DRAFT – February 27, 2015

Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers

Prepared on behalf of
Louisiana Public Service Commission

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DRAFT
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Executive Summary

The purpose of this report is to quantify the impacts and implications of the Net Energy Metering ("NEM") policies currently being utilized by the Louisiana Public Service Commission ("LPSC" or "the Commission") for smaller scale residential and commercial solar energy installations. Over the past several years (2008-2013), LPSC jurisdictional utilities report solar NEM installation growth of over 180 percent, on an annual average basis. This growth is likely the result of a combination of generous state and federal solar energy tax incentives that became available during this same time period. Louisiana solar energy tax incentive payments, for instance, have grown from an originally-estimated level of $500,000 per year, to a level of about $42 million in 2013, or $23 million on average each year since 2009. Louisiana's solar energy tax incentives have been considered by some industry observers as the most generous of any state tax incentives currently allowed in the U.S.

This rapid solar installation growth has raised a number of important policy questions about the Commission's NEM policies and their impacts on the ratepayers of LPSC jurisdictional utilities. This report utilizes three different empirical models to estimate a variety of impacts on the ratepayers of LPSC-regulated utilities including:

- A **cost-benefit analysis** (or "CBA") that examines a wide range of current and projected costs and benefits associated with solar NEM installations.
- A **cost-of-service analysis** (or "COS" analysis) that estimates the current ratemaking implications of the Commission's solar NEM policies.
- An **income distribution analysis** that examines the distribution of solar NEM benefits across various different income distribution categories.

Three different solar NEM installation levels were utilized for this study. The first baseline solar installation level was based upon the historic 2008-2014 solar NEM installations provided by each of the state's LPSC jurisdictional utilities. This report also uses two different solar NEM installation forecasts in order to project a range of potential outcomes associated with solar NEM installations in the 2014 to 2020 time period.

The first forecast assumes that solar NEM installations will continue to grow at each utility's observed 2012-2013 rates up to the year in which the capacity of these additional installations reaches 0.5 percent of each LPSC-jurisdictional utility's system peak load as measured by that utility's highest monthly peak in a 12 month period. Installation growth is held flat after each utility is estimated to have reached this target solar NEM penetration level. The second forecast assumes that solar NEM installations will continue to grow unbounded at their utility-specific 2012-2013 growth rates until 2017, at which time those growth rates are assumed to slow to 10 percent per year (for each utility) until 2020 as a result of the tax credit phase-out.

The CBA results show that the estimated costs associated with solar NEM installations outweighs their estimated benefits to the ratepayers of LPSC-jurisdictional utilities (i.e., results in "negative net benefits").

- The CBA results using historic solar NEM installations alone estimate a negative total net benefit to LPSC ratepayers of $89.0 million in NPV terms.
- Negative net benefits increase under each of the baseline solar NEM installation forecasts to levels that are between a negative $125.5 million (NPV) and a negative $488.3 million (NPV) impact on the ratepayers of LPSC-regulated utilities.

Three sensitivities were also examined in the CBA to determine potential outcomes under differing assumptions about future energy markets and environmental regulations.

- The first sensitivity (high natural gas price sensitivity) was developed by increasing the baseline $3.50/MMBtu natural gas price assumption to $5.00/MMBtu in real dollars through the analysis period. The CBA results associated with this sensitivity is a negative $78.5 million (NPV) impact on the ratepayers of LPSC-regulated utilities.

- The second sensitivity evaluated a high electric capacity price to determine whether increasing pressures on electrical generation capacity could make solar NEM more valuable to LPSC ratepayers. The high capacity price sensitivity estimates a negative $170.4 million (NPV) impact on the ratepayers of LPSC-regulated utilities.

- The third sensitivity incorporates a carbon price of $40 per ton across the entire analysis period in order to evaluate the sensitivity of the baseline results to a world in which carbon is regulated. Even in a world with $40 per ton carbon pricing, solar NEM installations are estimated to have a negative $72.2 million (NPV) impact on the ratepayers of LPSC-regulated utilities.

The COS analysis compares the difference in financial contributions that existing (and forecast) solar NEM installations make to each LPSC-jurisdictional utility's costs. The analysis estimates each solar NEM installation's contribution to their respective utility's COS before and after installing behind-the-meter solar equipment in order to estimate (a) the reduction in financial contributions made by these solar NEM installations and (b) whether or not the solar NEM installations are being cross-subsidized by other non-solar NEM ratepayers.

On average, solar NEM installations are estimated to make a 64 percent contribution to overall utility costs across all LPSC-jurisdictional utilities. Any level below 100 percent indicates that solar NEM customers are estimated to pay less than 100 percent of their full cost of service. If this cost is not being paid by solar NEM customers, it will have to be recovered from other utility ratepayers through some form of cross-subsidization.

The COS analysis estimates that over $2 million in typical year utility costs are being subsidized. This typical year subsidy is estimated to increase from between $5 million to $31.4 million in 2020, across all LPSC-jurisdictional utilities, under the two respective baseline solar NEM installation forecasts. Thus, the possibilities for very large and continued cross-subsidies are considerable if solar NEM installations continue to grow at their currently expansive rate.

The income distribution analysis results show that LPSC-jurisdictional solar NEM installations are estimated to have median household incomes of $60,460 relative to the statewide median household income levels of only $44,673. In other words, the median income for a LPSC-jurisdictional solar NEM installation is about 35 percent higher than the median statewide income level. Thus, the direct benefits of solar NEM installations fall more heavily on higher-income households in the LPSC-jurisdictional areas of the state.

1. Introduction

At its March 2014 monthly Business & Executive ("B&E") Session, the Louisiana Public Service Commission ("LPSC" or "the Commission) directed its Staff to issue a request for proposals ("RFP") for a technical consultant to conduct an evaluation of the "total cost and benefits of Net [Energy] Metering ("NEM")" in the State of Louisiana. Pursuant to this directive, RFP 14-07 was issued April 4, 2014 and the Commission hired the Acadian Consulting Group ("ACG") at its B&E held May 7, 2014. In accordance with the Commission's directive and RFP 14-07, the scope of ACG's research includes a "fully comprehensive cost-benefit analysis ("CBA") of net metering in Louisiana" as well as "utility specific ratepayer impacts at varying levels of participation in the Commission's net metering program, from the current participation levels to potential increases in participation." In conducting the CBA, ACG "assess[ed] both the direct and indirect costs and benefits of net metering, whether under a net metering or alternative policy scenario and consider and quantify both energy-related and non-energy costs and benefits." This Report identifies the data and methods used to comport with the Commission's directive and provides comprehensive estimates of the impacts of solar NEM development in Louisiana.

The history of the Commission's NEM policies dates to November 30, 2005 when the Commission promulgated its first set of NEM rules. The rules were adopted in response to Act 653 of the 2003 regular session of the Louisiana Legislature.[1] The Act stated, in part:

[1] La. R.S. 51:3061-3 (2003).

The legislature hereby finds and declares that:

(1) Net energy metering encourages the use of renewable energy resources and renewable energy technologies. Increasing the consumption of renewable energy resources promotes the wise use of Louisiana's natural energy resources to meet a growing energy demand, increases Louisiana's use of indigenous energy fuels and fosters investment in emerging renewable technologies to stimulate economic development and job creation in the state.

(2) Louisiana should actively encourage the manufacture of new technologies through promotion of emerging energy technologies. Net energy metering could help to further attract energy technology manufacturers, providing a foothold for these technologies in the Louisiana economy, and easier customer access to these technologies.

Act 653 called upon the Commission to "*establish appropriate rates, terms, and conditions for NEM contracts*" and stated that the Commission:

> Shall authorize an electric utility to assess a net energy metering customer a greater fee or charge, of any type, if the electric utility's direct costs of interconnection and administration of NEM outweigh the distribution system, environmental, and public policy benefits of allocating the cost among the electric utility's entire customer base. The [NEM] customer shall reimburse the utility for any costs in excess of those to serve a traditional customer.[2]

In 2008, the Louisiana Legislature revisited the legislation and through Act 543 of the regular legislative session and raised the individual installation capacity limit for commercial and agricultural NEM systems from its originally defined cap of 100 kW to 300 kW. In doing so, it also adopted the following language:

> Nothing in this Chapter shall derogate from the commission's constitutional authority to regulate, as applicable, all common carriers and public utilities, particularly the authority to implement rules, regulations, and tariffs to ensure that neither an electric utility nor its ratepayers shall

[2] Act 653 (2003).

be adversely affected, or to subsidize activities authorized under the Chapter.

Around the same period of time, Act 371 of the 2007 regular session of the Louisiana Legislature created a number of new tax incentives to stimulate in-state solar energy development. The Act amended Revised Statute 47:6030 to provide an income tax credit for "the purchase and installation of a wind or solar energy system by a resident individual at his residence or by the owner of a residential rental apartment located in Louisiana." The amount of the credit was equal to the 50 percent of the first $25,000 of the cost of each wind or solar energy system.

Likewise, shortly after Louisiana put this tax incentive in place, the American Recovery and Reinvestment Act of 2009 ("ARRA" or "Stimulus Act") was passed by Congress during one of the worst economic recessions and financial crises to arise over the past century. ARRA extended a number of generous tax incentives for renewable energy. For instance, it extended the Renewable Energy Production Tax Credit ("PTC") for commercial and industrial taxpayers originally enacted in 1992. In addition, ARRA it removed the maximum credit amount for residential installers such that taxpayers may now claim a credit of 30 percent on the total cost of a residential system. In Private Letter Ruling 09-108, the Louisiana Department of Revenue ruled that the same taxpayer could be eligible not only for both the federal and state credits but could also increase the potential state credit by purchasing multiple "systems".

In 2010, the Commission published notice of Rulemaking Docket No. R-31417 to consider whether it was appropriate to amend the NEM rules so that individual commercial and agricultural system limits were consistent with the 2008 legislation. In General Orders dated June 14, 2011 and July 22, 2011, the Commission revised its

NEM rules by: (1) raising the individual capacity limits for commercial and agricultural systems in accordance with Act 543; (2) adding a provision (Section 2.06) that defined a process to allow exceptions to the Commission's individual NEM system size limitation on a case-by-case basis and (3) revising Section 5.02 to require the Commission to review its NEM rules at such time that a utility "determines that its net metering purchases exceed .5% of its LPSC-jurisdictional retail peak load."

The combination of federal and state tax incentives, along with the Commission's NEM policies, have led to a significant increase in the development of behind-the-meter solar NEM installations in Louisiana. Collectively, LPSC jurisdictional utilities report solar NEM installation growth of over 180 percent, on an annual average basis, from 2008 to 2013. In addition, state tax incentives have grown from an originally estimated level of $500,000 million per year to a level of about $42 million in 2013, or $23 million on average each year since 2009. This solar installation growth has put direct pressure on the Commission's NEM program and has created a number of potential challenges for its jurisdictional utilities and ratepayers.

Due to concerns raised by utilities, the Commission revisited its NEM rules once again from 2012-2013, ultimately converting the 0.5 percent threshold adopted in 2011 into a cap on net metering applications for each utility in its General Order dated July 26, 2013. Solar NEM growth had already pushed some utilities to the edge of their LPSC-mandated total system NEM capacity limits. At least three jurisdictional utilities have already filed with the LPSC to examine whether or not such limits have been met.

This rapid turn of events has stimulated the Commission's interest in further study and evaluation of its NEM policies and the impact that behind-the-meter solar is having on its jurisdictional ratepayers: now as well as into the future. The LPSC is not alone it its concerns and interests regarding solar NEM impacts and policies. Many states, including California, Arizona, and Colorado have opened investigations, rulemakings or other regulatory proceedings to conduct similar assessments. The purpose of this research is to provide the Commission with additional policy and analytic insights into solar NEM in Louisiana. The findings of this research are provided in the individual chapters of this report.

The second section of this report explains the nature of distributed generation and examines its relationships with NEM policies. This section identifies and explores the perceived benefits of distributed generation and how those are facilitated by NEM policies and surveys the current status of NEM policies across the U.S., acknowledging that many states are grappling with some of the same challenges facing the LPSC. The second section of this report also provides some context on why solar energy, in particular, has become the distributed generation technology of choice, and the factors contributing to its rapid deployment over the past several years.

The third section of this report examines Louisiana-specific solar NEM growth trends. This analysis, like all of the analyses included in the report, focusses on the trends and impacts for LPSC-jurisdictional ratepayers only. The analysis does not include the impacts on various municipal and municipally-regulated utility systems in Louisiana. Section 3 also examines the rapid growth of solar NEM systems on a per LPSC jurisdictional basis and provides a variety of other descriptive statistics on these installations.

Nationwide, the impact of solar NEM on utility ratepayers has resulted in numerous studies examining the overall costs and benefits of NEM, with a particular emphasis on solar-based NEM. The fourth section of this report surveys these prior NEM studies, their empirical methodologies, and their results to assess their potential relevance and use for the study at hand.

This report, and its component analyses, relies on hourly solar NEM installation-specific information. However, detailed hourly information was not available from the LPSC-jurisdictional utilities requiring the development of a number of empirical models. Section 5 discusses the detailed and integrated methods used to develop a comprehensive set of observations on hourly, location-specific solar generation and NEM customer usage statistics. Primary billing data was utilized along with other Louisiana specific information in a series of algorithms and computational methods to develop a commercially proprietary process that takes an advanced computer workstation four days to execute. This section also outlines two forecasts of future NEM development consistent with the Commission's charge to investigate "ratepayer impacts at varying levels of participation."

Three primary analyses were conducted in this report, all of which were designed to examine various solar NEM impacts. As required by the Commission's directive, a traditional cost-benefit analysis was developed, examining a "comprehensive" set of solar NEM costs and benefits that include the direct, indirect and induced impacts associated with solar NEM and the Commission's solar NEM policies. A number of sensitivities were also examined to determine potential outcomes under differing assumptions about future energy markets and environmental regulations. The methods utilized in the development of the cost-benefit analysis are discussed in Section 6 of the report, while the empirical results from the analysis are provided in Section 7.

Solar NEM systems can raise a number of challenges to utility cost recovery and its overall cost of service. Section 8 explains the potential ratemaking challenges created by the Commission's solar NEM policies and how those challenges can negatively impact LPSC-jurisdictional ratepayers. A cost-of-service based model was developed to examine the degree to which solar NEM customers are subsidized by, or providing subsidies to, LPSC-jurisdictional ratepayers. This analysis was also prepared in direct response to the Commission's directives that a cost-of-service based approach in examining solar NEM issues be included in this research.

The cost-benefit and cost of service based approaches are alternative methods for examining total impacts of solar NEM. These methods are not as good in determining total distributional impacts, however, as they fail to identify the winners and losers associated with the Commission's NEM policies. Section 9 provides an income distributional impact analysis of solar NEM for the LPSC-jurisdictional areas of the state.

The various analyses that are included in this research are detailed and voluminous. Each section of this report provides summary conclusions. The detailed results are provided in a technical appendix (Appendix A). Appendix B includes a proposed, standardized annual solar NEM reporting framework that the Commission should consider adopting in order to facilitate the ongoing monitoring and regulation of its NEM policies and to facilitate future NEM studies of this nature.

2. Distributed Energy Resources and Nationwide Net Metering Trends and Policies[3]

2.1. Definition and Overview

NEM projects are almost exclusively associated with what are called "behind-the-meter" generation applications, or more commonly referred to as "distributed energy resources" ("DER"). DER applications are typically small-scale generation or storage devices located on the customer side of the meter designed primarily to serve customer (or "host") energy needs. DER applications are not developed to provide power to the grid, like a large scale merchant power plant or, in some instances, a combined heat and power ("CHP" or "cogeneration") facility. The size of what constitutes a DER application can often vary, is subjective, and is often constrained by regulatory decisions and/or state statutes. While DER sizes can vary, they are almost exclusively interconnected to the utility grid at either the primary or secondary distribution level.[4]

DER applications span a wide range of technologies that include solar, small-scale wind, and in some rare instances, biomass/biogas generation. DER is not limited, however, to just renewable energy technologies and can include a number of prime movers that combust/utilize fossil fuels such as reciprocating engines, micro-turbines, and fuel cells. Fixed location stand-by generators, common at many South Louisiana

[3] This Section of the report focuses on nationwide trends and distributed generation policies in general. A discussion of Louisiana specific trends will follow in Section 3.

[4] Electric energy leaves the distribution substation and is distributed to different areas by distribution lines. Distribution lines on the high voltage side of the distribution transformer are called primary distribution lines and those on the low-voltage side of the distribution transformer are called secondary distribution lines.

commercial establishments and homes, are used to generate electricity during tropical activity-created outages, and are examples of fossil-fuel based DER applications.

NEM applications are a subset of DER: not all DER applications are net metered, but all NEM applications represent various forms of DER. NEM generators are DER applications that are given special regulatory dispensations typically not afforded to other small-scale distribution-level generators. Energy use and generation at an NEM installation is generally measured in a fashion that "credits" an on-site generation customer when excess power is "put" to the distribution grid and then "charges" that same customer at times when usage is greater than the on-site generators capacity. Hence, the prefix "net:" these energy charges and credits are reconciled to calculate a "net" usage for the on-site generation customer. The special regulatory dispensation offered to these NEM generators includes providing a relatively streamlined and consistent process for distribution level interconnection, and a regulatory-established set of rates or credits that are offered as reimbursement for NEM-generated electricity put to a regulated electric utility's distribution grid.

The regulatory conditions for NEM eligibility vary across the U.S., although there are usually three basic requirements. The first eligibility requirement is usually based upon technology type. Most NEM policies across the U.S. require the NEM installation to be based upon a renewable technology. There are some exceptions to this eligibility requirement. For instance, Maine, Maryland and Massachusetts all allow CHP of up to a specified size and/or efficiency rating to qualify as a NEM facility. However, for all intents and purposes, most NEM programs across the U.S. are heavily dominated by rooftop solar technologies.

The second eligibility requirement is usually based upon customer class. NEM eligibility is usually restricted to residential customers, and in some instances, commercial customers. Both customer classes (residential and small commercial) are usually interconnected to the utility grid at the secondary distribution level, and are also perceived to be the customers facing the highest institutional and economic hurdles related to on-site generation installations.

The third eligibility requirement is based upon the size of the particular NEM installation. Many state NEM policies restrict residential installations to those under 25 kW although there are some states that have no direct size limitations on these residential installations provided they are not larger than on-site usage. Most states require NEM installations to be sized proximate to the loads being served by the on-site generators. For those states allowing small commercial customer participation, installation size restrictions are usually around 2 MW, but again, some states, like New Jersey, have no restrictions on small commercial installation sizes provided they are proximate to the customer's on-site usage.

Each of these restrictions have been adopted to limit NEM program scope, and to prevent NEM policies from becoming so large that they have unintended negative impacts on non-NEM participating customers (i.e., other utility ratepayers). An additional rationale for NEM policy restrictions is to reduce the opportunities for regulatory "gaming," preventing DER installations from becoming "mini-merchant power plants" that sell a considerable (relative) amount of power back to the distribution grid.

Historically, the purpose of NEM policies has been to remove barriers associated with the development of small-scale DER, particularly for residential and small commercial customers where these barriers are often perceived as being more challenging. Three common barriers to DER development that are typically eliminated by NEM policies include those associated with generator interconnection, the ability to access standby and emergency electrical service, and access to some type of market where excess electricity periodically generated when loads are lower than on-site generator capabilities arises. These barriers are not too dissimilar to those faced by large scale cogeneration applications, and removed by the Public Utilities Regulatory Policies Act of 1978 ("PURPA").[5]

In theory, the terms, conditions, and prices for providing NEM service, like any other type of utility service, should not be unduly discriminatory. NEM policies are typically designed to remove perceived DER development barriers through a utility-based tariff offering that: (1) requires electric utilities to interconnect a qualified NEM generator; (2) provide electricity to that NEM customer in instances where the customer's load is greater than the on-site generator's capabilities; and (3) to offer a payment or credit to the NEM customer when that customer's on-site generation is greater than on-site load. The last NEM service provision (payment/credit for excess generation) is a very important and often controversial aspect of most NEM policies. The provision is important since it expands and stabilizes the revenue stream that accrues to an NEM application that, in turn, can be used to support the payment of the on-site generation capital investment.

[5] In 1978, Congress passed the "National Energy Act" (NEA) which was composed of five different statutes, one of which was PURPA. The goal of PURPA was to eliminate barriers to industrial combined heat and power, or "CHP" applications in order to increase energy efficiency and improve electric system reliability.

Consider that NEM applications are financially supported by the revenue streams generated by the installation. These revenue streams often include:

- **On-site electricity savings:** the electricity savings, or electricity purchases avoided as a consequence of the on-site generation installation, represent one of the largest revenue streams providing financial support to an on-site generation application. NEM customers can take the revenues typically paid for utility service and apply those to the payment associated with the initial on-site generation investment. Once the DER application is "paid," NEM customers can pocket those revenues that were previously allocated to making utility service payments.

- **Tax incentives:** there are a wide range of federal and state tax incentives that reduce the upfront cost of on-site renewable generation projects, particularly solar. Until recently, Louisiana was noted as having the most generous state solar energy investment credit in the U.S.

- **REC/SREC[6] sales revenues:** these are revenue streams that arise from the sale (or use) of credits generated by a renewable energy application in states that have a renewable portfolio standard ("RPS").

- **Net metering revenues:** payments or credits made by regulated utilities to NEM customers for every kWh of on-site generation that is "put" to the distribution grid.

NEM policies have arisen over the past several decades to maximize the perceived benefits associated with DER. For instance, DER can provide electricity customers with greater reliability, higher power quality, and more flexible electric service choices, particularly on a qualitative basis. Many DER technologies, particularly renewables, can be more environmentally friendly than generation produced from typical utility service and, if structured properly, can reduce end-user price volatility that can arise with fossil-fuel based generation. Widespread use of DER technologies could also mitigate future utility capacity requirements that include avoiding future generation, transmission and distribution-related investments.

[6] Renewable Energy Certificate ("REC") and Solar Renewable Energy Certificate ("SREC"). These are credits that

2.2. Recent NEM Installation and Capacity Development Trends

Most publicly-available electric utility data originates from a variety of different forms and filing requirements that utilities file before the Energy Information Administration ("EIA") or the Federal Energy Regulatory Commission ("FERC"). Historically, both agencies have focused their respective information collection efforts for power generation on large-scale, central-station facilities and not on smaller-scale distributed resources. The growth of NEM policy initiatives over the past several years, however, persuaded EIA, in 2011, to begin the collection of small-scale NEM power generation information.

EIA's NEM data collections are part of the "Monthly Electric Sales and Revenue with State Distributions Report" that is filed by electric utilities and suppliers and also known as the Form EIA 826. The purpose of this form is to collect information from electric utilities, energy service providers, and distribution companies that sell or deliver electric power to end users. The survey was expanded in 2011 to include data on NEM installations, NEM installation types, NEM capacities, and NEM net generation[7]. While national and state level comparisons can be conducted with this data, these comparisons are unfortunately limited to the last three years.

Figure 1 shows the trend in U.S. and Louisiana NEM capacity over the past several years.[8] The most recently-available data (September 2014) reports total U.S. NEM customers at almost 600,000 accounting for 6,545 MW of NEM capacity: over 95

[7] Net generation is defined as gross NEM system generation less on-site electricity consumption.

[8] Louisiana NEM information here will be slightly different than the statistics discussed in later sections of this report. The differences between the EIA information and that used elsewhere appears to be due to (1) the use of Entergy New Orleans data in the EIA series which is a non-LPSC jurisdictional utility and (2) small reporting differences of around 5 MW.

percent of this national NEM capacity is associated with solar behind-the-meter installations. Over the past three years, U.S. NEM capacity has grown at an average annual rate of 60 percent compared to Louisiana NEM capacity which grew at an average annual rate of about 150 percent over the same time period. Louisiana currently ranks 12th among states in total NEM installed capacity. Interestingly, Louisiana ranks 8th in terms of total number of NEM installations, indicating that the average size of Louisiana NEM installations is smaller than those average NEM capacities observed in other states.

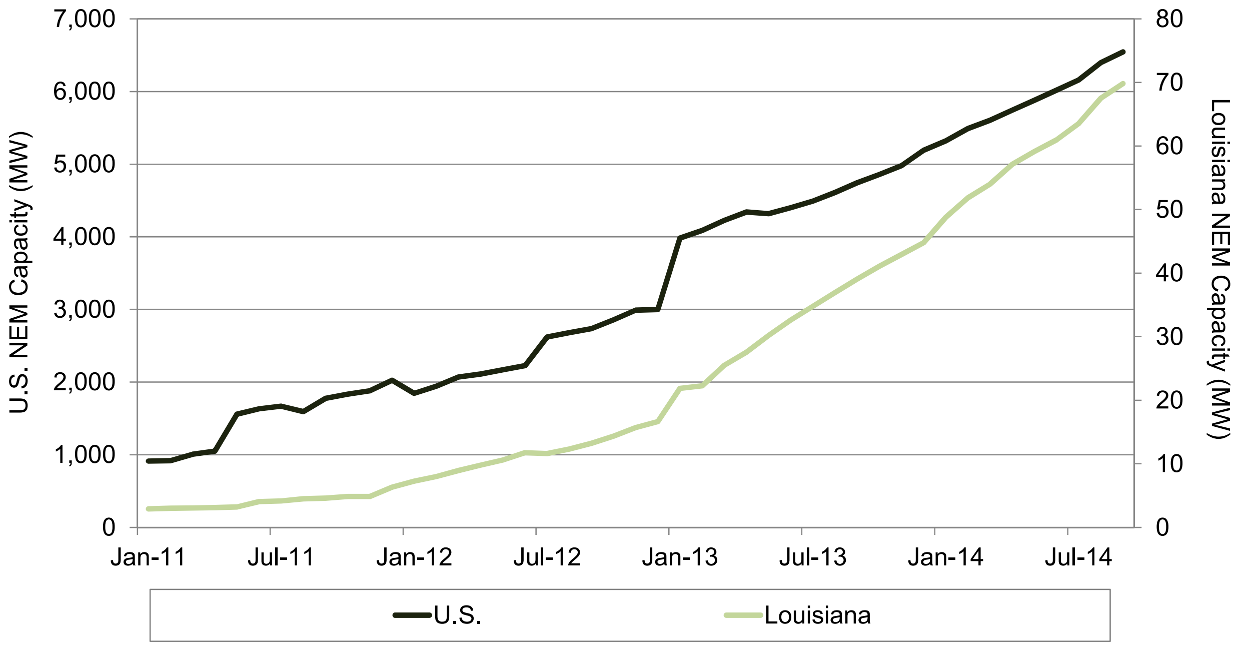

Figure 1: U.S. and Louisiana Installed NEM Capacity (MW)
Source: Energy Information Administration, Form 826.

Figure 2 compares state-level NEM capacity growth over the past three years. Louisiana's NEM capacity growth, on a percentage basis, is one of the fastest in the entire U.S. outpacing traditional renewable energy promoting states such as California, Washington, Oregon, and New York.

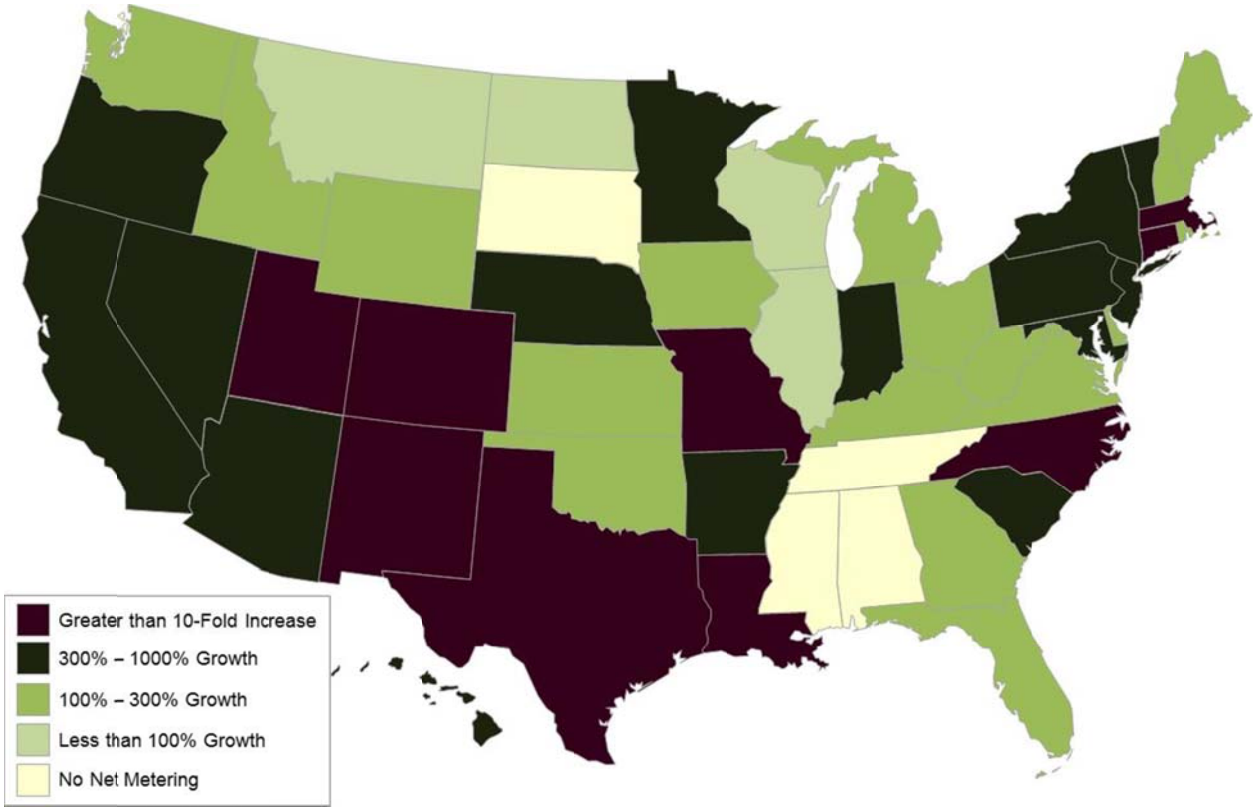

Figure 2: Net Metered Capacity Growth (January 2011 through April 2014)
Source: Energy Information Administration, Form EIA-826.

The dramatic growth in NEM installations, particularly solar NEM installations, can largely be attributed to three factors. The first is regulatory policy encouraging NEM development; the second is federal and state tax policy encouraging NEM development, and the last is reduction of solar panel and installation costs.

2.3. Regulatory Policies Supporting NEM Installation Growth

2.3.1. History of State NEM Adoption

The origins of state NEM polices date back to the early days of PURPA implementation in the early 1980s which attempted to extend the access, buy-back and back-up provisions afforded to large scale co-generators to smaller, distribution level generation resources. The Idaho Public Service Commission, as early as 1980, is cited as one of the earlier states adopting NEM policies allowing generation interconnection and buy-back for all distribution level resources below 100 kW. Likewise, the Arizona Corporation Commission and the Massachusetts Department of Public Utilities are also cited as early adopters, creating NEM-based programs for small-scale generators under 100 and 30 kW, respectively, in 1981 and 1982.[9] In 1983, the Minnesota legislature enacted Statute 216B.164, allowing net metering for all qualifying facilities under 40 kW on a statewide basis. The Minnesota legislation is often cited as the first enactment of a state-wide, rather than utility-specific, NEM policy.[10]

Through the remainder of the 1980's, six more states enacted net metering policies, primarily through regulatory decisions or administrative rulemakings. These six NEM policies, and the four mentioned earlier, were all similar in that few had restrictions on the type of NEM installation qualifying for the program. Only three states: Rhode Island (1985); Texas (1986); and Oklahoma (1988), explicitly limited eligibility of NEM installations, at that time, to being only renewable or cogeneration systems.[11]

The Congressional passage of the Energy Policy Act of 1992 ("EPAct 1992") brought a renewed interest in efficiency and small-scale generation opportunities. Several states during the 1990s, as part of reviewing and implementing policies outlined

[9] Larsen, Chris. 2000. A Guide to PV Interconnection Issues. Prepared by North Carolina Solar Center on behalf of the Interstate Renewable Energy Council, p. 18; and Massachusetts Office of Energy and Environmental Affairs, Net Metering Legislation and Regulations. Available at: http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/dpu/dpu-divisions/legal-division/dpu-and-green-communities-act/net-metering/net-metering-legislation-and-regulations.html.

[10] Database of State Incentives for Renewables and Energy Efficiency, U.S. Department of Energy. Minnesota Incentives/Policies for Renewables & Efficiency, Net Metering. Available at: http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=MN01R&re=1&ee=1; and Solar Electric Power Association. 2013. Ratemaking, Solar Value and Solar Net Energy Metering – A Primer, p. 1.

[11] Wan, Yih-huei and H. James Green. 1998. Current Experience with Net Metering Programs, National Renewable Energy Laboratory, Presented at Wind Power '98 (Bakersfield, CA), pp. 7-9.

in EPAct 1992, adopted utility-specific or statewide NEM policies. These policies represent the more "modern" period of NEM adoption, and are the basis for many state NEM policies that are still in place. The increased "sophistication" and understanding of DER resulted in new and additional restrictions on state regulatory NEM policies to ensure that only those generators bringing renewable or efficiency benefits, as opposed to those that simply offered simple cycle generation opportunities, were being promoted. All but two net metering regulations implemented during the 1990s limited NEM eligibility to only renewable technologies. Furthermore, seven state policies enacted during this period included limitations on the overall state and utility-wide adoption of net metering, either through customer/installation-specific capacity limits, or more often, aggregate (utility or statewide) capacity caps.[12]

Currently, 46 states and the District of Colombia have one or more utilities within the state offering net metering service, many state policies currently allow NEM state-wide. One of the important factors motivating this large-scale adoption of NEM regulatory policies has been the more recent adoption (at least over the past decade) of renewable energy portfolio ("RPS") policies. Figure 3 shows 37 states have adopted an RPS or renewable energy goal.[13]

[12] Wan, Yih-huei and H. James Green. 1998. Current Experience with Net Metering Programs, National Renewable Energy Laboratory, Presented at Wind Power '98 (Bakersfield, CA), pp. 7-9.

[13] U.S. Department of Energy; Database of State Incentives for Renewables & Efficiency, Renewable Portfolio Standard Policies; Internet website: www.dsireusa.org/documents/summarymaps/RPS_map.pdf

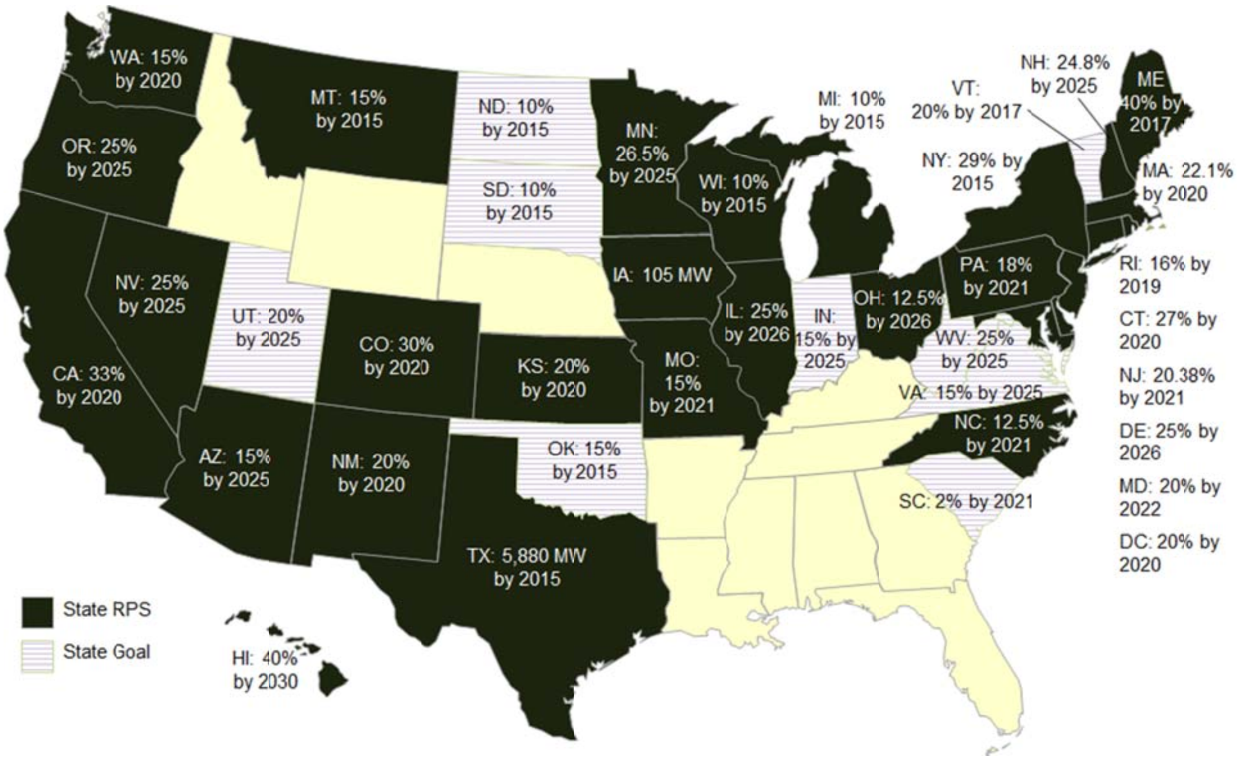

Figure 3: State Renewable Portfolio Standards as of September 2014
Source: Database of State Incentives for Renewables and Efficiency ("DSIRE")

RPS states, collectively, represent over 72 percent of current retail U.S. electricity sales and the anticipated growth of renewable generation shares are anticipated to increase by as much as one-third of some states' retail electricity sales by the 2030 time period. This rapid escalation of renewable generation, a large portion of which will likely come from behind-the-meter renewable generation applications, is largely the reason why many states have been compelled to revisit, and in some instances modify, their earlier NEM policies. NEM-facilitated DER has clearly moved from being niche installations, as envisioned in the 1980s and 1990s, to a resource base that could comprise a significant share of future U.S. electric generating resources. Thus, poor NEM policy design can have meaningful policy and rate impacts.

Some of the qualifications and changes in state regulatory NEM policies are discussed in the following subsections.

2.3.2. NEM Interconnection

Electric distribution systems are typically designed to step down electricity from higher voltage transmission facilities, to primary and secondary distribution lines, and ultimately to individual customers. Electric utility distribution systems have been developed over the past several decades to facilitate a centralized uni-directional flow of electricity from "upstream" generation resources to "downstream" distribution resources. Electric utility distribution systems were not originally designed to handle multiple types of distribution level generating resources: particularly those that are putting relatively significant amounts of electricity back on electric utility distribution grids. The advent of DER, including those facilitated by NEM, challenges this centralized model of power generation and consumption by creating multiple, disaggregate sources of generation. This new decentralized, or "distributed" model of power generation and distribution, however, does not come without certain concerns or costs.

For instance, distributed generation can pose safety hazards to utility line crews conducting system repairs during or after severe weather, or to personnel responding to emergency calls, and so many utilities insist on the installation of additional equipment such as remote disconnects to protect system crews and emergency personnel. Because of this, net metering imposes costs on the utility system as distribution equipment and circuits need to be modified, upgraded, or installed to accommodate a growing set of localized generation resources. Further, there are also additional regulatory and systems analyses that can be required to understand how these new distributed resources impact distribution-level operations and reliability: these studies involve a certain level of costs which must be recovered directly from the DER (NEM) installation, or shared across a utility's entire customer base. There can also be additional regulatory and administrative costs associated with facilitating these new interconnection requests that also require new costs and investments that will need to be recovered directly from the DER (NEM) applications or from a broader class of ratepayers.

The cost to interconnect an NEM facility is dependent upon a number of factors, including the size of the generating facility; the proposed location of the generating facility and the amount of electricity that could be exported to the grid.[14] Usually, the utility will furnish and install the meter, as it would for any non-NEM customer. However, much of the cost of interconnection falls on the NEM customer. For instance, as part of Cleco's Standard Interconnection Agreement for Net Metering Facilities, the NEM customer pays all "incremental costs of the interconnection above the cost to provide standard service to the customer's class of service." Similarly, Entergy customers pay for "the reasonable costs of connecting, switching, metering, transmission, distribution, safety provisions and administrative costs that are directly related to the interconnection and in excess of the corresponding costs if interconnection did not occur."[15]

[14] Massachusetts Office of Energy and Environmental Affairs, Net Metering Frequently Asked Questions and Answers. Available at: http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/dpu/net-metering-faqs.html.

[15] Entergy. Net Metering for Renewable Energy Resources. Available at: http://www.entergy-louisiana.com/your_home/net_metering.aspx.

2.3.3. Individual System Size Requirements

Most states limit the size of NEM resources. These size limitations, however, vary by state. For instance, 18 states allow generators greater than 1 MW to participate in NEM programs. There are eight states that limit net metering to generators with a nameplate capacity that is less than 100 kW with the remaining states having limitations that range from between 1 MW to 100 kW. There are currently four states (Arizona, Colorado, Ohio, and New Jersey) that do not implement a strict size limitation, but evaluate systems on an application by application basis based on a percentage of total annual usage. Each state's NEM installation-specific size limitations is presented in Figure 4.

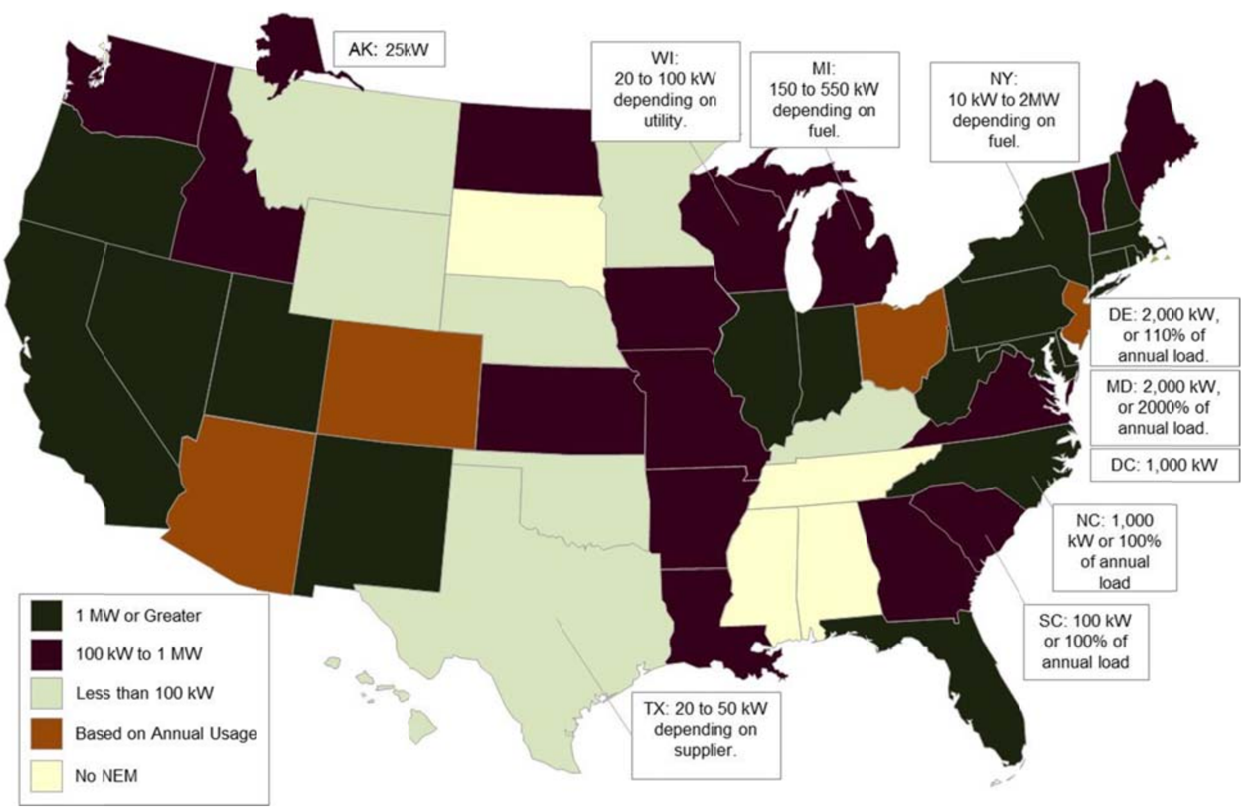

Figure 4: State Policies Regarding System Capacity Limits
Source: State Statutes and Regulations

Figure 5 shows that 14 states, including Louisiana, have system limitations for residential systems separate from larger commercial and industrial systems. Of these states, all but one (Pennsylvania[16]), set separate residential limits at or below 25kW. Louisiana has separate system limits for residential systems at 25 kW.[17]

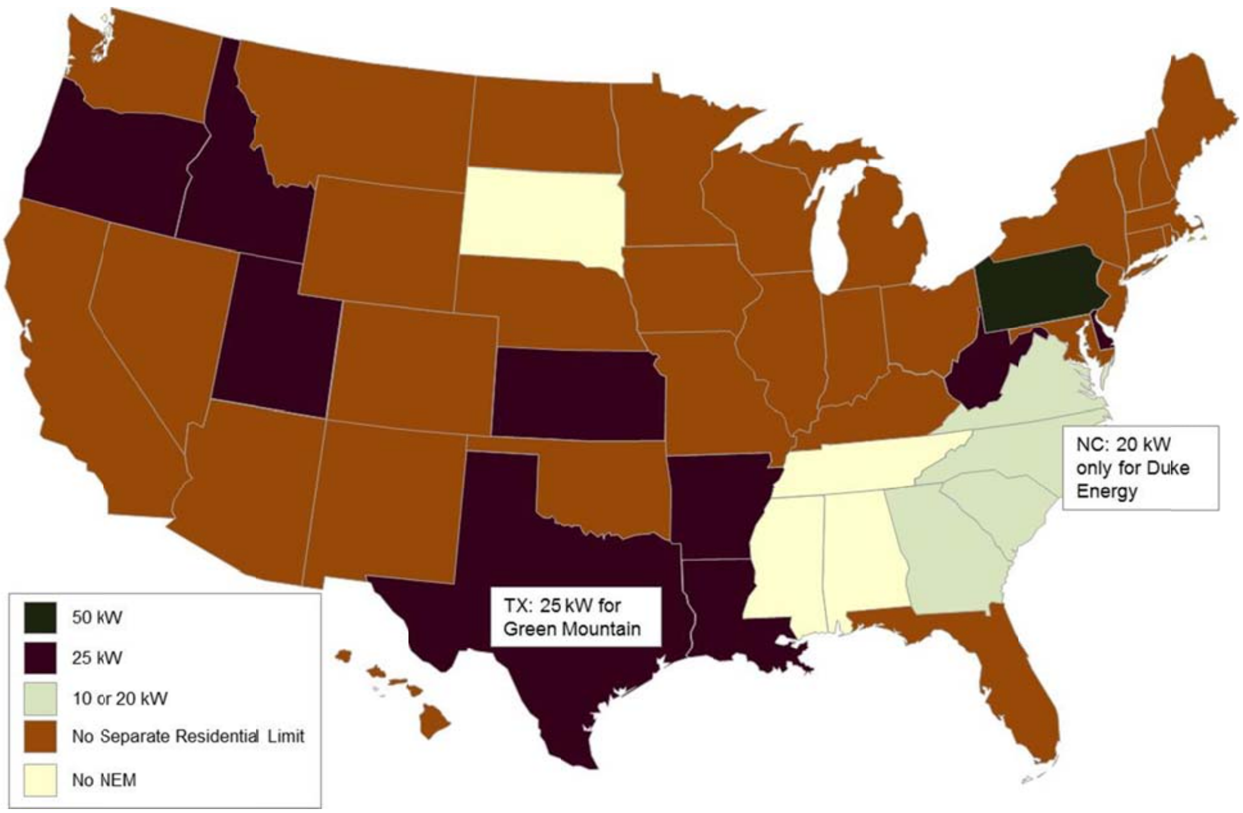

Figure 5: State Policies Regarding Residential System Capacity Limits
Source: State Statutes and Regulations

2.3.4. Aggregate Installation Limits

Most states have total aggregate limitations on the total NEM capacity that can be installed on a utility system during any given time. Figure 6 shows that 27 states (60 percent) have aggregate NEM installation limits. Nine states have aggregated capacity

[16] 73 Pennsylvania Statutes § 1648.2.
[17] Louisiana Net Metering Rules, Definitions.

limits of between one to two percent of a utility system's annual peak demand, while another six states, including Louisiana, have set aggregated capacity limits on net metering less than 1 percent of a utility system's annual peak demand. Four states (Maryland, Nevada, New Hampshire, and New Jersey) impose an aggregate NEM capacity cap that is not tied to a utility's annual system peak. For instance, Maryland has administratively-limited capacity from net metering to 1,500 MW[18] which applies on a statewide, not an individual utility system basis. Nevada and New Jersey assess their NEM aggregate capacity limitations on a percentage of annual statewide peak demand, rather than a fixed statewide capacity amount.

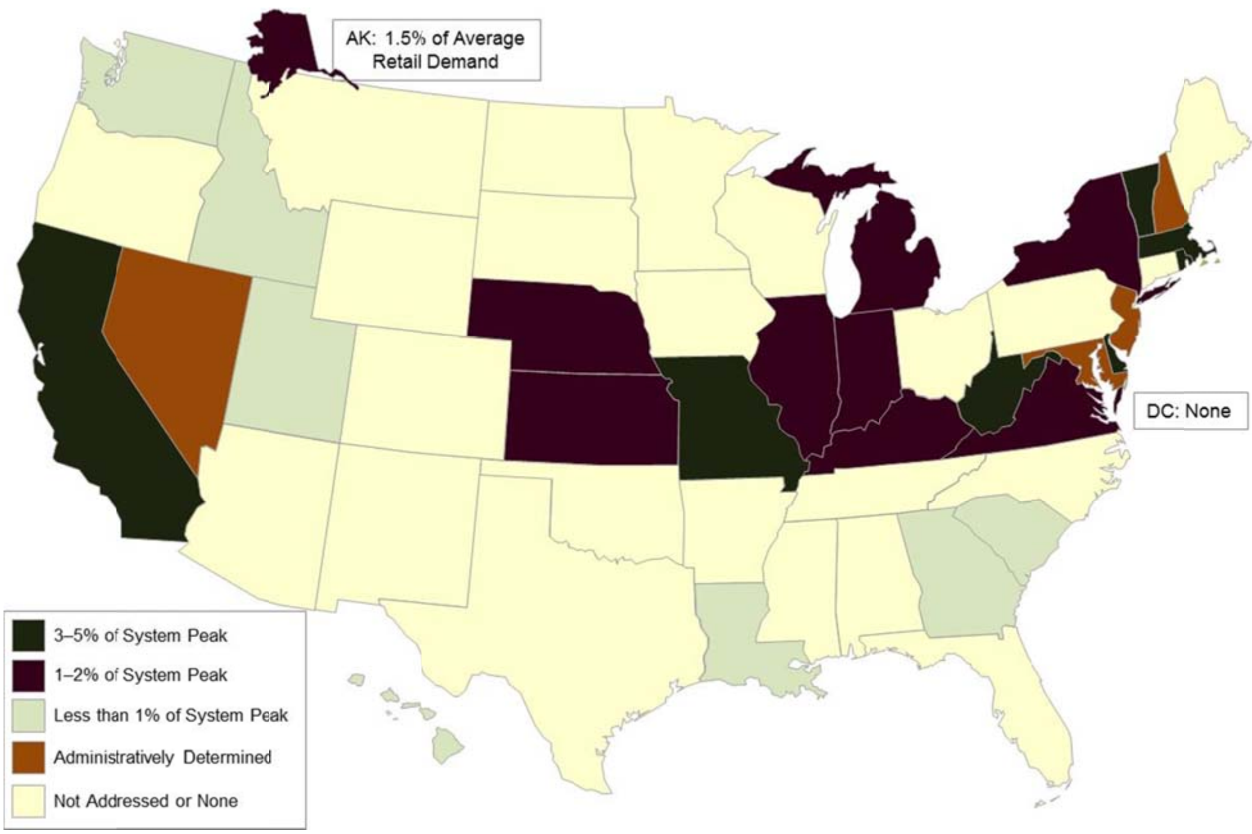

Figure 6: State Policies Regarding Aggregate Utility System Capacity Limits

[18] Code of Maryland Regulations (COMAR) 20.50.10.01(A)

Source: State Statutes and Regulations

2.3.5. Excess Generation Payments and Credits

Regulatory policies associated with the method by which net excess generation ("NEG") will be reimbursed can be controversial. Generally, there are two methods of financial reimbursement: (1) offering a credit for each kWh of NEG (direct credit); or (2) offering payment for each kWh of NEG (direct payment).

Most states use the first method, that is any net excess generation is carried over to the NEM customer's next bill as a kWh credit. These excess kWh are usually valued at either the utility's retail rate, or an avoided cost rate.[19] In some states, credits accrued during a 12-month period will be paid to the customer via check or billing credit.[20] Other states, including Louisiana, allow a cash payment for outstanding NEG credit balances if the NEM customer discontinues service, while others do not allow for a cash payment at all, and any unused credit is absorbed by the utility.[21] The direct payment method of reimbursement usually involves offering a NEM generator some type of pre-defined rate for each kWh of NEG, and then offering a monthly payment to that generator for the excess generation put to a utility's electric distribution grid.[22] Very few states however, reimburse for NEG via direct payment. In New Mexico for

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[19] Massachusetts Office of Energy and Environmental Affairs, Net Metering Frequently Asked Questions and Answers. Available at: http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/dpu/net-metering-faqs.html.

[20] Database of State Incentives for Renewables and Energy Efficiency, U.S. Department of Energy. California Incentives/Policies for Renewables & Efficiency, Net Metering. Available at: http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA02R&re=1&ee=0

[21] Section 2.04C, Attachment A, LPSC General Order dated July 26, 2013; and Database of State Incentives for Renewables and Energy Efficiency, U.S. Department of Energy. Indiana Incentives/Policies for Renewables & Efficiency, Net Metering. Available at: http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=IN05R&re=1&ee=0.

[22] New Mexico Administrative Code. NMAC 17.9.570.

example, the utility can choose how to deal with net excess generation. It may credit or pay the customer for NEG at the utility's avoided cost rate; or it may credit the customer for the kWh of NEG from month-to-month and pay for any accrued credits if the customer terminates service.[23]

The next controversy that arises with NEG reimbursement is the method by which the per-unit (per kWh) generation is valued. NEG unit valuation policies can be generally divided into two distinct models: cost-based or incentive-based approaches. Cost-based approaches value generation contributed by the net metered generation system at the utilities avoided cost of energy. This includes all variable production operating costs, such as fuel stock purchases and variable emission control costs, as well as utility purchase power costs. Essentially, cost-based net metering models value all excess generation amounts based on wholesale electric prices, representing the actual avoided costs the excess generation is displacing.

