calculating monthly payments, and FPL shall

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have the sole discretion to determine those benefits to which it would be entitled, under any such new franchise agreement.

(c) The City reserves the unilateral right at its sole discretion and at any time during the term of this franchise, but only once per calendar year, to reduce or increase the franchise fee percentage rate upon 120 days written notice to FPL, provided that the franchise fee percentage rate shall in no event exceed 6 percent or be reduced to zero percent.

(d) The City's options hereunder shall be limited solely to the percentages or calculations of the amount of the franchise fee to be paid by FPL as consideration for this franchise as specifically set forth in this Section 6. Except as provided in this Section 6, no other Section of this New Franchise Agreement may be altered, amended or affected by the City without the written concurrence of FPL, and nothing herein shall require the City to exercise any of its options hereunder.

Section 7. (a) As a further consideration, during the term of this franchise or any extension thereof, the City agrees: (a) not to engage in the distribution and/or sale, in competition with FPL, of electric capacity and/or electric energy to any other ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by FPL other than the City, and (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate FPL to transmit and/or distribute electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies). Nothing specified

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herein shall prohibit the City from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

(b) Nothing herein shall prohibit or limit a customer of FPL, including the City, if permitted by law, from installing an approved renewable generation system to generate electric energy for use at the customer's or the City's premises respectively. Furthermore, nothing herein shall prohibit or limit a person, including the City, if permitted by law, from selling renewable energy or capacity to FPL.

Section 8. If the City grants a right, privilege or franchise to any other person to provide retail electric service within any part of the incorporated areas of the City in which FPL may lawfully serve or compete on terms and conditions which FPL reasonably determines are more favorable than the terms and conditions contained herein, FPL may at any time thereafter terminate this franchise if such terms and conditions are not revised within the time period provided hereafter. FPL shall give the City at least one hundred eighty (180) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for FPL herein, advise the City of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The City shall then have ninety (90) days in which to correct or otherwise remedy the terms and conditions complained of by FPL. If FPL determines that such terms or conditions are not remedied by the City within said time period, FPL may terminate this franchise agreement by delivering written notice by Certified United States Mail to the City's Clerk with copies to the Mayor, the City Manager and the City Attorney and termination shall be effective on the date of

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delivery of such notice. Nothing contained herein shall be construed as constraining the City's rights to legally challenge at any time FPL's determination leading to termination under this section.

Section 9. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person who offers retail electric service to the public is permitted to provide electric service within the incorporated areas of the City to any applicant for electric service within any part of the incorporated areas of the City in which FPL may lawfully serve, and FPL reasonably determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, FPL may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage resulting from this franchise is not remedied within the time period provided hereafter. FPL shall give the City at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for FPL herein, advise the City of the consequences of such action which resulted in the competitive disadvantage. The City shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the City within said time period, either by a franchise agreement with such other person or otherwise, FPL may terminate this franchise agreement by delivering written notice to the City's Clerk and termination shall take effect on the date of delivery of such notice. Agreement by the City with

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such other person to enter into a franchise containing substantially the same terms as those provided herein shall be a sufficient, but not exclusive, remedy precluding FPL's termination of this franchise. Nothing contained herein shall be construed as constraining the City's rights to legally challenge at any time FPL's determination leading to termination under this section.

Section 10. Failure on the part of FPL to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by FPL until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that FPL has failed to comply in a substantial respect with any of the provisions of this franchise, and FPL shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the City at its discretion to grant such additional time to FPL for compliance as necessities in the case may warrant.

Section 11. Failure on the part of the City to comply in substantial respect with any of the provisions of this New Franchise Agreement, including but not limited to: (a) denying FPL use of public rights-of-way for reasons other than as set forth in Section 3 of this New Franchise Agreement; (b) imposing conditions for use of public rights-of-way contrary to Federal or Florida law or the terms and conditions of this franchise; (c) unreasonable delay in issuing FPL a use permit to construct its facilities in public rights-of-way, shall constitute breach of this franchise. FPL shall notify the City of any such breach in writing sent by Certified United States Mail or via nationally recognized overnight courier and the City shall then remedy such breach as soon as

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practicable. Should the breach not be timely remedied, FPL shall be entitled to seek a remedy available under law or equity from a court of competent jurisdiction, including the withholding of the payments provided for in Section 8 as a court of competent jurisdiction determines to be just and reasonable under all the circumstances hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination dispositive of the matter.

Section 12. The Parties to this franchise agree that it is in each of their respective best interests to avoid costly litigation as a means of resolving disputes which may arise hereunder. Accordingly, the Parties agree that prior to pursuing their available legal remedies, they will meet at the senior management level in an attempt to resolve any disputes. If such informal efforts are unsuccessful after a reasonable period of time, or when an impasse is declared by the Parties, then the Parties may exercise any of their available legal remedies.

Section 13. The City may, upon reasonable notice and within 90 days after each anniversary date of this franchise, at the City's expense, examine the records of FPL relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at FPL's office where such records are maintained. Records not prepared by FPL in the ordinary course of business or as required herein may be provided at the City's expense and as the City and FPL may agree in writing. Information identifying FPL's customers by name or their electric consumption shall not be taken from FPL's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the City, shall be reported to FPL. The City's right to examine

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FPL's records in accordance with this Section shall not be conducted by any third party employed by the City whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

The City waives, settles and bars all claims relating in any way to the amounts paid by FPL under the Current Franchise Agreement embodied in Ordinance No. 7-84-1202, however, this provision shall not be construed to waive, settle or bar claims relating to any amounts due after the effective date of this New Franchise Agreement, including those amounts to be paid in a manner consistent with the terms of the Current Franchise Agreement until the first payment is made under this New Franchise Agreement.

Section 14. The provisions of this ordinance are interdependent upon one another and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect by a court of competent jurisdiction (after the expiration of all rights of appeal), such finding or adjudication shall not affect the validity of the remaining provisions for a period of ninety (90) days, during which, this agreement may be amended by the Parties. If an agreement to amend the ordinance is not reached at the end of such ninety (90) day period, this entire ordinance shall then become null and void, and of no further force or effect.

Section 15. The City acknowledges it is fully informed concerning the existing franchise granted by Miami-Dade County, Florida, to FPL, and accepted by FPL as set out in Ordinance No. 60-16 adopted on May 3, 1960, and subsequently renewed and accepted by FPL as set out in Ordinance No. 89-81 adopted on September 5, 1989 by the Board of County Commissioners of Miami-Dade County,

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Florida. The City agrees to indemnify and hold FPL harmless against any and all liability, loss, cost, damage and expense incurred by FPL in respect to any claim asserted by Miami-Dade County against FPL arising out of the franchise set out in the above referenced ordinances for the recovery of any sums of money paid by FPL to the City under the terms of this New Franchise Agreement. FPL acknowledges and the City hereby relies, in part, on then Dade County Resolution No. R-709-78 adopted on June 20, 1978 in the granting of this franchise.

Section 16. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 17. Ordinance No. 7-84-1202, passed and adopted May 15, 1984 and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

Section 18. This New Franchise Agreement shall be governed and construed by the laws and administrative rules of the State of Florida and the United States. In the event that any legal proceeding is brought to enforce the terms of this franchise, it shall be brought by either party hereto in Miami-Dade County, Florida, or, if a federal claim, in the U.S. District Court in and for the Southern District of Florida, Miami Division.

Section 19. This New Franchise Agreement is intended to constitute the entire agreement between the City and FPL with respect to the subject matters hereof, and it supersedes all prior drafts and verbal or written agreements,

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commitments, or understandings, which shall not be used to vary or contradict the expressed terms hereof.

Section 20. Except in exigent circumstances, and except as otherwise may be specifically provided for in this franchise, all notices by either party shall be made by Certified United States Mail or via nationally recognized overnight courier service. Any notice given by facsimile or email is deemed to be supplementary, and does not alone constitute notice hereunder. All notices shall be addressed as follows:

To the City:

City Manager
City Hall, 1st Floor
6130 Sunset Drive
South Miami, FL 33143

To FPL:

Vice President, External Affairs
700 Universe Boulevard
Juno Beach, FL 33408

Copy to:

City Attorney
1450 Madruga Avenue
Suite 202
Coral Gables, FL 33146

Copy to:

General Counsel
700 Universe Boulevard
Juno Beach, FL 33408

Any changes to the above shall be in writing and provided to the other party as soon as practicable.

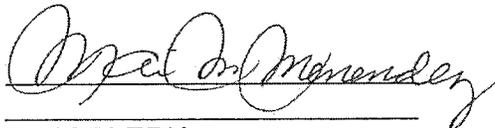
Section 21. As a condition precedent to the taking effect of the New Franchise Agreement, FPL shall file its acceptance hereof with the City's Clerk within 30 days of adoption of this ordinance. The effective date of the New Franchise Agreement shall be the date upon which FPL files such acceptance.

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PASSED AND ENACTED this 16th day of September, 2014.

ATTEST:

APPROVED:

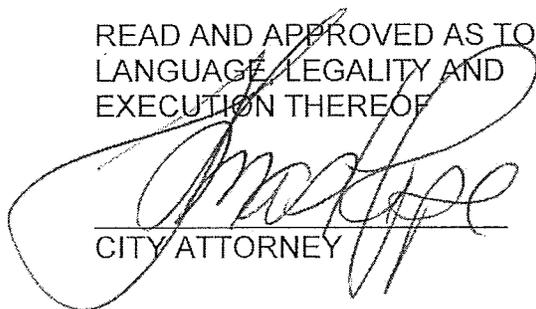




CITY CLERK
1st Reading = 9/2/14
2nd Reading - 9/16/14

MAYOR

READ AND APPROVED AS TO FORM,
LANGUAGE, LEGALITY AND
EXECUTION THEREOF


CITY ATTORNEY

COMMISSION VOTE: 4-1
Mayor Stoddard: Yea
Vice Mayor Harris: Yea
Commissioner Edmond: Nay
Commissioner Liebman: Yea
Commissioner Welsh: Yea

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 19-14-2197
BY FLORIDA POWER & LIGHT COMPANY

City of South Miami, Florida

October 1, 2014

Florida Power & Light Company does hereby accept the electric franchise in the City of South Miami, Florida, granted by Ordinance No. 19-14-2197, being:

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF SOUTH MIAMI, AND PROVIDING FOR AN EFFECTIVE DATE.

which was passed and adopted on September 16, 2014.

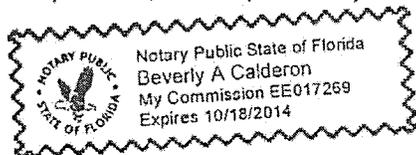
This instrument is filed with the City Clerk of the City of South Miami, Florida, in accordance with the provisions of Section 21 of said Ordinance.

FLORIDA POWER & LIGHT COMPANY

By Pamela M. Rauch
Pamela M. Rauch, Vice President

STATE OF FLORIDA
COUNTY OF PALM BEACH

The foregoing instrument was acknowledged before me this 30 day of September, 2014 by Pamela M. Rauch of Florida Power & Light Company, a Florida corporation, on behalf of the corporation, who is personally known to me.



Beverly A. Calderon
NOTARY PUBLIC Signature

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 19-14-2197 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City of South Miami, Florida on this 1st day of October, 2014.

(SEAL)

Ma. C. Menendez
City Clerk, City of South Miami, Florida

MIAMI DAILY BUSINESS REVIEW

Published Daily except Saturday, Sunday and
Legal Holidays
Miami, Miami-Dade County, Florida

STATE OF FLORIDA
COUNTY OF MIAMI-DADE:

Before the undersigned authority personally appeared MARIA MESA, who on oath says that he or she is the LEGAL CLERK, Legal Notices of the Miami Daily Business Review f/k/a Miami Review, a daily (except Saturday, Sunday and Legal Holidays) newspaper, published at Miami in Miami-Dade County, Florida; that the attached copy of advertisement, being a Legal Advertisement of Notice in the matter of

CITY OF SOUTH MIAMI
NOTICE OF PUBLIC HEARING FOR 9/16/2014

in the XXXX Court,
was published in said newspaper in the issues of

09/05/2014

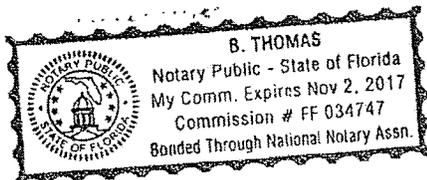
Affiant further says that the said Miami Daily Business Review is a newspaper published at Miami in said Miami-Dade County, Florida and that the said newspaper has heretofore been continuously published in said Miami-Dade County, Florida, each day (except Saturday, Sunday and Legal Holidays) and has been entered as second class mail matter at the post office in Miami in said Miami-Dade County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he or she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sworn to and subscribed before me this

05 day of SEPTEMBER, A.D. 2014

(SEAL)

MARIA MESA personally known to me



CITY OF SOUTH MIAMI NOTICE OF PUBLIC HEARING

NOTICE IS HEREBY given that the City Commission of the City of South Miami, Florida will conduct Public Hearing(s) at its regular City Commission meeting scheduled for Tuesday, September 16, 2014 beginning at 7:00 p.m., in the City Commission Chambers, 6130 Sunset Drive, to consider the following item(s):

An Ordinance granting to Florida Power & Light Company, its successors and assigns, an electric franchise, imposing provisions and conditions relating thereto, providing for monthly payments to the City of South Miami and providing for an effective date.

An Ordinance amending Section 20-7-12 of the City of South Miami Land Development Code concerning parking requirements for restaurants within the Hometown District Overlay (HD-OV) Zone.

An Ordinance of the City of South Miami, Florida, amending Section 2-7 Administrative department, functions and duties; creating a cost recovery administrative program; providing for repeal of ordinances in conflict; and providing an effective date.

An Ordinance relating to the fee schedule, amending ordinance 04-11-2077 to change the title to "Schedule of Fees and Fines" and to increase some fees, adding new fees, and deleting some fees from the schedule.

All interested parties are invited to attend and will be heard.

For further information, please contact the City Clerk's Office at 305-663-6340.

Maria M. Mendez, GMC
City Clerk

Pursuant to Florida Statutes 286.0105, the City hereby advises the public that if a person decides to appeal any decision made by this Board, Agency or Commission with respect to any matter considered at its meeting or hearing, he or she will need a record of the proceedings, and that for such purpose, affected person may need to ensure that a verbatim record of the proceedings is made which record includes the testimony and evidence upon which the appeals to be based.

14-3-345/2341375M

POLICE REPORT

• SOUTH MIAMI
A vandal painted red graffiti on the sign at the Rosie Lee Wesley Health Center at 6601 SW 62nd Ave. between 7 p.m. July 19 and 7:45 a.m. July 21. Damage was estimated at \$220.

A thief shattered the front passenger window of a black 2010 Audi TT and stole a backpack, an Apple MacBook Pro, and a Duo-fold pen, all valued at \$2,365, in a parking lot in the 6200 block of South Dixie Highway between 515 and 630 p.m. July 22.

• PINECREST
A woman reported damage to her 2012 Hyundai when she arrived at the police department at 2:15 p.m. July 28. The woman, who lives in the 11800 block of Southwest 69th Avenue, made with him.

A mail carrier called police about 12:30 p.m. Aug. 14 after he noticed a broken window at a residence in the 8200 block of Southwest 133rd Street. Police determined that a thief broke into the house and took an unknown number of items.

• KENDALL
A thief smashed the left rear window of a white 2012 Cadillac Escalade EXT and stole all four tires and tires while the vehicle was in the driveway of a residence in the 12000 block of Southwest 100th Avenue between 9 p.m. Aug. 4 and 8:45 a.m. Aug. 5. Damage and loss were estimated at \$3,000.

• PALMETTO BAY
A woman called police in reference to a personal identification number.

Southwest 69th Avenue, said the vehicle had been parked in an unfenced driveway since July 26 and had not been moved again until she discovered the damage, which is valued at \$2,300.

Police were called to the Bank of America at 9701 S. Dixie Hwy. about 4:15 p.m. July 28 in reference to verbal threats. The victim reported that a customer had verbally threatened her. The victim told police that when the offender arrived at the bank and inquired why his accounts had been closed, he became loud and offensive. When the offender was asked to leave, he was reported to have said, "Don't worry, I will take care of you." The offender was not on the scene when police arrived and contact was not

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NOTICE OF PUBLIC HEARING
CITY OF SOUTH MIAMI

Planning and Zoning Department
6130 Sunset Drive, South Miami, Florida 33143
Phone: (305) 663-6324; Fax #: (305) 666-4591

On Thursday September 18, 2014 at 7:00 P.M., the City of South Miami's Planning Board will conduct public hearings in the City Commission Chambers at the above address on the following items:

1. PB-14-008
Applicant: Ponce Davis, LLC
A Resolution of the City of South Miami relating to a request to allow for the creation of parcels A and B on property specifically located at 5980 SW 80th Street, South Miami, Florida within an RS-3, Low Density Single-Family Residential Zoning District, pursuant to provisions pertaining to "Waiver of Plan" set forth in Section 20-4-2(B) of the City of South Miami Land Development Code, and Section 28-4 of the Miami-Dade County Code; for the purpose of constructing two new single family houses; and providing for a legal description.
2. PB-14-009
Applicant: City of South Miami
Discussion of the compatibility between new single family home sizes, and existing homes within the single family zoning district, and possible recommendations for changes to the City's land development code.

All interested parties are urged to attend. Objections or expressions of approval may be made in person at the hearing or filed in writing prior to or at the hearing. The hearing board reserves the right to recommend any other action. Interested parties should consider it the best practice to provide written comments and information in order to assist the Planning and Zoning Department by calling 305-663-6324 or writing to the address indicated above.

You are hereby advised that if any person desires to appeal any decision made with respect to any matter considered at this meeting or hearing, such person will need a record of the proceedings, and for each purpose, affected person may need to ensure that a verbatim record of the proceedings is made, which record includes the testimony and evidence upon which the appeal is to be based (EA 368.0103). Refer to hearing number when making any inquiry.



Planning and Zoning Department
6130 Sunset Drive, South Miami, Florida 33143
Phone: (305) 663-6324; Fax #: (305) 666-4591

CITY OF SOUTH MIAMI
COURTESY NOTICE

NOTICE IS HEREBY given that the City Commission of the City of South Miami, Florida will conduct Public Hearing(s) at its regular City Commission meeting scheduled for Tuesday, September 16, 2014 beginning at 7:00 p.m., in the City Commission Chambers, 6130 Sunset Drive, to consider the following item(s):

An Ordinance granting to Florida Power & Light Company, its successors and assigns, an electric franchise, imposing provisions and conditions relating thereto, providing for monthly payments to the City of South Miami, and providing for an effective date.

An Ordinance amending Section 20-7.12 of the City of South Miami Land Development Code concerning parking requirements for restaurants within the Homeown District Overlay (HD-OV) Zone.

An Ordinance of the City of South Miami, Florida, amending Section 2-7, Administrative department functions and duties creating a cost recovery administrative program, providing for repeal of ordinances in conflict; and providing an effective date.

An Ordinance relating to the fee schedule; amending ordinance 04-11-2077 to change the title to "Schedule of Fees and Fines" and to increase some fees, adding new fees, and deleting some fees from the schedule.

ALL interested parties are invited to attend and will be heard.

For further information, please contact the City Clerk's Office at: 305-663-6340.

Maria M. Menendez, CMC
City Clerk

Pursuant to Florida Statute 286.0105, the City hereby advises the public that if a person desires to appeal any decision made by this Board, Agency or Commission with respect to any matter considered at its meeting or hearing, he or she will need a record of the proceedings, and that for such purpose, affected person may need to ensure that a verbatim record of the proceedings is made which record includes the testimony and evidence upon which the appeal is to be based.



Planning and Zoning Department
6130 Sunset Drive, South Miami, Florida 33143
Phone: (305) 663-6324; Fax #: (305) 666-4591

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LEE COUNTY ORDINANCE NO. 14-06

AN ORDINANCE OF LEE COUNTY GRANTING TO THE LEE COUNTY ELECTRIC COOPERATIVE, INC. ("LCEC"), ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC UTILITY FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING FOR FRANCHISE FEE PAYMENTS TO LEE COUNTY; PROVIDING FOR SEVERANCE, CONFLICTS, SEVERABILITY, AND AN EFFECTIVE DATE.

WHEREAS, the Lee County Board of County Commissioners is the governing body in and for Lee County, Florida ("County"), a political subdivision and Charter County of the State of Florida; and

WHEREAS, the Board of County Commissioners is lawfully authorized to enter into non-exclusive franchise agreements with electric utilities defining terms and conditions for the use of County Public Rights-of-Way and other County property for the purpose of supplying electricity and electric utility services (hereafter, "Grantor," "County," or Board"); and

WHEREAS, the Lee County Electric Cooperative, Inc. ("LCEC"), a not-for-profit electric cooperative organized under Chapter 425, F.S., is authorized to conduct business in the State of Florida and Lee County, and as such, is an electric utility desiring to enter into a non-exclusive franchise agreement with the County for such purpose (hereafter, "Grantee" or "LCEC"); and

WHEREAS, the County desires to grant a non-exclusive franchise to LCEC relating to LCEC's use of the County's Public Rights-of-Way and other County property for the purpose of supplying its customers with electricity within its service territory in unincorporated Lee County free of competition from Lee County.

NOW THEREFORE, BE IT ORDAINED BY THE LEE COUNTY BOARD OF COUNTY COMMISSIONERS that:

SECTION 1. The above recitations are hereby found to be true and accurate and are adopted and approved as if set out herein at length.

SECTION 2.

Lee County hereby grants to LCEC its successors and assigns, for the period of thirty (30) years from the Effective Date hereof, the nonexclusive right, privilege and franchise (hereafter, "Franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future County owned or held roads, streets, alleys, bridges, easements, and other County property (hereinafter, "Public Rights-of-Way") throughout the unincorporated area of Lee County. LCEC shall exercise its Franchise granted herein in accordance with its customary practices with respect to the construction and maintenance of the electric light and power related facilities, including, without limitation, conduits, underground conduits, poles, wires,

communications facilities, transmission and distribution lines, fiber optic, and any other facilities installed in conjunction with or ancillary to all of LCEC's electric power operations (hereafter, "facilities"), for the purpose of supplying its customers with electricity within its service territory in unincorporated Lee County and persons beyond the limits thereof as may be authorized by law or agreement. The County recognizes that LCEC must construct, maintain and own or have the lawful use of sites and facilities for the transmission and distribution of electric power in order to adequately serve its customers in unincorporated Lee County, and that the County will not unreasonably withhold from LCEC, permits to construct such facilities within the County's Public Rights-of-Way or authorized County-held easements for such placement, unless the operation, construction and maintenance of such facilities would unreasonably interfere with the traveling public's safety and welfare. The County also recognizes and agrees that nothing in this Franchise constitutes or shall be deemed to constitute a waiver of LCEC's delegated and independent right of Eminent Domain.

SECTION 3.

(i) LCEC Facilities shall be installed, located or relocated, so as not to unreasonably interfere with the Public's travel over the Public Rights-of-Way or the reasonable egress from and ingress to abutting properties. To avoid conflicts with the Public's travel, the location or relocation of all LCEC Facilities shall be made in accordance with the County's adopted reasonable rules and regulations as they may be revised, amended, or re-numbered from time to time, for the placement and maintaining of electric utility infrastructure in, under, upon, along, over and across the County's Public Rights-of-Way.

(ii) The County's adopted rules and regulations for the placement of electric utilities in its Rights-of-Way (a) shall not unreasonably prohibit the exercise of LCEC's right to use said Public Rights-of-Way for reasons other than when such use creates an unreasonable interference with the safety of the Public's travel thereon, (b) shall not unreasonably interfere with LCEC's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of LCEC's Facilities installed before or after the Effective Date hereof in any County Public Rights-of-Way unless or until: (1) the County's widening or reconfiguring of the paved portion of any Public Rights-of-Way used by motor vehicles causes such installed LCEC Facilities to unreasonably interfere with motor vehicular traffic, or (2) the location of the LCEC Facilities constitutes an unavoidable hazard to non-motor vehicular traffic exercising reasonable care, taking into account established customs and practices with respect to the placement of utility facilities, and other structures or obstructions commonly installed or located in and around sidewalks and other non-motor vehicular travel ways.

(iii) The County's adopted rules and regulations for the County's electric utility construction permits will recognize and take into consideration that the installation of the above grade (surficial) LCEC Facilities that are installed or relocated in the County's Rights-of-Way after the Effective Date hereof will be installed or relocated at, or as close to the

outermost boundaries of the Rights-of-Way to the extent most reasonably possible, unless otherwise permitted by the County in a writing.

(iv) The County will not be liable to LCEC for any costs or expenses relating to any installations or relocations of LCEC's Facilities made pursuant to subparagraphs (i) and (ii), above. However, if the County directs LCEC in a writing signed by the County Manager, to locate or relocate its Facilities in a manner that is not consistent with LCEC's then-existing standard construction methods for such installations or relocations, the County will then be liable to LCEC for those costs under LCEC's then-existing contribution-in-aid of construction policies, unless during the term of this Franchise Ordinance, there are changes in law or rules, or judicial determination(s) that dictate otherwise.

(v) If any construction work is performed in a portion of a County Public Right-of-Way by LCEC in the course of the location or relocation of any of its Facilities, the portion of the Public Right-of-Way where such construction work is performed shall be restored by LCEC at its sole cost and expense to as good a condition as it existed at the time immediately prior to the commencement of such construction work within thirty (30) days after its completion.

(vi) For so long as LCEC remains in substantial compliance with the provisions of this Section, the County will not unreasonably deny LCEC the use of the County's Public Rights-of-Way as defined herein, and will not deny LCEC the necessary County permits to construct, maintain and operate its Facilities within such Public Rights-of-Way, other than what will be reasonable and necessary for the County to preserve the traveling public's safety and welfare from time to time.

SECTION 4. The County by the grant of this Franchise to LCEC, shall in no way be liable to or responsible for in any manner whatsoever for, any accident, personal injury, property damage, or any claim or damage that may occur in the construction, installation, operation or maintenance by LCEC, its employees, agents, contractors, sublicenses or licensees for any of its facilities hereunder, except for any damage specifically caused by or arising solely out the negligence, strict liability, intentional torts or criminal acts of the County. For and in consideration of the sum of One-Hundred and 00/100 Dollars (\$100.00) in hand paid, and other good and valuable consideration accepted by the County, LCEC agrees to indemnify and hold the County harmless from and against any and all liability, loss costs, damages or expenses, to include any reasonable attorney fees of the County which may accrue to the County as the result of or by reason of any negligence, default or misconduct by LCEC in the construction, operation and maintenance of its facilities hereunder in or on the County's Public Rights-of-Way or any other County granted properties. For the term of this Franchise, LCEC shall maintain general liability insurance in such amounts as are ordinary in the course of LCEC's electric utility business to further support this indemnification. Copies of LCEC's general liability insurance policies shall be provided to the County upon its written request.

SECTION 5.

(i) As a consideration for this Franchise and as reasonable rent for LCEC's use of the County's Public Rights-of-Way granted herein, LCEC shall pay to the County, beginning on the first day of the month immediately following the month in which the Ordinance becomes effective, and then thereafter at the end of each calendar quarter for the remainder of the term of this Franchise; an amount which when added to the amount of all County licenses, excises, assessments, fees or charges (except ad-valorem property taxes), levied or imposed by the County against LCEC's property, business or operations during the quarterly billing period ending 30 days prior to each such payment, will equal no more than four and one-half percent (4.5%) of LCEC's billed revenues, less actual write-offs, from the sale of electricity to residential, commercial and industrial customers located within the unincorporated areas of the County within LCEC's service territory for the quarterly billing period ending thirty (30) days prior to each such payment (hereinafter, "Franchise Fee").

(ii) It is hereby provided and agreed to by LCEC, that the County shall have the unilateral option after the fifth (5th) anniversary date from the implementation of the Franchise Fee, or at any time thereafter, to increase the franchise percentage rate herein to no more than six percent (6.0%). Such increase will not be exercised more than twice by the County (if an initial increase is less than 6.0%) in years to be reasonably selected by the Board. The increase option(s) will be exercised through a County Ordinance, adopted by the Board at a duly advertised Public Hearing. A certified copy of which will be delivered to LCEC no later than ninety (90) days before the fifth (5th) anniversary date hereof on which such increase is to become effective following the Board's adoption of the Ordinance. Any such ordinance shall provide that LCEC shall pay to the County, no later than thirty (30) days after the end of LCEC's first quarterly billing period occurring after the fifth (5th) anniversary date as stated above, or after any subsequent year as the County may elect to exercise this option and the effective date of the County Ordinance establishing the new franchise rate percentage; and no later than thirty (30) days after the end of each succeeding quarterly billing of LCEC, an amount which, when added to the amount of all County licenses, excises, assessments, fees or charges (except ad-valorem property taxes), levied or imposed by the county against LCEC's property, business or operations during the quarterly billing period ending 30 days prior to each such payment, will equal no more than six percent (6.0%) of the billed revenues from the LCEC's sale of electricity, less actual write-offs, to residential, commercial and industrial customers located in the unincorporated area of the County within LCEC's service territory.

(iii) It is hereby further provided and agreed to by LCEC, that if during the term of this Franchise Agreement LCEC enters into a franchise agreement with any other municipality or county government, the terms of which provide for the payment of a Franchise Fee by LCEC at a rate greater than 6.0 percent of billed revenues from LCEC's residential, commercial and industrial customers under the same terms and conditions as specified in Section 5 (i) and (ii) hereof, then LCEC, upon written request of the County, shall negotiate and enter into a new franchise agreement with the County in which the percentage to be used in calculating the monthly payments under Section 5 (i) and (ii), using the same terms and conditions as specified

in said Section, shall be at the greater rate being paid to the other municipality or county, provided however, that if the franchise with such other municipality or county contains additional benefits given to LCEC in exchange for the increased Franchise Rate, and such additional benefits are not contained within this Franchise Agreement, then LCEC shall have the option to include within such new franchise agreement with the County, the additional benefits included in the initiating franchise (i.e., the new municipality or county franchise that initiated the negotiation of the new franchise as contemplated above).

(iv) In the event during the term of this Franchise that LCEC recovers and collects previously written-off and uncollected billed revenues from the sale of electrical energy to residential, commercial, and industrial customers, LCEC shall pay to the County in accordance with this Section and other relevant terms of this Ordinance, the then applicable Franchise Fee payment on such revenues so collected and received, such payment to be made in the next quarterly Franchise Fee payment to the County pursuant to the terms herein following the recovery of the funds.

(v) The County reserves the unilateral right, at its sole discretion and at any time during the term of this Franchise to reduce the Franchise Fee, by providing to LCEC a certified copy of an Ordinance adopted by the County Commission at a duly advertised Public Hearing, amending the Franchise Ordinance to reduce the Franchise Fee. The certified copy of the Amended Ordinance shall be provided to LCEC no later than thirty (30) days following the Board's adoption of the Ordinance. The reduced Franchise Fee will be applied by LCEC to its customers as of the date of the adoption of the Franchise Fee Reduction Ordinance unless otherwise provided for in the terms of the Ordinance.

(vi) The County's options hereunder shall be limited solely to the percentages or calculations of the amount of the Franchise Fee to be paid by LCEC as consideration for this Franchise as specifically set forth in this Section. No other Sections or provisions of this Franchise ordinance may be altered, amended or affected by the County without the written concurrence of LCEC. Nothing herein shall require the County to exercise any of its options as outlined under this Section.

SECTION 6.

(i) As consideration during the term of this Franchise, the County agrees not to: (a) engage in the distribution and/or sale, in competition with LCEC, of electric capacity and/or electric energy as set out above to any ultimate consumer of electric utility service ("retail customer") or to any electrical distribution system established solely to serve any customer formerly served by LCEC, (b) participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate LCEC to transmit and/or distribute, electric capacity and/or electric energy from any third party to any other LCEC customer's facility, or (c) seek to have LCEC transmit and/or distribute electric capacity and/or electric energy generated by or on behalf of the County at one location to the County's facility at any other location(s).

