Financial Impact Estimating Conference

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

Table of Contents

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

Ken Detzner
Secretary of State

KD/am

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

Enclosures

VIVA FLORIDA.

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**	

Date 3/25/2015 2 43 23 PM

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: 2014 Go

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

The Florida Senate

2014 Florida Statutes

Title XIV	Chapter 203
TAXATION AND FINANCE	GROSS RECEIPTS TAXES

CHAPTER 203
GROSS RECEIPTS TAXES

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

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

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

203.03 Penalties.—

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

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

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

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

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

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

History.—s. 5, ch. 76-261.

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

History.—s. 6, ch. 81-178.

The Florida Senate

2014 Florida Statutes

Title XXVII RAILROADS AND OTHER REGULATED UTILITIES	Chapter 366 PUBLIC UTILITIES **Entire Chapter**	**SECTION 02** **Definitions.**

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.

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.

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.

(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.

The Florida Senate

2014 Florida Statutes

Title XIV TAXATION AND FINANCE	Chapter 193 ASSESSMENTS Entire Chapter	**SECTION 624** **Assessment of residential property.**

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.

The Florida Senate

2014 Florida Statutes

Title XI COUNTY ORGANIZATION AND INTERGOVERNMENTAL RELATIONS	Chapter 163 INTERGOVERNMENTAL PROGRAMS Entire Chapter	**SECTION 04** **Energy devices based on renewable resources.**

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.

The Florida Senate

2014 Florida Statutes

Title XI COUNTY ORGANIZATION AND INTERGOVERNMENTAL RELATIONS	Chapter 163 INTERGOVERNMENTAL PROGRAMS Entire Chapter	**SECTION 08** **Supplemental authority for improvements to real property.**

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.

The Florida Senate

2014 Florida Statutes

Title XXVII RAILROADS AND OTHER REGULATED UTILITIES	Chapter 366 PUBLIC UTILITIES Entire Chapter	**SECTION 91 Renewable energy.**

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.

The Florida Senate

2014 Florida Statutes

Title XXVIII NATURAL RESOURCES; CONSERVATION, RECLAMATION, AND USE	Chapter 377 ENERGY RESOURCES Entire Chapter	**SECTION 705 Solar Energy Center; development of solar energy standards.**

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.

The Florida Senate

2014 Florida Statutes

Title XXIX PUBLIC HEALTH	Chapter 403 ENVIRONMENTAL CONTROL **Entire Chapter**	**SECTION 503** **Definitions relating to Florida Electrical Power Plant Siting Act.**

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.

The Florida Senate

2014 Florida Statutes

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

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

Title XXVII RAILROADS AND OTHER REGULATED UTILITIES	Chapter 366 PUBLIC UTILITIES **Entire Chapter**	**SECTION 14** **Regulatory assessment fees.**

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.

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 Utilites 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 (formery 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, Utilites 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**	**857**	**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
David Dowds, Public Utilities Supervisor, Office of Industry Development and Market Analysis
Mark Futrell, Director, Office of Industry Development and Market Analysis

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

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 Program[1]

- 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

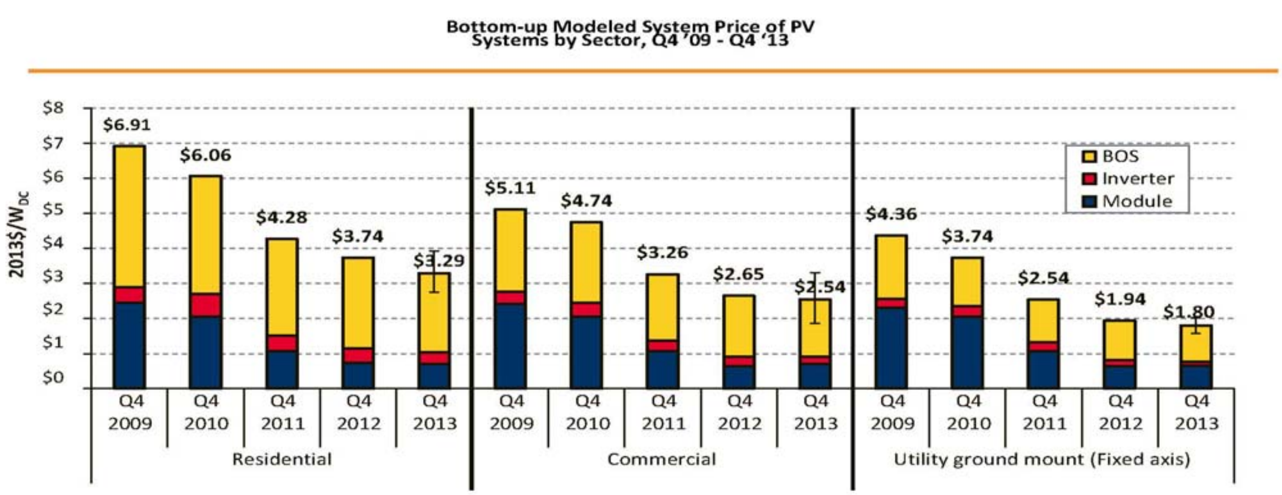
- On September 30, 2014, Tampa Electric Company (TECO) announced it will construct 2 MW of solar PV at the airport.
- The project is to be completed by the end of 2015.
- TECO will own the solar PV and will lease the airport garage roof on which the solar PV is to be located for $15,000/year.
- TECO 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.

<u>Cost Trends</u>

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.

Internal Affairs Memorandum
February 27, 2015

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 WC
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

-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

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

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 maxium 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 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:

R. WADE LITCHFIELD and JESSICA CANO, ESQUIRES, 700 Universe Blvd., Juno Beach, Florida 33408; and CHARLES A. GUYTON, ESQUIRE, Squire, Sanders & Dempsey, LLP, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301
On behalf of Florida Power & Light Company (FPL)

R. ALEXANDER GLENN and JOHN T. BURNETT, ESQUIRES, Progress Energy Service Company, LLC, Post Office Box 14042, St. Petersburg, Florida 33733-4042
On behalf of Progress Energy Florida, Inc. (PEF)

LEE L. WILLIS and JAMES D. BEASLEY, ESQUIRES, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO)

JEFFREY A. STONE, RUSSELL A. BADDERS, and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950
On behalf of Gulf Power Company (GULF)

NORMAN H. HORTON, JR., ESQUIRE, Messer, Caparello & Self, P.A., Post Office Box 15579, Tallahassee, Florida 32317
On behalf of Florida Public Utilities Company (FPUC)

ROY C. YOUNG, ESQUIRE, Young vanAssenderp, P.A., 225 South Adams Street, Suite 200, Tallahassee, Florida 32301; W. CHRIS BROWDER, ESQUIRE, Orlando Utilities Commission, 100 W. Anderson Street, Orlando, Florida 32802
On behalf of Orlando Utilities Commission (OUC)

GARY V. PERKO and BROOKE E. LEWIS, ESQUIRES, Hopping Green & Sams, P.A., Post Office Box 6526, Tallahassee, Florida 32314
On behalf of JEA

SUSAN CLARK, ESQUIRE, Radey Thomas Yon and Clark, 301 South Bronough Street, Suite 200, Tallahassee, Florida 32301
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)

SUZANNE BROWNLESS, ESQUIRE, Suzanne Brownless, PA, 1975 Buford Blvd., Tallahassee, Florida 32308
On behalf of the Florida Solar Coalition (FSC)

E. LEON JACOBS, JR., ESQUIRE, Williams & Jacobs, LLC, 1720 S. Gadsden St., MS 14, Suite 201, Tallahassee, Florida 32301; BENJAMIN LONGSTRETH, Natural Resources Defense Council, 1200 New York Avenue NW, Washington, DC 20005; BRANDI COLANDER, Natural Resources Defense Council, 40 West 20th Street, New York, NY 10011; DANIEL WEINER, Jenner & Block, 1099 New York Avenue NW, Washington, DC; and GEORGE S. CAVROS, ESQUIRE, 120 E. Oakland Park Boulevard, Suite 105, Fort Lauderdale, Florida 33334
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.

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 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.

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-effectivness 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 CO_2 as one of the generally accepted greenhouse gases close to being regulated. Other regulated gases, such as sulfur dioxide (SOx) and nitrous oxides (NOx), are already regulated by federal statute and the costs are included in the standard RIM and TRC tests. Each utility's calculation of a measures' cost-effectiveness employed modified versions of the RIM and the TRC tests that added a cost impact of CO_2 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 CO_2 emissions, thereby employing different values in their cost-effectiveness testing. Therefore, FPL's goals could not be determined using TECO's estimated CO_2 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 2008did 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 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

	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	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

	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	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

	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	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

	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	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

	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	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

	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	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

	Residential			Commercial/Industrial		
Year	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

	Residential			Commercial/Industrial		
Year	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.

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.

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.

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 <u>increasing the development of demand-side renewable energy systems</u>, 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, <u>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.</u>

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.

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 <u>increasing the development of demand-side renewable energy systems</u>. . . ." (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 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.

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.

(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
ANN COLE
Commission Clerk

(S E A L)

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,

Adam H. Putnam
Commissioner of Agriculture

FLORIDA DEPARTMENT OF AGRICULTURE AND CONSUMER SERVICES

OFFICE OF ENERGY

2014 ANNUAL REPORT

Adam H. Putnam, Commissioner

The Holland Building
600 South Calhoun Street, Suite 251
Tallahassee, FL 32399-0001
(850) 617-7470
www.FreshFromFlorida.com

Table of Contents

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)

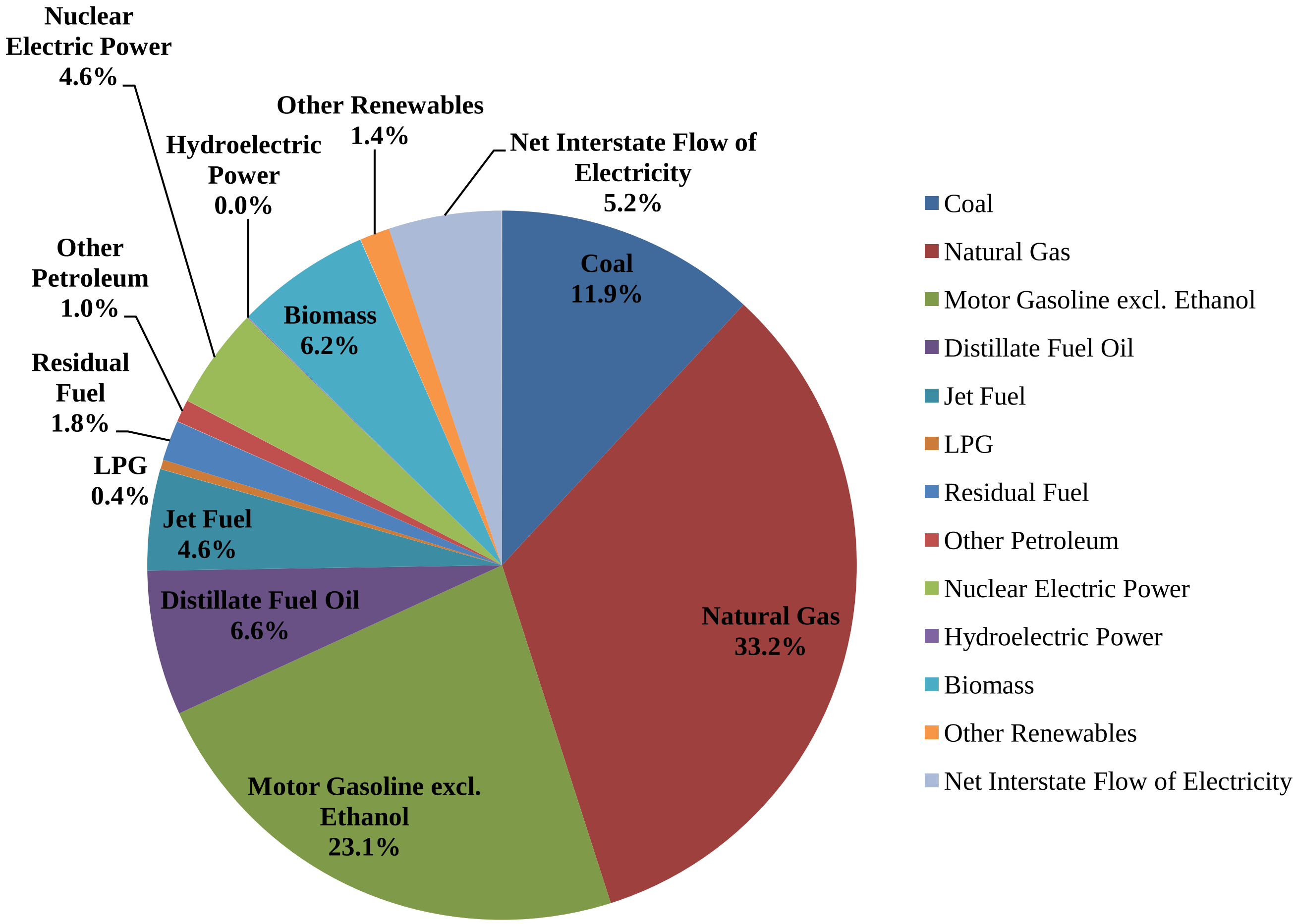
Florida is home to approximately 19 million people, and, as of December 2014, it is the third most populous state, according to the U.S. Census. With a population size of this magnitude, addressing Florida's energy needs are a top priority. As it relates to consumption, the United States Department of 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 Btu[1]s 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



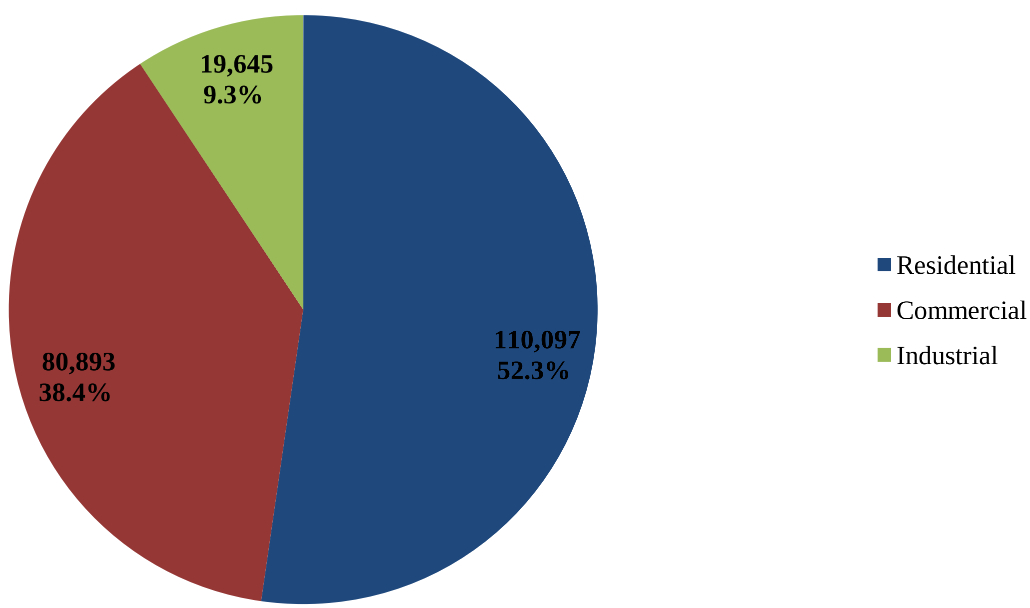
The Florida Public Service Commission (PSC) in its *Review of the 2014 Ten-Year Site Plans of Florida's Electric Utilities* stated that "natural gas has become the dominant fuel in Florida within the last ten years…and is anticipated to serve future growth until the end of the planning period, when additional 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



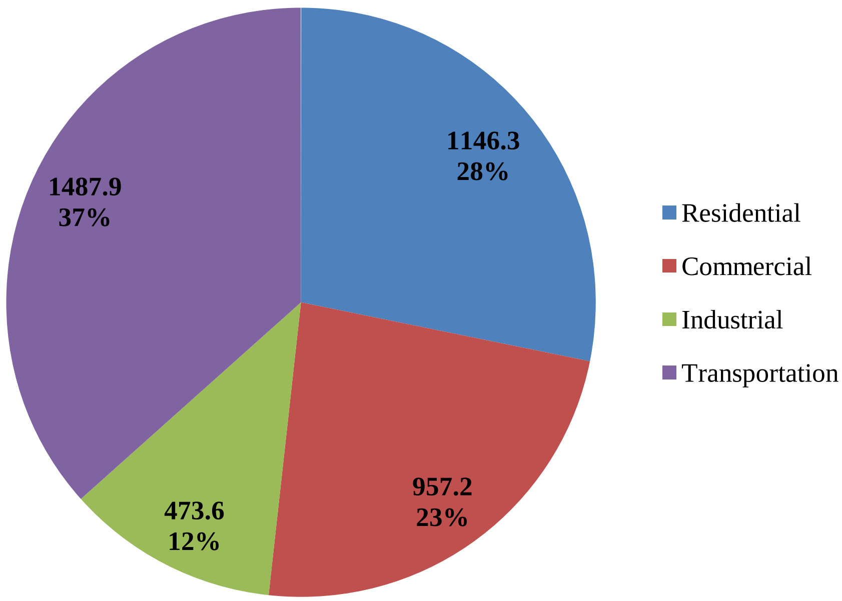
With Florida being the third most populous state, transportation fuel consumption is high relative to the rest of the nation. According to the US EIA, Florida is ranked third in the nation in terms of transportation fuel consumption, using 1,487.9 trillion Btus; this accounts for 5.6 percent of the total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