Incentive-based approaches value generation contributed by the net metered generation system at full retail rates, which not only include the utility cost of power, but also all fixed costs of service including capital plant costs such as wires/conductors, poles, meters, and transformers, as well as utility overhead costs such as employee salaries. These fixed costs are not displaced by the customer's self-generation as the customer remains connected to the electric grid. These displaced costs will thus be incorporated into future rate increases, effectively resulting in non-net metered customers subsidizing net metered customers.

[23] New Mexico Administrative Code. NMAC 17.9.570.

Figure 7 shows that a large number of states incentivize NEG by crediting it at the retail rate. Alaska, Missouri, Nebraska, Rhode Island and Utah value NEG on an avoided cost basis. Georgia, however, utilizes an administratively-determined rate to reimburse excess NEM generation.

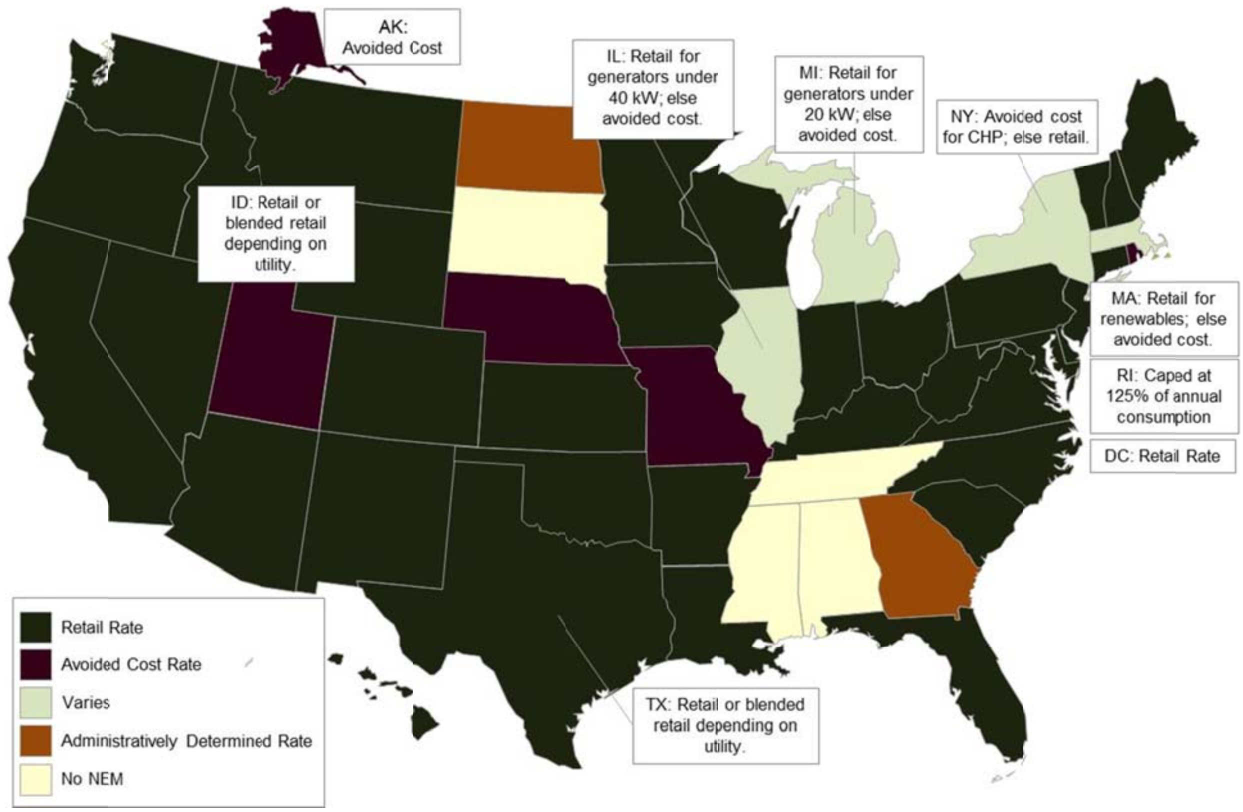

Figure 7: State Policies Regarding Excess Credit Valuation
Source: State Statutes and Regulations

Figure 8 highlights state policies for reimbursement of accrued NEG credits. Ten states, shown below in orange, permit excess usage credits to be carried forward indefinitely ("banked") and if the customer discontinues service, those credits are ceded to the utility. Others, shown below in green, reset all excess generation credits without compensation annually. So, at the end of an annualized period, any NEG credits in the customer's account expire and are ceded to the utility. In Oregon and Utah, any NEG credits accrued in an NEM customer's account at the end of 12 months are valued at the utility's avoided cost and paid to fund low-income assistance programs.[24]

The remaining states will pay annually accrued NEG credits at either the full retail rate, or an avoided cost rate. Louisiana requires utilities to compensate net metered generators based on the utilities' avoided cost rate for any excess generation remaining in the final month a customer takes service from the utility, i.e. when a customer closes out his or her account.

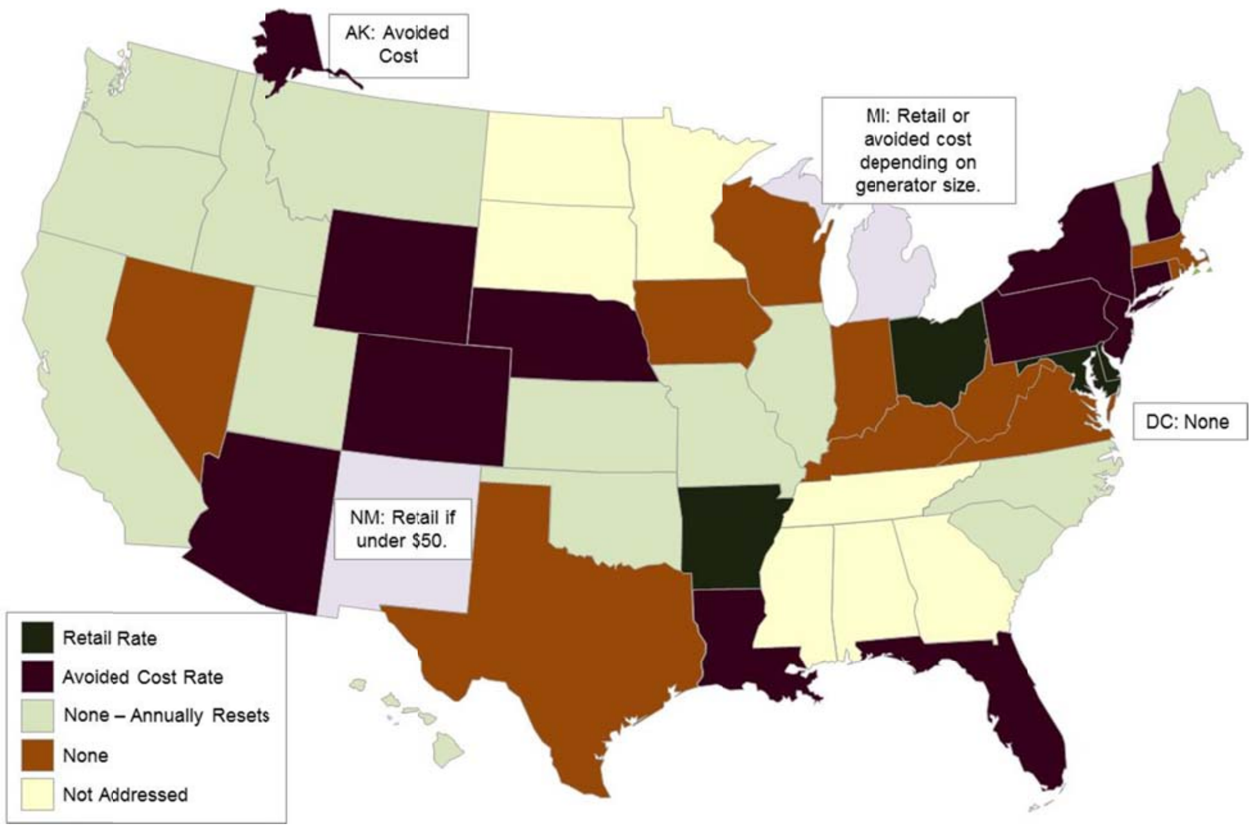

Figure 8: State Policies Regarding Payment of Accrued/Banked NEG Credits
Source: State Statutes and Regulations.

[24] Oregon Administrative Rule 860-039-0060 §1, and Utah Administrative Code 54-15-104 §4(a)

2.3.6. Net Metering Aggregation

Figure 9 shows that 21 states, or approximately 45 percent of jurisdictions with net metering policies, have implemented policies allowing customers to aggregate with one another to attain NEM service. This form of aggregation has been especially popular for solar energy and is often referred to as a "community solar program" or "virtual net metering." NEM aggregation allows individuals to benefit from participating in a solar project (even though the project may not be on the participating customer's property or even contiguous to that property) and attaining potential economies of scale associated with the installation of larger solar systems.

NEM aggregation polices differ substantially from state to state regarding specifics such as eligible customers and tariffs, and geographic limitations for aggregation. For instance, six states with NEM aggregation policies do not allow non-physically connected or "virtual" aggregation (solar farm or community). Furthermore, states with policies allowing virtual net metering aggregation appear to be concentrated in the Northeast and Mid-Atlantic. Only four states outside of these two regions (Arkansas, California, Colorado, and Washington), allow for virtual net metering aggregation.

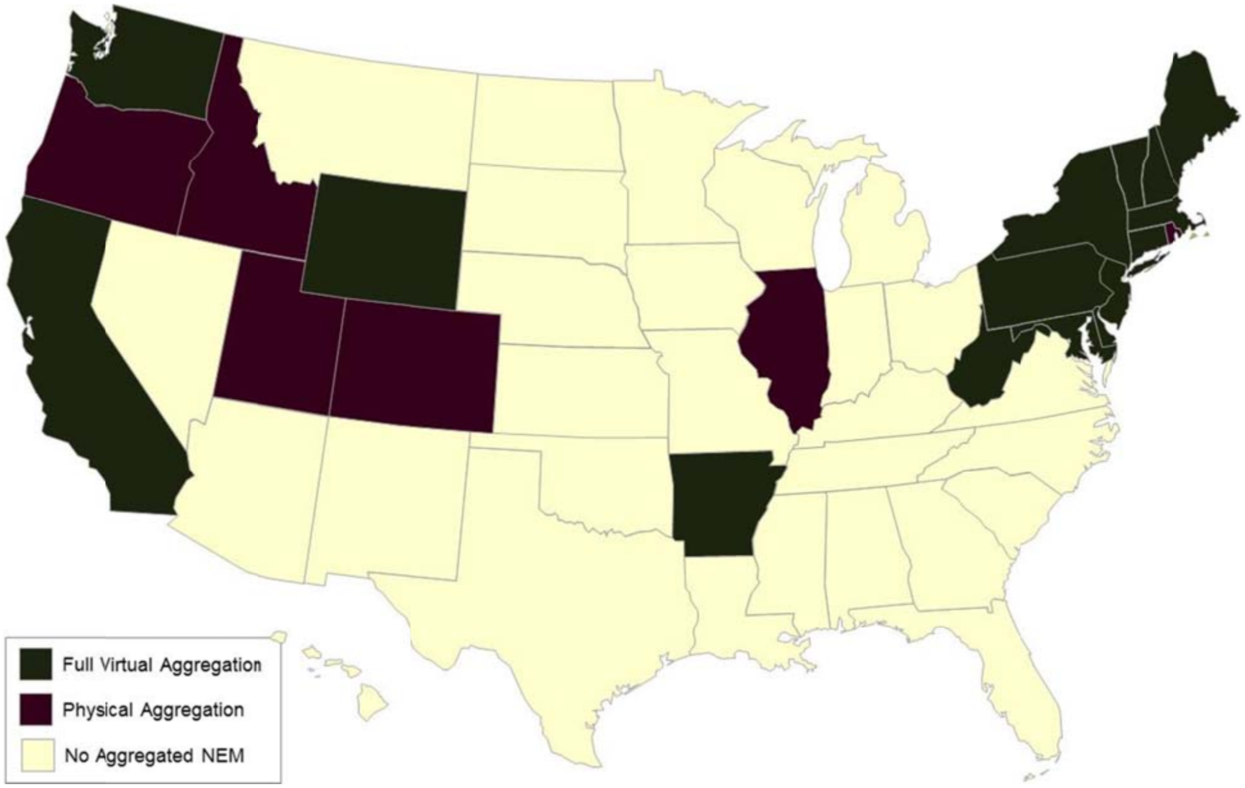

Figure 9: State Policies Regarding Net Energy Metering Aggregation
Source: State Statutes and Regulations

2.4. Federal and State Tax Policies Supporting NEM Installation Growth

Another element that has contributed to the substantial increase in net energy metering installations over the past few years is the increase in available federal and state incentives. ARRA included a series of tax credits for home and business owners to purchase renewable energy systems. Specifically, under ARRA residential homeowners were allowed to receive a tax credit equal to 30 percent of the value of the system. Even more significant, for the years 2009 and 2010, ARRA allowed organizations that invest in renewable energy sources to receive an investment tax credit ("ITC") equal to 30 percent of the capital costs of the project, in lieu of future production tax credits.[25] To date, the government has provided $602 million, nationally, under the alternative energy credit, and $144 million, nationally, under the business credit for renewable energy. The government has further provided $125 million, nationally, under the ITC provision of ARRA.[26]

ARRA also created the 1603 Treasury Program grant. Although this program has expired, for commercial properties placed into service from 2009 to 2012, developers were able to receive a 30 percent direct grant in lieu of the ITC.

In addition, the federal Modified Accelerated Cost-Recovery System ("MACRS") allows businesses to recover investments in certain tangible property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated.[27] Many renewable energy technologies, including a variety of solar-electric and solar-thermal technologies, are eligible for a cost recovery period of five years.[28]

In 2008, the *Economic Stimulus Act of 2008 added* a 50 percent first-year bonus depreciation provision for eligible renewable-energy systems. This bonus has been extended and modified a number of times since then, most recently by the *American Taxpayer Relief Act of 2012*. The Act extended the placed in service deadline for 50 percent first-year bonus depreciation by one year, from December 31, 2012 to

[25] American Recovery and Reinvestment Act of 2009: A Guide to Renewable Energy and Energy Efficiency Opportunities and Local and Tribal Governments (February 27, 2009), U.S. Environmental Protection Agency, pp. 13-14.

[26] The American Recovery and Reinvestment Act; Funding Overview, Tax Benefits Program. Internet Website: http://www.recovery.gov/arra/Transparency/fundingoverview/Pages/taxbenefits-details.aspx#EnergyIncentives.

[27] U.S. Department of Energy, Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation. Available at: http://energy.gov/savings/modified-accelerated-cost-recovery-system-macrs-bonus-depreciation-2008-2012.

[28] For equipment on which an ITC or 1603 Treasury grant is received, the owner must reduce the project's depreciable basis by one-half the value of the 30 percent ITC. This means the owner is able to deduct 85 percent of its tax basis.

December 31, 2013. The bonus depreciation allowance has not been extended since and is currently not available.

In 2007, the Louisiana Legislature passed Act 371 to allow an income tax credit for residential property owners that install solar or wind energy systems after January 1, 2008. The tax credit was for 50 percent of the first $25,000 of the cost of *each* system with a maximum incentive of $12,500 per system.[29] In 2009, the tax credit was extended to all taxpayers and the credit was applicable to personal, corporate or franchise taxes, depending on the entity purchasing and installing the system and the Department of Revenue confirmed via private letter ruling that a single taxpayer could be refunded multiple credits by purchasing multiple systems.

Louisiana's tax credit was one of the more generous in the nation. When the credit was first approved in 2007, the incentives were expected to total about $500,000 per year.[30] However, as shown in Figure 10, the lost tax revenue has exceeded that estimate exponentially. So far, lost tax revenue has totaled over $150 million.

[29]La. R.S. 47:6030B.

[30] Thompson, R. 2012. Boon or boondoggle? Mounting costs of Louisiana solar power tax breaks could spur changes. The Times-Picayune. December 7, 2012.

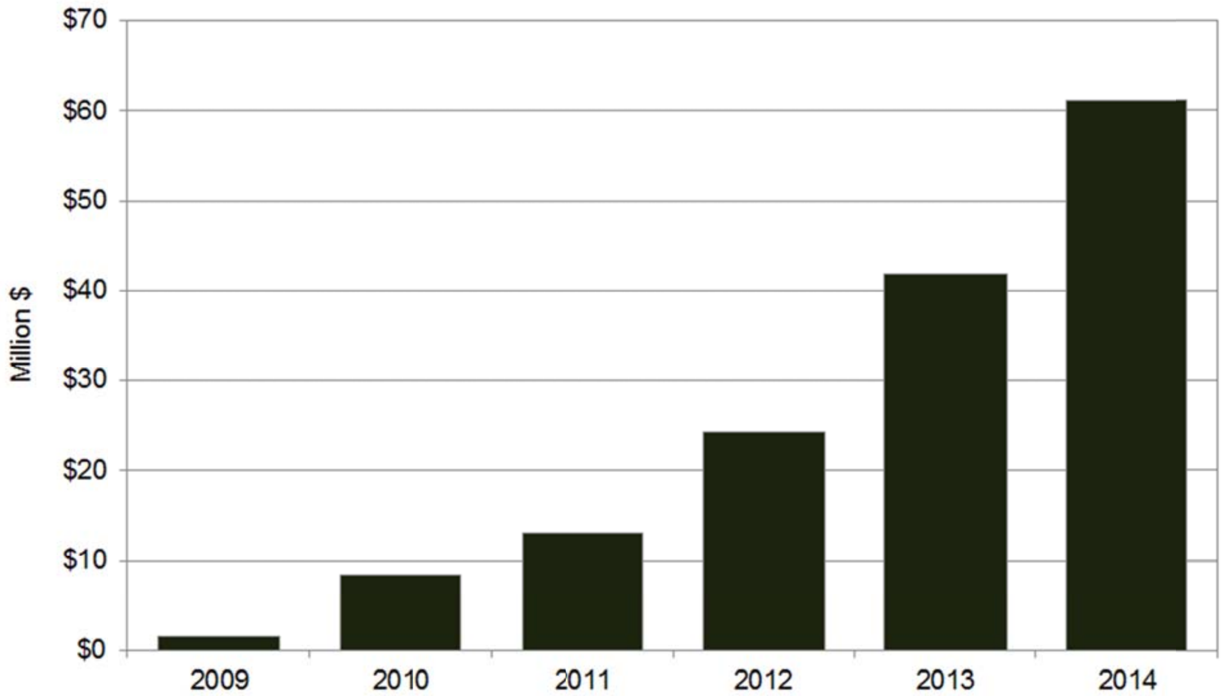

Figure 10: Annual Value of Louisiana Solar Tax Credit
Source: Author's construct from Advocate Graphic, Louisiana Department of Revenue.

In 2013, the Louisiana Legislature passed Act 428 which made numerous changes to the tax credit. First, it repealed the tax credit for wind energy and now provides only for installations at a single-family residence. The credit for customer-owned systems installed between January 1, 2014 and January 1, 2018 is still for 50 percent of the first $25,000. The Act provided additional restrictions for leased energy systems, reducing the amount of the credit. For systems installed before January 1, 2014, the credit remains at 50 percent of the first $25,000. However, for systems installed after this date, the tax credit is reduced to 38 percent of the first $25,000. In addition, in determining the amount of the credit, eligible costs are subject to the following: For systems purchased and installed between July 1, 2013, and July 1, 2014, the system must cost less than $4.50 per watt and provide more than six kW; for systems purchased and installed between July 1, 2014, and July 1, 2015, the system must cost less than $3.50 per watt and provide more than six kW; and for systems purchased and installed between July 1, 2015, and January 1, 2018, the system must cost less than $2.00 per watt and provide more than six kW.[31]

Like Louisiana, other states in the wake of the 2008 financial collapse implemented state tax incentives for the installation of small renewable energy systems, which when combined with existing federal incentives significantly reduced direct costs to renewable energy consumers, and increased demand for renewable energy.

2.5. Solar Panel Cost Trends Supporting NEM Installation Growth

An additional factor leading to the significant development of NEM installations has been the considerable cost decreases associated with solar PV systems. And, much of this cost decrease can be attributed to the acceleration of the global photovoltaic module market. As shown in Figure 1, PV exports across the globe have experienced a 53 percent compound annual growth rate from 2000 through 2010, reaching 17 gigawatts ("GW") of PV capacity shipped in 2010. In addition to seeing dramatic growth activity, the global market for PV has shifted over the past decade from country to country. In 2000, the U.S. accounted for 30 percent of global PV supply, but quickly lost its market share early on.[32] Growth in the market shifted first to Japan, which experienced significant growth due to residential subsidies enacted in the mid-1990s; then to Germany, whose generous feed-in tariff subsidy produced substantial growth in domestic solar demand; and finally to China and Taiwan, which invested

[31] Louisiana Department of Revenue. Revenue Information Bulletin No. 13-026, September 24, 2013.

[32] Afrin, David et. al. 2012. SunShot Vision Study. U.S. Department of Energy, pp. 3-4.

heavily in PV manufacturing during the 2006 to 2010 timeframe. In fact, by 2010, China and Taiwan accounted for 53 percent of global PV supply.[33]

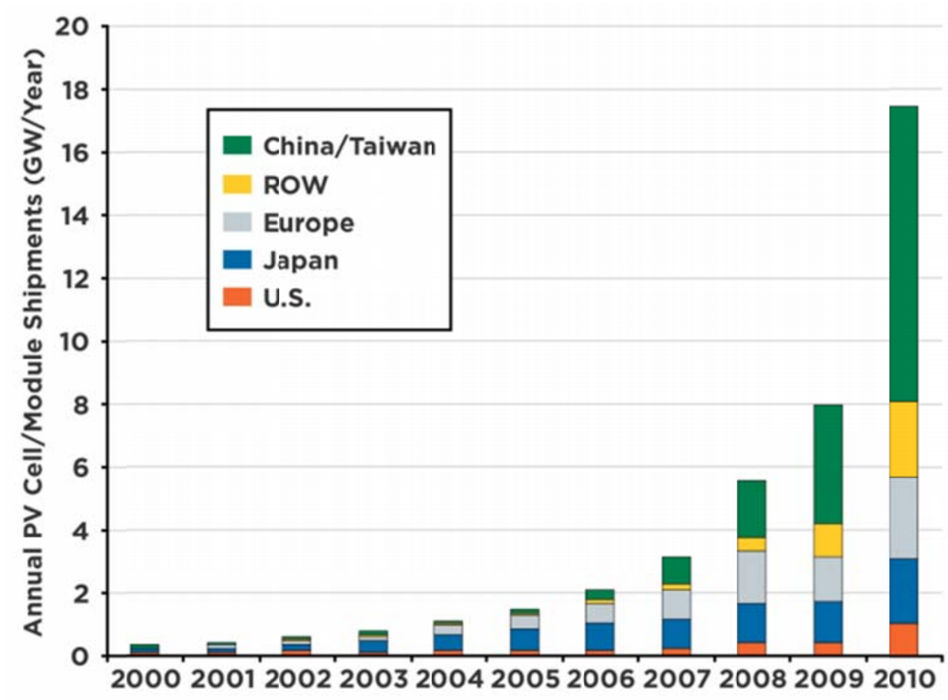

Figure 11: Photovoltaic Module Exports

Source: Afrin, David et. al. 2012. SunShot Vision Study. U.S. Department of Energy, Figure 1-1

The use of Chinese/Taiwanese manufactured PV modules is part of the reason for the decrease in PV prices. Installations using Chinese manufactured PV modules have been consistently less expensive than non-Chinese product installations (Figure 12).[34] However, the massive growth in PV manufacturing around the world has also increased supply and put downward pressure on PV module prices globally.[35]

[33] Afrin, David et. al. 2012. SunShot Vision Study. U.S. Department of Energy, p. 26.

[34] Barbose, Galen et al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 32.

[35] It should be noted that in January 2015, the U.S. International Trade Commission determined that the U.S. PV industry is being materially injured by imports of "certain crystalline silicon photovoltaic products from China and Taiwan that the U.S. Department of Commerce has determined are sold in the United States at less than fair value and are subsidized by the government of China." This decision will result in the U.S. Department of Commerce imposing countervailing duties and antidumping duties on

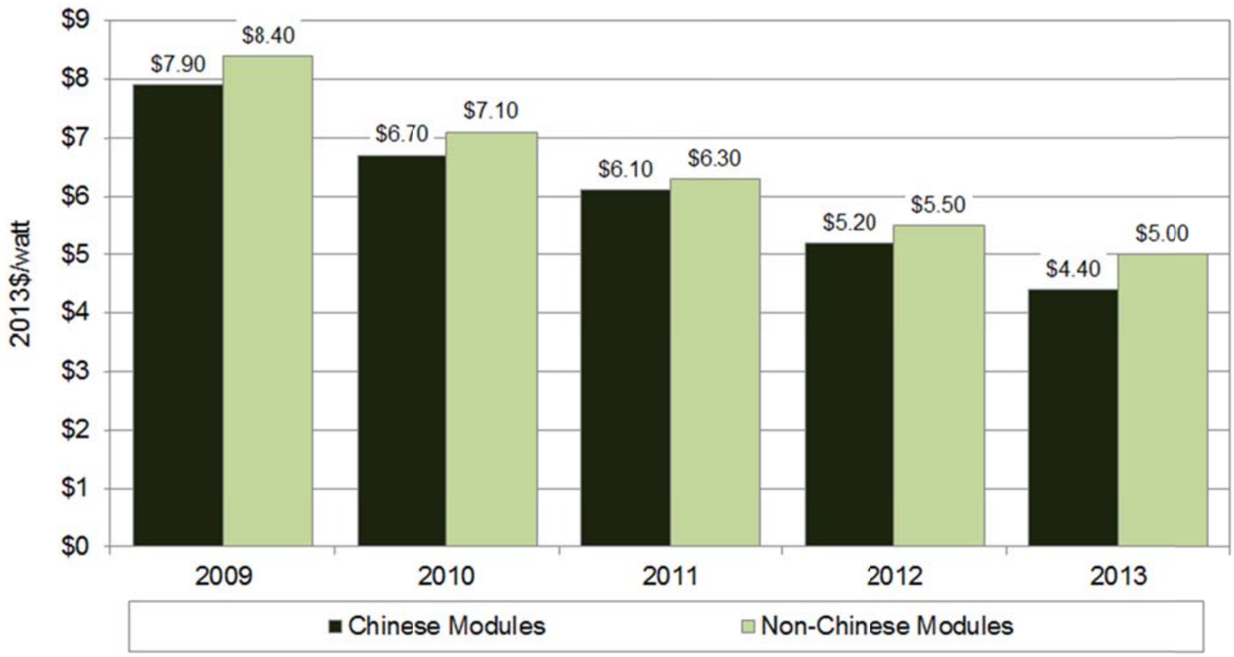

Figure 12: Price Differences between Chinese and non-Chinese Solar PV Installation for <10 kW Systems in the U.S. (2013 $)

Source: Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 32.

As shown in Figure 13, the cost of a solar PV module in 1998 was slightly less than $5 per watt of DC capacity, a level that held relatively constant until 2007, after which prices plunged to current levels of under $1 per watt. This has affected many domestic solar producers and U.S. PV manufacturing declined in 2012, from 1,161 MW in 2011 to 714 MW in 2012, a decrease of almost 40 percent. Employment in PV-related activities has also been affected as the number of full-time equivalent (FTE) employees decreased from 15,777 FTE in 2011 to 12,575 FTE in 2012[36]. While

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solar imports from China. See Pentland, W. 2015. Trade duties on solar imports from China and Taiwan clear final hurdle. Forbes.com. Available at: http://www.forbes.com/sites/williampentland/2015/01/22/trade-duties-on-solar-imports-from-china-and-taiwan-clear-final-hurdle/.

[36] U.S. Energy Information Administration (December 2013), Solar Photovoltaic Cell/Module Shipments Report

domestic solar producers have suffered, the increase in imports of less expensive solar modules has resulted in a boon for solar customers.[37]

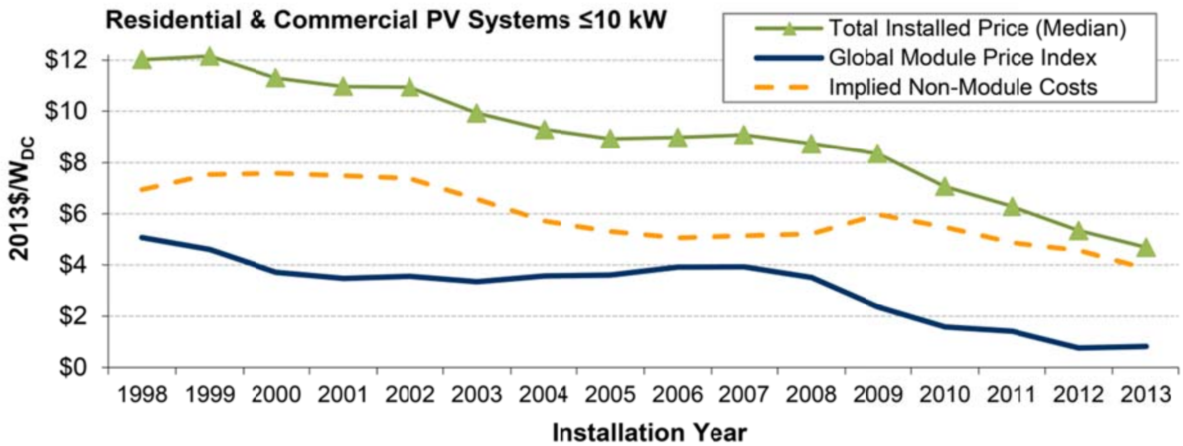

Figure 13: Total Installed PV Price is Decreasing Due to Low Module Costs
Source: Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, Figure 8.

The total cost of a PV system is made up of module costs, inverter costs and “balance of system” or “BOS” costs.[38] As module prices have fallen, BOS costs now account for a large share of the total PV system cost. Figure 14 depicts the cost components for residential, commercial and utility scale systems from 2009 to 2013. As of late 2013, the module and inverter costs were approximately $1 per watt for residential installations while the BOS costs were over $2 per watt.[39] While BOS costs are declining (from nearly $4 per watt for residential systems in 2009 to $2 per watt in 2013) their fall has not been as precipitous as the fall in PV module costs.

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[37] Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 15.

[38] Balance of system costs include items such as permitting fees, installation labor, overhead, racking, customer acquisition costs and sale tax.

[39] Feldman, David et. al. (September 2014), Photovoltaic System Pricing Trends, U.S. Department of Energy National Renewable Energy Laboratory, p. 17.

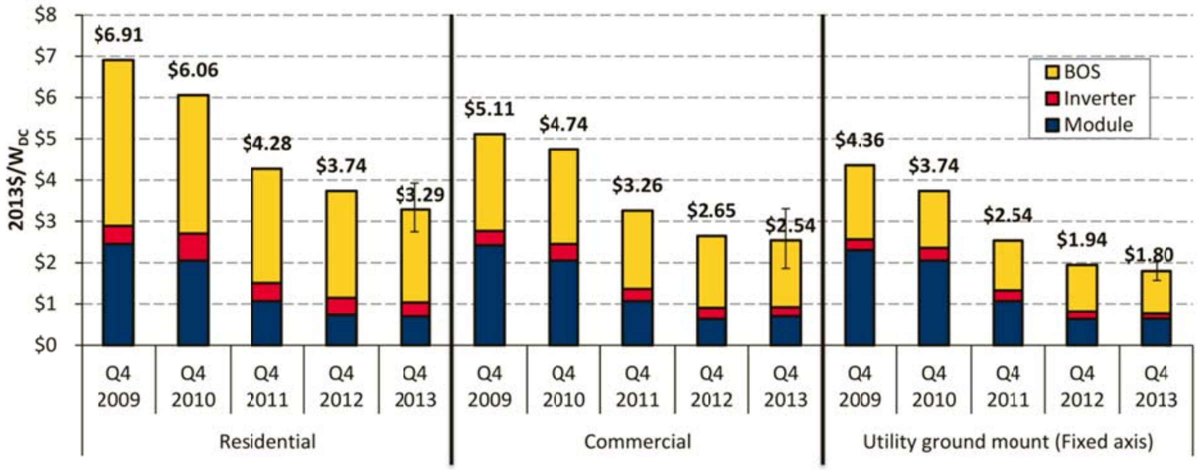

Figure 14: Module, Inverter and Balance of System Costs, 2009-2013
Feldman, David et. al. (September 2014), Photovoltaic System Pricing Trends, U.S. Department of Energy National Renewable Energy Laboratory, Figure 17.

State policy makers have started to respond to falling module and installed system cost by scaling back government-backed tax incentives and rebates. Figure 15 shows that the average pre-tax rebate for installed systems has decreased to less than $1 per watt from highs of $3 to $7 per watt in the 1998 to 2002 period. It should be noted that the magnitude of this decline is heavily influenced by reductions in California's incentive programs. However, nearly all of the sampled states were found to be reducing PV incentives.[40]

[40] Barbose, Galen et. al. (September 2014), Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013, U.S. Department of Energy Lawrence Berkeley National Laboratory, p. 17.

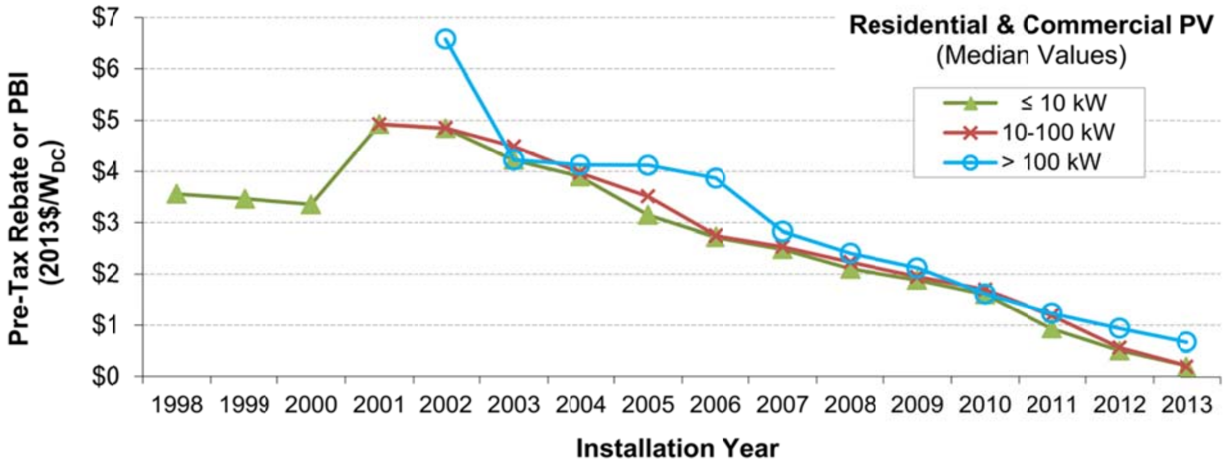

Figure 15: Declining State Rebates and Incentives

Source: Barbose, Galen et. al. 2014. Tracking the Sun VII: An Historical Summary of the Installed Price of Photovoltaic in the United States from 1998 to 2013. U.S. Department of Energy Lawrence Berkeley National Laboratory, Figure 9.

Figure 16 shows that the rate of decline in PV module costs is expected to moderate, yet PV module costs still are expected to continue to decline in the near term from $1.34 per watt in 2011 and $0.67 per watt in 2013 to approximately $0.60 per watt in 2015-2016.

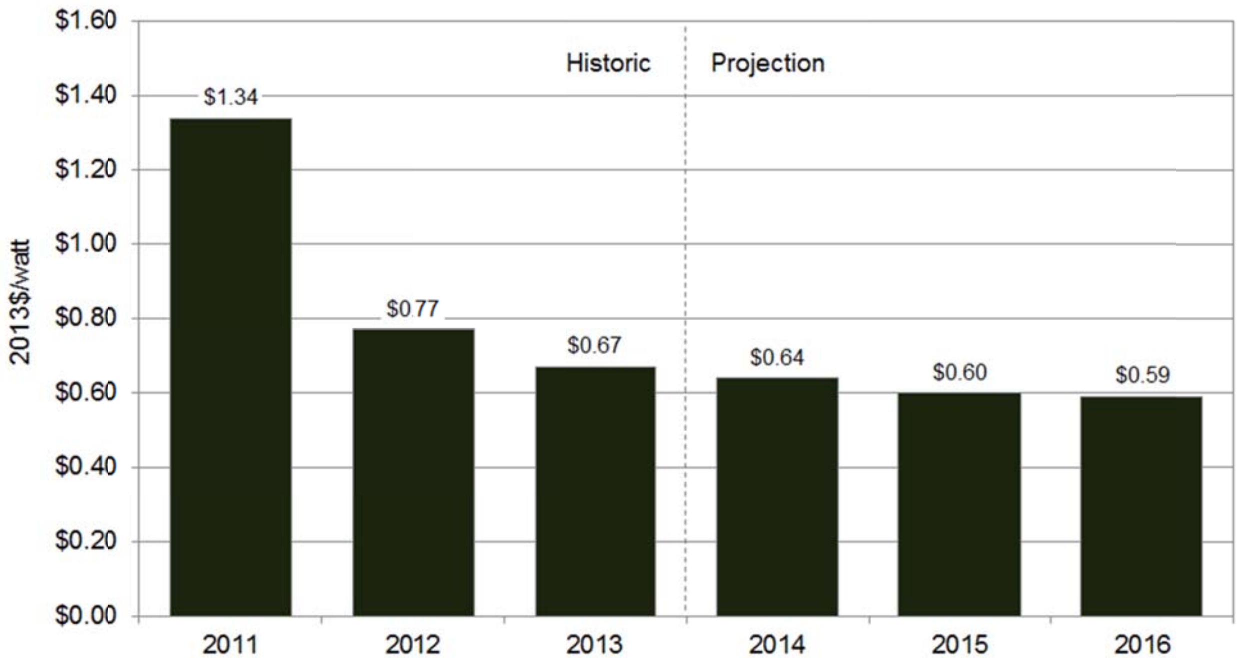

Figure 16: Historic and Predicted Future Price Trends in PV Modules
Feldman, David et. al. (September 2014), Photovoltaic System Pricing Trends, U.S. Department of Energy National Renewable Energy Laboratory, Figure 26.

Decreases in BOS costs combined with modest decreases in in PV module costs, will result in further decreases in the total installed cost of a PV system. Figure 17 shows that installed system prices are expected to range from around $1.80 per watt to just above $3.00 per watt in 2016.

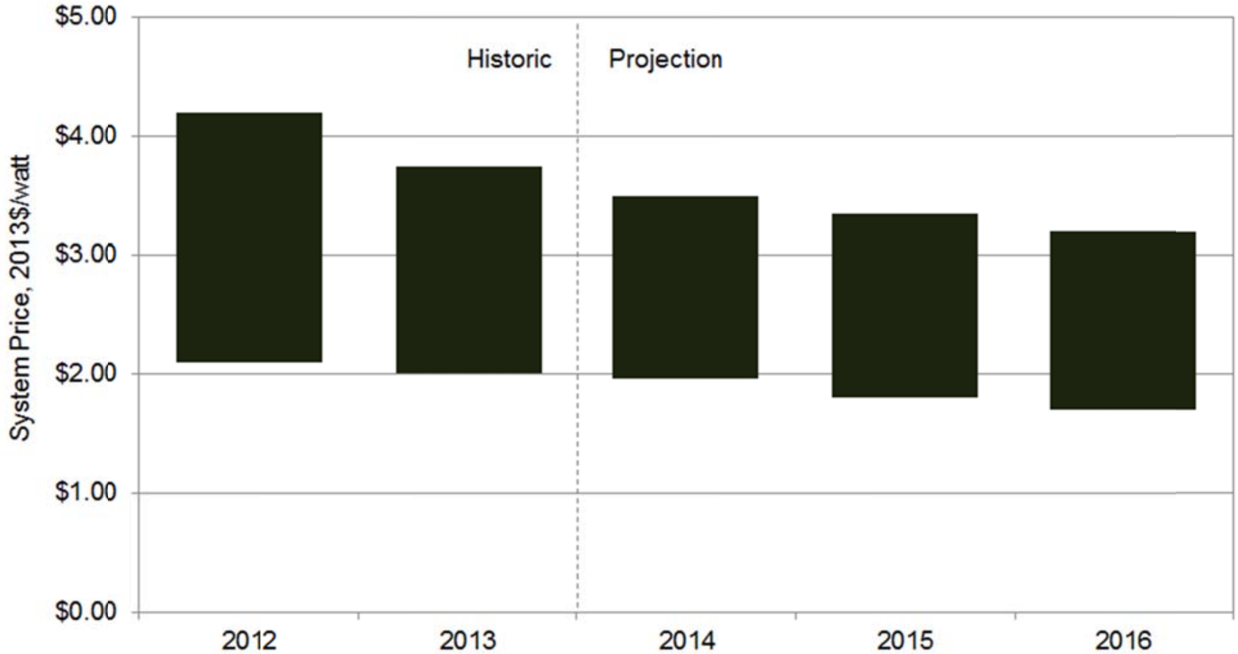

Figure 17: Historic and Predicted Future Price Trends in Installed System Price
Feldman, David et. al. (September 2014), Photovoltaic System Pricing Trends, U.S. Department of Energy National Renewable Energy Laboratory, Figure 27.

3. Louisiana Solar NEM Trends

3.1. Solar NEM Installation Data

One of the first steps in this research project was to issue data requests to each of the state's LPSC-jurisdictional utilities to obtain unit-specific information about solar NEM installations in each utility's service territory. Each utility provided solar NEM installation-specific information that included location, capacity, and generation levels and this served as one of the primary data inputs for the analyses included in this Report. This section summarizes some of the historic trends in solar NEM installations using this utility-provided information. Later sections of this Report will utilize the same set of information to estimate a range of hourly generation statistics, to compare the usage and revenue contributions of solar NEM installations to each utility's estimated cost of service, and to examine a variety of income distribution and equity issues associated with NEM installations.

3.2. Statewide Solar NEM Trends

Louisiana has seen a significant increase in the development of solar NEM installations from 2008 to 2014 as shown in Figure 18.[41] While few solar NEM installations were reported in 2008, installations increased five times that in 2009 and continued to increase each year subsequent. Solar NEM installations and capacity development surged in 2012 and peaked in 2013 with over 3,100 installations in that

[41] The remainder of this section examines LPSC-jurisdictional installations. The actual state-wide number of installations may be higher.

year alone. The 2014 numbers provided in Figure 18 are through July 2014, but if the same monthly installation rate is maintained, Louisiana will be on track to add a total of 3,357 solar NEM installations for the year. As of July 2014, Louisiana had a total of 7,517 active solar NEM installations.

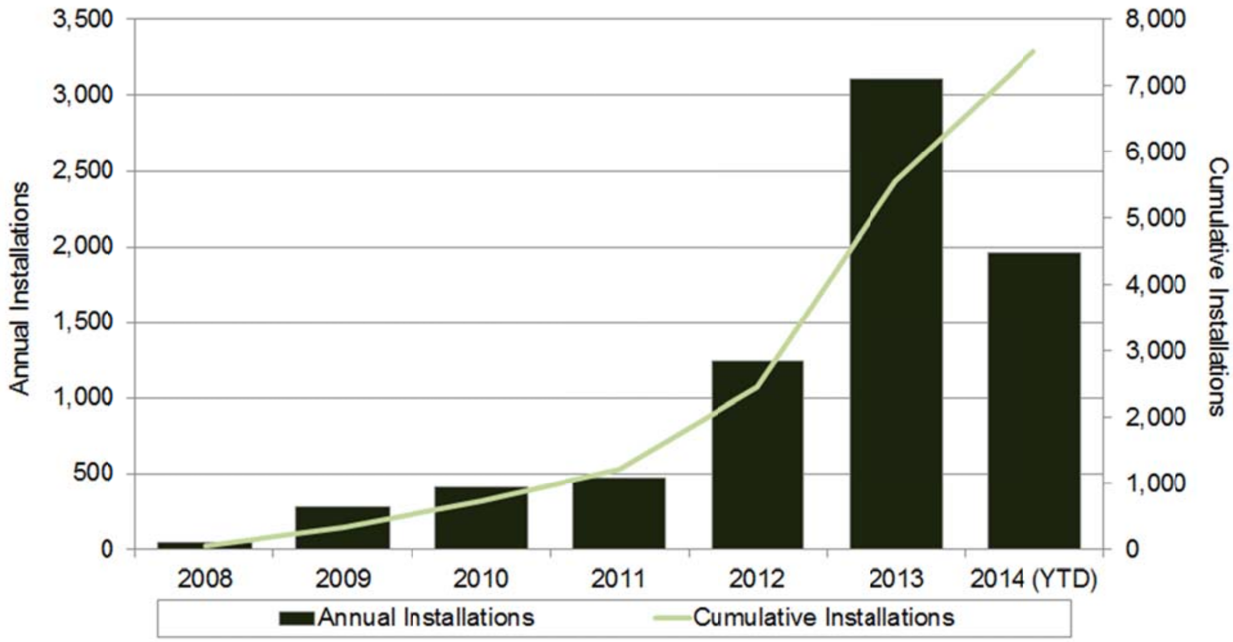

Figure 18: Total Louisiana NEM Installations
Note: 2014 data is through July.

Figure 19 shows the trends in the development of LPSC-jurisdictional solar NEM capacity from 2008 through 2014. The trends are comparable in nature to the number of installations presented in Figure 18. Solar NEM capacity development has increased rapidly over the past several years, increasing from just 160 kW in 2008 to over 42 MW in 2014, or an average annual rate of 220 percent. Louisiana's solar NEM capacity has more than doubled in each year from 2008 through 2012.

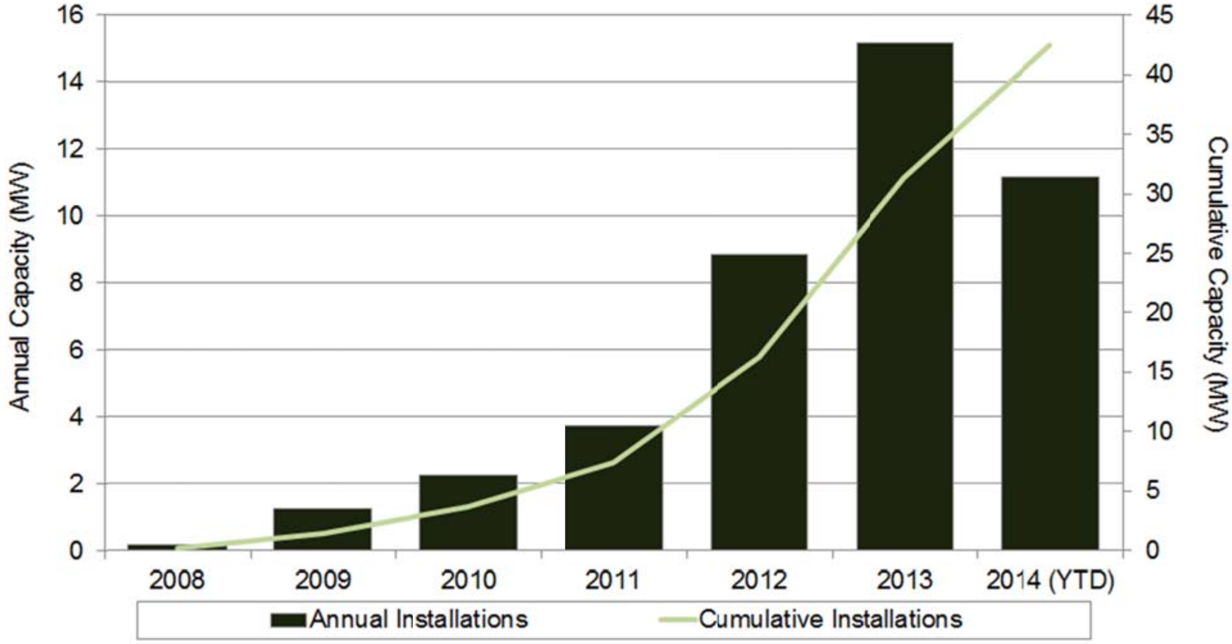

Figure 19: Total Louisiana NEM Capacity
Note: 2014 data is through July.

Figure 20 presents the trends in the average size of LPSC-jurisdictional solar NEM installations in the state from 2008 through 2014. In 2008, the average size for jurisdictional solar NEM installations was relatively small at around 3.6 kW. This increased over the next several years, until 2011 when the average size of a jurisdictional NEM installation peaked at 7.8 kW. Average solar installation sizes have fallen since 2011 and were down by as much as 37 percent in 2012 relative to prior-year levels. Average solar NEM installations for 2014 (through July) are up by 20 percent but still lower than the 2011 peak.

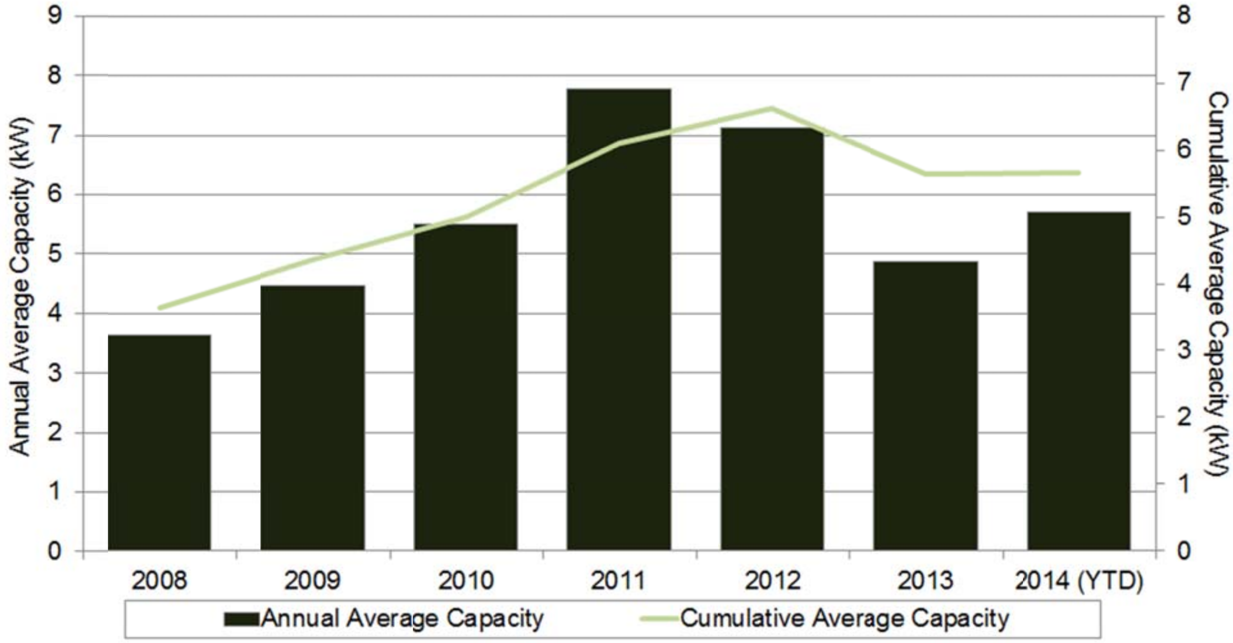

Figure 20: Total Louisiana NEM Average Capacity
Note: 2014 data is through July.

Figure 21 summarizes the trends in LPSC-jurisdictional solar NEM generation. The historic trends are comparable to those shown for solar NEM solar capacity development. Overall, solar NEM generation has been growing at a considerable rate, around 318 percent on an annual average basis from 2008 to 2013. If 2014 (through July) trends are continued, Louisiana should see an additional 175 percent increase in total NEM gross generation from solar NEM installations.

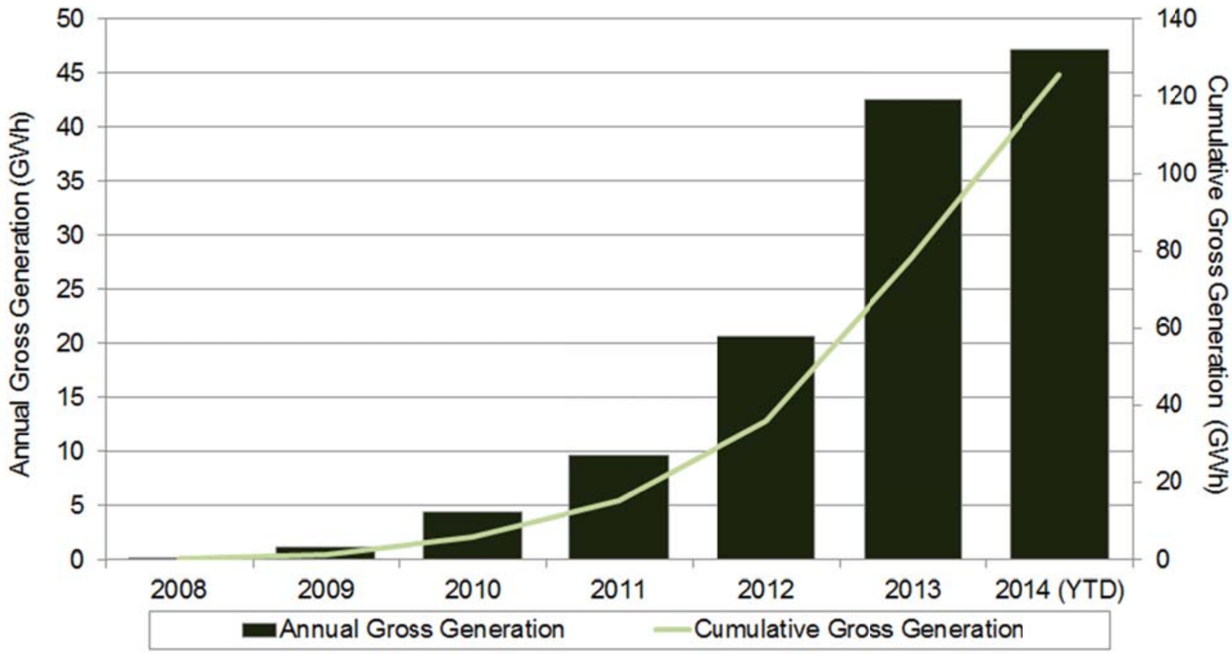

Figure 21: Estimated Louisiana NEM Gross Generation
Note: 2014 data is through July.

Figure 22 shows the concentration of solar NEM capacity and generation relative to statewide totals. Both solar NEM capacity and gross generation have been increasing rapidly over the past several years but, in the absolute, still comprise a relatively small share of total jurisdictional capacity and generation. The 2014 (through July) numbers are estimated to comprise around 0.17 percent of state electric generation capacity and just under 0.05 percent of state electric generation.