(ii) However, nothing herein shall prohibit the County, if permitted by law, or judicial determination, from: purchasing electric capacity and/or electric energy from any third party, or (ii) seeking to have LCEC transmit and/or distribute to any facility of the County, electric capacity and/or electric energy purchased by the County from any third party; provided, however, that before the County elects to purchase electric capacity and/or electric energy from any third party, the County shall notify the LCEC in writing. Such written notice shall include a summary of the specific rates, terms and conditions of the proposed purchase which have been offered by the third party and identify the County's facilities to be served under the offer. LCEC shall thereafter have ninety (90) days to evaluate the offer and, if LCEC offers rates, terms and conditions to the County which are equal to or better than those offered by the third party, the County shall be obligated to continue to purchase electric power capacity from LCEC and/or electric energy to serve the identified facilities of the County at the revised rates, terms and conditions for a term no longer than the remainder term of this franchise. If LCEC does not agree to provide rates, terms and conditions which are equal to or better than the third party's offer, then the terms and conditions of this franchise shall continue to remain in full force and effect for its term, and the County shall have the right to proceed with the purchase of either electric capacity or electric energy from the third party; or prohibit the County from engaging with other utilities in wholesale transactions for the sale of any amount of the electric power generated by its Waste-to-Energy Facility.

SECTION 7. If the County grants a right, privilege or franchise to any other party or otherwise enables any other such party to construct, operate or maintain electric light and power facilities within any part of the service territory of LCEC within the unincorporated area of the County on terms and conditions which LCEC determines are more favorable than the terms and conditions contained herein, LCEC may at any time thereafter terminate this Franchise if such terms and conditions are not revised by the County within the time period provided for herein. LCEC shall give the County at least sixty (60) Business Days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for LCEC herein, advise the County of such terms and conditions offered to the other party that it considers more favorable. The County shall then have sixty (60) Business Days in which to correct or otherwise remedy the terms and conditions complained of by LCEC. If LCEC determines that such terms and conditions are not remedied by the County within said time period, LCEC may terminate this Franchise agreement by delivering written notice by Certified United States Mail to the Chairman of the Board of County Commissioners with copies to the County Manager, County Attorney and the Lee County Clerk of Courts, and thereafter shall not be obligated to pay any Franchise Fee to the County for the use of County Public Rights-of-Way.

SECTION 8. If as a direct or indirect consequence of any legislative, judicial, regulatory or other action by the United States or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) enacted after the Effective Date of this Ordinance, any person is permitted to provide electric service within LCEC service territory in the unincorporated area of the County to a customer then being served by LCEC, or to any new applicant for electric service within any part of the unincorporated area of

the County in which LCEC may lawfully provide service, and LCEC determines that its obligations hereunder or otherwise resulting from this Franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person providing the electric service, LCEC may, at any time after the taking of such action, terminate this Franchise if such competitive disadvantage, and which is within the jurisdiction and authority of the County to remedy, is not remedied within the time period provided for in this Section 9. LCEC shall give the County at least sixty (60) Business Days advance written notice sent by United States Mail of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for LCEC herein, advise the County of the consequences of such action which resulted in the competitive disadvantage. The County shall then have sixty (60) Business Days or such other time as may be agreed to by LCEC in consultation with the County, for the County to correct or otherwise remedy the competitive disadvantage, if it is within the County's jurisdiction and authority to do so. If such competitive disadvantage is not remedied by the County within the determined time period and such remedy is within the County's jurisdiction and authority to do so, LCEC may terminate this Franchise agreement by delivering written notice by Certified United States Mail to the Chairman of the Board of County Commissioners with copies to the County Manager, County Attorney and Lee County Clerk of Courts, and thereafter shall not be obligated to pay any Franchise Fee to the County for the use of County Public Rights-of-Way.

SECTION 9. Failure on the part of LCEC to comply in any substantial respect with any of the provisions of this Franchise shall be grounds for a forfeiture of this Franchise by the County, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by LCEC through either administrative or judicial proceedings until there is final determination by a court of competent jurisdiction (after the expiration or exhaustion of all rights of appeal) that LCEC has failed to comply in a substantial manner with any of the provisions of this Franchise. Thereafter, LCEC shall have six (6) months after such final determination to remedy the default before a forfeiture shall result, with a right of the County at its sole discretion to grant such additional time to LCEC for its compliance, if found to be warranted. If the default is not cured within the prescribed time, LCEC shall then immediately forfeit this Franchise.

SECTION 10. Failure on the part of the County to substantially comply with any of the provisions of this Ordinance, including: (a) denying LCEC the use of County Public Rights-of-Way in the LCEC service territory for reasons other than the unreasonable interference with public travel; (b) imposing conditions for the use of Public Rights-of-Way contrary to Florida law or the terms and conditions of this Franchise; or (c) an unreasonable delay in issuing LCEC a use permit, if any such permit is required, to construct facilities in County Public Rights-of-Way pursuant to this Franchise, shall constitute a County breach of this Franchise. LCEC shall notify the County of any such breach in writing sent by United States Mail and the County shall then remedy such breach as soon as practicable, taking into account LCEC's obligation(s) to provide reasonably sufficient, adequate and efficient electric service to its customers; otherwise, within no later than thirty (30) Business Days. Should the breach not be remedied within the specified thirty (30) Business Days, LCEC shall be entitled to withhold up to the maximum of thirty percent (30%) of the payments to the County as provided for in Section 5 herein until such time

as the use permit is issued, or a court of competent jurisdiction has reached a final determination with respect to the issue(s) in dispute. In the event that such final determination by the court is in favor of the County as to such issue(s) in dispute, LCEC shall promptly remit to the County all payments withheld hereunder together with simple interest, for the period withheld at the then established rate for judgments pursuant to Florida law.

SECTION 11. The Parties to this Franchise agree that it is in each of their respective best interests to avoid costly litigation as a means of resolving disputes which may arise hereunder. Accordingly, the Parties agree to notify one another in writing sent by United States Mail and any other available electronic means commonly used in the ordinary course of business when such dispute arises, and agree that prior to pursuing their available legal remedies, they will meet at the senior management level in an attempt to resolve any disputes within no later than thirty (30) Business Days from such notice. If such efforts are unsuccessful, and after an impasse is declared by either of the Parties, then the Parties may exercise any of their other available legal remedies.

SECTION 12. The County may, upon reasonable notice and within ninety (90) days after each annual anniversary date from the Effective Date of this Franchise, at the County's sole expense, examine the records of LCEC relating to the calculation of the franchise payments for the year preceding such anniversary date. Such examination shall be made during normal business hours at the LCEC office where such records are generally maintained. Records not prepared by LCEC in the ordinary course of its business may be provided to the County at the County's expense, and as the Parties may agree in writing. Any information identifying individual LCEC customers by name, address or individual electric consumptions shall not be recorded in any manner, or taken from LCEC's premises by County auditors. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the County, shall be reported to LCEC. The County's right to examine the records of LCEC in accordance with this section shall not be conducted by any third party employed by the County whose fee, in whole or in part, for conducting such audit is contingent upon the third party's findings of the audit.

SECTION 13. The provisions of this ordinance are hereby deemed by the Parties to be interdependent upon one another and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect by a court of competent jurisdiction (after the expiration of all rights of appeal), such finding or adjudication shall not affect the validity of the remaining provisions for a period of sixty (60) days, during which, this Ordinance may be amended by the Parties. If an agreement to amend the ordinance is not reached at the end of the such sixty (60) day period, this entire ordinance shall then become null and void, and of no further force or effect.

SECTION 14. Any County ordinances and/or parts of County ordinances in conflict herewith are hereby repealed to the extent that they may be in conflict with the terms and provisions as set out herein.

SECTION 15. This Ordinance shall be governed and construed by the Laws, Administrative Rules and judicial determinations of the United States and the State of Florida. Nothing in this Franchise shall be either construed or considered as an abrogation, surrender or mitigation by the County of any of its rights and authority to use and to require the relocation of any uses within its Public Rights-of-Way as provided in Section 3. In the event that any legal proceeding is brought to enforce the terms of this Franchise, it shall be brought by either Party hereto in state court in Lee County, Florida, or, if a federal claim, in the U.S. District Court in and for the Middle District of Florida, Fort Myers Division. In any legal action between the Parties arising out of this Franchise, any attempts to enforce this Franchise, or any breach of this Franchise, the prevailing Party may recover its expenses from such legal action including, but not limited to, costs of litigation and reasonable attorneys' fees from the other party together with reasonable fees and costs on appeal.

SECTION 16. Except in exigent circumstances, and except as otherwise may be specifically provided for in this Franchise, all notices by either Party shall be made by either depositing such notice into the United States Mail or by facsimile or other electronic transmission. Certified Mail shall be deemed delivered five (5) days following the date of such deposit into the United States Mail unless otherwise provided. Any notice given by facsimile or email is deemed to be received on the same Business Day. "Business Day" for purposes of this Ordinance shall mean Monday through Friday, with Saturday, Sunday and observed holidays excepted. All notices shall be addressed as follows:

To the County:

Chairman, Board of County Commissioners
2120 Main Street
Fort Myers, Florida 33901
Telephone: (239) 533-2227
Facsimile: (239) 485-2021
Email: dist3@leegov.com

To LCEC:

Lee County Electric Cooperative, Inc.
Chief Executive Officer
4980 Bayline Drive
North Fort Myers, Florida 33917-3910
Telephone: (239) 995-2121
Facsimile: (239) 995-7904
Email: ceooffice@lcec.net

Copy to:

Lee County Attorney
P.O. Box 398
Fort Myers, Florida 33902
Telephone: (239) 533-2236
Facsimile: (239) 485-2106
Email: rwesch@leegov.com

Copy to:

LCEC General Counsel
John Noland, Esq.
Henderson Franklin Starnes & Holt, P.A.
1715 Monroe Street
Fort Myers, Florida 33907
Telephone: (239) 344-1140
Facsimile: (239) 344-1515
Email: John.Noland@henlaw.com

Any changes to the Parties' representatives above shall be made in writing and provided to the other Party as soon as practicable by U.S. Mail or other electronic conveyance.

SECTION 17. This Ordinance is intended to constitute the entire agreement between the County and LCEC with respect to the subject matters herein, and supersedes all prior drafts and verbal or written agreements, commitments, or understandings, which shall not be used to vary or contradict the expressed terms hereof.

SECTION 18. As used herein for the purposes of this Franchise Ordinance, the term "person" means an individual, or, a partnership, corporation, business trust, joint stock company, trust, unincorporated association, joint venture, governmental authority or any other entity authorized to conduct business in Florida.

SECTION 19. The Board of County Commissioners intends that this Ordinance will be made part of the Lee County Code. Sections of this Ordinance can be renumbered or relettered and the word "ordinance" can be changed to "section," "article," or other appropriate word or phrase to accomplish such codification. Regardless of whether this Ordinance is ever codified, this Ordinance can be renumbered or relettered and typographical errors that do not affect the intent or substantive provisions herein may be administratively corrected upon the authorization of the County Manager and County Attorney, without the need for a further public hearing. Any such administrative revisions made hereto will be provided to LCEC within five (5) Business Days of their being made and incorporated into this Ordinance.

[REMAINDER OF THIS PAGE LEFT INTENTIONALLY BLANK]

SECTION 20.

(i) A certified copy of this Ordinance shall be filed by the County with the Florida Department of State within ten (10) days following its adoption.

(ii) As a condition precedent to the taking effect of this Ordinance, LCEC shall file a written acceptance hereof on its official letterhead stationery and executed by the Chief Executive Officer of LCEC, within thirty (30) days after the adoption of this Ordinance. The effective date ("Effective Date") of this Ordinance shall then be the date upon which LCEC files such written acceptance with the Clerk to the Lee County Board of County Commissioners, with copies to the Chairman of the Board of County Commissioners, the County Manager and the County Attorney.

The foregoing Ordinance was offered by Commissioner Manning who moved its adoption. The motion was seconded by Commissioner Mann and being put to a vote, the vote was as follows:

JOHN MANNING	Aye
CECIL PENDERGRASS	Nay
LARRY KIKER	Aye
BRIAN HAMMAN	Nay
FRANK MANN	Aye

DULY PASSED AND ADOPTED this 18th day of March, 2014.

ATTEST: LINDA DOGGETT
CLERK OF THE COURT

BOARD OF COUNTY COMMISSIONERS
OF LEE COUNTY, FLORIDA

By: Marcia Wilson
Deputy Clerk

By: Larry Kiker
Larry Kiker, Chairman



APPROVED AS TO FORM:
By: Gudrea B. France
Office of the County Attorney

**FLORIDA DEPARTMENT of STATE**

RICK SCOTT
Governor

KEN DETZNER
Secretary of State

March 20, 2014

Honorable Linda Doggett
Clerk of the Circuit Courts
Lee County
Post Office Box 2469
Fort Myers, Florida 33902-2469

Attention: Lisa Pierce, Deputy Clerk

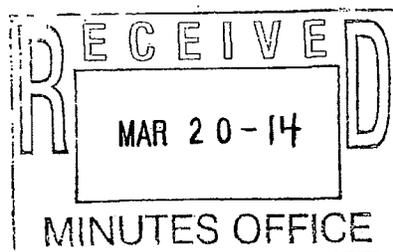
Dear Ms. Doggett:

Pursuant to the provisions of Section 125.66, Florida Statutes, this will acknowledge receipt of your electronic copy of Lee County Ordinance No. 14-06, which was filed in this office on March 20, 2014.

Sincerely,

Liz Cloud
Program Administrator

LC/elr





March 20, 2014

Ms. Linda Doggett
Clerk of the Circuit Court & Comptroller
Lee County Justice Center
1700 Monroe Street
Fort Myers, FL 33901

Dear Ms. Doggett:

Re: Lee County Ordinance No. 14-06

The Board of Trustees of Lee County Electric Cooperative, Inc. accepted Lee County Ordinance No. 14-06 at its meeting held on March 20, 2014. This letter serves as the written acceptance as required by paragraph 20 (ii) of the Ordinance.

Respectfully,

William D. Hamilton
Executive Vice President
and Chief Executive Officer

cc: Larry Kiker, Chairman, Board of County Commissioners
Roger Desjarlais, County Manager
Richard Wesch, County Attorney
David M. Owen, Esq.
John A. Noland, Esq.

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City of Boca Raton



Incorporated 1925

*expired
6-1-2036*

This is a true copy. No. of Pages 10
IN WITNESS WHEREOF, I hereunto set my hand
and affix the Seal of the City of Boca Raton,
Florida, this 26th day of April
A.D., 2006
Annmarie Casanova
City Clerk

ORDINANCE

4937

1
2 AN ORDINANCE OF THE CITY OF BOCA RATON
3 GRANTING TO FLORIDA POWER AND LIGHT COMPANY,
4 ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC
5 FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS
6 RELATING THERETO; PROVIDING MONTHLY PAYMENTS
7 TO THE CITY OF BOCA RATON; PROVIDING FOR
8 REPEALER; PROVIDING AN EFFECTIVE DATE
9

10 WHEREAS, the City Council of the City of Boca Raton recognizes that the City of
11 Boca Raton and its citizens need and desire the continued benefits of electric service; and

12 WHEREAS, the provision of such service requires substantial investments of capital
13 and other resources in order to construct, maintain and operate facilities essential to the
14 provision of such service in addition to costly administrative functions, and the City of Boca
15 Raton does not desire to undertake to provide such services; and

16 WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the
17 demonstrated ability to supply such services; and

18 WHEREAS, FPL and the City of Boca Raton desire to enter into a franchise
19 agreement providing for the payment of fees to the City of Boca Raton in exchange for the

1 nonexclusive right and privilege of supplying electricity and other services within the City of
2 Boca Raton free of competition from the City of Boca Raton, pursuant to certain terms and
3 conditions; and

4 WHEREAS, the City Council of the City of Boca Raton deems it to be in the best
5 interest of the City of Boca Raton and its citizens to enter into the New Franchise Agreement
6 prior to expiration of the Current Franchise Agreement; now therefore

7
8 THE CITY OF BOCA RATON HEREBY ORDAINS:
9

10 Section 1. There is hereby granted to Florida Power & Light Company, its successors
11 and assigns (hereinafter called the "Grantee"), for the period of 30 years from the effective date
12 hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to
13 construct, operate and maintain in, under, upon, along, over and across the present and future
14 roads, streets, alleys, bridges, easements, rights-of-way and other public places (hereinafter
15 called "public rights-of-way") throughout all of the incorporated areas, as such incorporated
16 areas may be constituted from time to time, of the City of Boca Raton, Florida, and its
17 successors (hereinafter called the "Grantor"), in accordance with the Grantee's customary
18 practice with respect to construction and maintenance, electric light and power facilities,
19 including, without limitation, conduits, poles, wires, transmission and distribution lines, and all
20 other facilities installed in conjunction with or ancillary to all of the Grantee's operations
21 (hereinafter called "facilities"), for the purpose of supplying electricity and other services to the
22 Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof.

23 Section 2. The facilities of the Grantee shall be installed, located or relocated so as to
24 not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress
25 from and ingress to abutting property. To avoid conflicts with traffic, the location or relocation of
26 all facilities shall be made as representatives of the Grantor may prescribe in accordance with

1 the Grantor's reasonable rules and regulations with reference to the placing and maintaining in,
2 under, upon, along, over and across said public rights-of-way; provided, however, that such
3 rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public
4 rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b)
5 shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient,
6 adequate and efficient electric service to all of its customers, and (c) shall not require the
7 relocation of any of the Grantee's facilities installed before or after the effective date hereof in
8 public rights-of-way unless or until widening or otherwise changing the configuration of the
9 paved portion of any public right-of-way used by motor vehicles causes such installed facilities
10 to unreasonably interfere with motor vehicular traffic. Such rules and regulations shall
11 recognize that above-grade facilities of the Grantee, installed after the effective date hereof,
12 should be installed near the outer boundaries of the public rights-of-way to the extent possible.
13 When any portion of a public right-of-way is excavated by the Grantee in the location or
14 relocation of any of its facilities, the portion of the public right-of-way so excavated be replaced
15 by the Grantee at its expense and in as good condition as it was at the time of such excavation
16 within the time provided in any permit for excavation issued by the Grantor or extension thereof
17 or if no permit is issued within a reasonable time. The Grantor shall not be liable to the Grantee
18 for any cost or expense in connection with any relocation of the Grantee's facilities required
19 under subsection (c) of this Section, except, however, the Grantee shall be entitled to
20 reimbursement of its costs from others and as may be provided by law.

21 Section 3. The Grantor shall in no way be liable or responsible for any accident or
22 damage that may occur in the construction, operation or maintenance by the Grantee of its
23 facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the
24 part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability,
25 loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence,

1 default or misconduct of the Grantee in the construction, operation or maintenance of its
2 facilities hereunder.

3 Section 4. All rates, rules, and regulations established by the Grantee from time to
4 time shall be subject to such regulation as may be provided by law.

5 Section 5. As a consideration for this franchise, the Grantee shall pay to the Grantor,
6 commencing 90 days after the effective date hereof, and each month thereafter for the
7 remainder of the term of this franchise, an amount which when added to the amount of all
8 licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad
9 valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by
10 the Grantor against the Grantee's property, business or operations and those of its subsidiaries
11 during the Grantee's monthly billing period ending 60 days prior to each such payment will equal
12 5.9 percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical
13 energy to residential, commercial and industrial customers (as such customers are defined by
14 FPL's tariff) within the incorporated areas of the Grantor for the monthly billing period ending 60
15 days prior to each such payment, and in no event shall payment for the rights and privileges
16 granted herein exceed 5.9 percent of such revenues for any monthly billing period of the
17 Grantee.

18 The Grantor understands and agrees that such revenues as described in the
19 preceding paragraph are limited, as in the existing franchise Ordinance No. 2310, to the precise
20 revenues described therein, and that such revenues do not include, by way of example and not
21 limitation: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting
22 (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities
23 (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads
24 and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from
25 Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late
26 Payment Charges; (g) Field Collection Charges; and (h) other service charges.

1 Section 6. As a further consideration, during the term of this franchise or any
2 extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in
3 competition with the Grantee, of electric capacity and/or electric energy to any ultimate
4 consumer of electric utility service (herein called a "retail customer") or to any electrical
5 distribution system established solely to serve any retail customer formerly served by the
6 Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or
7 terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity
8 and/or electric energy from any third party(ies) to any other retail customer's facility(ies), and (c)
9 not to seek to have the Grantee transmit and/or distribute electric capacity and/or electric
10 energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at
11 any other location(s). Nothing specified herein shall prohibit the Grantor from engaging with
12 other utilities or persons in wholesale transactions which are subject to the provisions of the
13 Federal Power Act.

14 Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric
15 capacity and/or electric energy from any other person, or (ii) from seeking to have the Grantee
16 transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or electric energy
17 purchased by the Grantor from any other person; provided, however, that before the Grantor
18 elects to purchase electric capacity and/or electric energy from any other person, the Grantor shall
19 notify the Grantee. Such notice shall include a summary of the specific rates, terms and
20 conditions which have been offered by the other person and identify the Grantor's facilities to be
21 served under the offer. The Grantee shall thereafter have 90 days to evaluate the offer and, if the
22 Grantee offers rates, terms and conditions which are equal to or better than those offered by the
23 other person, the Grantor shall be obligated to continue to purchase from the Grantee electric
24 capacity and/or electric energy to serve the previously-identified facilities of the Grantor for a term
25 no shorter than that offered by the other person. If the Grantee does not agree to rates, terms

1 and conditions which equal or better the other person's offer, all of the terms and conditions of this
2 franchise shall remain in effect.

3 Section 7. If the Grantor grants a right, privilege or franchise to any other person or
4 otherwise enables any other such person to construct, operate or maintain electric light and
5 power facilities within any part of the incorporated areas of the Grantor in which the Grantee
6 may lawfully serve or compete on terms and conditions which the Grantee determines are more
7 favorable than the terms and conditions contained herein, the Grantee may at any time
8 thereafter terminate this franchise if such terms and conditions are not remedied within the time
9 period provided hereafter. The Grantee shall give the Grantor at least 120 days advance written
10 notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved
11 for the Grantee herein, advise the Grantor of such terms and conditions that it considers more
12 favorable. The Grantor shall then have 120 days in which to correct or otherwise remedy the
13 terms and conditions complained of by the Grantee. If the Grantee determines that such terms
14 or conditions are not remedied by the Grantor within said time period, the Grantee may
15 terminate this franchise agreement by delivering written notice to the Grantor's Clerk and
16 termination shall be effective on the date of delivery of such notice.

17 Section 8. If during the term of this franchise the Grantee enters into a franchise
18 agreement with any other municipality located in Palm Beach County, Florida, the population of
19 which is equal to or less than that of the Grantor, the terms of which provide for the payment of
20 franchise fees by the Grantee at a rate greater than 6.0% of the Grantee's residential,
21 commercial and industrial revenues (as such customers are defined by FPL's tariff), under the
22 same terms and conditions as specified in Section 5 hereof, the Grantee, upon written request
23 of the Grantor, shall negotiate and enter into a new franchise agreement with the Grantor in
24 which the percentage to be used in calculating monthly payments under Section 5 hereof shall
25 be no greater than that percentage which the Grantee has agreed to use as a basis for the
26 calculation of payments to the other County municipality, provided, however, that such new

1 franchise agreement shall include additional benefits to the Grantee, in addition to all benefits
2 provided herein, at least equal to those provided by its franchise agreement with the other Palm
3 Beach County municipality. Subject to all limitations, terms and conditions specified in the
4 preceding sentence, the Grantor shall have the sole discretion to determine the percentage to
5 be used in calculating monthly payments, and the Grantee shall have the sole discretion to
6 determine those benefits to which it would be entitled, under any such new franchise
7 agreement.

8 Section 9. If, as a direct or indirect consequence of any legislative, regulatory or other
9 action by the United States of America or the State of Florida (or any department, agency,
10 authority, instrumentality or political subdivision of either of them), any person is permitted to
11 provide electric service within the incorporated areas of the Grantor to a customer then being
12 served by the Grantee, or to any new applicant for electric service within any part of the
13 incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee
14 determines that its obligations hereunder, or otherwise resulting from this franchise in respect to
15 rates and service, place it at a competitive disadvantage with respect to such other person, the
16 Grantee may, at any time after the taking of such action, terminate this franchise if such
17 competitive disadvantage is not remedied within the time period provided hereafter. The
18 Grantee shall give the Grantor at least 120 days advance written notice of its intent to terminate.
19 Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise
20 the Grantor of the consequences of such action which resulted in the competitive disadvantage.
21 The Grantor shall then have 90 days in which to correct or otherwise remedy the competitive
22 disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time
23 period, the Grantee may terminate this franchise agreement by delivering written notice to the
24 Grantor's Clerk and termination shall take effect on the date of delivery of such notice.

25 Section 10. Failure on the part of the Grantee to comply in any substantial respect
26 with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture

1 shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there
2 is final determination (after the expiration or exhaustion of all rights of appeal) by a court of
3 competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of
4 the provisions of this franchise, and the Grantee shall have six months after such final
5 determination to make good the default before a forfeiture shall result with the right of the
6 Grantor at its discretion to grant such additional time to the Grantee for compliance as
7 necessities in the case require.

8 Section 11. Failure on the part of the Grantor to comply in substantial respect with
9 any of the provisions of this ordinance, including but not limited to: (a) denying the Grantee use
10 of public rights-of-way for reasons other than unreasonable interference with motor vehicular
11 traffic; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms
12 and conditions of this franchise; (c) unreasonable delay in issuing the Grantee a use permit, if
13 any, to construct its facilities in public rights-of-way, shall constitute breach of this franchise and
14 entitle the Grantee to withhold all or part of the payments provided for in Section 5 hereof until
15 such time as a use permit is issued or a court of competent jurisdiction has reached a final
16 determination in the matter. The Grantor recognizes and agrees that nothing in this franchise
17 agreement constitutes or shall be deemed to constitute a waiver of the Grantee's delegated
18 sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such
19 right.

20 Section 12. The Grantor may, upon reasonable notice and within 120 days after each
21 anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee
22 relating to the calculation of the franchise payment for the year preceding such anniversary
23 date. Such examination shall be during normal business hours at the Grantee's office where
24 such records are maintained. Records not prepared by the Grantee in the ordinary course of
25 business may be provided at the Grantor's expense and as the Grantor and the Grantee may
26 agree in writing. Information identifying the Grantee's customers by name or their electric

1 consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and
2 all audit findings, whether they decrease or increase payment to the Grantor, shall be reported
3 to the Grantee.

4 Section 13. The provisions of this ordinance are interdependent upon one another,
5 and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or
6 of no effect, the entire ordinance shall be null and void and of no force or effect.

7 Section 14. As used herein "person" means an individual, a partnership, a
8 corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint
9 venture, a governmental authority or any other entity of whatever nature.

10 Section 15. Ordinance No. 2310, passed and adopted October 12, 1976, and all other
11 ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict
12 herewith, are hereby repealed.

13 Section 16. As a condition precedent to the taking effect of this ordinance, the
14 Grantee shall file its acceptance hereof with the Grantor's Clerk within 30 days of adoption of
15 this ordinance. The effective date of this ordinance shall be the date upon which the Grantee
16 files such acceptance, but not sooner than 10 days after the date of adoption of this ordinance.

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PASSED AND ADOPTED by the City Council of the City of Boca Raton this 25th
day of April, 2006.

CITY OF BOCA RATON, FLORIDA

ATTEST:


Steven L. Abrams, Mayor


Sharna Carannante, City Clerk

Approved as to form:


Diana Grub Frieser
City Attorney

COUNCIL VOTE			
	YES	NO	ABSTAINED
MAYOR STEVEN L. ABRAMS	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
DEPUTY MAYOR SUSAN WHELCHER	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
COUNCIL MEMBER M. J. MIKE ARTS	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
COUNCIL MEMBER PETER BARONOFF	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	
COUNCIL MEMBER BILL HAGER	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	



100

101 Legal Notices

CITY OF BOCA RATON NOTICE OF

REGULAR PUBLIC HEARINGS

NOTICE IS HEREBY GIVEN that the City Council of the City of Boca Raton, Florida will hold public hearings on the following proposed ordinances at the Regular Meeting on Tuesday, April 25, 2006 at 6:00 p.m., or as soon thereafter as possible, at which time they will consider their adoption. Presentations may be made by staff at the City Council Workshop Meeting on Monday, April 24, 2006 at 1:30 p.m., or as soon thereafter as possible.

Both meetings will be held in the Council Chamber at Boca Raton City Hall, 201 West Palmetto Park Road, Boca Raton, Florida. The ordinances in their entirety may be inspected at the Office of the City Clerk during regular business hours. All interested parties are invited to attend either or both meetings and be heard with respect to the proposed ordinances.

Ordinance No. 4936

An ordinance of the City of Boca Raton providing for the vacation and abandonment of the unimproved portion of Banyan Trail located south of N.W. Spanish River Boulevard and east of North Military Trail, as more specifically described herein; providing conditions for vacation and abandonment; providing for severability; providing for repealer; providing an effective date (AB-05-03)

Ordinance No. 4937

An ordinance of the City of Boca Raton granting to Florida Power and Light Company, its successors and assigns, an electric franchise; imposing provisions and conditions relating thereto; providing monthly payments to the City of Boca Raton; providing for repealer; providing an effective date

NOTICE: If any decision of City Council affects you, and you decide to appeal any decision made at this meeting with respect to any matter considered, you may need to ensure that a verbatim record of the proceedings is made, which record includes the testimony and evidence upon which the appeal is to be based. (The above NOTICE is required by State Law. If you desire a verbatim transcript, you shall have the responsibility, at your own cost, to arrange for the transcript.)

In accordance with the Americans with Disabilities Act and Florida Statutes 286.26, persons with disabilities

101 Legal Notices

needing special accommodation to participate in this proceeding should contact the Office of the City Clerk at 393-7741 at least three business days prior to the proceeding (whenever possible) to request such accommodation

Sharma Carannante CMC
City Clerk
City of Boca Raton Florida

PUBLISH: April 13, 2006
ACCOUNT NO. 98842
FURNISH PROOF OF PUBLICATION:
PO30429 (49-A)

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 4937
BY FLORIDA POWER & LIGHT COMPANY

Boca Raton, Florida

June 1, 2006

Florida Power & Light Company does hereby accept the electric franchise in the City of Boca Raton, Florida, granted by Ordinance No. 4937, being:

AN ORDINANCE OF THE CITY OF BOCA RATON GRANTING TO FLORIDA POWER AND LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING MONTHLY PAYMENTS TO THE CITY OF BOCA RATON; PROVIDING FOR REPEALER; PROVIDING AN EFFECTIVE DATE.

which was passed and adopted on April 25, 2006.

This instrument is filed with the City Clerk of the City of Boca Raton, Florida, in accordance with the provisions of Section 16 of said Ordinance.

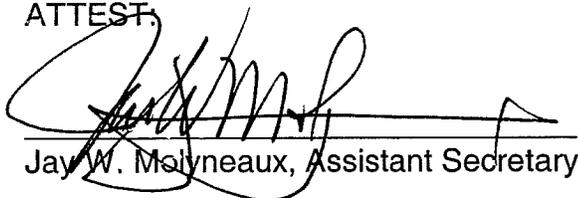
FLORIDA POWER & LIGHT COMPANY

By



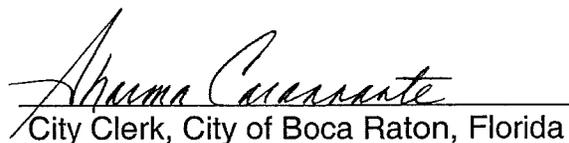
Jeffrey S. Bartel
Vice President

ATTEST:



Jay W. Molyneaux, Assistant Secretary

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 4937 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City of Boca Raton, Florida, on this 1st day of June, 2006.