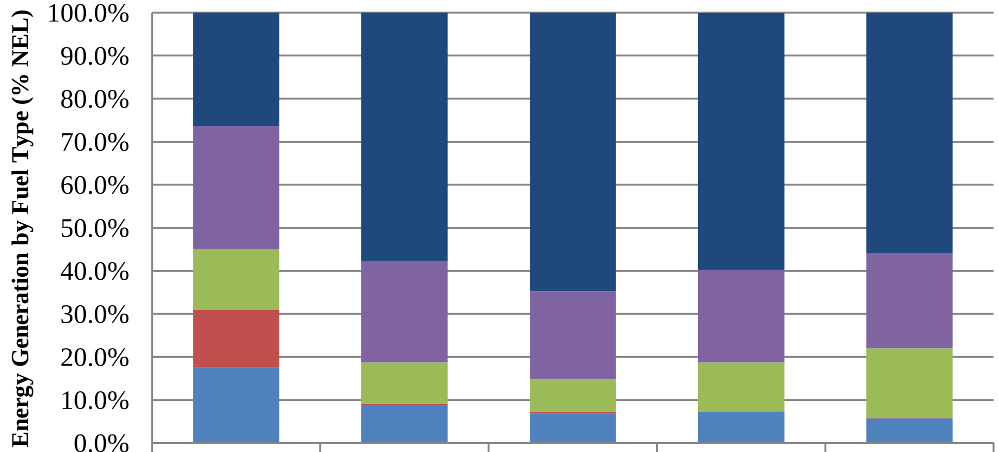
Source: US EIA



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



	2003 Actual	2011 Actual	2012 Actual	2013 Actual	2023 Projected
Natural Gas*	26.5%	57.7%	64.8%	59.6%	55.8%
Coal	28.5%	23.6%	20.3%	21.6%	22.2%
Nuclear	14.2%	9.6%	7.7%	11.3%	16.2%
Oil**	13.3%	0.5%	0.3%	0.2%	0.1%
Interchange, Renewable, NUG, Other	17.6%	8.6%	6.9%	7.2%	5.7%

** Includes both utility and non-utility generation*
*** Includes both residual and distillate oil*

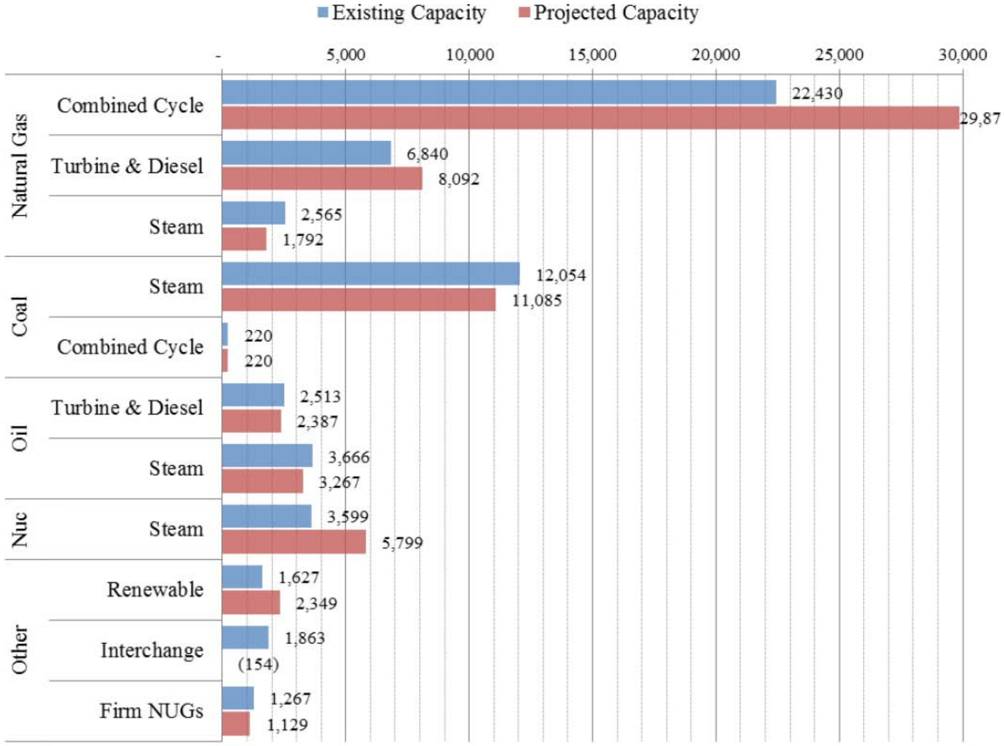
In the past, Florida's utilities adopted more of a balanced approach in terms of its electric generation fuel source mix. By building diverse plants that utilize different fuel sources, it provides a stability mechanism if one fuel source became unavailable or too costly. For example, in 2009, Florida's 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	High	$131.96
	$115.05	Low	$92.73
Municipal Electric Utilities	Average Bill	High	$141.15
	$119.40	Low	$100.49
Cooperative Electric Utilities	Average Bill	High	$146.99
	$128.53	Low	$113.50

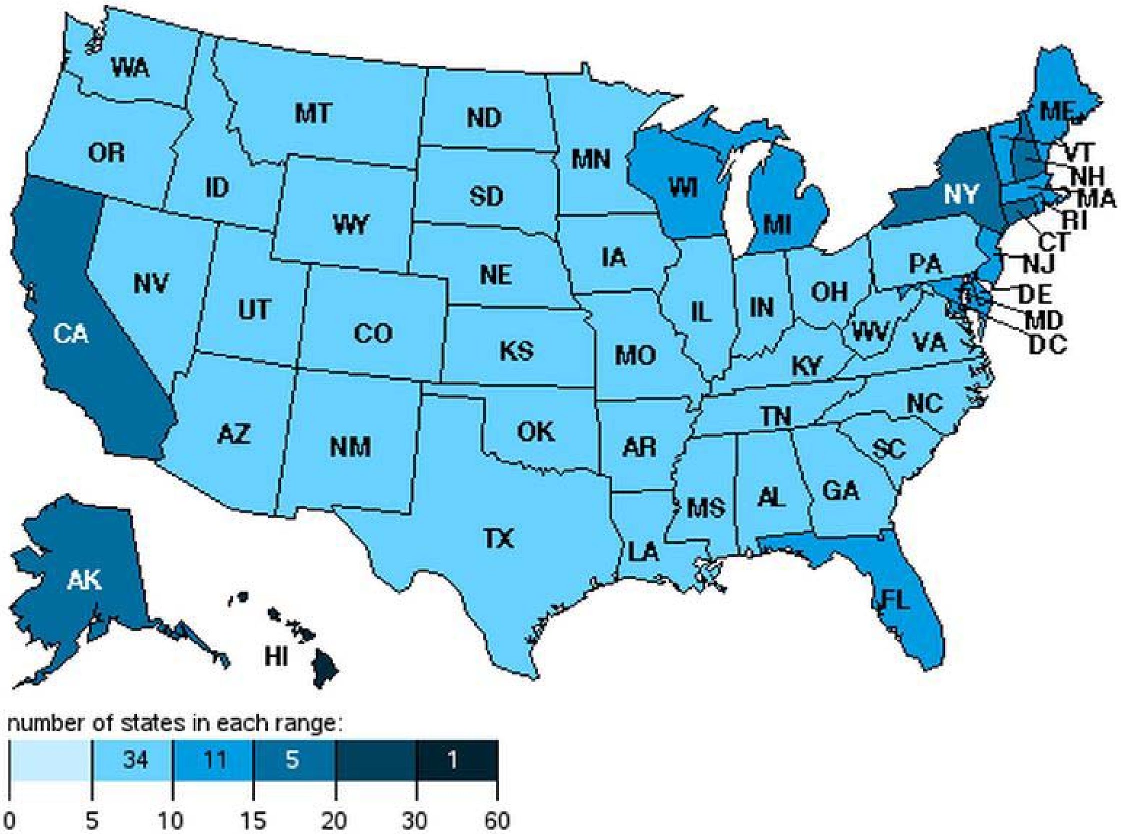
Source: PSC December 2013 Comparative Rate Statistics

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

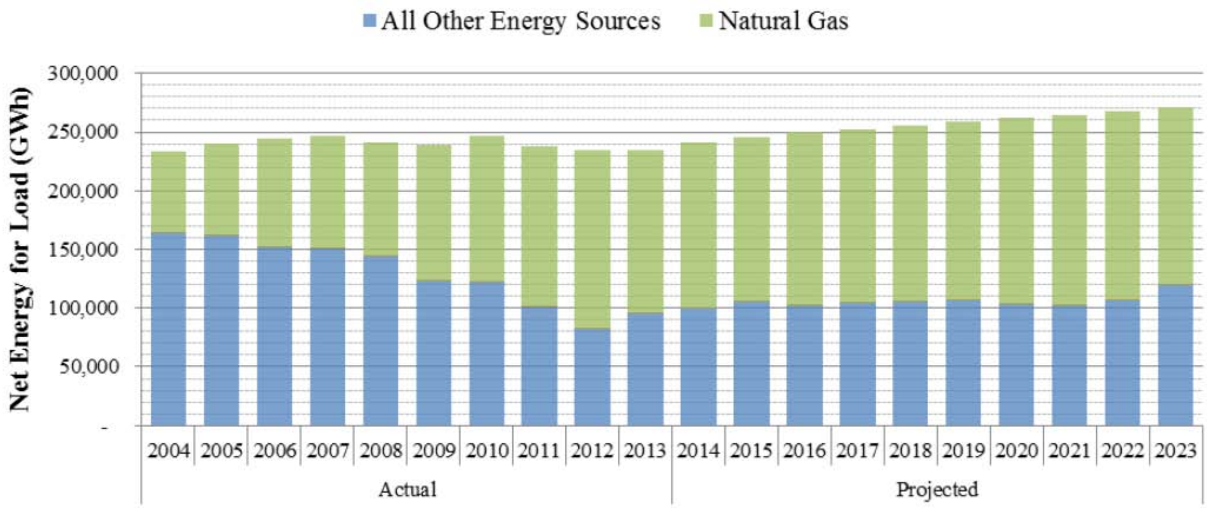


Source: Energy Information Administration [*http://www.eia.gov/electricity/monthly/update/end_use.cfm#tabs_prices-3*](http://www.eia.gov/electricity/monthly/update/end_use.cfm#tabs_prices-3)

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



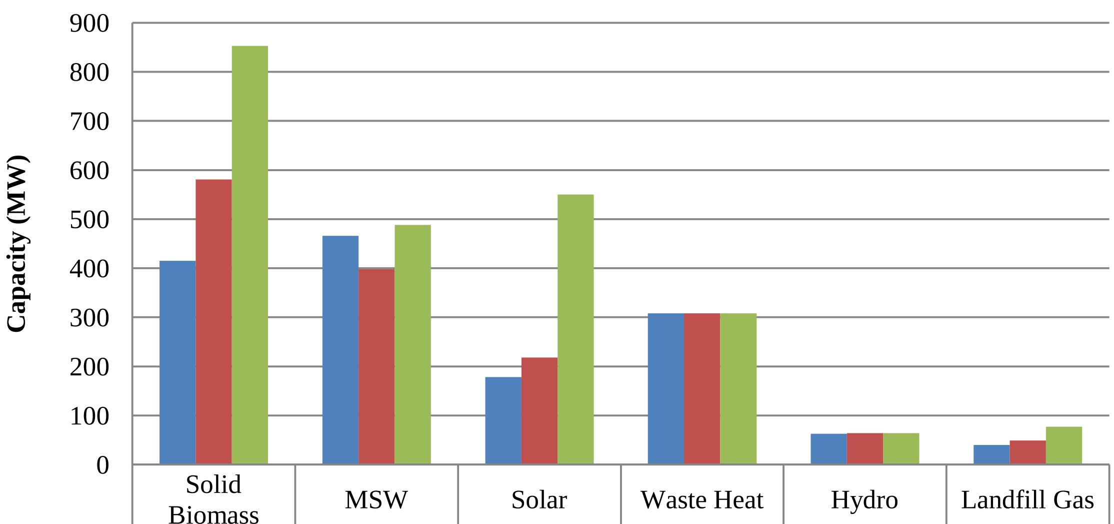
Source: PSC 2014 Ten-Year Site Plan Review, Figure 15, pg. 37

<u>Renewable Energy</u>

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



	Solid Biomass	MSW	Solar	Waste Heat	Hydro	Landfill Gas
2013	415	466	178	308	63	40
2014	581	398	218	308	64	49
Planned	853	488	550	308	64	77

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

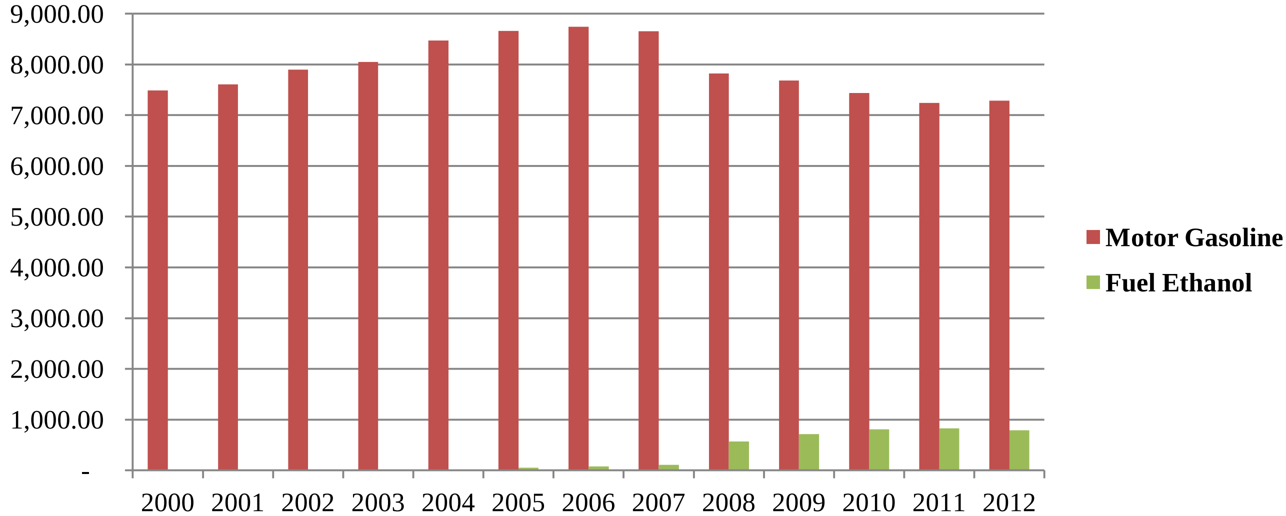
Florida is unique compared to other states in that it consists of a 447-mile long peninsula, which extends from the Georgia border south to the Florida Keys, a northern panhandle that stretches over 360 miles from the Atlantic to Alabama and nearly 1,200 miles of shoreline, totaling 54,157 square land 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:

<u>Solar Energy</u>
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.

<u>Electric Vehicles</u>
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.

<u>Ocean Energy</u>
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,

Adam H. Putnam
Commissioner of Agriculture

Table of Contents

Letter from Commissioner Adam H. Putnam

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 supervisorial 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.

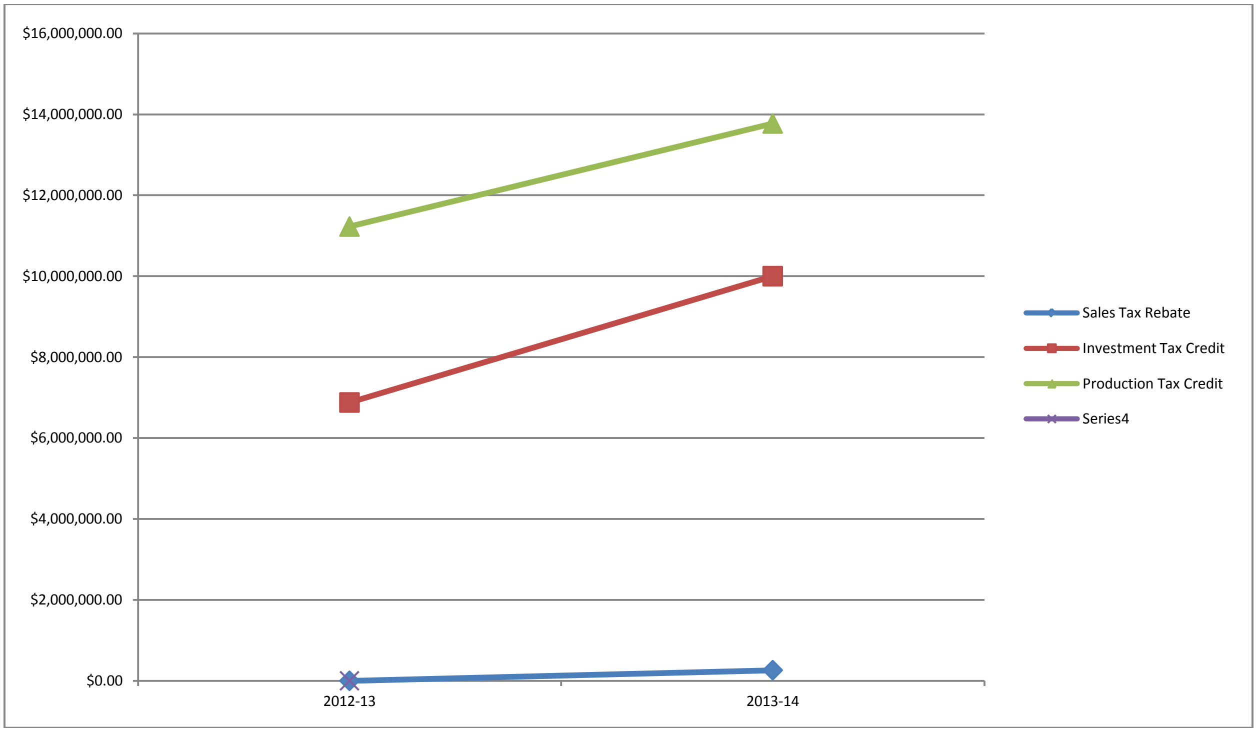


Figure 1. Funds awarded through the Renewable Energy Tax Incentives Program, FY2012-13 – FY2013-14.

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.