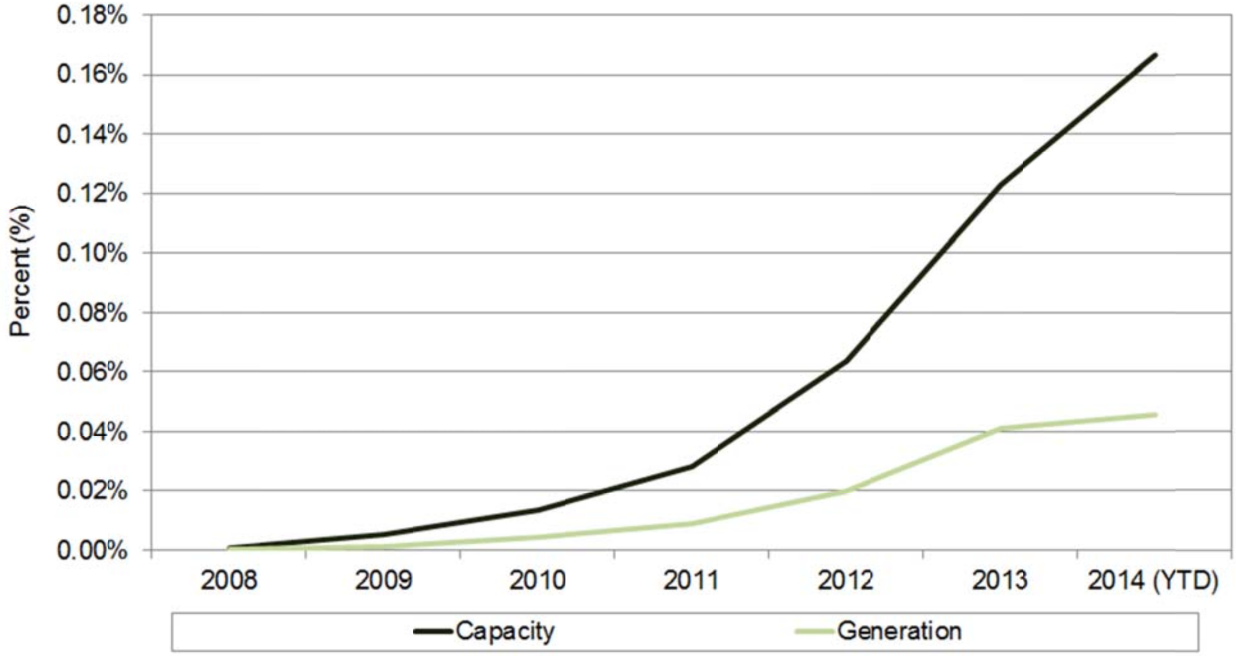

Figure 22: NEM Capacity and Generation as a Share of Total State Capacity and Generation

Note: Note: 2014 data is through July; Total state capacity includes independent power and CHP; and Total state capacity and generation values for 2013 and 2014 are assumed to be the same as 2012.

3.3. Jurisdictional Utility Solar NEM Installation Trends

Table 1 provides the annual installation trends for solar NEM installations by utility, while Figure 23 graphs those trends, also by utility. As noted earlier, statewide NEM installations were minimal in 2008, and almost half of these early installations were in SWEPCO's service territory. NEM solar installations increased significantly in 2009 and again, a larger share were concentrated within SWEPCO's service territory. In 2008 and 2009, 35 percent of all solar NEM installations were in the SWEPCO service territory. Utility-specific NEM installation trends became more balanced in 2010 with almost an equal number of installations occurring for three of the four jurisdictional investor-owned utilities ("IOUs"). Solar NEM installations for rural electric cooperatives also began to increase in 2010, particularly for Washington-St. Tammany Electric

Cooperative ("WST") which saw a leap of over 250 percent from the prior year's level of installations.

Table 1: NEM Installations by Utility and Year

Company	2008	2009	2010	2011	2012	2013	2014*
Investor-Owned Utilities							
Cleco	-	38	62	68	313	546	319
Southwestern Electric Power Company	24	90	59	102	167	287	159
Entergy Gulf States Louisiana	3	33	62	81	107	286	228
Entergy Louisiana	8	85	137	114	502	1,557	1,073
Cooperatives/Membership Corporations							
Beauregard-Harrison Electric Cooperative	-	5	2	11	14	23	32
Claiborne Electric Cooperative	-	-	19	9	10	5	1
Dixie Electric Membership Corporation	-	10	15	21	38	93	-
Jefferson Davis Electric Cooperative	-	-	-	5	5	2	4
Northeast Louisiana Power Cooperative	-	-	7	18	8	10	2
Panola-Harrison Electric Cooperative	6	5	8	5	9	6	1
Pointe Coupee Electric Membership Corporation	-	2	1	3	4	6	4
South Louisiana Electric Cooperative	-	-	2	1	-	28	13
Southwest Louisiana Electric Membership Corporation	3	4	10	18	32	63	57
Washington-St. Tammmany Electric Cooperative	-	7	25	20	35	195	65
Total Cooperative/Membership Corporations	**9**	**33**	**89**	**111**	**155**	**431**	**179**
Total State	**44**	**279**	**409**	**476**	**1,244**	**3,107**	**1,958**

Note: 2014 data is through July.
DEMCO did not report any installations for 2014.

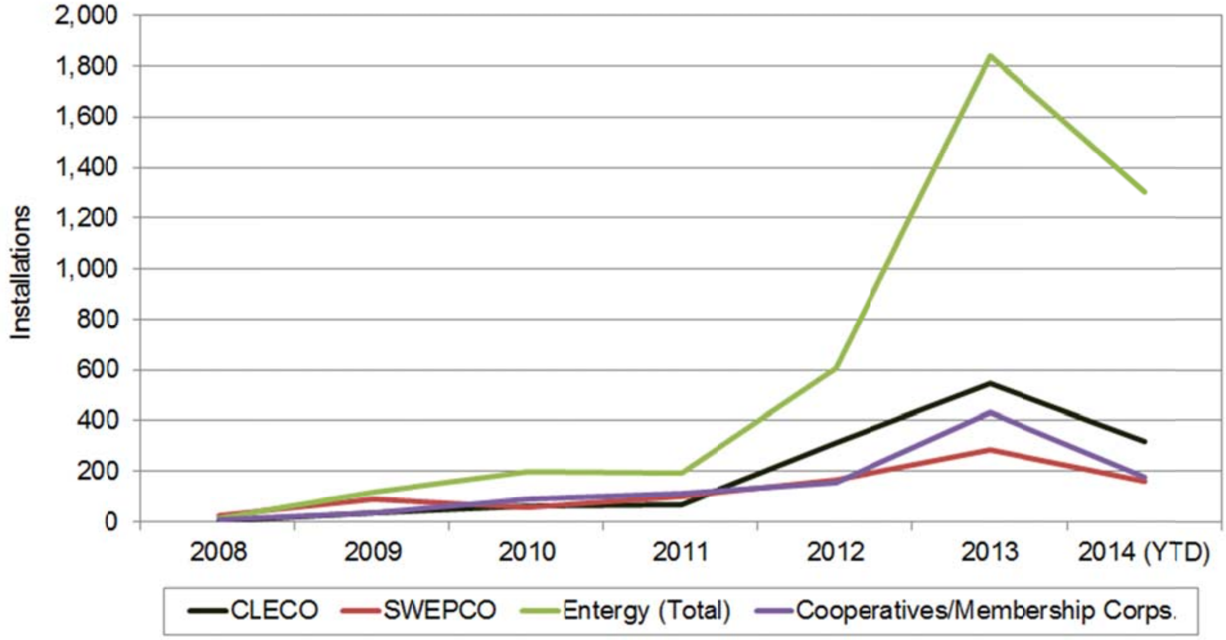

Figure 23: NEM Installations by Utility and Year
Note: 2014 data is through July.

The utility disposition of solar NEM installations shifted in 2012 with a large number of installations occurring in the Entergy service territory, particularly ELL where installations increased from 114 in 2011 to 502 in 2012. The number of installations in ELL's service territory jumped again, more than tripling, from 502 in 2012 to 1,557 in 2013. Other utilities saw similar relative installation surges in 2012. For instance, Southwest Louisiana Electric Membership Cooperative ("SLECA") saw installations almost double from 18 to 32 between 2011 and 2012, and then almost double again between 2012 and 2013 (from 32 to 63). Overall Washington St. Tammany has seen the fastest annual average rate of solar NEM growth at an average annual rate of 178 percent per year between 2010 and 2013, followed closely by Cleco and ELL which have had average annual growth rates of 133 percent and 132 percent, respectively.

Table 2 and Figure 24 provide comparable information on the number of cumulative NEM solar installations on an annual and per utility basis. Currently ELL has the largest number of solar NEM installations in Louisiana, accounting for 46 percent of all installations across the state's LPSC jurisdictional utilities. ELL and EGSL, on a combined basis, account for 57 percent of the solar NEM installations in the state. Cleco accounts for 18 percent of all statewide solar NEM installations while the rural cooperatives, collectively, account for 13 percent of all solar NEM installations. SWEPCO accounts for the remaining 12 percent of Louisiana's solar NEM installations.

Table 2: Cumulative NEM Installations by Utility and Year

Company	2008	2009	2010	2011	2012	2013	2014*
Investor-Owned Utilities							
Cleco	-	38	100	168	481	1,027	1,346
Southwestern Electric Power Company	24	114	173	275	442	729	888
Entergy Gulf States Louisiana	3	36	98	179	286	572	800
Entergy Louisiana	8	93	230	344	846	2,403	3,476
Cooperatives/Membership Corporations							
Beauregard-Harrison Electric Cooperative	-	5	7	18	32	55	87
Claiborne Electric Cooperative	-	-	19	28	38	43	44
Dixie Electric Membership Corporation	-	10	25	46	84	177	177
Jefferson Davis Electric Cooperative	-	-	-	5	10	12	16
Northeast Louisiana Power Cooperative	-	-	7	25	33	43	45
Panola-Harrison Electric Cooperative	6	11	19	24	33	39	40
Pointe Coupee Electric Membership Corporation	-	2	3	6	10	16	20
South Louisiana Electric Cooperative	-	-	2	3	3	31	44
Southwest Louisiana Electric Membership Corporation	3	7	17	35	67	130	187
Washington-St. Tammmany Electric Cooperative	-	7	32	52	87	282	347
Total Cooperative/Membership Corporations	**9**	**42**	**131**	**242**	**397**	**828**	**1,007**
Total State	**44**	**323**	**732**	**1,208**	**2,452**	**5,559**	**7,517**

Note: 2014 data is through July.

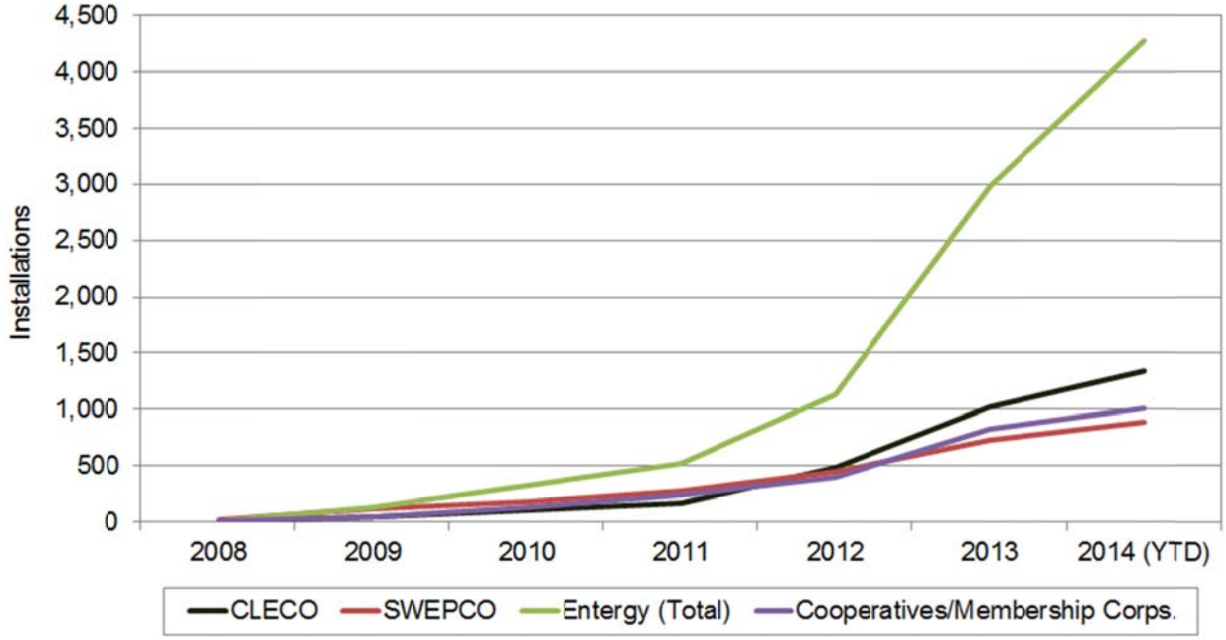

Figure 24: Cumulative NEM Installations by Utility and Year
Note: 2014 data is through July.

Figure 25 shows the concentration of cumulative solar NEM installations per utility on both a total utility customer and total utility capacity basis. This graph scales the number/size of solar NEM installations to the size of each utility in terms of the number of customers its services, and the total size of its generating capacity. Cleco has the highest density of solar NEM installations when compared to its customers and generation capacity followed closely by SWEPCO, Entergy, and the rural cooperatives, respectively.

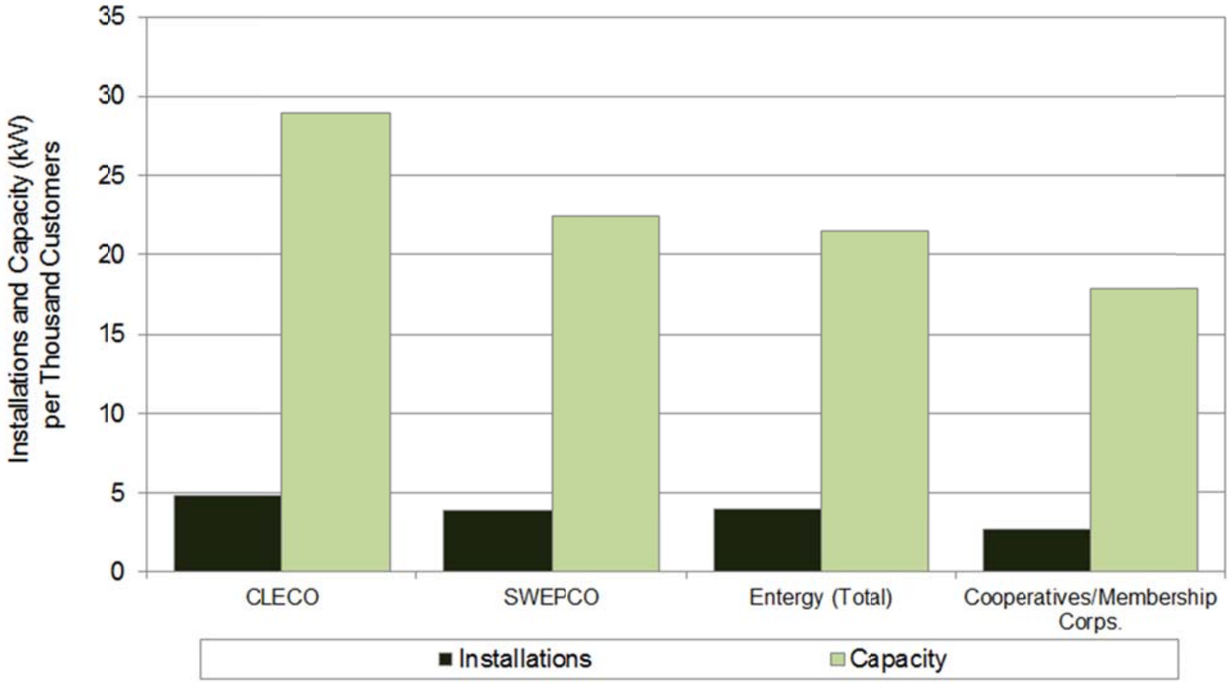

Figure 25: Total Number of Installations and Capacity per Utility Customer

Table 3 provides a geographic break-down of LPSC-jurisdictional solar NEM installations on a per-parish basis. The highest concentration of solar NEM installations is located in Jefferson (17.6 percent) and St. Tammany (10.9 percent) parishes. The next highest concentration of solar NEM installations is located in Caddo (6.3 percent), East Baton Rouge (6.0 percent) parishes, and to a lesser extent in St. Bernard (4.4 percent) and Tangipahoa (4.2 percent) parishes. Interestingly, each Louisiana parish has at least one solar NEM installation.

Table 3: Cumulative NEM Installations by Parish and Share of State Total

Parish	Number of Installations	Percent of Total (%)	Parish	Number of Installations	Percent of Total (%)
Acadia	45	0.60%	Madison	4	0.05%
Allen	21	0.28%	Morehouse	31	0.41%
Ascension	137	1.82%	Natchitoches	45	0.60%
Assumption	12	0.16%	Orleans	269	3.58%
Avoyelles	129	1.72%	Ouachita	204	2.72%
Beauregard	35	0.47%	Plaquemines	42	0.56%
Bienville	22	0.29%	Pointe Coupee	24	0.32%
Bossier	265	3.53%	Rapides	199	2.65%
Caddo	473	6.30%	Red River	25	0.33%
Calcasieu	155	2.06%	Richland	38	0.51%
Caldwell	12	0.16%	Sabine	31	0.41%
Cameron	7	0.09%	St. Bernard	327	4.35%
Catahoula	1	0.01%	St. Charles	166	2.21%
Claiborne	25	0.33%	St. Helena	8	0.11%
Concordia	5	0.07%	St. James	198	2.64%
De Soto	218	2.90%	St. John the Baptist	169	2.25%
East Baton Rouge	451	6.00%	St. Landry	97	1.29%
East Carroll	3	0.04%	St. Martin	38	0.51%
East Feliciana	20	0.27%	St. Mary	24	0.32%
Evangeline	61	0.81%	St. Tammany	820	10.92%
Franklin	38	0.51%	Tangipahoa	317	4.22%
Grant	43	0.57%	Terrebonne	104	1.38%
Iberia	41	0.55%	Union	21	0.28%
Iberville	27	0.36%	Vermilion	42	0.56%
Jackson	17	0.23%	Vernon	75	1.00%
Jefferson	1,324	17.63%	Washington	201	2.68%
Jefferson Davis	6	0.08%	Webster	29	0.39%
LaSalle	4	0.05%	West Baton Rouge	25	0.33%
Lafayette	93	1.24%	West Carroll	41	0.55%
Lafourche	79	1.05%	West Feliciana	6	0.08%
Lincoln	23	0.31%	Winn	5	0.07%
Livingston	94	1.25%			
Total				**7,511**	**100.00%**

Note: Totals do not match previous tables as addresses were not provided for six of Jefferson Davis' net metered installations and were therefore not assigned to a parish.

3.4. Jurisdictional Utility Solar NEM Capacity Trends

Table 4 and Figure 26 provide the annual solar NEM installation capacity trends for each LPSC-jurisdictional utility. The solar NEM installation capacity trends are similar in nature, on a per utility basis, to those discussed above on installations. Annual solar NEM installations have increased rapidly over the last several years, particularly during the 2012 to 2014 time period. Louisiana is on track to install over 19 MW of capacity in 2014, based upon current monthly capacity development rates. If this level of solar NEM capacity development materializes, it will represent a 26 percent increase in one year alone: the fastest development rate recorded by Louisiana's jurisdictional utilities.

Table 4: NEM Capacity by Utility and Year

Company	2008	2009	2010	2011	2012	2013	2014*
	(kW)						
Investor-Owned Utilities							
Cleco	-	157	316	670	2,190	2,889	1,859
Southwestern Electric Power Company	94	345	324	534	1,579	1,468	760
Entergy Gulf States Louisiana	8	183	328	582	965	1,225	1,247
Entergy Louisiana	18	373	815	1,013	2,697	7,110	6,200
Cooperatives/Membership Corporations							
Beauregard-Harrison Electric Cooperative	-	27	11	76	111	138	193
Claiborne Electric Cooperative	-	-	70	49	124	44	7
Dixie Electric Membership Corporation	-	57	86	183	420	539	-
Jefferson Davis Electric Cooperative	-	-	-	54	39	7	16
Northeast Louisiana Power Cooperative	-	-	45	140	115	88	18
Panola-Harrison Electric Cooperative	27	16	31	20	70	50	7
Pointe Coupee Electric Membership Corporation	-	10	5	44	34	33	24
South Louisiana Electric Cooperative	-	-	7	17	-	129	72
Southwest Louisiana Electric Membership Corporation	14	30	67	183	249	337	375
Washington-St. Tammmany Electric Cooperative	-	52	143	141	267	1,109	386
Total Cooperative/Membership Corporations	**41**	**190**	**464**	**906**	**1,429**	**2,473**	**1,099**
Total State	**160**	**1,248**	**2,247**	**3,705**	**8,859**	**15,164**	**11,165**

Note: 2014 data is through July.

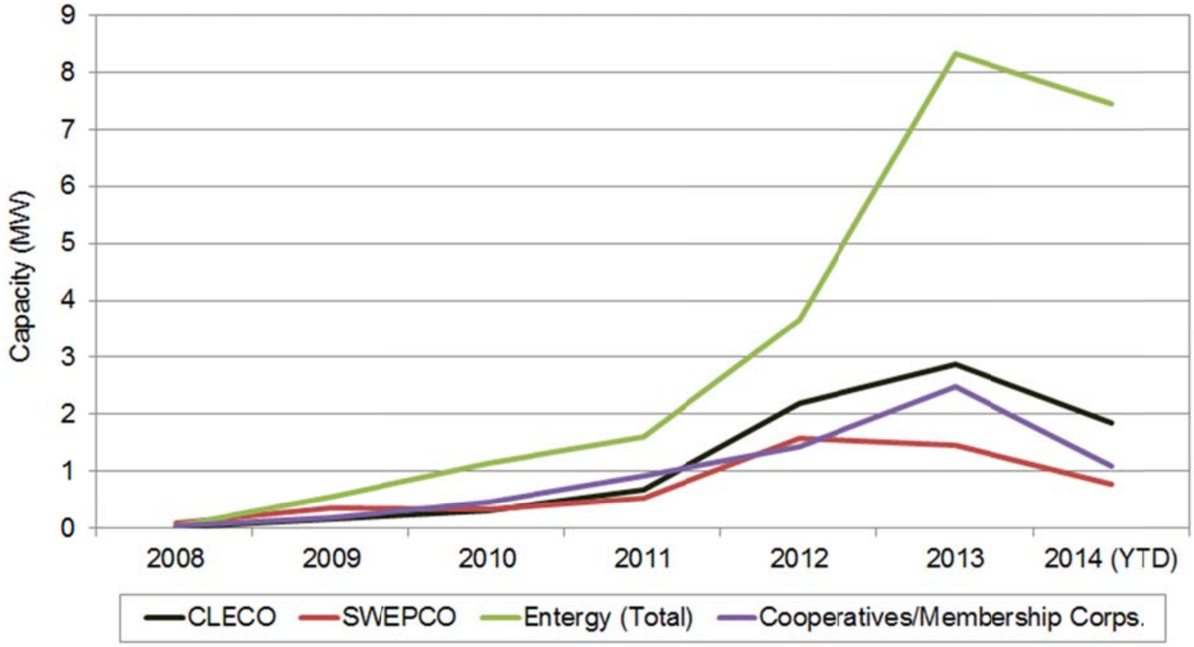

Figure 26: NEM Capacity by Utility and Year

Note: 2014 data is through July.

Table 5 and Figure 27 provide summaries of the cumulative annual capacity of solar NEM installations in the state. ELL has the largest concentration of NEM solar capacity in the state (43 percent) and when combined with EGSL, accounts for over half (53 percent) of all solar NEM capacity. Cleco accounts for 19 percent of the state's cumulative solar NEM capacity while SWEPCO accounts for 12 percent and the rural cooperatives collectively account for 16 percent of total capacity.

Table 5: Cumulative NEM Capacity by Utility and Year

Company	2008	2009	2010	2011	2012	2013	2014*
	----------	----------	----------	(kW)	----------	----------	----------
Investor-Owned Utilities							
Cleco	-	157	473	1,143	3,333	6,222	8,080
Southwestern Electric Power Company	94	439	763	1,297	2,876	4,344	5,104
Entergy Gulf States Louisiana	8	190	518	1,101	2,065	3,290	4,537
Entergy Louisiana	18	391	1,206	2,219	4,915	12,025	18,225
Cooperatives/Membership Corporations							
Beauregard-Harrison Electric Cooperative	-	27	37	113	224	361	555
Claiborne Electric Cooperative	-	-	70	119	243	287	294
Dixie Electric Membership Corporation	-	57	142	325	745	1,284	1,284
Jefferson Davis Electric Cooperative	-	-	-	54	93	100	116
Northeast Louisiana Power Cooperative	-	-	45	185	301	388	407
Panola-Harrison Electric Cooperative	27	42	73	93	163	213	220
Pointe Coupee Electric Membership Corporation	-	10	15	59	93	125	149
South Louisiana Electric Cooperative	-	-	7	24	24	153	225
Southwest Louisiana Electric Membership Corporation	14	44	111	294	543	880	1,254
Washington-St. Tammmany Electric Cooperative	-	52	195	336	603	1,712	2,098
Total Cooperative/Membership Corporations	**41**	**231**	**695**	**1,601**	**3,030**	**5,503**	**6,602**
Total State	**160**	**1,408**	**3,656**	**7,360**	**16,220**	**31,384**	**42,549**

Note: 2014 data is through July.

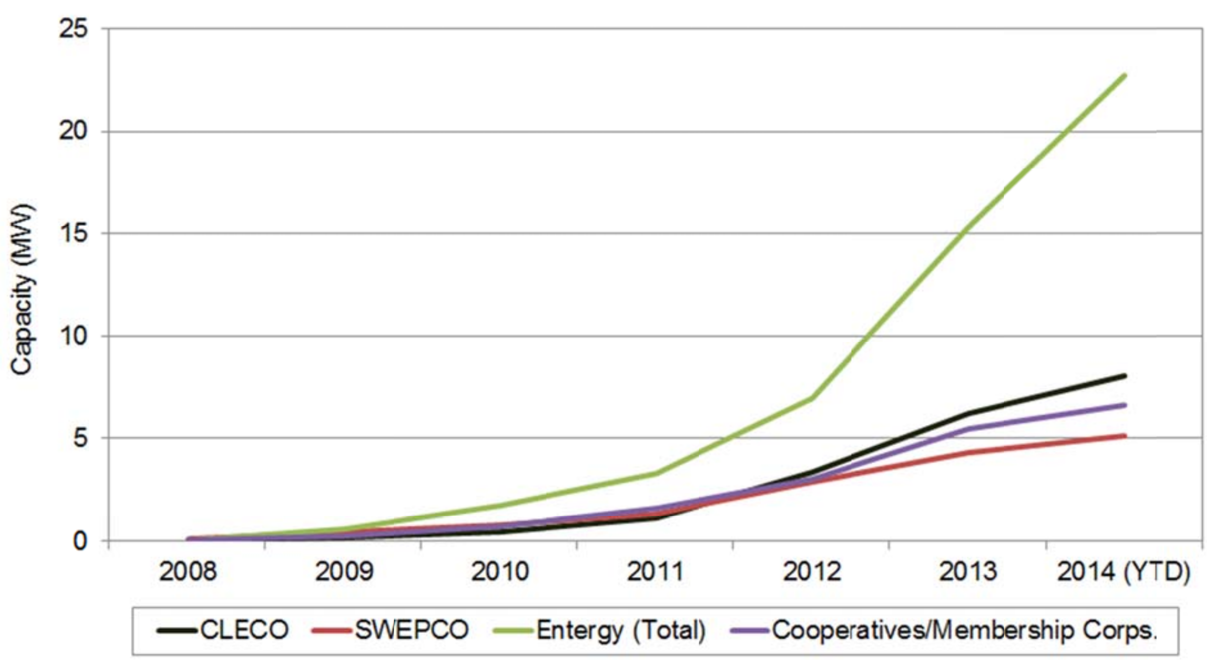

Figure 27: Cumulative NEM Capacity by Utility and Year
Note: 2014 data is through July.

Table 6 summarizes the geographic breakdown of the state's jurisdictional solar NEM capacity. Similar to installations, most of the state's solar NEM capacity is concentrated generally in the greater New Orleans area (Jefferson, St. Tammany, St. Bernard, Tangipahoa), with lower, but significant, concentrations around Shreveport (Caddo, Bossier) and Baton Rouge (East Baton Rouge).

Table 6: Cumulative NEM Capacity by Parish

Parish	Capacity (kW)	Percent of Total (%)	Parish	Capacity (kW)	Percent of Total (%)
Acadia	272	0.64%	Madison	33	0.08%
Allen	124	0.29%	Morehouse	302	0.71%
Ascension	782	1.84%	Natchitoches	362	0.85%
Assumption	88	0.21%	Orleans	1,355	3.19%
Avoyelles	888	2.09%	Ouachita	1,018	2.39%
Beauregard	248	0.58%	Plaquemines	253	0.60%
Bienville	142	0.33%	Pointe Coupee	182	0.43%
Bossier	1,510	3.55%	Rapides	1,213	2.85%
Caddo	2,483	5.84%	Red River	104	0.24%
Calcasieu	893	2.10%	Richland	296	0.70%
Caldwell	83	0.20%	Sabine	201	0.47%
Cameron	49	0.11%	St. Bernard	1,642	3.86%
Catahoula	5	0.01%	St. Charles	874	2.06%
Claiborne	132	0.31%	St. Helena	53	0.12%
Concordia	13	0.03%	St. James	742	1.74%
De Soto	1,404	3.30%	St. John the Baptist	865	2.03%
East Baton Rouge	2,669	6.28%	St. Landry	599	1.41%
East Carroll	28	0.07%	St. Martin	236	0.56%
East Feliciana	127	0.30%	St. Mary	129	0.30%
Evangeline	385	0.91%	St. Tammany	4,781	11.24%
Franklin	332	0.78%	Tangipahoa	1,840	4.33%
Grant	245	0.58%	Terrebonne	464	1.09%
Iberia	212	0.50%	Union	162	0.38%
Iberville	244	0.57%	Vermilion	308	0.73%
Jackson	113	0.27%	Vernon	491	1.15%
Jefferson	6,827	16.05%	Washington	1,223	2.88%
Jefferson Davis	36	0.08%	Webster	180	0.42%
LaSalle	29	0.07%	West Baton Rouge	120	0.28%
Lafayette	520	1.22%	West Carroll	313	0.74%
Lafourche	397	0.93%	West Feliciana	65	0.15%
Lincoln	180	0.42%	Winn	25	0.06%
Livingston	630	1.48%			
Total				**42,525**	**100.00%**

Note: Totals do not match previous tables as addresses were not provided for six of Jefferson Davis' net metered installations and were therefore not assigned to a parish.

3.5. Jurisdictional Utility Solar NEM Average Capacity Trends

Table 7 and Figure 28 provide the annual solar NEM installation average capacity trends for each LPSC-jurisdictional utility. The solar NEM installation average capacity trends are similar in nature, on a per utility basis, to the stateside trends discussed earlier. For every utility the average installation size peaked in either 2011 or 2012. For instance, Cleco's average installed capacity size increased from 4.1 kW and 5.1 kW in 2009 and 2010 to almost 10 kW in 2011. Similarly, SWEPCO's average installation size increased from around 5 kW in 2010 and 2011 to 9.5 kW in 2012. Most of these average capacities however, have fallen in 2013 and remained lower in the first half of 2014.

Table 7: NEM Average Capacity by Utility and Year

Company	2008	2009	2010	2011	2012	2013	2014*
	(kW)						
Investor-Owned Utilities							
Cleco	-	4.1	5.1	9.8	7.0	5.3	5.8
Southwestern Electric Power Company	3.9	3.8	5.5	5.2	9.5	5.1	4.8
Entergy Gulf States Louisiana	2.5	5.5	5.3	7.2	9.0	4.3	5.5
Entergy Louisiana	2.2	4.4	5.9	8.9	5.4	4.6	5.8
Cooperatives/Membership Corporations							
Beauregard-Harrison Electric Cooperative	-	5.3	5.3	6.9	7.9	6.0	6.0
Claiborne Electric Cooperative	-	-	3.7	5.4	12.4	8.9	7.4
Dixie Electric Membership Corporation	-	5.7	5.7	8.7	11.0	5.8	-
Jefferson Davis Electric Cooperative	-	-	-	10.7	7.9	3.4	4.0
Northeast Louisiana Power Cooperative	-	-	6.5	7.8	14.4	8.8	9.2
Panola-Harrison Electric Cooperative	4.5	3.1	3.8	3.9	7.8	8.3	7.1
Pointe Coupee Electric Membership Corporation	-	5.2	4.7	14.5	8.5	5.4	6.0
South Louisiana Electric Cooperative	-	-	3.5	17.0	-	4.6	5.5
Southwest Louisiana Electric Membership Corporation	4.7	7.4	6.7	10.2	7.8	5.4	6.6
Washington-St. Tammmany Electric Cooperative	-	7.4	5.7	7.1	7.6	5.7	5.9
Total Cooperative/Membership Corporations	4.5	5.8	5.2	8.2	9.2	5.7	6.1
Total State	**3.6**	**4.5**	**5.5**	**7.8**	**7.1**	**4.9**	**5.7**

Note: 2014 data is through July.

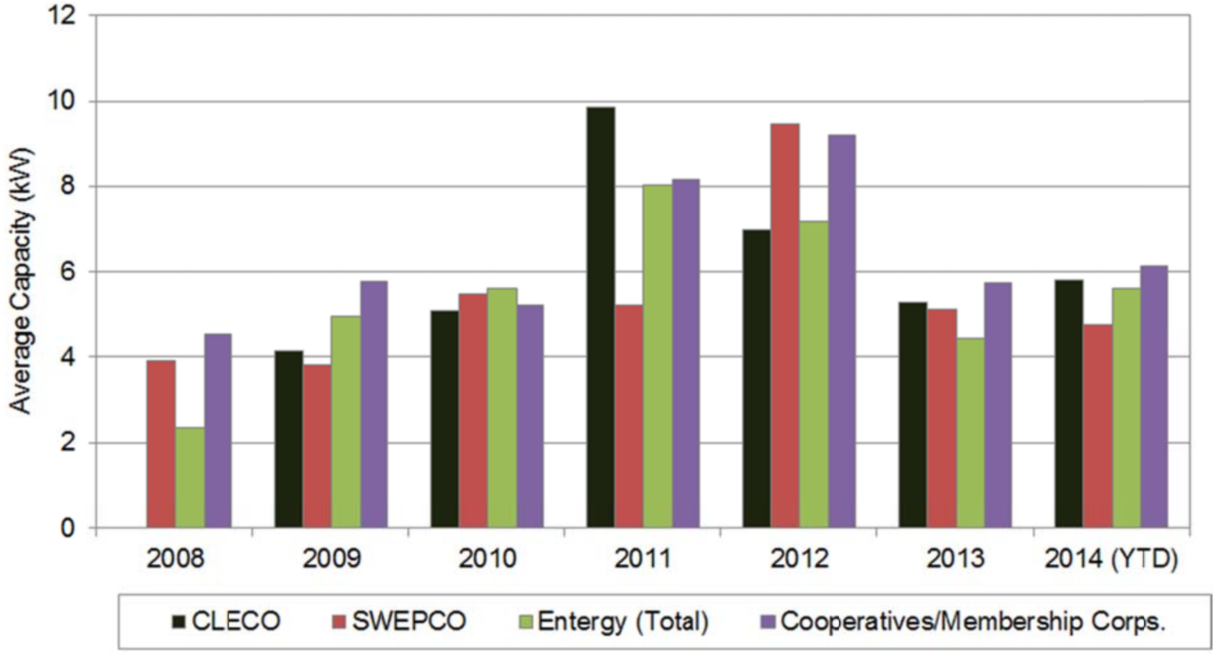

Figure 28: NEM Average Capacity by Utility and Year
Note: 2014 data is through July.

Table 8 and Figure 29 provide summaries of the cumulative annual average capacity of solar NEM installations in the state. Again, the average solar NEM installation size increases in 2011 and 2012, but then decreases in 2013 and 2014.

Table 8: Cumulative NEM Average Capacity by Utility and Year

Company	2008	2009	2010	2011	2012	2013	2014*
	(kW)						
Investor-Owned Utilities							
Cleco	-	4.1	4.7	6.8	6.9	6.1	6.0
Southwestern Electric Power Company	3.9	3.8	4.4	4.7	6.5	6.0	5.7
Entergy Gulf States Louisiana	2.5	5.3	5.3	6.1	7.2	5.8	5.7
Entergy Louisiana	2.2	4.2	5.2	6.4	5.8	5.0	5.2
Cooperatives/Membership Corporations							
Beauregard-Harrison Electric Cooperative	-	5.3	5.3	6.3	7.0	6.6	6.4
Claiborne Electric Cooperative	-	-	3.7	4.3	6.4	6.7	6.7
Dixie Electric Membership Corporation	-	5.7	5.7	7.1	8.9	7.3	-
Jefferson Davis Electric Cooperative	-	-	-	10.7	9.3	8.3	7.2
Northeast Louisiana Power Cooperative	-	-	6.5	7.4	9.1	9.0	9.0
Panola-Harrison Electric Cooperative	4.5	3.8	3.8	3.9	4.9	5.4	5.5
Pointe Coupee Electric Membership Corporation	-	5.2	5.0	9.8	9.3	7.8	7.5
South Louisiana Electric Cooperative	-	-	3.5	8.0	-	4.9	5.1
Southwest Louisiana Electric Membership Corporation	4.7	6.2	6.5	8.4	8.1	6.8	6.7
Washington-St. Tammmany Electric Cooperative	-	7.4	6.1	6.5	6.9	6.1	6.0
Total Cooperative/Membership Corporations	4.5	5.5	5.3	6.6	7.6	6.6	6.6
Total State	**3.6**	**4.4**	**5.0**	**6.1**	**6.6**	**5.6**	**5.7**

Note: 2014 data is through July.

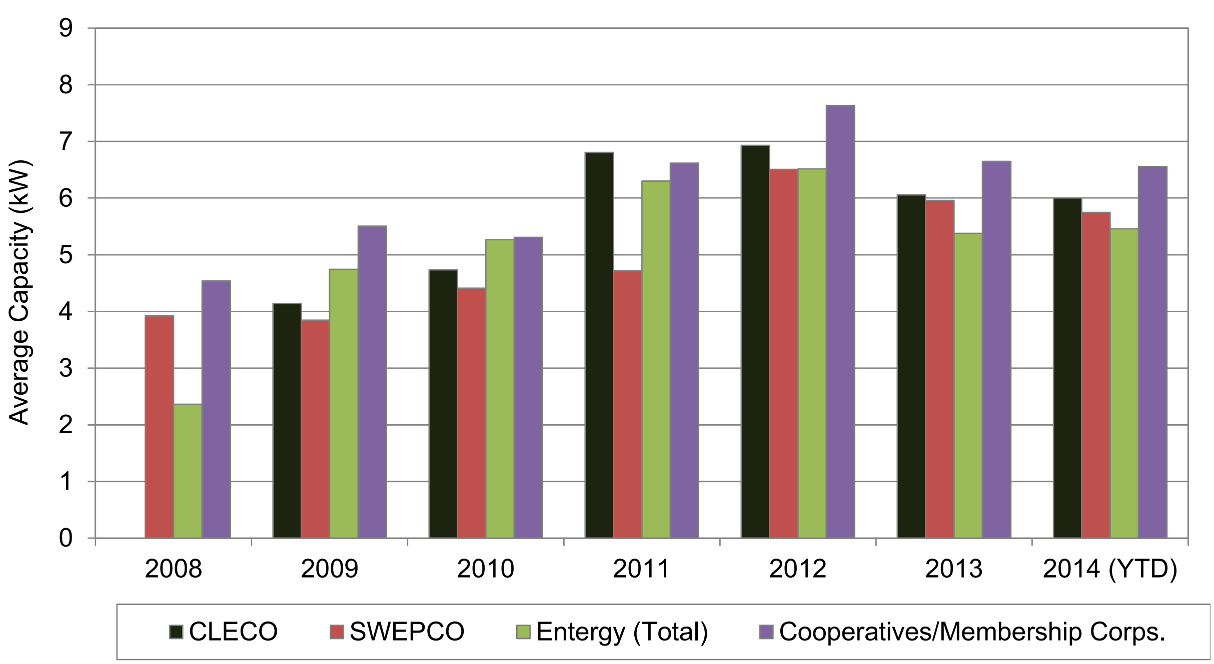

Figure 29: Cumulative NEM Average Capacity by Utility and Year
Note: 2014 data is through July.

Table 9 summarizes the geographic breakdown of the state's jurisdictional solar NEM capacity. West Feliciana has the largest average installation size, 10.8 kW. Morehouse is next with an average of 9.8 kW.

Table 9: Cumulative NEM Average Capacity by Parish

Parish	Capacity (kW)	Parish	Capacity (kW)
Acadia	6.0	Madison	8.4
Allen	5.9	Morehouse	9.8
Ascension	5.7	Natchitoches	8.0
Assumption	7.4	Orleans	5.0
Avoyelles	6.9	Ouachita	5.0
Beauregard	7.1	Plaquemines	6.0
Bienville	6.5	Pointe Coupee	7.6
Bossier	5.7	Rapides	6.1
Caddo	5.3	Red River	4.1
Calcasieu	5.8	Richland	7.8
Caldwell	6.9	Sabine	6.5
Cameron	6.9	St. Bernard	5.0
Catahoula	5.3	St. Charles	5.3
Claiborne	5.3	St. Helena	6.6
Concordia	2.7	St. James	3.7
De Soto	6.4	St. John the Baptist	5.1
East Baton Rouge	5.9	St. Landry	6.2
East Carroll	9.5	St. Martin	6.2
East Feliciana	6.4	St. Mary	5.4
Evangeline	6.3	St. Tammany	5.8
Franklin	8.7	Tangipahoa	5.8
Grant	5.7	Terrebonne	4.5
Iberia	5.2	Union	7.7
Iberville	9.0	Vermilion	7.3
Jackson	6.6	Vernon	6.5
Jefferson	5.2	Washington	6.1
Jefferson Davis	6.0	Webster	6.2
LaSalle	7.2	West Baton Rouge	4.8
Lafayette	5.6	West Carroll	7.6
Lafourche	5.0	West Feliciana	10.8
Lincoln	7.8	Winn	5.0
Livingston	6.7		
Total			**5.7**

Note: Totals do not match previous tables as addresses were not provided for six of Jefferson Davis' net metered installations and were therefore not assigned to a parish.

3.6. Jurisdictional Utility Solar NEM Gross Generation Trends

The following tables and charts show a number of solar NEM trends consistent with earlier discussions on a gross generation basis. Gross generation is the estimated total output arising from the installed solar NEM generation. The on-site usage for each solar NEM generator host has not been removed from these trends. A discussion of gross generation, net generation, gross on-site consumption and net on-site consumption for these jurisdictional NEM installations, will be provided in Section 5 of this Report. Table 10 and Figure 30 show the historic trends in estimated solar NEM gross generation on an annual basis, while Table 11 and Figure 31 show similar information on a cumulative annual basis. Table 12 provides the geographic dispersion of the estimated jurisdictional NEM gross generation. Lastly, Figure 32 and Figure 33 examine historic trends in estimated NEM gross generation on a total jurisdictional generation, and per utility generation, basis.

Table 10: Estimated NEM Gross Generation by Utility and Year

Company	2008	2009	2010	2011	2012	2013	2014*
		----------------------	----------------------	(MWh)	----------------------	----------------------	
Investor-Owned Utilities							
Cleco	-	113	576	1,366	3,544	8,647	8,998
Southwestern Electric Power Company	80	418	1,082	1,833	3,520	6,603	5,816
Entergy Gulf States Louisiana	5	126	577	1,512	2,750	4,812	4,974
Entergy Louisiana	9	264	1,376	2,950	6,743	14,704	20,023
Cooperatives/Membership Corporations							
Beauregard-Harrison Electric Cooperative	-	14	66	151	263	548	585
Claiborne Electric Cooperative	-	-	44	197	330	453	341
Dixie Electric Membership Corporation	-	11	178	405	922	1,743	1,498
Jefferson Davis Electric Cooperative	-	-	-	18	119	173	131
Northeast Louisiana Power Cooperative	-	-	30	218	419	659	473
Panola-Harrison Electric Cooperative	18	62	107	142	229	343	255
Pointe Coupee Electric Membership Corporation	-	11	24	55	147	198	170
South Louisiana Electric Cooperative	-	-	6	20	44	170	249
Southwest Louisiana Electric Membership Corporation	24	57	124	337	756	1,239	1,321
Washington-St. Tammmany Electric Cooperative	-	23	192	458	804	2,200	2,316
Total Cooperative/Membership Corporations	**42**	**178**	**771**	**2,003**	**4,032**	**7,727**	**7,340**
Total State	**136**	**1,099**	**4,382**	**9,664**	**20,589**	**42,492**	**47,151**

Note: 2014 data is through July.

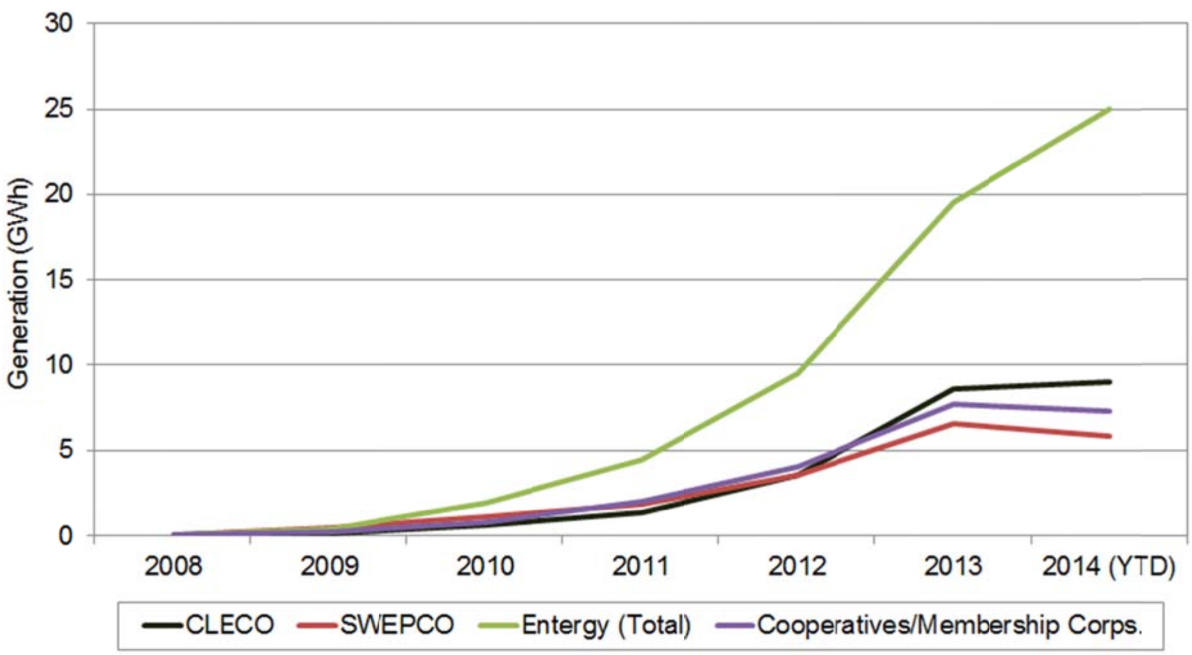

Figure 30: Estimated Gross Generation by Utility and Year
Note: 2014 data is through July.

Table 11: Estimated Cumulative NEM Gross Generation by Utility and Year

Company	2008	2009	2010	2011	2012	2013	2014*
	(MWh)						
Investor-Owned Utilities							
Cleco	-	113	690	2,055	5,599	14,247	23,245
Southwestern Electric Power Company	80	498	1,580	3,413	6,932	13,536	19,351
Entergy Gulf States Louisiana	5	131	708	2,219	4,970	9,781	14,755
Entergy Louisiana	9	273	1,649	4,600	11,343	26,046	46,069
Cooperatives/Membership Corporations							
Beauregard-Harrison Electric Cooperative	-	14	80	232	494	1,043	1,628
Claiborne Electric Cooperative	-	-	44	241	571	1,024	1,365
Dixie Electric Membership Corporation	-	11	189	595	1,516	3,260	4,758
Jefferson Davis Electric Cooperative	-	-	-	18	137	310	440
Northeast Louisiana Power Cooperative	-	-	30	249	667	1,326	1,799
Panola-Harrison Electric Cooperative	18	80	187	329	558	901	1,156
Pointe Coupee Electric Membership Corporation	-	11	35	90	237	435	606
South Louisiana Electric Cooperative	-	-	6	26	70	239	489
Southwest Louisiana Electric Membership Corporation	24	81	204	542	1,298	2,537	3,858
Washington-St. Tammmany Electric Cooperative	-	23	215	673	1,478	3,678	5,994
Total Cooperative/Membership Corporations	**42**	**220**	**991**	**2,994**	**7,026**	**14,753**	**22,093**
Total State	**136**	**1,235**	**5,617**	**15,281**	**35,870**	**78,362**	**125,513**

Note: 2014 data is through July.

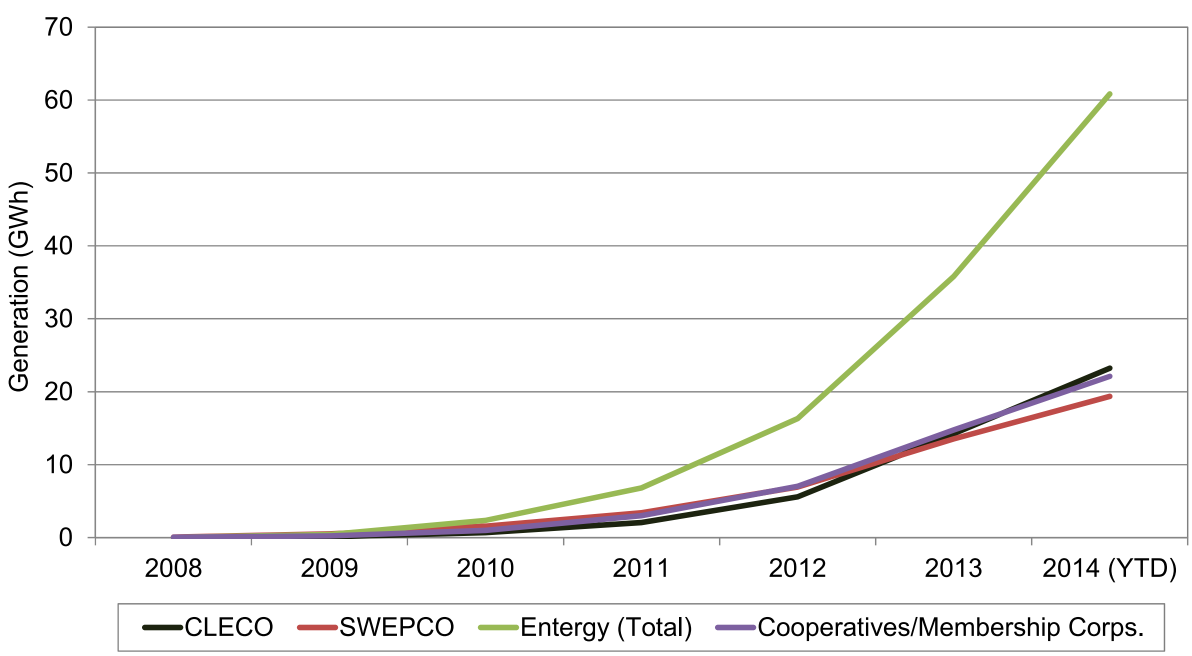

Figure 31: Cumulative Estimated NEM Gross Generation by Utility and Year

Table 12: Cumulative Estimated NEM Gross Generation by Parish

Parish	Gross Generation (MWh)	Percent of Total (%)	Parish	Gross Generation (MWh)	Percent of Total (%)
Acadia	564.5	0.45%	Madison	159.3	0.13%
Allen	151.4	0.12%	Morehouse	1,320.8	1.05%
Ascension	2,582.2	2.06%	Natchitoches	1,212.6	0.97%
Assumption	327.8	0.26%	Orleans	3,078.2	2.45%
Avoyelles	2,739.7	2.18%	Ouachita	4,851.2	3.87%
Beauregard	969.0	0.77%	Plaquemines	801.1	0.64%
Bienville	704.6	0.56%	Pointe Coupee	715.6	0.57%
Bossier	6,733.7	5.37%	Rapides	4,706.9	3.75%
Caddo	9,374.2	7.47%	Red River	272.7	0.22%
Calcasieu	2,903.8	2.31%	Richland	1,315.9	1.05%
Caldwell	514.4	0.41%	Sabine	695.8	0.55%
Cameron	233.2	0.19%	St. Bernard	3,206.1	2.56%
Catahoula	3.4	0.00%	St. Charles	1,864.6	1.49%
Claiborne	844.7	0.67%	St. Helena	189.4	0.15%
Concordia	42.2	0.03%	St. James	2,840.2	2.26%
De Soto	4,285.8	3.42%	St. John the Baptist	1,427.1	1.14%
East Baton Rouge	8,483.5	6.76%	St. Landry	1,846.9	1.47%
East Carroll	103.5	0.08%	St. Martin	647.2	0.52%
East Feliciana	497.1	0.40%	St. Mary	366.2	0.29%
Evangeline	630.8	0.50%	St. Tammany	13,348.8	10.64%
Franklin	1,337.4	1.07%	Tangipahoa	4,396.1	3.50%
Grant	1,024.6	0.82%	Terrebonne	833.3	0.66%
Iberia	720.6	0.57%	Union	654.2	0.52%
Iberville	958.0	0.76%	Vermilion	830.9	0.66%
Jackson	597.4	0.48%	Vernon	1,405.7	1.12%
Jefferson	13,504.3	10.76%	Washington	2,693.1	2.15%
Jefferson Davis	104.4	0.08%	Webster	861.0	0.69%
LaSalle	156.2	0.12%	West Baton Rouge	378.7	0.30%
Lafayette	1,918.9	1.53%	West Carroll	1,080.6	0.86%
Lafourche	930.8	0.74%	West Feliciana	265.4	0.21%
Lincoln	943.6	0.75%	Winn	184.5	0.15%
Livingston	2,127.3	1.70%			
Total				**125,463**	**100.00%**

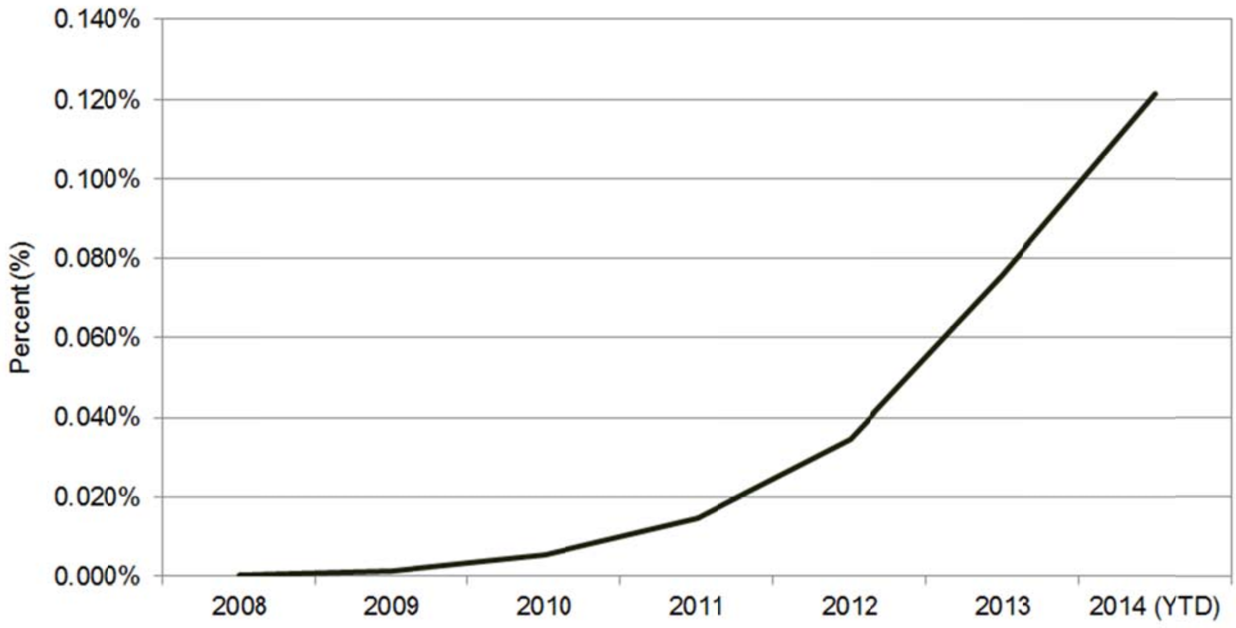

Figure 32: Estimated Annual NEM Gross Generation as a Share of State Generation

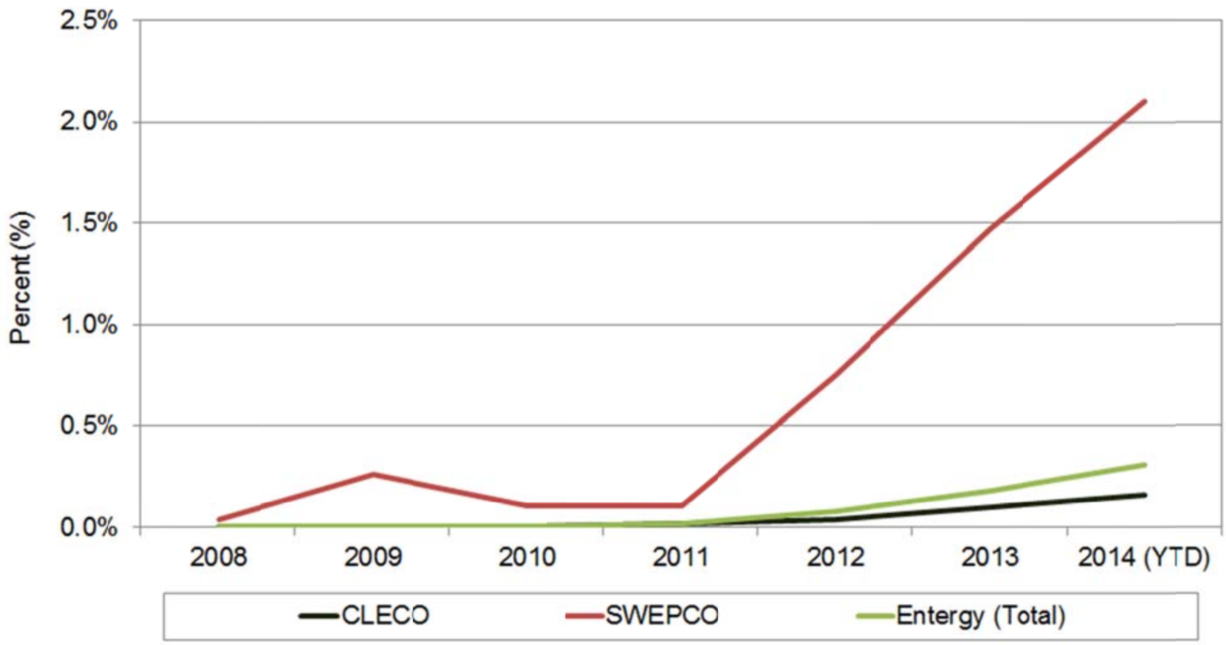

Figure 33: Estimated NEM Gross Generation as a Share of Utility Generation

4. Survey of Prior NEM Cost-Benefit Studies

4.1. Introduction

The significant growth of DER applications utilizing NEM has raised a host of important policy and ratemaking questions. As a result, state regulators across the country have opened investigations and/or commissioned studies examining the costs and benefits of NEM supported on-site generation. Some of these studies have been required by state statutes while others were initiated directly by state regulators.