Aranna Casarante
City Clerk, City of Boca Raton, Florida

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ORDINANCE NO. 00-08

AN ORDINANCE OF THE CITY OF BONITA SPRINGS GRANTING FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, A NON-EXCLUSIVE ELECTRIC UTILITY FRANCHISE, IMPOSING CITY-WIDE PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF BONITA SPRINGS, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Council of the City of Bonita Springs ("City" or "Grantor") recognizes that the citizens of the City need and desire the benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company ("FPL" or "Grantee") is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, FPL and the City desire to enter into a franchise agreement providing for the payment of fees to the City in exchange for the nonexclusive right and privilege of supplying electricity and other services within the City free of competition from the City, pursuant to certain terms and conditions.

NOW, THEREFORE, THE CITY COUNCIL OF BONITA SPRINGS

HEREBY ORDAINS:

Section 1. There is hereby granted to Florida Power & Light Company, its successors and assigns (herein called the "Grantee"), for the period of 25 years from the effective date hereof, with one additional five (5) year extension at FPL's sole option the non-exclusive right, privilege and franchise, (herein called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, rights-of-way and other public places (herein called "public rights-of-way") throughout all of the incorporated areas; as such incorporated areas may be constituted from time to time, of the City of Bonita Springs, Florida, and its successors (herein called the "Grantor"), in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (herein called "facilities"), for the purpose of supplying electricity and other services to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof.

Section 2. The facilities of the Grantee shall be installed, located or relocated so as to not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress from and ingress to abutting property. To avoid conflicts with traffic, the location or relocation of all facilities shall be made as representatives of the Grantor may prescribe in accordance with the Grantor's reasonable rules and regulations with reference to the placing and maintaining in,

under, upon, along, over and across said public rights-of-way; provided, however, that such rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b) shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with motor vehicular traffic. Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should be installed near the outer boundaries of the public rights-of-way to the extent possible. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of this Section, except, however, the Grantee shall be entitled to reimbursement of its costs from others and as may be provided by law.

Section 3. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance

by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 4. All rates and rules and regulations established by the Grantee from time to time shall be subject to such regulation as may be provided by law.

Section 5(a). As a consideration for this franchise, the Grantee shall pay to the Grantor, commencing sixty (60) days after the effective date of this Ordinance and each month thereafter for the remainder of the term of this franchise, an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending sixty (60) days prior to each such payment will equal three (3%) percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers within the incorporated areas of the Grantor for the monthly billing period ending sixty (60) days prior to each such payment, and in no event shall payment for the rights and privileges granted herein exceed three (3%) percent of such revenues for any monthly billing period of the Grantee.

Section 5(b): Notwithstanding the above, for the first eighteen months of

this franchise, the Grantee shall pay to the Grantor an amount equal to four (4%) percent of the Grantee's billed revenues, as specified in Section 5(a).

Section 5(c). It is further provided that the Grantor shall have the option, subject to the limitations specified below, once each calendar year to increase or reduce the amount to be paid by the Grantee as consideration for this franchise, such option to be exercised by the adoption of an ordinance, a certified copy of which must be delivered to the Grantee no later than 90 days before any such increase or reduction is to become effective. Such ordinance shall provide that the Grantee shall pay to the Grantor, no later than thirty (30) days after the end of the Grantee's first billing period and no later than 30 days after the end of each succeeding monthly billing of the Grantee during the term of this franchise, an amount which when added to the amount of all City licenses, excise fees or charges (except ad valorem property taxes and non-ad valorem special assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending thirty (30) days prior to each such payment will equal five (5%) percent (or such lesser percentage as the Grantor may elect) of the Grantee's billed revenues, less actual write-offs, from the sale of electricity to residential, commercial and industrial customers within the incorporated areas of the Grantor for the monthly billing period ending thirty (30) days prior to each such payment, and in no event shall the Grantee's payment for the rights and privileges granted herein exceed five (5%) percent, or such percent of such revenues as specified by the Grantor in the exercise of its option, for any monthly billing period

of the Grantee. In no event may the Grantor increase the amount by more than one (1%) percent from the percentage then being collected in any given year. The Grantor shall have the option to reduce the amount to be paid by the Grantee to zero, but in no event shall the Grantor have the option to increase the percentage used to calculate the amount to be paid by the Grantee as consideration for this franchise to any percentage which is greater than five (5%) percent. The Grantor's option hereunder shall be limited solely to the percentage to be used in the calculation of the amount to be paid by the Grantee as consideration for this franchise and as specifically set forth in this subsection, and no other section or provision of this franchise ordinance may be altered, amended or affected by the Grantor without the concurrence of the Grantee. Nothing herein shall require the Grantor to exercise its option hereunder.

Section 6. As a further consideration, during the term of this franchise or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or energy from any third party(ies) to any other retail customer's facility(ies), and (c) not to seek to have the Grantee transmit and/or distribute electric capacity and/or energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at any other

location(s). Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or energy from any other person, the Grantor shall notify the Grantee.

Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have sixty (60) days to evaluate the offer and, if the Grantee agrees to meet or beat the other person's offer, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or energy to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to meet or beat the other person's offer, all of the terms and conditions of this franchise shall remain in effect.

Section 7. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee determines are more favorable than the terms and

conditions contained herein, the Grantee may at any time thereafter terminate this franchise if such terms and conditions are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least sixty (60) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable. The Grantor shall then have sixty (60) days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice.

Section 8. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least ninety

(90) days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have ninety (90) days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice.

Section 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right in the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 10. Failure on the part of the Grantor to comply in substantial respect with any of the provisions of this ordinance, including: (a) denying the Grantee use of public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms and conditions of this franchise;

(c) unreasonable delay in issuing the Grantee a use permit, if any, to construct its facilities in public rights-of-way, shall constitute breach of this franchise and entitle the Grantee to withhold all or part of the payments provided for in Section 5 hereof until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination in the matter. The Grantor recognizes and agrees that nothing in this franchise constitutes or shall be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right.

Section 11. The Grantor may, upon reasonable notice and within ninety (90) days after each anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this section shall not be conducted by any third party employed by the Grantor whose fee for conducting such audit is contingent on findings of the audit.

Section 12. The provisions of this ordinance are interdependent upon

one another, and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect, the entire ordinance shall be null and void and of no force or effect.

Section 13. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 14. All ordinances and parts of ordinances in conflict herewith are hereby repealed.

Section 15. As a condition precedent to the taking effect of this ordinance the Grantee shall file its acceptance hereof with the Grantor's Clerk within forty (40) days of adoption of this ordinance. The effective date of this ordinance shall be the date on which Grantee files its acceptance.

DULY PASSED AND ENACTED by the City Council of the City of Bonita Springs, Florida this 19th day of July, 2000.

AUTHENTICATION:


MAYOR


CITY CLERK

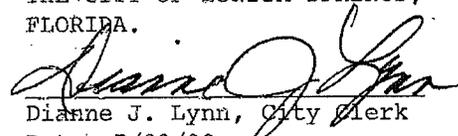
APPROVED AS TO FORM: 
City Attorney

7/20/00
Date

Vote: Arend Aye
Edsall Aye
Nelson Aye
Pass Aye

Piper Aye
Wagner Aye
Warfield Aye

I CERTIFY THAT THIS IS A CORRECT COPY OF AN OFFICIAL PUBLIC RECORD ON FILE WITH THE CITY OF BONITA SPRINGS, FLORIDA.


Dianne J. Lynn, City Clerk
Date: 7/20/00

Date Filed with City Clerk: 7/20/00

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ORDINANCE NO. 91-1

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE TOWN OF GLEN RIDGE, AND PROVIDING FOR AN EFFECTIVE DATE.

BE IT ORDAINED BY THE TOWN OF GLEN RIDGE, FLORIDA:

Section 1. There is hereby granted to Florida Power & Light Company (herein called the "Grantee"), its successors and assigns, the non-exclusive right, privilege or franchise to construct, maintain and operate in, under, upon, over and across the present and future streets, alleys, bridges, easements and other public places of the Town of Glen Ridge, Florida (herein called the "Grantor") and its successors, in accordance with established practice with respect to electrical construction and maintenance, for the period of 30 years from the date of acceptance hereof, electric light and power facilities (including conduits, poles, wires and transmission lines, and, for its own use, telephone and telegraph lines) for the purpose of supplying electricity to the Grantor and its successors, and inhabitants thereof, and persons and corporations beyond the limits thereof.

Section 2. As a condition precedent to the taking effect of this grant, the Grantee shall have filed its acceptance hereof with the Grantor's Clerk within 30 days hereof.

Section 3. The facilities of the Grantee shall be so located or relocated and so erected as to interfere as little as possible with traffic over said streets, alleys, bridges and public places, and with reasonable egress from and ingress to abutting property. The location or relocation of all facilities shall be made under the supervision and with the approval of such representatives as the governing body of the Grantor may designate for the purpose, but not so as to unreasonably interfere with the proper operation of the Grantee's facilities and service. When any portion of a street is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the street so excavated shall, within a reasonable time and as early as

practicable after such excavation, be replaced by the Grantee at its expense and in a condition as good as it was at the time of such excavation..

Section 4. Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage or expense which may accrue to the Grantor by reason of the negligence, default or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

Section 5. All rates and rules and regulations established by the Grantee from time to time shall at all times be reasonable and the Grantee's rates for electricity shall at all times be subject to such regulation as may be provided by law.

Section 6. No later than 60 days after the first anniversary date of this grant, and no later than 60 days after each succeeding anniversary date of this grant, the Grantee, its successors and assigns, shall have paid to the Grantor and its successors an amount which added to the amount of all taxes as assessed, levied, or imposed (without regard to any discount for early payment or any interest or penalty for late payment), licenses, and other impositions levied or imposed by the Grantor upon the Grantee's electric property, business, or operations, and those of the Grantee's electric subsidiaries for the preceding tax year, will equal six percent of the Grantee's revenues from the sale of electrical energy to residential, commercial and industrial customers within the corporate limits of the Grantor for the 12 fiscal months preceding the applicable anniversary date.

Section 7. Payment of the amount to be paid to the Grantor by the Grantee under the terms of Section 6 hereof shall be made in advance by estimated monthly installments commencing 90 days after the effective date of this grant. Each estimated monthly installment shall be calculated on the basis of 90% of the

Grantee's revenues (as defined in Section 6) for the monthly billing period ending 60 days prior to each scheduled monthly payment. It is also understood that for purposes of calculating each monthly installment, all taxes, licenses, and other impositions shall be estimated on the basis of the latest data available for all such amounts imposed on the Grantee, before being prorated monthly. The final installment for each fiscal year of this grant shall be adjusted to reflect any underpayment or overpayment resulting from estimated monthly installments made for said fiscal year.

Section 8. As a further consideration of this franchise, the Grantor agrees not to engage in the business of distributing and selling electricity during the life of this franchise or any extension thereof in competition with the Grantee, its successors and assigns.

Section 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this ordinance shall be grounds for forfeiture of this grant, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until a court of competent jurisdiction (with right of appeal in either party) shall have found that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after the final determination of the question to make good the default before a forfeiture shall result with the right in the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Section 10. Should any section or provision of this ordinance or any portion hereof be declared by a court of competent jurisdiction to be invalid, such decision shall not affect the validity of the remainder as a whole or as to any part, other than the part declared to be invalid.

Section 11. That all ordinances and parts of ordinances in conflict herewith be and the same are hereby repealed.

Section 12. This ordinance shall take effect on the date upon which the Grantee files its acceptance.

PASSED First Reading this 12th day of Sept 1991.

PASSED Second and Final Reading this 2nd day of Oct, 1991.

John Donald Decker
President of Council

ATTEST:

Mary A. Linnick
Town Clerk

APPENDIX C



**TAMPA-HILLSBOROUGH COUNTY EXPRESSWAY AUTHORITY, Petitioner,
v. K.E. MORRIS ALIGNMENT SERVICE, Inc., Respondent**

No. 62,281

Supreme Court of Florida

444 So. 2d 926; 1983 Fla. LEXIS 2899

November 10, 1983

SUBSEQUENT HISTORY: [**1] Rehearing
Denied February 22, 1984.

PRIOR HISTORY: Application for Review of the
Decision of the District Court of Appeal - Direct Conflict
of Decisions Second District - Case No. 81-1714.

COUNSEL: William C. McLean, Jr., Tampa, Florida,
for Petitioner.

Paul B. Johnson of Johnson, Paniello and Hayes, Tampa,
Florida, for Respondent.

JUDGES: Boyd, J. Alderman, C.J., Overton, McDon-
ald, Ehrlich and Shaw, JJ., concur. Adkins, J., dissents.

OPINION BY: BOYD

OPINION

[*927] This case is before us on the petition of the Tampa-Hillsborough County Expressway Authority for review of a decision of the District Court of Appeal for the Second Appellate District of Florida. The decision of which review is sought is reported as *K.E. Morris Alignment Service, Inc. v. Tampa-Hillsborough County Expressway Authority*, 414 So.2d 299 (Fla. 2d DCA 1982). The decision is in conflict with *Division of Administration, Department of Transportation v. Ely*, 351 So.2d 66 (Fla. 3d DCA 1977). We therefore have jurisdiction to provide the requested review. Art. V, § 3(b)(3), Fla. Const.

The Tampa-Hillsborough County Expressway Authority instituted eminent domain proceedings against numerous parcels of land in Hillsborough [**2] Coun-

ty, including a small tract owned by K.E. Morris Alignment Service, Inc. The Authority sought to take only a part of respondent's land, however, and respondent operated a business on remaining land adjoining the property taken.

In the course of the proceedings for determination of compensation, respondent made a claim for business damages under section 73.071(3)(b), Florida Statutes (1979). Although respondent had been in business at the location adjacent to the land being taken for only three years and two months, * its business had been in continuous operation for more than thirty years. The trial court held that since the business had been in operation at the location for which business damages were claimed for [*928] less than five years, no business damages were recoverable under section 73.071(3)(b). The landowner appealed.

* Pursuant to chapter 74, Florida Statutes (1979), the court entered an order of taking on September 7, 1979, prior to the proceedings for determination of just compensation.

[**3] The district court reversed and held that section 73.071(3)(b) does not require, as a prerequisite to an award of business damages, that the business have been in operation at the location for which business damages are claimed for more than five years.

Section 73.071(3)(b) provides in pertinent part as follows:

(3) The jury shall determine solely the amount of compensation to be paid, which compensation shall include:

....

(b) Where less than the entire property is sought to be appropriated, any damages to the remainder caused by the taking, including, when the action is by the Division of Road Operations of the Department of Transportation, county, municipality, board, district or other public body for the condemnation of a right-of-way, and the effect of the taking of the property involved may damage or destroy an established business of more than 5 years' standing, owned by the party whose lands are being so taken, located upon adjoining lands owned or held by such party, the probable damages to such business which the denial of the use of the property so taken may reasonably cause.

The district court looked at the three criteria for business damages [**4] and found that they were independent requirements: the business must be established for more than five years, the business must be owned by the party whose lands are being taken, and the business must be located upon adjoining land owned or held by such party. Thus the district court found that there was no requirement in the statute that the business for which damages are sought have been operated for more than five years at the location adjoining the land being taken. We believe contrarily that the words "located upon adjoining lands" and the words "established business of more than 5 years' standing" are intended to be read together and to qualify each other. We therefore hold that the district court erred in its construction of the statute. The statute indicates that the legislative intent is to allow business damages only to concerns having a physical existence for more than five years at the location where the partial taking is alleged to have caused business damages. Examined in the light of sound principles of statutory construction, the statute sustains the ruling of the circuit judge and demonstrates the error of the district court's holding.

The power of eminent domain [**5] is an inherent feature of the sovereign authority of the state. *Daniels v. State Road Department*, 170 So.2d 846 (Fla. 1964). The constitution limits this power by requiring that full compensation be paid to the owner for the property taken. *Art. X, § 6(a), Fla. Const.* The payment of compensation for intangible losses and incidental or consequential damages, however, is not required by the constitution, but is granted or withheld simply as a matter of legislative grace. *Jamesson v. Downtown Development Authority*, 322 So.2d 510 (Fla. 1975). Business damages such as those sustained in the instant case fall in the category where compensation is not constitutionally re-

quired but depends on legislative authorization. *City of Tampa v. Texas Co.*, 107 So.2d 216 (Fla. 2d DCA 1958), *cert. dismissed*, 109 So.2d 169 (Fla. 1959).

The allowance of business damages in eminent domain proceedings, being a matter of legislative grace, is analogous to other forms of legislative largess, such as grants of franchise rights. The allowance of business damages can also be compared to a waiver of sovereign immunity. Legislative grants of property or franchise rights must, when construction [**6] is necessary, be strictly construed in favor of the state and against the grantee. *Tampa & Jacksonville Railway v. Catts*, 79 Fla. 235, 85 So. 364 (1920). A waiver of sovereign immunity, similarly, should be strictly construed in favor of the state and against the claimant. *Arnold v. Shumpert*, 217 So.2d 116 (Fla. 1968); *Spangler v. Florida State Turnpike Authority*, 106 So.2d 421 (Fla. 1958). So, any ambiguity in *section 73.071(3)(b)* should be construed against the claim of business damages, and such damages should be awarded only when such an award appears clearly consistent with legislative intent.

Of course, the district court took the view that the plain language of the statute seemed to authorize an award, so that no resolution of ambiguity was necessary. But the district court gave the statute an interpretation it had never before received, and one that is at odds with the traditional understanding of the purpose and effect of the statutory business damages criteria. *See, e.g., State Road Department v. Bramlett*, 189 So.2d 481 (Fla. 1966); *State Road Department v. Lewis*, 170 So.2d 817 (Fla. 1964); *Glessner v. Duval County*, 203 So.2d 330 (Fla. [**7] 1st DCA 1967); *Intercoastal Drydock, Inc. v. State Road Department*, 203 So.2d 19 (Fla. 3d DCA 1967), *cert. denied*, 210 So.2d 223 (Fla. 1968); *State Road Department v. Abel Investment Co.*, 165 So.2d 832 (Fla. 2d DCA), *cert. denied*, 169 So.2d 485 (Fla. 1964); *State Road Department v. Peter*, 165 So.2d 771 (Fla. 2d DCA 1964). It is true that none of the above-cited cases dealt with the precise issue that has arisen now. But in reasoning that "if the legislature had intended the requirement that the business be located on the adjacent land for five years, it could have used plain language to so provide," 414 So.2d at 300, the district court construed the statute as though there existed a presumption in favor of the claimant.

Statutes should be construed in light of the manifest purpose to be achieved by the legislation. *Van Pelt v. Hilliard*, 75 Fla. 792, 78 So. 693 (1918); *Curry v. Lehman*, 55 Fla. 847, 47 So. 18 (1908). The purpose of *section 73.071(3)(b)* is to mitigate the hardship that may result when the state exercises the power of eminent domain paying only the constitutionally required full compensation for the property actually taken. The legislature [**8] in doing so has recognized that a business

location may be an asset of considerable value and susceptible of being substantially damaged by a partial taking. To assure the existence of a substantial business interest in the location as a prerequisite to an award of business damages, the legislature included the requirement of five years of operation at the location. The requirement of "more than 5 years' standing," seen in the light of the legislative purpose, obviously refers to the length of time the business has operated *at the location* where business damages are claimed to have been incurred due to condemnation of adjoining land. The length of time that the operator of the business has been in business at previous or other locations and the duration of its existence as a business entity are obviously irrelevant to the inquiry mandated by the statute.

When a statute is susceptible of and in need of interpretation or construction, it is axiomatic that courts should endeavor to avoid giving it an interpretation that will lead to an absurd result. *State ex rel. Florida Industrial Commission v. Willis*, 124 So.2d 48 (Fla. 1st DCA 1960), cert. denied, 133 So.2d 323 (Fla. [**9] 1961). If we were to adopt the district court's view of section 73.071(3)(b), there could be absurd and unfair results in hypothetical situations that readily come to mind. Under the district court's approach, two property owners operating businesses, both equally damaged by a partial taking of their respective properties, and both having been in operation at the affected location for less than five years, would be treated differently insofar as their eligibility to claim business damages is concerned if one of them had been in existence as a business entity for more than five years and the other had not. Thus the different treatment of the two landowners on the question of eligibility to claim business damages would be based on a factor having nothing whatsoever to do with the duration of their operations at the respective locations and therefore the degree of hardship imposed upon them by the partial taking of their respective premises. This would be an irrational [*930] distinction upon which to justify such differential treatment. "An interpretation of the language of a statute that leads to absurd consequences should not be adopted when, considered as a whole, the statute [**10] is fairly subject to another construction that will aid in accomplishing the manifest intent and the purposes designed." *City of Miami v. Romfh*, 66 Fla. 280, 285, 63 So. 440, 442 (1913). Since the construction given the statute by the circuit judge comports with the obvious purpose of the statute, it should have been sustained by the appellate court.

Decisions of the appellate courts of Florida clearly indicate that the essential inquiry under the business damages statute is that of continuous operation of the business at the location where business damages are alleged to have been suffered. In *Hooper v. State Road*

Department, 105 So.2d 515 (Fla. 2d DCA 1958), the trial court refused to allow a claim for business damages because the landowners had been operating the business for only about one year. The district court of appeal reversed because the owners had acquired the business as a going concern and it had been in continuous operation at the location for more than five years. Conversely, in *Hodges v. Division of Administration, Department of Transportation*, 323 So.2d 275 (Fla. 2d DCA 1975), the district court affirmed the trial court's refusal of a business damages [**11] claim because, although a business similar to the landowner's had some time previously been operated on the premises, the landowner had not acquired a business there but only a "business place" in which he opened a new business. 323 So.2d at 277. There was no continuous operation and the landowner's business had been in existence for less than five years. The same kind of situation produced a consistent holding in *Division of Administration, Department of Transportation v. Lake of the Woods, Inc.*, 404 So.2d 186 (Fla. 4th DCA 1981).

The district court of appeal in the instant case acknowledged that its decision was in conflict with *Division of Administration, Department of Transportation v. Ely*, 351 So.2d 66 (Fla. 3d DCA 1977). There a propane gas dealer claimed that the partial taking of a mobile home park with which it had a service agreement and where it had access easements for its facilities had taken its property and caused it business damages. The district court held that the service easement was not a kind of property the loss of which had to be compensated and rejected the claim of business damages for two reasons:

Business damages under Section 73.071(3)(b), [**12] Florida Statutes (1975) are equally inapplicable in the instant case. Southeastern Propane Gas Co. did not own or have any property interest in the condemned land as required by the statute in order to qualify for business damages. Moreover, its business had not been operating on the adjoining land for more than five years as further required by the statute. The fact that Southeastern Propane Gas Co. as a company has been incorporated and doing business elsewhere throughout the state since the early 1950's does not satisfy this five year requirement under the statute.

351 So.2d at 69. The second reason given, of course, pertains to the issue in the instant case upon which our

conflict jurisdiction is predicated. Under our holding today, the *Ely* decision was correct.

The decision of the district court of appeal is quashed and the case is remanded with instructions that the ruling of the trial court be affirmed.

It is so ordered.

ALDERMAN, C.J., OVERTON, McDONALD,
EHRlich and SHAW, JJ., Concur.

ADKINS, J., Dissents.

Data and Information Prepared for the Financial Impact Estimating Conference

Proposed Initiative: *“Limits or Prevents
Barriers to Local Solar Electricity Supply”*

Presented by Jerry McDaniel, on behalf of
Florida’s Four Major Investor-Owned Electric Utilities

April 10, 2015

Introduction

- This presentation has been prepared on behalf of Florida's four major investor-owned electric utilities for the Financial Impact Estimating Conference's analysis of the proposed constitutional amendment, *"Limits or Prevents Barriers to Local Solar Electricity Supply"*
- This presentation is not intended to advocate for or against the proposed constitutional amendment

Overview

- Floridians are served by 55 electric utilities
- The four major investor-owned electric utilities (FPL, Duke Energy, Tampa Electric and Gulf Power) serve and pay taxes/fees to a combined total of 345 Florida municipalities and counties
- Together, these four utilities supply about 76 percent of Florida's electricity needs while municipally owned and cooperative utilities serve about 24 percent

State/Local Government Taxes & Fees

- State laws and local governmental ordinances and agreements require all of Florida's electric utilities to pay a range of taxes and fees
- These taxes and fees are generally based on percentages of a utility's electricity sales

State/Local Government Taxes & Fees

- **Sales Tax (state)** – 4.35 percent, applicable to utilities' sales to commercial customers
- **Gross Receipts Tax (state)** – 2.5 percent on utilities' residential sales, 2.6 percent on' commercial sales
- **Municipal Public Service Tax (local)** – Rate varies by municipality from 0 percent to 10 percent
- **Municipal Franchise Fees (local)** – Rates vary by municipality up to a maximum of 6 percent
- **Regulatory Assessment Fees (state)** – Current rate is 0.00072 percent (cannot exceed 0.125 percent)

State/Local Government Taxes & Fees

In 2014, four major utilities paid state/local taxes & fees totaling \$2,229,228,642 (\$2.9 billion for state as a whole)

Utility	Total Taxes/Fees	Sales Tax	Gross Receipts Tax	Municipal Public Service Tax	Franchise Fees	Regulatory Assessment Fees
FPL	\$1,444,249,701	\$192,208,859	\$265,389,503	\$524,126,515	\$454,890,566	\$7,634,259
DUKE	\$477,695,719	\$79,526,314	\$103,713,790	\$187,960,611	\$103,299,937	\$3,195,067
TECO	\$187,878,745	\$38,243,579	\$46,263,324	\$52,314,525	\$44,896,719	\$1,428,233
GULF	\$119,404,477	\$22,398,470	\$32,118,573	\$23,115,210	\$40,813,388	\$958,837
Utility Total	\$2,229,228,642	\$332,377,222	\$447,485,190	\$787,516,861	\$643,900,610	\$13,216,996
State Total *	\$2.9 Billion	\$439 Million	\$591 Million	\$1.04 Billion	\$850 Million	\$17 Million

* Approximate Totals based on Utility total representing 76% of the State of Florida

State/Local Government Taxes & Fees

Effect on State-Wide Tax Revenues with Solar Penetration at Various Levels

	Total Taxes/Fees	Sales ¹	GRT ²	MPST ³	Franchise ⁴	RAF ⁵
1%	\$29,000,000	\$4,390,000	\$5,910,000	\$10,400,000	\$8,500,000	\$170,000
3%	\$87,000,000	\$13,170,000	\$17,730,000	\$31,200,000	\$25,500,000	\$510,000
5%	\$145,000,000	\$21,950,000	\$29,550,000	\$52,000,000	\$42,500,000	\$850,000
10%	\$290,000,000	\$43,900,000	\$59,100,000	\$104,000,000	\$85,000,000	\$1,700,000

- 1) Sales = Sales Tax;
- 2) GRT = Gross Receipts Tax;
- 3) MPST = Municipal Public Service Tax;
- 4) Franchise = Franchise Fees;
- 5) RAF = Regulatory Assessment Fee

State/Local Government Taxes & Fees

- While local taxes and fees vary from municipality to municipality, a broad analysis can be accomplished based on actual taxes paid by utilities
- Extrapolating from the investor-owned utility data (\$2.2 billion in state/local taxes and fees), we estimate that the combined state/local taxes and fees paid by all 55 electric utilities in 2014 totaled approximately \$2.9 billion

Proposed Constitutional Amendment

- If the proposed amendment results in increased electricity production and sales by non-utility entities that are not taxed, those non-utility sales will displace taxable sales of electricity by Florida's 55 electric utilities
- Displacement of taxable utility sales by untaxable non-utility entities will reduce revenues for state and local government

Proposed Constitutional Amendment

- The actual impact of the amendment on taxable utility electricity sales depends on a variety of factors
- Using the 2014 statewide utility tax/fee estimate of \$2.9 billion, we can project that each 1 percent displacement of taxable utility sales by untaxable non-utility entities would equate to a reduction in state/local revenue of approximately \$29 million
- This estimate can be scaled down or up based on a projected displacement of taxable electricity sales

MEMORANDUM

TO: Financial Impact Estimating Conference

FROM: Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company and Gulf Power Company

RE: Additional Information Concerning Financial Impact Statement for the Proposed Initiative Entitled Re: “Limits or Prevents Barriers to Local Solar Electricity Supplier”

DATE: April 22, 2015

At the Financial Impact Estimating Conference (“FIEC”) public meeting held on April 10, 2015, proponents of the proposed Initiative asserted that it would have no financial impact on the revenues of state and local government. At this time, Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company and Gulf Power Company (the “Utilities”) are not taking a position on the proposed Initiative. However, the proponents’ assertion of no financial impact is demonstrably incorrect, and the Utilities are submitting this additional information in support of that conclusion.

As summarized in the materials that the Utilities submitted at the April 10 public meeting, there is a range of taxes and fees that the Utilities, as well as municipal utilities and electric cooperatives, pay to state and local government based on their sales of electricity. Those taxes and fees include sales tax, gross receipts tax, municipal public service tax, the regulatory assessment fee and municipal franchise fees. Approximately \$2.9 billion of such fees and taxes were paid to state and local government in Florida during 2014.

The express purpose of the proposed Initiative is to “encourage and promote local small-scale solar-generated electricity” (Section (a) of the proposed Initiative) and to facilitate its sale to electric consumers in Florida. Those sales will necessarily displace sales of electricity currently made by the Utilities, as well as by municipal utilities and electric cooperatives. For some of the taxes and fees that are currently paid by utilities on electric sales, it is unclear whether or not sales by local solar electricity suppliers (“LSES”) would also be subject to those same taxes and fees. The FIEC has asked the Department of Revenue to advise it as to the applicability of certain taxes to LSES sales. However, one of the largest sources of revenues to *local* government from electric sales by utilities is franchise fees. The Utilities paid \$643,900,610 in franchise fees in 2014 and estimate that a total of about \$850 million was paid that year on sales by all utilities. There is no question that those franchise fees would *not* be paid on LSES sales. This is because the agreements pursuant to which utilities pay franchise fees are bilateral contracts between the specific utilities and the counties and municipalities that the

utilities serve. There is no counterpart to those franchise agreements for LSES sales. Thus, for every kilowatt-hour of electricity sold by an LSES rather than a utility, it is absolutely certain that there will be a county or municipality somewhere in Florida that loses revenue in the form of foregone franchise fees. This is not speculation; it is a fact.

Attachment 1 to these comments is a series of tables that show the counties and municipalities that have franchise agreements with each of the four Utilities. These are the local governments that will lose franchise-fee revenues on each LSES sale that displaces a Utility sale within their boundaries. There is insufficient information to predict the extent to which LSES sales will displace utility sales, but even displacement of 1% of the Utility sales would result in a loss of about \$8.5 million annually to the affected counties and municipalities. Higher levels of displaced sales would lead inexorably and proportionately to larger losses of local government franchise-fee revenues. And, of course, the displacement of Utility sales may reduce revenues from other taxes and fees as well, depending upon whether the applicability provisions for each tax and fees is ultimately construed to apply to LSES sales.

The Utilities are aware of no meaningful reductions in the costs of providing government services that would result from the proposed Initiative. Indeed, the displacement of their electric sales described above is likely to result in increased electric rates for all electric customers, including state and local governments.