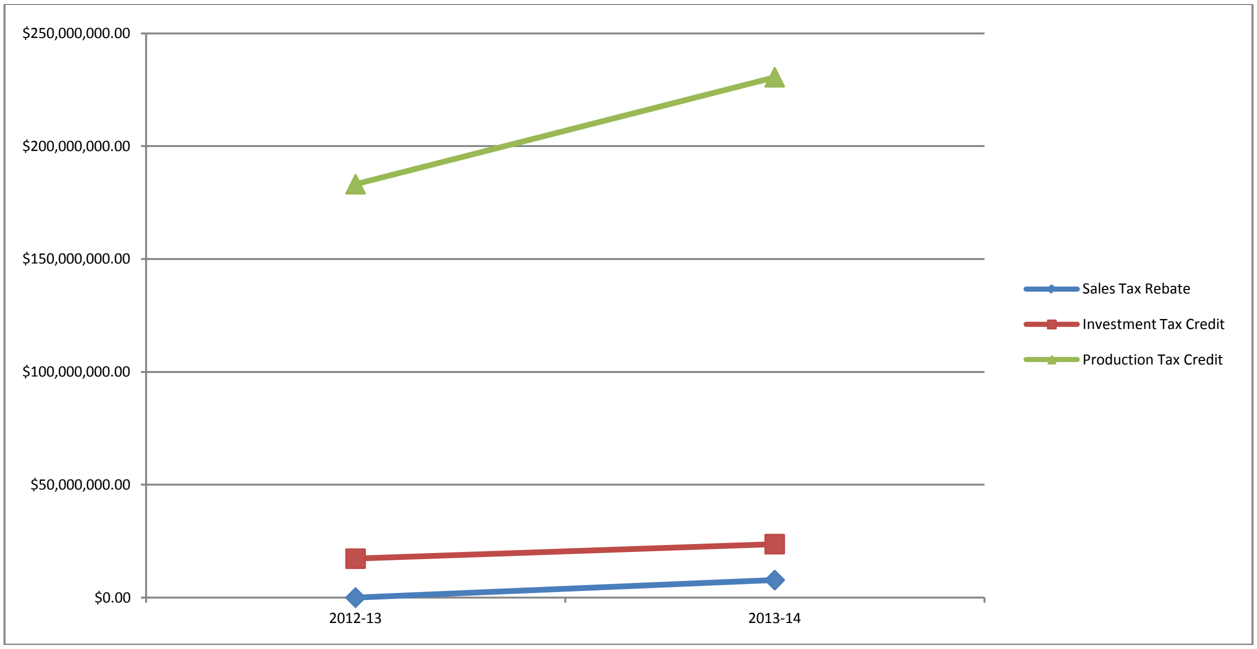


Figure 2. Economic contribution of the Renewable Energy Tax Incentives Program, FY2012-13 – FY2013-14.

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.

8. References

Energy Information Administration. (n.d.). *Electricity Data Browser*. Retrieved January 30, 2014, from U.S. Energy Information Administration: http://www.eia.gov/electricity/data/browser/

Enterprise Florida. (2013). *Florida: Eight Regions of Innovation and Economic Growth*. Retrieved February 19, 2014, from Enterprise Florida: http://wwww.eflorida.com/FloridasRegionsSubpage.aspx?id=54

Hodges, A., & Spreen, T. (2012). *Economic Impacts of Citrus Greening (HLB) in Florida, 2006/07 - 2010/11*. Gainesville, FL: IFAS Extension.

Minnesota Implan Group, Inc. (2013). Retrieved from Impact Analysis for Planning (IMPLAN): http://www.implan.com

Schlosser, J., Leatherman, J., & Peterson, J. (2008). Are biofuels revitalizing rural economies? Projected versus actual labor market impacts in the Great Plains. *American Agricultural Economics Association Annual Meetings.* Orlando, FL.

Swenson, D., & Eathington, L. (2006). *Determining the regional economic values of ethanol production in Iowa considering different levels of local investment.* Ames, IA: Iowa State University.

Watson, P., Wilson, J., Thilmany, D., & Winter, S. (2007). Determining economic contributions and impacts: What is the difference and why do we care? *The Journal of Regional Analysis and Policy*, 37 (2), 140 - 146.

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 **	333	$ 511,012,811	$ 618,942,517	82.6%	$ 30,506,694,638	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 **	346	$ 649,995,247				
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) Twenty-three municipalities have not yet submitted their 2012-13 Annual Financial Reports. 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.

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 **	318	$ 652,278,818	$ 826,977,220	78.9%	$ 30,506,694,638	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 **	333	$ 879,368,559
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) Twenty-three municipalities have not yet submitted their 2012-13 Annual Financial Reports. 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.

Tab 4

Reports

OPEN ACCESS
IOP PUBLISHING ENVIRONMENTAL RESEARCH LETTERS
Environ. Res. Lett. 8 (2013) 014022 (8pp) doi:10.1088/1748-9326/8/1/014022

Diffusion of environmentally-friendly energy technologies: buy versus lease differences in residential PV markets

Varun Rai[1,2,3] **and Benjamin Sigrin**[1]

[1] LBJ School of Public Affairs, The University of Texas at Austin, USA
[2] Mechanical Engineering Department, The University of Texas at Austin, USA

E-mail: raivarun@gmail.com

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

S 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

[3] Address for correspondence: LBJ School of Public Affairs and Mechanical Engineering, The University of Texas at Austin, 2315 Red River Street, SRH 3.256, Austin, TX 78712, USA.

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:

$$\mathrm{CF}_k = R_k - C_k. \tag{1}$$

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 ($C_{\mathrm{O\&M}_k}$), and (c) cost of inverter replacement (C_{Inverter_k}) where:

$$C_k = C_{\mathrm{system}_k} + C_{\mathrm{O\&M}_k} + C_{\mathrm{Inverter}_k}. \tag{2}$$

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}$) of leased systems (Mean = 8.3, Std. dev. = 0.53) were significantly more than those of bough systems (Mean = 6.2, Std. dev. = 1.4) and the mean differences were highly significant ($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

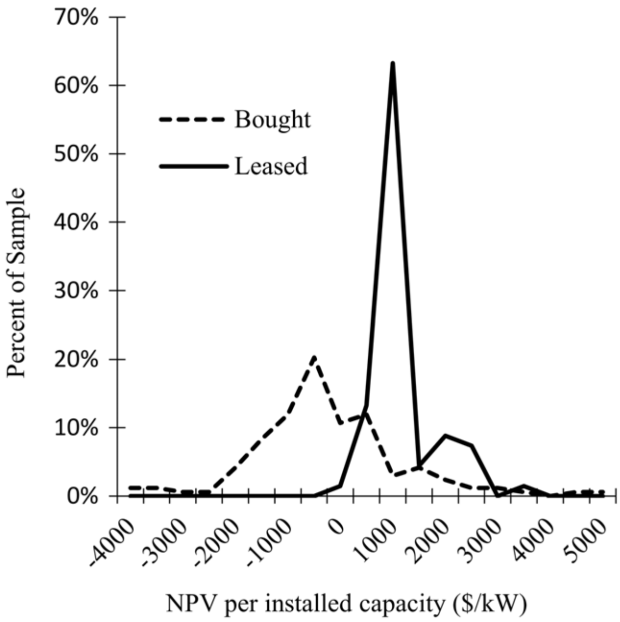


Figure 1. Distribution of modeled NPV kW^{-1} assuming *baseline* model parameters.

(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

[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.

would allow them to offer the leased systems at lower rates today. All of these mechanism 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 buy[5]. 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 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.

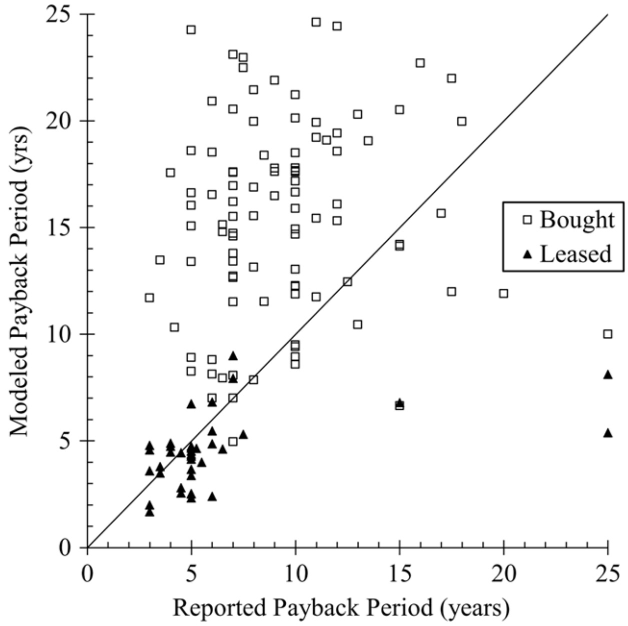


Figure 2. Comparison of reported and modeled payback period in scenario 3. Mean difference between modeled and consumer payback period: buyers = 7.1 yr^{-1}; leasers = 1.1 yr.

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.

[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.

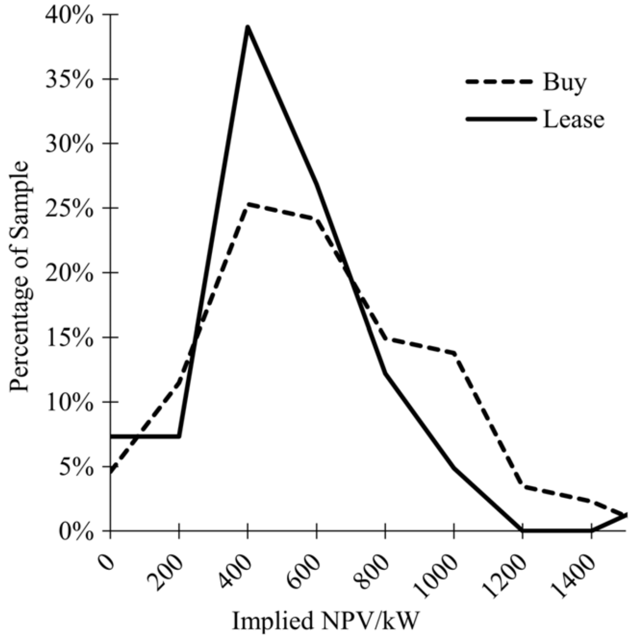


Figure 3. Distribution of implied NPV kW^{-1} for buyers and leasers; difference of mean is not significantly different than zero.

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.:

$$\mathrm{NPV}_{\mathrm{implied}} = \sum \mathrm{CF}_k = \sum \frac{[R_k - C_k]}{(1+r_m)^k}. \qquad (3)$$

The monthly discount rate is then annualized using (4):

$$r = (1+r_m)^{12} - 1. \qquad (4)$$

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 choices[6]. 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: $\mathrm{DR}_1 = \mathrm{DR}_2$, H_a: $\mathrm{DR}_1 \geq \mathrm{DR}_2$, and H_o: $\mathrm{DR}_2 = \mathrm{DR}_3$, H_a: $\mathrm{DR}_2 \geq \mathrm{DR}_3$, where DR_1 is the mean implied discount rate for income group 1 and so on[7]. This test was performed for both income pairs ($\mathrm{DR}_1 \geq \mathrm{DR}_2$, $\mathrm{DR}_2 \geq \mathrm{DR}_3$) 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+
N	**81**	22	37	22
Scen 2: conservative	**6%** $\pm$ **6%**	6% $\pm$ 5%	6% $\pm$ 8%	7% $\pm$ 6%
Scen 3: baseline	**7%** $\pm$ **5%**	7% $\pm$ 4%	6% $\pm$ 6%	7% $\pm$ 6%
Scen 4: optimistic	**13%** $\pm$ **6%**	12% $\pm$ 5%	13% $\pm$ 6%	13% $\pm$ 7%
Scen 5: V. Optimistic	**18%** $\pm$ **7%**	17% $\pm$ 5%	18% $\pm$ 7%	17% $\pm$ 8%

Table 3. Mean implied discount rate for leasers along income and scenarios with $\pm 1\sigma$.

Leasers	All incomes	\$0–\$85k	\$85k–\$150k	\$150k+
N	**37**	13	13	11
Scen 2: conservative	**20%** $\pm$ **15%**	22% $\pm$ 19%	20% $\pm$ 14%	18% $\pm$ 12%
Scen 3: baseline	**21%** $\pm$ **14%**	23% $\pm$ 18%	22% $\pm$ 13%	19% $\pm$ 12%
Scen 4: optimistic	**32%** $\pm$ **17%**	33% $\pm$ 22%	35% $\pm$ 15%	30% $\pm$ 14%
Scen 5: V. Optimistic	**35%** $\pm$ **13%**	29% $\pm$ 9%	38% $\pm$ 13%	36% $\pm$ 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.

References

Allcott H and Mullainathan S 2010 Behavior and energy policy *Science* **327** 1204–5

Barbose G, Darghouth N and Wiser R 2012 Tracking the sun V: a historical summary of the installed price of photovoltaics in the United States from 1998 to 2011 *LBNL-5919E* (Berkeley, CA: Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory)

Bergmann A, Hanley N and Wright R 2006 Valuing the attributes of renewable energy investments *Energy Policy* **4** 1004–14

Bolinger M A 2009 Full steam ahead for PV in US homes? *Renew. Energy Focus* **9** 58–60

Bollinger B and Gillingham K 2012 Peer effects in the diffusion of solar photovoltaic panels *Marketing Sci.* **31** 900–12

Camerer C, Loewenstein G and Rabin M (ed) 2004 *Advances in Behavioral Economics* (Princeton, NJ: Princeton University Press)

Conlisk J 1996 Why bounded rationality? *J. Econm. Literature* **34** 669–700

Coughlin J and Cory K 2009 Solar photovoltaic financing; residential sector deployment *National Renewable Energy Laboratory Technical Report* NREL/TP-6A2-44853

Darghouth N R, Barbose G and Wiser R 2011 The impact of rate design and net metering on the bill savings from distributed PV for residential customers in California *Energy Policy* **39** 5243–53

Dastrop S, Zivin J G, Costa D L and Kahn M E 2011 Understanding the solar home price premium: electricity generation & green social status *NBER Working Paper* No. 17200 (Cambridge, MA: National Bureau of Economic Research)

Dietz T 2010 Narrowing the US energy efficiency gap *Proc. Natl Acad. Sci. USA* **107** 16007–8
Drury E *et al* 2011 The transformation of southern California's residential photovoltaic market through third-party ownership *Energy Policy* **42** 681–90
ERCOT (Electricity Reliability Council of Texas) 2010 *ERCOT Backcasted (Actual) Load Profiles—Historical* (www.ercot.com/mktinfo/loadprofile/alp/, retrieved 15 August 2011)
EIA (Energy Information Agency, US) 2010 *Annual Energy Review* (www.eia.gov/totalenergy/data/annual/index.cfm, accessed 8 July 2011)
Faiers A and Neame C 2006 Consumer attitudes toward domestic solar power systems *Energy Policy* **34** 1797–806
Faiers A, Neame C and Cook C 2007 The adoption of domestic solar-power systems: do consumers assess product attributes in a stepwise process? *Energy Policy* **35** 3418–23
Frederick S, Loewenstein G and O'Donoghue T 2002 Time discounting and time preference: a critical review *J. Econm. Literature* **40** 351–401
Fuchs D A and Arentsen M J 2002 Green electricity in the market place: the policy challenge *Energy Policy* **30** 525–38
Gallagher K S and Muehlegger E 2011 Giving green to get green? incentives and consumer adoption of hybrid vehicle technology *J. Environ. Econm. Manag.* **61** 1–15
Gately D 1980 Individual discount rates and the purchase and utilization of energy-using durables: comment *Bell J. Econm.* **11** 373–4
Gigerenzer G and Todd P 1999 *Simple Heuristics That Make Us Smart* (Oxford: Oxford University Press)
Gintis H 2000 Beyond homo economicus: evidence from experimental economics *Ecol. Econm.* **35** 311–22
Goett A A, Hudson K and Train K E 2000 Customers' choice among retail energy suppliers: the willingness-to-pay for service attributes *Energy J.* **21** 1–28
Guidolin M and Mortarino C 2009 Cross-country diffusion of photovoltaic systems: modeling choices and forecasts for national adoption patterns *Technol. Forecast. Societal Change* **77** 279–96
Hart D M 2010 Making, breaking, and (partially) remaking markets: state regulation and photovoltaic electricity in New Jersey *Energy Policy* **38** 6662–73
Hassett K A and Metcalft G E 1993 Energy conservation investment: do consumers discount the future correctly? *Energy Policy* **21** 710–6
Hausman J 1979 Individual discount rates and the purchase and utilization of energy-using durables *Bell J. Econm.* **10** 33–54
Howarth R B and Sanstad A H 1995 Discount rates and energy efficiency *Contemp. Econm. Policy* **13** 101
Jager W 2006 Stimulating the diffusion of photovoltaic systems: a behavioural perspective *Energy Policy* **34** 1935–43
Johnson K *et al* 2012 Lessons learned from the field: key strategies for implementing successful on-the-bill financing programs *Energy Effic.* **5** 109–19
Keirstead J 2007 Behavioural responses to photovoltaic systems in the UK domestic sector *Energy Policy* **35** 4128–41
Kempton W and Montgomery L 1982 Folk quantification of energy *Energy* **7** 817–27
Kirchler E, Hoelzl E and Kamleitner B 2008 Spending and credit use in the private household *J. Socio-Econm.* **37** 519–32
Kollins K, Speer B and Cory K 2010 Solar PV project financing: regulatory and legislative challenges for third-party PPA system owners *National Renewable Energy Laboratory Technical Report* 6A2-46723
Labay D G and Kinnear T C 1981 Exploring the consumer decision process in the adoption of solar energy systems *J. Consum. Res.* **8** 271–8
Laitner J A *et al* 2003 Room for improvement: increasing the value of energy modeling for policy analysis *Util. Policy* **11** 87–94
Margolis R and Zuboy J 2006 Nontechnical barriers to solar energy use: review of recent literature *National Renewable Energy Laboratory Technical Report* NREL/TP-520-40116
Meier A K and Whittier J 1983 Consumer discount rates implied by purchases of energy-efficient refrigerators *Energy* **8** 957–62
Mills A, Wiser R, Barbose G and Golove W 2008 The impact of retail rate structures on the economics of commercial photovoltaic systems in California *Energy Policy* **36** 3266–77
Mont O 2004 Product-service systems: panacea or myth? *PhD Dissertation* Lund University
National Renewable Energy Laboratory 2009 Solar leasing for residential photovoltaic systems *NREL/FS-6A2-43572* (www.nrel.gov/docs/fy09osti/43572.pdf, accessed 7 October 2012)
National Renewable Energy Laboratory 2011 *About PVWATTS Viewer* (www.nrel.gov/rredc/pvwatts/about.html, retrieved 3 October 2012)
PUCT (Public Utility Commission of Texas) 2012 §25.242. Arrangements between qualifying facilities and electric utilities *Chapter 25. Substantive Rules Applicable to Electric Service Providers. Subchapter J. Costs, Rates and Tariffs* (www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.242/25.242.pdf)
Rai V and McAndrews K 2012 Decision-making and behavior change in residential adopters of solar PV *Proc. World Renewable Energy Forum (Denver, Colorado, May 2012)*
Roe B, Teisl M F, Levy A and Rissell M 2001 US consumers' willingness to pay for green electricity *Energy Policy* **29** 917–25
Rogers E M 2003 *Diffusion of Innovations* 5th edn (New York: Free Press)
Ruderman H, Levine M and McMahon J 1987 The behavior of the market for energy efficiency in residential appliances including heating and cooling equipment *Energy J.* **8** 101–24
SEC 2012 *Security and Exchange Commission Form S-1, SolarCity Corporation, October 5, 2012* (available from SEC online database, accessed 13 December 2012)
Sexton S E 2011 Conspicuous conservation: the Prius effect and willingness to pay for environmental bona fides *Working Paper* (http://works.bepress.com/sexton/11, accessed 7 October 2012)
Shih L H and Chou T Y 2011 Customer concerns about uncertainty and willingness to pay in leasing solar power systems *Int. J. Environ. Sci. Technol.* **8** 523–32
Sidiras D K and Koukios E G 2004 Solar systems diffusion in local markets *Energy Policy* **32** 2007–18
Taylor M 2008 Beyond technology-push and demand-pull: lessons from California's solar policy *Energy Econm.* **30** 2829–54
TECEP (Texas Electric Choice Education Program) 2012 *Website* (www.powertochoose.org/, retrieved 7 October 2012)
Timilsina G R *et al* 2011 A review of solar energy: markets, economics, and policies *Work Bank Policy Research Working Paper No.* 5845
Todd P M and Gigerenzer G 2003 Bounding rationality to the world *J. Econm. Psychol.* **24** 143–65
Tversky A and Kahneman D 1974 Judgment under uncertainty: heuristics and biases *Science* **185** 1124–31
US Department of Energy 2008 *Multi Year Program Plan 2008–2012* (Washington, DC: Government Printing Office)
US Department of Energy 2012 *Sunshot Vision Study* (Washington, DC: Government Printing Office) (www1.eere.energy.gov/solar/pdfs/47927.pdf)
Wilson C and Dowlatabadi H 2007 Models of decision making and residential energy use *Annu. Rev. Environ. Resources* **32** 169–203