The following survey summarizes the methods and findings associated with a representative selection of those NEM studies. The survey is not intended to be exhaustive, but does provide good coverage of the major studies in this area, and outlines what appears to be a growing consensus on NEM cost-benefit estimation methodologies.

4.2. California Studies

The California Public Utilities Commission's ("CPUC") experience in conducting cost-benefit studies for NEM applications dates back almost a decade in the aftermath of legislation passed to require the analysis of the impacts of NEM on utility rates and costs. Since that time, the CPUC and other groups have extensively studied NEM impacts and their costs and benefits. The 2013 study, conducted by an independent third party consultant, yet commissioned by the CPUC, serves as one of the most comprehensive cost-benefit analyses of NEM published to date. The following discussion examines each of the major NEM studies starting with the CPUC's early

2005 survey identifying the scope of costs and benefits, and culminating with the omnibus 2013 study that serves as an important basis for the analysis conducted in this report.

4.2.1. CPUC 2005 Analysis and Report

In 2002, the California Assembly required the CPUC to conduct the first cost benefit study associated with California NEM.[42] The findings of this study were required to be submitted to the Assembly and the California Governor by January 1, 2005.[43] The CPUC's research was not restricted to NEM alone, but included the analysis of the potential costs and benefits of a wide range of efficiency and technology options that included energy efficiency, demand response, renewable energy, and distributed generation.[44]

The CPUC prepared a written assessment (or "update") of its cost-benefit research in March 2005 as required per the earlier-discussed legislation.[45] This written assessment noted that there was considerable consensus on several of the methodological perspectives used to value NEM and efficiency resources.[46] A considerable amount of analytic support underpinning the CPUC's work identifying appropriate methodologies was conducted on the behalf of its outside consultant, Energy and Environmental Economics ("E3"), who remained active in evaluating these NEM cost-benefit issues for the CPUC up through 2013. The CPUC organized a

[42] California Assembly Bill 58, Codified as California Public Utility Code §2827(n)
[43] *Id. at* Chapter 836 § 2(n).
[44] Update on Determining the Costs and Benefits of California's Net Metering Program as Required by Assembly Bill 58 (March 29, 2005), California Public Utilities Commission Energy Division, p. 4. Hereafter referred to as "CPUC 2005 Update Report."
[45] CPUC 2005 Update Report, p. 3.
[46] CPUC 2005 Update Report, p. 9.

stakeholder workshop that identified a comprehensive list of 15 individual NEM "benefits" and 17 separate NEM "costs."[47] The CPUC's written assessment noted that benefits of the program could be estimated through the development of what it referred to as a set of "area- and time-specific" ("ATS") avoided costs.[48] At the time, the CPUC focused primarily on conceptual data, and methodological issues associated with NEM costs and benefits and did not attempt to specifically estimate the costs, benefits, or "net benefits" (i.e., benefits less costs) associated with NEM in California.[49] Collectively, these methods were adopted by the CPUC in Decision (D.) 09-08-026.

4.2.2. CPUC 2010 Cost Effectiveness Report

The CPUC expanded its cost-effectiveness analysis of NEM following additional Assembly legislation in 2009.[50] This report (hereafter called the CPUC 2010 NEM Report) published in 2010, found considerable NEM program benefits to NEM participants (i.e., solar NEM installations) that represented an ongoing and additional incentive equivalent to approximately $0.88 per watt.[51] The total financial impact on non-participant costs (i.e., other ratepayers), however, was not as favorable. The CPUC 2010 NEM Report found that, on a lifecycle basis, the development of 386 MW of solar NEM-based capacity would increase ratepayer costs by as much as $230 million, on a net present value ("NPV") basis, over a 20 year period, or about $20 million per

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[47] CPUC 2005 Update Report, pp. 10-11.
[48] CPUC 2005 Update Report, pp. 11-12.
[49] CPUC 2005 Update Report, p. 4.
[50] Assembly Bill (AB) 920 amended the law to allow customers, beginning in January 2011, to either continue to roll-over the bill credits indefinitely or receive compensation for the net-excess generation.
[51] CPUC 2010 Evaluation CE Effectiveness Report, p.2 and pp. 7, 12.

year on an annualized basis.[52] This amount would be equal to about 0.10 percent of total utility base revenues.

The CPUC 2010 NEM Report was the first attempt by the CPUC to put its prior-adopted methodologies to practice in estimating overall NEM net benefits and represents one of the larger and most unique NEM studies of its kind during this time period. "Costs" in the CPUC 2010 NEM Report were defined as including (1) the "purchase" price paid to NEM installations (i.e., the revenues paid to facilities for "putting" their generation to the distribution grid) and (2) any additional overhead costs to the utility, such as incremental billing and administration costs, that were created by NEM installations and recovered through overall utility rates from all customers (NEM participants and non-NEM participants).[53] The 2010 CPUC Report defined benefits of NEM as consisting of the avoided costs associated with displaced energy and generation capacity, including line losses, as well as avoided transmission and distribution capacity, avoided air pollution permits (including CO_2), avoided ancillary services, and avoided renewable energy purchases.[54]

The CPUC 2010 NEM Report attempted to use very disaggregate information focusing on hourly generation and consumption information for each individual NEM installation.[55] While this disaggregate method would presumably provide more accurate results, the CPUC 2010 NEM Report noted considerable data collection challenges[56] associated with attempting to do a study at this level of disaggregation (i.e., hourly, per

[52] CPUC 2010 Evaluation CE Effectiveness Report, p.2.
[53] CPUC 2010 Evaluation CE Effectiveness Report, pp. 18-19 and 21.
[54] CPUC 2010 Evaluation CE Effectiveness Report, pp. 21-22.
[55] CPUC 2010 Evaluation CE Effectiveness Report, pp. 23-24.
[56] CPUC 2010 Evaluation CE Effectiveness Report, p. 25.

generator level). This is a problem that has plagued later studies in California, as well as many other states, as will be discussed later. The CPUC 2010 NEM Report, therefore, was compelled to use estimates and various simulations that were "built-up" form actual observations representing around two percent (626 customers) of the total 31,236 active NEM customers/installations.[57]

For the vast majority of customers who did not have hourly generation data available, the CPUC 2010 NEM Report developed a stratification, or "binning," process based on (1) utility, (2) customer class, (3) climate zone, and (4) solar system age, to create a series of 32 separate customer groups, each with 1 to 68 different output profiles. The estimated capacity factors associated with each output profile was then multiplied by the reported nameplate capacity rating of the installed solar system to generate an estimated annual generation amount.[58]

The CPUC 2010 NEM Report used a similar stratification process to assign hourly generation and consumption profiles to 86 separate customer groups or "bins."[59] Customers were 'binned' based on factor that "are likely to result in relative homogeneity in generation and consumption profiles."[60] First, customers were divided into groups based on utility; customer class (residential or non-residential); climate zone; and retail rate. This created a total of 86 customer groups. For each of these customer groups, customers were further separated using an examination of gross

[57] CPUC 2010 Evaluation CE Effectiveness Report, p. 25.
[58] CPUC 2010 Evaluation CE Effectiveness Report, pp. 26-27.
[59] CPUC 2010 Evaluation CE Effectiveness Report, pp. 27-28; Note the stratification process here is identical to above, with the additional inclusion of separate retail rates.
[60] CPUC 2010 Evaluation CE Effectiveness Report, p. 27.

annual consumption of customers and the ratio of annual generation to annual gross consumption.[61] This increased the number of bins to 1,253.

Hourly gross consumption data in the CPUC 2010 NEM Report thus represented only two actual metered load data from utility load research profiles for customers in the bin (the 33 and 67 percentile of load factors), scaled to match the average annual gross consumption of the bin. Further, to generate hourly gross generation data the study randomly selected for each bin from 624 representative photovoltaic output profiles. Significantly, this means that although the CPUC 2010 NEM Report examined individual customer data, it aggregated its analysis in such a manner that only four separate hourly net load profiles (two gross generation and two gross consumption profiles) represent all customers in each of its 86 bins.[62]

The CPUC 2010 NEM Study was one of the first of its kind that attempted to estimate the costs and benefits of NEM. The Report noted that a number of improvements could be made in the research design and offered a number of suggestions for future research that included:

1. Incremental billing costs represented 27 percent of the overall net NEM costs. Pacific Gas & Electric's incremental billing costs were approximately $18.31/customer per month, significantly higher than the incremental costs of residential net metering billing for either San Diego Gas & Electric or Southern California Edison ($5.96 and $3.02, respectively) due to legacy billing systems.
2. The CPUC 2010 NEM Report omitted any incremental cost of interconnection, due to the lack of high quality data. The report noted that inclusion of these costs might raise the cost of net energy metering by as much as 10 percent.

[61] CPUC 2010 Evaluation CE Effectiveness Report, p. 28.
[62] CPUC 2010 Evaluation CE Effectiveness Report, pp. 30-32.

3. The avoided cost of deferred transmission and distribution system investment utilized in the CPUC 2010 NEM Report was considered controversial by some utilities. The Report did, in the end, include the estimated benefit of such deferred investment, but noted that omitting such benefits would increase the net cost of net metering by 12 percent.
4. The "cost" to net metering associated with lost standby charge revenues was not included in the Report.[63] Inclusion of these lost revenues was noted in the report to increase the net cost of net metering by 13 percent.[64]

4.2.3. Lawrence Berkeley National Laboratory 2010 California Study

Lawrence Berkeley National Laboratory ("LBNL") conducted a study on the benefits of NEM around the same time as the CPUC 2010 NEM Report (hereafter referred to as the "2010 LBNL Study"). The emphasis of the 2010 LBNL Study, however, was different than the CPUC 2010 NEM Report. The purpose of the 2010 LBNL Study was to focus primarily on developing detailed bill savings estimates for NEM projects alone, and to examine how those bill savings estimates were influenced by utility rate design. Thus, the purpose of the 2010 LBNL Study was considerably restricted, looking at only NEM installation benefits, relative to the broader research goals of the CPUC 2010 NEM Report that was tasked with examining total net benefits of NEM from an all-ratepayer perspective.[65]

The 2010 LBNL Study concentrates on estimating solar NEM installation benefits, and how those benefits are influenced by California's Market Price Referent

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[63] Standby rates are charges levied by utilities when an on-site generation system, such as CHP or NEM, experiences a scheduled or emergency outage, and then must rely on power purchased from the grid.

[64] CPUC 2010 Evaluation CE Effectiveness Report, p.9 and pp. 59-62.

[65] Darghouth, Naim, et. al., "The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California," April 2010, Ernest Orlando Lawrence Berkeley National Laboratory, p. 2.

("MPR") rate and the components of each utility's NEM program and rate design.[66] The MPR is a CPUC-regulated price, updated annually, that is intended to represent the long-term market price of electricity based on the costs associated with a new natural gas-fired combined cycle gas turbine electrical generating unit. Originally the MPR was developed to serve as a benchmark for assessing the degree to which utility-proposed renewable energy contracts were "above-market," where the MPR was design to be the market proxy. The use of the MPR was later expanded to also serve as a benchmark for evaluating small-scale generator contracts executed under California's feed-in tariff program.[67]

The 2010 LBNL Study used 15-minute interval load data from 442 residential customers that participated in California's Statewide Pricing Pilot program. Load data from the pilot program was available for 442 customers, however, once these data were cleaned, only 215 customers from Pacific Gas & Electric and Southern California Edison's service territories were used.[68,69] Load (usage) data from these customers were then matched with installation-specific estimated solar generation. Individual solar NEM installation was estimated/simulated using per installation-specific attributes (i.e., capacity, location) and regional weather data compiled from 73 different California weather stations.[70] Interestingly, the initial usage estimates generated by the 2010 LBNL Study found that customers with NEM installations tended to have doubled the

[66] Darghouth, Naim, et. al., p. viii.
[67] Darghouth, Naim, et. al., pp. 6-7.
[68] The data cleaning process removed customers from multi-family housing; customers with more than seven cumulative days of missing data.
[69] Darghouth, Naim, et. al., p. 8.
[70] Darghouth, Naim, et. al., p. 11.

average monthly electric consumption than a customer without.[71] This is a result that was also corroborated in the CPUC 2010 NEM Report.

The 2010 LBNL study found that total benefits for behind-the-meter solar installations were significantly higher for NEM installations than under an MPR-based feed-in tariff.[72] This makes sense considering that electricity "put" to the grid from California NEM installations at this time, was credited at full retail rates, not a lower market-based generation rate which the MPR was developed to emulate. The authors also evaluated the result of a MPR-based program allowing customers to displace 100 percent of usage on an hourly basis. This resulted in more customer savings than the monthly MPR analysis, but the savings were still less than the NEM installations.[73] The 2010 LBNL study found that even incorporating a value for avoided transmission and distribution costs and reduced line losses into the MPR the benefits would still be lower than full retail credit or kWh per kWh offset.[74]

4.2.4. 2012 UC Berkeley Center for Law, Energy & the Environment "Issue Brief"

In 2012, the University of California at Berkeley's Center for Law, Energy & the Environment published a position paper, called an "issue brief," raising a number of criticisms associated with the CPUC 2010 NEM Report (hereafter called "UC-B 2012 Issue Brief"). This "issue brief" was not an exhaustive alternative cost-benefit study, but

[71] Darghouth, Naim, et. al., p. 10.
[72] Darghouth, Naim, et. al., p. xii.
[73] Darghouth, Naim, et. al., p. xiii.
[74] Darghouth, Naim, et. al., pp. xiv-xv.

was offered primarily as policy/conceptual rebuttal to many of methods and findings included in the CPUC 2010 NEM Report.

The UC-B 2012 Issue Brief noted that the CPUC 2010 NEM Report results were likely biased since the methods did not consider the electric grid-related benefits associated with removing NEM customer loads from the system.[75] The UC-B 2012 Issue Brief also noted that the inclining block distribution-level retail rates utilized by the CPUC 2010 NEM Report were outdated and had recently been changed,[76] thereby likely leading to different results as it relates to estimated lost revenues and the cost of reimbursing NEM installations. For instance, Pacific Gas and Electric's 2010 distribution rate design was based upon five residential rate "tiers," with the highest tier being set at a staggering 44 cents per kWh. However, in 2012, these blocks were reduced from five to four, with the upper block rate being reduced to a lower, but still considerably high, 33 cents per kWh.[77]

The UC-B 2012 Issue Brief also noted that there was a certain degree of policy confluence associated with the CPUC 2010 NEM Report. California has a number of other policy mechanisms, that includes certain tax incentives, designed to encourage solar NEM installations. The UC-B 2012 Issue Brief recommends that the role of each additional exogenous policy mechanism (exogenous to the CPUC's jurisdiction/responsibilities) be isolated in the examination of NEM costs and benefits:

[75] Weissman, Steven and Nathaniel Johnson; "The Statewide Benefits of Net-Metering in California: & the Consequences of Changes to the Program," February 17, 2012, University of California Berkeley Law, Center for Law Energy & the Environment, p. 8.
[76] Weissman and Johnson, p. 8.
[77] Weissman and Johnson, p. 8.

the UC-B 2012 Issue Brief found that this objective had not been accomplished in any research on the cost of net metering.[78]

The UC-B 2012 Issue Brief also criticized the CPUC 2010 NEM Report's analysis of the income distributional impacts of solar NEM systems. The Issue Brief noted that while it is not illogical to expect wealthier customers to invest in solar, such a conclusion was not supportable since California's electric utilities did not provide specific data necessary to do this analysis appropriately. The UC-B 20120 Issue Brief concluded, without any formal analysis, that the results would look entirely different if the analysis were done on a more aggregate zip code basis as opposed to a census track-level basis.

According to the UC-B 2012 Issue Brief, a zip code based analysis would show that the income distribution of solar installations would be closer to a median income level rather than the higher than median results found in the census track level analysis. The UC-B 2012 Issue Brief noted that there were actually more solar NEM participants' incomes below $39,999 than above $160,000.[79] More importantly, the Issue Brief noted that the CPUC 2010 NEM Report was based on an overly-simplified premise and that NEM benefits, and the distribution (or equity) of benefits spans multiple additional considerations that are not measurable under an income-based analysis alone.

The UC-B 2012 Issue Brief concluded (without any formal analysis) that the net cost of California's NEM program was likely "very modest – in the context of the utilities'

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[78] Weissman and Johnson, p. 2.
[79] Weissman and Johnson, p. 12.

overall revenue requirements, and the context of California's many demand-side and supply-side programs."[80]

4.2.5. 2013 Crossborder Energy

Crossborder Energy, on contract for the Vote Solar Initiative,[81] published a 2013 cost-benefit analysis of California's net metering program as a rebuttal to the findings included in the prior-discussed CPUC 2010 NEM Report and the LBNL 2012 Study.[82] The Crossborder Energy study noted the "clear and present need" for a new cost-benefit analysis since many of the drivers in the prior two widely-cited studies suffered from four specific deficiencies. First, as noted earlier, the Crossborder Energy Study notes that the upper tier residential distribution rates had been significantly revised and lowered since the time of the prior 2010 studies. Second, the expected escalation of electric utility rates noticeably decreased. Third, new federal and state legislation had changed the prospective cost of renewable energy. Fourth, Crossborder Energy noted that the high NEM administrative costs used in both studies associated with NEM billing should be resolved by the near-completion of the California smart meter initiative.[83]

The Crossborder Energy 2013 Study results were based upon methodologies similar in nature to the prior mentioned CPUC and LBNL studies by utilizing an hourly generation/consumption based simulation model.[84] In addition, the Crossborder Energy

[80] Weissman and Johnson, p.10.

[81] Vote Solar is a non-profit organization engaged in state, local and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale.

[82] Evaluating the Benefits and Costs of Net Energy Metering in California (January 2013), The Vote Solar Initiative, pp. 12-15.

[83] The Vote Solar Initiative, pp. 16-21.

[84] The Vote Solar Initiative, p. 22.

2013 Study utilizes many of the same (yet updated) avoided cost drivers developed in the CPUC 2010 NEM Report.

However, the Crossborder 2013 Study simplifies various elements of the previous two analyses by utilizing each utility's published dynamic load profile for each customer class to simulate hourly load patterns. This aggregation results in one composite (statewide) climate zone rather than the different climate zones utilized in the prior two studies. While this aggregation, in theory, could negate the impacts of diverse geographic-specific solar generation levels, Crossborder Energy concludes that the differences across the state were, in fact, very minimal.

The Crossborder Energy 2013 Study found that the aggregate net cost of residential net metering was "essentially zero," with two of the three IOUs showing positive net benefits arising from their respective NEM programs.[85] The Crossborder Energy 2013 Study also noted that the economic impacts of NEM on non-participating ratepayers were highly dependent on existing rate design. Specifically, the Crossborder Energy 2013 Study found that movement towards flatter rate structures, increased use of time-of-use rates, and simplified rate tiers all resulted in an increase in the net benefits to non-participating ratepayers.[86] The Crossborder Energy 2013 Study noted this was particularly true with regard to promoting increased time-of-use rates.[87]

[85] The Vote Solar Initiative, p. 27.
[86] The Vote Solar Initiative, p. 3.
[87] The Vote Solar Initiative, p. 27.

4.2.6. 2013 CPUC Report

In 2013, the CPUC commissioned a revised/updated NEM cost-benefit analysis in response to then-recent legislation (Assembly Bill 2514) and its own regulatory ruling in Decision 12-05-036. This study, hereafter referred to as the CPUC 2013 NEM Report, was also tasked with answering the question of "who benefits, and who bears the economic burden, if any, of the net energy metering program."[88] The CPUC 2013 analysis, like its predecessor, is one of the more comprehensive analyses of NEM costs and benefits that has been conducted to date, building off of (and improving upon) its prior-study methodologies and approaches. The CPUC 2013 NEM report includes four separate analyses:

1. A cost-benefit analysis to estimate NEM impacts on NEM and non-NEM customers.
2. A cost of service evaluation to estimate the degree to which NEM customers are paying their fair share of a utility's embedded costs.
3. An analysis of how public purpose program financing is influenced by NEM programs.
4. An assessment of income distribution/equity considerations for NEM installations.[89]

The CPUC 2013 NEM Report uses hourly generation and consumption information, much like the prior CPUC report on the topic; however, the updated Report adjusts for some of the prior-identified challenges with other NEM-related administrative and interconnection costs.[90]

[88] Introduction to the Net Energy Metering Cost Effectiveness Evaluation (October 28, 2013), California Public Utilities Commission Energy Division, Introduction p. 1 and p. 1. Hereafter, CPUC 2013 NEM CE Report.
[89] CPUC 2013 NEM CE Report, pp. 1-2 and pp. 1-2.
[90] CPUC 2013 NEM CE Report, pp. 35-37 and pp. 63-64.

The CPUC 2013 NEM Report findings are similar, at least in nature, to its prior Report findings. The CPUC 2013 NEM Report concluded that electricity sales to the grid from California's NEM program would result in as much as $370 million in inflation-adjusted costs by the year 2020,[91] or as much as 1.1 percent of total utility revenue requirements.[92] The total net costs associated with California's NEM program were $1.1 billion in inflation-adjusted dollars, or as much as 3.13 percent of the total utility revenue requirements.[93]

The CPUC 2013 NEM Report found that, on a life-cycle levelized basis, the net costs of the California NEM program was equivalent to $1.00 per watt of installed net metered capacity for exported energy, or $2.9 per watt of installed net metered capacity for all generation.[94] Lastly, when net costs were examined on a per kWh generated basis, larger-use customers were estimated to impose considerably higher levelized costs upon other non-NEM participating ratepayers, than were smaller customers due to inclining block distribution rates.[95]

The results of the cost of service and income distribution analyses included in the CPUC 2013 NEM Report also corroborated many of the earlier Report findings questioning the equity of the California NEM program. Collectively, these analyses found that (a) NEM customers were not covering their fair share of their respective

[91] CPUC 2013 NEM CE Report, p. 5; The report chose 2020 as this was the year California is forecasted to reach the State's statutory 5 percent net energy metering cap.
[92] CPUC 2013 NEM CE Report, p. 6.
[93] CPUC 2013 NEM CE Report, p. 7.
[94] CPUC 2013 NEM CE Report, p. 69.
[95] CPUC 2013 NEM CE Report, p. 9.

utility's embedded cost of service[96] and (b) that the direct benefits of the NEM programs were skewed heavily towards upper income households.[97]

4.3. New York: NYSERDA Report

The Power New York Act of 2011 directed the New York State Energy Research and Development Authority ("NYSERDA"), a state public benefit corporation tasked generally with advancing innovative energy solutions that improve New York's economy and environment,[98] to conduct a study evaluating the costs and benefits of increasing the State's solar generation capacity to 5,000 MW by 2025 (hereafter "NYSERDA 2011 Study").[99] The NYSERDA 2011 Study is notably broad but does include elements directly related to understanding the costs and benefits of solar NEM.

The NYSERDA 2011 Study utilized the National Renewable Energy Laboratory's ("NREL") Cost of Renewable Energy Spreadsheet Tool ("CREST") for a range of economic outcomes associated with solar NEM all based on a variety of factors that includes equipment type, incentives, installation locations, and system sizes.[100] Benefits were pulled from inputs associated with the Integrated Production Model ("IPM") prepared by ICF Consulting,[101] and utilized extensively by the Environmental Protection Agency ("EPA").[102] The inputs pulled from the model include avoided electricity production costs, estimated avoided emission rates, avoided fossil fuel rates,

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[96] CPUC 2013 NEM CE Report, pp. 104-106.
[97] CPUC 2013 NEM CE Report, p. 11.
[98] *See,* New York Solar Study: An Analysis of the Benefits and Costs of Increasing Generation from Photovoltaic Devices in New York, January 2012, NYSERDA, title page.
[99] NYSERDA 2011 Study, p. ES-1.
[100] NYSERDA 2011 Study, p. ES-2.
[101] NYSERDA 2011 Study, pp. 5-2 through 5-3.
[102] NYSERDA 2011 Study, p. ES-3.

wholesale price suppression sensitivities, avoided distribution-related costs, and avoided line losses. The NYSERDA 2011 Study found that most solar NEM benefits were attributable to avoided generation and wholesale price suppression impacts created by solar generation.[103] However, the NYSERDA 2011 Study concluded that the costs of reaching 5,000 MW of solar generation capacity by 2025 would exceed the benefits produced, and was furthermore highly dependent on continued Federal financial subsidies.[104] In fact, the cost of reaching New York's solar energy goal was found to increase ratepayer costs by as much as $2.2 billion in NPV terms.

The NYSERDA 2011 Study estimated the rate impact of displaced distribution costs, and found that the NEM program created a direct cross-subsidy of NEM-participating customers by non-NEM customers of nearly $400 million in 2038, which is the forecasted peak year for energy production before projects begin to reach the end of their useful lives.[105]

4.4. Massachusetts: DOER 2013 Report

The Massachusetts Department of Energy Resources ("DOER") published a 2013 report addressing the economic benefits and costs of Commonwealth's solar RPS set-aside that has implications for solar NEM installations (hereafter "DOER 2013 Study"). The Massachusetts solar RPS set-aside establishes a solar energy capacity target of 1,600 MW by 2020.[106] The DOER 2013 Study consisted of two individual analyses: one consisting of an examination of the ratepayer impacts of the solar RPS

[103] NYSERDA 2011 Study, p. 5-13.
[104] NYSERDA 2011 Study, p. ES-16.
[105] NYSERDA 2011 Study, p. 7-4 through 7-5.
[106] Task 3b Report: Analysis of Economic Costs and Benefits of Solar Program (September 30, 2013), Massachusetts Department of Energy Resources, p. 1.

set-aside; and the second consisting of a state-wide solar energy cost-benefit analysis. The DOER 2013 Study relied heavily on avoided cost drivers included in a previously conducted regional study entitled the 2013 Avoided Energy Supply Cost ("2013 AESC").[107]

The 2013 DOER Study estimated rate impacts of between $500 and $933 million over a 32-year period[108] or an amount equivalent to average rate increases of between 1.2 and 1.5 percent, with an annual peak rate impact of between 2.4 to 3.4 percent in outlying years (relative to the no policy outcome).[109]

The DOER 2013 Study estimated separate cost-benefit results separate from the rate impacts finding a net benefit of between $138 and $571 million over a 32-year period, with a positive net benefit arising primarily due to avoided generation, transmission, and distribution capacity.[110]

4.5. Vermont: VPSD 2013 Study

The Vermont Public Service Department ("VPSD") recently published an evaluation of Vermont's NEM program in response to Act 125 (hereafter "VPSD 2013 Study"). Act 125 required the VPSD to analyze potential cross-subsidization issues, and NEM benefits and costs.[111] The VPSD's analysis was based upon a literature review of prior NEM cost-benefit studies, as well as the development of a spreadsheet-enabled empirical model projecting per-unit NEM costs and benefits over a 20 year

[107] DOER 2013 Study, pp. 10-15.
[108] DOER 2013 Study, p. 17.
[109] DOER 2013 Study, p. 18.
[110] DOER 2013 Study, p. 24.
[111] Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012 (January 15, 2013), Vermont Public Service Department, p. 2.

period for a "typical" NEM facility.[112] Typical systems included: a fixed 4 kW PV system, a 4 kW tracking PV system, a 4 kW wind generator, and composite 100 kW grouped NEM "community-based" system based upon combinations of each of the previously-defined renewable generation technologies.[113]

The VPSD 2013 Study results found that a 4 kW fixed PV system imposed as little as $0.006 costs per kWh rate impact which virtually disappears when aggregated to a statewide impact estimate. The use of avoided climate change costs (valued at an avoided cost of $78 per ton) was estimated to lead to ratepayer and total state net benefits of $0.036 and $0.043 per kWh generated, respectively.[114] All results for a 4 kW tracking solar photovoltaic system include an additional $0.010 per kWh generated cost.[115] Likewise, all 100 kW photovoltaic systems were found to impose minor costs before the inclusion of the assume avoided climate change costs.[116]

Notably, the VPSD 2013 Study admitted several short-comings with its analysis, specifically the model failed to:

1. Capture economic impacts outside of the utility-ratepayer context, such as job or economic impacts from the renewable electricity industry or changes to the economics of energy consumption among net metering participants or non-participants.

2. Identify impacts on energy prices, load shapes, or other inputs to the analysis that may have already occurred due to deployment of net metering

[112] Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012 (January 15, 2013), Vermont Public Service Department, p. 12.
[113] Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012 (January 15, 2013), Vermont Public Service Department, pp. 23-28.
[114] Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012 (January 15, 2013), Vermont Public Service Department, p. 23.
[115] Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012 (January 15, 2013), Vermont Public Service Department, p. 24.
[116] Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012 (January 15, 2013), Vermont Public Service Department, pp. 26-27.

systems in Vermont. For systems modeled as installed in years after 2013, the model does not account for potential changes in Vermont's load shape or other inputs that may occur prior to installation.

3. Capture potential changes in rate structures or regional costs, including those due to net metering. It models only the marginal impact of net metering under a "current policy" baseline scenario. That is, it does not model a situation in which rate structures change over time (such as adoption of time-of-use rates), or the impact that increasing net metering may have on future rates or rate structures.

4. Capture nonlinear or feedback effects in which additional deployment of net metering in subsequent years may change marginal costs or benefits attributable to systems installed in earlier years (such as through changes in load shape and resulting peak coincidence). For example, it does not capture changes in the costs or benefits (such as avoided infrastructure costs) attributed to systems deployed in 2013 that might occur if future net metering, or other generation or efficiency deployment, changes the state's load shape and therefore the need for or cost of infrastructure.

5. Include impact from advanced metering infrastructure or other grid modernization technologies, and the resulting potential changes to rate structures.

6. Account for integration costs (incremental costs due to the need to change the output of other resources to account for intermittency). These costs are expected to be very small for systems of the size eligible for net metering in Vermont.

7. Include monetary values for environmental impacts other than avoided greenhouse gas emissions or value as SPEED resources.

8. Capture differences between utilities.

9. Capture potential cross-subsidization between utilities.[117]

[117] Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012 (January 15, 2013), Vermont Public Service Department, pp. 12-13.

4.6. Mid-Atlantic Regional Analysis: Clean Power Research 2012 Study

In November 2012, Clean Power Research released an analysis of the value provided by grid-connected, distributed solar generation in the states of Pennsylvania and New Jersey, commissioned by two Mid-Atlantic solar industry trade groups: the Mid-Atlantic Solar Energy Industries Association ("MSEIA") and Pennsylvania Solar Energy Industries Association ("PSEIA") (hereafter the "Mid-Atlantic 2013 Solar NEM Study). The Mid-Atlantic 2013 Solar NEM Study identified 10 separate benefits resulting from four different solar generation configurations at seven locations across Pennsylvania and New Jersey that include: (1) fuel cost savings; (2) O&M cost savings; (3) security enhancement value; (4) long term societal value from extended life of systems; (5) fuel price hedge value; (6) savings from avoided generation capacity; (7) financial savings from deferring transmission and distribution capacity investments; (8) wholesale market price suppression; (9) avoided environmental costs; and (10) enhanced tax revenues associated with job creation. Costs considered in Mid-Atlantic 2013 Solar NEM Study were limited to additional costs associated with the variable nature of solar generation.[118]

The study estimated a total net value provided by grid-connected, distributed solar generation in Pennsylvania and New Jersey ranged from $256 to $318 per MWh of generation. Of the 10 separate benefits estimated, wholesale market price suppression and the enhanced tax revenues from new job creation were found to be the

[118] The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania (November 2012), Clean Power Research, p. 1.

largest benefits from increased solar generation, accounting for $55 and $44 per MWh, respectively.[119]

4.7. Mississippi: Synapse 2014 Report

In 2010, the Mississippi Public Service Commission opened a docket to investigate net metering and interconnection standards for Mississippi. Synapse Energy Economics, Inc. was contracted to report on potential net metering policies and analyze the impacts of residential and commercial rooftop solar.[120] The Synapse Report presents a review of net metering and the issues surrounding it, a list of the potential avoided costs from distributed generation facilities, and an overview of several technical implementation issues that may have impacts on ratepayer cost.[121] The report also provides a review of renewable energy policies in the region (Louisiana, Arkansas, Tennessee, Alabama and Mississippi).[122]

Synapse also performed a quantitative analysis of the benefits (primarily avoided costs) and costs of a net metering policy for Mississippi.[123] The analysis modeled solar rooftop only for the state on an aggregate basis with a net metering penetration level equivalent to 0.5 percent of historical peak load in 2015.[124] Synapse used the PVWatts Calculator developed by NREL's Renewable Resource Data Center to estimate hourly electric generation. However, PVWatts only had one location in Mississippi (in

[119] The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania (November 2012), Clean Power Research, p. 2.

[120] Net Metering in Mississippi, Costs, Benefits and Policy Considerations. Synapse Energy Economics, Inc., September 19, 2014, p. 1. Hereafter Synapse Mississippi Report.

[121] Synapse Mississippi Report, pp. 3-13.

[122] Synapse Mississippi Report, pp. 15-16.

[123] Synapse Mississippi Report, p. 20.

[124] Synapse Mississippi Report, p. 21.

Meridian), so this sole location was used "as a sample for our hourly data and to calculate a capacity factor."[125] Synapse also used effective load carrying capability ("ELCC") developed by NREL. The ELCC is used to determine the amount by which solar panels will contribute to reducing peak load. The NREL estimate was prepared in 2006 on a national level for several types of solar panels at varying degrees of penetration. Synapse chose a value corresponding to 2 percent solar penetration, which was the lowest value provided in NREL's report and an average of three types of panels: horizontal, south-facing, and southwest-facing. The value for these assumptions was an ELCC of 58 percent.[126]

In calculating the avoided energy costs, the Synapse study assumes that solar will replace oil and natural gas-fired CT units. Synapse assumes the marginal unit is a blend of oil and gas combustion turbines with a mix in 2015 of 25 percent oil and 75 percent natural gas. The marginal unit transitions to 100 percent natural gas by 2020 following a linear path. To estimate avoided capacity cost, Synapse follows another linear transition: from MISO's 2015-2016 capacity clearing price of $6/kW-year to a net CONE value of $57/kW-year by 2030. And, for avoided transmission and distribution costs, Synapse uses a general value of $88/kW year generated by an "in-house database."[127] In all, the Synapse model estimates six types of avoided costs: avoided energy cost; capacity value benefits; avoided transmission and distribution cost; avoided system losses; avoided environmental compliance costs; and avoided risk.[128]

[125] Synapse Mississippi Report, p. 21.
[126] Synapse Mississippi Report, p. 22.
[127] Synapse Mississippi Report, pp. 28.
[128] Synapse Mississippi Report, pp. 26-30.

To model costs, Synapse used the Cost of Renewable Energy Spreadsheet Tool ("CREST") developed for NREL. The CREST model is "an economic cash flow model designed to allow policymakers, regulators, and the renewable energy community to assess project economics, design cost-based incentives (e.g., feed-in tariffs), and evaluate the impact of various state and federal support structures."[129] Synapse used the CREST model to analyze residential PV projects of 5 kW and commercial PV projects of 500 kW). This resulted in a levelized cost of energy of $142/MWh for residential PV and $129/MWh for commercial PV, or an average of $135/MWh.[130]

The Synapse model resulted in avoided energy costs starting at over $100 per MWh and then decline over the first five years because of the transition in the assumed marginal unit from a mix of oil and gas, to gas only.[131] On a levelized basis, over the 25-year period, the avoided costs were $170/MWh. The largest share of these avoided costs was the avoided energy cost ($81/MWh).[132] On the cost side, Synapse estimates annual utility costs in the form of reduced utility revenue. These costs increase from just under $100/MWh in 2015 to about $200/MWh in 2039.[133]

In Mississippi, Rule 29 of the Public Utility Rules of Practice and Procedure specifies the cost-benefits tests to be used in evaluating energy efficiency programs: The Total Resource Cost ("TRC") test; the Program Administrator Cost ("PAC") test; the Rate Impact Measure ("RIM") test; and the Participant Cost Test ("PCT").[134] To analyze the costs and benefits to net metering customers, Synapse used the PCT. The results

[129] National Renewable Energy Library. CREST Cost of Energy Models. Available at: https://financere.nrel.gov/finance/content/crest-cost-energy-models.
[130] Synapse Mississippi Report, p. 32.
[131] Synapse Mississippi Report, p. 37.
[132] Synapse Mississippi Report, p. 37.
[133] Synapse Mississippi Report, p. 39.
[134] Synapse Mississippi Report, pp. 16-17.

of the PCT vary depending on how NEM customers are compensated. If NEM customers are only compensated at a variable retail rate, the levelized benefit of net metering is $124/MWh; which is lower than the average levelized cost of $135/MWh, and represents a benefit-cost ratio of 0.92. However, if NEM customers are compensated at the levelized avoided cost (benefit) of $170/MWh, the benefit-cost ratio increases to 1.26 and NEM customers would more than break-even.[135]

In addition, Synapse performed an analysis using the TRC test. This method compares the net economic costs and benefits to the state as a whole. It includes all utility avoided costs, but excludes the cost of avoided externalities and the benefits of economic development. On the cost side, only the cost of installing solar panels and administrative costs are considered. Again, with an estimated benefits of $170/MWh and estimated costs of $143/MWh, net metering results in a net benefit of $27/MWh and a passing TRC ratio of 1.19.[136]

[135] Synapse Mississippi Report, p. 40.
[136] Synapse Mississippi Report, p. 44.

5. Solar NEM Gross Generation and Consumption Estimates Among LPSC Jurisdictional Utilities

5.1. Methods Overview

An appropriately-designed examination of solar NEM should start at the generator level and examine the hour-to-hour impacts that gross solar generation, gross consumption, and net consumption has on utilities and their respective ratepayers. All three analyses conducted in this report (cost-benefit analysis, cost-of-service analysis, and income distribution analysis) will require this level of detail. Here, gross generation is defined as the total generation produced by a behind the meter solar facility. Gross consumption is the total pre-solar installation consumption of the NEM customer. Net consumption is the difference between these two series.

Unfortunately, Louisiana's jurisdictional utilities do not collect such detailed, hourly information for their respective NEM customers. Louisiana utilities, for the most part, use bi-directional meters that spin "forward" (pulling sales from the grid) and "backwards" (putting solar generation to the grid) but only record, in any given billing period, a "net" consumption amount.[137] This limitation requires that alternative simulation methods be utilized in order to develop gross solar generation estimates. Hourly gross (solar) generation, therefore, has been estimated by pairing NEM account-specific information provided by each of the jurisdictional utilities with other sources of information (primarily weather-related). Once gross generation has been estimated, it

[137] Interestingly, Northeast Louisiana Power Cooperative utilizes two separate meters for its NEM customers. One meter measures consumption while the other meter measures solar generation. Thus, at least for this utility, separate estimates for gross generation and gross consumption are available and can be used as a check against the simulations discussed later in this section.

becomes a simple algebraic process of taking the utility-measured net consumption billing data to estimate gross consumption, thereby providing each of the three pieces of the puzzle needed to estimate solar NEM impacts.

5.2. Data Requirements for Hourly NEM Generation Estimates

Each utility provided either an address or unique latitude/longitude coordinates for each solar NEM customer in their respective service territories. Most of the utilities provided address-specific information, requiring geo-referencing techniques to be used to match each NEM solar installation to a unique latitude and longitude. The U.S. Census Bureau maintains what is referred to as a "Census Geocoder" tool that it utilizes in its decanal census and annual surveys.[138] The geocoder was used to map NEM customer addresses to unique latitude and longitude coordinates. The geocoder algorithm was able to uniquely match 6,981 NEM customer accounts out of 7,966 (approximately 88 percent) provided by the jurisdictional utilities, with an additional 6 NEM customer accounts uniquely matched by zip code. The remaining 979 NEM accounts had either missing address or unrecognizable address information. All but 13 of these accounts had city-location information and were mapped to a central city location for geo-referencing purposes.

The next step in the analysis was to ensure that all solar NEM installation capacity was appropriately standardized to alternating current ("AC") terms. All of the jurisdictional utilities provided direct current ("DC") information for each NEM solar installation. The IOUs, however, generally provided NEM solar capacity information in

[138] See "Geocoding Services Web Application Programming Interface (API)," U.S. Census Bureau, available at: http://geocoding.geo.census.gov/geocoder/.

both AC and DC terms. However, 680 of the 6205 accounts that had reported AC values that were higher than their DC values, therefore AC/DC conversion factors for these accounts were simulated using statistical information from the 5,525 accounts with IOU-provided information. The average conversion factor reported for these 4,358 accounts was 87.6 percent with a standard deviation of 8.8 percent. Randomly generated conversion factors that were within one standard deviation of the mean of the known IOU data were then assigned to the ambiguously-rated NEM accounts/solar installations.

The last preliminary step needed to estimate hourly solar NEM generation was the collection of weather data to estimate the level and intensity of the sunlight needed to generate electricity from the NEM solar panels. Weather information was collected from the National Climatic Data Center ("NCDC") within the National Oceanic and Atmospheric Administration ("NOAA").[139] The NCDC maintains the world's largest climate data archive with data from monitoring stations located across the country and the world.[140] NOAA lists 184 individual weather monitoring stations within Louisiana most of which were utilized for purposes of this analysis. For instance, as will be explained later, humidity statistics are important in developing estimates of effective sunlight to estimate hourly solar generation estimates. Only 139 of Louisiana's 184 stations consistently report these humidity statistics. Thus, the analysis was limited to those 139 weather stations that consistently report humidity, among other important weather statistics. This not an important limitation since most Louisiana NEM

[139] http://www.ncdc.noaa.gov/
[140] "About NCDC," http://www.ncdc.noaa.gov/about-ncdc.

customers are estimated to be within 10 to 20 miles of any Louisiana NOAA weather station.

5.3. Solar Radiation Estimation Methods

The amount of effective sunlight available in any given hour for solar electricity generation can be approximated through the use of hourly terrestrial solar radiation estimates. Solar radiation can generally be separated into two components: direct beam radiation and diffused solar radiation.[141] Direct solar beam radiation refers to the amount of direct sunlight reaching a customer's solar array. Diffused solar radiation, on the other hand, represents solar radiation that is dispersed by Earth's atmosphere, most of which is reflected or absorbed by atmospheric gases, clouds, and dust particles, with only a relatively small percentage reaching Earth's surface.[142] The extent of this diffusion is a direct function of atmospheric conditions, leading to conditions where some solar radiation occurs even on an over-cast day (through reflected rather than direct sunlight).

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[141] Al Riza, Dimas Firmanda, et. al. (June 2011). "Hourly Solar Radiation Estimation Using Ambient Temperature and Relative Humidity Data." *International Journal of Environmental Science and Development*, Vol. 2, No. 3, p. 2.

[142] See, *Glossary of Solar Radiation Resource Terms*, National Renewable Energy Laboratory; See also, Shining On: A Primer of Solar Radiation Data (May 1992), National Renewable Energy Laboratory, p. 12. Note that a third solar radiation component, ground-reflected radiation, exists but is typically deemed insignificant and omitted from calculations.

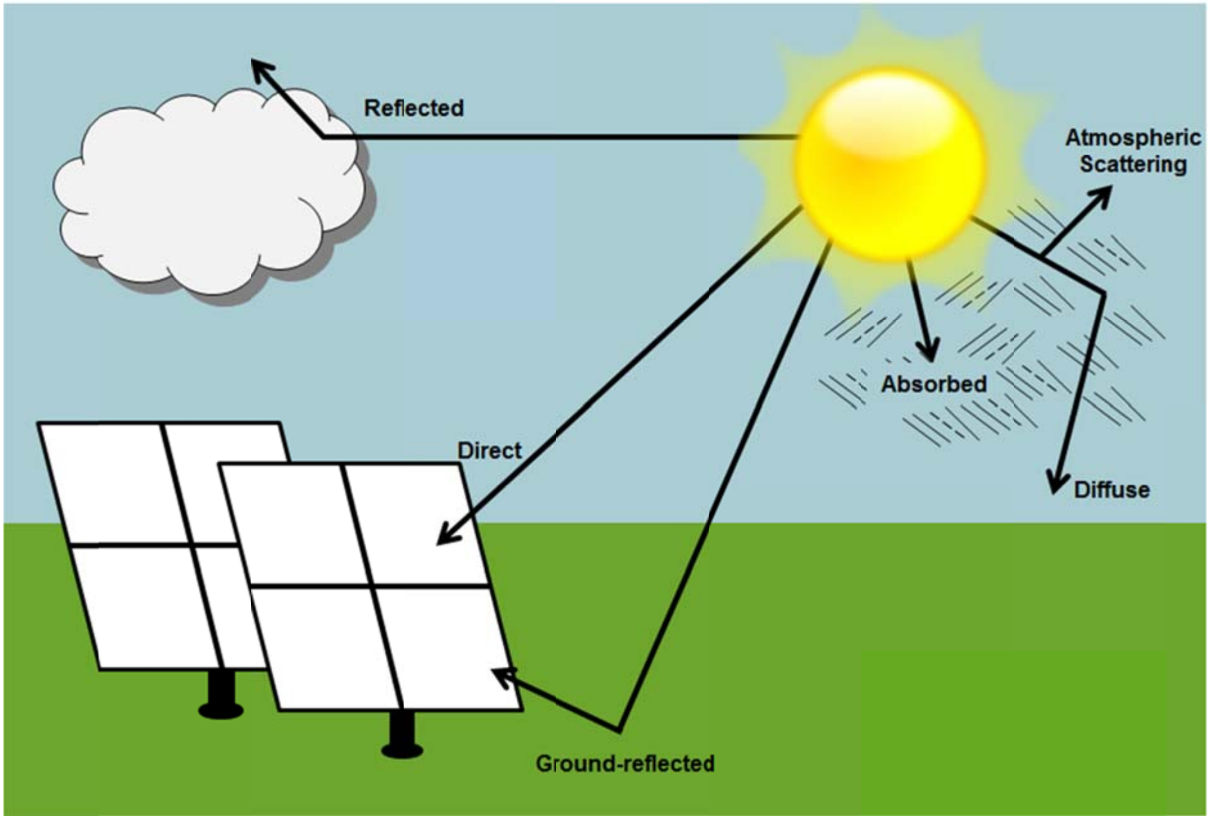

Figure 34: Illustration of Solar Radiation Components
Source: Shining On: A Primer of Solar Radiation Data, p.12 NREL (May 1992)

Direct radiation estimates can be developed by calculating hourly “zenith angles” of the sun, i.e. the location of the sun in the sky relative to the horizon for every hour of the year.[143] The equation used to estimate hourly zenith angles is given as:

$$\cos(\theta_z) = \sin(\varphi)\sin(\delta) + \cos(\varphi)\cos(\delta)\cos(\omega)$$

Where:

θ_z represents the zenith angle of the sun (i.e. the angle of the sun to the horizon);

φ represents the latitude of net metered customer converted from degrees to radians;

δ represents the “delineation of the sun,” i.e. the tilt of the earth which changes through the seasons; and

[143] *Shining On: A Primer of Solar Radiation Data* (May 1992), National Renewable Energy Laboratory, p. 11; See also, Al Riza, Dimas Firmanda, et. al. (June 2011), Hourly Solar Radiation Estimation Using Ambient Temperature and Relative Humidity Data, International Journal of Environmental Science and Development, Vol. 2, No. 3, p. 2.

ω represents the hour relative to 12:00 noon without daylight savings time.

From this equation, direct solar beam radiation and diffused solar beam radiation can be calculated from the following formulas:[144]

$$G_{Bh} = (\tau^m)\, G_{oh} \cos(\theta_z)$$

$$G_{Dh} = 0.30\,(1-\tau^m)\, G_{oh} \cos(\theta_z)$$

Where:

G_{Bh} represents direct solar beam radiation;
G_{Dh} represents diffused solar radiation;
G_{oh} represents the solar constant of 1,360 Watts/meter;^{2}
τ represents atmospheric transmittance;
m represents optical air mass number; and
θ_z represents the zenith angle of the sun as previously established.

If the Earth had no atmosphere, (τ^m) in the above equation would equal 1, G_{Dh} would equal 0, and G_{Bh} would equal the solar constant of 1,360 Watts/meter^2 times the relationship of the location on the planet's surface to the sun. As stated earlier, atmospheric conditions represented by (τ^m) effects the percentage of direct solar beam radiation that gets diffused within the atmosphere through the presence of clouds and other atmospheric conditions. Optical mass (m) is determined by local atmospheric pressure though the following formula.[145]

$$m = P_a / 101.3 \cos(\theta_z)$$

Where:

P_a represents local atmospheric pressure in kPa; and

[144] Al Riza, Dimas Firmanda, et. al. (June 2011). "Hourly Solar Radiation Estimation Using Ambient Temperature and Relative Humidity Data." *International Journal of Environmental Science and Development*, Vol. 2, No. 3, p. 2.

[145] Al Riza, Dimas Firmanda, et. al. (June 2011), Hourly Solar Radiation Estimation Using Ambient Temperature and Relative Humidity Data, International Journal of Environmental Science and Development, Vol. 2, No. 3, p. 2.

θ_z represents the zenith angle of the sun as previously established.

Local barometric pressure information was utilized, where available. However, the majority of weather Louisiana stations within the NOAA database did not record local barometric pressure. Average barometric pressure was estimated using the altitude of the station for those stations without recorded readings[146] with an equation given as:

$$P_a = 101.3\, e^{-(a/8200)}$$

Where:

a represents the elevation of the weather station in meters.

Finally, τ (atmospheric transmittance) was estimated using method identified in prior academic research.[147] This research developed methods utilizing ambient air temperatures and relative humidity readings to generate solar radiation methods with a normalized root mean square error ("RMSE") of 8.29 percent. The decision framework identified in this prior research assumes that a clear sky condition exists when relative humidity levels are less than 40 percent, wherein a τ value of 0.69 can be assumed. Estimates of the τ value will fall as relative humidity levels increase. These estimates will continue to fall to a value of 0.2 if relative humidity levels are greater than 80 percent. To put this value in context, the average relative humidity level for all net metered customers in all hours throughout the state was 72.3 percent, that translates to a τ value of 0.41.

[146] Al Riza, Dimas Firmanda, et. al. (June 2011), Hourly Solar Radiation Estimation Using Ambient Temperature and Relative Humidity Data, International Journal of Environmental Science and Development, Vol. 2, No. 3, p. 2.