ATTACHMENT I

Florida Power & Light Company Franchises

Florida Power & Light Company (“FPL” or “the company”) is an investor-owned electric public utility company serving more than 4.7 million customers throughout much of eastern and southwestern Florida. The company pays franchise fees to the following 177 counties and municipalities pursuant to franchise agreement ordinances:

Anna Maria	Davie	Hillsboro Beach	Malabar
Arcadia	Daytona Beach	Holly Hill	Manalapan
Atlantis	Daytona Beach Shores	Hollywood	Mangonia Park
Baker - Uninc.	DeBary	Holmes Beach	Margate
Bal Harbour	Deerfield Beach	Hypoluxo	Marineland
Bay Harbor Islands	Delray Beach	Indianalantic	Medley
Belle Glade	Deltona	Indian Creek	Melbourne
Beverly Beach	DeSoto - Uninc.	Indian Harbour Beach	Melbourne Beach
Biscayne Park	Edgewater	Indian River - Uninc.	Melbourne Village
Boca Raton	El Portal	Interlachen	Miami
Bonita Springs	Fellsmere	Jupiter	Miami Beach
Boynton Beach	Flagler Beach	Jupiter Inlet Colony	Miami Shores Village
Bradenton	Florida City	LaBelle	Miami Springs
Bradenton Beach	Fort Lauderdale	Lake Butler	Miami-Dade Uninc.[17]*
Bradford - Uninc.	Fort Myers	Lake City	Miramar
Brevard - Uninc.	Glen Ridge	Lake Clarke Shores	Naples
Broward - Uninc.	Glen Saint Mary	Lake Mary	North Bay Village
Bunnell	Golden Beach	Lake Park	North Lauderdale
Callahan	Golf	Lantana	North Miami Beach
Cape Canaveral	Grant-Valkaria	Lauderdale Lakes	North Miami[2]*
Charlotte - Uninc.	Greenacres	Lauderdale-by-the-Sea	North Palm Beach
Cloud Lake	Gulf Stream	Lauderhill	North Port
Cocoa	Hallandale Beach	Lawtey	Oak Hill
Cocoa Beach	Hampton	Lazy Lake	Oakland Park
Coconut Creek	Hastings	Lee - Uninc.	Ocean Ridge
Cooper City	Haverhill	Lighthouse Point	Okeechobee
Coral Gables	Hialeah	Live Oak	Opa-locka
Coral Springs	Hialeah Gardens	Longboat Key/Parent	Ormond Beach
Crescent City	Highland Beach	Loxahatchee Groves	Oviedo
Dania Beach	Hilliard	Macclenny	Pahokee

Palatka	South Bay	*Miami-Dade Cnty Cities listed below:
Palm Bay	South Daytona	Aventura
Palm Beach	South Miami/#1 Parent[2]*	Cutler Bay
Palm Beach - Uninc.	South Palm Beach	Doral
Palm Beach Gardens	Southwest Ranches	Key Biscayne
Palm Beach Shores	St. Augustine	Homestead
Palm Shores	St. Augustine Beach	Miami Gardens
Palm Springs	St. Lucie - Uninc.	Miami Lakes
Palmetto	Starke	Palmetto Bay
Pembroke Park	Stuart	Pinecrest
Pembroke Pines	Sunrise	Sunny Isles Beach
Penney Farms	Surfside	
Plantation	Sweetwater	
Pomona Park	Tamarac	
Pompano Beach	Tequesta	
Ponce Inlet	Titusville	
Port Orange	Venice	
Port St. Lucie	Virginia Gardens	
Punta Gorda	Waldo	
Raiford	Welaka	
Riviera Beach	Wellington	
Rockledge	West Melbourne	
Royal Palm Beach	West Miami	
Sanford	West Palm Beach	
Sarasota	West Park	
Sarasota - Uninc.	Weston	
Satellite Beach	Wilton Manors	
Sea Ranch Lakes		
Sebastian		
Sewall's Point		

Duke Energy Florida Franchises

Duke Energy Florida (“DEF”) is an investor-owned electric public utility company serving more than 1.7 million customers throughout much of western, central and northern Florida. DEF pays franchise fees to the following 123 counties and municipalities pursuant to franchise agreement ordinances:

Alachua	Fort White	Oakland
Altamonte Springs	Frostproof	Ocala
Apalachicola	Gilchrist County	Ocoee
Apopka	Groveland	Orange City
Archer	Gulfport	Orlando
Avon Park	Haines City	Oviedo
Bartow	High Springs	Perry
Belle Isle	Highland Park	Pierson
Belleair	Hillcrest Heights	Pinellas Park
Belleair Beach	Howey-In-The-Hills	Port Richey
Belleair Bluffs	Indian Rocks Beach	Port St Joe
Belleair Shore	Indian Shores	Reddick
Belleview	Inglis	Redington Beach
Bowling Green	Inverness	Redington Shores
Branford	Jasper	Safety Harbor
Bronson	Jennings	Sanford
Brooksville	Kenneth City	Sebring-SUC
Carrabelle	Lacrosse	Sebring
Casselberry	Lady Lake	Seminole
Center Hill	Lake Hamilton	So Pasadena
Chiefland	Lake Helen	Sopchoppy
Clearwater	Lake Mary	St. Marks
Clermont	Lake Placid	St. Pete Beach
Coleman	Lake Wales	St. Petersburg
Cross City	Largo	Tarpon Springs
Crystal River	Lee	Tavares
Davenport	Longwood	Treasure Island
Deland	Madeira Beach	Trenton
Deltona	Madison	Umatilla
Debary	Maitland	Wakulla County
DevImpt Dist - Celebration	Mascotte	Webster
DevImpt Dist - Enterprise	Mayo	White Springs

Dundee	Mcintosh	Wildwood
Dunedin	Mexico Beach	Windermere
Dunnellon	Micanopy	Winter Garden
Eatonville	Minneola	Winter Haven
Edgewood	Monticello	Winter Park
Eustis	Montverde	Winter Park Annexed
Eustis Manufacturing	Mt Dora	Winter Springs
Fanning Springs - Gilchrist	New Port Richey	Zephyrhills
Fanning Springs – Levy	No. Redington Beach	Zolfo Springs

Gulf Power Company Franchises

Gulf Power Company ("Gulf") is an investor-owned electric public utility company serving more than 440,000 thousand customers throughout much of Northwest Florida. Gulf pays franchise fees to the following 32 counties and municipalities pursuant to franchise agreement ordinances:

Chipley	Milton
Vernon	Defuniak Springs
Graceville	Paxton
Campbellton	Ponce de Leon
Bonifay	Crestview
Caryville	Laurel Hill
Panama City	Niceville
Springfield	Valparaiso
Cedar Grove	Shalimar
Lynn Haven	Fort Walton Beach
Panama City Beach	Cinco Bayou
Parker	Mary Esther
Callaway	Destin
Pensacola	Escambia County
Century	Jackson County
Gulf Breeze	Santa Rosa County

Tampa Electric Company Franchises

Tampa Electric Company (“Tampa Electric” or “the company”) is an investor-owned electric public utility company serving more than 706,000 customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties in Florida. The company pays franchise fees to the following 13 municipalities pursuant to franchise agreement ordinances:

Auburndale	Lake Alfred	Plant City	St. Leo
Dade City	Mulberry	Polk City	Tampa
Eagle Lake	Oldsmar	San Antonio	Temple Terrace
Winter Haven			



MEMORANDUM

TO: Financial Impact Estimating Conference

SUBJECT: Financial Impact Statement for the Proposed Amendment: Limits or Prevents Barriers to Local Solar Electricity Supply

DATE: April 24, 2015

Summary

The proposed solar energy amendment to Florida's constitution generally permits a "local solar electricity supplier" to use solar energy to generate up to two megawatts of electricity and to either consume it on the supplier's property or to sell it to the owners of "contiguous" property. The amendment prohibits electric utilities, including municipal electric utilities, from charging any fee or placing any service condition on the supplier's customers that are not imposed on the utility's other customers. The proposed amendment permits laws designed to protect the public's health, safety and welfare so long as the laws do not prohibit "the supply of solar generated electricity by a local solar electricity supplier."

Initial indications are the proposal will have a material financial impact on the membership of the Florida League of Cities largely because the amendment will affect the franchise fees and public service tax (PST) revenues received by Florida's municipalities. The magnitude and timing OF the financial impact that will occur will be primarily determined by the saturation level of generation of local small-scale solar-generated electricity into the traditional electric market.

Franchise Fees

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 local government's rights-of-way to conduct the utility business. The fee is considered fair rent for the use of such rights-of-way¹ and consideration for the local government's agreement not to provide competing utility services during the term of the franchise agreement. The franchise fee consists of three main components: it is fair rent for the use of the municipality's rights-of-way to make a profit; it is consideration for the municipality to agree not to compete with the electric utility and to prohibit others from competing with the electric utility during the term of the franchise agreement; and it is a fee paid the municipality to offset the costs incurred by the municipality as a result of the electric utilities' disparate and exclusive use of public property.²

¹ Leonard v Baylen Street Wharf Co., 52 So 718 (Fla 1910), City of Plant City v. Mayo, 337 So. 2d 966 (Fla. 1976)

² Florida Power Corp v. City of Winter Park, 887 So 2d 1237 (Fla. 2004), City of Hialeah Gardens v Dade Co., 348 So. 2d 1174 (Fla 3d DCA 1977), Santa Rosa Co. v. Gulf Power Co , 635 So 2d 96 (Fla 1st DCA 1994) rev denied, 645 So 2d 452 (Fla. 1994), Flores v. City of Miami, 681 So. 2d 803 (Fla. 3d DCA 1996).

The imposition of the fee requires the adoption of a franchise agreement. 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 areas while a fee imposed by a county is generally based upon the gross revenues received from the unincorporated areas.

Reported municipal franchise fee collections from electric utilities were \$ 563,206,940 for fiscal year 2011-12³. Franchise fees from electric constitutes approximately 1.8 percent of total municipal revenues⁴. Below is a sample selection of franchise fee rates throughout the state.

Municipality	County	Electricity	Electric Utility	Franchise Fee Rate
Ponce de Leon	Holmes	\$ -	Gulf Power Company	4.00%
Apopka	Orange	\$ 2,978,723	Duke Energy	6.00%
Cape Canaveral	Brevard	\$ 600,068	Florida Power & Light Company	6.00%
Clermont	Lake	\$ 1,995,234	Duke Energy	6.00%
Fernandina Beach	Nassau	\$ 1,252,097	Florida Public Utilities Company	6.00%
Fort Lauderdale	Broward	\$ 15,561,277	Florida Power & Light Company	6.00%
Lee	Madison	\$ 16,942	Duke Energy	6.00%
Longboat Key	Manatee/Sarasota	\$ 843,299	Florida Power & Light Company	6.00%
Miami	Miami-Dade	\$ 26,257,819	Florida Power & Light Company	6.00%
Ocoee	Orange	\$ 2,155,543	Duke Energy	6.00%
Panama City	Bay	\$ 3,798,295	Gulf Power Company	6.00%
Polk City	Polk	\$ 57,332	Tampa Electric Company	6.00%
Windermere	Orange	\$ 235,501	Florida Power & Light Company	6.00%
St. Augustine	St. Johns	\$ 1,125,547	Florida Power & Light Company	5.90%
Temple Terrace	Hillsborough	\$ 1,764,912	Tampa Electric Company	5.40%
Tampa	Hillsborough	\$ 31,646,686	Tampa Electric Company	4.60%

There are two scenarios in which the franchise fee revenues could be impacted. The first would be the reduction of the gross revenues of an electric utility due to the increased generation of local small-scale solar-generated electricity and a corresponding reduction of the franchise fees. Based on the purpose and intent statement of the petition form, it can be assumed that the purpose of the amendment is to encourage and promote such generation but the extent that this would occur has yet to be determined.

The second potential impact on franchise fees would come from the termination or renegotiation of the franchise fee agreement. Should the proposed amendment be approved by the voters, it will impair the electric utilities' exclusive rights to provide electric service within the geographical boundaries of the municipalities. It is not unreasonable to assume electric utilities will take the position there is now insufficient consideration to support the franchise agreement because the fee no longer bears a discernable relationship to the cost to municipalities for the use of the public rights-of-ways.⁵

Below is a segment of language that is found in the Town of Longboat Key Franchise Agreement with Florida Power and Light Company.⁶

SECTION 8: If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of

³ Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Governments

⁴ Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Governments

⁵ Alachua County v. State, 737 So. 2d 1065 (Fla. 1999); See also, Gulf Power Co., supra.

⁶ Town of Longboat Key Ordinance 2014-13

either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee reasonably determined that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it as a competitive disadvantage with respect to such other person, the Grantee may, at any time after taking of such action, terminate this franchise if such competitive disadvantage is not remedied as provided hereafter. The Grantee shall give the Grantor at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the claimed competitive disadvantage and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall have 90 days in which to correct or otherwise remedy the competitive disadvantage, and the Grantor and Grantee agree to negotiate in good faith toward a mutually acceptable resolution of the Grantee's claimed disadvantage during this 90-day period. If such competitive disadvantage is, in a reasonable determination of Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination of complete disadvantage leading to termination under this Section.

The League recognizes that the termination of franchise agreements will undoubtedly present significant problems for the utilities, the fact remains the proposed amendment will disrupt the current contractual relationship between Florida's municipalities and the electric utilities currently serving or servicing those jurisdictions. As a result, it places municipal franchise fees on electric utilities at risk.

Public Service Tax

Municipalities and charter counties may levy by ordinance a PST on the purchase of electricity, metered natural gas, liquefied petroleum gas either metered or bottled, manufactured gas either metered or bottled, and water service.⁷ The tax is levied only upon purchases within the municipality or within the charter county's unincorporated area and cannot exceed ten percent of the payments received by the seller of the taxable item. The tax proceeds are considered general revenue for the municipality or charter county. Municipal collections of the public service tax on the purchase of electricity were \$666,317,873 for fiscal year 2011-2012.⁸ Based on initial surveys, two municipalities and two counties have explicitly pledged the public utility tax as primary repayment for bonds. This does not include local governments that have utilized covenant to budget and appropriate, which is a security for debt to a covenant to budget and appropriate legally available non ad valorem revenues, and securities where the public service tax is a secondary pledged revenue source

⁷ Section 166.231(1), Florida Statutes

⁸ Florida Department of Financial Services, Division of Accounting and Auditing, Bureau of Local Governments

Potential impacts on the public services are expected to result from a reduction in the base of the public service tax base which could occur in two ways. The first would be an overall reduction in purchase of electricity due to the increase generation of local small-scale solar-generated electricity and onsite consumption. This would appear to be energy efficiently as it will not be accounted for in the traditional methods. Once again, the extent that this would occur has yet to be determined. The secondary impact will come from an anticipated increase in the utilization of net metering, a metering and billing methodology whereby customer-owned renewable generation is allowed to offset the customer's electricity consumption on-site⁹ or a similar relationship to buy excess local small-scale solar-generated electricity. While both of these reductions have the same impact or reducing the energy purchased from a utility, both incidences occur on the same property.

Based on initial research, the most common method of net metering allows for the utility to credit the customer for the amount of kilowatts that are produced by solar devices that can be used at a later date against kilowatts that are purchased from the electric utility. This will cause a reduction in the amount of the customer's bill that it owed to the electric utility and corresponding reduction in the PST owed on that taxable transaction.

One unique program is that of the Gainesville Regional Utilities (GRU) Solar Feed-in-Tariff (FIT) Program. Customers selected for the FIT Program invest in their own solar photovoltaic systems to generate electricity and sell that energy directly to GRU under a 20-year fixed-price contract. The 20-year fixed rate is based on the year the project was approved and the type of installation. The responsibility of collecting and remitting applicable taxes falls to the customer in the program. It is important to note that the Solar FIT program has been suspended and is no longer accepting applications or adding capacity.

Municipal and Utility Administration

The process for the installation of a solar energy system on a residential dwelling or commercial building generally follows the same process one would currently use to secure a building or electrical permit. The solar energy device owner, lessee or contractor (owner) makes application to the municipality's building department, submits a set of plans for the solar energy system, and pays the normal permit fee associated with the work. The municipality reviews and approves the plans, issues the permit, and inspects the work over the course of installation.

Specific to the installation of solar devices, there are two additional steps. The first is the requirement for the owner to enter a "net metering agreement" with the utility or municipality. The net metering agreement outlines the duties and responsibilities of the owner and the utility or municipality, provides or specifies the process by which the utility or municipality will compensate the owner for electricity generated by the system, and often requires the owner to carry insurance and indemnify the utility or municipality for any damages the system causes the utility or municipalities electrical system.¹⁰ Under the proposed amendment, a utility may not place any condition of service on a solar energy generator that is not placed on a customer who does not generate solar energy; therefore, it is questionable whether the utility or municipality will be able to require a net metering agreement should the amendment pass. Additionally, the municipality requires an electrical engineer to inspect the plans and assess the impact the system will have on the electric system's infrastructure, including electrical lines and

⁹ Section 366.91 (2)(a), Florida Statutes

¹⁰ 25-6.065, Florida Administrative Code.

Gainesville Regional utilities Agreement for Interconnection and Parallel Operation of Distributed Generation Resources. Electric Rate Tariffs Volume 1 Lakeland Electric.

transformers, to ensure the solar generated energy will not unduly disrupt the flow of the utility's electricity.

In the case of the City of Tallahassee, they do not currently charge the owner for the cost incurred with the additional steps. However, the city currently gets only one or two applications a year to install solar energy systems and would undoubtedly consider charging for the latter two steps should the applications increase significantly. Again, it is questionable whether the proposed amendment will permit the city to charge solar energy generators this fee if it does not charge the fee to customers who do not generate solar energy. Additionally, many municipalities and utilities charge an application for the net metering program.

Renewable generator systems connected to the grid without batteries are not a standby power source during an outage. The system must shut down when utility's grid shuts down in order to prevent dangerous back feed on the grid. This is required to protect utility employees who may be working on the grid. Most municipal electrics require the disconnect switch at the meter. Investor-owned electric utilities may only require the external disconnect for Tier 2 and Tier 3 systems OR systems greater than 10 kW.¹¹

When power outages occur during emergencies, the electric utility must be able to turn the solar energy system off to assure the unit doesn't sporadically send electricity through the electric lines. This minimizes the chance electrical workers work on "hot" lines while trying to restore power. With a disconnect switch, the utility worker can simply throw the switch to turn off the solar energy system. Then, the owner can simply throw the switch back on when overall power is restored. On the other hand, the electric utilities must physically remove the meter to assure the solar energy system is turned off and the electric lines aren't "hot." Then, when overall power is restored, the electric utility must return and reinstall the meter. Obviously, the latter process takes longer and, as a result, power remains off longer.

Generally speaking, municipal electric utilities must continue to maintain the infrastructure to provide utility service to solar energy customers because solar electricity generating facilities do not generate electricity all the time. So, regardless of whether a customer can generate solar electricity, the utility must remain capable of providing electricity to the customer when, for example, the customer's solar energy facility is not generating electricity for any number of reasons. Moreover, customers generating solar energy have a disparate cost impact on a utility's infrastructure that is not shared by the customers who do not generate or consume solar electricity. The transmission of solar generated electricity through transmission lines and transmission facilities, as well as the accounting of solar generated electricity, are but a few of the places where the customers of solar generated electricity will have a disparate cost impact on the utility that is different in kind and degree than the costs of customers who do not generate local solar electricity. But, a fair reading of the proposed amendment will not permit the utility to charge the solar electricity customer for disparate impact on the system. Therefore, it stands to reason the proposed amendment will have a financial impact on municipal electric utilities and it stands to reason the amendment will require the utilities will spread the disparate cost throughout its other customers.

¹¹ 25-6.065, Florida Administrative Code

ORDINANCE NO. 2014-13

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE TOWN OF LONGBOAT KEY, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the Town Commission of the Town of Longboat Key, Florida recognizes that the Town of Longboat Key and its citizens need and desire the continued benefits of electric service; and

WHEREAS, there is currently in effect a franchise agreement between the Town of Longboat Key and Florida Power and Light Company (FPL), the terms of which are set forth in Town of Longboat Key Ordinance No. 84-8, passed and adopted May 7, 1984, and FPL's written acceptance thereof dated May 29, 1984, granting to FPL, its successors, and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"); and

WHEREAS, FPL and the Town of Longboat Key desire to enter into a new agreement ("New Franchise Agreement") providing for the payment of fees to the Town of Longboat Key in exchange for the nonexclusive right and privilege of supplying retail electricity service within the Town of Longboat Key free of competition from the Town of Longboat Key, pursuant to certain terms and conditions, and

WHEREAS, the Town Commission of the Town of Longboat Key deems it to be in the best interests of the Town of Longboat Key and its citizens to enter into the New Franchise Agreement;

NOW, THEREFORE, BE IT ORDAINED BY THE TOWN COMMISSION OF THE TOWN OF LONGBOAT KEY, FLORIDA:

SECTION 1. There is hereby granted to Florida Power & Light Company (FPL), its successors and assigns (hereinafter called the "Grantee"), for the period of 30 years from the effective date hereof, the nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, easements, and rights-of-way (hereinafter called "public rights-of-way") throughout all of the incorporated areas, as such incorporated areas may be constituted from time to time, of the Town of Longboat Key, Florida, and its successors (hereinafter called the "Grantor"), in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (hereinafter called "facilities"), for the purpose of supplying retail electricity service and other electricity-related services incidental thereto (which other electricity-related services are defined as FPL's facility to facility data capabilities over the lines to identify faults, load information, and other data necessary or helpful to the provision of electric service, and which do not include any services that are sold to others) to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof

SECTION 2. (a) The facilities of the Grantee shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transportation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(b) To minimize such conflicts with the standards set forth in subsection (a) above, the location, relocation, installation, construction, or erection of all facilities shall be made as representatives of the Grantor may prescribe in accordance with all applicable federal, state, and local statutes, laws, ordinances, rules, and regulations and pursuant to Grantor's valid rules and regulations with respect to utilities' use of public rights-of-way relative to the placing and maintaining, in, under, upon, along, over, and across said public rights-of-way, provided such rules and regulations:

- (i) shall be for a valid municipal purpose,
- (ii) shall not prohibit the exercise of Grantee's rights to use said public rights-of-way for reasons other than conflict with the standards set forth above,
- (iii) shall not unreasonably interfere with Grantee's ability to furnish reasonably sufficient, adequate, and efficient electric service to all its customers while not conflicting with the standards set forth above, or
- (iv) shall not require relocation of any of the Grantee's facilities installed before or after the effective date hereof in any public right-of-way unless or until the facilities unreasonably interfere with the convenient, safe, or continuous use, or the maintenance, improvement, extension, or expansion of any such public "road".

(c) Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should, unless otherwise permitted, be installed near the outer boundaries of the public rights-of-way to the extent possible, and such installation shall be consistent with the Florida Department of Transportation's Manual of Uniform Minimum Standards for Design, Construction, and Maintenance for Streets and Highways.

(d) When any portion of a public right-of-way is excavated, damaged or impaired by Grantee or any of its agents, contractors, or subcontractors because of the installation, inspection, or repair of any of its facilities, the portion so excavated, damaged, or impaired shall, within a reasonable time and as early as practicable after such excavation, be restored to a condition equal to or better than its original condition before such damage by the Grantee at its expense.

(e) The Grantor shall not be liable to the Grantee for any cost or expense incurred in connection with the relocation of any of the Grantee's facilities required under this Section, except, however, that Grantee may be entitled to reimbursement of its costs and expenses from others and as provided by law.

SECTION 3. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation, or maintenance by the Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify the Grantor and hold it harmless against any and all liability, loss, cost, damage, or expense, including Grantor's reasonable attorneys fees and costs incurred in defending itself against any claims for such liabilities, losses, costs, damages, or expenses asserted against Grantor by others, which may accrue to the Grantor by reason of the negligence, default, or misconduct of the Grantee in the construction, operation or maintenance of its facilities hereunder.

SECTION 4. All rates and rules and regulations established by the Grantee from time to time shall be subject to such regulation as may be provided by law.

SECTION 5. (a) As a consideration for this franchise, the Grantee shall pay to the Grantor, commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem property taxes and non-ad valorem tax assessments on property) levied or imposed by the Grantor against the Grantee's property, business or operations and those of its subsidiaries during the Grantee's monthly billing period ending 60 days prior to each such payment will equal 6.0 percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment. In no event shall payment for the rights and privileges granted herein exceed 6.0 percent of such revenues for any monthly billing period of the Grantee, provided, however, that this limitation shall not apply if the Grantor and Grantee have, pursuant to Section 5(b) below, entered into a new franchise agreement providing for a rate greater than 6.0 percent.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 84-8, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; and (h) other service charges.

With each monthly payment remitted to Grantor, Grantee shall include a detailed calculation showing how the amount remitted was determined. Each such detailed calculation shall show: (i) the amount of Grantee's revenues subject to the franchise fee, (ii) the actual calculation of 6.0 percent of that amount, (iii) the resulting franchise fee amount before offsets and write-offs, (iv) the amount of actual write-offs deducted by Grantee, and (v) the resulting amount of the franchise fee payment being remitted to Grantor. Itemized information regarding any write-offs or deductions from the franchise fee shall be made available to the Grantor upon request to the Grantee.

(b) If during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Sarasota County, Manatee County, Charlotte County, Collier County, or Lee County, Florida, where the number of Grantee's active electrical customers is equal to or less than the number of Grantee's active electrical customers within the incorporated areas of Grantor, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 6.0% of the Grantee's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under the same terms and conditions as specified in Section 5(a) hereof, the Grantee, upon written request of the Grantor, shall negotiate and enter into a new franchise agreement with the Grantor in which the percentage to be used in calculating monthly payments under Section 5(a) hereof shall be equal to that percentage which the Grantee has agreed to use as a basis for the calculation of payments to the other municipality, provided, however, that such new franchise agreement shall include additional benefits to the Grantee, in addition to all benefits provided herein, at least equal to those provided by its franchise agreement with such other municipality.

SECTION 6. As a further consideration, during the term of this franchise or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or electric energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee; and (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies), provided that the Grantor shall not be considered a "third party" or an "other retail customer" for purposes of this provision. Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions, which are subject to the provisions of the Federal Power Act, or from utilizing generators and/or other electricity or energy-generating equipment during emergency situations. Nothing herein is intended to restrict the Grantor from providing services other than retail electricity service, which is the subject of the Grantor's agreement not to compete set forth in this paragraph.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or electric energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or electric energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or electric energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have 90 days to evaluate the offer and, if the Grantee offers rates, terms and conditions which are equal to or better than those offered by the other person, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or electric energy to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to rates, terms and conditions which equal or better the other person's offer, then Grantor may purchase such electric capacity and/or electric energy from such other person and all of the remaining terms and conditions of this franchise shall remain in effect.

SECTION 7. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this franchise if such terms and conditions are not remedied, or if the dispute between Grantee and Grantor is not resolved, as provided hereafter. The Grantee shall give the Grantor at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee, and the Grantor and Grantee agree to negotiate in good faith toward a mutually acceptable resolution of Grantee's claims during this 90-day period. If the Grantee reasonably determines that such terms or conditions are not remedied by the Grantor within said time period, and if no mutually acceptable resolution is reached by Grantee and Grantor through negotiation, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk, and termination shall be effective on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination leading to termination under this Section.

SECTION 8. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and such person is authorized, whether by federal or state law or regulations, or by the Grantor, to provide electric service without paying a franchise fee equal to that paid by the Grantee hereunder (such unequal application of franchise fees being hereafter referred to as the "competitive disadvantage" resulting from the legislative, regulatory, or other governmental action), the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage created by the unequal application of franchise fees on the Grantee and other persons supplying retail electricity is not remedied as provided hereafter. Such competitive disadvantage can be remedied by either of the following methods: (i) If the Grantor either cannot legally, or does not, charge a franchise fee to other electricity supplier(s), then the Grantor can remedy the disadvantage by reducing the Grantee's franchise fee rate to zero; or (ii) if the Grantor is able to charge, and does charge, such other electricity supplier(s) a franchise fee at a rate less than the 6.0% rate calculated as provided in Section 5 of this franchise, then the Grantor can remedy the disadvantage by reducing the Grantee's franchise fee rate to the same rate, with the same applicability and calculation methodology, as applies to such other electricity suppliers. If the Grantor does not implement either of the foregoing solutions, the Grantee may terminate the franchise, in accordance with the following process. The Grantee shall give the Grantor at least 180 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the claimed competitive disadvantage and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 90 days in

which to correct or otherwise remedy the competitive disadvantage, and the Grantor and Grantee agree to negotiate in good faith toward a mutually acceptable resolution of Grantee's claimed disadvantage during this 90-day period. If such competitive disadvantage is, in the reasonable determination of Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination of competitive disadvantage leading to termination under this Section.

SECTION 9. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

SECTION 10. Failure on the part of the Grantor to comply in substantial respect with any of the provisions of this ordinance, including but not limited to: (a) denying the Grantee use of public rights-of-way for reasons other than as set forth in Section 2 of this New Franchise Agreement; (b) imposing conditions for use of public rights-of-way contrary to Florida law or the terms and conditions of this New Franchise Agreement; or (c) unreasonable delay in issuing the Grantee a use permit, if any, to construct its facilities in public rights-of-way, shall constitute breach of this franchise and entitle the Grantee to withhold such portion of the payments provided for in Section 5 hereof as a court of competent jurisdiction has, upon action instituted by Grantee, determined to be equitable, just, and reasonable, considering the totality of the circumstances, until such time as a use permit is issued or a court of competent jurisdiction has reached a final determination (after the expiration or exhaustion of all rights of appeal) in the matter. The Grantor recognizes and agrees that nothing in this franchise agreement constitutes or shall be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right as provided by law. The Grantee recognizes and agrees that nothing in this franchise agreement constitutes or shall be deemed to constitute a waiver of the Grantor's delegated sovereign right of condemnation and that the Grantor, in its sole discretion, may exercise such right as provided by law, provided that the Grantor shall not exercise such right so as to violate the Grantor's covenant, set forth in Section 6 hereof, not to compete against the Grantee in the distribution and/or sale of electricity to ultimate consumers.

SECTION 11. The Grantor may, upon reasonable notice and within 90 days after each anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not otherwise created, prepared, maintained, or kept by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information

identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this Section shall not be conducted by any third party employed by the Grantor whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

Consistent with the foregoing, Grantor shall have 90 days following acceptance by the Grantee of the franchise granted by this New Franchise Agreement to initiate a final audit of Grantee's franchise fee payments pursuant to Ordinance No. 84-8. Upon the conclusion of any such audit, or upon the expiration of 90 days following Grantee's acceptance of the franchise granted by this New Franchise Agreement, whichever is later, any and all of Grantor's claims, other than such claims as may have been raised pursuant to the final audit contemplated by this section, relating in any way to the amounts paid by the Grantee under the Current Franchise Agreement embodied in Ordinance No. 84-8 shall be deemed waived, settled, and barred.

SECTION 12. Should any section or provision of this ordinance or any portion hereof be declared by a court of competent jurisdiction to be invalid, or otherwise rendered invalid or unenforceable as a direct or indirect consequence of any legislative, regulatory, or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them), such decision or action shall not affect the validity of the remainder hereof as a whole or any part hereof, other than the part declared to be invalid. Grantor and Grantee further agree that, in the event that any material provision of this ordinance is thus declared to be invalid or rendered invalid or unenforceable, the Grantor and Grantee will negotiate in good faith to amend this Agreement so as to restore, to the maximum extent legally permissible, the original economic bargain embodied in this ordinance. The parties recognize that Sections 1, 2, 3, 5, and 6 are critical to the fundamental economic bargain of this Franchise Agreement, and accordingly, if any of the provisions of these sections are found or adjudged to be invalid, or rendered invalid or unenforceable, and the Grantor and Grantee are unable to agree on replacement language that restores the original economic bargain embodied in the ordinance to their mutual satisfaction, then either party may, in its sole discretion, terminate the franchise by giving 60 days written notice to the other party.

SECTION 13. As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

SECTION 14. Subject to the Grantor's right to conduct a final audit expressly reserved by Section 11 of this New Franchise Agreement, Ordinance No. 84-8, passed and adopted May 7, 1984 and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

SECTION 15. Notwithstanding any provision of this Ordinance, nothing herein shall prevent, prohibit or in any way restrict the Grantor's ability to take advantage of all applicable services set forth in Grantee's tariffs as those tariffs are approved from time to time by Grantee's regulators, and nothing herein shall prevent, prohibit or in any way restrict the

Grantor's ability to avail itself of all rights accruing to Grantor as a retail customer of Grantee under Florida law and the rules and regulations of the Florida Public Service Commission.