VALUE OF THE GRID TO DG CUSTOMERS

IEE Issue Brief
September 2013
Updated October 2013

IEE | INNOVATION ELECTRICITY EFFICIENCY
An Institute of The Edison Foundation

Value of the Grid to DG Customers

IEE Issue Brief

September 2013
Updated October 2013

Prepared by

Lisa Wood
IEE

Robert Borlick
Borlick Associates

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-

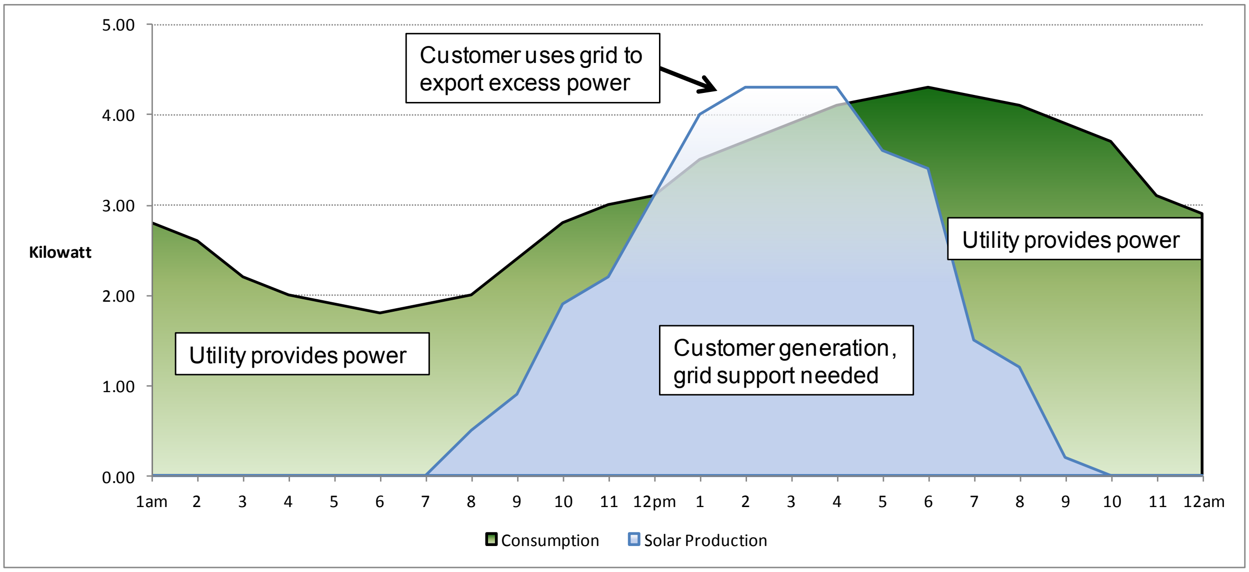
---

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.

About IEE

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.

IEE is governed by a Management Committee of electric industry Chief Executive Officers. IEE members are the investor-owned utilities that represent about 70% of the U.S. electric power industry. IEE has a permanent Advisory Committee of leaders from the regulatory community, federal and state government agencies, and other informed stakeholders. IEE has a Strategy Committee of senior electric industry executives and 30 smart grid techology company partners.

Visit us at: **www.edisonfoundation.net/IEE**

For more information contact:

Lisa Wood
Executive Director
IEE

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696

202.508.5440

lwood@edisonfoundation.net

IEE | INNOVATION ELECTRICITY EFFICIENCY

An Institute of The Edison Foundation

A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering

Prepared by

Jason B. Keyes
Joseph F. Wiedman
Interstate Renewable Energy Council

Solar America Board for Codes and Standards

www.solarabcs.org

Solar America Board for Codes and Standards Report

A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering

Jason B. Keyes
Joseph F. Wiedman
Interstate Renewable Energy Council

January 2012

Disclaimer

Download a copy of the report:

www.solarabcs.org/rateimpact

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.

Author Biographies

Jason B. Keyes focuses on regulatory matters related to interconnection of distributed generation to the U.S. electric grid. On behalf of the Interstate Renewable Energy Council, he has participated in interconnection and net metering rulemakings at the utility commissions of fifteen states. As a partner at Keyes & Fox, LLP, he also represents private clients with all regulatory aspects of renewable energy project development. Prior to his legal career, Mr. Keyes managed government contracts and business development for eight years at JX Crystals Inc., a pioneer in the field of high-concentration solar energy systems. In the early 1990s, he helped develop the integrated resource plan and the demand forecast at Washington State's largest utility. Mr. Keyes received his juris doctor from the Seattle University School of Law, a master of arts in economics from the University of Washington, and a bachelor of arts from Dartmouth College. Mr. Keyes is a member of the Washington State Bar Association.

Joseph F. Wiedman represents clients before regulatory commissions nationwide with a particular focus on expanding renewable energy markets through establishment of state programs and policies that facilitate the growth of renewable energy. On behalf of the Interstate Renewable Energy Council, he has participated in rulemakings related to interconnection, net metering, and development of community renewables programs nationwide. As a partner at Keyes & Fox, LLP, Mr. Wiedman has worked on a broad range of matters related to the development and implementation of renewable energy programs. Over the course of his career, he has worked in academia, government, and private business related to regulation of the energy and telecommunications industries in various capacities. Mr. Wiedman holds a juris doctor from the University of California, Berkeley. He also holds a master of arts from Illinois State University in applied economics with an emphasis in the economics of electricity, natural gas, and telecommunications, and a dual bachelor of arts from the University of Illinois-Urbana in economics and Russian and Eastern European Studies. Mr. Wiedman is a member of the State Bar of California.

Solar America Board for Codes and Standards

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.

For more information, visit Solar ABC's website:
www.solarabcs.org

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.

Table of Contents

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—the size of a very large residential system—to two megawatts (MW) or more in 14 states.

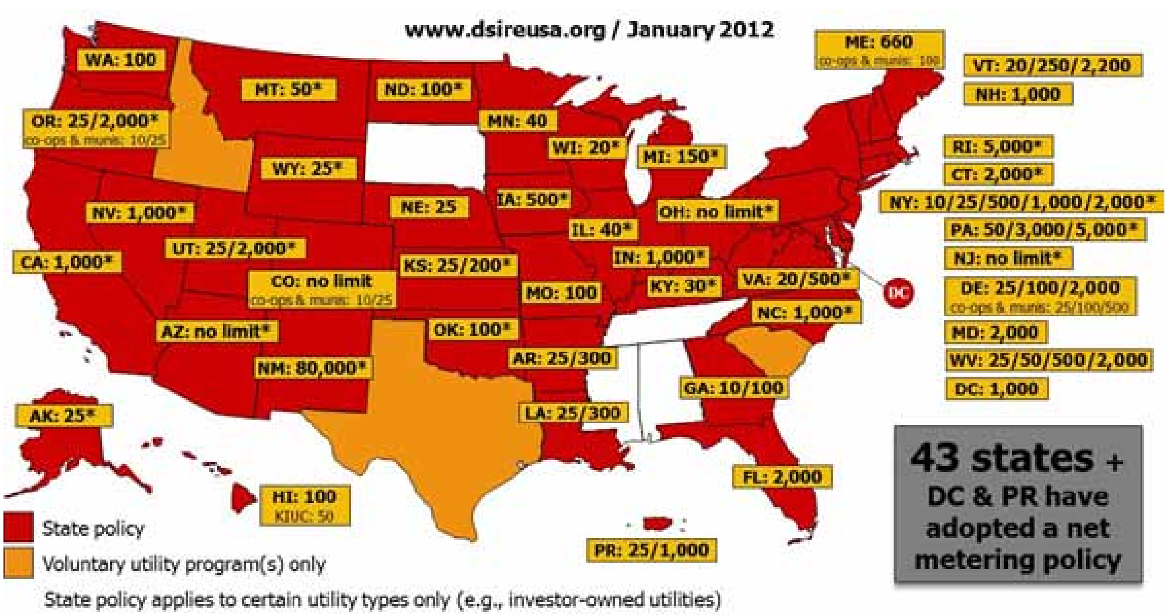


Figure 1. State net energy metering (January 2012, http://www.dsireusa.org). Numbers indicate residential/ commercial individual system capacity limits.

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.

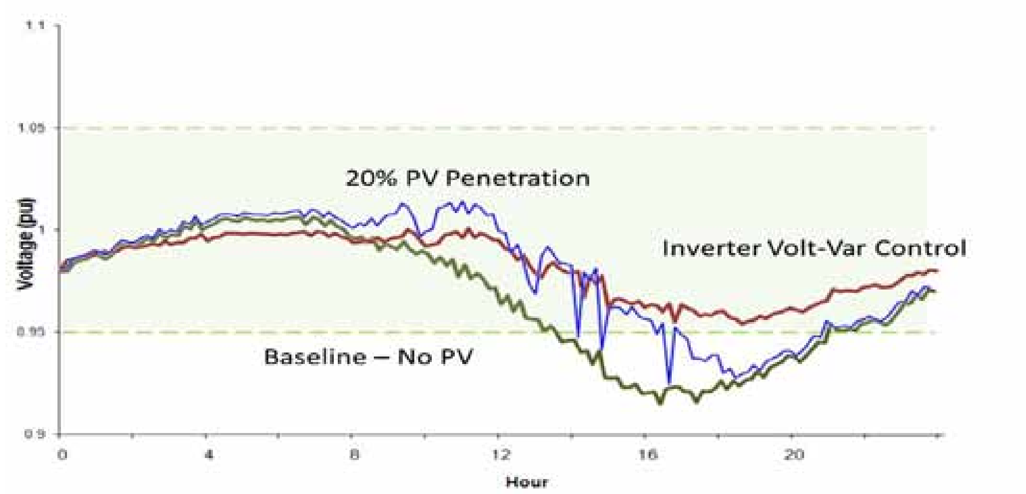


Figure 2. Percentage variation from rated voltage on a typical 12 kV line without PV (the green line, with lowest point), with 20% PV penetration without voltage and reactive power control (the jagged blue line), and with "Inverter Volt-Var Control" (the brown line, with the least voltage variability). 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. Stunningly, 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.

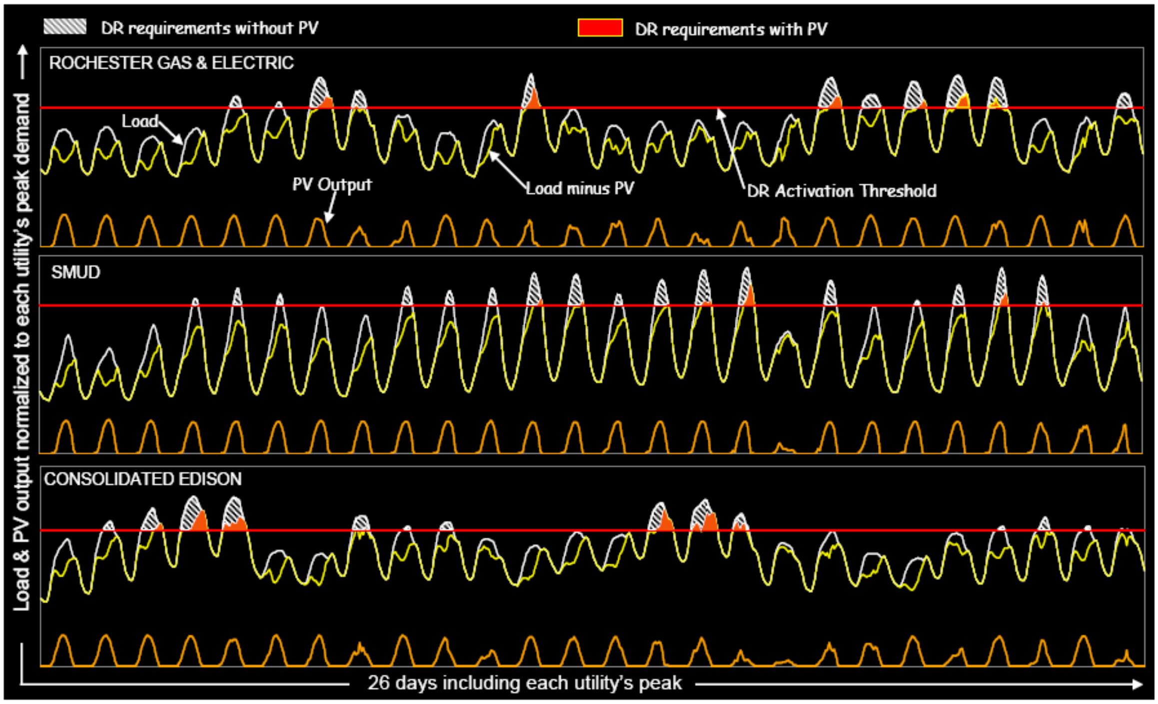


Figure 3. Integration of PV in demand response programs, using PV rated capacity of 20% of utility peak demand and showing the peak line at 90% of utility peak. Solid shading indicates periods of demand side management. Source: Perez et al., 2006.

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 CO_2, 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 CO_2 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.

REFERENCES

Arizona Public Service (2010). Review of residential rates. Available at http://www.aps.com/_files/rates/e-12.pdf

Austin Energy (2010). Review of residential rates. Available at http://www.austinenergy.com/About%20Us/Rates/residential.htm

California Energy Commission (2009). California energy demand 2010-2020 adopted forecast. Available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF

Doris, E., McLaren, J., Healey, V., & Hockett, S. (2009). *State of the states 2009: renewable energy development and the role of policy* (NREL/TP-6A2-46667). Golden, CO: National Renewable Energy Laboratory.

Doris, E., Busche, S., & Hockett, S. (2009). *Net Metering Policy Development in Minnesota: Overview of Trends in Nationwide Policy Development and Implications of Increasing the Eligible System Size Cap.* (NREL/TP-6A2-46670). Golden, CO: National Renewable Energy Laboratory.

Energy and Environmental Economics, Inc. (2010). *Net energy metering (NEM) cost effectiveness evaluation* (E3 study). Available at http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm

Hoff, T.E., Perez, R., Braun, G., Kuhn, M., & Norris, B. (2006). *The value of distributed photovoltaics to Austin Energy and the city of Austin* (AE study).

Itron, Inc. (2010). *CPUC California solar initiative 2009 impact evaluation final report.*

Itron, Inc. (2009). *CPUC self-generation incentive program eighth-year impact evaluation revised final report.*

Mills, A., & Wiser, R. (2010). *Implications of wide-area geographic diversity for short-term variability of solar power* (LBNL-3884E). Berkeley, CA: Lawrence Berkeley National Laboratory. Available at http://eetd.lbl.gov/EA/EMP

Network for New Energy Choices (2011). *Freeing the grid.* Retrieved 12 January 2012 from http://www.newenergychoices.org

Paidipati, J., Frantzis, L., Sawyer, H., & Kurrasch, A. (2008). *Rooftop photovoltaics market penetration scenarios* (NREL/SR-581-42306). Golden, CO: National Renewable Energy Laboratory.

Perez, R. et al. (2006). *Integration of PV in demand response programs.* Available at http://www.asrc.cestm.albany.edu/perez/directory/LoadMatch.html

R.W. Beck, Inc. (2009). *Distributed renewable energy operating impacts and valuation study* (APS study).

Schlissel, D., Johnston, L., Biewald, B., White, D., Hausman, E., James, C., & Fisher, J. (2008). *Synapse 2008 CO_2 price forecasts.* Cambridge, MA: Synapse Energy Economics, Inc.

Wiser, R., Barbose, G., Peterman, C., & Darghouth, N. (2009). *Tracking the sun II: the installed costs of photovoltaics.* Berkeley, CA: Lawrence Berkeley National Laboratory.

Wiser, R., Bolinger, M., & St. Clair, M. (2005). *Easing the natural gas crisis: reducing natural gas prices through increased deployment of renewable energy and energy efficiency.* Berkeley, CA: Lawrence Berkeley National Laboratory.

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

Solar America Board for Codes and Standards

www.solarabcs.org

Environmental Research Letters

OPEN ACCESS

RECEIVED
1 October 2014

ACCEPTED FOR PUBLICATION
19 December 2014

PUBLISHED
4 February 2015

LETTER

Exploring the market for third-party-owned residential photovoltaic systems: insights from lease and power-purchase agreement contract structures and costs in California

Carolyn Davidson, Daniel Steinberg and Robert Margolis

National Renewable Energy Laboratory (NREL), 15013 Denver West Parkway, Golden, CO 80401, USA

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) depreciation[1]. Under a TPO contract, the contract type and payment structure between the solar customer (homeowner) and the system owner (solar integrator or third-party financer) 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 2010–2012[2]. 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 2013[3]. 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.