[147] Al Riza, Dimas Firmanda, et. al. (June 2011), Hourly Solar Radiation Estimation Using Ambient Temperature and Relative Humidity Data, International Journal of Environmental Science and Development, Vol. 2, No. 3, p. 3.

Louisiana weather can differ significantly across locations within the state, particularly between the coastal and inland areas. Thus, it is important to use weather observations from locations as near the solar NEM installation as possible. NCDC measures and maintains records from 139 weather stations throughout Louisiana. Hourly weather data was normalized for each solar NEM installation by averaging the information reported from each of the three nearest operating weather stations. This requires the use of a rather complicated interpolation routine that inversely weights the information from each of the three stations by the distance from the solar NEM installation to the weather station. In other words, nearby weather stations are relied upon more than those located further from the solar NEM installation. This method has the added benefit of compensating for missing data that can sometimes arise within NOAA's database.

Lastly, few NOAA weather stations record relative humidity directly. Instead, many weather stations record hourly dry bulb and wet bulb temperatures. From these readings, the stations record ambient temperature and dew point. The dew point represents the saturation temperature for water in air, and is associated with relative humidity, but not directly equivalent. Specifically, a high relative humidity will see dew point temperatures closer to actual air temperatures, while low relative humidity will see dew point temperatures far less than actual air temperatures. Therefore, a simple approximation of relative humidity from actual ("dry bulb") temperature readings and dew point temperature readings can be estimated by the following equation:[148]

[148]See, Lawrence, Mark G. (February 2005), The Relationship between Relative Humidity and the Dewpoint Temperature in Moist Air: A Simple Conversion and Applications, American Meteorological Society.

$$RH \approx 100 - (25/9) * (T - T_{dp})$$

Where:

T represents actual (“dry bulb”) temperature; and
T_{dp} represents dew point temperatures.

The last step in weather data collection and processing was to put all weather series on a “weather-normalized” basis. Thirty year averages were used to develop weather normal values for each of the above-discussed series. NOAA has historically defined normal weather periods utilizing 30 year averages. This standard was adopted at the International Meteorological Conference in Warsaw, Poland in 1935, and adopted by the U.S. during the same period of time. NOAA notes that using the 30-year normalization period accounts for slow changes in climate, and not shorter run cycles which can move from cooler to warmer and back to cooler.

5.4. Estimating Solar NEM Gross Generation

The development of solar NEM gross generation estimates starts with an evaluation of the rated capacity for each of the 7,517 NEM solar installations. As noted earlier, solar installation (NEM customer) information was provided by the jurisdictional utilities and subjected to an initial screen evaluating the reasonableness of their reported AC and DC ratings. These ratings were examined further to assess how Louisiana-specific information compares to other publicly-available information on installed solar systems.

Manufacturers typically rate photovoltaic modules under Standard Test Conditions (“STC”) set by rules promulgated by the International Electrotechnical

Commission ("IEC"), a non-profit, non-governmental, standards organization.[149] STC utilizes solar intensity of 1,000 Watts per meter^2 (W/m^2) in determining nameplate DC capacity ratings.[150] In other words, a standard 4 kW solar system will actually generate 4 kW of electricity when solar radiation reaching the array amounts to 1,000 W/m^2. For instance, if estimated solar radiation reaching the array was 800 W/m^2, generation from the system was estimated to be 3.2 kW. This information can be coupled with the NREL's PVWatts model, to estimate typical solar system efficiency factors.

The PVWatts model, for instance, utilizes a default solar PV system size of 4 kW and system panel area of approximately 35 square meters.[151] Utilizing these default assumptions in conjunction with the STC assumptions noted above, suggests that, under an ideal scenario where a solar PV system could capture all solar radiation impacting the array, the default PVWatts solar system could generate 35 kW of electricity. In reality, such a system typically only generates 4 kW of electricity, implying that the technology is about 11.5 percent efficient.

The largest net metered solar customer in Louisiana is International Snubbing Services ("ISS"), located in Arnaudville northeast of Lafayette. ISS advertises this system as having a capacity rating of 219 kW.[152] Satellite imagery suggests that the ISS facility's array is approximately 450 by 50 feet (137.2 meters by 15.2 meters), or approximately 2,090.3 square meters. This implies that the ISS system has a solar efficiency of roughly 10.5 percent, similar to the 11.5 percent efficiency factor implied in

[149] See, About the IEC, http://www.iec.ch/about/?ref=menu.

[150] "PVWatts: Changing System Parameters" National Renewable Energy Laboratory (NREL), http://rredc.nrel.gov/solar/calculators/pvwatts/version1/change.html.

[151] "PVWatts: Changing System Parameters" National Renewable Energy Laboratory (NREL), http://rredc.nrel.gov/solar/calculators/pvwatts/version1/change.html.

[152] International Snubbing Services (ISS) Goes Green (March 18, 2014), Superior Energy Services Press Release, http://superiorenergy.com/about/news/iss/.

the NREL PVWatts model. These estimates, coupled with the utility-provided AC/DC conversion factors, implies that a standard 4 kW system in Louisiana would generate approximately 646 kWh of electricity on average during the summer months and 238 kWh of electricity on average during the winter months.

The last step in the analysis was to put together all of the weather and unit-specific information to calculate hourly, NEM solar generator-specific estimate of gross generation. A computer algorithm was programed to execute each of the steps necessary to develop these hourly estimates for the time period spanning January 2012 to July 2014, the longest period in which consistent utility-provided data was available. This algorithm utilizes 12 separate sub-routines, each performing an individual function within the larger analysis. This algorithm, and its component sub-routines, requires three full days for execution, performing the following tasks: (1) estimating total system generating potentials from listed capacities and ratings; (2) sculpting individual system generation potentials across location-specific hourly estimated direct solar radiation; (3) adjusting hourly generation estimates for other weather impacts for indirect solar radiation; and (4) developing a composite hourly solar gross generation profile for each individual NEM system on a weather-normalized basis.

The contribution that solar NEM systems make in reducing utility peaks can be estimated once a complete set of hourly gross solar generation statistics are developed. Over the past five years, Louisiana's jurisdictional utilities have experienced system peaks during the summer months around 5:00 p.m. (usually between 4:00 p.m. and 6:00 p.m.). These peaks occur late in the day, particularly relative to other states in the western U.S. that have relatively higher concentrations of solar installations, like

California.[153] In those western states, peaks also occur in the summer, but usually more towards the middle of the day, during which solar is at more effective.

Louisiana's peaks, however, are very late in the afternoon, thereby significantly reducing the contribution that solar can make to offsetting utility peaks. A typical 4 kW solar unit will see its overall effectiveness reduced from an assumed 1,000 W/m^2 noted earlier to somewhere around 500W/m^2, on average, or roughly 50 percent of the nameplate capacity.

5.5. Gross Consumption Estimation

Earlier sections identified three critical hourly data series needed as inputs for the various analyses in this report: net consumption; gross generation; and gross consumption. As noted earlier, each utility provided net metering information for each of its NEM installations in its respective service territory including billing information which represents the net consumption associated with each solar NEM installation. Further, the above sub-sections detail in depth how gross generation was developed for each solar NEM installation. The estimation of gross consumption, therefore, becomes a relatively straightforward, two-step process.

First, mathematically, aggregate net consumption is simply the difference between gross generation and gross consumption. Rearranging terms of this relationship entails that gross generation can be defined as gross generation plus net consumption; two variables that, at this point of the analysis are either know or

[153] See, for example, Annual Report of San Diego Gas & Electric Company (2013 Quarter 4), Federal Energy Regulatory Commission, p. 401b. San Diego Gas & Electric Company saw a maximum annual peak demand on system during 2013 which occurred August 30 at 3:00 p.m.

estimated. Second, total annual gross consumption data for each solar NEM installation can be converted, or "sculpted" to hourly estimates using the load profile information provided by each of the IOUs in the initial LPSC Staff data request. Rural electric cooperatives did not provide load research information so their solar NEM customers' locations were matched to the nearest IOU, and then sculpted with that IOUs load research information. With these estimates in hand, complete hourly-specific estimates of (1) net consumption, (2) gross generation, and (3) gross generation are complete and can be used in the various analyses discussed later in this report.

5.6. Forecast Scenarios

The above sections discuss the methods by which net consumption, gross generation and gross consumption are estimated for historic solar NEM installations arising during the 2008 to mid-year 2014 time period. Solar NEM installations, however, will likely continue given the near-term continuation of state and federal tax incentives and ongoing reductions in solar system costs. Therefore, two forecasts were developed to examine the potential ongoing impact that various new solar installation profiles may have on LPSC jurisdictional ratepayers. Both forecasts were developed for a time period starting in 2014 and continuing to 2020. Estimated impacts, however, extend for a much longer time period than just 2020 given the potential 30 year life of a solar installation.

The first forecast scenario (hereafter referred to as "Forecast Scenario 1") assumes that each utility will continue to experience growth in solar NEM installations as measured by the 2012-2013 annual growth rate. Solar NEM installation growth rates were robust during this time period, but were started to moderate relative to the extremely large percentage increases during 2008-2012 which were somewhere around the 100 percent per year mark (i.e., LPSC jurisdictional installations were effectively doubling every year during this period). The absolute growth in Forecast Scenario 1, however, is bounded to a target level of 0.5 percent of the highest monthly peak demand in a 12 month period for each utility. No new incremental installations are assumed to occur once a utility reaches this solar NEM installation capacity threshold.

A recent proceeding at the LPSC has examined what has been considered by some parties as a degree of ambiguity in how the solar NEM installation cap will be determined for LPSC-jurisdictional utilities.[154] The solar NEM installation threshold utilized in this report is estimated using installed capacity and utility-specific peak demand. The use of this alternative cap definition (referenced hereafter as a "threshold" in order to reduce confusion regarding the ALJ's recent decision) will allow the Commission to understand the full implications of an alternative solar NEM installation cap definition, or, alternatively, the ratemaking implications of raising the cap to this higher level without any other solar NEM policy changes. As a result, Forecast Scenario 1 can be considered as the maximum likely impact (positive and negative) that solar NEM installations will likely have on LPSC jurisdictional ratepayers if a higher alternative definition is utilized.

Table 13 estimates the year in which each LPSC jurisdictional utility is anticipated to reach this threshold (assuming that the threshold has not already been met). Figure 35 graphs the total LPSC jurisdictional capacity likely to materialize under

[154] LPSC Consolidated Docket U-32913.

this forecast assumption. Detailed annual information for each utility, and each year in the Scenario 1 forecast period, is provided in Appendix A-1.

Table 13: Anticipated Year in Which Utilities Reach Forecast Threshold Level

Company	Year Threshold Reached
CLECO	2014
Entergy Gulf States	2020
Entergy Louisiana	2014
SWEPCO	2015
Beauregard	2016
Claiborne	2013
DEMCO	2015
Jefferson Davis	n.a.
Northeast Louisiana	2013
Panola Harrison	2014
Pointe Coupee	2016
South Louisiana	2018
SLEMCO	2016
Washington St. Tammany	2013

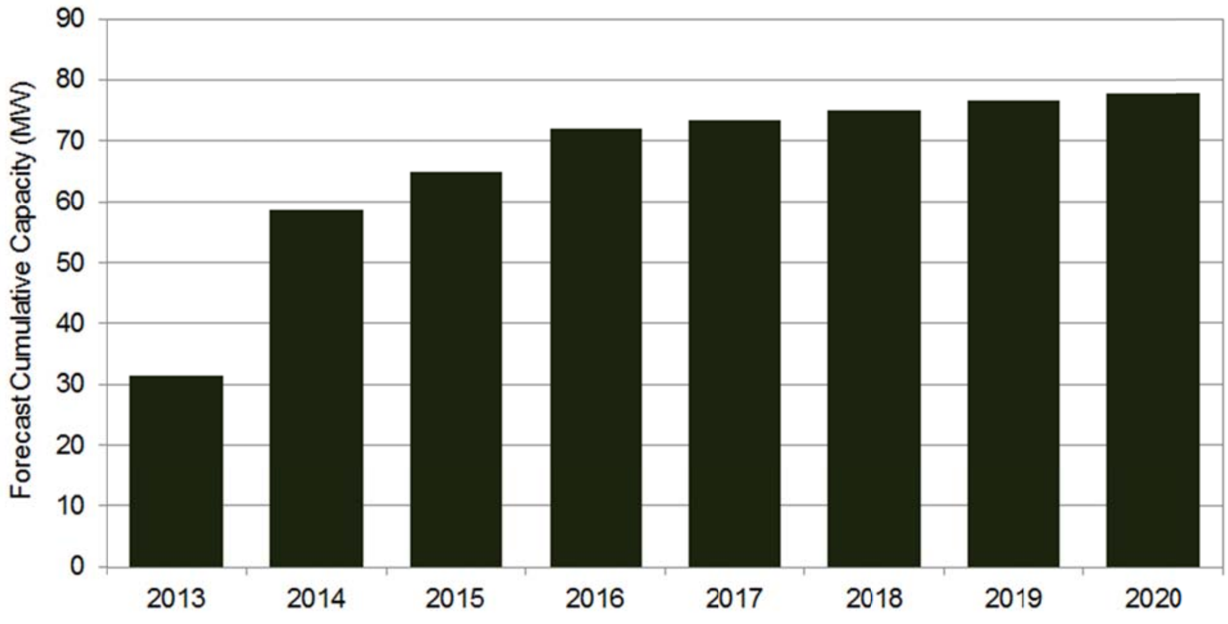

Figure 35: Forecast Scenario 1 Solar NEM Cumulative Capacity

Forecast Scenario 2 simply allows solar NEM installations to grow unbounded to 2020 and relaxes the solar NEM penetration threshold utilized in Forecast Scenario 1 (assuming no other policy change arises). Like above, solar NEM installations are assumed to increase at their 2012-2013 growth rates until the year 2016 at which time they are assumed to slow to 10 percent per year (2017-2020), reflecting the end of both state and federal solar installation tax credits. This scenario can be thought of as defining the maximum impact that solar NEM installations will have on LPSC jurisdictional ratepayers over the next several years given the anticipated changes in solar installation tax credits at the state and federal level. It also gives the Commission an appreciation for the ratemaking implications of eliminating the current solar NEM installation threshold without changing any other solar NEM policies. Figure 36 provides a summary of the total cumulative installed capacity likely to arise under this forecast and compares it to the forecast outcome assumed in Scenario 1. Detailed per-utility information on this forecast has been provided in table Appendix A-2.

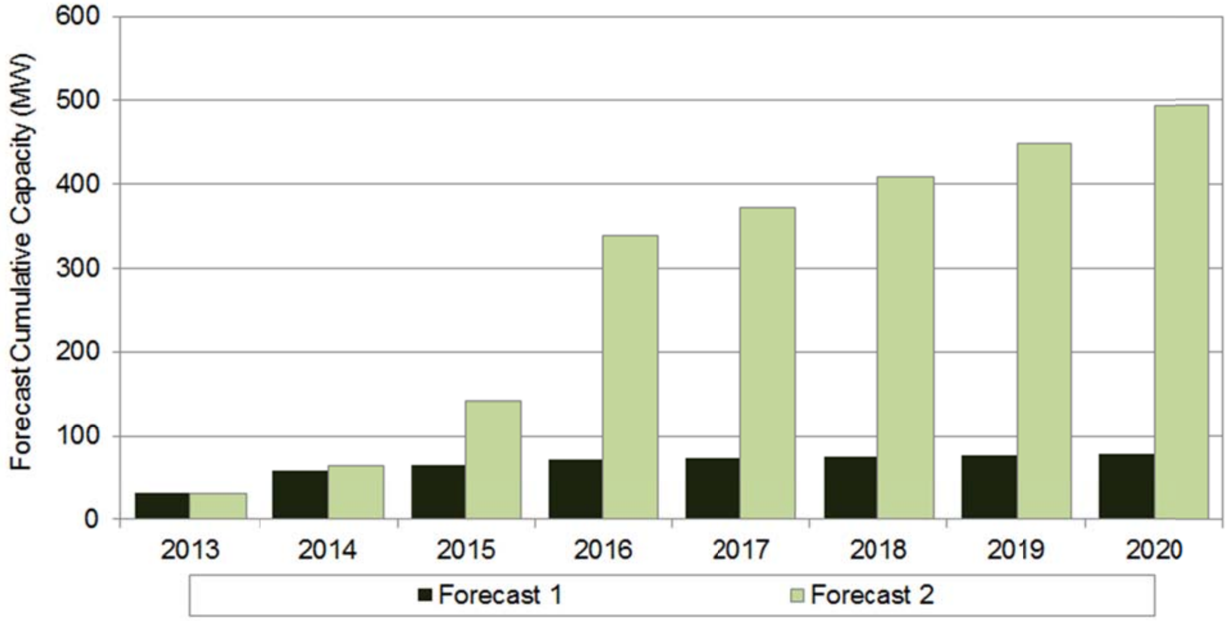

Figure 36: Comparison of Scenario 1 and Scenario 2 Solar NEM Forecasts (Cumulative Capacity, MW)

6. Cost-Benefit Analysis: Methods

6.1. Overview: Solar NEM Costs and Benefits

A CBA of solar NEM should take into account the full range of costs and benefits to utilities, ratepayers and NEM ratepayers. Current Louisiana solar NEM polices can be said to be efficient if the benefits are greater than the costs or, alternatively, if solar NEM can be expected to lead to positive net economic benefits. The benefits of solar NEM generation can include all of the future capital investments and costs that a utility will be able to forego, or "avoid" as a consequence of having solar NEM resources. Solar NEM can also impose a number of costs including unrecovered interconnection and administrative costs, incentive payments on NEM generation put to the utility grid, and lost base revenues, that are passed on to other ratepayers through rate increases necessary to meet revenue requirements. An appropriately-designed CBA is a calculus seeking to assess the net impacts of all of these costs and benefits.

Figure 37 provides a schematic that highlights the various benefits and costs components associated with solar NEM implementation. The following subsections of this report discuss each of these components in further detail.

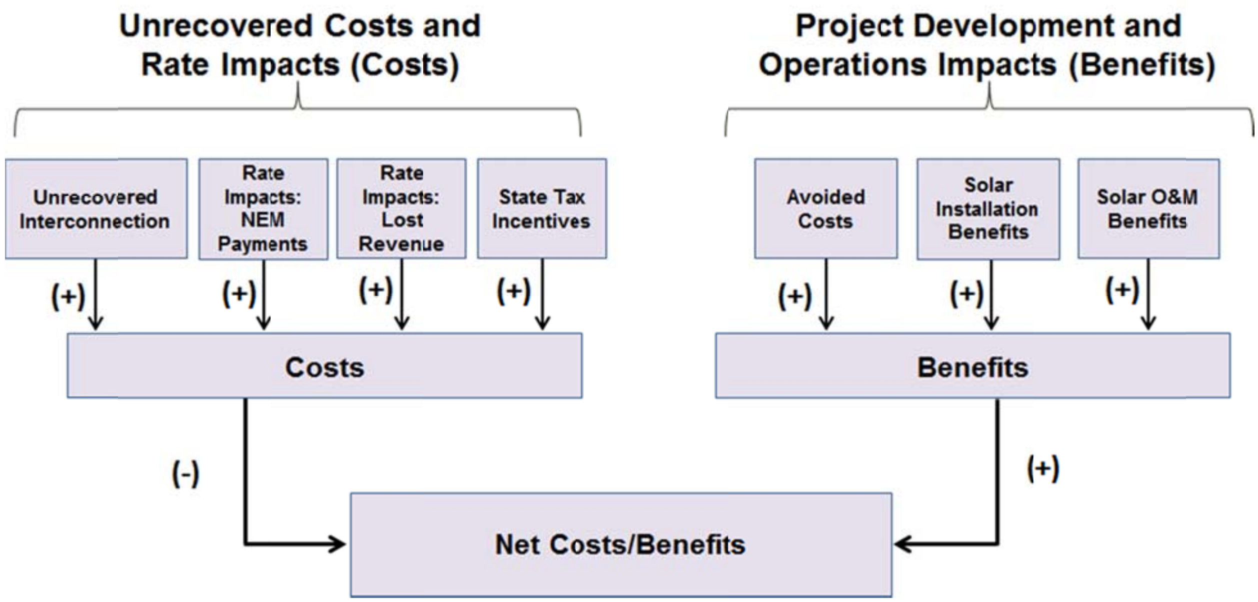

Figure 37: Solar NEM Costs and Benefits

6.2. Solar NEM Benefits

6.2.1. Avoided Generation Energy

Electricity produced by a solar NEM installation avoids current and future utility generation over its economic life. The value of these avoided electricity costs, or "energy" costs, is simply the product of the unit cost of the avoided electricity (cost per MWh) and the on-site solar NEM generation. The previous section of this report discussed the methods utilized to develop solar NEM-specific hourly gross generation. Unit cost estimates for avoided energy, therefore, is the only missing piece of information needed to develop a total avoided energy cost (benefit) attributable to solar NEM installations.

Today, spot electricity prices, or "energy" prices, are set by market forces on open and competitive wholesale power markets. Prices in these markets are usually set by the marginal (or incremental) costs of the marginal unit needed to clear the last increment of market demand. Current and projected avoided cost estimates are typically based on the variable, not total average costs of dispatching the marginal unit. So, while the estimates are highly influenced by fuel costs and the efficiency at which the marginal unit converts this fuel to electricity, it typically does not include the capital costs of new generation capacity. There are instances, however, when capacity-related factors such as generation resource scarcity and other physical constraints (like transmission constraints) can influence prices. These energy prices can also be impacted by environmental requirements such as emission credit purchases needed to offset regulated air emissions for the marginal unit.

Natural gas-fired generating resources have dominated new incremental generation over the past decade and continue to serve as the “marginal” unit in most regional wholesale power markets given their relatively low capital costs and operating flexibility. Thus, an advanced natural gas fired combustion turbine, with an assumed thermal efficiency of 9,750 British thermal units per kWh (“Btu/kWh”), serves as an appropriate proxy for the marginal unit setting energy prices in wholesale power markets over the next decade, and correspondingly, serves as an appropriate proxy for estimating avoided energy costs. A constant natural gas price of $3.50/MMBtu was used to estimate the fuel component of this avoided energy cost. Table 14 provides the assumed operating statistics for this marginal unit.

Table 14: Natural Gas Advanced Combustion Turbine Assumptions

Advanced CT Generation Characteristics	
Heat Rate (Btu/kWh)	9,750
Variable O&M Cost ($/MWh)	$ 10.37
Fixed O&M Cost ($/kW)	$ 7.04
Fixed O&M Cost ($/MWh)	$ 2.68

Source: Energy Information Administration, Department of Energy; and Bureau of Labor Statistics, U.S. Department of Labor

6.2.2. Avoided Generation Capacity

Capacity in the electric power industry is usually thought of as the maximum generating capability of an electric generating resource. Evaluating current capacity capabilities and future capacity needs are important aspects of reliability planning, since one important reliability consideration is ensuring that enough capacity exists to meet anticipated and unanticipated changes in load. Determining a renewable resource's capacity value or contribution to overall system/regional capacity can be controversial since renewable generation, unlike traditional generation, is intermittent and sometimes not available to serve as peak loads. Many regional power authorities will discount the capacity value of renewables given their intermittency. MISO, for instance, uses a two-step process that calculates a system-wide ELCC value for all wind resources in the region and also considers the historic output of each wind resources and its location. The system-wide ELCC value is allocated across all wind Commercial Pricing Node ("CPNode") in the MISO system to determine a wind capacity credit for each wind

CPNode.[155] Similarly, PJM discounts the capacity of intermittent resources by computing each resource's annual capacity factors for each of the prior three summers. If there is no data, or incomplete data for one or more of the summers for a resource, then that resource is assigned the value of the class average capacity factor.[156]

Thus, a solar NEM system's effective load carrying capability ("ELCC") needs to be established in order to adjust the estimated avoided capacity cost benefit. The ELCC measures the effective amount of load that can be displaced by a solar NEM resource without compromising reliability. The important aspect of this calculation is that it adjusts the rated capacity of the solar NEM resource for its likely operating conditions under system peak conditions.

As noted earlier, an ELCC can be calculated for each solar NEM installation by examining the estimated hourly solar NEM generation available from that installation at the relatively late system peak hours for each of Louisiana's utilities (between 4:00 p.m. to 6:00 p.m.). Estimates were developed for each IOU using a five-year average of peak load information provided in their respective FERC Form 1s. System peak information was not available for the rural cooperatives, so solar NEM installations in those areas were matched to the observed peak demand hours associated with the geographically closest IOU.

The next step in the determination of the avoided capacity cost benefits from solar NEM installations was estimating the hourly unit values of the avoided capacity. The total annual avoided capacity cost benefit is simply the product of the unit cost for

[155] MISO 2014 Wind Capacity Credit Report, December 2013.

[156] The effective class average capacity factors are 13 percent for wind; and 38 percent for solar. See: "Rules and Procedures for Determination of Generating Capability, PJM Manual 21." Prepared by System Planning Department, PJM. Effective Date: May 1, 2010.

the avoided capacity (in dollars per kW-year or dollars per MW-day terms) and the ELCC. Two different means can be utilized for estimating these unit capacity costs that include (1) inferences from observed historic information or (2) direct estimation.

Many regional wholesale power markets over the past several years have developed capacity-based markets including PJM, ISO New England, and MISO. Capacity prices are set by the supply and demand conditions existing in each of those markets and are influenced by many of the same factors impacting energy costs but in a different fashion. The marginal technology clearing the marking is certainly important, but equally important are the market's perceptions about near and longer term resource scarcity. The tighter the market, in terms of excess generating capacity, the higher the capacity price and vice versa. In April 2014, MISO held its annual Planning Resource Auction for the 2014-2015 planning year. The capacity market cleared at $16.44 per MW-day (or $6.00 per kW-year) for zones 8 and 9 (Arkansas, Louisiana, Mississippi and Texas). Markets valuing capacity at less than $100 per kW-year can be thought of as relatively "long" in capacity where as those around or above $100 per kW-year can be thought of as capacity tight or "short."

Direct estimates for capacity costs can also be developed by estimating what can be characterized as the net "cost of new entry" ("CONE") which is simply an estimate of the total levelized cost of a new gas unit (typically a CT), less the energy revenues the unit will receive.[157] The net CONE approach, however, is not without its analytic

[157] ICF International. 2014. The True Value of Solar; Energy and Environmental Economics. 2012. Technical Potential for Local Distributed Photovoltaics in California; Clean Power Research & Solar San Antonio. 2013. The Value of Distributed Solar Electric Generation to San Antonio; Navigant Consulting for NREL. 2008. Photovoltaics Value Analysis; and Rocky Mountain Institute. 2013. A Review of Solar PV Benefit & Cost Studies.

challenges since the underlying method, if not reconciled with anticipated market conditions, will likely yield an estimate reflecting the full cost of new capacity. For instance, if market conditions are not capacity constrained, the avoided capacity estimates developed from the CONE approach will likely be overstated since the method is based on the cost of full capacity development. Thus, some type of market information may be necessary in order to "condition" or "discount" the full cost/full capacity need assumption implicit in the CONE approach, particularly in markets with excess capacity.

Central Gulf Coast power markets have seen a long period of excess generating capacity dating back to the merchant power build-out of 1998-2001. Most regional capacity markets continue to reflect this condition. For instance, MISO recently noted, in completing the Planning Resource Auction this past spring that:

> Results of the auction indicate an excess of 12,201 MW resource credits above the system's need to meet forecasted demand during the 2014-15 planning year, despite increases to MISO's Planning Reserve Margin and increases in Coincident Peak Forecasts.[158]

The current state of regional power markets can also be assessed by current and projected capacity and reserve margin trends prepared by regional reliability authorities. Figure 38, for instance, provides the recent trends in MISO, SPP and SERC-SE reserve margins. All three regions have been in excess of the typical 13 percent to 15 percent planning margins used for reliability purposes. And, while reserve margins are projected to fall, all three regions are expected to remain above the planning requirement used for reliability purposes.

[158] MISO. 2014. MISO Clears Second Annual Capacity Auction. Available at: https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/MISOClearsSecondAnnualCapacityAuction.aspx.

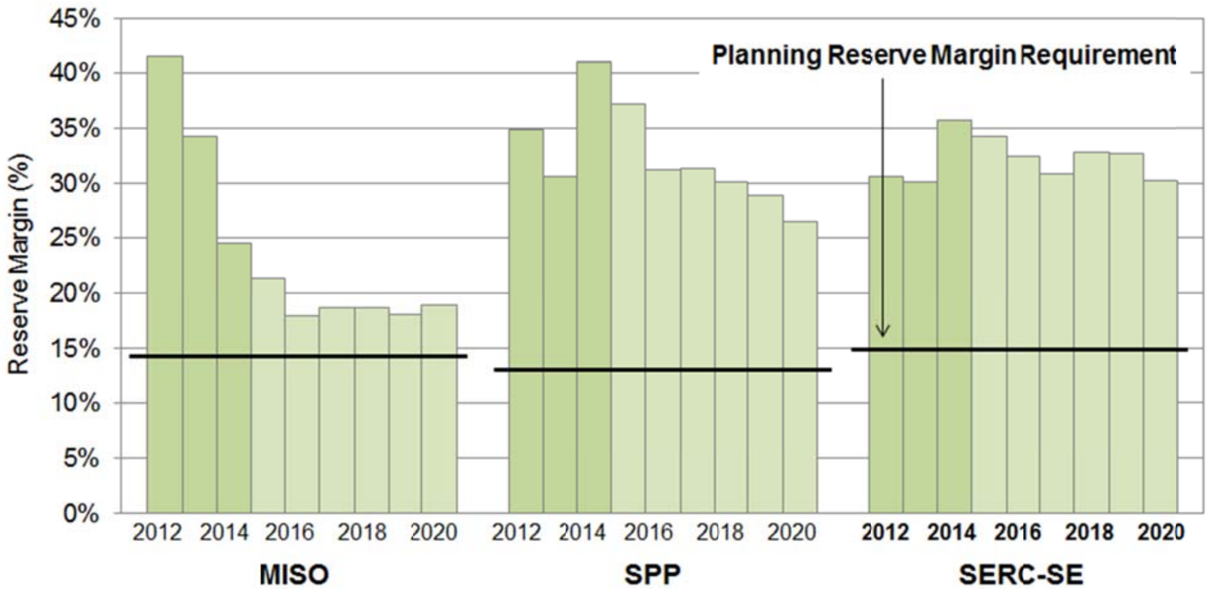

Figure 38: SPP, SERC and MISO Historic Reserve Margins
Source: North American Electric Reliability Council

Lastly, as shown in Figure 39, the results of recent capacity auctions throughout the U.S. are significantly lower than the typical Net CONE value of $100/kW-year used in a number of studies.[159] Low natural gas prices, continued moderate economic growth (and electricity demand growth), continued (and projected) high reserve margins, and lower finance costs should prevent these capacity values from increasing in any appreciable fashion, holding other factors constant, at least through 2020.

[159] ICF International. 2014. The True Value of Solar; Energy and Environmental Economics. 2012.

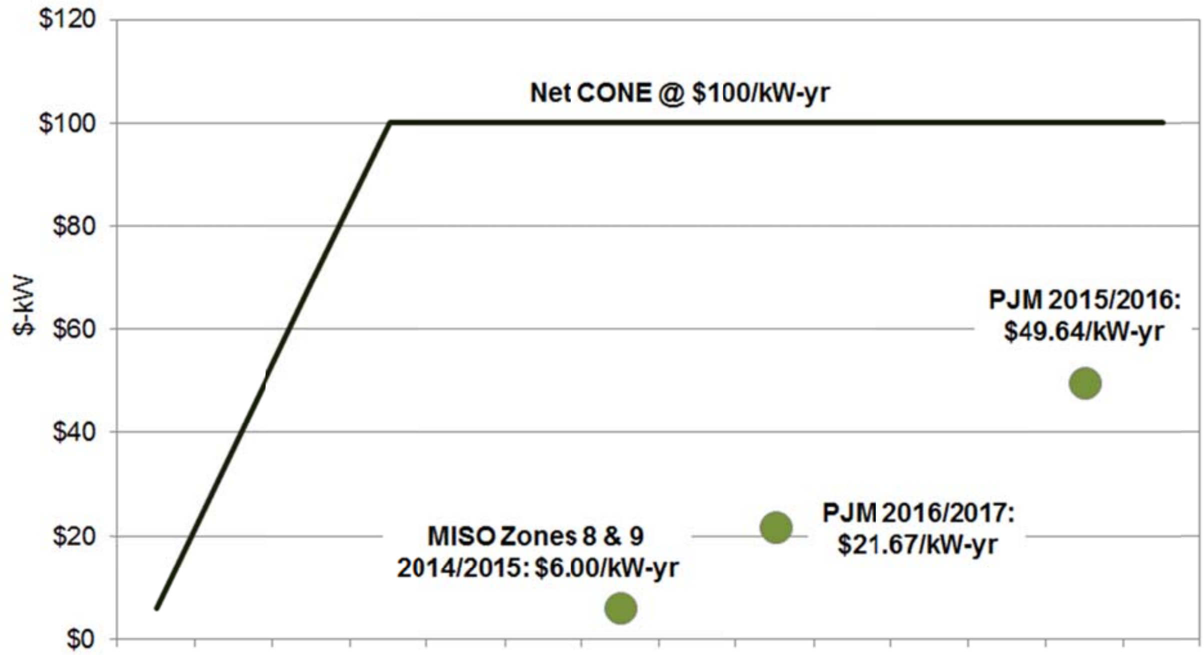

Figure 39: Results of Recent Capacity Auctions
Source: MISO and PJM News Releases.

Estimated avoided capacity cost benefits, therefore, have been estimated using a constant 2014 value of $16.44 per MW-day consistent with the most recent MISO auction price. This unit capacity value is held constant each year through the 2020 forecast period (avoided energy prices, as noted earlier, are also projected on the EIA AEO natural gas forecast). While there are a number of factors that could create capacity tightening over the next few years along the Gulf Coast, like continued industrial growth due to the recent Louisiana manufacturing renaissance, and/or the potential retirement of a large number of older coal and natural gas steam generating facilities created by the EPA's proposed Clean Power Plan ("CPP"), those potential scenarios are better left to a sensitivity analysis that will be provided after the baseline net benefits analysis results are complete. Figure 40 charts the projected avoided capacity costs utilized for determining solar NEM benefits.

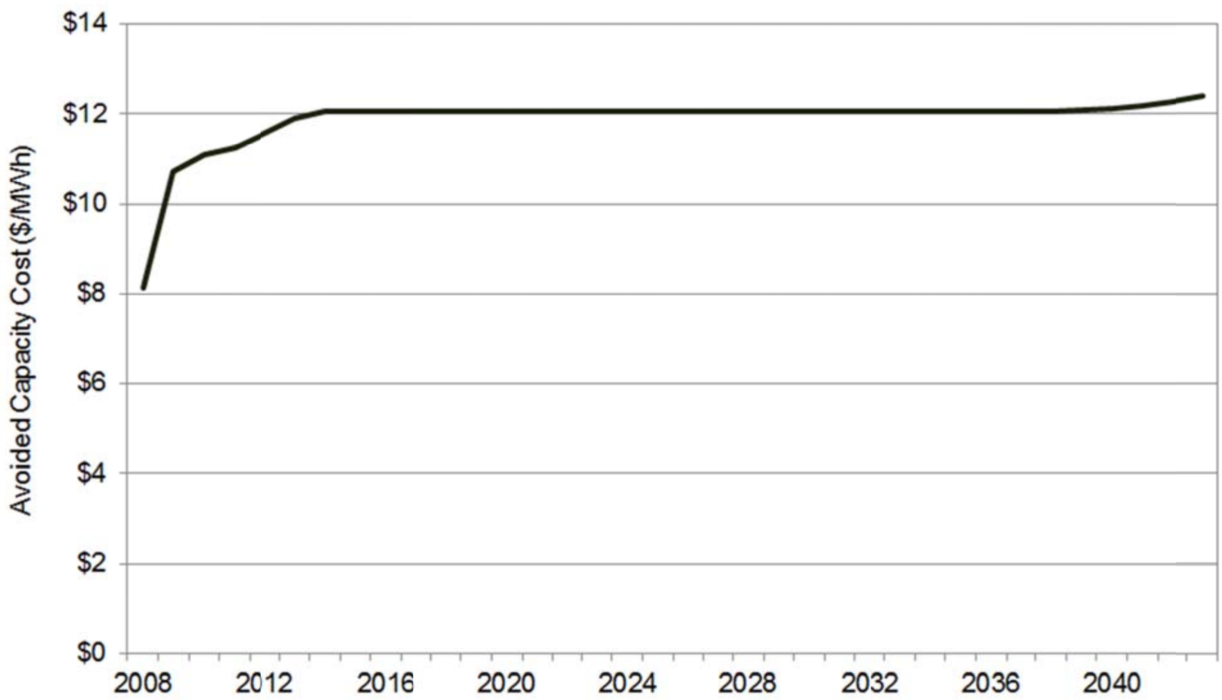

Figure 40: Projected Avoided Capacity Cost

6.2.3. Avoided Transmission and Distribution

Solar NEM installations also create opportunities to avoid investments in transmission and distribution ("T&D") capacity. The valuation of these potential T&D capacity benefits is comparable to those discussed earlier for avoided generation capacity costs. Avoided transmission and distribution capacity cost benefits are developed in two steps. First, the ELCC used to adjust the avoided generation capacity cost benefits needs to be utilized to adjust a solar NEM installation's effective contribution at reducing capacity: in this case, T&D capacity. Second, a unit cost estimate (in dollars per kW or "$/kW") for avoided T&D benefits needs to be developed.

Total annual avoided T&D capacity cost benefits are simply the product of the ELCC and the estimated avoided T&D capacity costs.

Unit cost estimates for avoided T&D capacity investments were estimated in two steps. The first step involved looking at the relationship between the change in T&D assets and historic annual peak loads over the based decade as reported in each IOU's FERC Form 1. Detailed FERC Form 1 account information was utilized to identify, and employ, only those FERC subaccounts (and investments) that were truly avoidable. Table 15 outlines those accounts.

Table 15: Deferrable FERC Distribution Accounts

Distribution Plant in Service Account	Percent Deferrable
(360) Land and Land Rights	**100%**
(361) Structures and Improvements	**100%**
(362) Station Equipment	**100%**
(363) Storage Battery Equipment	0%
(364) Poles, Towers, and Fixtures	0%
(365) Overhead Conductors and Devices	**25%**
(366) Underground Conduit	**25%**
(367) Underground Conductors and Devices	**25%**
(368) Line Transformers	0%
(369) Services	0%
(370) Meters	0%
(371) Installations on Customer Premises	0%
(372) Leased Property on Customer Premises	0%
(373) Street Lighting and Signal Systems	0%

The average marginal T&D investment, estimated for each utility over the past decade, was then capitalized using utility-specific financial information, and their achieved rates of return over the past decade, in order to develop an estimated annual revenue requirement in $/kW terms. This estimate represents the unit cost used to develop total avoided T&D capacity cost estimates. Avoided transmission costs are estimated to be $30/kW and avoided distribution costs are estimated to be $49.50/kW to $158.30/kW depending on the utility. These costs are held constant in 2014 dollars in developing the final CBA results.

6.2.4. Solar Installation Benefits

Solar energy investments can lead to a number of direct, indirect and induced economic benefits. The direct economic benefits can be classified as those associated with the solar panel purchases and their installation at residential and commercial locations. The indirect economic benefits include all of the economic activity arising from the direct activities (i.e., the solar panel purchases and installation). These can include such activities and equipment and tool purchases, office and accounting services, transportation equipment purchases, and rentals. The induced effects include the economic activity associated with the incomes generated in the direct and indirect economic activities.

The direct, indirect, and induced benefits created by Louisiana solar investments have been modeled using the Jobs and Economic Development Impact ("JEDI") solar PV economic impact models. JEDI is a state-specific economic impact model developed by the National Renewable Energy Laboratories to specifically estimate the economic impacts associated with renewable energy investments.[160] NREL maintains state-specific "modules" for each type of major renewable investment including solar,

[160] http://www.nrel.gov/analysis/jedi/about_jedi.html

onshore wind, biomass, and geothermal. JEDI uses Implan,[161] another well-recognized economic impact modeling tool, as its base modeling platform, and "re-compiles" various Implan sectors in order to develop a unique customized model for each renewable investment type. JEDI has a number of benefits that include (1) it is a well-recognized model utilized by a number of practitioners working in the energy and utility industries; (2) has been created by an independent, federally-funded national energy lab that specializes in renewable energy research; (3) is Louisiana-specific; and (4) can be utilized or purchased for direct use by third parties in order to do independent analyses.

The first step in quantifying solar NEM installation benefits is to account for total expenditure leakages. An economic leakage occurs when a portion of some overall economic "shock" (which can be an expenditure or cost) is made outside of the study area under investigation. When the study area of interest is a State, a leakage simply represents the out-of-state share of total expenditures. So, if a particular project is anticipated to make 30 percent of its expenditures out of state, and total capital expenditures for the project is assumed to be $100 million, then $30 million can be thought of as a "leakage." In order to estimate economic impacts, this $30 million is typically "backed-out" of the economic impact analysis since it represents purchases (and theoretically benefits or costs) that occur out-of-state as opposed to in-state. Failure to properly account for these leakages can lead to a bias in economic impact modeling results. JEDI includes a calculation default that explicitly corrects for this type of economic leakage.

[161] http://www.implan.com

Direct economic impacts are estimated as the leakage-adjusted total expenditures associated with the annual solar installations associated with LPSC-jurisdictional NEM customers. The total historic solar installation information discussed in Section 4 was used to identify annual total solar projects and capacities. Cost per unit of capacity was then utilized to develop total individual solar project expenditures. These per unit solar capacity costs were taken from solar unit cost installation included in JEDI. The sum of the individual solar NEM installations in any given year represents total LPSC-jurisdictional solar NEM expenditures. JEDI was then used to estimate the indirect and induced impacts for each year.

The methods utilized to estimate solar NEM installation benefits are conservative and missing from this analysis is an adjustment to discount these solar benefits that would arise from their opportunity cost on society. The opportunity costs associated with solar construction can be defined as the lost, or forgone investment and economic activity that would have been made in traditional power generation investments (like natural gas, coal, or nuclear). The net of the two investments (i.e., solar less traditional power generation) would then be the net economic benefit associated with solar NEM construction activity. Such adjustments have not been included in the analysis in order to give NEM investments full credit for their direct, indirect, and induced economic benefits.

6.2.5. Solar Operations and Maintenance Benefits

Solar NEM customers can also be expected to incur maintenance costs on their solar installations over their economic life. These maintenance expenditures create additional economic opportunities for in-state solar businesses. Annual solar expenditures are based upon solar O&M assumptions also included as a default in the JEDI modelling tool, and provided on a per solar kWh generated basis. Solar O&M expenditures are simply the product of the NREL/JEDI solar O&M unit cost estimates and the total annual solar NEM generation. Indirect and induced benefits are estimated using JEDI.

Likewise, an argument could also be made that solar NEM O&M benefits should be discounted for the foregone O&M activity associated with traditional power generation investments. Again, such an adjustment has not been made here, giving solar NEM O&M expenditures full credit for their direct, indirect and induced economic benefits.

6.3. Solar NEM Costs

6.3.1. Unrecovered Interconnection Costs

Solar NEM installations are small behind the meter power generators and like other power generators, must be interconnected to the grid in order for the NEM customer to receive backup power from the utility and to sell the utility its excess generation. There are a variety of costs that are incurred when a small scale solar facility is interconnected to the grid that include, but are not limited to, application costs, site inspections, NEM billing set-up, meter installation, and service line setups.[162]

Interconnection cost information was requested by Staff from the jurisdictional utilities early in this project. This information was used to estimate a per installation

[162] The current LPSC NEM rules do not allow utilities to collect for the cost of the meter; the “meter installation” cost referred to here is for installation costs only.

interconnection cost of $325 per customer. In addition, some utilities indicated in their data responses that they apply interconnection fees for solar NEM installations of around $100 per installation. However, not all utilities apply such charges to solar NEM projects when they are initially installed and interconnected. Even for those utilities assessing fees on solar NEM connections, the currently applied interconnection fees are $100 per customer, far lower than the total estimated interconnection costs. This means that solar NEM interconnection costs are likely being partially, or totally subsidized by the remaining set of ratepayers and represents a cost that should be taken into consideration in the CBA.

Total annual unrecovered interconnection costs utilized in the CBA were estimated at $325 per installation times the number of installations per year. These costs were considered one-time fees and were discounted for utilities that have some level of required financial contribution. These interconnection costs were held constant in 2014 dollars throughout the time period under investigation in the CBA.

6.3.2. Solar NEM Administrative Costs

Solar NEM installations also impose a number of ongoing and recurring costs on utilities that are not recovered directly from these program participants, but are recovered from the general class of ratepayers. These ongoing administrative costs include NEM program and tariff management cost, incremental billing costs, ongoing integration costs including engineering monitoring of solar NEM generation and load balancing. Again, utilities were requested, and provided information associated with their ongoing solar NEM program administrative costs. These costs were compiled, and averaged, leading to an estimated administrative cost used for the CBA of $75 per customer-year.

6.3.3. Rate Impacts: NEM Credits

One of the attractive features of a NEM program are the “payments” NEM customers receive from utilities for the on-site solar NEM generation they put to the utility’s distribution grid. These “payments” represent another source of financial support for a solar NEM investment and can be used to offset the large, upfront costs associated with solar investments. Solar NEM customers, however, do not receive a direct cash “payment” from utilities, but instead, are given a credit on their monthly electricity bills for their excess self-generated electricity. This credit is valued as simply as the product of the payment rate (in $/kWh) and the excess generation.

The rate at which excess solar NEM generation is valued, however, differs significantly from how other grid-connected sources of on-site power generation are reimbursed, particularly large energy efficient industrial CHP applications. Solar NEM generation put to the utility grid is valued at full base retail rates, whereas CHP generation put to the utility grid is valued only at a utility’s avoided energy cost. The avoided energy cost, as noted earlier in this section, is simply the variable cost of operating a generation facility (mostly variable fuel related costs), whereas the full base retail rate includes the full cost (capital and expenses) associated with the total cost of utility service (including generation, transmission and distribution). The payments made to solar NEM installations, therefore, are much larger than the true avoided opportunity cost of solar generation (i.e., avoided utility energy costs).

Solar NEM payments create ratepayer costs since the generation put to the utility grid is reimbursed at a rate higher than the generation it is offsetting or avoiding. These additional costs are included in the CBA and estimated as simply the difference between the base retail rate and the earlier-discussed estimated avoided energy cost. These differentials are calculated for each solar NEM installation and assessed against each jurisdictional utility's current tariff.

The sum of the dollar value of the excess solar generation imposes a rate impact on other non-NEM customers since the utility must recover those dollars somewhere, and that is usually through its cost of service. Increases in the cost of service, which are created by the excess solar NEM incentive payments, result in increased rates. Increased rates, in turn, will reduce household, business, and industrial expenditures, which ripples through the local economy in a negative fashion. These additional negative impacts are considered in the CBA as an offset to the positive impacts discussed earlier.

6.3.4. Rate Impacts: Lost Revenues

While solar NEM installations will create bill savings for the NEM customer, these savings represent a potentially sizeable loss in direct revenue for the utilities. These direct revenue losses, like the solar NEM incentive payments, have to get recovered from somewhere, and that is usually through a utility's cost of service. If a utility's achieved rate of return falls substantially below its allowed rate of return, it usually files a rate case in order to raise rates high enough to bring the achieved and allowed rates of return in balance. If a utility's achieved rate of return falls because its sales have decreased from solar NEM installations, the rates of other ratepayers will increase. The economic impact of this additional rate increase (in addition to the rate impact of the NEM payments) also needs to be considered in the CBA. Direct rate impacts are simply calculated as the utility-specific base revenue decrease associated with the NEM generation. Indirect and induced impacts are estimated through the Implan modeling software discussed earlier.

6.3.5. Government Incentive Costs

As discussed in Section 2.4, Louisiana has been noted as having one of the most generous solar tax incentives in the nation. This tax incentive, passed by the Louisiana Legislature in 2008, included a 50 percent rebate on the first $25,000 of the cost of a solar system. Louisiana's solar tax incentive program, when coupled with a comparable federal solar incentive of 30 percent on the total cost of a system, results in a total installed cost discount of 80 percent.[163] The combined federal/state solar tax credits are said by many to have led to the explosion of new solar installations in Louisiana.[164]

The solar tax incentive, however, does not come without a cost. Figure 41 shows that the Louisiana solar tax credit program, over the past six years is estimated to have paid out over $150 million during a time when the state has repeated serious budgetary problems. Every dollar spent by the State on solar tax credits is a dollar that cannot be spent on state health care programs, transportation infrastructure, and higher education, among other state programs and social services. The reduction in state spending for these programs needs to be included as a cost in the CBA, particularly if

[163] The federal Residential Renewable Energy Tax Credit, established by the *Energy Policy Act of 2005,* allows taxpayers to claim a credit of 30 percent for a system that is serves a residential unit owned an occupied by the taxpayer. Availability of this credit is set to expire on December 31, 2016.

[164] Jeff Adelson. (2014). "Giving Away Louisiana: Solar Energy Tax Credits." *The Advocate*.

the benefits of solar construction and O&M activity are included. The direct impacts of the Louisiana solar tax credit program were estimated from a review of Department of Revenue information and historic installations. Ultimately, direct impacts were estimated as the credit percent of the estimated annual installed solar installation investment amount since installation-specific information was unavailable. Indirect and induced impacts of a reduction in state government spending were estimated through the Implan modeling software discussed earlier.

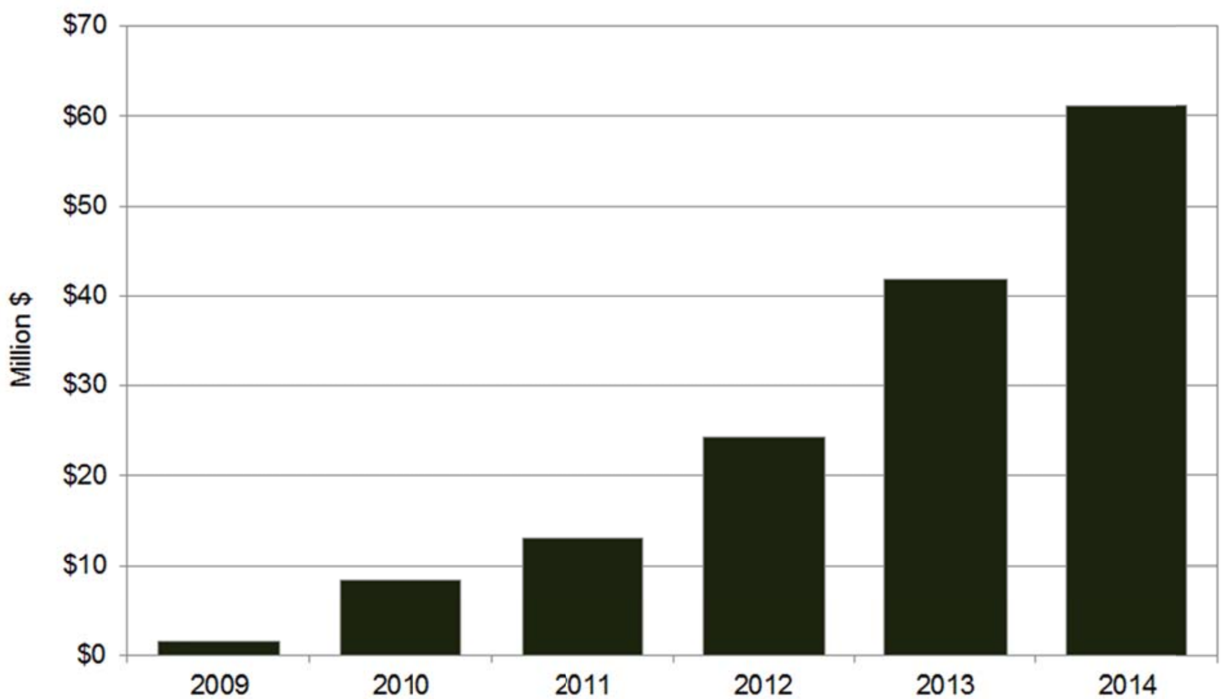

Figure 41: Estimated Annual Solar Tax Credits
Source: Author's construct from Advocate Graphic, Louisiana Department of Revenue.

7. Cost-Benefit Analysis: Net Benefits Estimates

7.1. Overview: Net Benefits Results Calculation

As noted earlier, net economic benefits are calculated as simply the difference between total estimated economic benefits of the solar NEM program and total estimated economic costs. Positive net benefits are said to arise if the benefits of the solar NEM program are greater than their costs whereas negative net benefits are the result of program costs that are greater than program benefits.

The following subsections provide the summary results from: (a) the total benefits analysis; (b) the total cost analysis; and (c) the net benefits calculations. The overall results from the total benefits analysis will be provided followed by those from the total cost and net benefits analysis. Each subsection will discuss two sets of results. The first set of results is associated with the known historic trend in solar NEM installations between 2008 and mid-2014. The second set of results will discuss the results (meaning there is no change in underlying assumptions) for the two forecast scenarios.

As noted in Section 5, there are two forecast outlooks. The first forecast outcome assumes that solar NEM installations will continue to grow for each utility, unconstrained, until that utility's LSPC-mandated NEM threshold is reached (one-half percent of peak load). The second forecast outcome allows solar NEM installations to grow unconstrained, at a rate equal to their 2012-2013 growth rates to the year 2020. Both baseline-forecast results preserve all underlying assumptions.

The following subsections will discuss the summary NPV results for each component of the CBA. Detailed results for each component of the analysis, across the historic baseline and forecast periods are provided in Appendix A-3 through A-5.

7.2. Summary Estimates: Total Solar NEM Benefits

The summary results estimating the individual and total benefits associated with historic solar NEM installation has been provided in Table 16. Detailed results are provided in Appendix A-3.

Table 16: Summary Results, Solar NEM Benefits (Historic Installations)

	Economic Benefits							
	Direct (2008-2043)		Indirect (2008-2043)		Induced (2008-2043)		Total (2008-2043)	
Economic Benefits	------------------------------- (million $ NPV) -------------------------------							
Avoided Generation Energy	$	33.89	$	-	$	-	$	33.89
Avoided Generation Capacity		8.20		-		-		8.20
Avoided T&D		0.12		-		-		0.12
Total Avoided Power Costs	**$**	**42.21**	**$**	**-**	**$**	**-**	**$**	**42.21**
Total Solar Installation Benefits	$	49.26	$	57.52	$	29.33	$	136.12
Total Solar O&M Benefits		5.86		5.87		2.58		14.30
Total Solar Benefits	**$**	**55.12**	**$**	**63.39**	**$**	**31.91**	**$**	**150.42**
Total Solar NEM Benefits	**$**	**97.33**	**$**	**63.39**	**$**	**31.91**	**$**	**192.62**

Avoided generation capacity and energy benefits are, collectively, the second largest source of potential benefits created by solar NEM installations. Total solar NEM avoided generation capacity benefits are estimated to amount to over $8 million over their respective economic lives. Total solar NEM avoided generation energy benefits however, are much larger at $33.9 million in NPV terms. The fact that avoided energy benefits are substantially greater than avoided capacity benefits should come as no surprise given the low effective capacity value of solar in Louisiana. Avoided generation capacity benefits, however, are not trivial, and represent the third largest source of benefits from solar NEM installations. Avoided transmission and distribution benefits are relatively small at less than $1 million, primarily because, (1) the unit cost of avoiding T&D is much smaller than generation and (2) the effective capacity of solar NEM is relatively small.