SECTION 16. As a condition precedent to the taking effect of this ordinance, the Grantee shall file its acceptance hereof with the Grantor's Clerk within 30 days of adoption of this ordinance. The effective date of this ordinance shall be the date upon which the Grantee files such acceptance.

PASSED on first reading the 21st day of April, 2014.

PASSED AND ADOPTED on second reading and public hearing the _____ day of _____, 2014.

TOWN OF LONGBOAT KEY, FLORIDA

ATTEST:

By: _____
Jack G. Duncan, Vice Mayor

By: _____
Trish Granger, Town Clerk
Town of Longboat Key, Florida

(SEAL)

APPROVED AS TO FORM AND LEGALITY

Maggie Mooney-Portale, Town Attorney
Town of Longboat Key, Florida



Florida Power & Light - 1177 N. Lime Avenue, Sarasota, FL 34237

May 5, 2014

The Honorable Jim Brown
Mayor
Town of Longboat Key
501 Bay Isles Road
Longboat Key, FL 34228

Re: Florida Power & Light Company

Dear Mayor Brown,

Please accept this letter as acknowledgment and agreement by FPL to the following:

(1) FPL will provide reasonable and sufficient advance notice to the Town of any planned relocation or replacement of three or more consecutive FPL poles within the incorporated areas of the Town so that the Town may: (i) evaluate underground conversions of such poles and associated facilities pursuant to FPL's applicable tariffs and Florida Public Service Commission rules; or (ii) request different locations for the poles and associated facilities as desired by the Town pursuant to FPL's applicable tariffs and Florida Public Service Commission rules. Additionally, FPL agrees that it will provide sufficient notice of any relocations or replacements of overhead distribution facilities that cross Gulf of Mexico Drive within the Town so that the Town can avail itself of such opportunities to have such facilities converted to underground service, pursuant to FPL's applicable tariffs and Florida PSC rules. Conversely, we would ask that the Town notify FPL within a reasonable period if it becomes aware of a construction project or other circumstance that may include or require the relocation or replacement of overhead distribution facilities that cross Gulf of Mexico Drive. The foregoing notice provisions shall not apply in emergencies, e.g., installing facilities to restore service following damage to FPL's system due to a hurricane, tropical storm, tornado, or other weather event or other event necessitating the emergency restoration of service by FPL.

(2) FPL acknowledges and agrees that the Town may apply to FPL for approval to attach telecommunications and cable devices to FPL's poles. All FPL authorized pole attachments will be made on a non-discriminatory basis and in compliance with all applicable federal, state, and local laws, rules, codes, and regulations. FPL's commitment in this paragraph (2) shall apply and continue throughout the term of the Franchise without regard to whether there is any legal mandate that FPL do so. Any pole attachments, if authorized, will be made by a separate agreement between FPL and the Town.

These commitments represent FPL's binding commitments with respect to the subjects of the foregoing paragraphs.

Florida Power & Light - 1177 N. Lime Avenue, Sarasota, FL 34237

FPL sincerely appreciates the opportunity to serve the Town of Longboat Key and has enjoyed the ongoing cooperative relationship with the Town. We look forward to a continuing cooperative effort in the future.

Sincerely,

Rae Dowling
External Affairs Manager

ORDINANCE NO. 05-2011

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF CAPE CANAVERAL, BREVARD COUNTY, FLORIDA, GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY; PROVIDING FOR THE REPEAL OF PRIOR INCONSISTENT ORDINANCES AND RESOLUTIONS, PROVIDING FOR QUALIFIED SEVERABILITY, PROVIDING FOR INCORPORATION INTO APPENDIX "A" OF THE CITY CODE, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Council is granted the authority, under Section 2(b), Article VIII, of the State Constitution, to exercise power for municipal purposes, except when expressly prohibited by law; and

WHEREAS, Section 166.021(1) provides that municipalities shall have the 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 when expressly prohibited by law; and

WHEREAS, the City Council of the City of Cape Canaveral, Florida recognizes that the City of Cape Canaveral and its citizens need and desire the continued benefits of electric service; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, on December 15, 1981, the City Council granted a 30 year franchise to Florida Power & Light Company (FPL) for the purpose of supplying electricity to the City and for the other purposes stated therein; and

nonexclusive right, privilege and franchise (hereinafter called "franchise") to construct, operate and maintain, in accordance with the National Electrical Safety Code to the extent applicable, in, under, upon, along, over and across the present and future roads, streets, alleys, bridges, publicly dedicated rights-of-way, applicable publicly dedicated utility easements and other public places (hereinafter called "public rights-of-way") in the City of Cape Canaveral, Florida, and its successors (hereinafter called the "Grantor") throughout all of Grantor's incorporated areas, as such incorporated areas may be constituted from time to time, in accordance with the Grantee's customary practice with respect to construction and maintenance, electric light and power facilities, including, without limitation, conduits, poles, wires, transmission and distribution lines, and all other facilities installed in conjunction with or ancillary to all of the Grantee's operations (hereinafter called "facilities"), for the purpose of supplying electricity and other directly electric-related services to the Grantor and its successors, the inhabitants thereof, and persons beyond the limits thereof. This grant is intended to provide a franchise to Grantee for the provision of electric and directly electric-related services, and is not intended to be a grant or franchise for the placement or construction of gas lines or appurtenances thereto, or for fiber optics or appurtenances thereto.

Section 2. Facilities Requirements.

(a) The facilities of Grantee shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transportation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(d) When any portion of a public right-of-way is excavated, damaged or impaired by Grantee or any of its agents, contractors or subcontractors because of the installation, inspection, or repair of any of its facilities, the portion so excavated, damaged or impaired shall, within a reasonable time and as early as practicable after such excavation, be restored to its original condition before such damage by the Grantee at Grantee's expense.

(e) If Grantor requires the removal or relocation of Grantee's facilities because the facilities interfere with the standards set forth in subsection (a) above, and Grantee fails to remove or relocate such facilities at Grantee's expense within thirty (30) days after written notice from Grantor, then Grantor may proceed to cause the facilities to be removed or relocated and the expense therefore shall be charged against the Grantee.

(f) The Grantor shall not be liable to the Grantee for any cost or expense incurred in connection with the relocation of any of the Grantee's facilities required under this Section, except, however, that Grantee may be entitled to reimbursement of its costs and expenses from others and as provided by law.

Section 3. Indemnification. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by Grantee of its facilities hereunder, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee, to indemnify Grantor, its officers, agents, attorneys, servants, employees, or contractors and hold it harmless against any and all liability, loss, costs, injuries (including death), damages, attorneys' fees, or expense, which may accrue to, or be incurred by or charged against Grantor or any of its officers, agents, attorneys, servants, employees, or contractors by reason of

commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment, and in no event shall payment for the rights and privileges granted herein exceed 6.0 percent of such revenues for any monthly billing period of the Grantee.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 25-81, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

Section 6. Most Favored Nations. If during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Brevard County, Florida, or within any contiguous county of Brevard County where the number of Grantee's active electrical customers is equal to or less than the number of Grantee's active electrical customers within the incorporated area of the Grantor, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 6.0% of the Grantee's residential, commercial and industrial revenues (as such customers are defined by FPL's tariff), under the same terms and conditions as specified in Section 5 hereof, the Grantee, upon written request of the Grantor, shall negotiate and enter into a new

utilities or persons in wholesale transactions which are subject to the provisions of the Federal Power Act.

Nothing herein shall prohibit the Grantor, if permitted by law, (i) from purchasing electric capacity and/or electric energy from any other person, or (ii) from seeking to have the Grantee transmit and/or distribute to any facility(ies) of the Grantor electric capacity and/or electric energy purchased by the Grantor from any other person; provided, however, that before the Grantor elects to purchase electric capacity and/or electric energy from any other person, the Grantor shall notify the Grantee. Such notice shall include a summary of the specific rates, terms and conditions which have been offered by the other person and identify the Grantor's facilities to be served under the offer. The Grantee shall thereafter have 90 days to evaluate the offer and, if the Grantee offers rates, terms and conditions which are equal to or better than those offered by the other person, the Grantor shall be obligated to continue to purchase from the Grantee electric capacity and/or electric energy to serve the previously-identified facilities of the Grantor for a term no shorter than that offered by the other person. If the Grantee does not agree to rates, terms and conditions which equal or better the other person's offer, then Grantor may proceed with the other person's offered sale and purchase arrangement and all of the terms and conditions of this franchise shall remain in effect except as provided herein.

Section 8. Competitive Disadvantage; Termination by Grantee. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee determines are more favorable

terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have 150 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Notwithstanding the foregoing, upon written request of the Grantor within the 150 day notice period for a face to face meeting between representatives of the Grantor and Grantee, Grantee agrees that it shall meet in good faith with Grantor prior to terminating the franchise. Nothing contained herein shall be construed as constraining Grantor's right to legally challenge Grantee's reasonable determination of competitive disadvantage leading to termination pursuant to Section 8 and/or 9 herein.

Section 10. Default by Grantee. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction that the Grantee has failed to comply in a material respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require.

Grantor may, upon reasonable notice given within one (1) year following the Grantee's acceptance of the New Franchise Agreement, conduct a final audit of the Grantee's records relating to the calculation of the franchise payments that have been made to Grantor pursuant to the Current Franchise Agreement embodied in Ordinance No. 25-81. Other than any claims arising from alleged fraud, deceit, misrepresentation, intentional withholding of information, or other similar intentional misconduct by Grantee in relation to the calculation or remittance of the franchise payments under the Current Franchise Agreement, Grantor waives, settles, and bars all claims relating to the amounts paid by the Grantee under the Current Franchise Agreement embodied in Ordinance No. 25-81.

Section 13. Renewable Energy.

(a) Grantor and Grantee recognize that it is in the best interests of the City, its residents, businesses and inhabitants thereof to reduce and control the growth rates of electric consumption; to reduce the growth rates of weather-sensitive peak demand; to increase the overall efficiency and cost-effectiveness of electricity production and use and to encourage further development of demand-side renewable energy systems. To that end Grantor and Grantee agree to use their best efforts to cooperatively work each with the other to promote incentives for customer-owned and utility owned- energy efficiency and demand-side renewable energy intended to offset all or part of a customer's electricity requirements. Nothing contained in this franchise shall be construed as prohibiting or impeding the residents, businesses, and inhabitants within the incorporated area of the City from installing and using renewable energy systems provided the renewable energy systems referred to are otherwise permitted by Florida law.

FPSC or regulatory approval, Grantee shall implement its infrastructure hardening plan within the Grantor's boundaries.

Section 17. Preferential or Discriminatory Practices Prohibited. All services rendered and all rules and regulations adopted by the Grantee shall have general application to all persons and shall not subject any person to prejudice or disadvantage on account of race, gender, religion, origin, physical condition or ethnicity. No otherwise qualified person shall, solely by reason of his or her race, gender, religion, origin, physical condition or ethnicity, be excluded from participation in, be denied services, or be subject to discrimination under any provision of this franchise.

Section 18. No Joint Venture. Nothing herein shall be deemed to create a joint venture or principal-agent relationship between the parties, and neither party is authorized to, nor shall either party act toward third persons or the public in any manner which would indicate any such relationship with the other.

Section 19. Notices. All notices from the Grantee to the Grantor pursuant to this ordinance shall be sent to: City Manager, City of Cape Canaveral, 105 Polk Avenue, or such other address where City Hall may be located in the City of Cape Canaveral, Florida, 32920. All notices from the Grantor to the Grantee pursuant to this ordinance shall be sent to: Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408, or such other address where Grantee's corporate office may be located, marked: Attention: External Affairs.

Section 20. Captions. Captions to sections throughout this ordinance are solely to facilitate the reading and reference to the sections and provisions of the ordinance. Such captions shall not affect the meaning or interpretation of the ordinance.

Section 24. Qualified Severability. If any clause, section, provision or other part of this ordinance or any portion thereof shall be held invalid or unconstitutional by a court of competent jurisdiction, then said holding in no way affects the validity of the remaining portions of this ordinance. Notwithstanding the foregoing, it is expressly provided that if any of the provisions or Sections of this ordinance are held invalid or unconstitutional, the parties shall attempt in good faith to negotiate a new lawful agreement that restores the fundamental terms of the original agreement. In the event the parties are unable to reach a new lawful agreement, the ordinance shall be null and void and of no force and effect.

Section 25. Definition of "Person". As used herein "person" means an individual, a partnership, a corporation, a business trust, a joint stock company, a trust, an incorporated association, a joint venture, a governmental authority or any other entity of whatever nature.

Section 26. Repeal of Prior Inconsistent Ordinance, Resolutions and Agreements. Ordinance No. 25-81, passed and adopted December 15, 1981, and all other ordinances and parts of ordinances and all resolutions and parts of resolutions in conflict herewith, are hereby repealed.

Section 27. Incorporation Into Code. This Ordinance shall be incorporated into "Appendix A" of the Cape Canaveral City Code and any section or paragraph, number or letter, and any heading may be changed or modified as necessary to effectuate the foregoing. Grammatical, typographical, and like errors may be corrected and additions, alterations, and omissions, not affecting the construction or meaning of this ordinance and the City Code may be freely made.

ACCEPTANCE OF ELECTRIC FRANCHISE
ORDINANCE NO. 05-2011
BY FLORIDA POWER & LIGHT COMPANY

City of Cape Canaveral, Florida

September 1, 2011

Florida Power & Light Company does hereby accept the electric franchise in the City of Cape Canaveral, Florida, granted by Ordinance No. 05-2011, being:

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF CAPE CANAVERAL, BREVARD COUNTY, FLORIDA, GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY; PROVIDING FOR THE REPEAL OF PRIOR INCONSISTENT ORDINANCES AND RESOLUTIONS, PROVIDING FOR QUALIFIED SEVERABILITY, PROVIDING FOR INCORPORATION INTO APPENDIX "A" OF THE CITY CODE, AND PROVIDING FOR AN EFFECTIVE DATE.

which was passed and adopted on August 16, 2011.

This instrument is filed with the City Clerk of the City of Cape Canaveral Florida, in accordance with the provisions of Section 28 of said Ordinance.

FLORIDA POWER & LIGHT COMPANY

By Pamela Rauch
Pamela M. Rauch, Vice President

STATE OF FLORIDA
COUNTY OF PALM BEACH

The foregoing instrument was acknowledged before me this 24th day of August, 2011 by Pamela M. Rauch of Florida Power & Light Company, a Florida corporation, on behalf of the corporation, who is personally known to me.



Heather P. Meligons
NOTARY PUBLIC Signature

I HEREBY ACKNOWLEDGE receipt of the above Acceptance of Electric Franchise Ordinance No. 05-2011 by Florida Power & Light Company, and certify that I have filed the same for record in the permanent files and records of the City of Cape Canaveral, Florida on this 1 day of September, 2011.

(SEAL)

Adam Apperson
City Clerk, City of Cape Canaveral, Florida

projects premised upon the use of green energy, conservation, sustainability and the use of renewable energy.

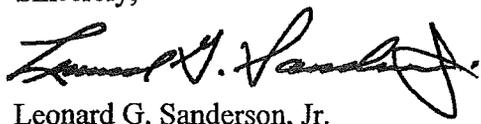
(6) FPL agrees to use reasonable efforts to coordinate FPL activities with any City sidewalk projects and in accordance with applicable laws and regulations. FPL will use reasonable efforts to avoid constructing new poles within sidewalk areas, bicycle paths, or in any other place where such poles might interfere with pedestrian or bicycle traffic.

(7) FPL will use reasonable efforts to avoid the placement of electric facilities in public places other than public rights-of-way where practical and feasible alternatives exist. FPL recognizes the sensitivity of the City of Cape Canaveral to electric facilities being installed in public places other than public rights-of-way. Additionally, FPL will use reasonable efforts to accommodate the City of Cape Canaveral's concerns related to electric facility installation, operation and maintenance in public places other than public rights-of-way. Upon request by the City of Cape Canaveral, FPL will meet with the City to address specific concerns of the City. FPL agrees that it will not install electric facilities over or under any community center, police station, fire station, any existing or future city hall complex, or structures located within any city park. Additionally, FPL will use reasonable efforts to avoid installing electric facilities upon city-owned waterfront property and city-owned cemeteries (if any).

(8) FPL will not assert in any dispute with the City of Cape Canaveral, or in any legal or regulatory proceeding to which the City of Cape Canaveral and FPL are parties, that the terms of the franchise, with respect to substation siting and construction, prevail over state statutes or state regulations pertaining to substation siting and construction, including specifically Florida Statute Section 163.3208.

FPL has enjoyed an ongoing cooperative relationship with the City of Cape Canaveral and we look forward to a continuing cooperative effort in the future.

Sincerely,



Leonard G. Sanderson, Jr.

Accepted by:



Angela M. Apperson
City Clerk

cc: Anthony A. Garganese, Esq.
Kenneth M. Rubin, Esq.

CERTIFICATION

I certify this to be a true and correct copy of the record of the City of Fort Lauderdale, Florida.

WITNESSETH my hand and official seal of the City of Fort Lauderdale, Florida, this the 23 day of October, 2009

[Signature] City Clerk
S. A. SET

ORDINANCE NO. C-09-26

AN ORDINANCE GRANTING TO **FLORIDA POWER & LIGHT COMPANY**, ITS SUCCESSORS AND ASSIGNS, A NONEXCLUSIVE ELECTRIC FRANCHISE, PROVIDING FOR MONTHLY FRANCHISE FEE PAYMENTS TO THE CITY; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, INCLUDING PROVISIONS FOR INDEMNIFICATION; MAINTENANCE OF BOOKS AND RECORDS AND THE RIGHT TO AUDIT SAME; MOST FAVORED NATIONS CLAUSE PROTECTING THE CITY; IMPOSITION OF RESTRICTIONS ON CITY COMPETING BY SELLING ELECTRICITY; AUTHORITY OF CITY TO GENERATE ELECTRICITY TO TRANSMIT BETWEEN CITY FACILITIES; PROVISIONS RESPECTING FORFEITURE OF THE FRANCHISE; GRANTING TO CITY THE OPTION TO PURCHASE FACILITIES AT THE END OF THE TERM; AND PROVIDING AN EFFECTIVE DATE.

Be it Ordained by the City Commission of the City of Fort Lauderdale, Florida:

WHEREAS, the City Commission of the City of Fort Lauderdale, Florida recognizes that the City of Fort Lauderdale and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of Fort Lauderdale does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, the City of Fort Lauderdale is vested with jurisdiction, authority and control of certain public rights-of-way within its corporate boundaries based upon functional classifications under the Florida Transportation Code and is responsible for management of such public rights-of-way and balancing the competing needs for use of its public rights-of-way with regard to, among other matters, installing, constructing, placing, maintaining, operating and relocating, from time to time, over, across, under, above and within any public right-of-way any aerial or underground electric generating and transmission facilities, telephone transmission facilities, telegraph transmission facilities, electronic data transmission facilities, communication

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SECTION 1. Grant of Electric Utility Franchise; Term of Franchise. That there is hereby granted to Florida Power & Light Company, its successors and assigns, (herein called the "Grantee") for a period of thirty (30) years from the date of acceptance hereof by Grantee, the nonexclusive right, privilege, or franchise to construct, install, locate, relocate, maintain, and operate in accordance with the National Electrical Safety Code to the extent applicable, in, under, upon, over, and across the present and future streets, alleys, bridges, publicly dedicated rights-of-way that have been classified as "city streets" under the Florida Transportation Code and publicly dedicated utility easements, but not including easements granted to Grantee (hereinafter called "public rights-of-way") in the City of Fort Lauderdale, Florida, (herein called the "Grantor") and its successors and assigns, throughout all of Grantor's incorporated areas, as such incorporated areas may be constituted from time to time, and subject to any applicable federal, state and local laws, statutes, ordinances, rules and regulations, including Grantor's valid regulation of public rights of way with respect to electrical construction, installation, location, relocation and maintenance, of electric light and power facilities (including conduits, poles, wires, transmission and distribution lines, and appurtenances incidental thereto) installed in conjunction with and ancillary to Grantee's electrical generating, transmission and distribution operations and, for Grantee's own facility-to-facility use, telephone, telegraph and telecommunication lines and facilities) (hereinafter called "facilities") for the purpose of supplying electricity to Grantor, and its successors, and inhabitants thereof, and persons beyond the limits thereof ("2009 Electric Utility Franchise").

SECTION 2. Condition Precedent; Acceptance by Grantee. As a condition precedent to the taking effect of this Grant, Grantee shall have filed its acceptance hereof with the Grantor's clerk within thirty (30) days of the date this ordinance is adopted on second reading.

SECTION 3. Facilities Requirements.

(a) That the facilities of Grantee shall be so located, relocated, installed, constructed and so erected as to not unreasonably interfere with the convenient, safe, continuous use or the maintenance, improvement, extension or expansion of any public "road" as defined under the Florida Transportation Code, nor unreasonably interfere with reasonable egress from and ingress to abutting property.

(b) To minimize such conflicts with the standards set forth in subsection (a) above, the location, relocation, installation, construction or erection of all facilities shall be made as representatives of the Grantor may prescribe in accordance with all applicable federal, state and local statutes, laws, ordinances, rules and regulations and pursuant to Grantor's valid rules and regulations with respect to utilities' use of public rights-of-way relative to the placing and

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except, however, that Grantee may be entitled to reimbursement of its costs and expenses from others and as provided by law.

SECTION 4. Indemnification of Grantor. Acceptance of this ordinance by Grantee shall be deemed an agreement on the part of Grantee to indemnify Grantor, its officers, agents, servants, employees, or contractors and hold it harmless against any and all liability, loss, costs, damages, attorneys' fees, or expense which may accrue to or be incurred by or charged or sought against Grantor or any of its officers, agents, servants, employees or contractors by reason of installation, location, relocation, construction, reconstruction, operating, maintenance or repair of Grantee's facilities or acts or omissions of negligence, gross negligence or intentional torts, default or misconduct of the Grantee, its officers, directors, agents, servants, employees, contractors or subcontractors. The indemnity hereunder includes not only the reasonable costs, expenses and attorneys' fees incurred by the Grantor in defense of any third party's claim (prior to and during all phases of litigation, including trial and post trial and appellate proceedings) and also includes the reasonable costs, expenses and attorneys' fees incurred by the Grantor in the event it must enforce the terms of this indemnity prior to and during all litigation including trial, post trial and appellate proceedings. This indemnity shall survive termination of this franchise.

SECTION 5. Rates, Rules and Regulations of Grantee. That all rates and rules and regulations established by Grantee from time to time shall at all times be reasonable, subject to and not in conflict with such rules and regulations as may be provided by law.

SECTION 6. Franchise Fee; Calculation; Payment.

(a) As a consideration for the nonexclusive right to use the Grantor's public rights-of-way under this 2009 Electric Utility Franchise, the Grantor's agreement to not compete with the Grantee as set forth in Section 9 hereof, and other valuable consideration all as set forth herein, the Grantee shall pay to the Grantor a franchise fee, commencing ninety (90) days after the effective date hereof, and each month thereafter for the remainder of the term of this franchise, an amount which when added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever (except ad valorem tax and non-ad valorem assessments on property) levied or imposed by the Grantor against Grantee's property, business or operations during the Grantee's monthly billing period ending sixty (60) days prior to each such payment will equal 6.0 percent of the Grantee's billed revenues including fuel charges, less actual write-offs from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff within the incorporated areas of the Grantor ("Retail Customers") for the monthly billing period ending sixty (60) days prior to each such payment, and in no event shall payment for the rights and privileges granted herein

ORDINANCE NO. C-09-26

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calculating the franchise fee. Such examination of books and records of Grantee by Grantor shall be made during the regular business hours of the Grantee at the general office of the Grantee. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this Section shall not be conducted by any third party employed by the Grantor whose fee, in whole or part, for conducting such audit is contingent on findings of the audit. Records shall be retained by Grantee for a period of five (5) years. The provisions of this Section 7 shall survive termination of this franchise.

SECTION 8. Most Favored Nations. If during the term of this franchise the Grantee enters into a franchise agreement with any other municipality located in Broward or Miami-Dade County, Florida, the terms of which provide for the payment of franchise fees by the Grantee at a rate greater than 8.0% of the Grantee's revenues for all Retail Customers, under the same terms and conditions as specified in Section 6 hereof, then the Grantee, upon written request of the Grantor, shall enter into a new franchise agreement with the Grantor in which the percentage to be used in calculating monthly payments under Section 6, utilizing the same terms and conditions as set forth in Section 6 hereof shall be that greater rate provided for such other municipality within Broward or Miami-Dade County; provided, however, that if the franchise with such other municipality within Broward or Miami-Dade County contains additional benefits given to Grantee in exchange for the increased franchise rate, which such additional benefits are not contained in this 2009 Electric Utility Franchise, such new franchise agreement shall include those additional benefits to the Grantee.

SECTION 9. Non-Competition by Grantor.

(a) As a further consideration during the term of this franchise, Grantor agrees not to engage in the business of distributing and/or sale, in competition with Grantee, of electric capacity and/or electric energy to any Retail Customer of electric utility service or to any electrical distribution system established solely to serve any Retail Customer formerly served by the Grantee. Grantor further agrees not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or electric energy from any third party(ies) other than governmental bodies, to any other Retail Customer's facility(ies). Nothing specified herein shall prohibit the Grantor from engaging with other utilities or persons in wholesale transactions

any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee reasonably determines that its obligations hereunder, or otherwise resulting from this franchise in respect to the franchise fee, place it at a material competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such material competitive disadvantage is, in the reasonable determination of Grantee, not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 120 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the material competitive disadvantage and the objective basis or bases of the material competitive disadvantage. The Grantor shall then have 120 days in which to correct or otherwise remedy the material competitive disadvantage. If such material competitive disadvantage is, in the reasonable determination of Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time FPL's determination of material competitive disadvantage leading to termination under this Section 11 and/or 14.

SECTION 12. Default by Grantee; Forfeiture. That failure on the part of the Grantee to comply in any material respect with any of the provisions of this ordinance, shall be grounds for a forfeiture of this grant, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by Grantee until a court of competent jurisdiction (with right of appeal in either party) shall have found that Grantee has failed to comply in a material respect with any of the provisions of this franchise, and the Grantee shall have six (6) months after the final determination of the question, to make good the default before a forfeiture shall result with the right in Grantor at its discretion to grant such additional time to Grantee for compliance as necessitates in the case require.

SECTION 13. Default by Grantor. Failure on the part of the Grantor to comply in substantial respect with any of the provisions of this ordinance, including but not limited to:

- (i) denying the Grantee use of public rights-of-way for reasons other than as set forth in Section 3;

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Recovery of Undergrounding Fees (MGRUF), along with other undergrounding tariffs. Requests made by Grantor for undergrounding shall be implemented by Grantee with the applicable tariffs in effect on the date of Grantor's request.

SECTION 17. Renewable Energy.

(a) The parties recognize that it is in the best interests of the City of Fort Lauderdale, its residents, businesses and inhabitants thereof to reduce and control the growth rates of electric consumption; to reduce the growth rates of weather-sensitive peak demand; to increase the overall efficiency and cost-effectiveness of electricity production and use and to encourage further development of demand-side renewable energy systems. To that end Grantor and Grantee agree to use their best efforts to cooperatively work each with the other to promote incentives for customer-owned and utility-owned energy efficiency and demand-side renewable energy intended to offset all or part of a customer's electricity requirements.

(b) Grantor may, if permitted by law, (i) generate electric capacity and/or energy at any facility owned by the Grantor for storage or utilization at that facility or other Grantor facilities, operations or equipment; (ii) use renewable energy sources to generate electric capacity and/or energy for use in demonstration projects or at Grantor's facilities, operations or its equipment; and (iii) sell electric capacity and/or energy to Grantee or other wholesale purchaser in compliance with applicable rules and regulations controlling such transactions.

SECTION 18. Smart Grid Technology. Grantee acknowledges that Grantor's policies strongly favor the widespread dissemination of meters featuring "smart grid technology" which utilize an interactive monitoring network capable of providing real time electrical energy usage information to both Grantee and Grantee's Retail Customers via an advanced, two-way communication device. If this technology is implemented by Grantee, Grantee shall utilize its best practicable efforts to provide Retail Customers located in the incorporated area of Grantor receipt of such technology.

SECTION 19. Infrastructure Hardening. Grantee understands and acknowledges that Grantor's policies strongly favor strengthening electric utility infrastructure. Grantee has filed and received Florida Public Service Commission (FPSC) approval for a plan which includes strengthening feeders delivering power to critical infrastructure facilities, including feeders located within the Grantor's boundaries. Subject to continued FPSC or regulatory approval, Grantee will implement its infrastructure hardening plan within the Grantor's boundaries.

ORDINANCE NO. 2008-15

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF ST. AUGUSTINE, AND PROVIDING FOR AN EFFECTIVE DATE.

WHEREAS, the City Commission of the City of St. Augustine, Florida recognizes that the City of St. Augustine and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of St. Augustine does not desire to undertake to provide such services; and

WHEREAS, Florida Power & Light Company (FPL) is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, there is currently in effect a franchise agreement between the City of St. Augustine and FPL, the terms of which are set forth in City of St. Augustine Ordinance No. 79-21, passed and adopted June 25, 1979, and FPL's written acceptance thereof dated June 27, 1979 granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"); and

WHEREAS, FPL and the City of St. Augustine desire to enter into a new agreement (New Franchise Agreement) providing for the payment of fees to the City of St. Augustine in exchange for the nonexclusive right and privilege of supplying electricity and

Section 2. The facilities of the Grantee shall be installed, located or relocated so as to not unreasonably interfere with traffic over the public rights-of-way or with reasonable egress from and ingress to abutting property. To avoid conflicts with traffic, the location or relocation of all facilities shall be made as representatives of the Grantor may prescribe in accordance with the Grantor's reasonable rules and regulations with reference to the placing and maintaining in, under, upon, along, over and across said public rights-of-way; provided, however, that such rules or regulations (a) shall not prohibit the exercise of the Grantee's right to use said public rights-of-way for reasons other than unreasonable interference with motor vehicular traffic, (b) shall not unreasonably interfere with the Grantee's ability to furnish reasonably sufficient, adequate and efficient electric service to all of its customers, and (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with motor vehicular traffic. Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should be installed near the outer boundaries of the public rights-of-way to the extent possible. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of

shall payment for the rights and privileges granted herein exceed 5.9 percent of such revenues for any monthly billing period of the Grantee.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited, as in the existing franchise Ordinance No. 79-21, to the precise revenues described therein, and that such revenues do not include, by way of example and not limitation: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment Charges; (g) Field Collection Charges; (h) other service charges.

Section 6. As a further consideration, during the term of this franchise or any extension thereof, the Grantor agrees: (a) not to engage in the distribution and/or sale, in competition with the Grantee, of electric capacity and/or electric energy to any ultimate consumer of electric utility service (herein called a "retail customer") or to any electrical distribution system established solely to serve any retail customer formerly served by the Grantee, (b) not to participate in any proceeding or contractual arrangement, the purpose or terms of which would be to obligate the Grantee to transmit and/or distribute, electric capacity and/or electric energy from any third party(ies) to any other retail customer's facility(ies), and (c) not to seek to have the Grantee transmit and/or distribute electric capacity and/or electric energy generated by or on behalf of the Grantor at one location to the Grantor's facility(ies) at any other location(s). Nothing specified herein shall prohibit

are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 60 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable. The Grantor shall then have 60 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice.

Section 8. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 90 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage. The Grantor shall then have

be deemed to constitute a waiver of the Grantee's delegated sovereign right of condemnation and that the Grantee, in its sole discretion, may exercise such right.

Section 11. The Grantor may, upon reasonable notice and within 90 days after each anniversary date of this franchise, at the Grantor's expense, examine the records of the Grantee relating to the calculation of the franchise payment for the year preceding such anniversary date. Such examination shall be during normal business hours at the Grantee's office where such records are maintained. Records not prepared by the Grantee in the ordinary course of business may be provided at the Grantor's expense and as the Grantor and the Grantee may agree in writing. Information identifying the Grantee's customers by name or their electric consumption shall not be taken from the Grantee's premises. Such audit shall be impartial and all audit findings, whether they decrease or increase payment to the Grantor, shall be reported to the Grantee. The Grantor's right to examine the records of the Grantee in accordance with this Section shall not be conducted by any third party employed by the Grantor whose fee, in whole or part, for conducting such audit is contingent on findings of the audit.