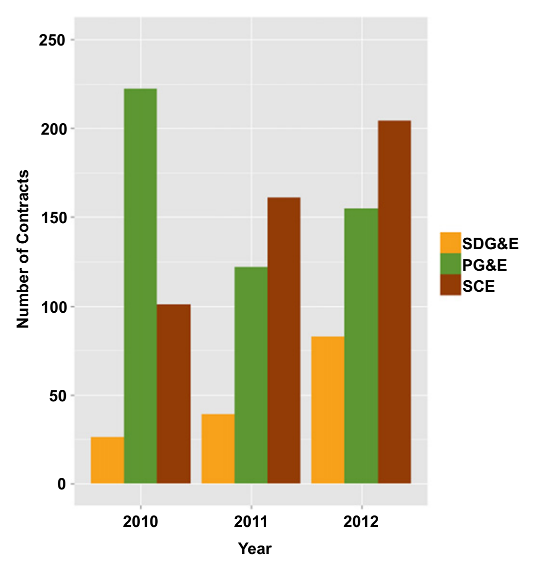


Figure 1. Number of TPO contracts in sample by year and utility.

during 2010–2012[4]. 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 database[6]. 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 Metcalft 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.

$$\begin{aligned}&\text{Real contract price}\,(\$2012)_i\\&\quad = \text{Upfront payment}\\&\qquad + \sum_{y=1}^{t}\Big(\Big[\text{monthly payment}^{*}(1+e)^{y}{}^{*}12\Big]/\\&\qquad \Big[(1+d)^{y-1}\Big]\Big),\end{aligned} \tag{1}$$

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 contract[7]. We assume system production declines of 0.05% per year (Jordan and Kurtz 2011) and calculate the estimated monthly payment as follows:

$$\begin{aligned}&\text{Estimated monthly payment}\\&\quad = \text{estimated monthly production} \times (0.995)^{y-1}\\&\qquad \times \text{PPA rate}.\end{aligned} \tag{2}$$

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 inflation[8]. 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 financer/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 financer/integrator preferences.

[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).

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

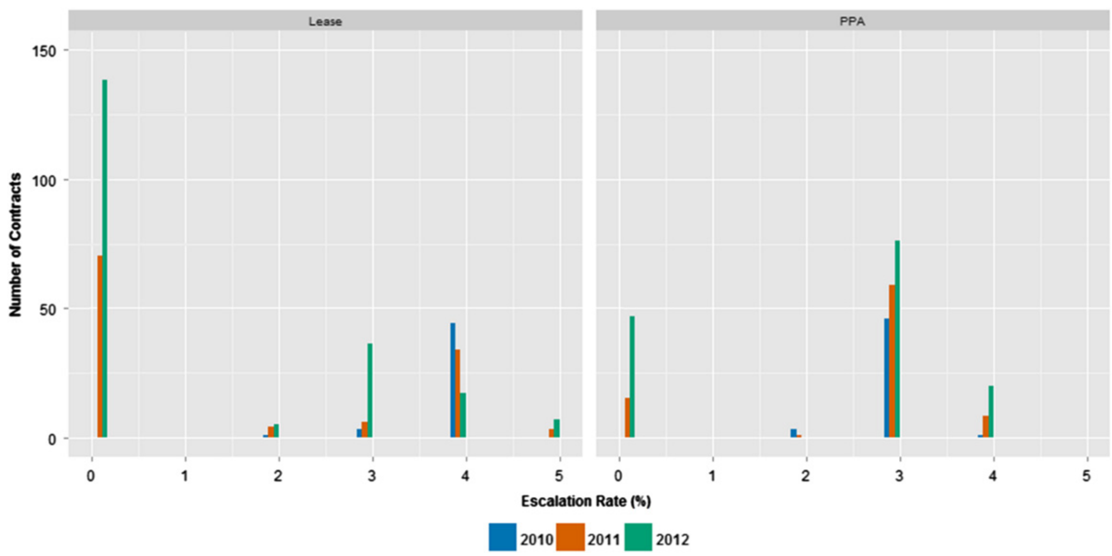


Figure 2. Escalation rate by contract type and year.

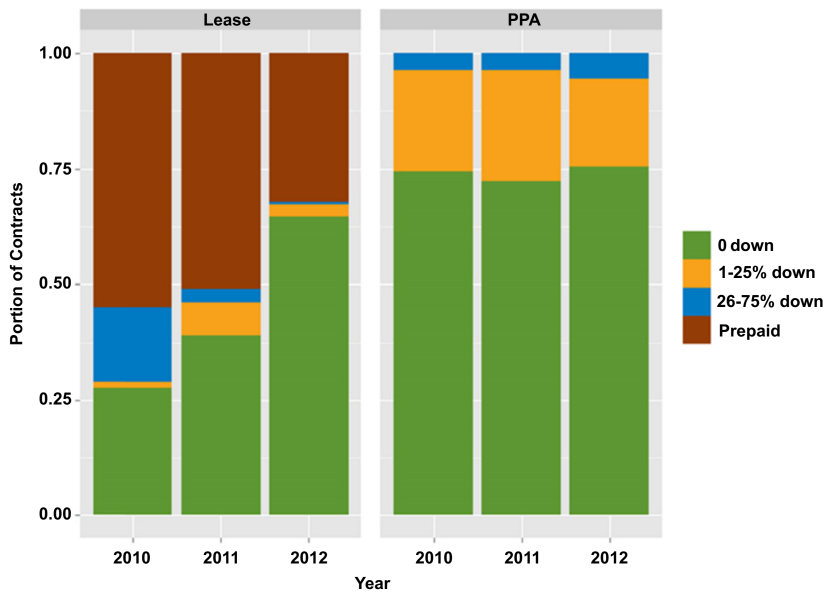


Figure 3. Contract payment schedule by contract type and year.

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].

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 escalators[10]. 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

[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.

[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%.

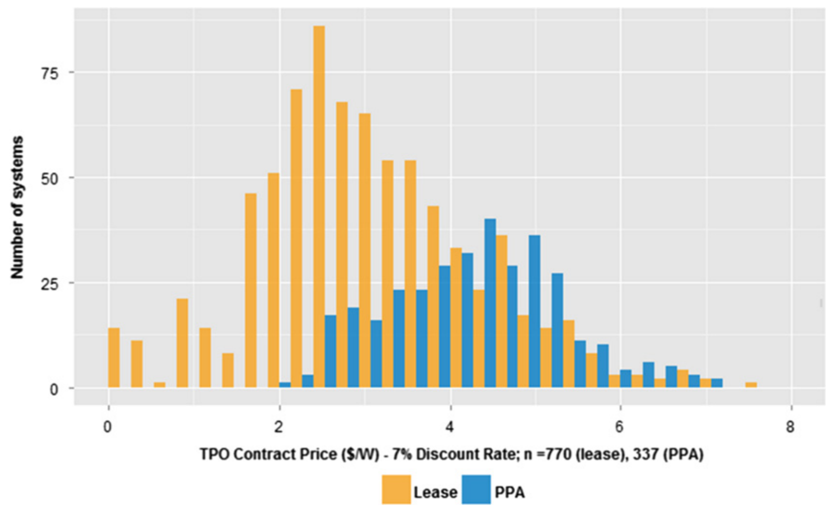


Figure 4. Distribution of contract prices for PPAs and leases (assuming a 7% discount rate).

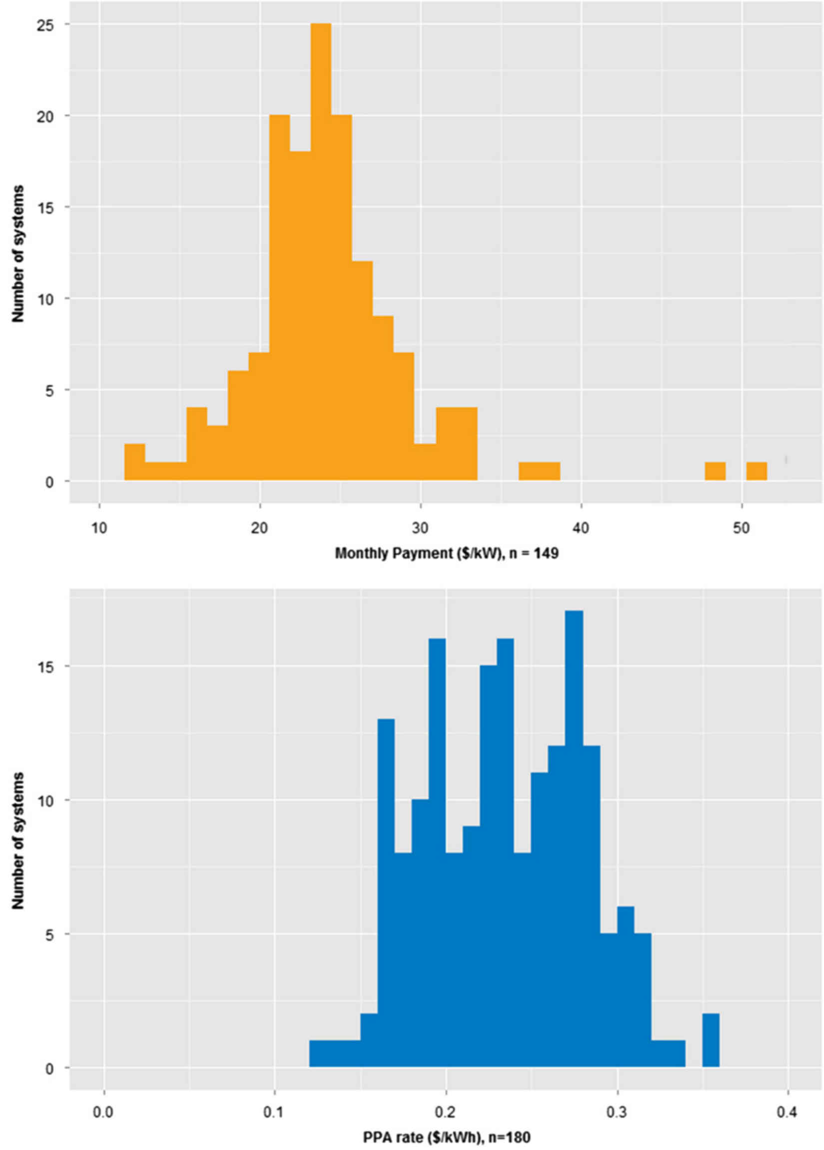
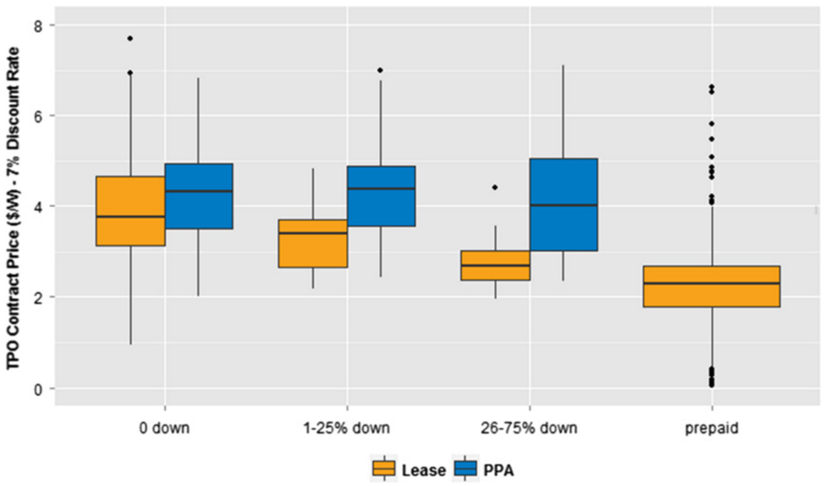


Figure 5. Distribution of monthly lease payments (top) and PPA rates (bottom); no-money down contracts.



	Lease	PPA
	Mean Contract Price ($/W) and observations	
0 down	$3.79 (n=351)	$4.31 (n=251)
1-25% down	$3.39 (n=27)	$4.38 (n=71)
26-75% down	$2.70 (n=46)	$4.01 (n=15)
prepaid	$2.30 (n=346)	NA (n=0)
All contracts	$3.04 (n=770)	$4.27 (n=337)

Figure 6. Real contract price by contract type, discount rate, and payment structure.

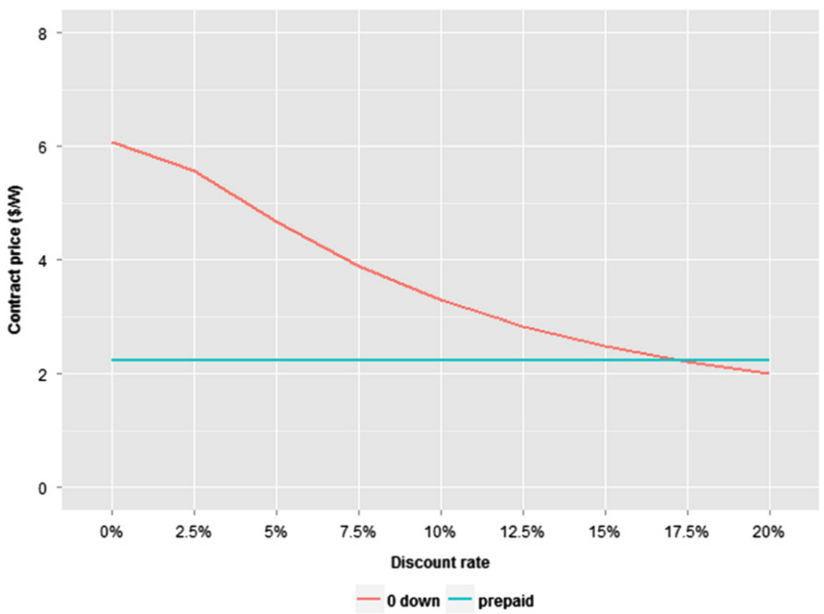


Figure 7. Present-value lease price by payment structure and discount rate.

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,

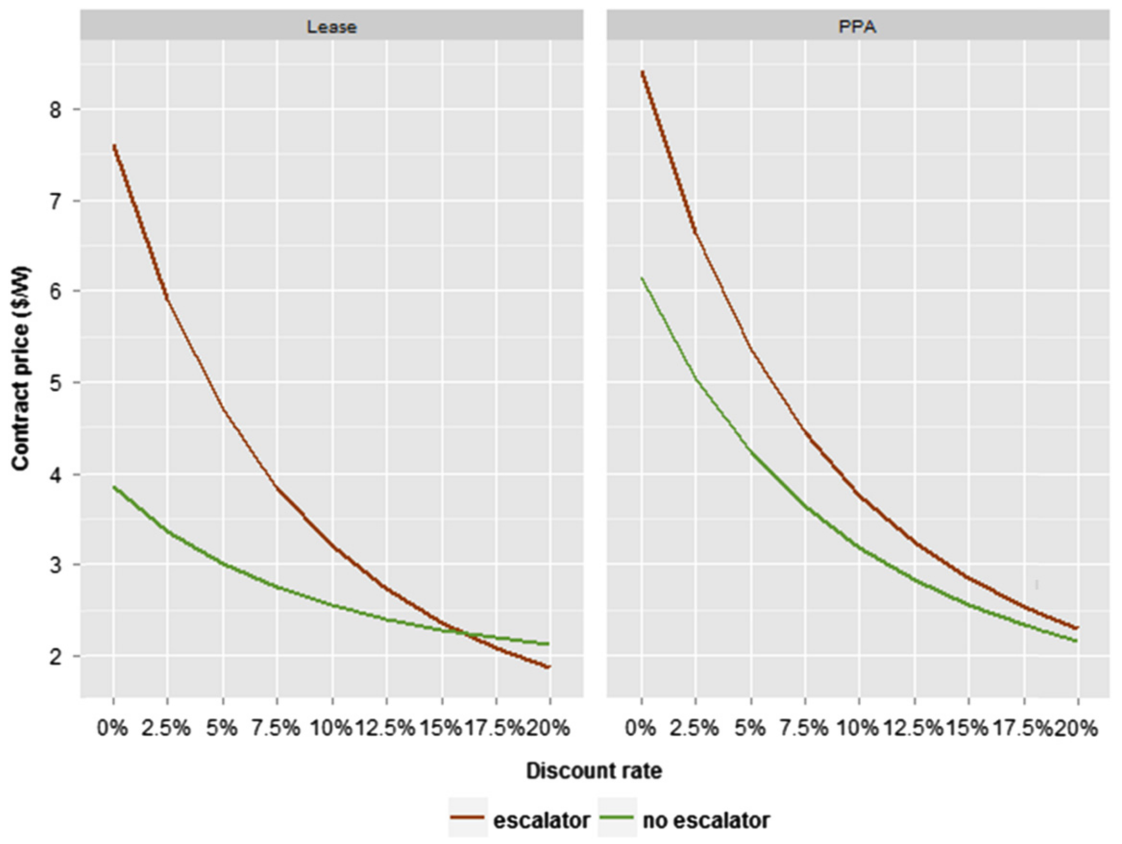


Figure 8. Real contract price by discount rate, contract type, and escalator.

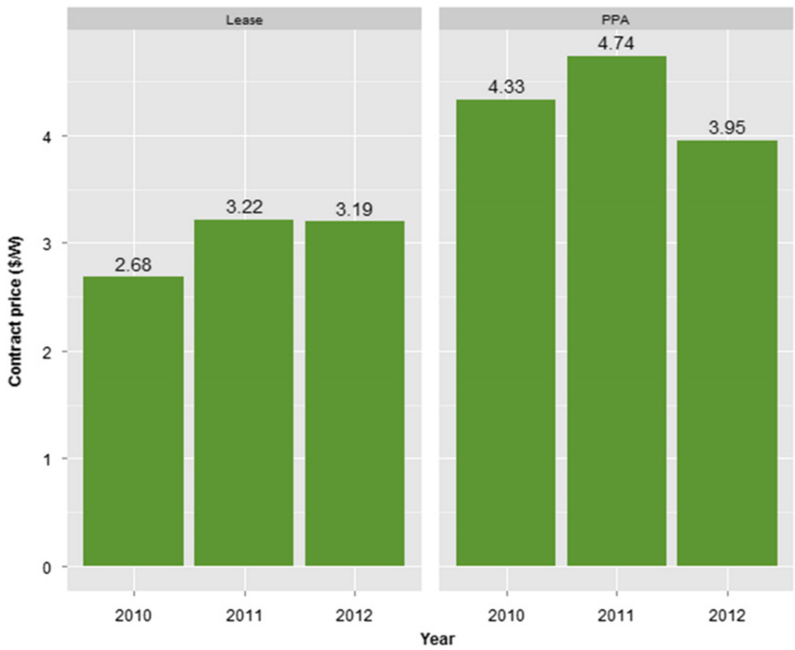


Figure 9. Real contract price (mean) by year for leases (left) and PPAs (right), 7% discount rate.

while lease prices remained flat (figure 9)[11]. While 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

[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%.

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 2012[12]. 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 financer. 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 rage 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

[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.

[14] This difference is found to be statistically significant at >0.1%.