Solar installation impacts represent the single largest source of total NEM program benefits. Direct solar installation activity is estimated to lead to over $49.2 million in direct economic benefits, $57.5 million in indirect economic benefits and $29.3 million in induced economic benefits. Total solar installation activity is estimated to result in a total economic benefit of $136.1 million. Total solar O&M economic benefits are also estimated to lead to considerable economic benefits with a total economic benefit of $14.3 million.

The sum of the power-related and solar-related benefits represents the total baseline historic solar NEM benefits to LPSC ratepayers. The solar NEM installations to date have created and will continue to lead to significant economic benefits for LPSC ratepayers. Solar NEM projects that have been installed to date are estimated to contribute some $192.6 million in total economic NPV benefits (direct, indirect, and induced) over their lifetime: some of those benefits have already been experienced, while other benefits will continue so long as these installations continue to remain in operation.

Summary results estimating the individual and total benefits associated with historic and projected solar NEM installation, under the Forecast Scenario 1 projection (all utility installations grow to the LPSC-allowed cap) has been provided in Table 17. Detailed results are provided in Appendix A-4.

Table 17: Summary Results, Solar NEM Benefits (Historic and Projected Installations, Forecast Scenario 1)

Economic Benefits	Economic Benefits Direct (2008-2049)	Indirect (2008-2049)	Induced (2008-2049)	Total (2008-2049)
	------------- (million $ NPV)	-------------	-------------	
Avoided Generation Energy	$ 58.94	$ -	$ -	$ 58.94
Avoided Generation Capacity	14.19	-	-	14.19
Avoided T&D	0.20	-	-	0.20
Total Avoided Power Costs	**$ 73.33**	**$ -**	**$ -**	**$ 73.33**
Total Solar Installation Benefits	$ 72.50	$ 84.66	$ 43.17	$ 200.33
Total Solar O&M Benefits	8.62	8.63	3.80	21.05
Total Solar Benefits	**$ 81.12**	**$ 93.29**	**$ 46.97**	**$ 221.38**
Total Solar NEM Benefits	**$ 154.45**	**$ 93.29**	**$ 46.97**	**$ 294.71**

The results from the economic benefit analysis of historic and projected solar NEM installations, under the Forecast Scenario 1 solar installation assumption, are relatively similar to the ones discussed earlier for the historic solar NEM projects to date. The Forecast Scenario 1 results show the total benefits that the state can expect to attain from the LPSC-jurisdiction NEM program if the program continues to grow at its current rate, but is capped at the currently-defined LPSC limit. These results can be interpreted to reflect the maximum benefits the state will likely attain under a status quo scenario.

Total power benefits associated with the Forecast Scenario 1 solar installation forecast is $73.3 million in NPV terms. Total solar benefits, including the solar installation and O&M total to $221.4 million in NPV terms. Total solar NEM benefits, from the Forecast Scenario 1 solar installations are $294.7 million.

Summary results estimating the individual and total benefits associated with historic and projected solar NEM installation under the Forecast Scenario 2 solar installation forecast has been provided in Table 18. Detailed results are provided in Appendix A-5.

Table 18: Summary Results, Solar NEM Benefits (Historic and Projected Installations, Forecast Scenario 2)

	Economic Benefits							
		Direct (2008-2049)		Indirect (2008-2049)		Induced (2008-2049)		Total (2008-2049)
Economic Benefits	------------------------------ (million $ NPV) ------------------------------							
Avoided Generation Energy	$	296.75	$	-	$	-	$	296.75
Avoided Generation Capacity		72.33		-		-		72.33
Avoided T&D		1.02		-		-		1.02
Total Avoided Power Costs	**$**	**370.10**	**$**	**-**	**$**	**-**	**$**	**370.10**
Total Solar Installation Benefits	$	308.07	$	359.72	$	183.45	$	851.24
Total Solar O&M Benefits		36.63		36.68		16.13		89.44
Total Solar Benefits	**$**	**344.70**	**$**	**396.40**	**$**	**199.58**	**$**	**940.68**
Total Solar NEM Benefits	**$**	**714.80**	**$**	**396.40**	**$**	**199.58**	**$**	**1,310.78**

The results from the economic benefit analysis of historic and projected solar NEM installations, under the Forecast Scenario 2 solar installation assumption, are again, similar to the ones discussed earlier for the historic solar NEM projects to date. The Forecast Scenario 2 results show the total benefits that LPSC ratepayers can expect to attain if solar installations continue to grow at their 2012-2013 growth, unbounded to 2016 (the year state and federal tax incentives expire), and then grow at 10 percent annual rate to 2020. The results can be interpreted to reflect the maximum benefits the state will likely attain under a continued high solar installation growth scenario. This growth is not unbounded since it is assumes to slow dramatically during

2017-2020 (i.e., around 10 percent per year relative to pre-2017 rates of around 100 percent per year).

Total power benefits associated with the Forecast Scenario 2 solar installation forecast is $370.1 million in NPV terms. Total solar benefits, including the solar installation and O&M benefits, total to $940.7 million in NPV terms. Total Solar NEM benefits, from the Forecast Scenario 2 solar installation forecast are $1.3 billion.

7.3. Summary Estimates: Total Solar NEM Costs

Summary results estimating the individual and total costs associated with historic solar NEM installations are provided in Table 19. Detailed results are provided in Appendix A-3.

Table 19: Summary Results, Solar NEM Costs (Historic Installations)

Economic Costs	Economic Costs Direct (2008-2043)	Indirect (2008-2043)	Induced (2008-2043)	Total (2008-2043)
	-------------------------------- (million $ NPV)	--------------------------------		
Unrecovered Interconnection Costs	$ 1.54	$ -	$ -	$ 1.54
NEM Administrative Costs	6.46	-	-	6.46
Rate Impacts: NEM Payments	6.57	1.06	4.42	12.04
Rate Impacts: Lost Revenues	33.60	0.44	32.05	66.09
Total Ratemaking Costs	**$ 48.17**	**$ 1.50**	**$ 36.47**	**$ 86.14**
State Tax Incentive Costs	$ 99.96	$ 60.59	$ 34.94	$ 195.50
Total Legislative Costs	**$ 99.96**	**$ 60.59**	**$ 34.94**	**$ 195.50**
Total Solar NEM Costs	**$ 148.14**	**$ 62.09**	**$ 71.41**	**$ 281.63**

Collectively, unrecovered NEM interconnection costs, NEM administrative costs and rate impacts comprise what can be referred to as total ratemaking costs since each of these cost components have direct, negative implications for LPSC ratepayers through increases in their respective regulated utilities' cost of service. Unrecovered interconnection costs for historic solar NEM installations (2008-2014) have the smallest cost impacts of any solar NEM cost category ($1.9 million). Total NEM administrative costs are anticipated to impose as much as $6.5 million on Louisiana jurisdictional ratepayers in NPV terms. Rate impacts, collectively, are anticipated to impose considerable costs onto LPSC ratepayers and the overall Louisiana economy. Collectively, total rate impacts are anticipated to impose as much as $40.2 million in direct costs, $1.5 in indirect costs, and $36.5 in induced negative impacts on the Louisiana economy. In total, the negative rate impacts associated with the solar NEM program are anticipated to impose as much as $78.1 million in negative economic impacts on the Louisiana economy and LPSC ratepayers.

State tax incentives and other state tax revenue losses represent an additional economic cost of the solar NEM program since these tax incentives are the primary mechanism by which solar NEM installations are incented in Louisiana. The Louisiana solar tax incentive program is anticipated to have a direct cost of $100 million in incenting LPSC-jurisdictional solar NEM installations. This is not the total economic cost of the Louisiana solar program, but just the cost of the tax program attributable to stimulating LPSC-jurisdictional solar NEM installations. The indirect and induced economic impacts (costs) associated with the solar tax incentives for LPSC solar NEM installations are estimated to total, collectively, $95.5 million. The total negative economic impacts (costs) attributable to the Louisiana solar tax incentive program, and attributable to LPSC-jurisdictional solar NEM installations, is $195.5 million.

Economic costs associated with the LPSC solar NEM program is anticipated to have a total direct economic impact of $148.1 million, $62.1 million in indirect impacts, and $71.4 million in induced impacts. Total economic impacts associated with the solar NEM program is $281.6 million in NPV terms.

Summary results estimating the individual and total costs associated with historic and projected solar NEM installation, under the Forecast Scenario 1 installation assumptions projection (all utility installations grow to the LPSC-allowed cap) has been provided in Table 20. Detailed results are provided in Appendix A-4.

Table 20: Summary Results, Solar NEM Costs (Historic and Projected Installations, Forecast Scenario 1)

Economic Costs	Economic Costs: Direct (2008-2049)	Indirect (2008-2049)	Induced (2008-2049)	Total (2008-2049)
	------------------------------- (million $ NPV)		-------------------------------	
Unrecovered Interconnection Costs	$ 2.75	$ -	$ -	$ 2.75
NEM Administrative Costs	11.90	-	-	11.90
Rate Impacts: NEM Payments	9.00	1.32	6.31	16.62
Rate Impacts: Lost Revenues	55.86	1.12	52.53	109.50
Total Ratemaking Costs	**$ 79.50**	**$ 2.44**	**$ 58.84**	**$ 140.78**
State Tax Incentive Costs	$ 142.90	$ 86.62	$ 49.95	$ 279.48
Total Legislative Costs	**$ 142.90**	**$ 86.62**	**$ 49.95**	**$ 279.48**
Total Solar NEM Costs	**$ 222.40**	**$ 89.06**	**$ 108.79**	**$ 420.25**

The results from the economic cost analysis of historic and projected solar NEM installations, under the Forecast Scenario 1 solar installation assumption, are relatively similar to the ones discussed earlier for the historic solar NEM projects to date. The Forecast Scenario 1 results show the total costs that the state can expect to incur from the LPSC-jurisdiction NEM program if the program continues to grow at its current rate, but is capped at the currently-defined LPSC limit. These results can be interpreted to reflect the maximum costs, or potential liabilities, the state will likely incur under a status quo scenario.

Total ratemaking costs associated with the Forecast Scenario 1 solar installation forecast is $140.8 million in NPV terms. Total government incentive program costs total to $279.5 million in NPV terms. Total solar NEM costs, from the Forecast Scenario 1 solar installation forecast, is $420.3 million.

Summary results estimating the individual and total costs associated with historic and projected solar NEM installation, under the Forecast Scenario 2 solar installation forecast (all utility installations grow unbounded at their recent rates to 2016, then 10 percent to 2020) has been provided in Table 21. Detailed results are provided in Appendix A-5.

Table 21: Summary Results, Solar NEM Costs (Historic and Projected Installations, Forecast Scenario 2)

	Economic Costs			
	Direct (2008-2049)	Indirect (2008-2049)	Induced (2008-2049)	Total (2008-2049)
Economic Costs	---------- (million $ NPV) ----------			
Unrecovered Interconnection Costs	$ 14.77	$ -	$ -	$ 14.77
NEM Administrative Costs	63.17	-	-	63.17
Rate Impacts: NEM Payments	50.87	9.05	32.65	92.56
Rate Impacts: Lost Revenues	320.85	6.01	302.54	629.40
Total Ratemaking Costs	**$ 449.65**	**$ 15.06**	**$ 335.19**	**$ 799.90**
State Tax Incentive Costs	$ 512.35	$ 310.68	$ 176.11	$ 999.14
Total Legislative Costs	**$ 512.35**	**$ 310.68**	**$ 176.11**	**$ 999.14**
Total Solar NEM Costs	**$ 962.00**	**$ 325.74**	**$ 511.30**	**$ 1,799.04**

The Forecast Scenario 2 results show the total costs that LPSC ratepayers can expect to incur if solar installations continue to grow at their 2012-2013 growth, uncapped to 2016 (the year state and federal tax incentives expire), and then grow at 10 percent annual rate to 2020. These results can be interpreted to reflect the maximum liability the state will likely attain under a continued high solar installation growth scenario (and removal of the current LPSC NEM installation caps). This growth is assumed to slow dramatically during 2017-2020 (i.e., around 10 percent per year relative to pre-2017 rates of around 100 percent per year) given the removal of federal and then state solar tax incentives.

Total ratemaking costs associated with the Forecast Scenario 2 solar installation forecast is $799.9 million in NPV terms. Total government incentive costs total to $999.1 million in NPV terms. Total Solar NEM costs, from the Forecast Scenario 2 solar installation forecast, is $1.8 billion.

7.4. Summary Estimates: Total Solar NEM Net Benefits

Summary results for total solar NEM net benefits, with historic solar NEM installations, are provided in Table 22. Detailed results are provided in Appendix A-3.

Table 22: Summary Results, Total Solar NEM Net Benefits (Historic Installations)

	Economic Impacts			
	Direct (2008-2043)	Indirect (2008-2043)	Induced (2008-2043)	Total (2008-2043)
Economic Benefits & Costs	(million $ NPV)			
Total Avoided Power Costs	$ 42.21	$ -	$ -	$ 42.21
Total Solar Benefits	55.12	63.39	31.91	150.42
Total Solar NEM Benefits	**$ 97.33**	**$ 63.39**	**$ 31.91**	**$ 192.62**
Total Ratemaking Costs	$ 48.17	$ 1.50	$ 36.47	$ 86.14
Total Legislative Costs	99.96	60.59	34.94	195.50
Total Solar NEM Costs	**$ 148.14**	**$ 62.09**	**$ 71.41**	**$ 281.63**
Total Solar Net Benefits	**$ (50.81)**	**$ 1.30**	**$ (39.50)**	**$ (89.01)**

Table 22 summarizes the CBA findings for current installations. The estimated major benefit categories (avoided power costs, solar development benefits) associated with current solar NEM installations is provided and compared to their corresponding major cost components (ratemaking costs, legislative incentive costs). The difference between benefits and costs represent the net benefits. If the net benefits are positive, then the solar NEM program can be said to have benefits in excess of their costs and are beneficial, overall, to LPSC ratepayers. If net benefits are negative, then the solar NEM program is imposing net costs upon LPSC ratepayers.

Total avoided cost benefits (generation, transmission, distribution) associated with the current level of NEM installations are estimated to be $42.2 million in NPV terms. Total solar benefits (construction, service activities) are estimated to be $150.4 million in NPV terms. Total solar NEM program benefits are the sum of these two benefit categories and are estimated to be $192.6 million in NPV terms.

Total ratemaking costs that arise from the current and more recent level of NEM installations are estimated to be $86.1 million in NPV terms. Total legislative incentive costs (tax incentive and other lost tax revenues) are estimated to be $195.5 million. Total solar NEM program costs are estimated to be $281.6 million in NPV terms.

The current solar NEM program, estimated from the perspective of only recently-installed solar NEM installations, is estimated to have negative net benefits of $89 million to LPSC ratepayers. This signifies that program costs are greater than program benefits. The benefit cost ratio for the program is 0.68 where any value less than 1.0 means that program costs are greater than program benefits, and any value equal to or greater than 1.0 means that the program has benefits greater than costs.

Summary results total solar NEM net benefits, with historic and projected solar NEM installations, under the Forecast Scenario 1 projection assumption, are provided in Table 23. Detailed results are provided in Appendix A-4.

Table 23: Summary Results, Total Solar NEM Net Benefits (Historic and Projected Installations, Forecast Scenario 1)

Economic Benefits & Costs	Economic Impacts: Direct (2008-2049)	Indirect (2008-2049)	Induced (2008-2049)	Total (2008-2049)
	---- (million $ NPV) ----			
Total Avoided Power Costs	$ 73.33	$ -	$ -	$ 73.33
Total Solar Benefits	81.12	93.29	46.97	221.38
Total Solar NEM Benefits	**$ 154.45**	**$ 93.29**	**$ 46.97**	**$ 294.71**
Total Ratemaking Costs	$ 79.50	$ 2.44	$ 58.84	$ 140.78
Total Legislative Costs	142.90	86.62	49.95	279.48
Total Solar NEM Costs	**$ 222.40**	**$ 89.06**	**$ 108.79**	**$ 420.25**
Total Solar Net Benefits	**$ (67.95)**	**$ 4.23**	**$ (61.82)**	**$ (125.54)**

Table 23 summarizes the CBA findings for current and projected installations under the Forecast Scenario 1 installation forecast assumption. Total avoided cost benefits (generation, transmission, distribution) associated with the current and projected (Forecast Scenario 1) level of NEM installations are estimated to be $73.3 million in NPV terms. Total solar benefits (construction, service activities) are estimated to be $221.4 million in NPV terms. Total solar NEM program benefits are the sum of these two major benefit categories and are estimated to be $294.7 million in NPV terms.

Total ratemaking costs that arise from the current and projected (Forecast Scenario 1) level of NEM installations are estimated to be $140.8 million in NPV terms. Total legislative incentive costs (tax incentives and other lost tax revenues) are estimated to be $279.5 million. Total solar NEM program costs are estimated to be $420.3 million in NPV terms.

The current solar NEM program, estimated from current and projected (Forecast Scenario 1) solar NEM installations is estimated to have negative net benefits of $125.5

million. This indicates that program costs are greater than program benefits. The benefit cost ratio for the program is 0.70 where any value less than 1.0 means that program costs are greater than program benefits, and any value equal to or greater than 1.0 means that the program has benefits greater than costs.

Summary results total solar NEM net benefits, with historic and projected solar NEM installations, under the Forecast Scenario 2 projection assumption, are provided in Table 24. Detailed results are provided in Appendix A-5.

Table 24: Summary Results, Total Solar NEM Net Benefits (Historic and Projected Installations, Forecast Scenario 2)

	Economic Impacts							
		Direct (2008-2049)		Indirect (2008-2049)		Induced (2008-2049)		Total (2008-2049)
Economic Benefits & Costs	---------------------------------- (million $ NPV) ----------------------------------							
Total Avoided Power Costs	$	370.10	$	-	$	-	$	370.10
Total Solar Benefits		344.70		396.40		199.58		940.68
Total Solar NEM Benefits	**$**	**714.80**	**$**	**396.40**	**$**	**199.58**	**$**	**1,310.78**
Total Ratemaking Costs	$	449.65	$	15.06	$	335.19	$	799.90
Total Legislative Costs		512.35		310.68		176.11		999.14
Total Solar NEM Costs	**$**	**962.00**	**$**	**325.74**	**$**	**511.30**	**$**	**1,799.04**
Total Solar Net Benefits	**$**	**(247.20)**	**$**	**70.66**	**$**	**(311.72)**	**$**	**(488.26)**

Table 24 summarizes the CBA findings for current and projected installations under the Forecast Scenario 2 installation forecast assumption. Total avoided cost benefits (generation, transmission, distribution) associated with the current and projected level of NEM installations are estimated to be $370.4 million in NPV terms. Total solar benefits (construction, service activities) are estimated to be $940.7 million in NPV terms. Total solar NEM program benefits are the sum of these two benefit categories and are estimated to be $1.3 billion in NPV terms.

Total ratemaking costs that arise from the current and projected (Forecast Scenario 2) level of solar NEM installations are estimated to be $799.9 million in NPV terms. Total legislative incentive costs, accounting for the Louisiana state incentive program impacts and other state revenue losses are estimated to be $999.1 million. Total solar NEM program costs are estimated to be $1.8 billion in NPV terms.

The current solar NEM program, estimated from current and projected (Forecast Scenario 2) solar NEM installations is estimated to have negative net benefits of $488.3 million. This signifies that program costs are greater than program benefits. The benefit cost ratio for the program is 0.73 where any value less than 1.0 means that program costs are greater than program benefits, and any value equal to or greater than 1.0 means that the program has benefits greater than costs.

7.5. Sensitivity Analysis

7.5.1. Sensitivity Overview

The earlier-discussed CBA results were subjected to three different sensitivities in order to ascertain how the baseline results (historic installations only) may change given a change in the underlying model assumptions. Three critical underlying assumptions were changed in the sensitivity analysis: (1) a change in natural gas prices; (2) a change in future capacity prices; and (3) a change in environmental costs (carbon regulation).

The first sensitivity analysis increases the underlying $3.50 per MMBtu natural gas price to $5.00 per MMBtu. Higher natural gas prices, holding other factors constant, should increase avoided generation cost benefits without changing underlying

NEM program costs. This increase in natural gas price should improve the cost-benefit relationships of the current LPSC NEM policies.

The second sensitivity analysis increases the anticipated capacity price for avoided generation. Capacity prices under this sensitivity are assumed to ramp up quickly from a starting point of 18 percent of the full CONE value to 50 percent of the full CONE value by 2020. A higher capacity price outlook, holding other factors constant, should increase the avoided cost benefits of NEM without dramatically increasing any other NEM program cost components.

The third sensitivity analysis examines the impact of potential carbon regulation in solar NEM costs and benefits. Carbon prices of $40 per ton were incorporated into the model in order to assess the impact that future environmental regulation could have on NEM benefits. The use of carbon prices, or any cost that increases environmental compliance costs for traditional fossil-fuel generation, should increase the avoided generation benefit associated with NEM policies (holding other factors constant).

7.5.2. High Natural Gas Price Sensitivity

Summary results estimating the individual and total benefits associated with historic solar NEM installations under the first sensitivity (high natural gas prices) are provided in Table 25. Detailed results are provided in Appendix A-6. The results show that NEM-induced avoided cost benefits increase as a result of the changes in underlying natural gas prices. Total avoided generation (energy) cost benefits increase in this sensitivity by 25 percent (in total NPV terms) relative to the original baseline (historic installation) estimates.

Table 25: Summary Results, Solar NEM Benefits (Historic Installations), Sensitivity Scenario 1

Economic Benefits		Economic Benefits Direct (2008-2043)		Indirect (2008-2043)		Induced (2008-2043)		Total (2008-2043)
		(million $ NPV)						
Avoided Generation Energy	$	44.39	$	-	$	-	$	44.39
Avoided Generation Capacity		8.20		-		-		8.20
Avoided T&D		0.12		-		-		0.12
Total Avoided Power Costs	**$**	**52.71**	**$**	**-**	**$**	**-**	**$**	**52.71**
Total Solar Installation Benefits	$	49.26	$	57.52	$	29.33	$	136.12
Total Solar O&M Benefits		5.86		5.87		2.58		14.30
Total Solar Benefits	**$**	**55.12**	**$**	**63.39**	**$**	**31.91**	**$**	**150.42**
Total Solar NEM Benefits	**$**	**107.83**	**$**	**63.39**	**$**	**31.91**	**$**	**203.13**

Summary results estimating the individual and total costs associated with historic solar NEM installations for the first sensitivity are provided in Table 26. Detailed results are provided in Appendix A-6. The results show no change in overall ratemaking or state government incentive costs relative to the baseline analysis given the fact that natural gas price changes do not meaningfully impact any of the direct NEM program costs which are mostly capital-oriented in nature.

Table 26: Summary Results, Solar NEM Costs (Historic Installations), Sensitivity Scenario 1

Economic Costs		Economic Costs Direct (2008-2043)		Indirect (2008-2043)		Induced (2008-2043)		Total (2008-2043)
		(million $ NPV)						
Unrecovered Interconnection Costs	$	1.54	$	-	$	-	$	1.54
NEM Administrative Costs		6.46		-		-		6.46
Rate Impacts: NEM Payments		6.57		1.06		4.42		12.04
Rate Impacts: Lost Revenues		33.60		0.44		32.05		66.09
Total Ratemaking Costs	**$**	**48.17**	**$**	**1.50**	**$**	**36.47**	**$**	**86.14**
State Tax Incentive Costs	$	99.96	$	60.59	$	34.94	$	195.50
Total Legislative Costs	**$**	**99.96**	**$**	**60.59**	**$**	**34.94**	**$**	**195.50**
Total Solar NEM Costs	**$**	**148.14**	**$**	**62.09**	**$**	**71.41**	**$**	**281.63**

Summary results estimating the individual and total costs associated with historic solar NEM installations under the first sensitivity are provided in Table 27. Detailed results are provided in Appendix A-6. The results show that even with the increase in natural gas prices, the LPSC's current NEM policies result in costs greater than benefits (i.e., negative net benefits). The benefit-cost ratio for the NEM program under the first sensitivity is 0.72. The results of this analysis indicate that the current NEM program is not cost-effective even when natural gas prices are increased by almost 43 percent in 2020.

Table 27: Summary Results, Total Solar NEM Net Benefits (Historic Installations), Sensitivity Scenario 1

Economic Benefits & Costs	Economic Impacts: Direct (2008-2043)	Indirect (2008-2043)	Induced (2008-2043)	Total (2008-2043)
	(million $ NPV)			
Total Avoided Power Costs	$ 52.71	$ -	$ -	$ 52.71
Total Solar Benefits	55.12	63.39	31.91	150.42
Total Solar NEM Benefits	**$ 107.83**	**$ 63.39**	**$ 31.91**	**$ 203.13**
Total Ratemaking Costs	$ 48.17	$ 1.50	$ 36.47	$ 86.14
Total Legislative Costs	99.96	60.59	34.94	195.50
Total Solar NEM Costs	**$ 148.14**	**$ 62.09**	**$ 71.41**	**$ 281.63**
Total Solar Net Benefits	**$ (40.30)**	**$ 1.30**	**$ (39.50)**	**$ (78.50)**

7.5.3. Increased Capacity Price Sensitivity:

Summary results estimating the individual and total benefits associated with historic solar NEM installations under the second sensitivity are provided in Table 28. Detailed results are provided in Appendix A-7. The results show that the avoided cost benefits increase as a result of the changes in underlying capacity prices. Total avoided generation (capacity) cost benefits increase in this sensitivity by 326 percent (in total NPV terms) relative to the original baseline (historic installation) estimates.

Table 28: Summary Results, Solar NEM Benefits (Historic Installations), Sensitivity Scenario 2

Economic Benefits	Economic Benefits: Direct (2008-2043)	Indirect (2008-2043)	Induced (2008-2043)	Total (2008-2043)
	---------- (million $ NPV) ----------			
Avoided Generation Energy	$ 33.89	$ -	$ -	$ 33.89
Avoided Generation Capacity	27.53	-	-	27.53
Avoided T&D	0.12	-	-	0.12
Total Avoided Power Costs	**$ 61.53**	**$ -**	**$ -**	**$ 61.53**
Total Solar Installation Benefits	$ 49.26	$ 57.52	$ 29.33	$ 136.12
Total Solar O&M Benefits	5.86	5.87	2.58	14.30
Total Solar Benefits	**$ 55.12**	**$ 63.39**	**$ 31.91**	**$ 150.42**
Total Solar NEM Benefits	**$ 116.65**	**$ 63.39**	**$ 31.91**	**$ 211.95**

Summary results estimating the individual and total costs associated with historic solar NEM installations for the second sensitivity are provided in Table 29. Detailed results are provided in Appendix A-7. The results show some changes in NEM lost revenues since increased capacity costs are assumed to increase not only NEM benefits, but the rates charged to non-NEM ratepayers.

Table 29: Summary Results, Solar NEM Costs (Historic Installations), Sensitivity Scenario 2

Economic Costs		Economic Costs Direct (2008-2043)		Indirect (2008-2043)		Induced (2008-2043)		Total (2008-2043)
		------------------		(million $ NPV)		------------------		
Unrecovered Interconnection Costs	$	1.54	$	-	$	-	$	1.54
NEM Administrative Costs		6.46		-		-		6.46
Rate Impacts: NEM Payments		16.93		2.34		12.14		31.41
Rate Impacts: Lost Revenues		74.97		0.94		71.57		147.48
Total Ratemaking Costs	**$**	**99.91**	**$**	**3.29**	**$**	**83.70**	**$**	**186.90**
State Tax Incentive Costs	$	99.96	$	60.59	$	34.94	$	195.50
Total Legislative Costs	**$**	**99.96**	**$**	**60.59**	**$**	**34.94**	**$**	**195.50**
Total Solar NEM Costs	**$**	**199.87**	**$**	**63.88**	**$**	**118.64**	**$**	**382.39**

Summary results estimating the individual and total costs associated with historic solar NEM installations under the second sensitivity are provided in Table 30. Detailed results are provided in Appendix A-7. The results show that even with the increase in capacity prices, the LPSC's current NEM policies result in costs greater than benefits (i.e., negative net benefits). The benefit-cost ratio for the NEM program under the second sensitivity is 0.55 where any value less than 1.0 means that program costs are greater than program benefits, and vice versa. The results of this analysis indicate that the current NEM program is not cost-effective even when capacity prices are increased.

Table 30: Summary Results, Total Solar NEM Net Benefits (Historic Installations), Sensitivity Scenario 2

Economic Benefits & Costs		Direct (2008-2043)		Indirect (2008-2043)		Induced (2008-2043)		Total (2008-2043)
				Economic Impacts				
		--- (million $ NPV) ---						
Total Avoided Power Costs	$	61.53	$	-	$	-	$	61.53
Total Solar Benefits		55.12		63.39		31.91		150.42
Total Solar NEM Benefits	**$**	**116.65**	**$**	**63.39**	**$**	**31.91**	**$**	**211.95**
Total Ratemaking Costs	$	99.91	$	3.29	$	83.70	$	186.90
Total Legislative Costs		99.96		60.59		34.94		195.50
Total Solar NEM Costs	**$**	**199.87**	**$**	**63.88**	**$**	**118.64**	**$**	**382.39**
Total Solar Net Benefits	**$**	**(83.22)**	**$**	**(0.49)**	**$**	**(86.73)**	**$**	**(170.44)**

7.5.4. Carbon Regulation:

Summary results estimating the benefits associated with historic solar NEM installations under the third sensitivity are provided in Table 31. Detailed results are provided in Appendix A-8. The results show that the avoided cost benefits increase as a result of the changes in environmental regulation. Total avoided generation cost benefits increase in this sensitivity by 39 percent (in total NPV terms) relative to the original baseline (historic installation) estimates.

Table 31: Summary Results, Solar NEM Benefits (Historic Installations), Sensitivity Scenario 3

Economic Benefits	Economic Benefits: Direct (2008-2043)	Indirect (2008-2043)	Induced (2008-2043)	Total (2008-2043)
	---------- (million $ NPV) ----------			
Avoided Generation Energy	$ 33.89	$ -	$ -	$ 33.89
Avoided Generation Capacity	8.20	-	-	8.20
Avoided T&D	0.12	-	-	0.12
Avoided Environmental Cost	16.31	-	-	16.31
Total Avoided Power Costs	**$ 58.51**	**$ -**	**$ -**	**$ 58.51**
Total Solar Installation Benefits	$ 49.26	$ 57.52	$ 29.33	$ 136.12
Total Solar O&M Benefits	5.86	5.87	2.58	14.30
Total Solar Benefits	**$ 55.12**	**$ 63.39**	**$ 31.91**	**$ 150.42**
Total Solar NEM Benefits	**$ 113.63**	**$ 63.39**	**$ 31.91**	**$ 208.93**

Summary results estimating the total costs associated with historic solar NEM installations for the third sensitivity are provided in Table 32. Detailed results are provided in Appendix A-8. The results show no changes in overall NEM program costs from carbon pricing since this carbon pricing impact is conservatively assumed to not impact utility capital costs. Carbon costs are assumed to be covered through the use of credits, which like fuel, is passed along to ratepayers on a dollar-for-dollar basis through the LPSC's environmental cost recovery clause.

Table 32: Summary Results, Solar NEM Costs (Historic Installations), Sensitivity Scenario 3

Economic Costs	Economic Costs: Direct (2008-2043)	Indirect (2008-2043)	Induced (2008-2043)	Total (2008-2043)
	---- (million $ NPV) ----			
Unrecovered Interconnection Costs	$ 1.54	$ -	$ -	$ 1.54
NEM Administrative Costs	6.46	-	-	6.46
Rate Impacts: NEM Payments	6.57	1.06	4.42	12.04
Rate Impacts: Lost Revenues	33.60	0.44	32.05	66.09
Total Ratemaking Costs	**$ 48.17**	**$ 1.50**	**$ 36.47**	**$ 86.14**
State Tax Incentive Costs	$ 99.96	$ 60.59	$ 34.94	$ 195.50
Total Legislative Costs	**$ 99.96**	**$ 60.59**	**$ 34.94**	**$ 195.50**
Total Solar NEM Costs	**$ 148.14**	**$ 62.09**	**$ 71.41**	**$ 281.63**

Summary results estimating the costs associated with historic solar NEM installations under the third sensitivity are provided in Table 33. Detailed results are provided in Appendix A in Schedule A-8. The results show that even with the inclusion of new environmental costs, the LPSC's current NEM policies result in costs greater than benefits (i.e., negative net benefits). The benefit-cost ratio for the NEM program under the third sensitivity is 0.74 again indicating that the current NEM program is not cost-effective even with the addition of avoided environmental costs.

Table 33: Summary Results, Total Solar NEM Net Benefits (Historic Installations), Sensitivity Scenario 3

Economic Benefits & Costs		Direct (2008-2043)		Indirect (2008-2043)		Induced (2008-2043)		Total (2008-2043)
		Economic Impacts						
		------------------------------- (million $ NPV) -------------------------------						
Total Avoided Power Costs	$	58.51	$	-	$	-	$	58.51
Total Solar Benefits		55.12		63.39		31.91		150.42
Total Solar NEM Benefits	**$**	**113.63**	**$**	**63.39**	**$**	**31.91**	**$**	**208.93**
Total Ratemaking Costs	$	48.17	$	1.50	$	36.47	$	86.14
Total Legislative Costs		99.96		60.59		34.94		195.50
Total Solar NEM Costs	**$**	**148.14**	**$**	**62.09**	**$**	**71.41**	**$**	**281.63**
Total Solar Net Benefits	**$**	**(34.50)**	**$**	**1.30**	**$**	**(39.50)**	**$**	**(72.70)**

8. Cost of Service Analysis

8.1. Overview

The CBA discussed in the prior sections of this report examines the forward-looking costs and benefits associated with solar NEM generation for LPSC ratepayers. The analysis considers a wide range of potential "avoidable" future costs (as benefits) versus a range of likely direct and indirect costs. The analysis does not offer, however, significant insights regarding the near-term impacts that solar NEM installations have on a utility's rates as reflected in that utility's cost of service ("COS") or what is often referred to, on an annual basis, as its "revenue requirement." The costs included in a utility's COS reflect, or at least approximate, the current costs of providing service that are what many rate analysts refer to as a utility's "embedded costs." These embedded costs are simply the sum of a utility's annual investments and expenses, which ultimately serve as the basis for setting utility rates.

The purpose of this section of the report is to examine the impact that solar NEM installations have on a utility's COS. This differs from the CBA analysis, as noted earlier, which is more flexible (all costs are variable) and forward looking. This analysis will attempt to estimate the degree to which solar NEM installations are contributing to a utility's COS and whether or not any cross subsidies arise due to the presence of NEM installations from an embedded cost perspective.

8.2. Ratemaking and COS Issues with NEM

Traditional utility COS regulation sets rates that generally based upon a utility's average costs. This differs from the pricing outcome observed in competitive markets where prices are set by marginal costs. As seen in Figure 42, average cost pricing is necessary for the electric utility industry given its "natural monopoly" cost characteristics. A natural monopoly arises when one firm dominates an industry given its scale, usually large up-front capacity investments, and declining average costs. Thus, pricing at marginal, rather than average costs will deprive a utility of its ability to earn a return on and of its prudently-incurred investments.

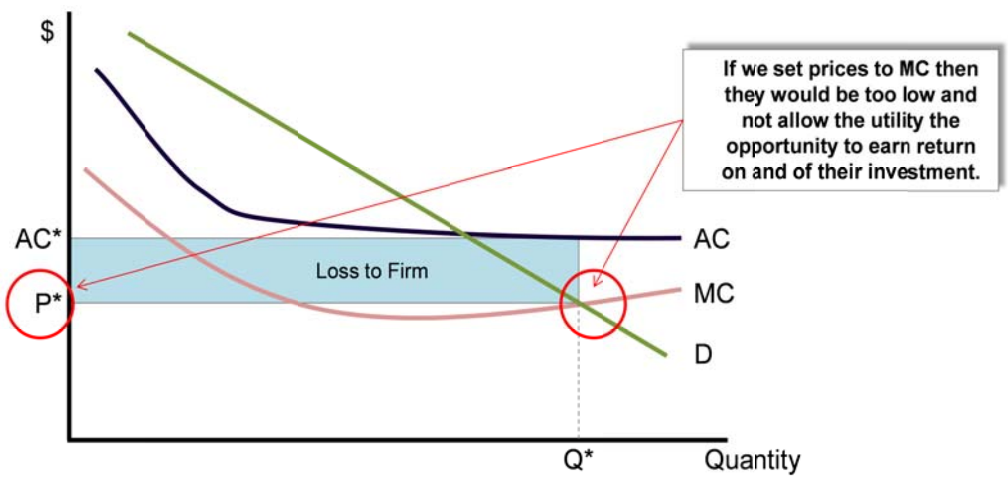

Figure 42: Natural Monopoly Pricing Challenge

The method by which large capital costs are recovered, and how they are allocated to customer classes, is often a contentious part of the ratemaking process. However, it is an important process, since the failure to set rates that reflect these large capital costs can result in a utility recovering revenues that fall short of its full COS, or one set of customers subsidizing another for the recovery of these costs.

Utility rates set on an average cost basis are simply costs divided by some unit of measurement. The ratemaking process uses a number of different units of measurement to standardize costs that include those set on a per customer basis, a volumetric basis (kWh or energy basis), and a demand basis (kW). The regulatory process often relies heavily on a tool, referred to as a "class cost of service study" ("COSS") that functionalizes costs across different utility operations (i.e., generation, transmission, distribution), then classifies those costs (i.e., customer, energy, demand-related), and then allocates those costs to various customer classes (i.e., residential, commercial, and industrial). The classification process is one that ultimately provides insights into how costs should be standardized and charged to customers.

For instance, large industrial customers often see a set of costs that are assessed on a per customer (facility) basis, per unit of demand basis (kW) and on an energy basis. Many utility costs are incurred to meet system peaks or system demand at times which loads are peaking. Thus, it is not uncommon to assign a number of those costs to customers based upon the demand that they impose on the system. Large customers typically have more sophisticated meters, and are billed on both a demand and energy basis. Smaller customer classes, particularly residential classes, are not billed on a demand basis, thus the charges associated with the demands they pace on the system are typically assessed on a volumetric, or per kWh (energy) basis. Thus, if electricity sales to residential customers are down for any period of time, many of these relatively fixed demand-related costs will go unrecovered potentially requiring a utility to file a "rate case" seeking to increase its rates to account for these shortfalls.

Utilities typically design rates to recover revenues proportional to the cost of service for each customer class. So aggregate utility costs (the revenue requirement or COS discussed above) are often allocated to customer classes on the basis of a set of complicated allocation factors included in the CCOSS designed to account for the differences in providing service to each customer class. Once a customer-class specific cost responsibility is determined, these class specific costs are split and "standardized" on per customer and volumetric bases.

This standardization process essentially determines an average cost since that classes' total revenue responsibility is divided by historic sales for that customer class (often called billing determinants) to get an average rate. Some customers within a given customer class may have much higher than average usage (or billing determinants) whereas as smaller use customers will have smaller than average usage. The rate, however, is set on a class average (or for the average customer). Rates are generally not differentiated by type of customer within a class based on their usage (with the exception of some block rates). So customers with larger-than-average usage will be making a more significant total revenue contribution (on a per customer basis) to the overall class than those customers with smaller-than-average usage.

One of the conclusions reached in other NEM studies, and corroborated here, is that solar NEM customers tend to have consistently larger-than-average usage relative to the class average.[165] Figure 43 underscores this finding for the LPSC-jurisdictional IOUs. For instance, the average annual use for typical customer for each of the IOUs is

[165] The Edison Foundation. 2014. Net Energy Metering: Subsidy Issues and Regulatory Solutions, p. 4; Solar Electric Power Association. Ratemaking, Solar Value and Solar Net Energy Metering – A Primer, pp. 18-19; and Energy and Environmental Economics, Inc. 2013. Introduction to the California Net Energy Metering Ratepayers Impacts Evaluation, Section 5.2.

around 15 MWh per year.[166] NEM customers, however, are estimated to have annual usage levels that are about 55 percent higher than the average customer for all four IOUs.

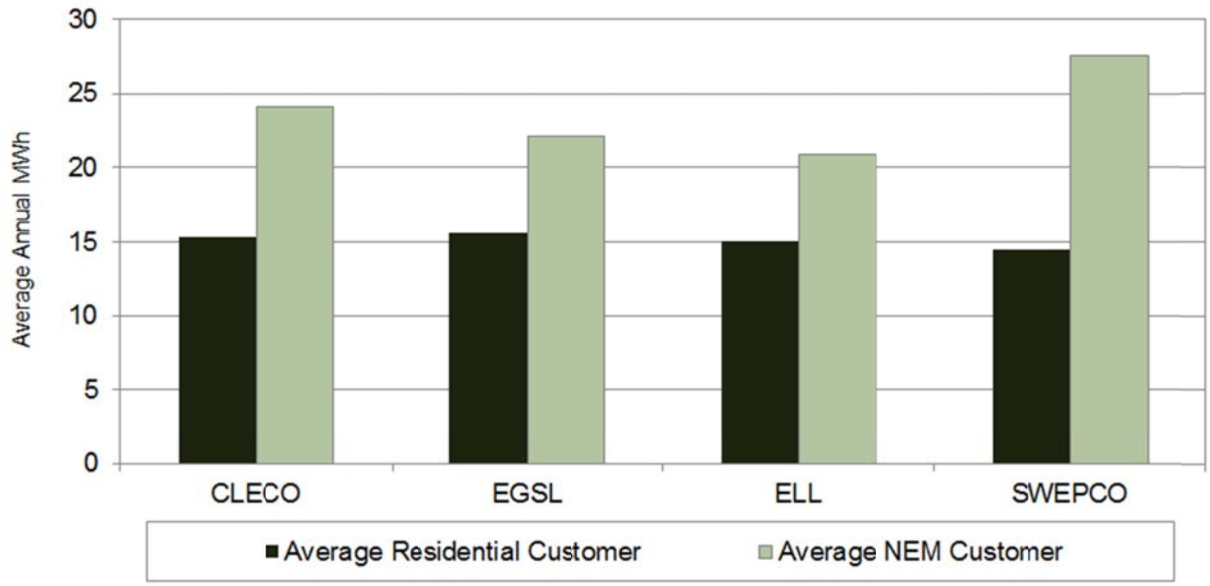

Figure 43: Average Use Comparison: Typical Residential Customer to Estimated Solar NEM Customer

Thus, the installation of an on-site generator by these large average use NEM customers will likely shift a considerable amount of load (and revenue) away from the utility (on per customer basis). As noted above, these revenues short falls will need to be made up somewhere, and that is usually by the remaining customers in the class not installing solar NEM. The COS analysis discussed below will examine the degree to which this solar NEM-induced revenue short fall arises and its magnitude.

[166] This average use per customer is based on data filed in the FERC Form 1.

8.3. Utility Cost of Service Estimation

The development of a utility revenue requirement, or COS, is often a complicated and involved process. In addition, utilities can often utilize differing approaches, particularly in determining the nature of the costs to include and the adjustments to those costs (upwards and downwards) necessary to arrive at a final revenue requirement estimate. Additional adjustments are often necessary to account for multi-state operations (like SWEPCO). However, there are a number of common steps utilized in estimating a utility's COS despite these differences. These common steps can be employed here to develop a generalized residential COS for each IOU and compare this to the revenue recovery amounts associated with the implementation of solar NEM.

A generalized revenue requirement was estimated for each IOU using information filed in their annual reports before the FERC. These annual reports, often referred to as FERC Form 1s, include annual revenue, expense and investment information in addition to sales and peak demand information. The three most recent years of annual reports for each utility were utilized in order to smooth cyclical annual variations.

Rate base estimates were developed from various plant-in-service accounts. An achieved return on rate base was estimated annually and used as the cost of capital for each utility. Expense information was also compiled to complete the development of the overall revenue requirement.

A residential class-specific revenue requirement for each utility was then estimated utilizing an equally weighted customer/sales allocation factor. This residential revenue requirement was used as the COS to evaluate the ratemaking impacts of residential solar NEM installations based upon 2013 installation levels. Illustrative impacts, utilizing these estimated utility-specific "typical year" revenue requirements, along with the Scenario 1 and Scenario 2 forecast projections for solar NEM installations are also developed.

8.4. Estimating Solar NEM Customer COS Contributions

The CBA identified three potential solar NEM costs that are currently being recovered through rates and are not being paid for by solar NEM installations including: (1) uncollected/recovered interconnection costs; (2) solar NEM-related administrative costs; and (3) incentive NEM payments for grid-provided electricity. These additional unrecovered costs need to be included in a COS evaluation, along with any decreases in solar NEM-contributions to the COS, since they represent current costs (as well as projected costs) that are being imposed on LPSC-jurisdictional ratepayers.

Table 34 compares the difference in contributions to the utility COS between each jurisdictional IOU's typical residential customer; that of an NEM customer absent net metering; and that of an NEM customer with net metering. Three sets of estimates are provided that include: (1) the difference in solar NEM contributions to COS on a per installation basis; (2) the total difference in NEM contribution to COS (aggregated across all solar NEM installations); and (3) the percent contribution that solar NEM customers make to COS. Each of these three sets of analyses examine contribution before (or without) solar NEM and after (with) solar NEM installation. In other words, the "before" (or without) analysis examines the contribution a typical solar NEM customer would have made if it had not installed behind-the-meter solar, while the after (with) analysis examines the contribution after the installation of a solar NEM project. The table and analysis is restricted to IOUs only.

Table 34: Solar NEM Customer Contributions to IOU COS (active 2013 Installations Only)

	Annual Per NEM Customer Contributions to COS		Aggregate Annual NEM Contribution to COS		Percent of COS Recovery	
	without NEM	with NEM	without NEM	with NEM	without NEM	with NEM
	---------- ($) ----------		---------- ($) ----------		---------- (%) ----------	
CLECO	$ 777.59	$ (451.19)	$ 736,376	$ (427,276)	157.7%	66.5%
EGSL	$ 500.59	$ (557.92)	$ 230,269	$ (256,643)	141.8%	53.4%
ELL	$ 411.28	$ (504.31)	$ 929,906	$ (1,140,238)	139.2%	51.9%
SWEPCO	$ 946.83	$ 57.09	$ 608,813	$ 36,710	190.6%	105.5%
Total IOU			**$ 2,505,364**	**$ (1,787,445)**	**157.3%**	**69.3%**

The first two columns of Table 34 show that most solar NEM customers made considerably higher contributions to their respective utilities COS than a typical residential customer prior to solar NEM installation. For instance, prior to installing net metering, solar NEM customers are estimated to have contributed as much as $778 more on a per customer basis than Cleco's average residential customer. After installation, the solar NEM contribution drops to $451 less than an average residential customer in Cleco's service territory. Without NEM, the NEM customer would contribute almost 158 percent above its estimated per customer COS. With net metering however, the same customer contributes just 67 percent of its estimated per customer COS, Likewise, solar NEM customers are estimated to have contributed as much as $947 more on a per customer basis to SWEPCO's estimated residential COS prior to installation. After installation, the solar NEM contribution drops to just $57 more than an average residential customer.

The second two columns of Table 34 show the overall solar NEM customer COS contributions on a total utility basis. For instance, EGSL's solar NEM customers are estimated to have contributed as much as $230,269, in total, above their share of residential COS prior to installation. After installation, the total solar NEM COS contribution drops to $256,643 below EGSL's estimated residential COS. Likewise, solar NEM customers are estimated to have contributed as much as $0.92 million to ELL's estimated residential COS prior to installation. After installation, the total solar NEM COS contribution drops to $1.1 million below ELL's estimated COS.

The last two columns of Table 34 show the overall solar NEM customer COS contributions to each utility's COS on percentage terms basis. Solar NEM installations are estimated to have made as much as a 191 percent contribution to Swepco's COS prior to installation but a low of 52 percent to ELL's COS after solar NEM installation. On average, solar NEM installations are estimated to have made a pre-installation 157 percent contribution to the IOUs average COS; post installation, solar NEM installations are estimated to have made a 69 percent contribution on an average basis across all IOUs.

Rural cooperatives do not file FERC Form 1 information necessary to develop an annual COS estimates. However, as noted earlier, regulated rates are cost-based, and can be used as a proxy for the cooperatives' COS utilizing an assumption that these rates have not drifted considerably from actual costs. Thus, each rural cooperative's current residential tariffs were utilized to develop a tariff-based COS analysis. A typical customer bill was priced out for an average customer using sales information provided in EIA-Form 861. This typical residential customer bill was used as an estimate of the typical residential customer COS. Estimated rural cooperative residential solar NEM UPC was then taken from the gross consumption estimates discussed earlier in Section 5 to develop pre-NEM COS and post-NEM COS contributions. The results of this analysis, coupled with the estimated unrecovered interconnection costs, NEM administrative costs, and solar NEM payment costs are provided in Table 35.

The estimated COS results for the rural cooperatives are similar, at least in percentage terms, to those found for the IOUs. Pre-solar NEM COS contributions range as high as 171 percent of COS for Claiborne and as low as 131 percent of COS for Beauregard. Post-solar NEM COS contributions range from a high of 83 percent of COS for Panola-Harrison and as low as 43 percent of COS for Beauregard. The results indicate that solar NEM customers are being subsidized for all rural cooperatives.

Table 35: Solar NEM Contributions to Cooperative COS, Tariff Based Approach (active 2013 Installations Only)

	Annual Per NEM Customer Contributions to COS		Aggregate Annual NEM Contribution to COS		Percent of COS Recovery	
	without NEM	with NEM	without NEM	with NEM	without NEM	with NEM
	---------- ($) ----------		---------- ($) ----------		---------- (%) ----------	
Beauregard	$ 310.18	$ (569.36)	16,129	(29,607)	131.1%	42.9%
Claiborne	$ 608.39	$ (113.76)	26,161	(4,892)	171.4%	86.6%
Dixie	$ 774.93	$ (312.48)	132,513	(53,434)	165.2%	73.7%
Jefferson Davis	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Northeast Louisiana	$ 317.01	$ (602.20)	13,632	(25,894)	137.2%	29.3%
Panola-Harrison	$ 460.22	$ (157.23)	17,948	(6,132)	150.6%	82.7%
Pointe Coupee	$ 250.30	$ (237.27)	3,504	(3,322)	149.5%	53.0%
South Louisiana	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Southwest Louisiana	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Washington-St. Tammany	$ 431.39	$ (370.07)	119,064	(102,140)	144.8%	61.6%
Total Cooperative			**328,952**	**(225,420)**	**150.0%**	**61.4%**

Table 36 and Table 37 provide comparable COS results to those discussed above, utilizing 2020 installation levels under the two forecast scenarios identified earlier in this report. The per customer and percent contribution columns do not change, only the total dollar contributions given the significant anticipated increase in installations under the two scenarios. The tables show how large solar NEM COS subsidies will increase if (1) solar NEM installations grow to each utility's LPSC-defined threshold and (2) are left unbounded to 2020.

Table 36: Solar NEM Contributions to Utility COS (Scenario 1 Forecast)

	Annual Per NEM Customer Contributions to COS		Aggregate Annual NEM Contribution to COS		Percent of COS Recovery	
	without NEM	with NEM	without NEM	with NEM	without NEM	with NEM
	---------- ($) ----------		---------- ($) ----------		---------- (%) ----------	
CLECO	$ 777.59	$ (451.19)	$ 1,395,404	$ (809,671)	157.7%	66.5%
EGSL	$ 500.59	$ (557.92)	$ 1,453,475	$ (1,619,945)	141.8%	53.4%
ELL	$ 411.28	$ (504.31)	$ 2,104,294	$ (2,580,255)	139.2%	51.9%
SWEPCO	$ 946.83	$ 57.09	$ 1,085,183	$ 65,435	190.6%	105.5%
Total IOU			**$ 6,038,355**	**$ (4,944,436)**	**157.3%**	**69.3%**

Table 37: Solar NEM Contributions to Utility COS (Scenario 2 Forecast)

	Annual Per NEM Customer Contributions to COS		Aggregate Annual NEM Contribution to COS		Percent of COS Recovery	
	without NEM	with NEM	without NEM	with NEM	without NEM	with NEM
	---------- ($) ----------		---------- ($) ----------		---------- (%) ----------	
CLECO	$ 777.59	$ (451.19)	$ 7,497,192	$ (4,350,179)	157.7%	66.5%
EGSL	$ 500.59	$ (557.92)	$ 1,500,221	$ (1,672,045)	141.8%	53.4%
ELL	$ 411.28	$ (504.31)	$ 18,068,120	$ (22,154,874)	139.2%	51.9%
SWEPCO	$ 946.83	$ 57.09	$ 3,329,392	$ 200,757	190.6%	105.5%
Total IOU			**$ 30,394,925**	**$ (27,976,341)**	**157.3%**	**69.3%**

Table 38 and Table 39 provide the same forecast scenarios for the rural cooperatives.