Grantor waives, settles and bars all claims relating in any way to the amounts paid by the Grantee under the Current Franchise Agreement embodied in Ordinance No. 79-21.

Section 12. The provisions of this ordinance are interdependent upon one another, and if any of the provisions of this ordinance are found or adjudged to be invalid, illegal, void or of no effect, the entire ordinance shall be null and void and of no force or effect.

RECEIVED
JUL 23 2008
CITY CLERK

COPY OF ADVERTISEMENT

The St. Augustine Record

PUBLISHED EVERY MORNING SUNDAY THROUGH SATURDAY
ST. AUGUSTINE AND ST. JOHNS COUNTY, FLORIDA

STATE OF FLORIDA,
COUNTY OF ST. JOHNS

Before the undersigned authority personally appeared **KAREN J BRANNON**

who on oath says that she is an Employee of the St. Augustine Record,
a daily newspaper published at St. Augustine in St. Johns County, Florida;

that the attached copy of advertisement, being a **NOTICE OF HEARING**

In/ the matter of **ORDINANCE #2008-15**

was published in said newspaper **JULY 17, 2008.**

Affiant further says that the St. Augustine Record is a newspaper published at St. Augustine, in said St. Johns County, Florida, and that the said newspaper heretofore been continuously published in said St. Johns County, Florida, each day and has been entered as second class mail matter at the post office in the City of St. Augustine, in said St. Johns County, for a period of one year preceding the first publication of the copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing the advertisement for publication in the said newspaper.

Sworn to and subscribed before me this **17th** day of **JULY 2008.**

Karen J Brannon who is personally known to me
or who has produced **PERSONALLY KNOWN** as identification.

Patricia A Bergquist
(Signature of Notary Public)
PATRICIA A BERGQUIST

Notary Public State of Florida
Patricia A Bergquist
My Commission DD732015
Expires 12/18/2011
(Seal)

NOTICE OF PROPOSED ENACTMENT OF ORDINANCE 2008-15 BY THE CITY OF ST. AUGUSTINE, FLORIDA
NOTICE IS HEREBY GIVEN OF A PUBLIC HEARING TO BE HELD BY THE CITY COMMISSION OF THE CITY OF ST. AUGUSTINE CONCERNING THE SECOND READING OF ORDINANCE 2008-15. THE PUBLIC HEARING WILL BE HELD ON JULY 28, 2008, BEGINNING AT 5:00 P.M. IN THE ALCAZAR ROOM, 1ST FLOOR, WEST WING, CITY HALL, 75 KING STREET, ST. AUGUSTINE, FLORIDA. PUBLIC COMMENTS ARE INVITED ON THE FOLLOWING MATTER.

ORDINANCE NO. 2008-15

AN ORDINANCE GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE, IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO, PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF ST. AUGUSTINE, AND PROVIDING FOR AN EFFECTIVE DATE.

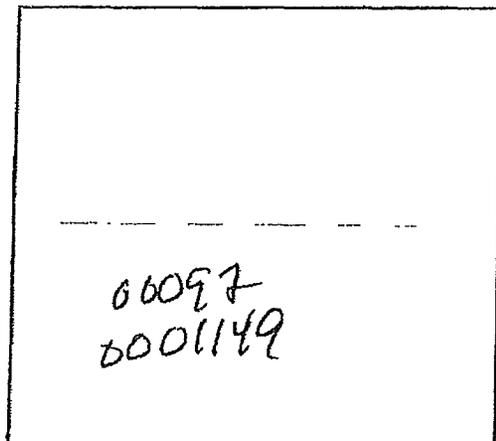
Related documents may be inspected by the public at the office of the City Clerk, City Hall, Lobby B, 1st floor, 75 King Street, St. Augustine, FL 32084 during the hours of 8:00 A.M. and 5:00 P.M. on weekdays and holidays.

All interested parties may appear at the meeting to be heard with respect to the proposed ordinance.

In accordance with Florida Statute 286.0105, "If a person decides to appeal any decision made by the City Commission with respect to any matter covered at this scheduled meeting or hearing, the person will need a record of the proceedings, and such purpose the person may need to ensure that a verbatim record of the proceedings is made, which record includes the testimony and evidence in which the appeal is to be based."

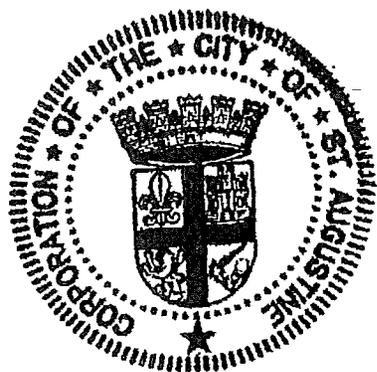
In accordance with the Americans with Disabilities Act, persons needing a special accommodation to participate in this proceeding should contact the individual or agency sending notice not later than seven days prior to the proceeding at the address given on notice. Telephone: Karen Rogers, City Clerk (904) 925-1007; or 1-800-955-8771 (TDD) 1-800-955-8770 (V), via Florida Relay Service.
Karen Rogers,
City Clerk
L2012-8 July 17,

CITY OF ST. AUGUSTINE
COUNTY OF ST. JOHNS
STATE OF FLORIDA



I, Karen Rogers, City Clerk, City of St. Augustine, Florida, do hereby certify that the attached copy of the proof of publishing from the St. Augustine Record for Ordinance 2008-15, granting Florida Power and Light Company, its successors and assigns, an electric franchise imposing provision and conditions relating to provisions for monthly payments to the City of St. Augustine, contains a full, true and correct copy as the same appears of Record and on file in my office, City of St. Augustine, 2nd Floor, S.E., Elevator B, City Hall, 75 King Street.

IN WITNESS WHEREOF, I have hereto set my hand and affixed the corporate seal of the City of St. Augustine, Florida, this 19th day of February, 2009.




Karen Rogers, CMC, City Clerk

FPL FRANCHISE AGREEMENT ORDINANCE 13169
ADOPTED 5/13/10

..Title

AN ORDINANCE OF THE MIAMI CITY COMMISSION GRANTING TO FLORIDA POWER & LIGHT COMPANY, ITS SUCCESSORS AND ASSIGNS, AN ELECTRIC FRANCHISE; IMPOSING PROVISIONS AND CONDITIONS RELATING THERETO; PROVIDING FOR MONTHLY PAYMENTS TO THE CITY OF MIAMI DURING A TERM OF 30 YEARS; CONTAINING A SEVERABILITY CLAUSE, AND PROVIDING FOR AN EFFECTIVE DATE.

..Body

WHEREAS, the City Commission of the City of Miami Florida, a Florida municipal corporation (hereunder "Grantor" or "City"), recognizes that the City of Miami and its citizens need and desire the continued benefits of electric service; and

WHEREAS, the provision of such service requires substantial investments of capital and other resources in order to construct, maintain and operate facilities essential to the provision of such service in addition to costly administrative functions, and the City of Miami does not desire to undertake to provide such services at this time; and

WHEREAS, Florida Power & Light Company (hereinafter "Grantee" or "FPL") is a public utility which has the demonstrated ability to supply such services; and

WHEREAS, there is currently in effect a franchise agreement between the City of Miami and FPL, the terms of which are set forth in City of Miami Ordinance No. 9472, passed and adopted September 9, 1982, and FPL's written acceptance thereof dated October 7, 1982 granting to FPL, its successors and assigns, a thirty (30) year electric franchise ("Current Franchise Agreement"); and

WHEREAS, FPL and the City of Miami desire to enter into a new agreement (New Franchise Agreement) providing for the payment of fees to the City of Miami in exchange for the nonexclusive right and privilege of supplying electricity and other services within the City of Miami free of competition from the City of Miami, pursuant to certain terms and conditions; and

WHEREAS, the City Commission of the City of Miami deems it to be in the best interest of the City of Miami and its citizens to enter into the New Franchise Agreement prior to expiration of the Current Franchise Agreement;

NOW, THEREFORE, BE IT ORDAINED BY THE CITY COMMISSION OF THE CITY OF MIAMI, FLORIDA:

Each "WHEREAS" clause set forth above is true and correct and herein incorporated in this Ordinance by this reference.

DEFINITIONS

As used in this New Franchise Agreement, the following words and terms shall have the following meanings:

City shall mean the City of Miami, Florida, a municipal corporation organized and existing under the laws of the State of Florida and also the Grantor for purposes of this Franchise.

City Commission shall mean the local legislative body of the City of Miami. The City Commission is the body that approves City Franchises.

File # 10-00179

customers, (c) shall not require the relocation of any of the Grantee's facilities installed before or after the effective date hereof in public rights-of-way unless or until widening or otherwise changing the configuration of the paved portion of any public right-of-way used by motor vehicles causes such installed facilities to unreasonably interfere with Traffic. Such rules and regulations shall recognize that above-grade facilities of the Grantee installed after the effective date hereof should be installed near the outer boundaries of the public rights-of-way to the extent possible and practicable. When any portion of a public right-of-way is excavated by the Grantee in the location or relocation of any of its facilities, the portion of the public right-of-way so excavated shall within a reasonable time be replaced by the Grantee at its expense and in as good condition as it was at the time of such excavation. The Grantor shall not be liable to the Grantee for any cost or expense in connection with any relocation of the Grantee's facilities required under subsection (c) of this Section, except, however, the Grantee shall be entitled to reimbursement of its costs from others, excluding the City of Miami, and as is provided by law.

Section 3. Indemnification of Grantor. The Grantor shall in no way be liable or responsible for any accident or damage that may occur in the construction, operation or maintenance by the Grantee of its facilities hereunder, regardless of other easement agreements that may be or have been executed by the parties to this Franchise without hold harmless and indemnification provisions, and the acceptance of this ordinance shall be deemed an agreement on the part of the Grantee to indemnify and defend the Grantor and hold the Grantor, its officials, employees and assigns, harmless against any and all liability, loss, cost, damage, judgment, decree, action, cause of action, claim, or expense which may accrue to the Grantor by reason of the negligence, default, omission, or misconduct of the Grantee in the installation, removal, relocation, sub-lease, construction, operation or maintenance of its Facilities.

Section 4. Rates, Rules and Regulations of Grantee. All rates and rules and regulations established by the Grantee from time to time shall be subject to regulation as may be provided by law.

Section 5(a). Franchise Fee; Calculation; Payment. As a consideration for this Franchise, the Grantee shall pay to the Grantor the following amounts: (a) commencing 90 days after the effective date hereof, and each month thereafter for the remainder of the term of this Franchise, the Grantee shall pay an amount which added to the amount of all licenses, excises, fees, charges and other impositions of any kind whatsoever, except ad valorem property taxes and non-ad valorem tax assessments on property, levied or imposed by the Grantor against the Grantee's property, business, facilities, or operations and those of its subsidiaries during the Grantee's monthly billing period ending 60 days prior to each such payment will equal six (6%) percent of the Grantee's billed revenues, less actual write-offs, from the sale of electrical energy to residential, commercial and industrial customers (as such customers are defined by FPL's tariff) within the incorporated areas of the Grantor for the monthly billing period ending 60 days prior to each such payment and in no event shall payments for the rights and privileges granted herein exceed six (6%) percent of such revenues for any monthly billing period of Grantee. For purposes of this section, the term "write-offs" refers to uncollectable billed revenues from the sale of electrical energy to residential, commercial, and industrial customers within the incorporated areas of Grantor. For the term of this franchise, Grantor waives construction permit fees for facilities which otherwise would be imposed on Grantee by the Grantor.

The Grantor understands and agrees that such revenues as described in the preceding paragraph are limited to the precise revenues described therein, and that such revenues do not include, by way of example and not limited to: (a) revenues from the sale of electrical energy for Public Street and Highway Lighting (service for lighting public ways and areas); (b) revenues from Other Sales to Public Authorities (service with eligibility restricted to governmental entities); (c) revenues from Sales to Railroads and Railways (service supplied for propulsion of electric transit vehicles); (d) revenues from Sales for Resale (service to other utilities for resale purposes); (e) franchise fees; (f) Late Payment

Section 7. Competitive Disadvantage; Grantee's Rights. If the Grantor grants a right, privilege or franchise to any other person or otherwise enables any other such person to construct, operate or maintain electric light and power facilities within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve or compete on terms and conditions which the Grantee reasonably determines are more favorable than the terms and conditions contained herein, the Grantee may at any time thereafter terminate this franchise if such terms and conditions are not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 90 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of such terms and conditions that it considers more favorable and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the terms and conditions complained of by the Grantee. If the Grantee reasonably determines that such terms or conditions are not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall be effective on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination of competitive disadvantage leading to termination under this Section 7.

Section 8. Legislative or Regulatory Action. If as a direct or indirect consequence of any legislative, regulatory or other action by the United States of America or the State of Florida (or any department, agency, authority, instrumentality or political subdivision of either of them) any person is permitted to provide electric service within the incorporated areas of the Grantor to a customer then being served by the Grantee, or to any new applicant for electric service within any part of the incorporated areas of the Grantor in which the Grantee may lawfully serve, and the Grantee reasonably determines that its obligations hereunder, or otherwise resulting from this franchise in respect to rates and service, place it at a competitive disadvantage with respect to such other person, the Grantee may, at any time after the taking of such action, terminate this franchise if such competitive disadvantage is not remedied within the time period provided hereafter. The Grantee shall give the Grantor at least 90 days advance written notice of its intent to terminate. Such notice shall, without prejudice to any of the rights reserved for the Grantee herein, advise the Grantor of the consequences of such action which resulted in the competitive disadvantage and the objective basis or bases of the claimed competitive disadvantage. The Grantor shall then have 90 days in which to correct or otherwise remedy the competitive disadvantage. If such competitive disadvantage is, in the reasonable determination of Grantee, not remedied by the Grantor within said time period, the Grantee may terminate this franchise agreement by delivering written notice to the Grantor's Clerk and termination shall take effect on the date of delivery of such notice. Nothing contained herein shall be construed as constraining Grantor's rights to legally challenge at any time Grantee's determination of competitive disadvantage leading to termination under this Section 8.

Section 9. Grantee's Failure to Comply. Failure on the part of the Grantee to comply in any substantial respect with any of the provisions of this franchise shall be grounds for forfeiture, but no such forfeiture shall take effect if the reasonableness or propriety thereof is protested by the Grantee, until there is final determination (after the expiration or exhaustion of all rights of appeal) by a court of competent jurisdiction within Miami-Dade County, Florida that the Grantee has failed to comply in a substantial respect with any of the provisions of this franchise, and the Grantee shall have six months after such final determination to make good the default before a forfeiture shall result with the right of the Grantor at its discretion to grant such additional time to the Grantee for compliance as necessities in the case require. Venue in any proceedings involving a civil action or actions between the parties under the terms of this Franchise shall be with courts of competent jurisdiction located within Miami-Dade County, Florida.

Section 10. Grantor's Failure to Comply. Failure on the part of the Grantor to comply in substantial

Section 14. Previous Franchise. Ordinance No. 9472 passed and adopted September 9, 1982 is hereby repealed, and all ordinances and parts of ordinances in conflict herewith are hereby superseded to the extent of any such conflict.

Section 15. Effective Date. As a condition precedent to the taking effect of this ordinance, the Grantee shall file its acceptance hereof with the Grantor's Clerk within 30 days of adoption of this ordinance. The effective date of this ordinance shall be the date upon which the Grantee files such acceptance. {1}

Section 16. Notice. For the present, the parties designate the following as the respective places for giving of notice, to-wit:

CITY OF MIAMI GRANTOR
c/o City Manager
3500 Pan American Drive
Miami, Florida, 33133

FPL GRANTEE
c/o Vice-President
External Affairs
700 Universe Blvd.
Juno Beach, FL 33408

Section 17. Compliance with Federal, State and Local Laws. FPL understands that agreements between private entities and local governments are subject to certain laws and regulations, including laws pertaining to public records, conflict of interest, and recordkeeping. City and FPL agrees to comply with and observe all applicable Federal, State and local laws, rules, regulations, Codes and Ordinances, as they may be amended from time to time.

Section 18. Nondiscrimination. FPL represents and warrants to the City that FPL does not and will not engage in discriminatory practices and that there shall be no discrimination in connection with FPL's performance under this Franchise on account of race, color, sex, religion, age, handicap, marital status or national origin. FPL further covenants that no otherwise qualified individual shall, solely by reason of his/her race, color, sex, religion, age, handicap, marital status or national origin, be excluded from participation in, be denied services, or be subject to discrimination under any provision of this Franchise.

Section 19. Governing laws. This Agreement shall be governed by applicable laws of the Federal Government, State of Florida, Miami-Dade County and the Codes and Ordinances of the City of Miami.

Section 20. No Rights to City's Employment Benefits. Grantee shall not attain, nor be entitled to, any rights or benefits under the Civil Service or Pension Ordinances of the Grantor, nor any rights generally afforded classified or unclassified employees. Grantee further understands that Florida Workers' Compensation benefits available to employees of the Grantor are not available to Grantee's employees or agents.

Section 21. Entire Agreement. This Franchise Agreement and its attachments constitute the sole and only AGREEMENT of the parties relating to the subject matter hereof and correctly sets forth the rights, duties, and obligations of each of the other as of its date. Any prior Agreements, promises, negotiations, or representations not expressly set forth in this Agreement are of no force or effect. Both parties were represented by counsel with regard to this Agreement.

Section 22. Modification. It is further understood that no modification, amendment or alteration in the

FEED IN TARIFF SOLAR ENERGY PURCHASE AGREEMENT

Seller Name: _____

Seller Address: _____

Facility Location _____

This Solar Energy Purchase Agreement ("SEPA" or "Agreement") is made by and between _____ ("Seller") and the City of Gainesville, Florida, a municipal corporation d/b/a Gainesville Regional Utilities ("Buyer") with its principal place of business at 301 SE 4th Ave, Gainesville, FL. Seller and Buyer may hereinafter be referred to individually as "Party" and collectively as "Parties"

WHEREAS, Buyer seeks to purchase solar electric energy together with the "Environmental Attributes" (which term is defined herein below in Paragraph 2.1) associated with it, and

WHEREAS, Seller seeks to develop, design, construct, own and operate a solar electric generating facility with an expected combined nameplate capacity of approximately

_____ **Kilowatts (direct current rating –DC)**

which is further described hereinafter below as "Facility" or "Facilities", and

WHEREAS, the scale and design of the Facility or Facilities is accommodated by the Buyer's current criteria and policies for interconnection and purchase of solar power by means of a "Feed In Tariff" as defined and legislated by City of Gainesville in Appendix A of Section 27, City of Gainesville's Code of Ordinances, and

WHEREAS, Seller seeks to sell 100% of the net output of the Facilities as alternating current (AC) electricity at standard voltage and frequency, further defined below as Solar Energy, to Buyer, and Buyer has accepted Seller's offer in accordance with the terms and conditions set forth in this SEPA, and

NOW THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following

ARTICLE 1 – DEFINITION OF MILESTONES

- 1.1 “Completion Date” is October 31, 2013 for roof mounted and December 31, 2013 for ground mounted
- 1.2 “Termination Date” is December 31, 2033

ARTICLE 2 – DEFINITIONS

- 2.1 “**Environmental Attributes**” means any and all regulatory credit or market value accrued as the result of generating solar energy, including but not limited to renewable energy credits (RECs), carbon offsets, SO₂ and NO_x emission offsets, and any other environmental benefits, reductions, offsets, allowances, certificates, or green tags resulting from the generation of Solar Energy or the avoidance of the emissions of any gas, chemical or other substance to the air attributable to the electricity generated by the Facility (defined below). For the avoidance of doubt, “Environmental Attributes” exclude (i) any local, state or federal production or investment tax credit, depreciation deductions or other tax consideration providing a tax benefit based on ownership or a security interest in the Facility, or energy production from any portion of the Facility, including any investment tax credit expected to be available to Seller with respect to the Facility, including but not limited to any tax credit available under United States Code Title 26, Subtitle A, Chapter 1, Subchapter A, Part IV, Subpart E, Section 48 (*Energy Credits*), as amended; and (ii) depreciation deductions and benefits, and other tax benefits arising from ownership or operation of the Facility unrelated to its status as a generator of renewable or environmentally clean energy.
- 2.2 “**Facility**” or “**Facilities**” means Seller’s solar electric generating equipment which produces solar energy subject to this SEPA, each of which delivers such electricity to the Buyer at a single Point of Interconnection (defined below) Each Facility will include equipment or other tangible assets necessary for the operation and maintenance of the Facility, including but not limited to solar modules, mounting systems, wiring harnesses, conduits, inverters, transformers, breakers, lightning protection, and grounding apparatus, together with any easements or leases Seller needs for the construction operation and maintenance of the Facility and the delivery of Solar Energy to the Point of Interconnection Any Facility covered by this SEPA will be owned by Seller and will be operated and maintained by Seller at Seller’s sole cost and expense, for Seller’s benefit as legal and beneficial owner of the Facility.
- 2.3 “**Interconnection Agreement**” is defined as the agreements between the Buyer and Seller setting forth the terms and conditions under which Seller’s Facilities are Interconnected with the Buyer’s, as attached here as Attachment A to the SEPA, which by this reference is incorporated herein
- 2.4 “**Point of Interconnection**” is defined as the point at which the ownership of electric facilities and/or equipment transitions from Buyer to Seller.
- 2.5 “**Solar Energy**” means the energy produced by the Facility from the conversion of sunlight to electricity The devices that perform this conversion produce direct current (DC) voltage which then must be transformed to alternating current (AC) synchronized to the Buyer’s frequency and voltage at the Point of Interconnection Revenue metering and payment is based on AC kilowatt-hours System capacity is measured in DC watts.

ARTICLE 3 – GENERAL PROVISIONS

- 3.1 Disclaimer.** Should any section in this SEPA be in conflict with The City of Gainesville's Code of Ordinances, the Code of Ordinances shall prevail
- 3.2 Applicability.** This SEPA shall only apply to Facilities approved pursuant to Attachment A that are to be installed by Seller at the aforementioned "Facilities Address" for the express purpose of selling 100% of the net Solar Energy output of the Facility to the Buyer. Attachment A describes the approved Facilities covered under this SEPA
- 3.3 Interconnection Requirements.** Notwithstanding any other provision of this SEPA, Buyer shall have no obligation to purchase Solar Energy from any Facility until and unless Seller is in compliance with the approved interconnection requirements for the Facility. If any conflict arises between any portion of this SEPA and the requirements of Attachment A, Attachment A shall take precedence. Disconnection of any Facility from the Buyer's electric system for any contractual, operational or safety reason, shall not obligate the Buyer to replace any revenues thus lost by the Seller
- 3.4 Metering.** Seller shall, at Seller's sole cost and expense, provide and install the meter socket approved by the Buyer. Except as provided under Section 4.2 of Attachment A, the Buyer shall provide a revenue meter to be read by the Buyer at approximately monthly intervals for determination of payment due to Seller. Seller will incur a monthly service administrative charge as imposed by the City of Gainesville in Appendix A of Section 27, City of Gainesville Code of Ordinances, and the charge will be deducted from Seller's monthly payment received from Buyer for kilowatt-hours ("kWh") of solar energy that are produced and delivered to the revenue meter at point of interconnection. Any request by Seller to test the metering accuracy shall be conducted at Seller's cost pursuant to Buyer's prevailing rates, practices and policies for testing retail revenue meters
- 3.5 No Electric Supply to the Facility.** The Parties recognize that this SEPA does not provide for the supply of any electric service by Buyer to Seller or to Seller's Facility, and Seller must enter into separate arrangements for the supply of electric services to the Facility. Should the Facility need any electric service, Buyer will identify a connection point and Seller shall make the appropriate connection arrangements and shall pay Buyer for power consumed and customer service charges in accordance with the prevailing applicable retail electric rates in Appendix A, City of Gainesville Code of Ordinances
- 3.6 Facility Operation.** Seller shall provide staff to control and operate each Facility in a manner consistent at all times with Attachment A. Personnel employed by Seller capable of starting, operating and stopping the Facilities shall be reachable by telephone, cell phone, or pager at all times
- 3.7 Information Requirement.** Seller shall provide documentation signed by system provider of final total installed cost and installed capacity of the Facility covered by this agreement before any payments for energy are made by the Buyer
- 3.8 Conflict with Business Partners Rate Discount Agreement.** Buyer waives the prohibition contained in any Business Partners Rate Discount Agreement between Seller and Buyer that prohibits Seller from utilizing self-generated electricity. This waiver shall survive the termination of this Agreement
- 3.9 Adherence to FIT Program Rules.** Buyer agrees to abide by all applicable Feed In

Tariff Program rules and guidelines promulgated by the General Manager of Utilities which are in effect on the Effective Date of this Agreement.

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ARTICLE 4 – TERM OF AGREEMENT

The Term hereof shall begin on the Effective Date, when SEPA is executed by Buyer and shall, unless sooner terminated or amended as provided herein, end on the Termination date as designated in Article 1. Seller may terminate this agreement at any time and is under no obligation to produce Solar Energy. In the event that this SEPA is terminated, Seller may continue to self-generate electricity but may not interconnect with the Buyer's distribution system until a replacement interconnection agreement is executed. Upon execution of the replacement interconnection agreement, Seller shall be allowed to deliver energy to the Buyer in accord with the prevailing policies of the Buyer at that time.

ARTICLE 5 – SALE AND PURCHASE OF SOLAR ENERGY

- 5.1 **Sale and Purchase Obligation.** During the Term and subject to the provisions of this SEPA, Seller shall sell and deliver or cause to be delivered, and Buyer shall purchase and receive or cause to be received, one hundred percent (100%) of the net Solar Energy and Environmental Attributes generated by the Facility.
- 5.2 **Solar Fuel Exclusivity.** No energy from a fuel source other than solar shall be generated, distributed or transmitted from this Facility.
- 5.3 **Solar Energy Price.** Buyer shall pay Seller for each kilowatt hour ("kWh") of solar energy that is actually produced and delivered by Seller to the Point of Interconnection, inclusive of the associated Renewable Energy Credits, at the following rates:
- Tier one \$0.21/kWh 10 kW or less rooftop
 - Tier one \$0.21/kWh 10 kW or less ground mount
 - Tier two \$0.18/kWh greater than 10 kW up to 300 kW rooftop
 - Tier two \$0.18/kWh greater than 10 kW up to 25 kW ground mount
 - Tier three \$0.15/kWh greater than 25 kW ground mount

as required by the City of Gainesville. Should the rate in this section be in conflict with the rate in Appendix A of Section 27, City of Gainesville's Code of Ordinances, the Code of Ordinances shall prevail. Further, should any term in this SEPA conflict with the City of Gainesville Code of Ordinances, the Code of Ordinances shall prevail.

- 5.4 **Taxes and Fees.** Seller shall have sole responsibility for paying any taxes or fees applicable to the Facility or from the sale of Solar Energy to the Buyer. Seller is subject to all applicable fees and charges set forth in Appendix A of Section 27, City of Gainesville Code of Ordinances. These fees include a monthly service administrative charge deducted from Seller's monthly payment received from Buyer for solar energy; a one-time capacity reservation deposit as applicable based on system size which is refundable if the facility is completed in accordance with the terms of this Agreement and if not otherwise used to pay for GRU system upgrades, and a one-time non-refundable application processing fee as applicable based on system size.

ARTICLE 6 – BILLING AND PAYMENT

- 6.1 **Records, Invoices, and Payments.** Each Facility shall be treated as a unique account in the Buyer's accounting system which shall record the amount of Solar Energy delivered by Seller and which will produce the invoice of payment due from the Buyer. The meter at the Point of Interconnection of each Facility shall be read as part of the Buyer's normal meter reading procedures, which is approximately once a month. The kilowatt-hours delivered to the Buyer shall then be recompensed to Seller on a monthly basis. All documents received or created by the Buyer shall be subject to disclosure under the

Public Records Law of Florida as may be amended from time to time

- 6.2 **Billing Disputes.** *Either Party may dispute invoiced amounts, but shall pay to the other Party the undisputed portion of invoiced amounts on or before the invoice due date. To resolve any billing dispute, the Parties shall use the procedures set forth in Section 9.2. When a billing dispute is resolved, the Party owing shall pay within thirty (30) Business Days of the date of such resolution, with late payment interest charges calculated at 0.016% compounded daily.*

ARTICLE 7 – SUCCESSORS AND ASSIGNS

- 7.1 **Assignment by Seller** This Agreement shall be freely assignable by Seller to any third party upon written notice of such assignment to Buyer within 10 days of the assignment, which notice contains complete contact information regarding the assignee and is accompanied by Buyer's Assignment Form(s); and, provided said third party qualifies by owning and operating a Solar Electric Generating Facility which qualifies under Buyer's criteria and policies for interconnection and purchase of solar power by means of a "Feed In Tariff" as provided under applicable ordinances of the City of Gainesville at the time of said Assignment; the assignee executes a written undertaking acceptable in form to Buyer by which assignee is bound to all the terms and conditions of this Agreement; and further provided, that Seller may collaterally assign its interest in this Agreement to any lender or any financial institution or institutions participating in the financing of the Facility, provided, however, Seller shall remain fully responsible according to this Agreement for all of its obligations and liabilities hereunder. No such assignment shall alter or impair the rights of any surety.
- 7.2 **Assignment by Buyer.** This Agreement shall not be assigned by Buyer without the prior written consent of Seller, which shall not be unreasonably withheld or delayed.
- 7.3 **Successors and Assigns** This Agreement shall bind and inure to the benefit of the parties to this Agreement and any successor or assignee acquiring an interest hereunder consistent with Sections 7.1 and 7.2 hereof.

ARTICLE 8 – EVENTS OF DEFAULT

Failure of Seller to satisfy and comply with all of the terms, provisions and conditions set forth in this Agreement, which failure continues beyond 30 days after receiving written notice of the failure, shall be an event of default. Failure of this Facility to stay in compliance with the requirements of Attachment A shall be an event of default and may result in the Buyer disconnecting this Facility from the electric system. Should Seller participate in any form of current diversion or theft of electricity from the Buyer, such act will be considered an event of default. Upon an event of default by Seller and upon the expiration of any cure or notice period required by this Agreement, Buyer may:

- (1) Terminate this Agreement, and
- (2) Recover from Seller the damages Buyer incurred as a direct result of the event of default; and
- (3) Except as may be limited under the terms of this SEPA, exercise any other remedy Buyer may have at law or equity.

ARTICLE 9 – CONTRACT ADMINISTRATION AND NOTICES

9.1 **Notices in Writing.** Except as provided below, notices required by this SEPA shall be addressed to the other Party at the addresses noted below.

Seller. _____

Buyer. Assistant General Manager/Customer Support Services
P.O Box 147117 Station A118
Gainesville, Florida 32614-7117
Phone 352-393-1035
Fax 352-334-3498

For the purpose of making emergency or other communications relating to the operation of the Facility under the provisions of this Agreement, the Parties designate the following for said notification.