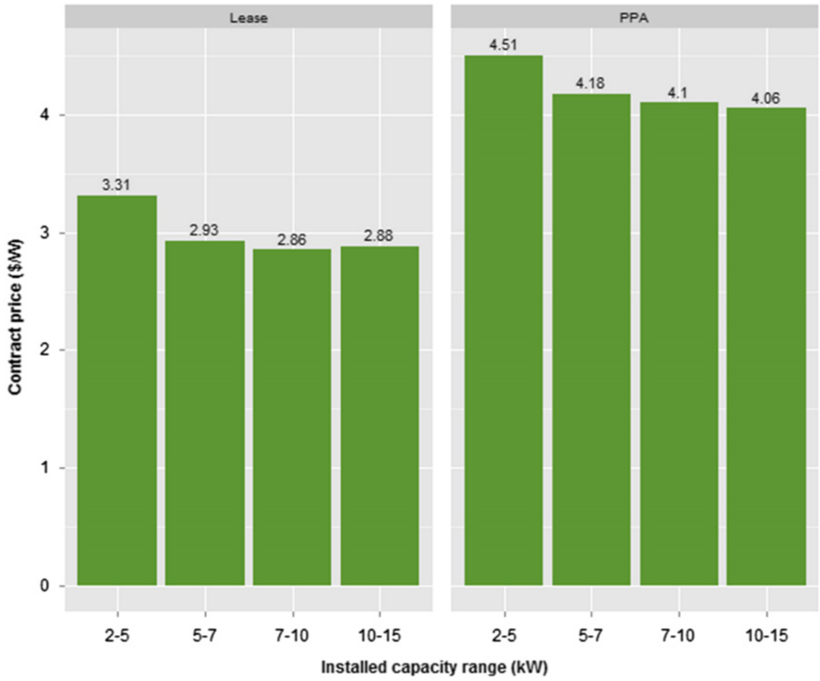


Figure 10. Real contract price (mean) by system capacity for leases (left) and PPAs (right), 7% discount rate.

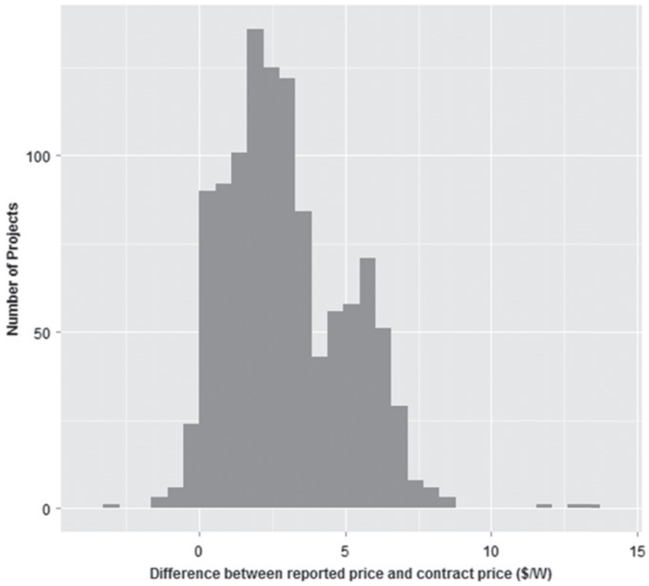


Figure 11. Difference between CSI-reported installed price and calculated contract price, 7% discount rate.

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 behavior[15].

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 financers 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 lease[16].

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 watt[17].
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.

References

Barbose G, Darghouth N, Weaver S and Wiser R 2014 Tracking the Sun V An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013.

California Solar Statistics 2014 http://californiasolarstatistics.ca.gov/(accessed 7/10/2014)

Dasgupta S, Siddarth S and Silva-Risso J 2007 To lease or to buy? A structural model of a consumer's vehicle and contract choice decisions *J. Mark. Res.* **44** 490–502

Davidson C and Steinberg D 2013 Evaluating the impact of third-party price reporting and other drivers on residential photovoltaic price estimates *Energy Policy* **62** 752–61

DOE (United States Department of Energy) 2012 SunShot Vision Study February 2012

Feldman D and Friedman B 2013 *Financing, Overhead and Profit: An In-Depth Discussion of Costs Associated with Third-Party Financing of Residential and Commercial Photovoltaic Systems* NREL/TP-6A20-6040 (Golden, CO: National Renewable Energy Laboratory)

GTM Research 2013 US Solar Market Insight. The Vendor, Installer and Financier Landscape 2013–2016, 1–70

GTM Research 2014 US Residential Solar Financing 2014–2018

Hassett K A and Metcalft G E 1993 Energy conservation investment: do consumers discount the future correctly? *Energy Policy* **21** 710–6

Jordan D C and Kurtz S R 2012 Photovoltaic degradation rates—an analytical review *Prog. Photovolt.* **21** 12–29

Meier A and Whittier J 1983 Consumer discount rates implied by purchases of energy-efficient refrigerators *Energy* **8** 957–62

Navigant Consulting 2014 *California Solar Initiative: Third-Party Ownership Market Impact Study* (Navigant Consulting)

Nunnally B and Plath D 1989 Leasing versus borrowing: Evaluating alternative forms of consumer credit *J. Consum. Affairs* **23** 383–92

Rai V and Sigrin B 2013 Diffusion of environmentally-friendly energy technologies: buy versus lease differences in residential PV markets *Environ. Res. Lett.* **8** 014022

Train K 1985 Discount rates in consumers' energy related decisions: a review of the literature *Energy J.* **10** 1243–53

U.S. Energy Information Administration 2011 2011 Annual Energy Review

U.S. Energy Information Administration 2014 Annual Energy Outlook 2014(www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=0-AEO2014&table=4-AEO2014&region=0-0&cases=full2013full-d102312a,ref2014-d102413a)

Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners

Technical Report
NREL/TP-6A2-46723
Revised February 2010

Katharine Kollins
Duke University

Bethany Speer and Karlynn Cory
National Renewable Energy Laboratory

Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners

Technical Report
NREL/TP-6A2-46723
Revised February 2010

Katharine Kollins
Duke University

Bethany Speer and Karlynn Cory
National Renewable Energy Laboratory

Prepared under Task No. PVB9.4210

NOTICE

Available electronically at http://www.osti.gov/bridge

Available for a processing fee to U.S. Department of Energy and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: mailto:reports@adonis.osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: http://www.ntis.gov/ordering.htm

Printed on paper containing at least 50% wastepaper, including 20% postconsumer waste

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 <u>not</u> 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 <u>not</u> 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 <u>the utility</u>.

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 / Solution	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 *not* 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 *used* 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.

Table of Contents

List of Figures

List of Tables

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).

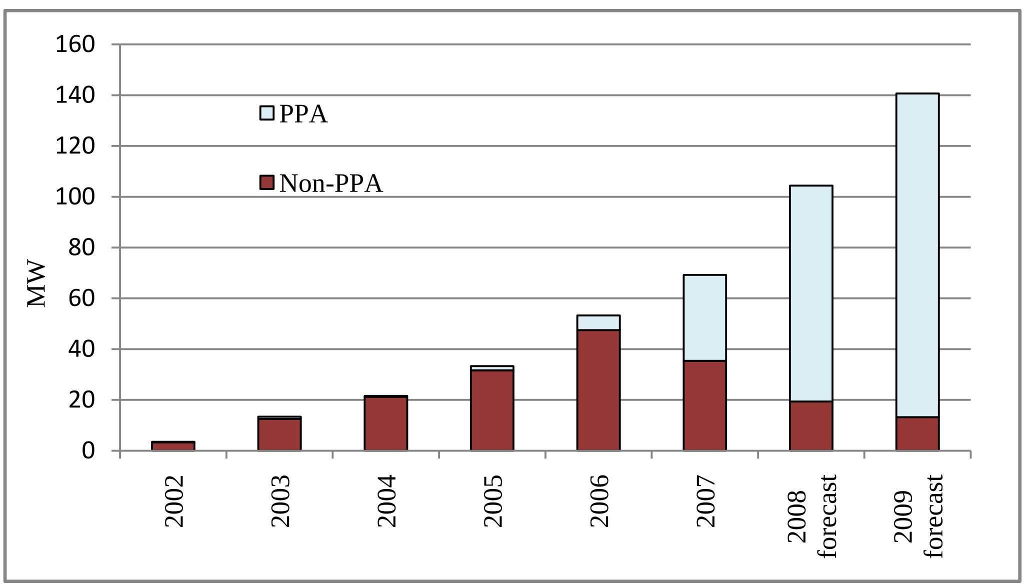


Figure 1. Use of PPAs for U.S. non-residential solar PV installations

[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.

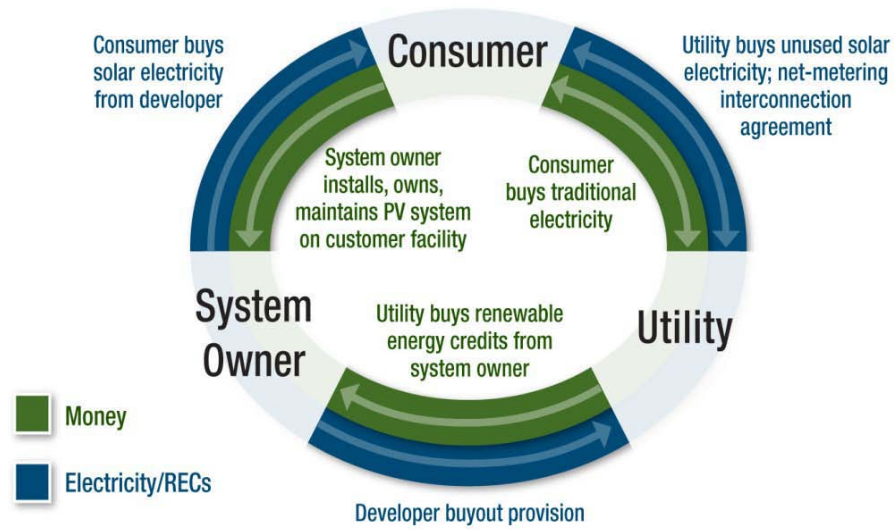


Figure 2. Third-party PPA model
(DOE Solar Energy Technologies Program)

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)."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.

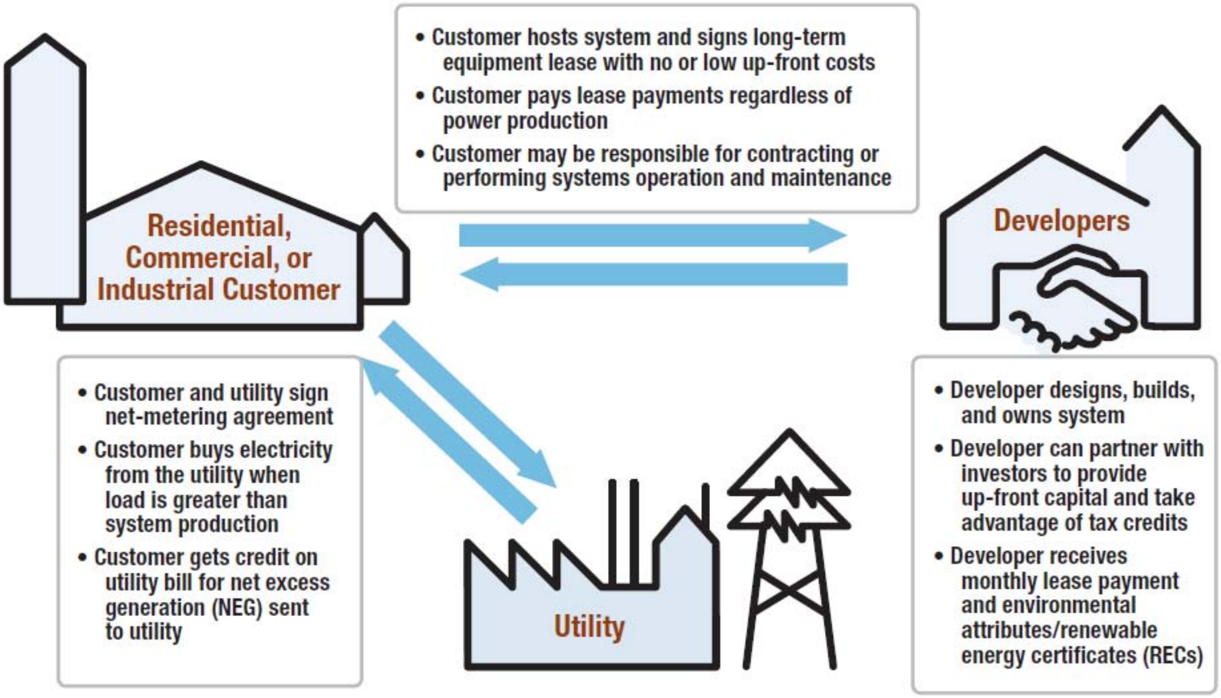


Figure 3. Solar lease structure (aka solar services agreement)

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**
Incentives			
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**
Responsibilities			
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

Solutions \ 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
<u>PPA Solutions</u>					
Clarify third-party owned systems are *not* 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 *used* 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.

References

Arizona Corporation Commission. (2008). “Application for a Declaratory Order that Providers of Certain Solar Service Agreements Would Not be Public Service Corporations,” Arizona Corporation Commission Docket No. E-20633A-08-0513, October 3, 2008. http://images.edocket.azcc.gov/docketpdf/0000089217.pdf (accessed January 29, 2009).

Bolinger, M. (2009). “Financing Non-Residential Photovoltaic Projects: Options and Implications.” Lawrence Berkeley National Laboratory. http://eetd.lbl.gov/ea/ems/reports/lbnl-1410e.pdf (accessed February 13, 2009).

Borenstein, S.; Bushnell, J. (2000). “Electricity Restructuring: Deregulation or Regulation?” *Regulation Magazine for The Cato Institute.* (23:2), pp. 46-52. http://www.cato.org/pubs/regulation/regv23n2/boren.pdf

California Public Utilities Commission. (2009). “California Solar Initiative: Staff Progress Report.” http://www.energy.ca.gov/2009publications/CPUC-1000-2009-002/CPUC-1000-2009-002_report_only.PDF (accessed January 30, 2009).

Chadbourne & Parke. (January 2009). “Project Finance NewsWire.” http://www.chadbourne.com/files/Publication/810dde60-3c78-4a9a-9c5d-a5fae8014b4f/Presentation/PublicationAttachment/51fc06c5-1407-48ac-9dff-a605de0f58e1/pfn0109.pdf (accessed February 13, 2009).

Corbin Solar. (2007). “Financial Incentives.” http://www.corbinsolar.com/incentives.php (accessed November 2008).

Cory, K.; Coggeshall, C.; Kollins, K. (2008). “San Antonio Memo regarding Solar America Cities program.”

Cory, K.; Coughlin, J.; Coggeshall, C. (2008). *Solar Photovoltaic Financing: Deployment on Public Property by State and Local Governments*. NREL/TP-670-43115. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy08osti/43115.pdf (accessed January 30, 2009).

Coughlin, J.; Cory, K. (2009). *Solar Photovoltaic Financing: Residential Sector Deployment*. NREL report no. TP-6A2-44853. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy09osti/44853.pdf (accessed August 31, 2009).

Database of State Incentives for Renewable and Efficiency (DSIRE). (2008a). “Xcel Energy – Solar Rewards Program.” (updated March). http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CO12F&state=CO&CurrentPageID=1&RE=1&EE=1 (accessed January 30, 2009).

DSIRE. (2008b). “Ohio – Net Metering” (updated August). http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=OH02R&state=OH&CurrentPageID=1&RE=1&EE=1 (accessed January 30, 2009).

DSIRE. (2008c). “Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation” (updated February). http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US06F&State=Federal&currentpageid=1 (accessed January 30, 2009).

DSIRE. (2009). “California Solar Initiative” (updated June). http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA134F&state=CA&CurrentPageID=1&RE=1&EE=1 (accessed January 30, 2009).

Energy Information Agency (EIA). (2008). “Status of Electricity Restructuring by State” (updated September). http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html (accessed January 30, 2009).

Federal Energy Regulatory Commission (FERC). (2006). “Legal Resources Order No. 888.” http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp (accessed October 28, 2008).

FERC. (2009a). Declaratory Order, Docket EL09-31-000. http://www.ferc.gov/whats-new/comm-meet/2009/111909/E-29.pdf (accessed November 23, 2009).

FERC. (2009b). “What is a Qualifying Facility?” FERC Web site. http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp (accessed August 31, 2009).

Florida Public Service Commission (FPSC). (1987). “In Re: Petition of Monsanto Company for a Declaratory Statement Concerning the Lease Financing of a Cogeneration Facility.” Docket No. 860725-EU; Order No. 17009, March 9, 1987.

Frantzis, L.S.; Katofsky, R.; Sawyer, H. (2008). *Photovoltaics Business Models*. NREL/SR-581-42304. Work performed by Navigant Consulting, Burlington, MA. Golden, CO: National Renewable Energy Laboratory. http://www.navigantconsulting.com/downloads/NREL Report_PV_Business_Models_US_EG.pdf

Guice, J.; King, J. D. H. (February 2008). “Solar Power Services: How PPAS Are Changing The PV Value Chain. Greentech in Detail.” Greentech Media. http://www.greentechmedia.com/reports/research-report-solar-power-services.html (accessed March 16, 2009).

Holt, E.; Wiser, R.; Bolinger, M. (2006). *Who Owns Renewable Energy Certificates? An Exploration of Policy Options and Practice*. LBNL/TP-59965. Berkeley, CA: Lawrence Berkeley National Laboratory. Available at http://eetd.lbl.gov/EA/EMP/reports/59965.pdf (accessed January 30, 2009).

Interstate Renewable Energy Council (IREC). (2008a). “Nevada PUC Allows Third-Party Ownership.” November 12. Connecting to the Grid News. http://irecusa.org/index.php?id=56&tx_ttnews[tt_news]=1281&cHash=d8712cd6b9 (accessed February 8, 2009).

Keyes, J. (2008). Personal communications. Keyes & Fox, LLP, September–October 2008.

Network for New Energy Choices (NNEC). (2008). *Freeing the Grid 2008 Edition*. Report No. 02-07, October. New York: Network for New Energy Choices. http://www.newenergychoices.org/uploads/FreeingTheGrid2008_report.pdf (accessed January 29, 2009).

New Jersey Clean Energy Program (NJ Clean Energy). (2007). "New Jersey Approves Solar REC-Based Financing System" (December 17). http://www.njcleanenergy.com/files/file/SOLARTransitionFAQs121707%20fnl2(2).pdf (accessed January 30, 2009).