Table 38: Solar NEM Contributions to Cooperative COS, Tariff Based Approach (Scenario 1 Forecast)

	Annual Per NEM Customer Contributions to COS		Aggregate Annual NEM Contribution to COS		Percent of COS Recovery	
	without NEM	with NEM	without NEM	with NEM	without NEM	with NEM
	---------- ($) ----------		---------- ($) ----------		---------- (%) ----------	
Beauregard	$ 310.18	$ (569.36)	74,814	(137,330)	131.1%	42.9%
Claiborne	$ 608.39	$ (113.76)	26,161	(4,892)	171.4%	86.6%
Dixie	$ 774.93	$ (312.48)	360,420	(145,333)	165.2%	73.7%
Jefferson Davis	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Northeast Louisiana	$ 317.01	$ (602.20)	13,632	(25,894)	137.2%	29.3%
Panola-Harrison	$ 460.22	$ (157.23)	20,517	(7,009)	150.6%	82.7%
Pointe Coupee	$ 250.30	$ (237.27)	9,191	(8,713)	149.5%	53.0%
South Louisiana	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Southwest Louisiana	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Washington-St. Tammany	$ 431.39	$ (370.07)	119,064	(102,140)	144.8%	61.6%
Total Cooperative			**$ 119,064**	**$ (102,140)**	**150.0%**	**61.4%**

Table 39: Solar NEM Contributions to Cooperative COS, Tariff Based Approach (Scenario 2 Forecast)

	Annual Per NEM Customer		Aggregate Annual NEM		Percent of COS Recovery	
	without NEM	with NEM	without NEM	with NEM	without NEM	with NEM
	---------- ($) ----------		---------- ($) ----------		---------- (%) ----------	
Beauregard	$ 310.18	$ (569.36)	114,593	(210,347)	131.1%	42.9%
Claiborne	$ 608.39	$ (113.76)	68,996	(12,902)	171.4%	86.6%
Dixie	$ 774.93	$ (312.48)	1,236,725	(498,689)	165.2%	73.7%
Jefferson Davis	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Northeast Louisiana	$ 317.01	$ (602.20)	59,320	(112,685)	137.2%	29.3%
Panola-Harrison	$ 460.22	$ (157.23)	55,875	(19,089)	150.6%	82.7%
Pointe Coupee	$ 250.30	$ (237.27)	17,664	(16,744)	149.5%	53.0%
South Louisiana	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Southwest Louisiana	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Washington-St. Tammany	$ 431.39	$ (370.07)	3,928,214	(3,369,835)	144.8%	61.6%
Total Cooperative			**$ 3,945,878**	**$ (3,386,579)**	**150.0%**	**61.4%**

9. Income Distribution

9.1. Introduction

Prior sections of the report have focused on the costs and benefits of LPSC-jurisdictional solar NEM, as well as examining whether or not solar NEM installations are covering their fair share of utility system costs. This section changes the direction of the analysis to focus on the distribution of costs and benefits among Louisiana households (in areas served by LPSC-jurisdictional utilities). An analysis of this nature can be conducted by comparing Louisiana-specific geographic-based income distribution data, to the earlier discussed solar NEM installation data provided by each of Louisiana's LPSC-regulated utilities. This comparison can assist in understanding whether or not the costs and benefits of solar NEM installations are distributed equitably across all Louisiana income distribution categories.

9.2. Data and Methods

NEM installation data provided by each of the LPSC-jurisdictional utilities serves as one of two primary sources of information in the income distribution analysis.[167] This utility-provided data included locational information that identifies the specific physical address of the solar NEM installation and/or the latitude/longitude coordinates for the individual installations. This analysis only uses residential solar NEM installation information.

[167] This analysis does not include the service territories of Entergy New Orleans, or municipally served areas of Lafayette Utilities System and City of Alexandria.

The second primary data source used in this analysis included Louisiana-specific census tract information collected by the U.S. Bureau of the Census. The Census Bureau defines a "census tract" as a small, relatively permanent statistical subdivision of a county (or parish) or comparable geographic unit.[168] These units are updated by local participants prior to each decennial census.[169] Census tracts are important demographic/geographic delineations that facilitate the development of relatively consistent and stable statistical analyses.

Louisiana has 1,148 census tracts with an average size of about 1,500 households with the largest census tract housing over 4,900 households. Census tracts, in general, vary in size usually depending upon the geographic/population density of the area in question. A map of the census tracts in the greater Baton Rouge metropolitan area is provided in Figure 44.

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[168] https://www.census.gov/geo/reference/gtc/gtc_ct.html
[169] Ibid.

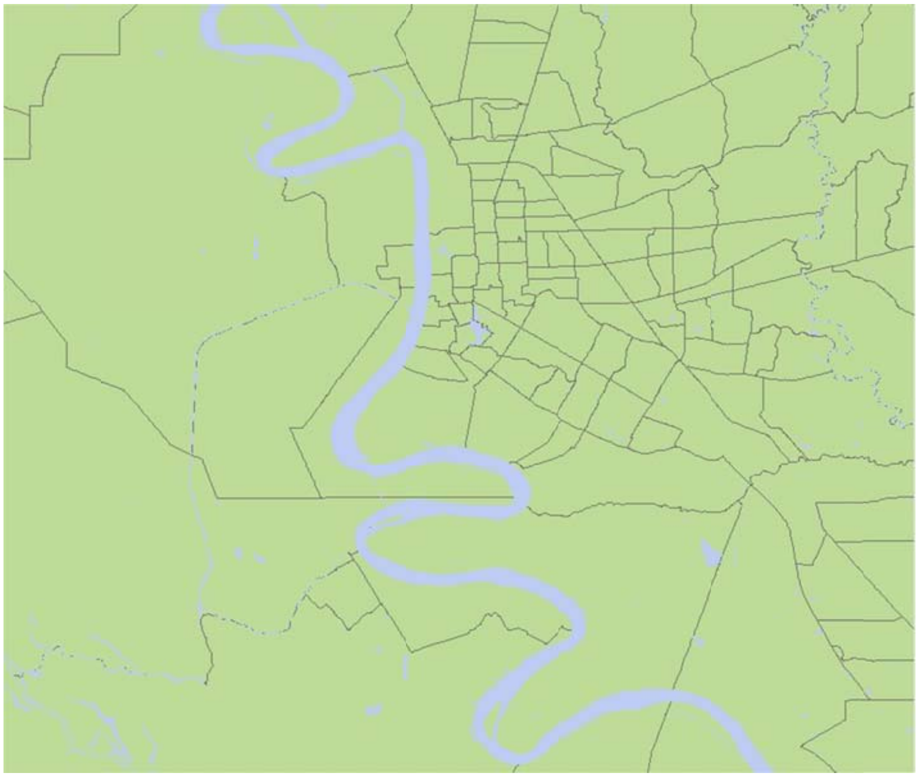

Figure 44: Illustrative Census Tract Map for Metropolitan Baton Rouge
Source: U.S. Census Bureau

Louisiana reports a median household income of $44,673, which can be decomposed into a number of income distribution categories that range from $5,000 to $10,000 increments of annual income starting with an annual income level as low as $10,000, with the highest category being those households with annual income greater than $200,000. Figure 45 provides a histogram of household income across each census tract income distribution level.

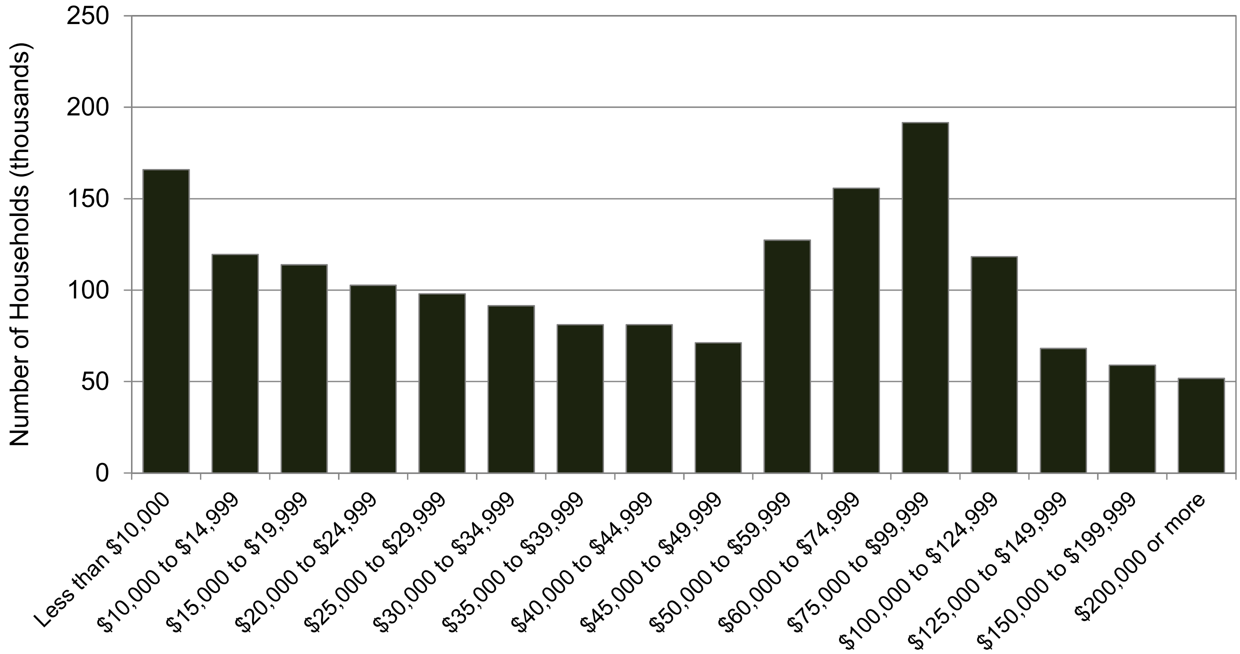

Figure 45: Histogram of Louisiana Household Income Distribution
Source: U.S. Census Bureau

9.1. Empirical Results

Figure 46 compares the median household income level for LPSC-jurisdictional solar NEM installations relative to the Louisiana median household income level. Statewide, LPSC-jurisdictional solar NEM installations are estimated to have median household incomes of $60,460 relative to the statewide median household income of only $44,673. In other words, the median income for a LPSC-jurisdictional solar NEM installation is about 35 percent higher than the median statewide income level.

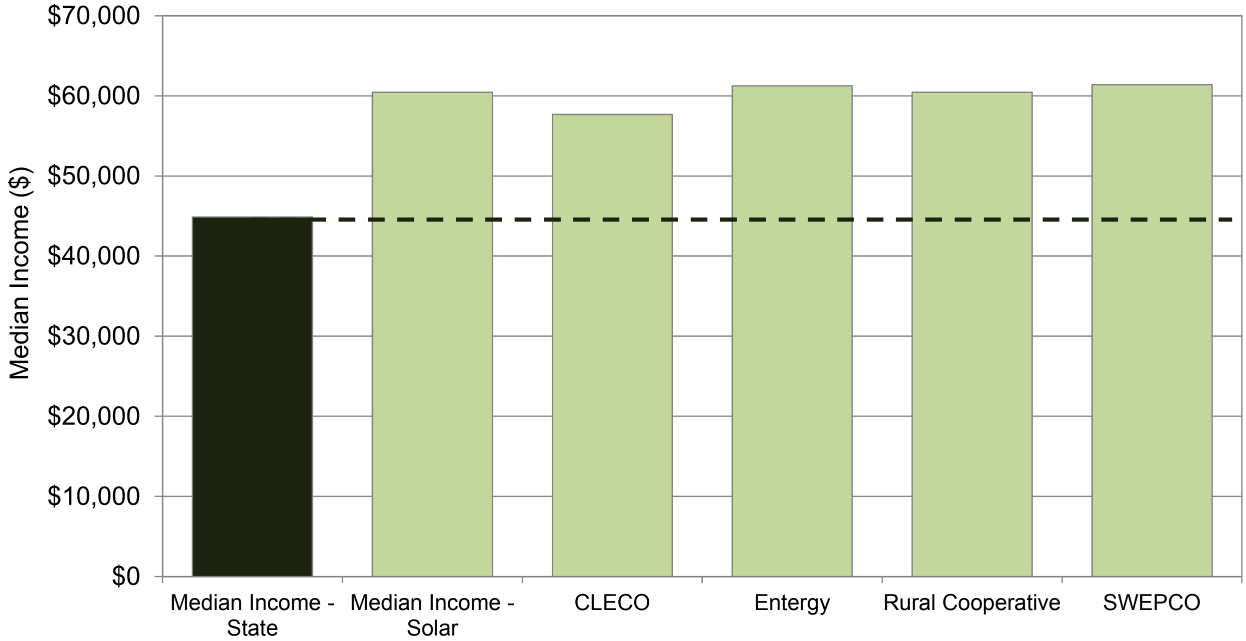

Figure 46: Comparison of Estimated NEM Median Incomes to Statewide Averages

Figure 46 also compares the utility-specific solar NEM installation income level data to the statewide medians. Solar NEM installations in the Entergy service territory, for instance, are estimated to be as high as $61,245 or some 40 percent higher than the statewide median. Solar NEM installations in the SWEPCO service territory are estimated to have household incomes of $61,378 or 38 percent higher than the statewide median, while the solar NEM installations located in the Cleco and the rural cooperative service territories are estimated to be installed on households with incomes that are 30 percent and 36 percent higher than the statewide medians, respectively.

Figure 47 charts the estimated median annual income levels for jurisdictional NEM installations on an annual basis (per installation year) compared to the statewide median income for that same year. These median income levels are standardized for inflation to 2012 dollars. The chart shows that at the beginning of NEM program in 2008, only households with a median income of almost $70,000 per year tended to develop NEM-eligible installations. As time has progressed, the income differential between NEM customers and median households has declined. In 2014, the estimated income is $59,745 compared to the median statewide income of $44,874.

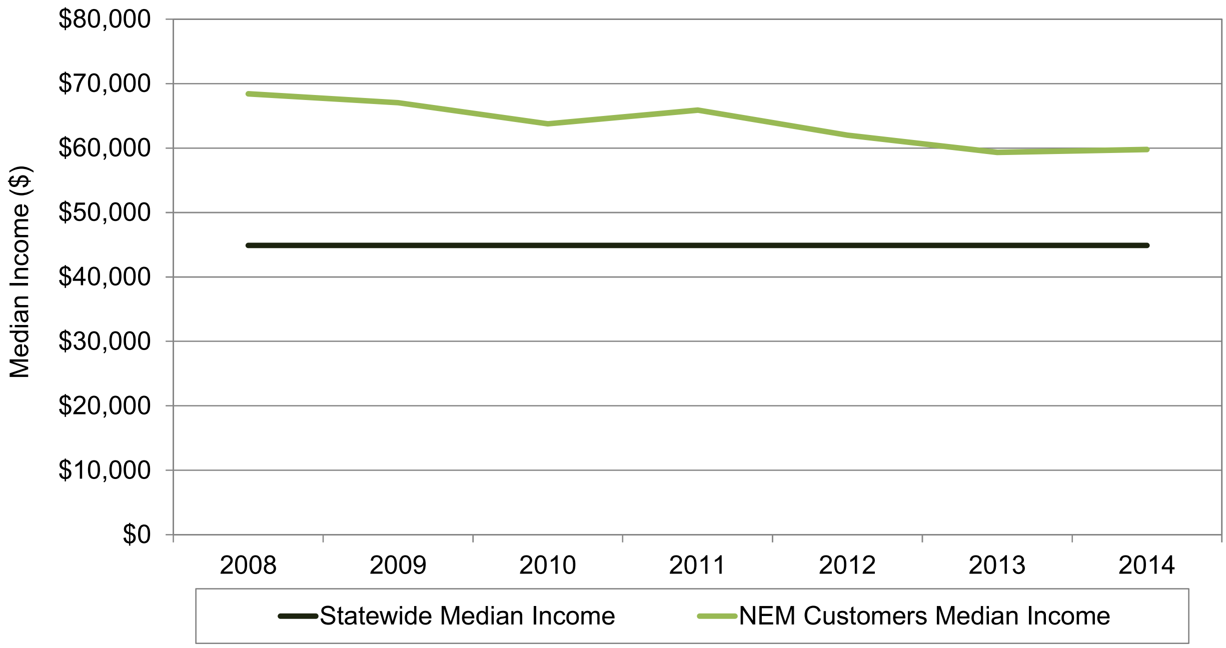

Figure 47: Annual Comparison of Estimated NEM Median Incomes to Statewide Annual Median Incomes

Table 40 compares the distribution of Louisiana households across major income distribution categories and compares those to the income distribution of Louisiana's solar NEM installations. The table shows that while 0.34 percent of all Louisiana households are estimated to earn annual incomes between $10,000 to $14,999, only 0.05 percent of all NEM installations are located in households with incomes in this very low range. By definition, half of all Louisiana households have incomes less than the statewide median level of $44,673 yet only 40 percent of Louisiana households with NEM installations are reported to be within this range.

Conversely, the other half of Louisiana households who report incomes above the statewide median level, whereas 60 percent of all solar NEM installations are reported to be installed on households in this income range. In other words, the overwhelming share of solar NEM installations are located on households with incomes that are greater than the statewide median level. Thus, the distribution of solar NEM installations are clearly tilted to higher income levels than lower income levels.

Table 40: Comparison of Louisiana Income Distribution and the Income Distribution of Solar NEM Installations

Income Bracket	Number of Installations	Percent of Total Installations (%)	Average Capacity per Installation (kW)	Percent Capacity per Installation (%)
$10,000 to $14,999	2	0.0%	9.0	10.5%
$15,000 to $19,999	141	2.3%	6.2	7.3%
$20,000 to $24,999	155	2.6%	6.3	7.3%
$25,000 to $29,999	230	3.8%	5.5	6.4%
$30,000 to $34,999	621	10.2%	5.8	6.8%
$35,000 to $39,999	550	9.1%	5.5	6.4%
$40,000 to $44,999	761	12.5%	5.7	6.7%
$45,000 to 49,999	609	10.0%	5.8	6.8%
$50,000 to $59,999	1,227	20.2%	5.8	6.8%
$60,000 to $74,999	1,025	16.9%	5.9	6.9%
$75,000 to 99,999	607	10.0%	6.2	7.2%
$100,000 to $124,999	121	2.0%	5.9	6.9%
$125,000 to $149,999	13	0.2%	7.0	8.2%
$150,000+	3	0.0%	5.2	6.0%
Total	6,065	100.0%	6.1	100.0%

Table 41 provides a similar income distribution comparison, but is provided on capacity as opposed to installation terms. The results from this analysis are comparable to the installation-based comparison discussed earlier. Most of the solar NEM-based capacity is tied to households that earn higher than median incomes.

Again, approximately 60 percent of the total solar NEM-based capacity is located on households with annual incomes greater than the statewide median income level.

Table 41: Comparison of Louisiana Income Distribution and the Income Distribution of Solar NEM Capacity.

Income Bracket	Number of Installations	Total Installed Capacity (kW)	Percent of Capacity per Installation (%)	Cumulative Percent Capacity per Installation (%)
$10,000 to $14,999	2	18	0.05%	0.05%
$15,000 to $19,999	141	879	2.48%	2.54%
$20,000 to $24,999	155	970	2.74%	5.28%
$25,000 to $29,999	230	1,258	3.56%	8.84%
$30,000 to $34,999	621	3,608	10.20%	19.04%
$35,000 to $39,999	550	3,033	8.58%	27.61%
$40,000 to $44,999	761	4,346	12.29%	39.90%
$45,000 to 49,999	609	3,529	9.98%	49.88%
$50,000 to $59,999	1,227	7,107	20.09%	69.97%
$60,000 to $74,999	1,025	6,054	17.11%	87.08%
$75,000 to 99,999	607	3,748	10.60%	97.68%
$100,000 to $124,999	121	715	2.02%	99.70%
$125,000 to $149,999	13	91	0.26%	99.96%
$150,000+	3	15	0.04%	100.00%

Figure 48 graphs the relationship between solar NEM installations per households and major household income distribution categories. Here, solar NEM installations are standardized on an "installations per 10,000 household" basis, where larger bars represent higher NEM concentration rates relative to the overall size (in terms of total number of households) in any given income distribution category.

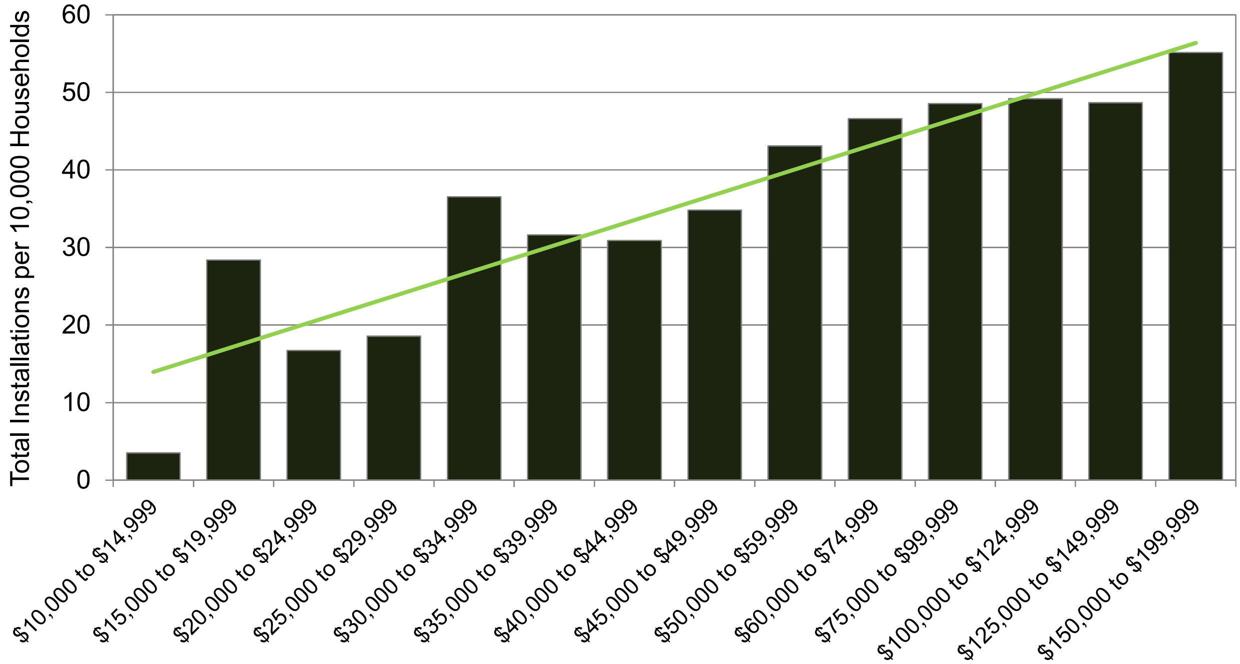

Figure 48: Solar NEM Installation Concentration Rate by Income Distribution Category (Installations per 10,000 Households)

Figure 49 compares average installation size, in terms kW of capacity per installation, across various different household income levels. Interestingly, average solar NEM installation capacity does not increase as median income household income increases. One would expect, other things being equal, that higher income households would tend, on average, to be larger, thereby needing larger solar NEM installations. Figure 49 does not support that conclusion and shows, generally, that the average size of a solar NEM installation in Louisiana is relatively constant at around six kW per installation.

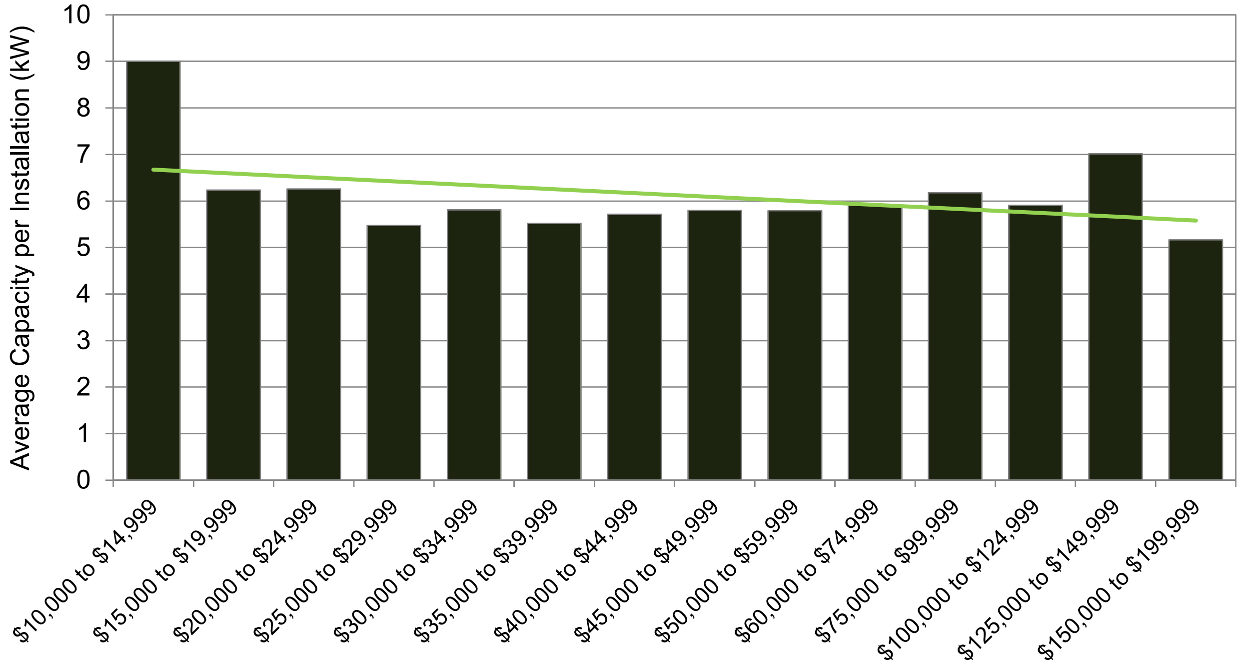

Figure 49: Comparison of Average Solar NEM Installation Size and Louisiana Income Distribution.

Figure 50 puts together the information from the prior two charts (installations, average installation size) to compare changes in solar NEM capacity per income distribution category. The analysis provides striking evidence supporting the conclusion that an overwhelming share of solar NEM installations is concentrated, on a standardized basis, in higher income Louisiana households. Thus, households with a higher income, on a standardized basis, tend to have greater levels of solar NEM-capacity than those with lower than median incomes.

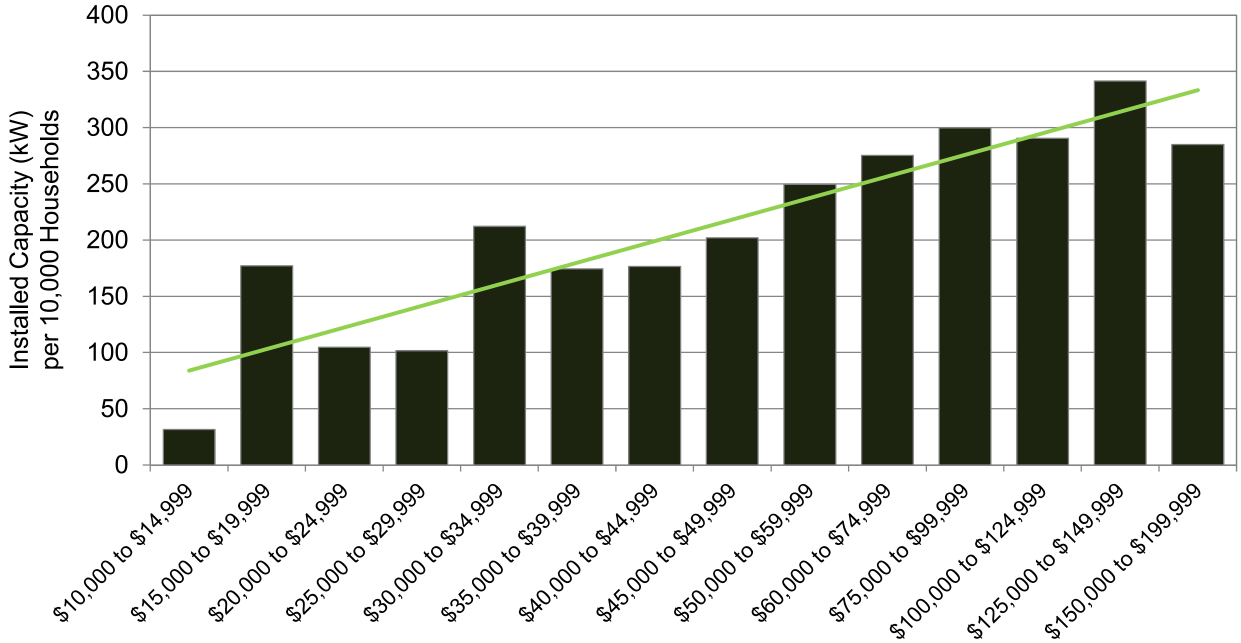

Figure 50: Solar NEM Capacity Concentration Rate by Income Distribution Category (Capacity per 10,000 Households)

Table 42 presents an alternative analysis comparing the estimates of income levels for solar NEM installation to those reported for each Louisiana parish with at least one solar NEM installation. The deviations between parish-specific median incomes and those estimated to be associated with local solar NEM installations are considerable. For instance, in Iberia Parish, the average income of net metering customers is more than $24,000 more than the median income, or 42 percent higher. In other parishes, such as Acadia Parish, though, the average income of net metering customers is actually estimated to be lower than non-net metering customers. It should be noted, though, that the estimated income of NEM customers is based on the census tract of which the household presides, and therefore might explain some of this discrepancy.

Table 42: Income Distribution Analysis Across Louisiana Parishes (Jurisdictional NEM Installations Only)

	Average Income				Average Income		
Parish	Net Metetering	Parish	Number of Installations	Parish	Net Metetering	Parish	Number of Installations
Acadia	$ 43,747	$ 51,726	13	Madison	$ 36,606	$ 37,637	1
Allen	54,895	51,990	15	Morehouse	48,763	42,582	21
Ascension	80,137	76,644	105	Natchitoches	54,115	48,274	47
Assumption	59,021	57,724	10	Orleans	45,914	54,507	260
Avoyelles	45,242	47,853	97	Ouachita	62,608	54,960	131
Beauregard	62,278	58,993	22	Plaquemines	81,876	69,583	35
Bienville	42,667	45,070	21	Pointe Coupee	61,157	55,464	20
Bossier	81,941	64,990	219	Rapides	60,419	54,215	123
Caddo	60,439	56,127	352	Red River	44,913	49,954	19
Calcasieu	69,447	58,955	91	Richland	50,093	49,079	23
Caldwell	50,021	53,235	10	Sabine	56,772	51,697	26
Cameron	68,337	68,732	6	St. Bernard	49,812	53,608	322
Catahoula	50,886	49,975	1	St. Charles	70,756	71,710	147
Claiborne	50,620	47,365	14	St. Helena	48,194	46,547	8
Concordia	51,356	46,197	2	St. James	70,601	66,488	22
De Soto	36,758	53,188	180	St. John the Baptist	65,539	61,519	164
East Baton Rouge	71,526	64,092	396	St. Landry	50,484	50,035	55
East Carroll	48,314	38,427	2	St. Martin	51,360	55,177	10
East Feliciana	57,598	56,644	18	St. Mary	58,278	53,604	11
Evangeline	47,715	46,805	50	St. Tammany	66,260	74,434	732
Franklin	45,994	49,642	24	Tangipahoa	55,852	53,517	221
Grant	53,694	50,115	38	Terrebonne	62,029	62,997	101
Iberia	82,389	57,855	28	Union	58,219	50,280	20
Iberville	63,450	56,124	23	Vermilion	67,606	57,084	10
Jackson	49,858	50,351	17	Vernon	58,775	56,646	54
Jefferson Davis	51,689	54,139	5	Washington	46,896	43,998	174
Jefferson	63,207	62,808	1,286	Webster	53,045	48,606	30
LaSalle	54,593	59,244	3	West Baton Rouge	85,813	64,976	18
Lafayette	57,512	65,418	16	West Carroll	49,321	49,797	20
Lafourche	63,759	62,440	59	West Feliciana	75,955	69,714	6
Lincoln	61,075	51,716	21	Winn	54,731	45,999	4
Livingston	67,715	66,979	86				
				Total	**$ 61,164**	**$ 60,534**	**6,065**

Figure 51 through Figure 56 provides various maps examining the relationship of solar NEM installation information and various census tract reported/surveyed incomes, across four major metropolitan areas under the Commission’s jurisdiction: Baton Rouge; Metairie; Lafayette, Shreveport; Lake Charles; and Monroe. In these maps, darker colors indicate higher income at the census tract level while lighter colors indicate lower income census tracts. As can be seen there is an obvious concentration of solar installations in census tracts with higher than average household incomes in many of the major municipal areas, corroborating the overall trends discussed earlier in this section.

Figure 51 provides the map for the jurisdictional solar NEM installations in the Baton Rouge metropolitan area. There is a noticeable difference in the concentration of solar panels between north and south Baton Rouge with a clearly higher concentration of solar panel installations in the higher income portions of south Baton Rouge than in the more predominant lower income areas in the northern part of the city.

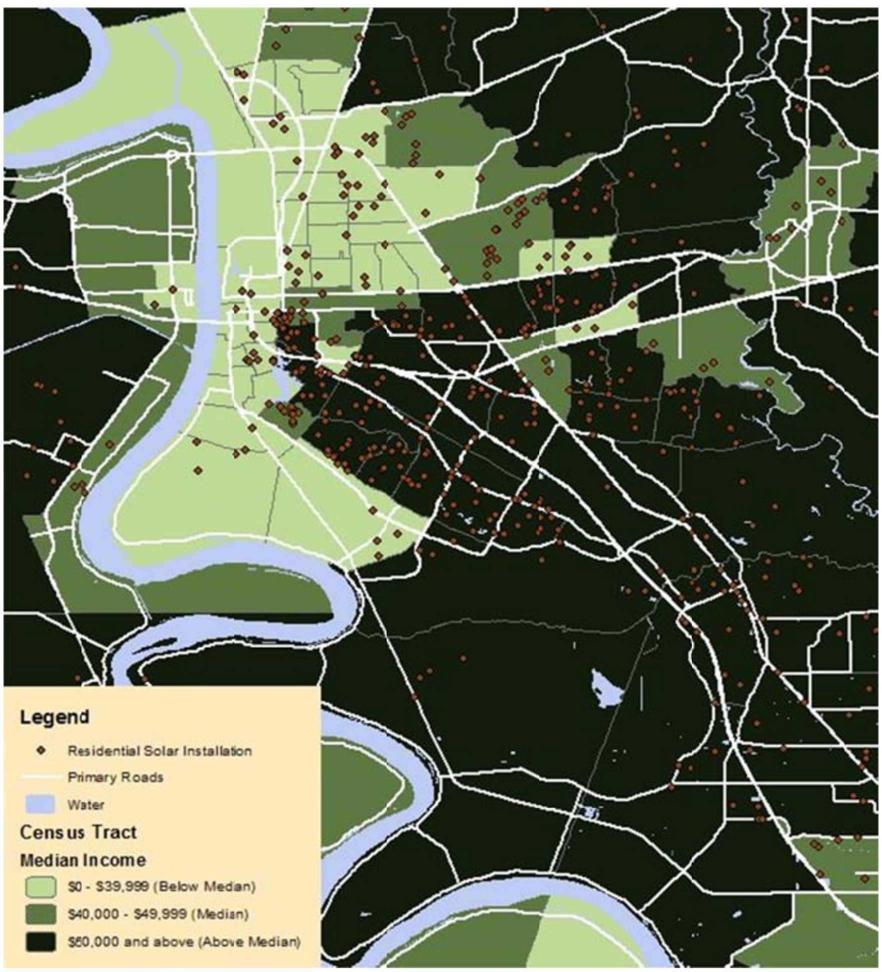

Figure 51: Solar NEM Installations and Census Track Incomes: Baton Rouge

Figure 52 provides the map for the jurisdictional solar NEM installations in the Metairie area. Clusters of solar installations are observed primarily in two areas. First, census tracts on the high income area of Metairie close to Lake Pontchartrain have a noticeably high concentration of solar installations. Second, wealthier census tracts south of New Orleans also have a high concentration of solar installations.[170]

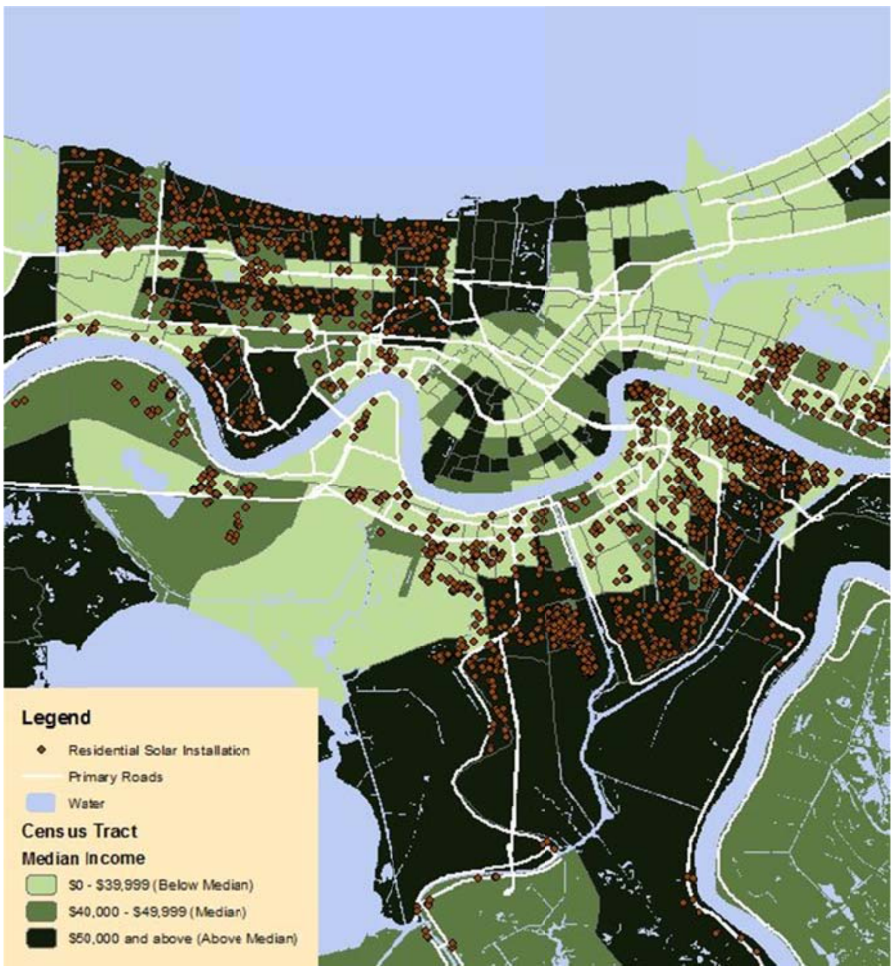

Figure 52: Solar NEM Installations and Census Track Incomes: Metairie

Figure 53 provides the map for the jurisdictional solar NEM installations in the Lafayette metropolitan area. Compared to Baton Rouge and Metairie, Lafayette has a

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[170] It should be noted that data for New Orleans is not included because it is not LPSC-jurisdictional.

noticeably less installations. These installations are concentrated in the high income census tracts in northern Lafayette as well as the high income census tracts in south-east Lafayette.

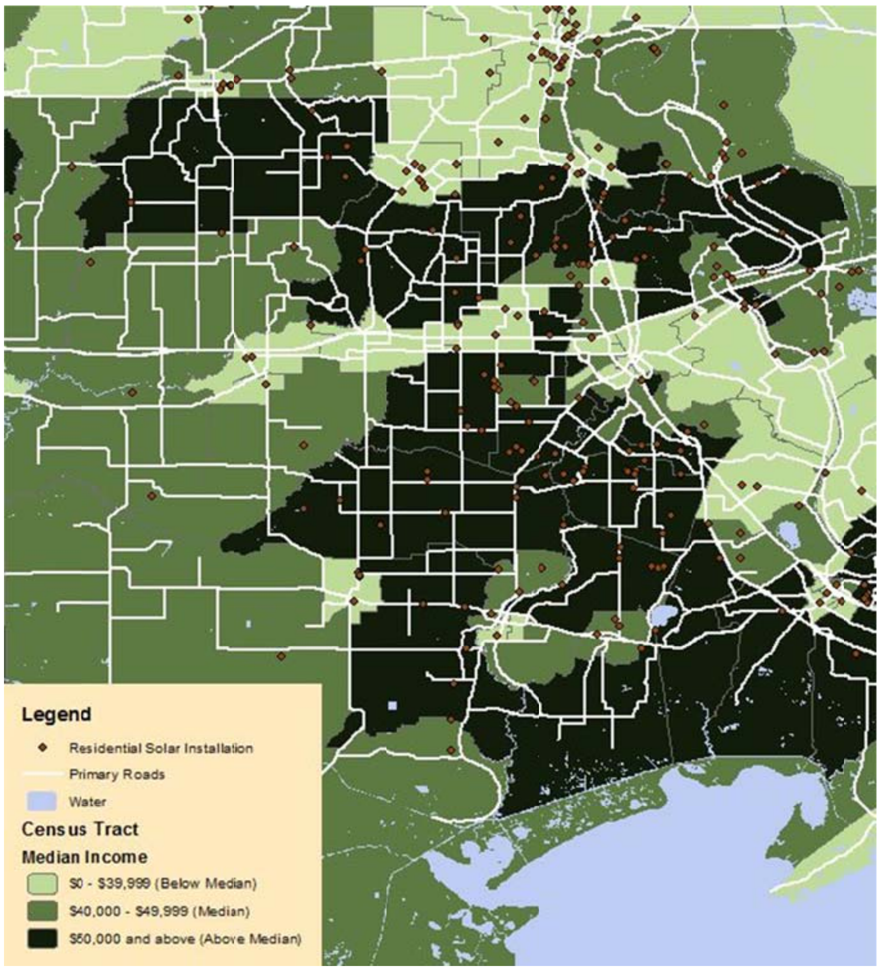

Figure 53: Solar NEM Installations and Census Track Incomes: Lafayette

Shreveport also has noticeable differences in solar installations across income levels of census tracts as illustrated in Figure 54. Most noticeable is the cluster of solar installations west of the Red River and south of downtown Shreveport.

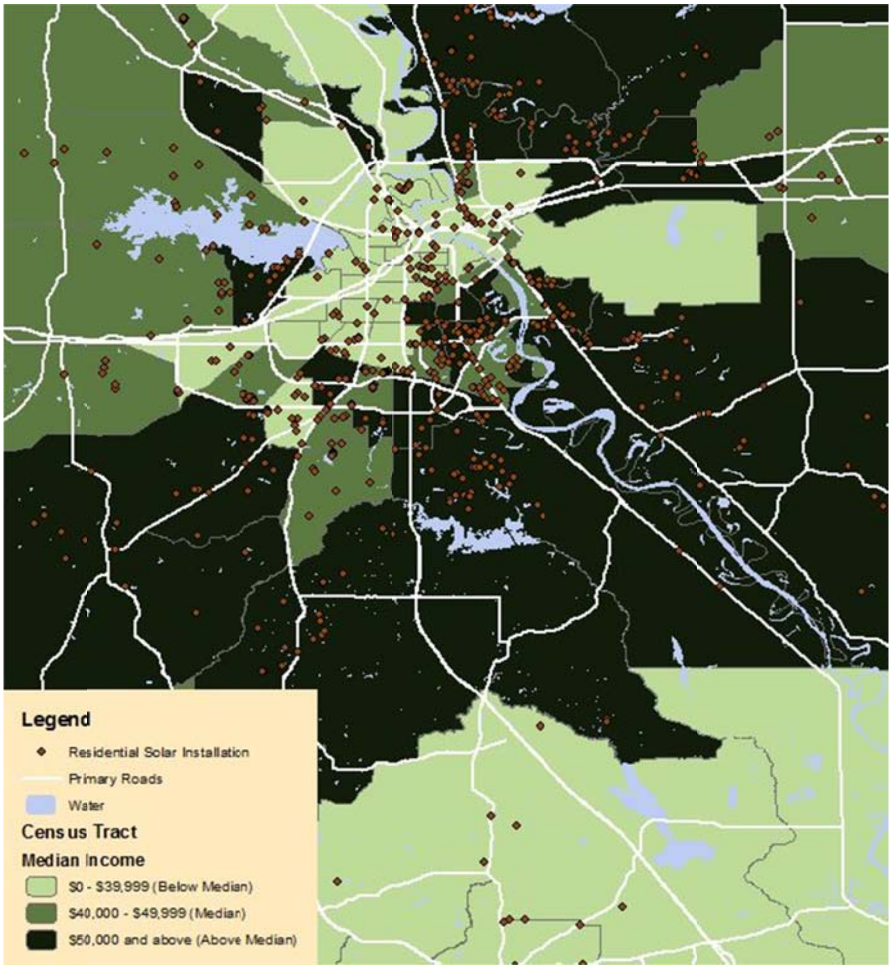

Figure 54: Solar NEM Installations and Census Track Incomes: Shreveport

As illustrated in Figure 55 , the solar installations in Lake Charles are concentrated in the south central part of the city which has higher than median income.

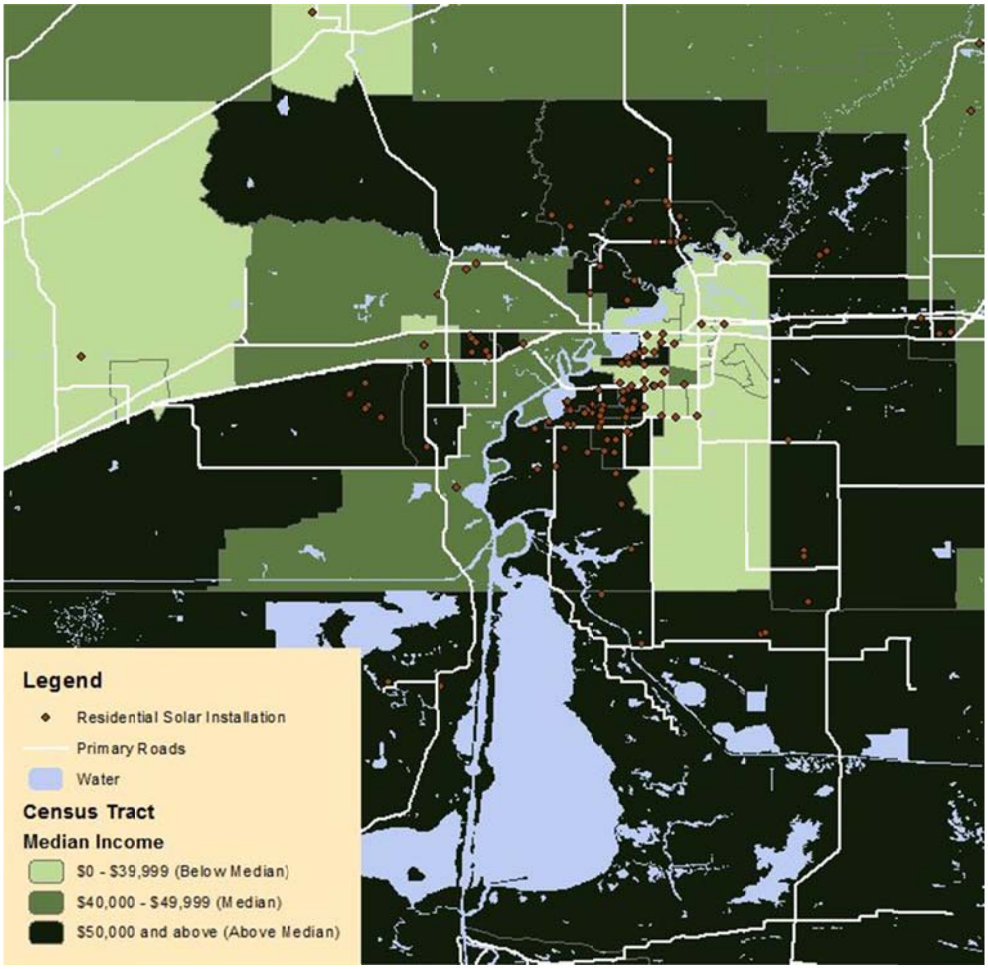

Figure 55: Solar NEM Installations and Census Track Incomes: Lake Charles

The solar installations show in Figure 56 for Monroe are concentrated in the northern-central part as well as in relatively high income rural areas.

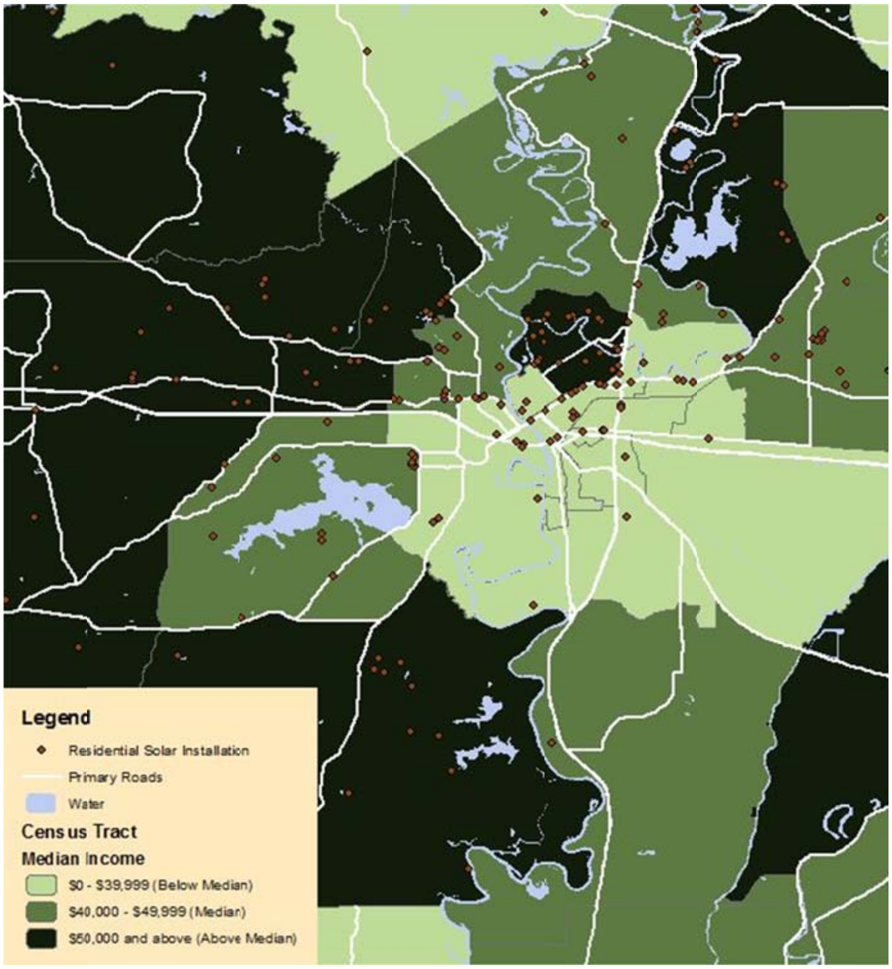

Figure 56: Solar NEM Installations and Census Track Incomes: Monroe

10. Conclusions

Even the best-intentioned regulatory policies can have unintended consequences if not modified to reflect changing market conditions, regulations, and technologies. NEM policies were adopted decades ago when there were limited behind-the-meter power generation technologies in an industry that was still tightly governed and regulated. NEM policies were the primary means by which behind-the-meter technologies were supported. These programs were often designed, in part, to mimic the policies and early successes observed in the promotion of larger scale (industrial) CHP projects under PURPA. During this time, renewables and particularly solar energy, were the primary technologies used for small-scale behind-the-meter generation and distributed solar energy, while not new, was still expensive and primarily considered a niche application.

Since the late 1980s and early 1990s when NEM policies were being adopted by state utility regulators, however, the electric power industry has been completely reorganized: more so in some states, than in others. There are new electric power market institutions and players, and scores of policies have been adopted to use the power distribution and transmission grid in ways not generally imaginable over twenty years ago. Today, a large number of states have adopted RPS standards mandating that an increasing share of future electricity demand be met with renewable resources. Energy costs have fluctuated, and the costs of utilizing renewable resources of all types has fallen considerably. Renewables are no longer a niche application and are increasingly becoming a more integrated resource in the electric power industry.

These changes in renewable opportunities have caused NEM policy to result in higher costs to ratepayers than originally anticipated.. Many states are recognizing the need to reevaluate NEM policies given changes in market conditions, technology, and customer willingness/interest in behind-the-meter generation. As NEM becomes increasingly more common there are even suggestions that distributed generation resources represent a type of disruptive technology that will lead to a new order in power systems operations and markets.[171]

The Commission's NEM policies, coupled with generous state and federal tax incentives, have led to an explosion of small-scale solar installations in Louisiana since 2008. Based upon the most recently-available information, there are 7,517 solar installations in the LPSC-jurisdictional areas of Louisiana accounting for over 42 MW of solar generating capacity. If these trends continue, many of the LPSC-regulated utilities in the state will reach their Commission-defined NEM installation caps by 2016, if they have not already. Even with these caps, Louisiana would see a total of 15,240 solar NEM installations, for a total of about 78 MWs of solar capacity, in the LPSC-jurisdictional areas of the state, if growth rates continue at their current pace.

If the LPSC-mandated NEM capacity limitations were released, and solar installations continue at a comparable installation rate to those observed over the past several years, Louisiana could see over 84,500 solar NEM installations amounting to over 494 MW of capacity in LPSC-jurisdictions alone, by 2020. As shown in Section 7.3 of this report, there would be considerable ratepayer impacts if the state were to see an

[171] LaMonica, M. 2013. Will Utilities Embrace Distributed Energy? MIT Technology Review. May 3; Downes, L. and P. Nunes. 2013. Big-Bang Disruption. Harvard Business Review; and Edison Electric Institute. 2013. Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business.

un-capped level of solar NEM installations arise given current LPSC NEM policies. Ratepayer bills, under such a scenario, could increase by $809 million (in NPV terms) given the above referenced 2020 installation outlook.

This research provides three separate analyses for the Commission's consideration in its evaluation of its current NEM policies. All three analyses, in addition to the various forecast scenarios and sensitivities are responsive to the Commission's charges and directives at the onset of this study. Further, each analysis was developed to provide three different perspectives on solar NEM installations and their impacts for LPSC ratepayers.

The CBA (cost-benefit analysis) presented in this report examines the costs and benefits from a broad, forward-looking perspective. The benefits included in the CBA are comprised of the generation, transmission, and distribution costs that are avoided by the use of on-site solar generation (i.e. "avoided cost benefits"). The additional, positive economic activity associated with solar installation development and ongoing service activities are also included as an important benefit in the CBA. The costs included in the CBA are those associated with the unrecovered interconnection and utility administrative costs, in addition to all NEM incentive payments and lost revenues. The costs incurred by the State of Louisiana, including those associated with solar tax incentives, and decreased state tax revenue and expenditure impacts, are included as a cost of solar NEM development.

The CBA examined three different installation conditions. The first baseline condition examines the impacts created by solar NEM installations to-date. The second forecasts solar installations, at a growth rate comparable to the past few years, up to their per-utility, LPSC-defined NEM installation capacity threshold. The third allows solar NEM installations to continue to grow without the LPSC threshold to the year 2020. The results from all three of these analyses finds that the costs associated with solar NEM installations are greater than their estimated benefits by a considerable margin. For instance, the costs are 1.5 times higher than the benefits under the baseline CBA analysis (currently installed solar NEM projects): this results in negative total net benefits to LPSC ratepayers of some $89 million in NPV terms. These negative net benefits increase upon both of the solar installation forecasts to levels that are between a negative $125.5 million (NPV) and a negative $488.3 million (NPV) impact on LPSC ratepayers.

The CBA also examines three different sensitivities to the baseline (current installation) analysis. All three sensitivities were designed in a manner intended to maximize the upside opportunities for solar NEM, not the downside additional risks that could be borne by LPSC ratepayers. The sensitivities were developed to test whether there were any reasonable conditions under which current NEM policies would result in positive LPSC ratepayer benefits. The first sensitivity (high natural gas price sensitivity) was developed by taking the $3.50/MMBtu natural gas assumption included in the baseline analysis, and increasing it to $5.00/MMBtu. The second sensitivity evaluated a high electric capacity price to determine whether increasing pressures on capacity could make solar NEM more valuable to LPSC ratepayers. Lastly, a sensitivity including a carbon price of $40 per ton was included to evaluate the sensitivity of the baseline results to a world in which carbon is regulated. Unfortunately, none of the three sensitivities shifted the results of the cost-benefit calculus in a direction favorable to LPSC ratepayers.