Emergency Contact _____

Phone Numbers Office/Home _____

Cell _____

Address: _____

Buyer Assistant General Manager/Energy Delivery
P O Box 147117 Station A126
Gainesville, Florida 32614-7117
Phone 352-393-1513
Fax 352-334-2784

9.2 **Dispute Resolution.** In the event of any dispute arising under this SEPA (a "Dispute"), within ten (10) business days following the delivered date of a written request by either Party (a "Dispute Notice"), the Parties' authorized representatives shall meet, negotiate and attempt in good faith to resolve the Dispute quickly, informally and inexpensively. In the event the authorized representatives cannot resolve the Dispute within thirty (30) business days after commencement of negotiations, within ten (10) business days following any request by either Party at any time thereafter, each authorized representative (i) shall independently prepare a written summary of the Dispute describing the issues and claims, (ii) shall exchange its summary with the summary of the Dispute prepared by the other authorized representative, and (iii) shall submit a copy of both summaries to a senior officer of the respective Parties with authority to irrevocably bind the Party to a resolution of the Dispute. Promptly upon receipt of the Dispute summaries, the senior officers for both Parties shall negotiate in good faith to resolve the Dispute. If the Parties are unable to resolve the Dispute within fourteen (14) business days following receipt of the Dispute summaries by the senior officers, either Party may seek available legal remedies. Notwithstanding any provision in this SEPA to the contrary, if no Dispute Notice has been issued within four (4) months following the occurrence of all events and the existence of all circumstances giving rise to the Dispute (regardless of the knowledge or potential knowledge of either Party of such events and circumstances), the Dispute and all claims related thereto shall be deemed waived and the aggrieved Party shall thereafter be barred from proceeding thereon.

ARTICLE 10 -SELLER INSURANCE REQUIREMENTS

- 10.1 Coverage.** Seller and/or property owner shall maintain in full force and effect, general liability insurance for personal injury and property damage of at least \$200,000 per occurrence per Facility identified on page one of this agreement. A home owner, system owner or business owner's policy that provides at least this level of coverage is acceptable for meeting the insurance requirement of this Agreement. Buyer shall be named as an "additional interest" or an interested party on the insurance policy, since Buyer has an interest in being notified whenever a policy cancels or has a major change made to it.
- 10.2 Certificate of Insurance.** Seller shall provide a Certificate of Insurance documenting the required coverage as set forth above in Article 10.1 to Buyer and the Certificate of Insurance, including all updated or modified Certificates of Insurance shall become a part of this Agreement. Automatic notification to Buyer must be established for both annual renewals and, if appropriate, any termination of such insurance. In the event that Seller fails to maintain the insurance coverage required in accordance with this Agreement, Buyer has the right to immediately terminate this Agreement, immediately terminate the Facility interconnection and require Seller to permanently disconnect the Facility from the distribution system.

ARTICLE 11 - INDEMNIFICATION

Seller shall indemnify, hold harmless and defend the City of Gainesville, Buyer, its officers and employees from and against any and all liability, proceedings, suits, cost or expense for loss, damage or injury to persons or property, including the Facility, in any manner directly or indirectly connected with, or growing out of the installation, operation or maintenance of Seller's Facility, except in those cases where loss occurs due solely to the negligent actions of Buyer.

ARTICLE 12 - TERMINATION OF AGREEMENT

- 12.1 Completion.** This SEPA will terminate automatically if Seller's Facility as described in Exhibit I is not fully completed and operational by the Completion Date defined above in Article 1, unless an extension has been granted in writing by the Buyer. A single extension may be granted by Buyer if the Facility is substantially, but not fully, completed by the Completion Date. The Facility will be deemed substantially completed if sixty-five percent (65%) or more, by cost, of total budgeted equipment for this Facility has been installed on site by the Completion Date and a current year's SEPA has already been executed by both Parties.
- 12.2 Failure to Insure.** In the event that Seller fails to maintain the insurance coverage required by this Agreement, Buyer shall have the right to immediately terminate this Agreement.
- 12.3 Audit/Disconnection.** Buyer may perform periodic audits and testing of the Facility at such intervals as it may deem proper. In the event that Buyer has, pursuant to the provisions of this Agreement (including but not limited to 6.1 of Attachment A hereto) disconnected the Facility, Buyer shall provide written notice thereof as soon as practicable to Seller of the issue or deficiency causing Buyer to disconnect the Facility. If after thirty (30) calendar days from the receipt of the aforementioned notice, the issue which caused the disconnection is not remedied to Buyer's satisfaction, Buyer may terminate this Agreement and provide written notification to Seller to that effect. Once this Agreement has been terminated, Seller may be required to submit a new Application and adhere to the then current process for Facility interconnection.

- 12.4 Right to Lock Out.** Upon termination of this SEPA for any reason, Buyer may padlock the manual disconnect switch in the open (disconnected) position and may modify or remove any Buyer installed equipment.
- 12.5 Supplementary Rights.** The rights described in this section are supplementary to any rights Buyer may have in law or equity arising out of any violation of the terms of this Agreement.
- 12.6** Engineering design changes are permitted as long as the installed capacity is not materially increased more than 5%. A material change in the design or capacity exceeding 5% will result in the SEPA being voided and forfeiture of the capacity allocation and capacity reservation charge.

ARTICLE 13 – NO THIRD PARTY BENEFICIARIES

Nothing in this SEPA confers, is intended to confer, or shall be deemed to confer upon any party other than the Parties hereto and their permitted successors and assigns any rights, remedies, obligations, or liabilities under or by reason of this SEPA except as expressly provided in this SEPA

ARTICLE 14 - COMPLETE AGREEMENT; AMENDMENTS

The terms and provisions contained in this SEPA constitute the entire agreement between Buyer and Seller and supersedes any prior agreement between the Parties regarding the subject matter hereof. No amendment to this SEPA shall be effective unless in writing and signed by both Parties hereto.

ARTICLE 15 – CONTROLLING LAW; VENUE

The validity, performance, and all matters relating to the interpretation and effect of this SEPA shall be governed by the laws of the State of Florida and the venue for any dispute shall be Alachua County, Florida.

IN WITNESS WHEREOF, the Parties have executed this SEPA

Seller

Name of Company (if applicable)

Signature of Authorized Representative

Print Name

Title

Date

Buyer.

**The City of Gainesville, Florida
d/b/a Gainesville Regional Utilities**

Signature of Authorized Representative

Print Name

Title

Date

Approved as to form and legal sufficiency:

Shayla L. McNeill, Utilities Attorney

ATTACHMENT A

APPROVAL OF FACILITIES FOR INTERCONNECTION AND CONDITIONS FOR OPERATION

This Attachment A constitutes the approval of Seller's facilities for interconnection with Buyer's electric distribution system and conditions required for parallel operation of Seller's distributed generation resource under this SEPA. This approval is required in order to provide interconnection of Seller's facilities under conditions which will insure the safety of Buyer's customers and employees, as well as the reliability and integrity of its distribution system. For the purposes of this Attachment A, the term Distributed Generation Resource ("DGR") shall be interchangeable with the term Facility as used in the SEPA and is defined as any source of electrical energy that is not connected directly to the high voltage electrical transmission system, but typically connected to the medium voltage electrical distribution system. For the purpose of this SEPA the DGR is defined as a solar photovoltaic generation system and any reference to the "distribution system" will mean Buyer's electrical distribution system which the Buyer operates pursuant to authority of its Charter, Ch. 90-394, Laws of Florida, as amended, serving the City of Gainesville and certain unincorporated areas of Alachua County, Florida.

1. SCOPE

This Attachment defines the terms and conditions under which Seller and Buyer agree to interconnect a specific DGR at a specific location on the electric distribution system (both as described in Exhibit I of this Attachment).

2. ESTABLISHMENT OF POINT OF INTERCONNECTION

- 2.1 Buyer will evaluate the capability of the existing distribution system and make an initial determination of the feasibility of interconnecting the DGR. If the initial evaluation is inconclusive a system study may be required to determine the adequacy of the distribution system to interconnect a DGR. Seller is responsible for all costs for the system impact study and Buyer will not approve interconnecting any DGR until the system impact study is completed. Buyer reserves the right to disallow the interconnection of the DGR if in its sole discretion the DGR will adversely impact the Buyer's distribution system.
- 2.2 Determination of the Point of Interconnection is at Buyer's sole discretion. Buyer and Seller agree to interconnect the DGR at the Point of Interconnection in accordance with Buyer's rules, regulations, rates, and tariffs (the "Rules") which are incorporated herein by reference. The interconnection equipment installed by Seller ("Interconnection Facilities") shall be in accordance with the Rules as well.

3. EQUIPMENT AND INSTALLATION STANDARDS

- 3.1. Seller must provide written documentation satisfactory to Buyer that the design specifications of the DGR, including but not limited to, the associated inverter, all connecting wiring and disconnect means, control and protective circuits, meters and any other related equipment adhere to the prevailing versions of the following applicable standards in effect at the time of this Agreement:
- 3.1.1. IEEE Standard 1547, entitled "Interconnecting Distributed Resources with Electric Power Systems"
- 3.1.2. UL Standard 1741, entitled "Standard for Safety for Static Inverters and Charge Controllers for use in Distributed Resources"

- 3.1.3. UL Standard 1703 entitled "Standard for Safety Flat Plate Photovoltaic Modules and Panels
- 3.1.4. IEEE Standard 1262-1995, entitled "Recommended Practice for Qualification of Photovoltaic Modules" or IEC Standard 61646
- 3.1.5. The National Electrical Code.
- 3.2. Seller agrees that the requirements of this Attachment shall be in effect prior to interconnection of any DGR equipment with the distribution system. It is the responsibility of Seller to ensure that this condition is satisfied. If a DGR system (or elements thereof) is found to be interconnected to the distribution system without a fully executed SEPA, Buyer reserves the right to isolate, secure, and lock out of service the DGR system. If such efforts are not practical or effective, Buyer may operate or configure its equipment as necessary to isolate the DGR system from the distribution system
- 3.3. Seller agrees that the installer of the DGR will be a licensed Florida Solar Contractor or Florida Electrical Contractor and will meet at least one of the following conditions to the satisfaction of Buyer.
 - 3.3.1. Possess a solar PV installer certification issued by the North American Board of Certified Energy Practitioners (NABCEP), or
 - 3.3.2. Have completed the course "Installing Photovoltaic Systems" offered by the Florida Solar Energy Center.
- 3.4. Seller shall provide written certification that the installation of the DGR was permitted and inspected by all local building code officials having jurisdiction over the DGR installation. Seller shall also provide written certification that the equipment and installation have met all applicable mechanical and electrical code requirements and has been approved by local code officials for operation. Seller may meet this requirement by attaching a letter from the installation contractor certifying compliance with all equipment and installation standards. A copy of the construction permit shall be forwarded to the Buyer representative identified in Article 9.1 so that it can be attached to this document.
- 3.5. Seller shall provide all materials, labor and equipment necessary to deliver the output of the DGR to the Point of Interconnection. In accordance with Buyer's Energy Delivery Service Guide, Seller shall install, at Seller expense, and within ten (10) feet of the Buyer meter, a dedicated DGR disconnect switch. This device shall be manually operated, lockable, and of the visible load break type to isolate the output of the DGR and any Seller wiring connected to Buyer's distribution system. Seller shall also be responsible for any and all costs to be incurred by Buyer to establish the Point of Interconnection as set forth in Section Two of Exhibit I of this Attachment. Payment is required by Seller prior to execution of such work by Buyer. Upon Completion of the DGR project Seller shall be responsible for any additional distribution system modification cost, if required, to deliver the output of the DGR to the Point of Interconnection not accounted for initially. An additional invoice will be generated and must be paid prior to final interconnection of the DGR. No Facility shall be allowed to deliver energy to Buyer until the cost of interconnection is fully resolved. Any deviation from Buyer's interconnection requirements shall be reviewed and approved in writing by Buyer prior to construction.
 - 3.5.1. The manual disconnect means shall be mounted on the same wall, if practical, but shall be separate from the meter socket, readily accessible to Buyer personnel, and capable of being locked in the open position with a standard Buyer padlock.

- 3.5.2. The disconnect means must be clearly labeled "Auxiliary Generation Disconnect" and be readily visible to GRU personnel. The label shall be permanently riveted to the disconnect device, and shall be made of red, weatherproof, hard plastic, with engraved white block lettering (see Exhibit II)
- 3.6. Buyer shall have the right to open the disconnect means isolating the DGR without prior notice to Seller. To the extent practicable, Buyer will make reasonable attempts to provide prior notice to Seller but assumes no liability if such notice is not given. Buyer shall make reasonable efforts to reconnect the DGR to the distribution system as soon as practical following resolution of the issue that required the disconnection. Seller should take an active interest in ensuring that the DGR is reconnected within a reasonable period of time.
- 3.7. In the event that the DGR manual disconnect switch is opened or the DGR is otherwise isolated from the distribution system for any reason and for any expanse of time, Seller shall not be due any compensation associated with the inability to deliver energy to the distribution system.

4. METERING REQUIREMENTS

- 4.1. Buyer shall solely determine the equipment required to properly and accurately meter the DGR Installation.
- 4.2. Should the nameplate rating of the DGR be 250 kilowatts DC or greater, telemetry and metering equipment shall be installed to provide the Buyer with DGR monitoring and performance data. The required telemetry and metering equipment shall be installed by the Buyer at Seller's expense. Seller shall also be responsible for the recurring communication costs and maintenance costs of the telemetry equipment. Buyer shall be solely responsible for supplying the communications link between the telemetry equipment and the Buyer's systems for monitoring the operation and performance of the DGR. Should the nameplate rating of the DGR be less than 250 kilowatts DC, the installation of telemetry by Seller is optional.
- 4.3. The meter socket and all other required metering equipment (if any) shall be provided by Seller and shall be approved by Buyer in advance of installation.
- 4.4. For self-contained metering applications, the meter socket shall have a clearly legible label reading "Warning electric shock hazard Do not touch terminals Terminals on both the line and load sides may be energized in the open position." The labels shall be made of hard plastic, permanent, weatherproof, colored red with engraved white block lettering (see Exhibit III) and readily visible to Buyer personnel.
- 4.5. An appropriate electric meter shall be provided by Buyer at no cost to Seller, except as provided in Section 4.2 above.

5. INITIAL TESTING, STARTUP AND OPERATION

- 5.1. Initial testing, startup, and operation shall not commence until all construction required by Buyer to establish the point of interconnection is completed and final payments are made, pursuant to Section 3.5 of this Attachment.

- 5.2. Upon execution of this SEPA, receipt of all required DGR documentation, including the final building and electrical inspection by the local codes enforcement personnel and upon request by Seller, an authorized representative of Buyer shall audit the DGR installation to ensure operational and interconnection requirement compliance within five (5) business days. A successful audit and test may result in an immediate interconnection of the DGR if so requested followed by written confirmation of the action taken
 - 5.3. In the event that Buyer determines, in the exercise of its sole discretion as a result of the above mentioned audit, that the DGR is unacceptable for interconnection, Buyer shall provide Seller written notice of the DGR deficiencies including but not limited to safety and/or reliability risks. Such notice shall include a list of all noted DGR equipment or documentation issues that must be remedied. Seller shall be solely responsible for correcting all deficiencies and notifying Buyer of readiness for re-audit and possible interconnection. A failed DGR audit will prevent interconnection until all deficiencies have been remedied.
- 6. BUYER'S RIGHT TO DISCONNECT THE DGR FOR CAUSE**
- 6.1. Buyer shall have the right to disconnect Seller's DGR without notice if Buyer, in the exercise of its sole discretion determines any of the following conditions have occurred, or are occurring:
 - 6.1.1. Adverse electrical effects (such as power quality problems) imposed upon the distribution system and/or the electrical equipment of Buyer's electrical customers attributed to the DGR as determined by Buyer.
 - 6.1.2. Utility system emergencies or maintenance requirements
 - 6.1.3. Hazardous conditions existing on the utility system due to the operation of Seller's DGR generating or protective equipment.
 - 6.1.4. Failure of Seller to comply with applicable federal, state or local law, regulation or rules relating to the operation of the DGR
 - 6.1.5. Buyer's identification of un-inspected or unapproved equipment, or modifications to the DGR after initial approval.
 - 6.1.6. Recurring abnormal operation, substandard operation or inadequate maintenance of DGR
 - 6.2. In the event that Buyer opens the manual disconnect means for routine meter maintenance, system emergencies, or any other operating consideration, other than events or conditions arising out of Seller's operation of the DGR, Buyer shall make reasonable efforts to reconnect Seller generation equipment. This Agreement shall not entitle Seller to any restoration priority over any other of Buyer's customer.

7. DGR OPERATION AND MAINTENANCE REQUIREMENTS

- 7.1. Seller shall operate and maintain the DGR and all associated equipment in accordance with the manufacturer's requirements and all applicable state or local building codes
- 7.2. Seller shall be solely responsible for protecting its generating equipment, inverters, protection devices, and other system components from damage from the normal and abnormal conditions and operations that may occur on the distribution system in delivering or restoring power including temporarily grounding of said system as required for safe work practices.
- 7.3. Seller shall promptly notify Buyer if any modifications, repairs, or component replacements result in a change to the initial configuration, rating, and/or operation of the DGR. Buyer shall have right to audit the DGR prior to its reconnection to the distribution system
- 7.4. Buyer shall have the right to periodically audit the DGR installation to ensure compliance with operational and interconnection requirements
- 7.5. If during the Term of the Agreement the operation of the DGR adversely impacts the distribution system, Seller shall be responsible for any and all costs for Buyer to remedy these impacts if possible including disconnection, as stated in Section 6

EXHIBIT I

LIST OF FACILITIES SCHEDULES AND POINTS OF INTERCONNECTION

DGR Seller will, at its own cost and expense, operate, maintain, repair, and inspect, and shall be fully responsible for its facilities, unless otherwise specified on Exhibit I. The following information is to be specified for each Point of Interconnection, if applicable.

SECTION ONE - Owner Information (to be supplied by applicant)

1. System Owner

Name _____

Address _____

City, State, ZIP _____

Phone _____

Email _____

2. System Installer/Contractor

Name _____

Address _____

City, State, ZIP _____

Phone _____

Email _____

Location of system

Storefront name (if applicable) _____

Address _____

City, State, ZIP _____

Phone _____

3. PV System Specifications

DC Power Rating (Watts) _____ No Phases. _____

AC Power Rating (Watts) _____

4. Three-Line Diagram/System Sketch

Attach diagram for proposed system with all major components, both DC and AC
Diagram must be dated and initialed.

SECTION TWO - Interconnection Requirements *(to be completed by Buyer)*

1. Engineering Review of PV System Information Provided By Seller

- A) Elevation/Riser Diagram with Site Plan & Metering Location _____
 B) 1-line Diagram with Point of Interconnection & Metering Description _____
 C) Panel schedule (on 3-phase installations) _____
 D) Verify Installation does not exceed PV Allocation Size _____

Determination of Point of Interconnection

- A) Summary of required distribution system additions or modifications

B) Cost of additions/modifications above

C) GIS graphic depicting Point of Interconnection (attach)

D) Point of Interconnection detail

Padmount transformer no (if known) _____

Overhead transformer at pole no. (if known) _____

Approved by _____

Date Approval Completed _____

2. Metering Requirements

A) Voltage _____

B) Meter installation description

C) Communication protocol (including Seller's access to data)

D) Summary of required metering Cost and infrastructure

Approved by _____

Date Approval Completed. _____

3. Summary of Required Upgrades and Estimated Costs to Seller

ESTIMATED TOTAL COST \$ _____

4. Supplemental terms and conditions attached (check one): / _____ Yes / _____ No

**SIGNATURES INDICATING ENGINEERING APPROVAL ON THE NEXT PAGE REQUIRED
 BEFORE SEPA CAN BE EXECUTED**

Acknowledged By DGR Seller

Signature _____ Print Name _____ Date _____

Buyer Authorized Representative for Engineering

Signature _____ Print Name _____ Date _____

Buyer Authorized Representative for Measurement and Energy Regulation

Signature _____ Print Name _____ Date _____

Buyer Authorized Representative – Final Approval

Based on the information contained herein, Seller's DGR system will meet the interconnection requirements of the Buyer

Signature _____ Print Name _____ Date: _____

EXHIBIT II
MANUAL DISCONNECT LABEL

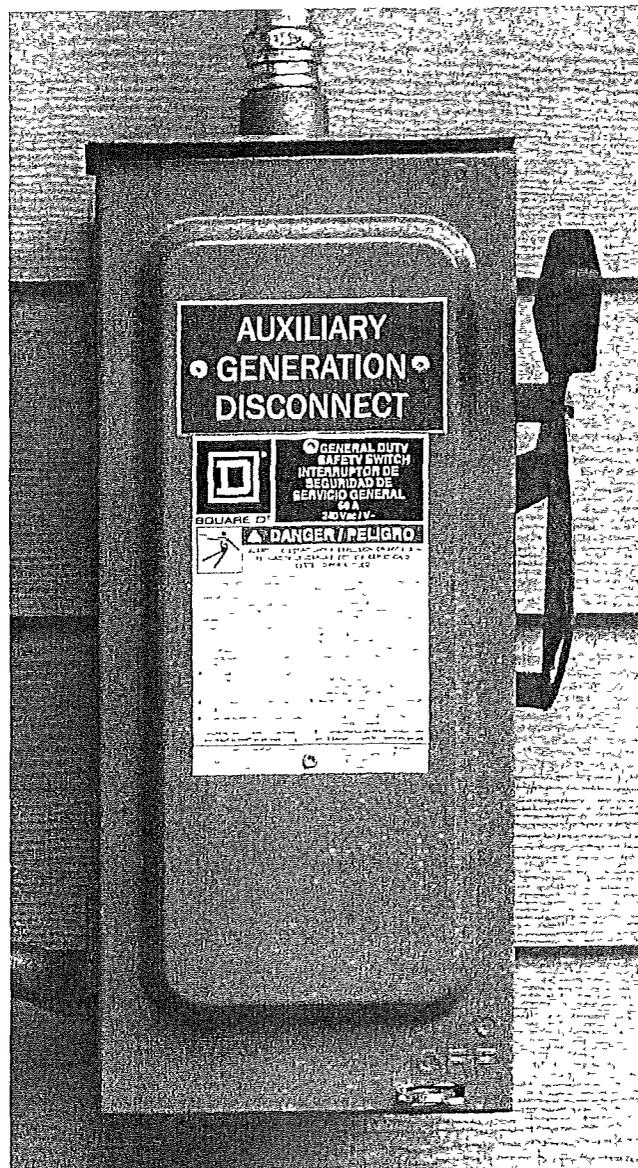


EXHIBIT III
METER LABEL



EXHIBIT IV

SOLAR PHOTOVOLTAIC INSTALLER'S INFORMATION

Please provide names and contact information for all installation contractors and subcontractors. If any of the parties are to be determined at a later date, signify this with "TBD" in the appropriate line.

System designer:

Name: _____
Address: _____
Telephone: _____
Email: _____

Electrical contractor

Name: _____
Address: _____
Telephone: _____
Email: _____

Roofing contractor (if applicable)

Name: _____
Address: _____
Telephone: _____
Email: _____

GAINESVILLE REGIONAL UTILITIES (GRU)
AGREEMENT FOR INTERCONNECTION AND PARALLEL OPERATION
OF DISTRIBUTED GENERATION RESOURCES (DGR)

This **Interconnection Agreement ("Agreement")** is made and entered into this ___ day of _____, 20____, by and between _____ (hereinafter called the Owner/Operator) located at _____ in Gainesville, Florida and the City of Gainesville, a Florida municipal corporation doing business as Gainesville Regional Utilities ("GRU"). Owner/Operator's Account pursuant to this Agreement is GRU Account Number _____

This Agreement constitutes the approval of Owner/Operator's facilities for interconnection with GRU's electric distribution system and sets forth the conditions required for parallel operation of Owner/Operator's distributed generation resource. This approval is required in order to provide interconnection of Owner/Operator's facilities under conditions which will insure the safety of GRU's customers and employees, as well as the reliability and integrity of its distribution system. For purposes of this Agreement, the term Distributed Generation Resource ("DGR") shall be interchangeable with the term "Facility". For purposes of this Agreement, DGR is defined as a solar photovoltaic generation system and any reference to the "distribution system". For purposes of this Agreement, any reference to the "distribution system" will mean GRU's electrical distribution system which GRU operates pursuant to its Charter, as authorized by Chapter 90-394, Laws of Florida, as amended.

1. SCOPE OF AGREEMENT

This Agreement defines the terms and conditions under which GRU and Owner/Operator agree to interconnect a specific DGR of _____ kW DC or less as more particularly described in Attachment A, attached hereto and made a part hereof by reference as if fully set forth herein, at the specific location as stated above and at a standard GRU primary or secondary voltage to the distribution system.

2. ESTABLISHMENT OF POINT OF INTERCONNECTION

- 2.1. The "Point of Interconnection" is defined as the point at which ownership of electric facilities and/or equipment transitions from GRU to Owner/Operator. GRU will evaluate the capability of the existing distribution system and make an initial determination of the feasibility of interconnecting the DGR. If the initial evaluation is inconclusive a system study may be required to determine the adequacy of the distribution system to interconnect a DGR. Owner/Operator is responsible for all costs for the system impact study and GRU will not approve interconnecting any DGR until the system impact study is completed. GRU reserves the right to disallow the interconnection of the DGR if in its sole discretion the DGR will adversely impact GRU's distribution system.
- 2.2. Determination of the Point of Interconnection is at GRU's sole discretion. GRU and Owner/Operator agree to interconnect the DGR at the Point of Interconnection in accordance with GRU's rules, regulations, rates, and tariffs (the "Rules") incorporated herein by reference. The interconnection equipment installed by Owner/Operator ("Interconnection Facilities") shall be consistent with and pursuant to the Rules.

3. EQUIPMENT AND INSTALLATION STANDARDS

- 3.1. Owner/Operator must provide written documentation satisfactory to GRU that the design specifications of the DGR, associated inverter, all connecting wiring and disconnect means, control and protective circuits, meters and any other related equipment adhere to the prevailing versions of the following applicable standards in effect at the time of this Agreement.

3.1.1 IEEE Standard 1547, entitled "Interconnecting Distributed Resources with Electric Power Systems"

- 3 1 2 UL Standard 1741, entitled "Standard for Safety for Static Inverters and Charge Controllers for use in Distributed Resources
 - 3 1 3 UL Standard 1703 entitled "Standard for Safety Flat Plate Photovoltaic Modules and Panels
 - 3 1.4. IEEE Standard 1262-1995, entitled "Recommended Practice for Qualification of Photovoltaic Modules" or IEC Standard 61646
 - 3 1 5 IEEE Standard 929 "Recommended Practice for Utility Interface of Photovoltaic (PV) Systems
 - 3 1 6 and the National Electrical Code
- 3 2 Owner/Operator agrees that the requirements of this Agreement shall be in effect prior to *interconnection of any DGR equipment with the distribution system*. It is the responsibility of Owner/Operator to ensure that this condition is satisfied. If a DGR system (or elements thereof) is found to be interconnected to the distribution system without a fully executed Agreement, GRU reserves the right to isolate, secure, and lock out of service the DGR system. If such efforts are not practical or effective, GRU may operate or configure its equipment as necessary to isolate the DGR system from the distribution system.
- 3 3 Owner/Operator agrees that the installer of the DGR will be a licensed Florida Solar Contractor or Florida Electrical Contractor.
- 3 4 Owner/Operator shall provide written certification that the installation of the DGR was permitted and *inspected by all local building code officials having jurisdiction over the DGR installation*. Owner/Operator shall also provide written certification that the equipment and installation have met all applicable mechanical and electrical code requirements and has been approved by local code officials for operation. Owner/Operator may meet this requirement by attaching a copy of the final electrical permit and a copy of any necessary construction permit(s) shall be forwarded to the GRU representative identified in Section 13 so that it can be attached to this Agreement.
- 3 5 Review of Owner/Operator specifications by GRU shall not be construed as confirming or endorsing the design or any warranty of safety or durability of the DGR.
- 3 6 Owner/Operator shall provide all materials, labor and equipment necessary to deliver the output of the DGR to the *Point of Interconnection*. Pursuant to GRU's Energy Delivery Service Guide, Owner/Operator shall install, at Owner/Operator's sole expense, within ten (10) feet and within site of the GRU revenue meter, a dedicated DGR disconnect switch. This device shall be manually operated, lockable, and of the visible load break type to isolate the output of the DGR and any Owner/Operator wiring connected to GRU's distribution system. Owner/Operator shall also be responsible for any and all costs to be incurred by GRU to establish the Point of Interconnection as set forth in Section Two of Attachment A. Payment is required by Owner/Operator prior to execution of such work by GRU. Upon Completion of the DGR project Owner/Operator shall be responsible for any additional distribution system modification cost, if required, to deliver the output of the DGR to the Point of Interconnection not accounted for initially. An additional invoice will be generated and must be paid prior to final interconnection of the DGR. No Facility shall be allowed to deliver energy to GRU until the cost of interconnection is fully resolved. Any deviation from Owner/Operator interconnection requirements must be reviewed and approved in writing by GRU prior to construction.
- 3.6 1. The manual disconnect means shall be mounted on the same wall as the revenue meter, but shall be separate from the revenue meter socket, readily accessible to GRU personnel, and capable of being locked in the open position with a GRU padlock.

- 3.6.2 The disconnect means must be clearly labeled "**Auxiliary Generation Disconnect**" and be readily visible to GRU personnel. The label shall be permanently riveted to the disconnect device, and shall be red, weatherproof, hard plastic with engraved white block lettering. (see Exhibit 1)¹
- 3.7 The disconnect means shall have an interrupting rating sufficient for the nominal circuit voltage and the current that is available at the line terminals of this equipment
- 3.8 GRU shall have the right to open the disconnect means isolating the DGR without prior notice to Owner/Operator. To the extent practicable, GRU will make reasonable attempts to provide prior notice to Owner/Operator but assumes no liability if such notice is not given. GRU shall make reasonable efforts to reconnect the DGR to the distribution system as soon as practical following resolution of the issue that required the disconnection. Owner/Operator should take an active interest in ensuring that the DGR is reconnected within a reasonable period of time.
- 3.9. In the event the DGR manual disconnect switch is opened or the DGR is otherwise isolated from the distribution system for any reason and for any expanse of time, Owner/Operator shall not be due any compensation associated with the inability to deliver energy to his/her load or to the distribution system.
- 3.10 When the size of the DGR system precludes the use of Owner/Operator's service entrance equipment as the connection point, an alternate disconnect means must be designed and provided by Owner/Operator and approved by GRU before installation.
- 3.11. On both the REC and GRU revenue meter socket covers the labeling shall state "**Warning: Electric Shock Hazard. The terminals on both line and load side may be energized in the open position**" and be readily visible to GRU personnel. The labels shall be permanently riveted to the covers, and shall be made of red, weatherproof, hard plastic with engraved white block lettering (see Exhibit 2)²

4. OWNER/OPERATOR INSURANCE REQUIREMENTS

- 4.1 Owner/Operator shall maintain in full force and effect, general liability insurance for personal injury and property damage of at least \$100,000 per occurrence. Owner/Operator's policy that provides at least this level of coverage is acceptable for meeting the insurance requirements of this Agreement.
- 4.2. Owner/Operator shall provide a Certificate of Insurance to GRU and the certificate shall become a part of the Application. If applicable, automatic notification to GRU must be established for both annual renewals and any termination of such insurance. In the event that Owner/Operator fails to maintain the insurance coverage required by this Agreement, GRU has the right to immediately terminate this Agreement, immediately terminate the DGR interconnection and require Owner/Operator to permanently disconnect the DGR from the distribution system.

5. METERING REQUIREMENTS

- 5.1. GRU shall solely determine the equipment required to properly and accurately meter the DGR Installation.
- 5.2. Should the nameplate rating of the DGR be 250 kilowatts DC or greater, telemetry and metering equipment shall be installed to provide GRU with DGR monitoring and performance data. The required telemetry and metering equipment shall be installed by GRU at Owner/Operator's expense. Owner/Operator shall also be responsible for the recurring communication costs and maintenance costs of the telemetry equipment. If Owner/Operator so chooses, he shall be solely responsible for

¹ GRU Energy Delivery Service Guide

² GRU Energy Delivery Service Guide

supplying the communications link between the telemetry equipment and Owner/Operator's systems for monitoring the operation and performance of the DGR. Should the nameplate rating of the DGR be less than 250 kilowatts DC, the installation of telemetry by Owner/Operator is optional.