NJ Clean Energy. (2009). "SREC Pricing" (November 17). http://www.njcleanenergy.com/renewable-energy/project-activity-reports/srec-pricing/srec-pricing (accessed January 30, 2009).

Oregon Public Utilities Commission (OPUC). (2008). "Declaratory Ruling in the Matter of Honeywell International, Inc., and Honeywell Global Finance, LLC, and Pacificorp, dba Pacific Power," Oregon Public Utilities Commission Order No. 08-388, 31 July 2008. http://apps.puc.state.or.us/orders/2008ords/08-388.pdf (accessed January 30, 2009).

Public Utilities Commission of Nevada (PUCN). (2008). "Staff Comments on Docket 07-06024," Public Utilities Commission of Nevada, September 24, http://pucweb1.state.nv.us/PUCN/DktInfo.aspx?Util=All (accessed January 30, 2009).

Renewable Ventures. (March 6, 2009). "MMA Renewable Ventures and Global Solar Sign First PPA for CIGS Thin Film**:** 750 kW thin film installation marks solar energy industry first." Accessed June 9, 2009. http://mmarenew.com/news/docs/MMA_GSE_Final.pdf.

Solar Energy Industries Association (SEIA). (2008). *Guide to Federal Tax Incentives for Solar Energy: Version 2.0.* Solar Energy Industries Association, October 7.

SEIA. (2009). "About Solar Energy: Growth of the U.S. Market," SEIA Web site. Available online at: http://www.seia.org/cs/about_solar_energy/industry_data (accessed April 30, 2009).

Showalter, M. (2008). *Electricity Price Trends Deregulated vs. Regulated States*. Olympia, WA: Power in the Public Interest, February 12, 2008. http://www.ppinet.org/PDFs/NA%20Rpt%20Elec%20Prices%20OCT07data%202-12-08C.pdf (accessed January 30, 2009).

Smith, R. (7 May 2008). "Expect a Jolt When Opening the Electric Bill." *Wall Street Journal.* http://finance.yahoo.com/family-home/article/105023/Expect-a-Jolt-When-Opening-the-Electric-Bill

State of Arizona (AZ). (2007). "An Act Amending Sections 43-1085 and 43-1164, Arizona Revised Statutes; Relating to Income Tax Credits," House Bill 2491. http://www.azleg.gov/legtext/48leg/1r/bills/hb2491h.pdf (accessed January 30, 2009).

State of Colorado (CO). (2009). "An Act Concerning Measures to Facilitate the Financing of Energy-Efficient Structures," Senate Bill 51. http://www.leg.state.co.us/clics/clics2009a/csl.nsf/fsbillcont3/571064D80C28D7C387257537001B9472?open&file=051_enr.pdf (accessed May 19, 2009).

State of Oregon (OR). (2007). "Electricity Supply and Oregon, Sources of Electricity." http://www.oregon.gov/ENERGY/supply.shtml#Sources_of_Electricity (accessed October 22, 2008).

Stoel Rives. (2006). "Energy Law Alert: New FERC Order Weakens PURPA's QF 'Must Buy' Provisions." Stoel Rives LLP, October 23. http://www.stoel.com/showalert.aspx?Show=2308 (accessed January 30, 2009).

U.S. Congress. House (H.R.). (2008). "Emergency Economic Stabilization Act of 2008," House of Representatives Bill 1424, 1 October 2008. http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi ?dbname=110_cong_bills&docid=f:h1424eas.txt.pdfh (accessed January 30, 2009).

Western Area Power Association (WAPA). (2008). "Nellis AFB Credits Teamwork for Largest PV System in U.S.," Western Area Power Association Energy Services Bulletin, February 2008. http://www.wapa.gov/ES/pubs/esb/2008/feb/feb081.htm (accessed January 30, 2009).

Wiser, R.; Barbose, G. (2008). *Renewables Portfolio Standards in the United States: A Status Report with Data Through 2007*. LBNL/TPL-154E. Berkeley, CA: Lawrence Berkeley National Laboratory. http://eetd.lbl.gov/ea/EMS/reports/lbnl-154e-revised.pdf-(accessed January 30, 2009).

Bibliography

Colorado Public Utilities Commission (CPUC). (2008a). Interim Order of Administrative Law Judge Ken F. Kirkpatrick Providing Draft Rules, Decision No. R08-1148-I, Docket No. 08R-424E. Available online at: http://www.dora.state.co.us/PUC/DocketsDecisions/decisions/2008/R08-1148-I_08R-424E.pdfh(accessed February 19, 2009).

CPUC. (2008b). Notice of Proposed Rulemaking September 17, 2008, Decision No. C08-1001, Docket No. 08R-424E. Available online at: http://www.dora.state.co.us/PUC/DocketsDecisions/decisions/2008/C08-1001_08R-424E.pdf (accessed February 19, 2009).

CPUC. (2008c). Recommended Decision of Administrative Law Judge Ken F. Kirkpatrick, Adopting Rule. http://www.dora.state.co.us/puc/DocketsDecisions/decisions/2009/R09-0413_08R-424E.pdf (accessed May 4, 2009).

Cory, K.; Coggeshall, C.; Coughlin, J.; Kreycik, C. (July 2009). *Solar Photovoltaic Financing: Deployment by Federal Government Agencies*. NREL report no. TP-6A2-46397. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy09osti/46397.pdf (accessed August 31, 2009).

Database of State Incentives for Renewable and Efficiency (DSIRE). (2008d). "Austin Energy—Net Metering" (updated November). http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=TX04R&state=TX&CurrentPageID=1&RE=1&EE=1h (accessed January 30, 2009).

DSIRE. (2008e). "Net Metering Summary Map" (updated October). http://www.dsireusa.org/library/includes/topic.cfm?TopicCategoryID=6&CurrentPageID=10&EE=1&RE=1 (accessed January 30, 2009).

DSIRE. (2008f). "NYSERDA - PV Incentive Program" (updated June). http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NY03F&state=NY&CurrentPageID=1&RE=1&EE=1h (accessed January 30, 2009).

DSIRE. (2008g). "Solar and Fuel Cell Tax Credit." Database of State Incentives for Renewables and Efficiency, Updated September 24. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NY03F&state=NY&CurrentPageID=1&RE=1&EE=1h (accessed January 30, 2009).

Florida Energy Commission (FEC). (2007). "Recommendations Adopted by the FEC – Renewable Energy – Recommendation 42." http://www.floridaenergycommission.gov/UserContent/docs/File/Renewables.pdf (accessed January 30, 2009).

Haynes, R. (2009). Personal communication. N.C. Solar Center/Database of State Incentives for Renewable Energy (DSIRE), February 5, 2009.

Interstate Renewable Energy Council (IREC). (2008b). *Updates and Trends*. IREC's 2008 Annual Report. Latham, NY: Interstate Renewable Energy Council. http://irecusa.org/index.php?id=

68&tx_ttnews%5bpS%5d=1224609229&tx_ttnews%5btt_news%5d=1238&tx_ttnews%5bbackPid%5d=70&cHash=5d8e335c41h (accessed January 30, 2009).

Miller, C. (2008). Telephone conversation. Florida Public Service Commission Senior Attorney, September 23, 2008.

New Jersey Board of Public Utilities. (2008). New Jersey Amendment Code 14:8-4.2 and 4.3, which Docket #: EX08070548. Available online at: http://www.state.nj.us/bpu/pdf/rules/NMIX.pdf (accessed February 27, 2009).

Public Utilities Commission of Texas (PUCT). (2008). Order adopting new 25.217 and amendment to 25.242, December 18, 2008 Open Meeting, December 22. http://www.puc.state.tx.us/rules/subrules/electric/25.217/34890adt.pdfh (accessed January 30, 2009).

World Resources Institute (WRI). (2003). *Case Study: Purchasing an Onsite Solar PV System: Johnson & Johnson's Janssen Pharmaceutical Facility – Titusville, New Jersey*. Washington, D.C.: World Resources Institute Green Power Market Development Group. http://www.thegreenpowergroup.org/pdf/case_studies_JJ.pdf (accessed January 30, 2009).

WRI. (2008). *The Bottom Line on Renewable Energy Tax Credits*. Washington, D.C.: World Resources Institute. http://www.wri.org/publication/bottom-line-series-renewable-energy-tax-creditsh (accessed January 30, 2009).

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.

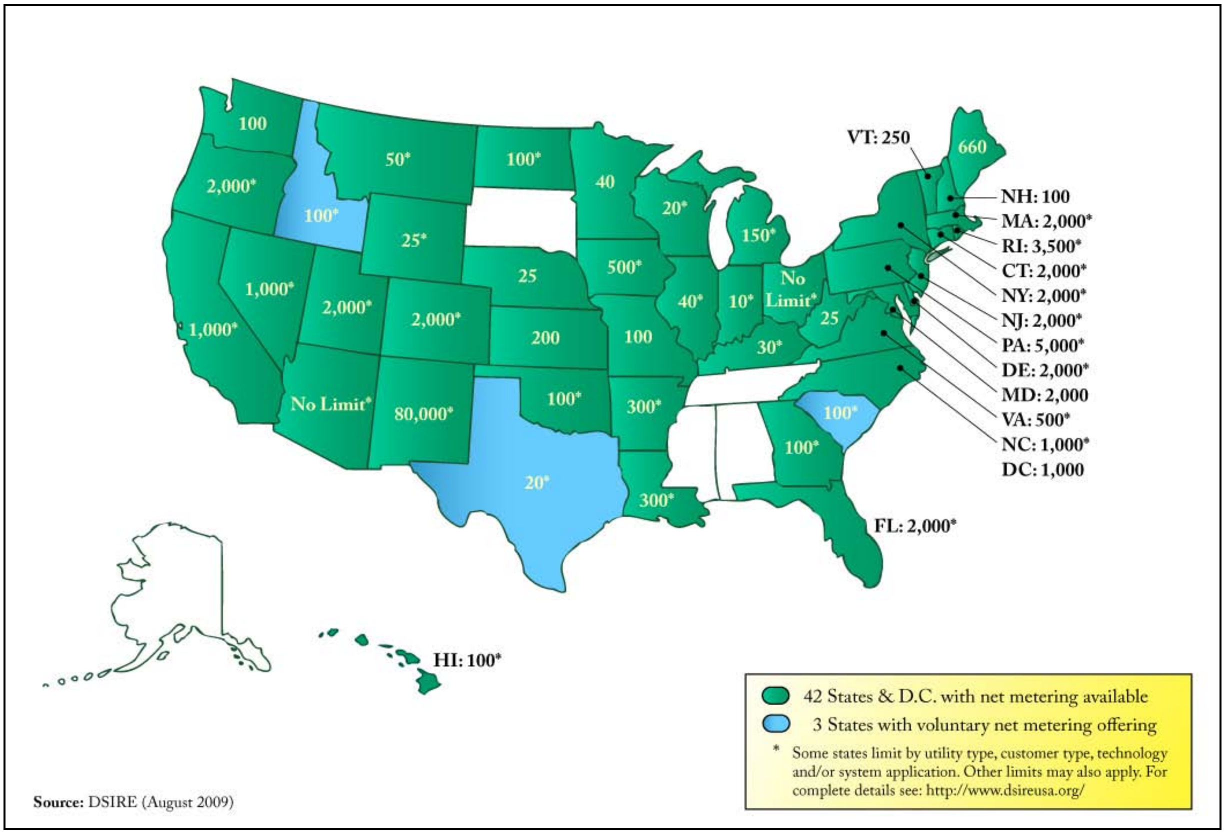


Figure B-1. Map of states with net metering standards (August 2009)

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 business[16] 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.

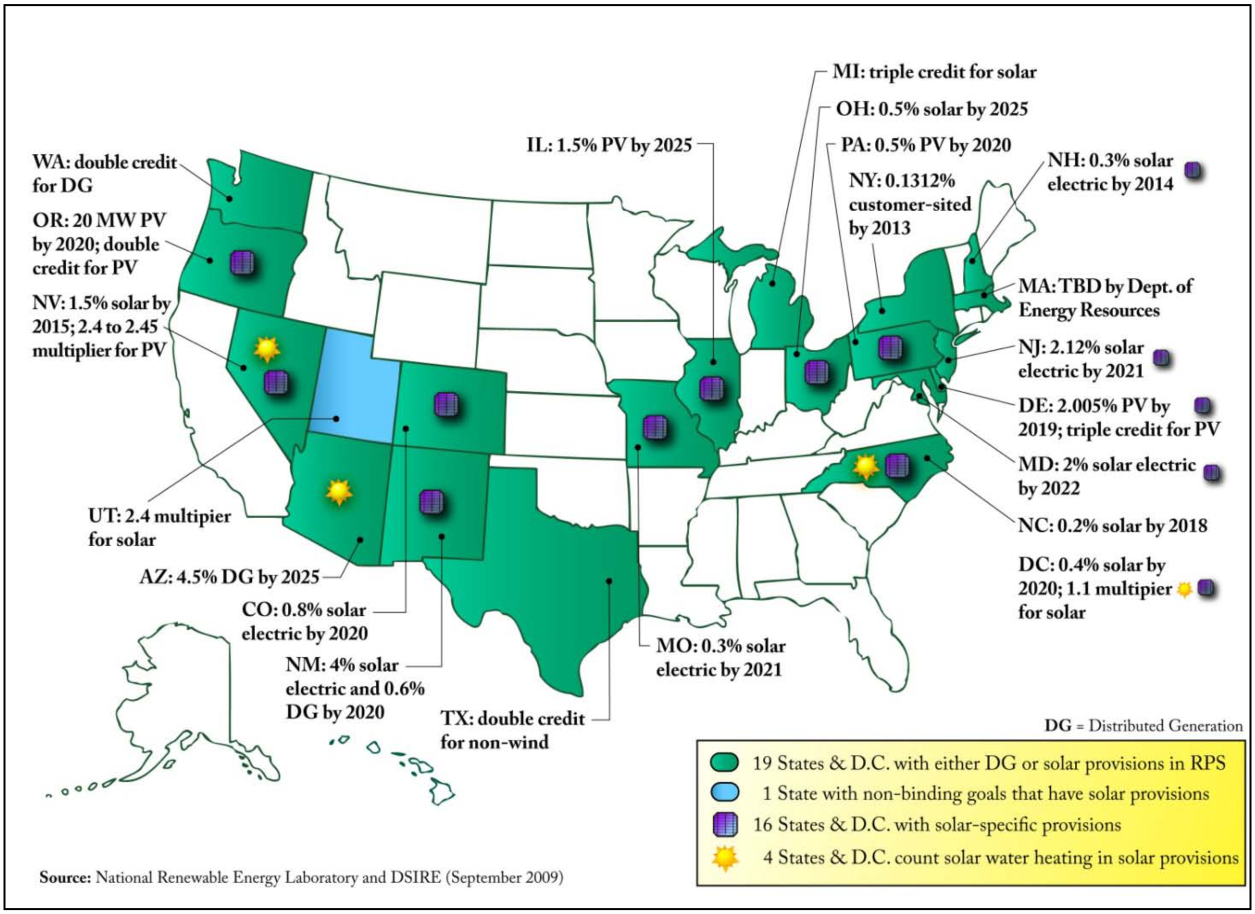


Figure C-1. Map of solar and DG provisions in RPS policies (August 2009)

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 3rd 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 PAGE	*Form Approved* *OMB No. 0704-0188*

1. **REPORT DATE** *(DD-MM-YYYY)*	2. **REPORT TYPE**	3. **DATES COVERED** *(From - To)*
Revised February 2010	Technical Report	

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;

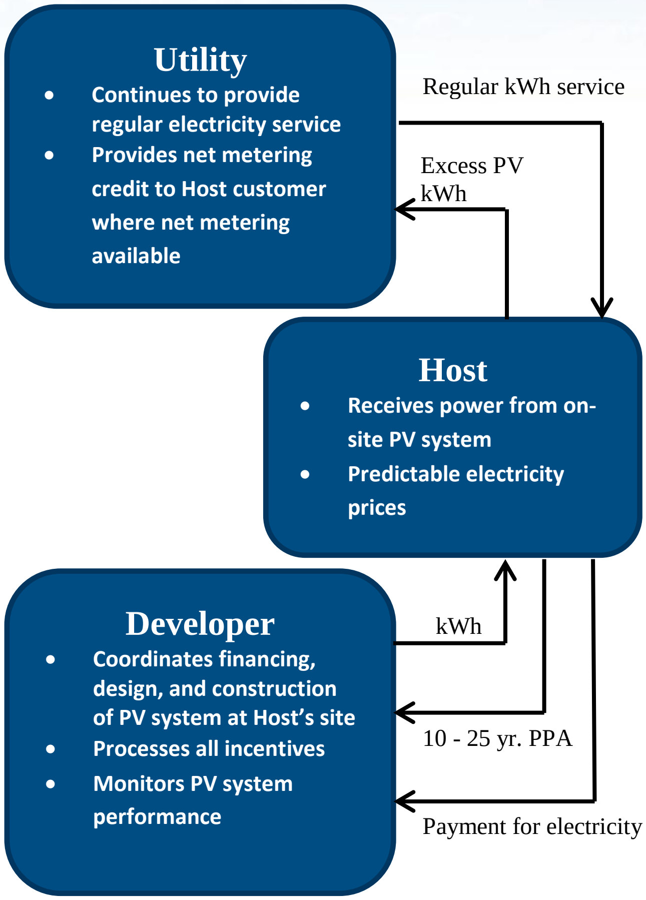
regulatory problems; regulated electricity providers; electric services providers; competitive electricity suppliers; power generation equipment; sellers of electricity; Colorado; Florida; New Mexico; Nevada; New Jersey; Oregon; Texas; net meter; net metering; contracts, contract language; financial incentives

16. SECURITY CLASSIFICATION OF:			**17. LIMITATION OF ABSTRACT**	**18. NUMBER OF PAGES**	**19a. NAME OF RESPONSIBLE PERSON**
a. REPORT	**b. ABSTRACT**	**c. THIS PAGE**			
Unclassified	Unclassified	Unclassified	UL		**19b. TELEPHONE NUMBER** (*Include area code)*

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.