- 5.3. The meter socket and all other required metering equipment, if any, shall be provided by Owner/Operator and shall be approved by GRU in advance of installation
- 5.4. For self-contained revenue metering applications, the meter socket shall have a clearly legible label reading **"Warning: electric shock hazard. Do not touch terminals. Terminals on both the line and load sides may be energized in the open position."** The labels shall be made of hard plastic, permanent, weatherproof, colored red with engraved white block lettering and readily visible to GRU personnel (see Exhibit 2)³
- 5.5. An appropriate electric meter(s) shall be provided by GRU at no cost to Owner/Operator, except as provided in Section 5.2 above

6. INITIAL TESTING, STARTUP AND OPERATION

- 6.1 Initial testing, startup, and operation shall not commence until all construction required by GRU to establish the point of interconnection is completed and final payments are made, pursuant to Section 3.6 of this Agreement.
- 6.2. Upon execution of this Agreement, receipt of all required DGR documentation and fees, including the final building and electrical inspection by the local codes enforcement personnel and upon request by Owner/Operator, an authorized representative of GRU shall audit the DGR installation to ensure operational and interconnection requirement compliance. A successful audit and test may result in an immediate interconnection of the DGR
- 6.3 In the event that GRU determines, in the exercise of its sole discretion as a result of the above mentioned audit, that the DGR is unacceptable for interconnection, GRU shall provide Owner/Operator written notice of the DGR deficiencies including but not limited to safety and/or reliability risks. Such notice shall include a list of all noted DGR equipment or documentation issues that must be remedied. Owner/Operator shall be solely responsible for correcting all deficiencies and notifying GRU of readiness for re-audit and possible interconnection. A failed DGR audit will prevent interconnection until all deficiencies have been remedied

7. METERING AND COMPENSATION FOR EXCESS ELECTRIC ENERGY SUPPLIED TO THE GRU ELECTRICAL DISTRIBUTION SYSTEM BY OWNER/OPERATOR DGR

- 7.1. GRU shall solely determine the metering equipment required at Owner/Operator location to measure any excess generation produced by the DGR that is delivered into the distribution system if Owner/Operator desires. For the purposes of this Agreement, excess generation is defined as any kWh of electrical energy produced by the DGR which is not consumed by Owner/Operator's electrical requirements and is delivered to the distribution system. The cost of metering equipment, installation, maintenance, and any recurring or non-recurring costs for reading and billing shall be borne by GRU.
- 7.2 Owner/Operator shall receive a monthly energy credit for all excess kilowatt-hours delivered into the distribution system. If the energy credit exceeds the total electric energy billed amount in any corresponding month, the excess energy credit shall be applied to the subsequent month's billing. An annual true up with conversion to money will be applied at the end of each calendar year using an avoided cost price. GRU reserves the right to develop the annual avoided cost pricing and/or modify its tariff at any time without prior notice to Owner/Operator

³ GRU Energy Delivery Service Guide

- 7.4. In the event that GRU opens the DGR manual disconnect means for any reason for any time period, Owner/Operator agrees that GRU shall have no liability for and shall not pay Owner/Operator for any actual or potential generation that may or could have occurred while the DGR was disconnected from the distribution system.

8. GRU'S RIGHTS TO DISCONNECT THE DGR FOR CAUSE

- 8.1. GRU shall have the right to disconnect Owner/Operator's DGR without notice if GRU, determines any of the following conditions have occurred, or are occurring.
- 8.1.1 Adverse electrical effects (such as power quality problems) imposed upon the distribution system and/or the electrical equipment of GRU's electrical customers attributed to the DGR as determined by GRU.
 - 8.1.2 Utility system emergencies or maintenance requirements.
 - 8.1.3. Hazardous conditions existing on the utility system due to the operation of Owner/Operator's DGR generating or protective equipment.
 - 8.1.4 Failure of Owner/Operator to comply with applicable federal, state or local law, regulation or rules relating to the operation of the DGR.
 - 8.1.5. GRU's identification of un-inspected or unapproved equipment, or modifications to the DGR after initial approval
 - 8.1.6 Recurring abnormal operation, substandard operation or inadequate maintenance of DGR.
- 8.2. In the event that GRU opens the manual disconnect means for routine meter maintenance, system emergencies, or any other operating consideration, other than events or conditions arising out of Owner/Operator's operation of the DGR, GRU shall make reasonable efforts to reconnect Owner/Operator's generation equipment. This Agreement shall not entitle Owner/Operator to any restoration priority over any other of GRU's customers.

9. DGR OPERATION AND MAINTENANCE REQUIREMENTS

- 9.1. Owner/Operator shall operate and maintain the DGR and all associated equipment in accordance with the manufacturer's requirements and all applicable state or local building codes.
- 9.2. Owner/Operator shall be solely responsible for protecting its generating equipment, inverters, protection devices, and other system components from damage from the normal and abnormal conditions and operations that may occur on the distribution system in delivering or restoring power including temporarily grounding of said system as required for safe work practices
- 9.3. Owner/Operator shall promptly notify GRU if any modifications, repairs, or component replacements result in a change to the initial configuration, rating, and/or operation of the DGR. GRU shall have the right to audit the DGR prior to its reconnection to the distribution system
- 9.4. GRU shall have the right to periodically audit the DGR installation to ensure compliance with operational and interconnection requirements
- 9.5 If during this Agreement, the operation of the DGR adversely impacts the distribution system, Owner/Operator shall be responsible for any and all costs for GRU to remedy these impacts if possible including disconnection.

10. RENEWABLE ENERGY CREDITS

- 10.1. A Renewable Energy Credit (REC) represents the environmental attributes of one thousand kWh (1 MWh) of electricity produced by a renewable resource (i.e., solar). A REC is the commodity used by electric providers to account for their participation in renewable energy programs.
- 10.2. Owner/Operator retains all REC's generated by this DGR facility. The REC meter shall be owned and maintained by GRU for the purpose of providing operational data as needed by GRU.

11. OWNER/OPERATOR INDEMNIFICATION OF GRU FOR OPERATION OF DGR

Any fines or other penalties incurred by Owner/Operator for noncompliance with any Laws shall not be reimbursed by GRU but shall be the sole responsibility of Owner/Operator. Owner/Operator shall indemnify, hold harmless and defend the City of Gainesville, GRU, its elected officials and employees from and against any and all liability, proceedings, suits, cost or expense for loss, damage or injury to persons or property, including the Facility, in any manner directly or indirectly connected with, or growing out of the installation, operation or maintenance of Owner/Operator's Facility, except in those cases where loss occurs due solely to the negligent actions of GRU. If Owner/Operator is not a single legal entity, then all such entities comprising Owner/Operator shall be jointly and severally liable for all representations, warranties, obligations, covenants, and liabilities under this Agreement and all other agreements.

12. TERMINATION OF AGREEMENT

- 12.1. In the event that Owner/Operator fails to maintain the insurance coverage required by this Agreement, GRU shall have the right to immediately terminate this Agreement.
- 12.2. GRU may perform periodic inspections and testing of the DGR at such intervals as it may deem proper. In the event that GRU, in the exercise of its sole discretion, determines that the DGR is performing in an abnormal or unsafe manner on a recurring basis, GRU shall have the right to immediately disconnect the DGR and shall provide written notice to Owner/Operator of the issue or deficiency. If after a reasonable time as determined by GRU the issue which caused the disconnection is not remedied to GRU's satisfaction, GRU will terminate this Agreement and provide written notification to Owner/Operator to that effect. Once this Agreement has been terminated, Owner/Operator will be required to submit a new Application and adhere to the then current process for DGR interconnection.
- 12.3. This Agreement is not transferable or assignable. In the event that the DGR located at the above location is sold, leased, or if ownership is transferred to another person or entity without GRU's prior written consent, this Agreement may be terminated.
- 12.4. Upon termination of this Agreement for any reason, GRU may padlock the manual disconnect means in the open position and may modify or remove any GRU installed metering equipment.
- 12.5. The rights described in this section are supplementary to any rights GRU may have in law or equity arising out of any violation of the terms of this Agreement.

13. POWER SALES THROUGH GRU

Interconnection of DGR facilities with GRU's distribution system does not grant Owner/Operator any right to export power to others nor does it constitute an agreement by GRU to wheel excess power.

14. OFFICIAL NOTIFICATION

For the purpose of making emergency or other communication relating to the operation of the DGR under the provisions of this Agreement, the parties designate the following for said notification:

For Owner/Operator: Name: _____
Address: _____
Phone: _____
Email: _____

For Gainesville Regional Utilities:
Rachel D Meek or her successor
Business Efficiency Program Coordinator
Gainesville Regional Utilities
(352) 393-1484
(352) 334-2731 (Fax)
meekrd@gru.com

IN WITNESS WHEREOF, and intending to be legally bound hereby, Owner/Operator and GRU have caused this Agreement to be executed this _____ day of _____, 20_____.

Owner/Operator Individual's Name
or Organization's Title

GAINESVILLE REGIONAL UTILITIES

By: _____
Title: _____
Date _____

By: _____
David Beaulieu or designee
Title: Assistant General Manager Energy Delivery
Date _____

Approved as to Form and Legality:
Shayla L McNeill, on November 30, 2014
City Attorney, Utilities

Attachment A – Section 1

LIST OF FACILITIES SCHEDULES AND POINTS OF INTERCONNECTION

Facility Customer will, at its own cost and expense, operate, maintain, repair, and inspect, and shall be fully responsible for its facilities, unless otherwise specified on this Attachment A. The following information is to be specified for each Point of Interconnection, if applicable.

SECTION ONE - Owner Information (to be supplied by applicant)

1. System Owner

Name. _____
Address. _____
City, State, ZIP _____
Phone. _____
Email _____

2. System Installer/Contractor

Name. _____
Address. _____
City, State, ZIP _____
Phone. _____
Email: _____

3. Location of system

Storefront name (if applicable): _____
Address. _____
City, State, ZIP _____
Phone _____
Email _____

4. PV System Specifications

DC Power Rating (Watts) _____
Number of Phases. _____

Contractor must submit an Electrical One Line Diagram, Mounting Elevation drawing, a Location site plan and a solar panel layout that will be included with this document.

Customer must submit a copy of their Declaration page for their home owner's insurance that will be included with this document.

Attachment A – Section 2

SECTION TWO – Interconnection Requirements *(to be completed by GRU)*

1. Engineering Review of PV System Information Provided By Owner/Operator

- a. Elevation Drawing with Metering Location _____
- b. One-line Diagram with Point of Interconnection & Metering Description _____
- c. Electric Panel schedule (on all installations) _____
- d. Verify Installation does not exceed PV Allocation Size _____
- e. Verify voltage rise concerns do not exist. If it does, take needed action
- f. Verify project does not exceed the PV Saturation Threshold for Circuit
- g. Developer confirmed by email that they reviewed Section 8 of the ED Service Guide and have abided by its contents in their design & drawings
- h. Solar Panel Layout
- i. Location Site Plan

2. Determination of Point of Interconnection

- a. Summary of required distribution system additions or modifications:
- b. Cost estimate of additions/modifications above: \$ _____
- c. GIS graphic depicting Point of Interconnection (see attached map)
- d. Point of Interconnection detail: (Indicate where on GRU system)
 - i. (Circle One) Underground or Overhead transformer no. NNNNN, NN kVA, VVV Voltage
 - ii. Approved by _____ *GRU Engineer*
 - iii. Date Approval Completed: _____

3. Metering Requirements

- a. Voltage _____
- b. Meter installation description
- c. Communication protocol
- d. Summary of required metering infrastructure and costs:
 - i. Approved by. _____ *GRU METERING Engineer*
 - ii. Date Approval Completed: _____

4. Summary of Required Upgrades and Estimated Costs to Owner/Operator

5. ESTIMATED TOTAL COST \$ _____

6. Supplemental terms and conditions attached (check one): _____ Yes / _____ No

SIGNATURES INDICATING ENGINEERING/METERING APPROVAL ON THIS PAGE REQUIRED BEFORE INTERCONNECTION AGREEMENT CAN BE EXECUTED.

Regulatory Assessment Fees

Presentation to the

Financial Impact Estimating Conference



Mark Futrell

Florida Public Service Commission Staff

April 24, 2015

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%



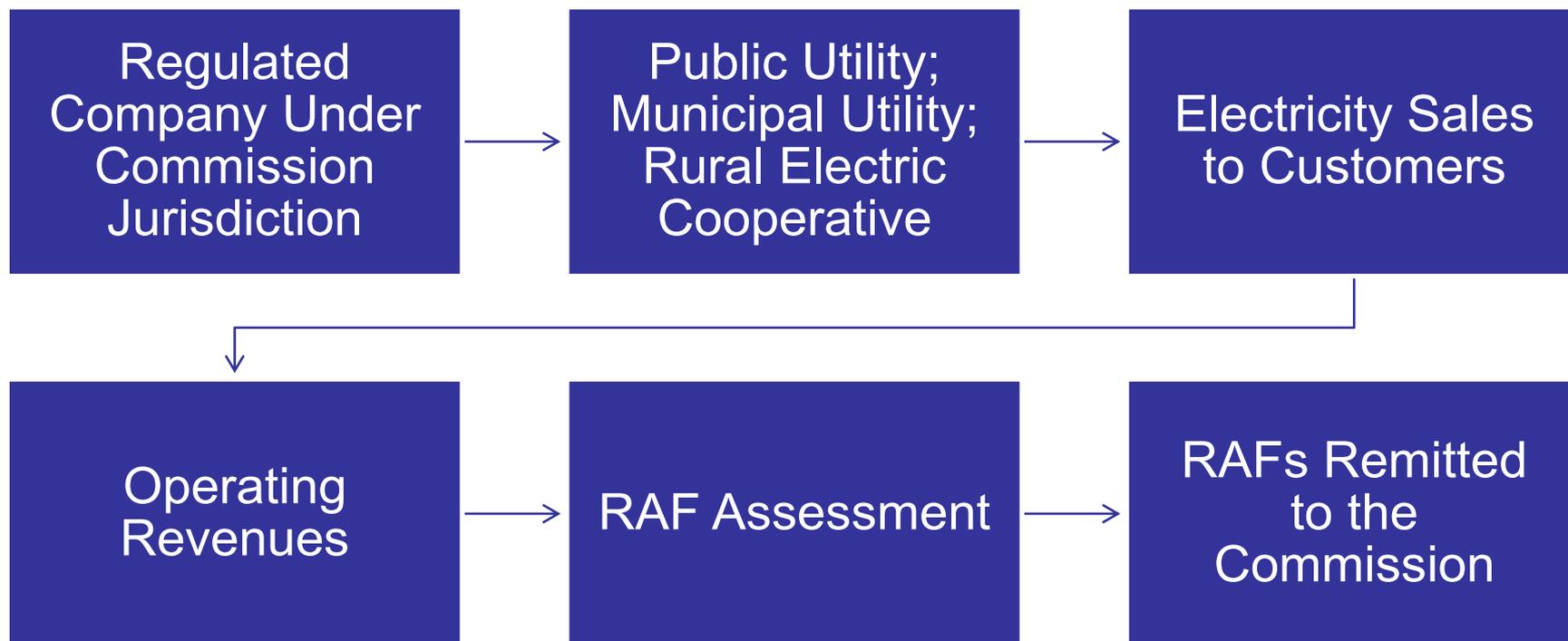
Regulatory Assessment Fees – Electric Utilities

(\$ millions)

Fiscal Year	Investor-Owned Utilities			Municipal and Rural Cooperative Utilities		
	Percentage Rate	RAF Collected	Operating Revenues	Percentage Rate	RAF Collected	Operating Revenues
13/14	0.072%	\$12.4	\$17,267.3	0.015625%	\$0.945	\$6,302.8
12/13	0.072%	\$12.5	\$17,384.0	0.015625%	\$0.962	\$7,769.1
11/12	0.072%	\$12.9	\$17,969.2	0.015625%	\$0.993	\$6,791.7



Regulatory Assessment Fees – Electric Utilities



Public Utility: Entity supplying electricity to or for the public, and subject to the full regulatory authority of the Commission (s. 366.02, F.S.)



Tab 6

Impact

**INITIATIVE FINANCIAL INFORMATION STATEMENT
LIMITS OR PREVENTS BARRIERS TO LOCAL SOLAR ELECTRICITY SUPPLY**

SUMMARY OF INITIATIVE FINANCIAL INFORMATION STATEMENT

[500 WORD SUMMARY]

FINANCIAL IMPACT STATEMENT

[75 WORD SUMMARY]

I. SUBSTANTIVE ANALYSIS

A. Proposed Amendment

Ballot Title:

Limits or Prevents Barriers to Local Solar Electricity Supply

Ballot Summary:

Limits or prevents government and electric utility imposed barriers to supplying local solar electricity. Local solar electricity supply is the non-utility supply of solar generated electricity from a facility rated up to 2 megawatts to customers at the same or contiguous property as the facility. Barriers include government regulation of local solar electricity suppliers' rates, service and territory, and unfavorable electric utility rates, charges, or terms of service imposed on local solar electricity customers.

Text of Proposed Amendment:

The amendment proposes to add Section 29 to Article X as follows:

Purchase and sale of solar electricity. –

(a) PURPOSE AND INTENT. It shall be the policy of the state to encourage and promote local small-scale solar-generated electricity production and to enhance the availability of solar power to customers. This section is intended to accomplish this purpose by limiting and preventing regulatory and economic barriers that discourage the supply of electricity generated from solar energy sources to customers who consume the electricity at the same or a contiguous property as the site of the solar electricity production. Regulatory and economic barriers include rate, service and territory regulations imposed by state or local government on those supplying such local solar electricity, and imposition by electric utilities of special rates, fees, charges, tariffs, or terms and conditions of service on their customers consuming local solar electricity supplied by a third party that are not imposed on their other customers of the same type or class who do not consume local solar electricity.

(b) PURCHASE AND SALE OF LOCAL SMALL-SCALE SOLAR ELECTRICITY.

(1) A local solar electricity supplier, as defined in this section, shall not be subject to state or local government regulation with respect to rates, service, or territory, or be subject to any assignment, reservation, or division of service territory between or among electric utilities.

(2) No electric utility shall impair any customer's purchase or consumption of solar electricity from a local solar electricity supplier through any special rate, charge, tariff, classification, term or condition of service, or utility rule or regulation, that is not also imposed on other customers of the same type or class that do not consume electricity from a local solar electricity supplier.

(3) An electric utility shall not be relieved of its obligation under law to furnish service to any customer within its service territory on the basis that such customer also purchases electricity from a local solar electricity supplier.

(4) Notwithstanding paragraph (1), nothing in this section shall prohibit reasonable health, safety and welfare regulations, including, but not limited to, building codes, electrical codes, safety codes and pollution control regulations, which do not prohibit or have the effect of prohibiting the supply of solar-generated electricity by a local solar electricity supplier as defined in this section.

(c) DEFINITIONS. For the purposes of this section:

(1) "local solar electricity supplier" means any person who supplies electricity generated from a solar electricity generating facility with a maximum rated capacity of no more than 2 megawatts, that converts energy from the sun into thermal or electrical energy, to any other person located on the same property, or on separately owned but contiguous property, where the solar energy generating facility is located.

(2) "person" means any individual, firm, association, joint venture, partnership, estate, trust, business trust, syndicate, fiduciary, corporation, government entity, and any other group or combination.

(3) "electric utility" means every person, corporation, partnership, association, governmental entity, and their lessees, trustees, or receivers, other than a local solar electricity supplier, supplying electricity to ultimate consumers of electricity within this state.

(4) "local government" means any county, municipality, special district, district, authority, or any other subdivision of the state.

(d) ENFORCEMENT AND EFFECTIVE DATE. This amendment shall be effective on January 3, 2017.

Effective Date:

January 3, 2017

B. Effect of Proposed Amendment

The proposed amendment would allow small businesses and individuals to produce and sell solar power to others at the same or contiguous property. The amendment also limits and prevents regulatory and economic barriers that would discourage the supply of electricity generated from solar power at the site where the solar power is produced.

C. Background

Sponsor of the Proposed Amendment

Floridians for Solar Choice, Inc. is the official sponsor of the proposed amendment. The sponsor's website describes the organization as a "grassroots citizens' effort to allow more homes and businesses to generate electricity by harnessing the power of the sun."¹

¹ Floridians for Solar Choice website: <http://www.fl solarchoice.org/>

Public Service Commission (PSC)

The Florida Public Service Commission is an arm of the legislative branch that regulates the electric, natural gas, water and wastewater, and telecommunications industries in the state. The PSC is lead by five commissioners that are appointed by the Governor to four-year terms. The 12-member PSC Nominating Council provides commissioner nominations to the Governor.²

For electric utilities, the commission has economic regulation authority over each “public utility,” which is defined to mean every person or legal entity supplying electricity to or for the public within this state, but to expressly exclude both a rural electric cooperative and a municipality or any agency thereof.³

With respect to electric utilities, the PSC regulates investor-owned electric companies, rates and charges, meter and billing accuracy, electric lines up to the meter, reliability of the electric service, new construction safety code compliance for transmission and distribution, territorial agreements and disputes, and the need for certain power plants and transmission lines. The PSC does not regulate rates and adequacy of services provided by municipally owned and rural cooperative electric utilities, except for safety oversight; electrical wiring inside the customer’s building; taxes on the electric bill; physical placement of transmission and distribution lines; damage claims; right of way; and the physical placement or relocation of utility poles.⁴

Electric Utilities

Pursuant to Chapter 366, F.S., the PSC has regulatory authority over 58 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives.⁵ According to the PSC’s 2012 publication entitled, “Statistics of the Florida Electric Utility Industry”, for each year between 1998 and 2012, of total net capacity statewide, investor-owned utilities had approximately 75% of total megawatts, and municipal and cooperates combined made up the other 25%.

Investor-Owned Electric Utilities

Currently, five investor-owned utilities (i.e., Florida Power and Light Company, Duke Energy Florida, Tampa Electric Company, Gulf Power Company, and Florida Public Utilities Corporation) operate in Florida. The PSC has regulatory authority over all aspects of operations, including rates and safety.⁶

² Chapter 350, Florida Statutes.

³ Section 366.02(1), F.S.

⁴ Florida Public Service Commission, “When to Call the Florida Public Service Commission” available at http://www.psc.state.fl.us/publications/consumer/brochure/When_to_Call_the_PSC.pdf

⁵ Florida Public Service Commission, “Facts and Figures of the Florida Utility Industry” March 2015 available at <http://www.psc.state.fl.us/publications/pdf/general/factsandfigures2015.pdf>

⁶ *Ibid*, p. 10.

Municipal Electric Utilities

According to the PSC, there are 35 generating and non-generating municipal electric utilities in Florida.⁷ According to the Florida Municipal Electric Association, municipal utilities are not-for-profit and are governed by an elected city commission or an appointed or elected utility board. Capital is raised through operating revenues or the sale of tax-exempt bonds.⁸ Together, these utilities serve 15 percent of the state's population.⁹

Rural Electric Cooperatives

Rural electric cooperatives were created as the result of the Rural Electrification Act of 1936. At the time, electric utilities did not provide service in large portions of Florida since the cost of providing such service in the non-urban areas was prohibitive. The investor-owned utilities refused to extend distribution into non-urban areas until there was enough development to make a profit. These cooperatives were formed to make electricity available in rural areas. Today these electric cooperatives are still not-for-profit electric utilities that are owned by the members they serve and provide at-cost electric service to their members. Each cooperative is governed by a board of cooperative members that is elected by the membership. Today, Florida has sixteen distribution cooperatives and two generation and transmission cooperatives that serve 10 percent of the state's population.¹⁰

Solar Energy in Florida

According to the PSC, as of 2013, there are 6,678 customer-owned solar systems in Florida.¹¹ This number has dramatically increased over the past six years, as can be seen in the following table prepared by the PSC. The increase is primarily due to the rapidly decreasing price of solar energy systems and the availability of a variety of new financing options which alleviate substantial up-front costs to customers.

Customer-Owned Solar Generation												
	# of Customer-Owned Solar Systems						kW Gross Power Rating					
	2008	2009	2010	2011	2012	2013	2008	2009	2010	2011	2012	2013
IOU	383	1,045	1,855	2,803	3,799	4,818	1,696	7,653	12,442	19,441	30,401	43,876
Municipal	137	313	493	614	791	1,007	797	3,378	4,099	5,002	7,021	11,787
Rural Electric Cooperative	57	267	461	549	684	853	272	1,955	2,667	3,262	4,099	4,865
TOTAL	577	1,625	2,809	3,966	5,274	6,678	2,765	12,986	19,208	27,705	41,521	60,528

⁷ Ibid, p.11.

⁸ Florida Municipal Electric Association, "Florida Public Power" webpage, available at <http://publicpower.com/floridas-electric-utilities-2/>

⁹ Florida Municipal Electric Association, "Who is FMEA?" webpage, available at <http://publicpower.com/who-is-fmea/>

¹⁰ Florida Electric Cooperatives Association, "About Us" webpage, available at <http://www.feca.com/about.html>

¹¹ PSC Memorandum provided for presentation at April 10, 2015 FIEC Public Workshop

Net Metering

Net metering allows customers with renewable energy systems to pay their utility for only the net energy used. A home or business with a solar energy system may export excess power to the electric grid or import power from the grid, depending on supply and demand of electricity at various times. If a customer produces more electricity than they consume, their utility bill will be credited for that amount.

Third-Party Financing Models

Third-party financing models alleviate the large upfront costs of purchasing and installing solar energy systems, making it more affordable for customers to adopt the use of solar power without the initial capital investment requirements.

Solar Leases

A solar lease is a financial agreement in which a property owner enters into a lease for the installation of a solar energy system. The property owner pays the company for the use and maintenance of the solar equipment, and the solar energy is consumed on the property.

Solar Power Purchase Agreements (PPAs)

A solar power purchase agreement (PPA) is a financial agreement in which a developer installs and finances a solar energy system on a customer's property. The customer then purchases the power generated from the system from the developer at a fixed rate, which is typically lower than the local utility's retail rate. The developer maintains responsibility for the operation and maintenance of the system for the duration of the PPA, which typically ranges from 10 to 25 years.

In the US Department of Energy's 2010 report entitled "Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners", they cite the following court case and ruling related to PPAs in Florida:

"In 1987, the Florida Public Service Commission (FPSC) considered a proposed cogeneration project for which PW Ventures, Inc. (PW Ventures) would have sold electricity from their plant exclusively to Pratt and Whitney (the customer) to provide most of their power needs (PW Ventures v. Nichols, 533 So. 2d 281). Supplementary power needs and emergency backup power would have come from the local utility, Florida Power & Light. The definition of a "Public utility" as defined by Florida Statute 366.02 is:

Every person, corporation, partnership, association, or other legal entity and their lessees, trustees, or receivers supplying electricity or gas...to or for the public within this state.

In their ruling on the issue, the FPSC focused on the definition of "to or for the public." PW Ventures argued that to be considered a utility they would have to sell their power to the general public to be considered a utility. However, the Commission determined that

the definition of “to or for the public” could mean one customer, meaning that by selling only to Pratt and Whitney, PW Ventures was selling to the public and would be deemed a public utility. Without a change in statute, this ruling appears to eliminate the possibility of using the third-party PPA model in Florida without PUC regulation (FPSC 1987).”

Further, in regards to net metering and PPAs, Floridians for Solar Choice, the proponents of the ballot amendment provided the following:

“Currently, a property owner who owns his own solar panels can net meter. A property owner who leases panels from a third party can net meter. These activities are permitted because the property owner is not purchasing solar electricity from a third party, but is instead purchasing or leasing the panels. A property owner who buys solar generated power from a company which has placed solar panels on his or her property cannot net meter.”

State and Local Revenues

Sales Tax

Section 212.08(7)(hh), F.S., provides a sales tax exemption for solar energy systems and any component thereof. Section 212.02(26), F.S., defines “solar energy system” as “the equipment and requisite hardware that provide and are used for collecting, transferring, converting, storing, or using incident solar energy for water heating, space heating, cooling, or other applications that would otherwise require the use of a conventional source of energy such as petroleum products, natural gas, manufactured gas, or electricity.” The Florida Solar Energy Center publishes a comprehensive list of solar energy system components.

Section 212.05, F.S., levies a 4.35 percent tax on the sale of electrical services to nonresidential tax base.

Gross Receipts Tax

Pursuant to ch. 203, F.S., Gross Receipts Taxes are imposed on sellers of electricity and natural or manufactured gas at a rate of 2.5 percent and on the sale of communications services at a rate of 2.52 percent. A firm’s electricity sales tax base has levied against it a 2.6 percent gross receipts base and a reciprocal 2.65 percent drop in the sales tax rate on electricity.

The gross receipts “use tax” in ss. 203.01(1)(h)&(i), F.S., provides that any electricity produced by a person, cogenerator, or small power producer, is subject to Gross Receipts Tax.

All Gross Receipts Tax revenues are deposited in the Public Education Capital Outlay (PECO) Trust Fund, which is administered by the Department of Education (DOE). These revenues are primarily used to pay debt service on outstanding PECO bonds, but may be used for additional education-related purposes if any revenues are available after debt service is paid.

Ad Valorem Tax

The ad valorem tax is an annual tax levied by local governments based on the value of real and tangible personal property as of January 1 of each year. Florida's constitution prohibits the state government from levying an ad valorem tax except on intangible personal property. The taxable value of real and tangible personal property is the just value (i.e., the fair market value) of the property adjusted for any exclusion, differential, or exemption allowed by the Florida Constitution or the statutes. The Florida Constitution strictly limits the Legislature's authority to provide exemptions or adjustments to fair market value. Also, with certain exceptions for millage levies approved by the voters, the Florida Constitution limits county, municipal and school district levies to ten mills each.

Franchise Fees

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, inspection fees, impact 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 user fees, rental fees, and franchise 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 on the Office of Economic and Demographic Research's (EDR) website.¹²

Public Service Tax

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.¹³ 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.¹⁴ 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.¹⁵ In 1994, the Court held that Orange County could levy a public service tax without specific statutory authority to do so.¹⁶

The tax is collected by the seller of the taxable item from the purchaser at the time of payment.¹⁷ 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.¹⁸ A number of tax exemptions are specified in law.¹⁹

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.²⁰

¹² <http://edr.state.fl.us/Content/local-government/data/data-a-to-z/index.cfm>

¹³ Section 166.231(1), F.S.

¹⁴ Section 166.231(2), F.S.

¹⁵ *Volusia County vs. Dickinson*, 269 So.2d 9 (Fla. 1972).

¹⁶ *McLeod vs. Orange County*, 645 So.2d 411 (Fla. 1994).

¹⁷ Section 166.231(7), F.S.

¹⁸ Section 166.232, F.S.

¹⁹ Section 166.231(3)-(6) and (8), F.S.

²⁰ Section 166.233(2), F.S.

The seller of the service remits the taxes collected to the governing body in the manner prescribed by ordinance.²¹ 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 and the Department maintains an online database that can be searched or downloaded.²²

Summaries of prior years' revenues reported by county and municipal governments are available on EDR's website.²³

Regulatory Assessment Fees

Section 366.14, F.S., provides that each regulated company under the jurisdiction of the PSC must pay a fee based on 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. The rate for investor-owned utilities that supply electricity is 0.125 percent. The rate for municipal electric utilities and rural electric cooperatives is 0.015625 percent.

Administrative Costs

II. FISCAL ANALYSIS & ECONOMIC IMPACT STATEMENT

Section 100.371(5)(a), F.S., requires that the Financial Impact Estimating Conference "...complete an analysis and financial impact statement to be placed on the ballot of the estimated increase or decrease in any revenues or costs to state or local governments resulting from the proposed initiative."

As part of determining the fiscal impact of this amendment, the Conference held three public meetings:

- Public Workshop on April 10, 2015
- Principals' Workshop on April 24, 2015
- Formal Conference on May 6, 2015

A. FISCAL ANALYSIS

B. OTHER CONSIDERATIONS AND ASSUMPTIONS

²¹ Section 166.231(7), F.S.

²² <http://dor.myflorida.com/dor/governments/mpst/>

²³ <http://edr.state.fl.us/Content/local-government/data/data-a-to-z/index.cfm>