SEIA Solar Energy Industries Association®

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%20lbnl-4476e.pdf

[ii] Solar Market Insight Q2 2012 – Executive Summary. https://www.slideshare.net/SEIA/us-solar-market-insight-report-q2-2012

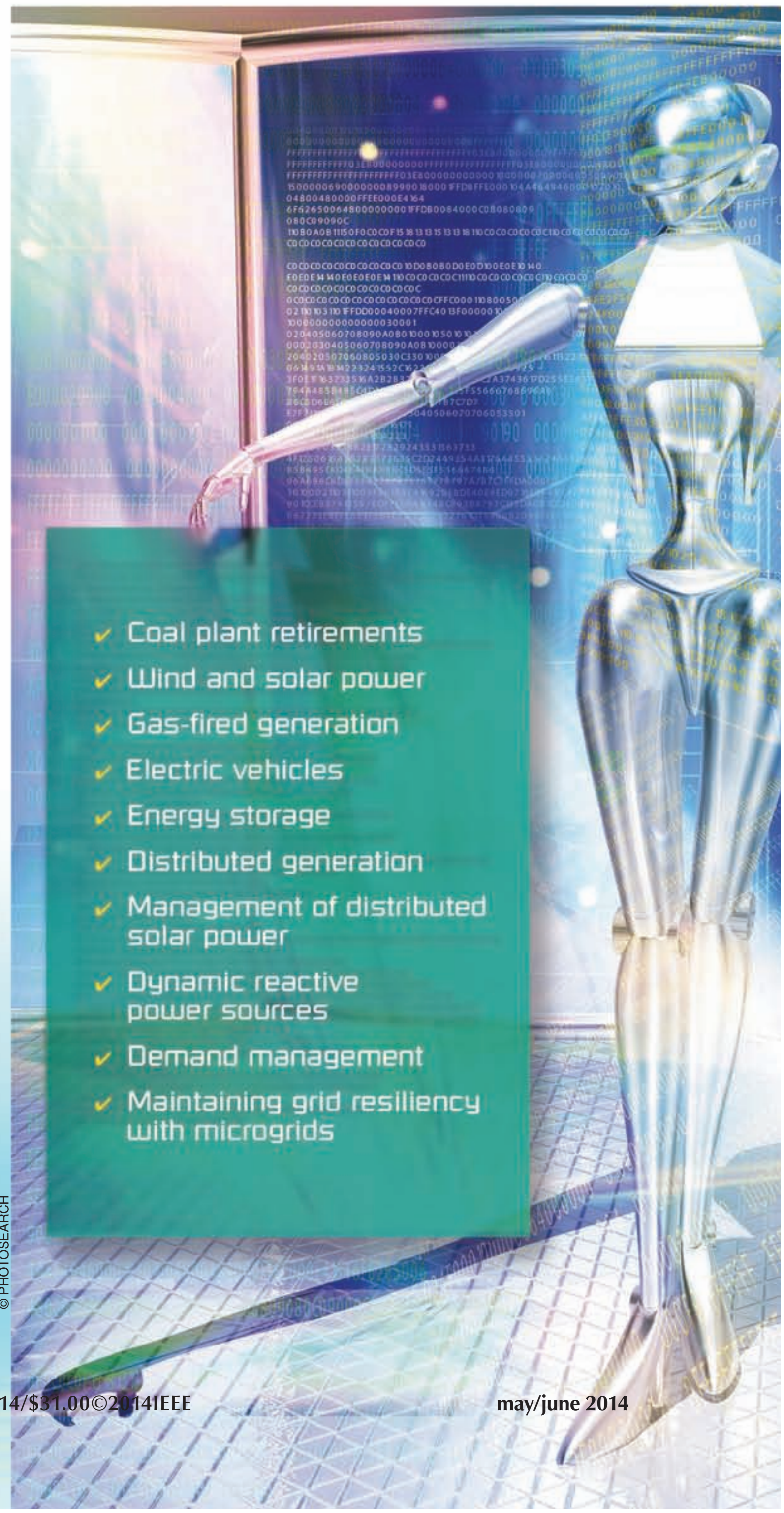
About the Solar Energy Industries Association®

Established in 1974, the Solar Energy Industries Association is the national trade association of the U.S. solar energy industry. Through advocacy and education, SEIA® and its 1,100 member companies are building a strong solar industry to power America. As the voice of the industry, SEIA works to make solar a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry and educating the public on the benefits of solar energy.

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

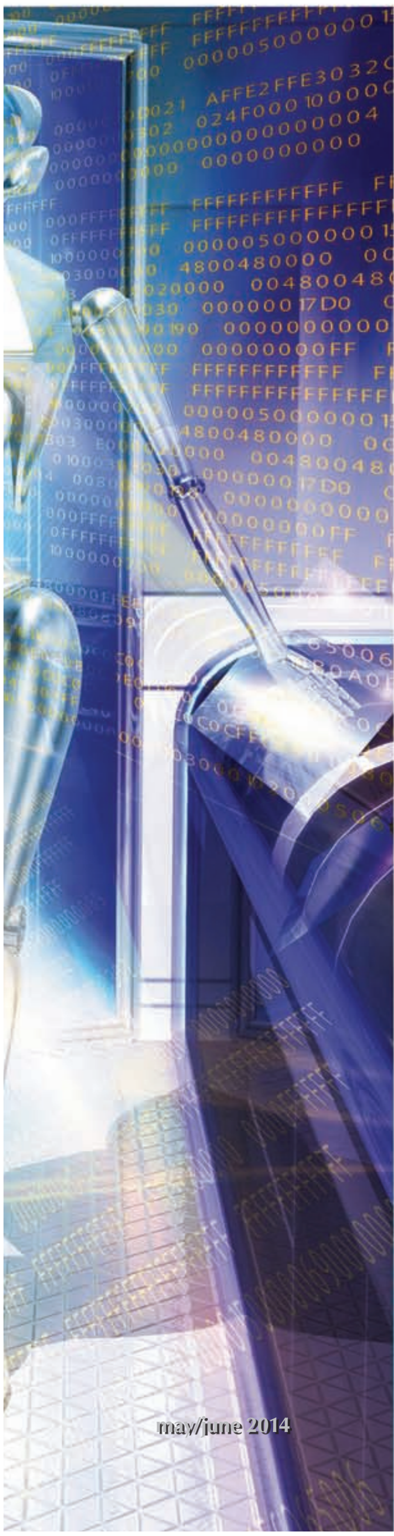


© PHOTOSEARCH

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 revolutionalized 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

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

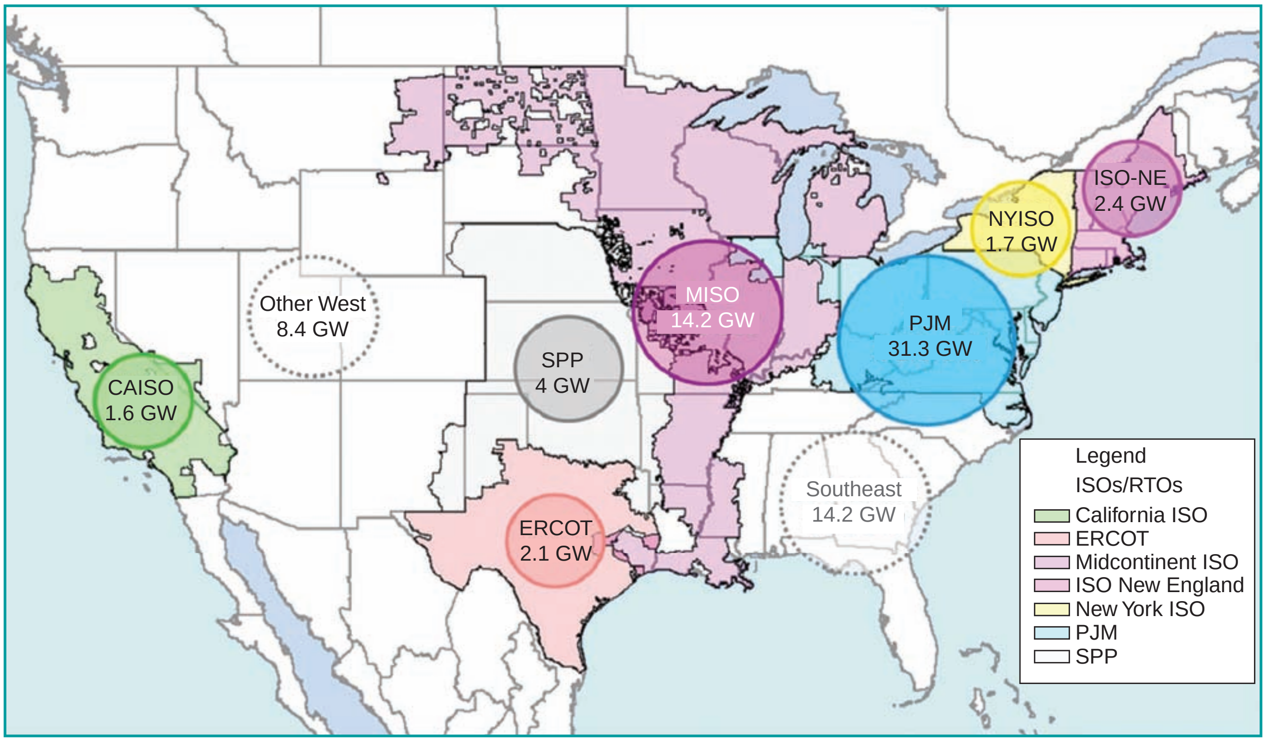


figure 1. Potential coal retirements (map created with Ventyx, an ABB Company, Energy Velocity Suite, Intelligent Map).

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

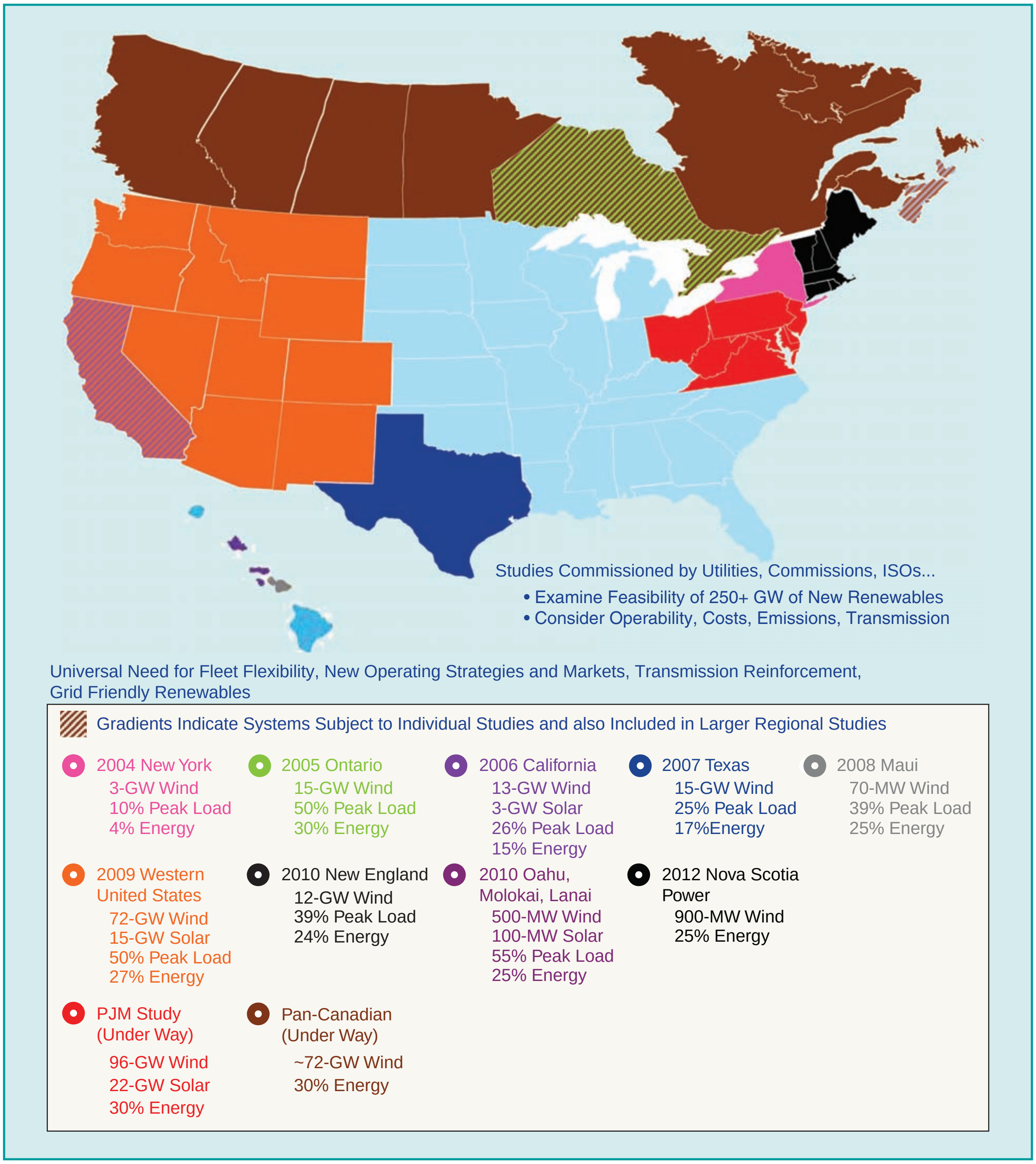
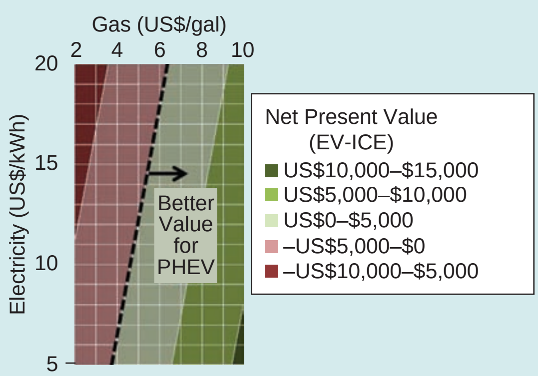


figure 2. Recent GE wind and solar integration studies.

> 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.



	PHEV	Hybrid ICE
Vehicle Cost	US$35,000	US$30,000
Fuel Economy	35 kWh/100 mi	51 mi/gal

10,000 mi/Year, 2% Interest Rate (Car Loan)

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).

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 capabiliies 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.

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

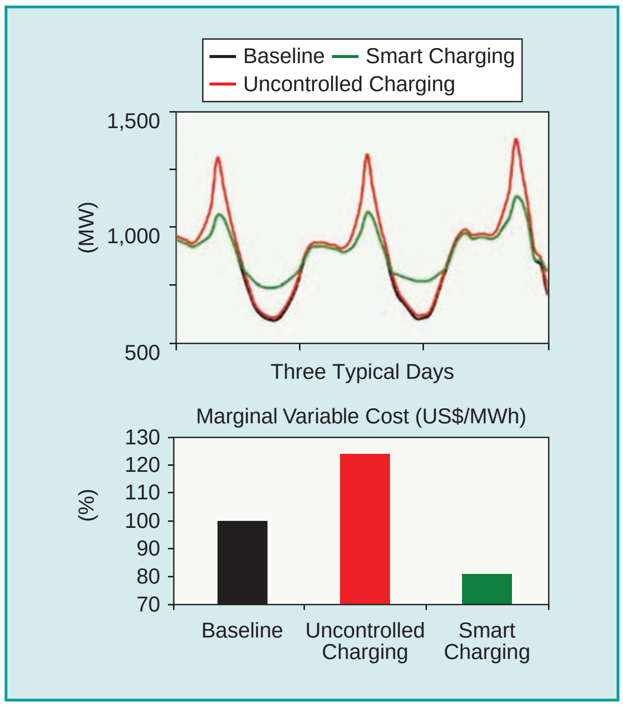


figure 4. Marginal variable cost of serving the EV load for two EV charging strategies, with respect to the marginal cost of serving uniform load growth. (Used with permission from "Integrating Electric Vehicles into the Power System," 2011 CIGRE Symposium.)

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, sudies 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 Metlakatla, 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

B. Daryanian, H. Elahi, E. LaRose, and R. Walling, “Trends for the grid of the future,” in *Proc. 2012 CIGRE U.S. National Committee, Grid of the Future Symposium,* Kansas City, MO.

National Renewable Energy Laboratory. (2010). Western wind and solar integration study. [Online]. Available: http://www.nrel.gov/wind/systemsintegration/wwsis.html

Independent System Operators of New England (ISO-NE). New England wind integration study. [Online]. Available: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf

Proposed Decision of Commissioner Peterman. (2010, Dec. 16). Decision adopting energy storage procurement framework and design program. [Online]. Available: http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&DocID=76387883

G. Hunt, “Metlakatla battery energy storage system: 12 yrs. of success,” *GNB Industrial Power*, Exide Technologies, presented at 2009 Storage Week, San Diego, CA.

D. Manz, N. Miller, and G. Hinkle, “Integrating electric vehicles into the power system,” in *Proc. 2011 CIGRE Symp.*, Bologna, Italy.

FERC. (2010, June 17). National action plan on demand response. [Online]. Available: https://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf

The Brattle Group. (2010, Aug. 12). Demand response & energy efficiency: The long view. [Online]. Available: http://www.brattle.com/system/publications/pdfs/000/004/516/original/Demand_Response_and_Energy_Efficiency_-_The_Long_View_Faruqui_Aug_12_2010.pdf?1378772111

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.”

Biographies

Devon Manz is with GE Energy Consulting, Schenectady, New York.

Reigh Walling is with Walling Energy Systems Consulting.

Nick Miller is with GE Energy Consulting, Schenectady, New York.

Beth LaRose is with GE Energy Consulting, Schenectady, New York.

Rob D’Aquila is with GE Energy Consulting, Schenectady, New York.

Bahman Daryanian is with GE Energy Consulting, Schenectady, New York.

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

.

APPENDIX A

The 2014 Florida Statutes

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 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 [**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 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, [**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 . . . .

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.

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

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

<u>Sponsor of the Proposed Amendment</u>

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.flsolarchoice.org/

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

Sales Tax

Section 212.08(7)(hh), Florida Statutes, provides a sales tax exemption for solar energy systems and any component thereof.

Chapter 212 levies a 4.35% tax on the sale of electrical services to nonresidential tax base.

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.

Gross Receipts Tax

Gross Receipts Taxes are imposed on sellers of electricity and natural or manufactured gas at a rate of 2.5% and on the sale of communications services at a rate of 2.52%. 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.

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.

Public Education Capital Outlay (PECO) Funding

The PECO program provides funding for educational facilities construction and fixed capital outlay needs for school districts, the Florida College System, the State University System, and other public education programs. Funding is provided by both PECO bond proceeds and cash appropriations.

The PECO Revenue Estimating Conference meets at least three times each fiscal year to estimate the maximum available appropriations for bonding and cash from the PECO Trust Fund for the next ten years. These estimates are developed using the most recently adopted forecasts for Gross Receipts Tax revenues and PECO bond rates, and also incorporate expected disbursements for capital projects as provided by DOE.

B. OTHER CONSIDERATIONS AND ASSUMPTIONS