This report also examines the impact that the Commission's NEM policies have on rates using a COS based model to assess the degree of potential cross subsidization within ratepayer classes. The COS analysis estimates the impact that solar NEM may have utility embedded cost recovery. The COS analysis uses a revenue requirement model to determine a typical residential-customer COS and compares that cost to an NEM customer pre and post-solar NEM installation. The COS model estimates total cross subsidies at the current solar NEM installation level of $1.8 million.[172] This subsidy could increase to an estimated $4.9 million if all utilities reach their LPSC-mandated threshold over the next several years, and could grow to almost $28 million if solar NEM installations were allowed to grow unbounded to 2020.

Lastly, an income distribution analysis was conducted to determine how the benefits of solar NEM installations are distributed across household income categories. The analysis cross-references census-block specific income information to LPSC-jurisdictional solar NEM installation. The analysis estimates that an overwhelming share of solar NEM installations are concentrated, on a standardized basis, in higher income Louisiana households. Thus, households with higher income, on a standardized basis, tend to have greater levels of solar NEM-capacity than those with lower than median incomes suggesting that the benefits of the LPSC's NEM policies fall more heavily on higher income households relative to median income households.

[172] This estimate is for the four IOUs, the estimated cross subsidy for the regional cooperatives is an additional $225,420.

The purpose of this study has been to provide the Commission with a wide range of information and estimates of the impacts and potential impacts of solar NEM on LPSC jurisdictional ratepayers. No explicit policy recommendations are provided here except one that will enable the Commission to more uniformly track information provided by the utilities. That is, we recommend that at its earliest opportunity the Commission adopt a standardized reporting format for utilities to provide solar NEM information on an annual basis. We believe this is a recommendation that is noncontroversial and necessary. One of the more significant challenges in this analysis was gathering information from each of the jurisdictional utilities, and then standardizing this information into a format that could be utilized for ratepayer impact analysis. Updates to this study, as well as the ability of the Staff to provide the Commission with regular status reports on solar NEM development, could be significantly improved if a standardized reporting form, and reporting process were adopted. Generally, this report recommends:

- That the Commission require utilities, as of the filing of the filing of their next annual report, to provide a standardized set of NEM data and information comparable to the straw proposal provided in Appendix B of this report.
- Current LPSC rules require utilities to file annual data by March 1 of each year. To enable utilities to acquaint themselves with this form and gather the necessary information, this date should be extended by 90 days, until June 2015.

Appendix A-1

Forecast Scenario 1, 0.5% Peak Demand Threshold

	Annual Installed Capacity														
	CLECO	Entergy Gulf States	Entergy Louisiana	SWEPCO	Beauregard	Claiborne	DEMCO	Jefferson Davis	Northeast Louisiana	Panola Harrison	Pointe Coupee	South Louisiana	SLEMCO	Washington St. Tammany	Total
	(kW)														
2008	-	8	18	94	-	-	-	-	-	27	-	-	14	-	160
2009	157	183	373	345	27	-	57	-	-	16	10	-	30	52	1,248
2010	316	328	815	324	11	70	86	-	45	31	5	7	67	143	2,247
2011	670	582	1,013	534	76	49	183	54	140	20	44	17	183	141	3,705
2012	2,190	965	2,697	1,579	111	124	420	39	115	70	34	-	249	267	8,859
2013	2,889	1,225	7,110	1,468	138	44	539	7	88	50	33	129	337	1,109	15,164
2014	5,168	1,951	16,840	2,216	222	-	929	7	-	32	44	84	547	-	28,043
2015	-	3,109	-	859	359	-	792	8	-	-	60	131	887	-	6,204
2016	-	4,952	-	-	532	-	-	8	-	-	28	203	1,372	-	7,096
2017	-	1,330	-	-	-	-	-	12	-	-	-	57	-	-	1,400
2018	-	1,463	-	-	-	-	-	14	-	-	-	54	-	-	1,530
2019	-	1,610	-	-	-	-	-	15	-	-	-	-	-	-	1,624
2020	-	1,175	-	-	-	-	-	16	-	-	-	-	-	-	1,191
Total	**11,390**	**18,880**	**28,865**	**7,419**	**1,474**	**287**	**3,006**	**180**	**388**	**245**	**257**	**683**	**3,686**	**1,712**	**78,472**

	Cumulative Installed Capacity														
	CLECO	Entergy Gulf States	Entergy Louisiana	SWEPCO	Beauregard	Claiborne	DEMCO	Jefferson Davis	Northeast Louisiana	Panola Harrison	Pointe Coupee	South Louisiana	SLEMCO	Washington St. Tammany	Total
	(kW)														
2008	-	8	18	94	-	-	-	-	-	27	-	-	14	-	160
2009	157	190	391	439	27	-	57	-	-	42	10	-	44	52	1,408
2010	473	518	1,206	763	37	70	142	-	45	73	15	7	111	195	3,656
2011	1,143	1,101	2,219	1,297	113	119	325	54	185	93	59	24	294	336	7,360
2012	3,333	2,065	4,915	2,876	224	243	745	93	301	163	93	24	543	603	16,220
2013	6,222	3,290	12,025	4,344	361	287	1,284	100	388	213	125	153	880	1,712	31,384
2014	11,390	5,241	28,865	6,560	584	287	2,213	107	388	245	169	238	1,427	1,712	58,751
2015	11,390	8,350	28,865	7,419	943	287	3,006	115	388	245	229	369	2,314	1,712	64,955
2016	11,390	13,302	28,865	7,419	1,474	287	3,006	123	388	245	257	572	3,686	1,712	72,051
2017	11,390	14,632	28,865	7,419	1,474	287	3,006	136	388	245	257	629	3,686	1,712	73,451
2018	11,390	16,096	28,865	7,419	1,474	287	3,006	149	388	245	257	683	3,686	1,712	74,981
2019	11,390	17,705	28,865	7,419	1,474	287	3,006	164	388	245	257	683	3,686	1,712	76,606
2020	11,390	18,880	28,865	7,419	1,474	287	3,006	180	388	245	257	683	3,686	1,712	77,797
Total	**11,390**	**18,880**	**28,865**	**7,419**	**1,474**	**287**	**3,006**	**180**	**388**	**245**	**257**	**683**	**3,686**	**1,712**	**77,797**

Appendix A-2

Forecast Scenario 2, Unbounded Growth

	Annual Installed Capacity (kW)														
	CLECO	Entergy Gulf States	Entergy Louisiana	SWEPCO	Beauregard	Claiborne	DEMCO	Jefferson Davis	Northeast Louisiana	Panola Harrison	Pointe Coupee	South Louisiana	SLEMCO	Washington St. Tammany	Total
2008	-	8	18	94	-	-	-	-	-	27	-	-	14	-	160
2009	157	183	373	345	27	-	57	-	-	16	10	-	30	52	1,248
2010	316	328	815	324	11	70	86	-	45	31	5	7	67	143	2,247
2011	670	582	1,013	534	76	49	183	54	140	20	44	17	183	141	3,705
2012	2,190	965	2,697	1,579	111	124	420	39	115	70	34	-	249	267	8,859
2013	2,889	1,225	7,110	1,468	138	44	539	7	88	50	33	129	337	1,109	15,164
2014	5,392	1,951	17,393	2,216	222	52	929	7	113	65	44	823	547	3,151	32,907
2015	10,064	3,109	42,551	3,347	359	62	1,601	8	146	84	60	5,244	887	8,952	76,475
2016	18,786	4,952	104,096	5,055	580	73	2,759	8	189	110	81	33,424	1,438	25,432	196,984
2017	4,046	1,330	17,606	1,496	152	47	657	12	84	47	31	3,964	375	3,925	33,775
2018	4,451	1,463	19,367	1,646	167	52	723	14	92	52	34	4,361	413	4,317	37,152
2019	4,896	1,610	21,304	1,810	184	57	795	15	101	57	37	4,797	454	4,749	40,868
2020	5,386	1,771	23,434	1,992	203	63	875	16	111	63	41	5,277	499	5,224	44,954
Total	**59,244**	**19,476**	**257,777**	**21,907**	**2,229**	**695**	**9,624**	**180**	**1,224**	**691**	**453**	**58,044**	**5,493**	**57,463**	**494,499**

	Cumulative Installed Capacity (kW)														
	CLECO	Entergy Gulf States	Entergy Louisiana	SWEPCO	Beauregard	Claiborne	DEMCO	Jefferson Davis	Northeast Louisiana	Panola Harrison	Pointe Coupee	South Louisiana	SLEMCO	Washington St. Tammany	Total
2008	-	8	18	94	-	-	-	-	-	27	-	-	14	-	160
2009	157	190	391	439	27	-	57	-	-	42	10	-	44	52	1,408
2010	473	518	1,206	763	37	70	142	-	45	73	15	7	111	195	3,656
2011	1,143	1,101	2,219	1,297	113	119	325	54	185	93	59	24	294	336	7,360
2012	3,333	2,065	4,915	2,876	224	243	745	93	301	163	93	24	543	603	16,220
2013	6,222	3,290	12,025	4,344	361	287	1,284	100	388	213	125	153	880	1,712	31,384
2014	11,613	5,241	29,418	6,560	584	340	2,213	107	501	277	169	976	1,427	4,863	64,290
2015	21,678	8,350	71,969	9,908	943	402	3,814	115	647	362	229	6,221	2,314	13,816	140,765
2016	40,464	13,302	176,065	14,963	1,522	475	6,573	123	836	472	310	39,645	3,752	39,248	337,749
2017	44,511	14,632	193,671	16,459	1,674	522	7,231	136	920	519	341	43,609	4,127	43,173	371,524
2018	48,962	16,096	213,038	18,105	1,842	575	7,954	149	1,012	571	375	47,970	4,539	47,490	408,677
2019	53,858	17,705	234,342	19,915	2,026	632	8,749	164	1,113	628	412	52,767	4,993	52,239	449,544
2020	59,244	19,476	257,777	21,907	2,229	695	9,624	180	1,224	691	453	58,044	5,493	57,463	494,499
Total	**59,244**	**19,476**	**257,777**	**21,907**	**2,229**	**695**	**9,624**	**180**	**1,224**	**691**	**453**	**58,044**	**5,493**	**57,463**	**494,499**

DRAFT - February 27, 2015

APPENDIX A-3
BASELINE, COST-BENEFIT RESULTS

	ESTIMATED DIRECT BENEFITS (BASELINE)													
	(a)	(b)	(c)	(d) = (a)+(b)+(c)	(e)	(f)	(g)	(h) = (e)+(f)+(g)	(i)	(j)	(k)	(l) = (i)+(j)+(k)	(m) = (h)+(l)	(n) = (d)+ (e)+(i)
	Avoided Power Costs				Solar Installation Benefits				Solar O&M Benefits				Total Solar Benefits	Total Direct Benefits
	Energy	Capacity	T&D	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total		
	(million $)													
2008	$ 0.01	$ 0.00	$ 0.00	$ 0.02	$ 0.44	$ 0.51	$ 0.26	$ 1.21	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 1.22	$ 0.46
2009	0.11	0.03	0.00	0.13	3.05	3.56	1.82	8.43	0.03	0.03	0.01	0.07	8.50	3.21
2010	0.28	0.07	0.00	0.35	4.92	5.74	2.93	13.59	0.07	0.07	0.03	0.16	13.75	5.34
2011	0.57	0.13	0.00	0.70	7.26	8.47	4.32	20.05	0.12	0.12	0.05	0.30	20.35	8.08
2012	1.21	0.29	0.00	1.51	15.31	17.88	9.12	42.31	0.24	0.24	0.11	0.59	42.90	17.06
2013	2.33	0.56	0.01	2.90	22.72	26.53	13.53	62.78	0.42	0.42	0.18	1.03	63.80	26.04
2014	3.15	0.76	0.01	3.92	11.73	13.70	6.99	32.42	0.51	0.51	0.23	1.25	33.67	16.17
2015	3.13	0.76	0.01	3.90	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.41
2016	3.12	0.76	0.01	3.88	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.39
2017	3.10	0.75	0.01	3.86	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.37
2018	3.08	0.75	0.01	3.84	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.35
2019	3.07	0.74	0.01	3.82	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.34
2020	3.05	0.74	0.01	3.80	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.32
2021	3.04	0.74	0.01	3.79	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.30
2022	3.02	0.73	0.01	3.77	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.28
2023	3.01	0.73	0.01	3.75	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.26
2024	2.99	0.73	0.01	3.73	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.24
2025	2.98	0.72	0.01	3.71	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.22
2026	2.96	0.72	0.01	3.69	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.20
2027	2.95	0.71	0.01	3.67	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.18
2028	2.93	0.71	0.01	3.65	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.17
2029	2.92	0.71	0.01	3.64	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.15
2030	2.90	0.70	0.01	3.62	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.13
2031	2.89	0.70	0.01	3.60	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.11
2032	2.88	0.70	0.01	3.58	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.09
2033	2.86	0.69	0.01	3.56	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.08
2034	2.85	0.69	0.01	3.55	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.06
2035	2.83	0.69	0.01	3.53	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.04
2036	2.82	0.68	0.01	3.51	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.02
2037	2.80	0.68	0.01	3.49	-	-	-	-	0.51	0.51	0.23	1.25	1.25	4.01
2038	2.78	0.67	0.01	3.46	-	-	-	-	0.51	0.51	0.22	1.24	1.24	3.97
2039	2.68	0.65	0.01	3.34	-	-	-	-	0.48	0.49	0.21	1.18	1.18	3.83
2040	2.52	0.61	0.01	3.14	-	-	-	-	0.45	0.45	0.20	1.09	1.09	3.59
2041	2.26	0.55	0.01	2.82	-	-	-	-	0.39	0.39	0.17	0.95	0.95	3.21
2042	1.69	0.41	0.01	2.11	-	-	-	-	0.27	0.27	0.12	0.66	0.66	2.38
2043	0.72	0.18	0.00	0.90	-	-	-	-	0.09	0.09	0.04	0.22	0.22	0.99
NPV:	**$ 33.89**	**$ 8.20**	**$ 0.12**	**$ 42.21**	**$ 49.26**	**$ 57.52**	**$ 29.33**	**$ 136.12**	**$ 5.86**	**$ 5.87**	**$ 2.58**	**$ 14.30**	**$ 150.42**	**$ 97.33**

APPENDIX A-3
BASELINE, COST-BENEFIT RESULTS

	ESTIMATED DIRECT COSTS (BASELINE)														
	(a)	(b)	(c)	(d)	(e)	(f) = (c)+(d)+(e)	(g)	(h)	(i)	(j) = (g)+(h)+(i)	(k)	(l)	(m)	(n) = (k)+(l)+(m)	(o) = (a)+(b)+(f)+(j)+(n)
	Unrecovered Interconnection Costs	NEM Admin. Costs	Rate Impacts: NEM Payments				Rate Impacts: Lost Revenues				State Tax Incentives				Total NEM Program Costs
			Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	
	($)														
2008	$ 0.02	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.02	$ 0.00	$ 0.01	$ 0.03	$ 0.80	$ 0.49	$ 0.28	$ 1.57	$ 1.62
2009	0.08	0.02	0.02	0.00	0.01	0.04	0.11	0.00	0.10	0.21	6.26	3.79	2.19	12.24	12.60
2010	0.11	0.05	0.04	0.01	0.03	0.08	0.27	0.00	0.26	0.54	10.20	6.18	3.56	19.94	20.73
2011	0.14	0.09	0.16	0.04	0.09	0.29	0.52	0.01	0.48	1.01	13.82	8.38	4.84	27.04	28.57
2012	0.34	0.18	0.33	0.06	0.21	0.61	1.13	0.02	1.07	2.22	30.95	18.76	10.82	60.53	63.87
2013	0.81	0.41	0.50	0.08	0.33	0.92	2.28	0.04	2.17	4.49	46.54	28.21	16.27	91.02	97.64
2014	0.59	0.58	0.60	0.09	0.40	1.10	3.13	0.04	2.99	6.16	24.30	14.73	8.49	47.52	55.94
2015	-	0.58	0.59	0.09	0.40	1.09	3.11	0.04	2.97	6.13	-	-	-	-	7.80
2016	-	0.58	0.59	0.09	0.40	1.09	3.10	0.04	2.96	6.10	-	-	-	-	7.76
2017	-	0.58	0.59	0.09	0.40	1.08	3.08	0.04	2.94	6.07	-	-	-	-	7.72
2018	-	0.58	0.59	0.09	0.40	1.08	3.07	0.04	2.93	6.04	-	-	-	-	7.69
2019	-	0.58	0.58	0.09	0.39	1.07	3.05	0.04	2.91	6.00	-	-	-	-	7.65
2020	-	0.58	0.58	0.09	0.39	1.06	3.04	0.04	2.90	5.97	-	-	-	-	7.62
2021	-	0.58	0.58	0.09	0.39	1.06	3.02	0.04	2.89	5.95	-	-	-	-	7.58
2022	-	0.58	0.57	0.09	0.39	1.05	3.01	0.04	2.87	5.92	-	-	-	-	7.55
2023	-	0.58	0.57	0.09	0.39	1.05	2.99	0.04	2.86	5.89	-	-	-	-	7.51
2024	-	0.58	0.57	0.09	0.39	1.04	2.98	0.04	2.84	5.86	-	-	-	-	7.48
2025	-	0.58	0.57	0.09	0.38	1.04	2.96	0.04	2.83	5.83	-	-	-	-	7.44
2026	-	0.58	0.56	0.09	0.38	1.03	2.95	0.04	2.81	5.80	-	-	-	-	7.41
2027	-	0.58	0.56	0.09	0.38	1.03	2.93	0.04	2.80	5.77	-	-	-	-	7.37
2028	-	0.58	0.56	0.09	0.38	1.02	2.92	0.04	2.79	5.74	-	-	-	-	7.34
2029	-	0.58	0.55	0.09	0.38	1.02	2.90	0.04	2.77	5.71	-	-	-	-	7.31
2030	-	0.58	0.55	0.09	0.37	1.01	2.89	0.04	2.76	5.68	-	-	-	-	7.27
2031	-	0.58	0.55	0.09	0.37	1.01	2.87	0.04	2.74	5.65	-	-	-	-	7.24
2032	-	0.58	0.55	0.09	0.37	1.00	2.86	0.04	2.73	5.63	-	-	-	-	7.21
2033	-	0.58	0.54	0.09	0.37	1.00	2.85	0.04	2.72	5.60	-	-	-	-	7.17
2034	-	0.58	0.54	0.09	0.37	0.99	2.83	0.04	2.70	5.57	-	-	-	-	7.14
2035	-	0.58	0.54	0.09	0.36	0.99	2.82	0.04	2.69	5.54	-	-	-	-	7.11
2036	-	0.58	0.54	0.09	0.36	0.98	2.80	0.04	2.68	5.51	-	-	-	-	7.07
2037	-	0.58	0.53	0.08	0.36	0.98	2.79	0.04	2.66	5.49	-	-	-	-	7.04
2038	-	0.57	0.53	0.08	0.36	0.97	2.76	0.03	2.64	5.43	-	-	-	-	6.98
2039	-	0.55	0.51	0.08	0.35	0.93	2.67	0.03	2.55	5.25	-	-	-	-	6.74
2040	-	0.52	0.49	0.08	0.33	0.90	2.51	0.03	2.40	4.94	-	-	-	-	6.36
2041	-	0.49	0.38	0.05	0.28	0.71	2.29	0.02	2.19	4.51	-	-	-	-	5.70
2042	-	0.40	0.23	0.03	0.17	0.43	1.75	0.02	1.68	3.45	-	-	-	-	4.27
2043	-	0.17	0.08	0.01	0.07	0.16	0.74	0.00	0.72	1.47	-	-	-	-	1.79
NPV:	**$ 1.54**	**$ 6.46**	**$ 6.57**	**$ 1.06**	**$ 4.42**	**$ 12.04**	**$ 33.60**	**$ 0.44**	**$ 32.05**	**$ 66.09**	**$ 99.96**	**$ 60.59**	**$ 34.94**	**$ 195.50**	**$ 281.63**

APPENDIX A-3
BASELINE, COST-BENEFIT RESULTS

	ESTIMATED DIRECT NET BENEFITS (BASELINE)				
	(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) - (d)
	Total Avoided Power Costs	Total Solar Benefits	Total Benefits	Total Costs	Net NEM Program Benefits
	($)				
2008	$ 0.02	$ 1.22	$ 1.24	$ 1.62	$ (0.39)
2009	0.13	8.50	8.63	12.60	(3.96)
2010	0.35	13.75	14.10	20.73	(6.63)
2011	0.70	20.35	21.05	28.57	(7.53)
2012	1.51	42.90	44.41	63.87	(19.46)
2013	2.90	63.80	66.70	97.64	(30.94)
2014	3.92	33.67	37.59	55.94	(18.35)
2015	3.90	1.25	5.15	7.80	(2.65)
2016	3.88	1.25	5.13	7.76	(2.63)
2017	3.86	1.25	5.11	7.72	(2.61)
2018	3.84	1.25	5.09	7.69	(2.60)
2019	3.82	1.25	5.07	7.65	(2.58)
2020	3.80	1.25	5.05	7.62	(2.56)
2021	3.79	1.25	5.03	7.58	(2.55)
2022	3.77	1.25	5.02	7.55	(2.53)
2023	3.75	1.25	5.00	7.51	(2.52)
2024	3.73	1.25	4.98	7.48	(2.50)
2025	3.71	1.25	4.96	7.44	(2.48)
2026	3.69	1.25	4.94	7.41	(2.47)
2027	3.67	1.25	4.92	7.37	(2.45)
2028	3.65	1.25	4.90	7.34	(2.44)
2029	3.64	1.25	4.89	7.31	(2.42)
2030	3.62	1.25	4.87	7.27	(2.41)
2031	3.60	1.25	4.85	7.24	(2.39)
2032	3.58	1.25	4.83	7.21	(2.37)
2033	3.56	1.25	4.81	7.17	(2.36)
2034	3.55	1.25	4.80	7.14	(2.34)
2035	3.53	1.25	4.78	7.11	(2.33)
2036	3.51	1.25	4.76	7.07	(2.31)
2037	3.49	1.25	4.74	7.04	(2.30)
2038	3.46	1.24	4.70	6.98	(2.28)
2039	3.34	1.18	4.53	6.74	(2.21)
2040	3.14	1.09	4.23	6.36	(2.13)
2041	2.82	0.95	3.77	5.70	(1.93)
2042	2.11	0.66	2.77	4.27	(1.51)
2043	0.90	0.22	1.12	1.79	(0.67)
NPV:	**$ 42.21**	**$ 150.42**	**$ 192.62**	**$ 281.63**	**$ (89.01)**

APPENDIX A-4
FORECAST, SCENARIO 1, COST-BENEFIT RESULTS

	ESTIMATED DIRECT BENEFITS (BASELINE)													
	(a)	(b)	(c)	(d) = (a)+(b)+(c)	(e)	(f)	(g)	(h) = (e)+(f)+(g)	(i)	(j)	(k)	(l) = (i)+(j)+(k)	(m) = (h)+(l)	(n) = (d)+(e)+(i)
	Avoided Power Costs				Solar Installation Benefits				Solar O&M Benefits				Total Solar Benefits	Total Direct Benefits
	Energy	Capacity	T&D	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total		
	(million $)													
2008	$ 0.01	$ 0.00	$ 0.00	$ 0.02	$ 0.44	$ 0.51	$ 0.26	$ 1.21	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 1.22	$ 0.46
2009	0.11	0.03	0.00	0.13	3.05	3.56	1.82	8.43	0.03	0.03	0.01	0.07	8.50	3.21
2010	0.28	0.07	0.00	0.35	4.92	5.74	2.93	13.59	0.07	0.07	0.03	0.16	13.75	5.34
2011	0.57	0.13	0.00	0.70	7.26	8.47	4.32	20.05	0.12	0.12	0.05	0.30	20.35	8.08
2012	1.21	0.29	0.00	1.51	15.31	17.88	9.12	42.31	0.24	0.24	0.11	0.59	42.90	17.06
2013	2.33	0.56	0.01	2.90	22.72	26.53	13.53	62.78	0.42	0.42	0.18	1.03	63.80	26.04
2014	4.40	1.07	0.02	5.48	29.47	34.42	17.55	81.44	0.65	0.65	0.29	1.59	83.03	35.61
2015	4.84	1.17	0.02	6.03	6.29	7.35	3.75	17.39	0.70	0.70	0.31	1.71	19.10	13.02
2016	5.36	1.29	0.02	6.67	6.95	8.11	4.14	19.19	0.75	0.75	0.33	1.84	21.03	14.37
2017	5.44	1.31	0.02	6.78	1.32	1.54	0.79	3.65	0.76	0.77	0.34	1.87	5.52	8.86
2018	5.54	1.34	0.02	6.89	1.39	1.63	0.83	3.85	0.78	0.78	0.34	1.89	5.75	9.06
2019	5.64	1.36	0.02	7.02	1.43	1.67	0.85	3.95	0.79	0.79	0.35	1.92	5.87	9.23
2020	5.71	1.38	0.02	7.10	1.01	1.18	0.60	2.79	0.79	0.80	0.35	1.94	4.73	8.91
2021	5.68	1.37	0.02	7.07	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.86
2022	5.65	1.36	0.02	7.03	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.83
2023	5.62	1.35	0.02	7.00	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.79
2024	5.60	1.35	0.02	6.96	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.76
2025	5.57	1.34	0.02	6.93	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.72
2026	5.54	1.33	0.02	6.89	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.69
2027	5.51	1.33	0.02	6.86	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.65
2028	5.48	1.32	0.02	6.82	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.62
2029	5.46	1.31	0.02	6.79	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.58
2030	5.43	1.31	0.02	6.76	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.55
2031	5.40	1.30	0.02	6.72	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.52
2032	5.38	1.29	0.02	6.69	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.48
2033	5.35	1.29	0.02	6.66	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.45
2034	5.32	1.28	0.02	6.62	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.42
2035	5.30	1.28	0.02	6.59	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.38
2036	5.27	1.27	0.02	6.56	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.35
2037	5.24	1.26	0.02	6.52	-	-	-	-	0.79	0.80	0.35	1.94	1.94	7.32
2038	5.20	1.25	0.02	6.47	-	-	-	-	0.79	0.79	0.35	1.93	1.93	7.27
2039	5.10	1.23	0.02	6.34	-	-	-	-	0.77	0.77	0.34	1.87	1.87	7.11
2040	4.92	1.19	0.02	6.12	-	-	-	-	0.73	0.73	0.32	1.78	1.78	6.85
2041	4.65	1.12	0.02	5.79	-	-	-	-	0.67	0.67	0.30	1.64	1.64	6.46
2042	4.07	0.98	0.01	5.06	-	-	-	-	0.55	0.55	0.24	1.35	1.35	5.61
2043	3.08	0.73	0.01	3.82	-	-	-	-	0.37	0.37	0.16	0.91	0.91	4.20
2044	1.28	0.28	0.00	1.56	-	-	-	-	0.14	0.14	0.06	0.35	0.35	1.71
2045	0.87	0.19	0.00	1.07	-	-	-	-	0.09	0.09	0.04	0.23	0.23	1.16
2046	0.40	0.09	0.00	0.49	-	-	-	-	0.04	0.04	0.02	0.10	0.10	0.53
2047	0.30	0.07	0.00	0.37	-	-	-	-	0.03	0.03	0.01	0.07	0.07	0.40
2048	0.20	0.04	0.00	0.24	-	-	-	-	0.02	0.02	0.01	0.05	0.05	0.26
2049	0.08	0.02	0.00	0.10	-	-	-	-	0.01	0.01	0.00	0.02	0.02	0.11
NPV:	**$ 58.94**	**$ 14.19**	**$ 0.20**	**$ 73.33**	**$ 72.50**	**$ 84.66**	**$ 43.17**	**$ 200.33**	**$ 8.62**	**$ 8.63**	**$ 3.80**	**$ 21.05**	**$ 221.38**	**$ 154.45**

APPENDIX A-4
FORECAST, SCENARIO 1, COST-BENEFIT RESULTS

	ESTIMATED DIRECT COSTS (BASELINE)														
	(a)	(b)	(c)	(d)	(e)	(f) = (c)+(d)+(e)	(g)	(h)	(i)	(j) = (g)+(h)+(i)	(k)	(l)	(m)	(n) = (k)+(l)+(m)	(o) = (a)+(b)+(f)+(j)+(n)
	Unrecovered Interconnection Costs	NEM Admin. Costs	Rate Impacts: NEM Payments				Rate Impacts: Lost Revenues				State Tax Incentives				Total NEM Program Costs
			Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	
	($)														
2008	$ 0.02	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.02	$ 0.00	$ 0.01	$ 0.03	$ 0.80	$ 0.49	$ 0.28	$ 1.57	$ 1.62
2009	0.08	0.02	0.02	0.00	0.01	0.04	0.11	0.00	0.10	0.21	6.26	3.79	2.19	12.24	12.60
2010	0.11	0.05	0.04	0.01	0.03	0.08	0.27	0.00	0.26	0.54	10.20	6.18	3.56	19.94	20.73
2011	0.14	0.09	0.16	0.04	0.09	0.29	0.52	0.01	0.48	1.01	13.82	8.38	4.84	27.04	28.57
2012	0.34	0.18	0.33	0.06	0.21	0.61	1.13	0.02	1.07	2.22	30.95	18.76	10.82	60.53	63.87
2013	0.81	0.41	0.50	0.08	0.33	0.92	2.28	0.04	2.17	4.49	46.54	28.21	16.27	91.02	97.64
2014	1.49	0.84	0.70	0.09	0.51	1.31	4.49	0.05	4.29	8.83	60.78	36.84	21.24	118.86	131.32
2015	0.33	0.93	0.75	0.10	0.54	1.39	4.75	0.06	4.53	9.34	12.55	7.61	4.39	24.55	36.54
2016	0.35	1.04	0.80	0.11	0.57	1.48	5.07	0.08	4.82	9.96	13.67	8.29	4.78	26.74	39.57
2017	0.07	1.06	0.81	0.11	0.58	1.50	5.18	0.10	4.88	10.16	2.57	1.56	0.90	5.02	17.82
2018	0.08	1.09	0.82	0.12	0.58	1.52	5.25	0.10	4.94	10.29	-	-	-	-	12.97
2019	0.09	1.12	0.83	0.12	0.59	1.54	5.32	0.11	4.99	10.42	-	-	-	-	13.16
2020	0.06	1.14	0.84	0.12	0.59	1.55	5.37	0.12	5.03	10.52	-	-	-	-	13.27
2021	-	1.14	0.84	0.12	0.59	1.55	5.34	0.12	5.01	10.47	-	-	-	-	13.15
2022	-	1.14	0.83	0.12	0.59	1.54	5.32	0.12	4.98	10.41	-	-	-	-	13.09
2023	-	1.14	0.83	0.12	0.58	1.53	5.29	0.11	4.96	10.36	-	-	-	-	13.03
2024	-	1.14	0.82	0.12	0.58	1.52	5.26	0.11	4.93	10.31	-	-	-	-	12.97
2025	-	1.14	0.82	0.12	0.58	1.52	5.24	0.11	4.91	10.26	-	-	-	-	12.91
2026	-	1.14	0.82	0.12	0.57	1.51	5.21	0.11	4.88	10.21	-	-	-	-	12.85
2027	-	1.14	0.81	0.12	0.57	1.50	5.18	0.11	4.86	10.16	-	-	-	-	12.80
2028	-	1.14	0.81	0.12	0.57	1.49	5.16	0.11	4.84	10.11	-	-	-	-	12.74
2029	-	1.14	0.80	0.12	0.57	1.49	5.13	0.11	4.81	10.06	-	-	-	-	12.68
2030	-	1.14	0.80	0.12	0.56	1.48	5.11	0.11	4.79	10.01	-	-	-	-	12.62
2031	-	1.14	0.80	0.12	0.56	1.47	5.08	0.11	4.76	9.96	-	-	-	-	12.56
2032	-	1.14	0.79	0.11	0.56	1.46	5.06	0.11	4.74	9.91	-	-	-	-	12.51
2033	-	1.14	0.79	0.11	0.55	1.46	5.03	0.11	4.72	9.86	-	-	-	-	12.45
2034	-	1.14	0.78	0.11	0.55	1.45	5.01	0.11	4.69	9.81	-	-	-	-	12.39
2035	-	1.14	0.78	0.11	0.55	1.44	4.98	0.11	4.67	9.76	-	-	-	-	12.34
2036	-	1.14	0.78	0.11	0.55	1.43	4.96	0.11	4.65	9.71	-	-	-	-	12.28
2037	-	1.14	0.77	0.11	0.54	1.43	4.93	0.11	4.62	9.66	-	-	-	-	12.23
2038	-	1.13	0.77	0.11	0.54	1.42	4.89	0.11	4.59	9.59	-	-	-	-	12.14
2039	-	1.11	0.75	0.11	0.53	1.38	4.79	0.10	4.49	9.38	-	-	-	-	11.88
2040	-	1.08	0.72	0.10	0.51	1.34	4.62	0.10	4.33	9.05	-	-	-	-	11.47
2041	-	1.05	0.62	0.08	0.45	1.15	4.39	0.09	4.12	8.60	-	-	-	-	10.79
2042	-	0.96	0.47	0.06	0.35	0.87	3.84	0.09	3.59	7.52	-	-	-	-	9.34
2043	-	0.73	0.32	0.04	0.24	0.60	2.82	0.07	2.62	5.52	-	-	-	-	6.84
2044	-	0.30	0.14	0.03	0.08	0.25	0.90	0.06	0.77	1.73	-	-	-	-	2.28
2045	-	0.21	0.10	0.02	0.05	0.17	0.65	0.05	0.54	1.25	-	-	-	-	1.63
2046	-	0.10	0.05	0.01	0.03	0.09	0.35	0.04	0.27	0.66	-	-	-	-	0.85
2047	-	0.07	0.04	0.01	0.02	0.07	0.23	0.02	0.19	0.44	-	-	-	-	0.59
2048	-	0.05	0.03	0.01	0.01	0.05	0.15	0.01	0.13	0.29	-	-	-	-	0.39
2049	-	0.02	0.01	0.00	0.01	0.02	0.07	0.01	0.06	0.13	-	-	-	-	0.17
NPV:	**$ 2.75**	**$ 11.90**	**$ 9.00**	**$ 1.32**	**$ 6.31**	**$ 16.62**	**$ 55.86**	**$ 1.12**	**$ 52.53**	**$ 109.50**	**$ 142.90**	**$ 86.62**	**$ 49.95**	**$ 279.48**	**$ 420.25**

APPENDIX A-4
FORECAST, SCENARIO 1, COST-BENEFIT RESULTS

	ESTIMATED DIRECT NET BENEFITS (BASELINE)				
	(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) - (d)
	Total Avoided Power Costs	Total Solar Benefits	Total Benefits	Total Costs	Net NEM Program Benefits
	($)				
2008	$ 0.02	$ 1.22	$ 1.24	$ 1.62	$ (0.39)
2009	0.13	8.50	8.63	12.60	(3.96)
2010	0.35	13.75	14.10	20.73	(6.63)
2011	0.70	20.35	21.05	28.57	(7.53)
2012	1.51	42.90	44.41	63.87	(19.46)
2013	2.90	63.80	66.70	97.64	(30.94)
2014	5.48	83.03	88.51	131.32	(42.81)
2015	6.03	19.10	25.12	36.54	(11.42)
2016	6.67	21.03	27.70	39.57	(11.87)
2017	6.78	5.52	12.29	17.82	(5.52)
2018	6.89	5.75	12.64	12.97	(0.33)
2019	7.02	5.87	12.89	13.16	(0.28)
2020	7.10	4.73	11.84	13.27	(1.44)
2021	7.07	1.94	9.01	13.15	(4.14)
2022	7.03	1.94	8.97	13.09	(4.12)
2023	7.00	1.94	8.94	13.03	(4.10)
2024	6.96	1.94	8.90	12.97	(4.07)
2025	6.93	1.94	8.87	12.91	(4.05)
2026	6.89	1.94	8.83	12.85	(4.02)
2027	6.86	1.94	8.80	12.80	(4.00)
2028	6.82	1.94	8.76	12.74	(3.97)
2029	6.79	1.94	8.73	12.68	(3.95)
2030	6.76	1.94	8.70	12.62	(3.93)
2031	6.72	1.94	8.66	12.56	(3.90)
2032	6.69	1.94	8.63	12.51	(3.88)
2033	6.66	1.94	8.59	12.45	(3.86)
2034	6.62	1.94	8.56	12.39	(3.83)
2035	6.59	1.94	8.53	12.34	(3.81)
2036	6.56	1.94	8.49	12.28	(3.79)
2037	6.52	1.94	8.46	12.23	(3.76)
2038	6.47	1.93	8.41	12.14	(3.73)
2039	6.34	1.87	8.21	11.88	(3.66)
2040	6.12	1.78	7.90	11.47	(3.57)
2041	5.79	1.64	7.43	10.79	(3.36)
2042	5.06	1.35	6.41	9.34	(2.94)
2043	3.82	0.91	4.74	6.84	(2.10)
2044	1.56	0.35	1.91	2.28	(0.37)
2045	1.07	0.23	1.30	1.63	(0.33)
2046	0.49	0.10	0.59	0.85	(0.27)
2047	0.37	0.07	0.44	0.59	(0.14)
2048	0.24	0.05	0.29	0.39	(0.10)
2049	0.10	0.02	0.12	0.17	(0.05)
NPV:	**$ 73.33**	**$ 221.38**	**$ 294.71**	**$ 420.25**	**$ (125.54)**

APPENDIX A-5
FORECAST, SCENARIO 2, COST-BENEFIT RESULTS

	ESTIMATED DIRECT BENEFITS (BASELINE)													
	(a)	(b)	(c)	(d) = (a)+(b)+(c)	(e)	(f)	(g)	(h) = (e)+(f)+(g)	(i)	(j)	(k)	(l) = (i)+(j)+(k)	(m) = (h)+(l)	(n) = (d)+ (e)+(i)
	Avoided Power Costs				Solar Installation Benefits				Solar O&M Benefits				Total Solar Benefits	Total Direct Benefits
	Energy	Capacity	T&D	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total		
	(million $)													
2008	$ 0.01	$ 0.00	$ 0.00	$ 0.02	$ 0.44	$ 0.51	$ 0.26	$ 1.21	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 1.22	$ 0.46
2009	0.11	0.03	0.00	0.13	3.05	3.56	1.82	8.43	0.03	0.03	0.01	0.07	8.50	3.21
2010	0.28	0.07	0.00	0.35	4.92	5.74	2.93	13.59	0.07	0.07	0.03	0.16	13.75	5.34
2011	0.57	0.13	0.00	0.70	7.26	8.47	4.32	20.05	0.12	0.12	0.05	0.30	20.35	8.08
2012	1.21	0.29	0.00	1.51	15.31	17.88	9.12	42.31	0.24	0.24	0.11	0.59	42.90	17.06
2013	2.33	0.56	0.01	2.90	22.72	26.53	13.53	62.78	0.42	0.42	0.18	1.03	63.80	26.04
2014	4.72	1.15	0.02	5.88	34.59	40.38	20.60	95.57	0.69	0.69	0.30	1.69	97.25	41.16
2015	10.11	2.46	0.03	12.60	77.57	90.57	46.19	214.32	1.30	1.30	0.57	3.17	217.49	91.46
2016	22.99	5.60	0.08	28.67	192.80	225.12	114.81	532.73	2.80	2.81	1.23	6.85	539.58	224.27
2017	25.18	6.13	0.09	31.40	31.90	37.25	19.00	88.15	3.05	3.06	1.34	7.46	95.60	66.35
2018	27.59	6.72	0.09	34.41	33.86	39.54	20.16	93.57	3.32	3.32	1.46	8.10	101.67	71.59
2019	30.24	7.36	0.10	37.71	35.95	41.97	21.40	99.32	3.60	3.60	1.59	8.79	108.11	77.26
2020	33.16	8.08	0.11	41.35	38.16	44.55	22.72	105.43	3.90	3.90	1.72	9.52	114.95	83.41
2021	33.00	8.04	0.11	41.15	-	-	-	-	3.90	3.90	1.72	9.52	9.52	45.04
2022	32.83	7.99	0.11	40.94	-	-	-	-	3.90	3.90	1.72	9.52	9.52	44.84
2023	32.67	7.95	0.11	40.74	-	-	-	-	3.90	3.90	1.72	9.52	9.52	44.63
2024	32.51	7.92	0.11	40.53	-	-	-	-	3.90	3.90	1.72	9.52	9.52	44.43
2025	32.34	7.88	0.11	40.33	-	-	-	-	3.90	3.90	1.72	9.52	9.52	44.23
2026	32.18	7.84	0.11	40.13	-	-	-	-	3.90	3.90	1.72	9.52	9.52	44.03
2027	32.02	7.80	0.11	39.93	-	-	-	-	3.90	3.90	1.72	9.52	9.52	43.83
2028	31.86	7.76	0.11	39.73	-	-	-	-	3.90	3.90	1.72	9.52	9.52	43.63
2029	31.70	7.72	0.11	39.53	-	-	-	-	3.90	3.90	1.72	9.52	9.52	43.43
2030	31.54	7.68	0.11	39.33	-	-	-	-	3.90	3.90	1.72	9.52	9.52	43.23
2031	31.38	7.64	0.11	39.13	-	-	-	-	3.90	3.90	1.72	9.52	9.52	43.03
2032	31.23	7.60	0.11	38.94	-	-	-	-	3.90	3.90	1.72	9.52	9.52	42.84
2033	31.07	7.57	0.11	38.74	-	-	-	-	3.90	3.90	1.72	9.52	9.52	42.64
2034	30.92	7.53	0.11	38.55	-	-	-	-	3.90	3.90	1.72	9.52	9.52	42.45
2035	30.76	7.49	0.11	38.36	-	-	-	-	3.90	3.90	1.72	9.52	9.52	42.26
2036	30.61	7.45	0.10	38.17	-	-	-	-	3.90	3.90	1.72	9.52	9.52	42.06
2037	30.45	7.42	0.10	37.97	-	-	-	-	3.90	3.90	1.72	9.52	9.52	41.87
2038	30.29	7.38	0.10	37.77	-	-	-	-	3.89	3.90	1.72	9.51	9.51	41.67
2039	30.06	7.33	0.10	37.49	-	-	-	-	3.87	3.88	1.70	9.45	9.45	41.36
2040	29.76	7.28	0.10	37.14	-	-	-	-	3.83	3.84	1.69	9.36	9.36	40.97
2041	29.36	7.20	0.10	36.66	-	-	-	-	3.78	3.78	1.66	9.22	9.22	40.44
2042	28.66	7.06	0.10	35.81	-	-	-	-	3.66	3.66	1.61	8.93	8.93	39.47
2043	27.55	6.86	0.10	34.50	-	-	-	-	3.48	3.48	1.53	8.49	8.49	37.98
2044	25.34	6.31	0.09	31.74	-	-	-	-	3.21	3.21	1.41	7.83	7.83	34.95
2045	20.56	5.12	0.07	25.75	-	-	-	-	2.60	2.60	1.15	6.35	6.35	28.36
2046	9.33	2.32	0.03	11.68	-	-	-	-	1.09	1.10	0.48	2.67	2.67	12.78
2047	7.30	1.81	0.03	9.14	-	-	-	-	0.84	0.85	0.37	2.06	2.06	9.99
2048	5.08	1.26	0.02	6.36	-	-	-	-	0.58	0.58	0.26	1.41	1.41	6.94
2049	2.65	0.66	0.01	3.32	-	-	-	-	0.30	0.30	0.13	0.73	0.73	3.62
NPV:	**$ 296.75**	**$ 72.33**	**$ 1.02**	**$ 370.10**	**$ 308.07**	**$ 359.72**	**$ 183.45**	**$ 851.24**	**$ 36.63**	**$ 36.68**	**$ 16.13**	**$ 89.44**	**$ 940.68**	**$ 714.80**

APPENDIX A-5
FORECAST, SCENARIO 2, COST-BENEFIT RESULTS

	ESTIMATED DIRECT COSTS (BASELINE)														
	(a)	(b)	(c)	(d)	(e)	(f) = (c)+(d)+(e)	(g)	(h)	(i)	(j) = (g)+(h)+(i)	(k)	(l)	(m)	(n) = (k)+(l)+(m)	(o) = (a)+(b)+(f)+(j)+(n)
	Unrecovered Interconnection Costs	NEM Admin. Costs	Rate Impacts: NEM Payments				Rate Impacts: Lost Revenues				State Tax Incentives				Total NEM Program Costs
			Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	
	($)														
2008	$ 0.02	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.02	$ 0.00	$ 0.01	$ 0.03	$ 0.80	$ 0.48	$ 0.27	$ 1.55	$ 1.61
2009	0.08	0.02	0.02	0.00	0.01	0.04	0.11	0.00	0.10	0.21	6.22	3.77	2.14	12.13	12.48
2010	0.11	0.05	0.04	0.01	0.03	0.08	0.27	0.00	0.26	0.54	10.13	6.14	3.48	19.76	20.55
2011	0.14	0.09	0.16	0.04	0.09	0.29	0.52	0.01	0.48	1.01	13.73	8.32	4.72	26.77	28.30
2012	0.34	0.18	0.33	0.06	0.21	0.61	1.13	0.02	1.07	2.22	30.74	18.64	10.57	59.95	63.30
2013	0.81	0.41	0.50	0.08	0.33	0.92	2.28	0.04	2.17	4.49	46.24	28.04	15.89	90.17	96.79
2014	1.73	0.89	0.88	0.14	0.59	1.61	4.81	0.07	4.58	9.45	70.50	42.75	24.23	137.49	151.18
2015	3.90	2.00	1.77	0.29	1.17	3.24	10.55	0.13	10.07	20.75	158.24	95.95	54.39	308.59	338.47
2016	9.42	4.66	3.97	0.71	2.53	7.21	24.28	0.28	23.23	47.79	393.15	238.40	135.14	766.69	835.77
2017	1.68	5.13	4.33	0.77	2.77	7.87	27.31	0.52	25.72	53.56	65.03	39.43	22.35	126.82	195.05
2018	1.84	5.65	4.73	0.84	3.03	8.60	29.93	0.58	28.19	58.70	-	-	-	-	74.79
2019	2.03	6.22	5.17	0.92	3.31	9.40	32.81	0.63	30.91	64.35	-	-	-	-	81.99
2020	2.23	6.85	5.65	1.01	3.62	10.28	35.98	0.69	33.90	70.57	-	-	-	-	89.92
2021	-	6.85	5.62	1.00	3.61	10.23	35.80	0.69	33.73	70.22	-	-	-	-	87.29
2022	-	6.85	5.59	1.00	3.59	10.18	35.62	0.68	33.56	69.86	-	-	-	-	86.89
2023	-	6.85	5.56	0.99	3.57	10.13	35.44	0.68	33.39	69.52	-	-	-	-	86.49
2024	-	6.85	5.54	0.99	3.55	10.07	35.27	0.68	33.22	69.17	-	-	-	-	86.09
2025	-	6.85	5.51	0.98	3.53	10.02	35.09	0.67	33.06	68.82	-	-	-	-	85.69
2026	-	6.85	5.48	0.98	3.52	9.97	34.92	0.67	32.89	68.48	-	-	-	-	85.30
2027	-	6.85	5.45	0.97	3.50	9.92	34.74	0.67	32.73	68.14	-	-	-	-	84.91
2028	-	6.85	5.43	0.97	3.48	9.87	34.57	0.66	32.56	67.79	-	-	-	-	84.52
2029	-	6.85	5.40	0.96	3.46	9.83	34.39	0.66	32.40	67.46	-	-	-	-	84.13
2030	-	6.85	5.37	0.96	3.45	9.78	34.22	0.66	32.24	67.12	-	-	-	-	83.74
2031	-	6.85	5.35	0.95	3.43	9.73	34.05	0.65	32.08	66.78	-	-	-	-	83.36
2032	-	6.85	5.32	0.95	3.41	9.68	33.88	0.65	31.92	66.45	-	-	-	-	82.97
2033	-	6.85	5.29	0.94	3.40	9.63	33.71	0.65	31.76	66.12	-	-	-	-	82.59
2034	-	6.85	5.27	0.94	3.38	9.58	33.54	0.64	31.60	65.79	-	-	-	-	82.21
2035	-	6.85	5.24	0.93	3.36	9.53	33.38	0.64	31.44	65.46	-	-	-	-	81.84
2036	-	6.85	5.21	0.93	3.34	9.49	33.21	0.64	31.28	65.13	-	-	-	-	81.46
2037	-	6.85	5.19	0.92	3.33	9.44	33.04	0.63	31.13	64.80	-	-	-	-	81.09
2038	-	6.84	5.16	0.92	3.31	9.39	32.86	0.63	30.96	64.45	-	-	-	-	80.69
2039	-	6.82	5.12	0.91	3.28	9.31	32.62	0.63	30.73	63.98	-	-	-	-	80.11
2040	-	6.79	5.07	0.90	3.25	9.23	32.31	0.62	30.44	63.37	-	-	-	-	79.39
2041	-	6.76	4.94	0.87	3.18	9.00	31.94	0.61	30.09	62.65	-	-	-	-	78.40
2042	-	6.67	4.77	0.85	3.07	8.68	31.25	0.60	29.44	61.29	-	-	-	-	76.64
2043	-	6.44	4.60	0.82	2.94	8.37	30.10	0.59	28.34	59.03	-	-	-	-	73.83
2044	-	5.95	4.25	0.77	2.70	7.73	27.77	0.56	26.12	54.44	-	-	-	-	68.12
2045	-	4.85	3.46	0.63	2.19	6.28	22.67	0.50	21.24	44.40	-	-	-	-	55.53
2046	-	2.19	1.55	0.27	1.00	2.82	10.70	0.37	9.76	20.83	-	-	-	-	25.84
2047	-	1.72	1.21	0.21	0.78	2.20	7.93	0.15	7.47	15.56	-	-	-	-	19.48
2048	-	1.20	0.84	0.15	0.54	1.53	5.52	0.11	5.20	10.83	-	-	-	-	13.56
2049	-	0.63	0.44	0.08	0.28	0.80	2.88	0.06	2.72	5.66	-	-	-	-	7.09
NPV:	**$ 14.77**	**$ 63.17**	**$ 50.87**	**$ 9.05**	**$ 32.65**	**$ 92.56**	**$ 320.85**	**$ 6.01**	**$ 302.54**	**$ 629.40**	**$ 512.35**	**$ 310.68**	**$ 176.11**	**$ 999.14**	**$ 1,799.04**

APPENDIX A-5
FORECAST, SCENARIO 2, COST-BENEFIT RESULTS

	ESTIMATED DIRECT NET BENEFITS (BASELINE)				
	(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) - (d)
	Total Avoided Power Costs	Total Solar Benefits	Total Benefits	Total Costs	Net NEM Program Benefits
	($)				
2008	$ 0.02	$ 1.22	$ 1.24	$ 1.61	$ (0.37)
2009	0.13	8.50	8.63	12.48	(3.85)
2010	0.35	13.75	14.10	20.55	(6.45)
2011	0.70	20.35	21.05	28.30	(7.25)
2012	1.51	42.90	44.41	63.30	(18.89)
2013	2.90	63.80	66.70	96.79	(30.09)
2014	5.88	97.25	103.13	151.18	(48.04)
2015	12.60	217.49	230.09	338.47	(108.38)
2016	28.67	539.58	568.25	835.77	(267.53)
2017	31.40	95.60	127.00	195.05	(68.05)
2018	34.41	101.67	136.07	74.79	61.29
2019	37.71	108.11	145.82	81.99	63.83
2020	41.35	114.95	156.30	89.92	66.38
2021	41.15	9.52	50.66	87.29	(36.63)
2022	40.94	9.52	50.46	86.89	(36.43)
2023	40.74	9.52	50.25	86.49	(36.23)
2024	40.53	9.52	50.05	86.09	(36.04)
2025	40.33	9.52	49.85	85.69	(35.85)
2026	40.13	9.52	49.65	85.30	(35.65)
2027	39.93	9.52	49.45	84.91	(35.46)
2028	39.73	9.52	49.25	84.52	(35.27)
2029	39.53	9.52	49.05	84.13	(35.08)
2030	39.33	9.52	48.85	83.74	(34.89)
2031	39.13	9.52	48.65	83.36	(34.70)
2032	38.94	9.52	48.46	82.97	(34.52)
2033	38.74	9.52	48.26	82.59	(34.33)
2034	38.55	9.52	48.07	82.21	(34.15)
2035	38.36	9.52	47.88	81.84	(33.96)
2036	38.17	9.52	47.68	81.46	(33.78)
2037	37.97	9.52	47.49	81.09	(33.60)
2038	37.77	9.51	47.28	80.69	(33.41)
2039	37.49	9.45	46.94	80.11	(33.17)
2040	37.14	9.36	46.49	79.39	(32.90)
2041	36.66	9.22	45.88	78.40	(32.52)
2042	35.81	8.93	44.74	76.64	(31.90)
2043	34.50	8.49	43.00	73.83	(30.84)
2044	31.74	7.83	39.58	68.12	(28.54)
2045	25.75	6.35	32.11	55.53	(23.43)
2046	11.68	2.67	14.35	25.84	(11.48)
2047	9.14	2.06	11.20	19.48	(8.28)
2048	6.36	1.41	7.78	13.56	(5.78)
2049	3.32	0.73	4.05	7.09	(3.03)
NPV:	**$ 370.10**	**$ 940.68**	**$ 1,310.78**	**$ 1,799.04**	**$ (488.26)**

APPENDIX A-6
BASELINE, SENSITIVITY 1, COST-BENEFIT RESULTS

ESTIMATED DIRECT BENEFITS (BASELINE)														
	(a)	(b)	(c)	(d) = (a)+(b)+(c)	(e)	(f)	(g)	(h) = (e)+(f)+(g)	(i)	(j)	(k)	(l) = (i)+(j)+(k)	(m) = (h)+(l)	(n) = (d)+(e)+(i)
	Avoided Power Costs				Solar Installation Benefits				Solar O&M Benefits				Total Solar Benefits	Total Direct Benefits
	Energy	Capacity	T&D	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total		
	(million $)													
2008	$0.02	$0.00	$0.00	$ 0.02	$ 0.44	$ 0.51	$ 0.26	$ 1.21	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 1.22	$ 0.46
2009	0.14	0.03	0.00	0.17	3.05	3.56	1.82	8.43	0.03	0.03	0.01	0.07	8.50	3.25
2010	0.37	0.07	0.00	0.44	4.92	5.74	2.93	13.59	0.07	0.07	0.03	0.16	13.75	5.42
2011	0.74	0.13	0.00	0.88	7.26	8.47	4.32	20.05	0.12	0.12	0.05	0.30	20.35	8.25
2012	1.59	0.29	0.00	1.88	15.31	17.88	9.12	42.31	0.24	0.24	0.11	0.59	42.90	17.44
2013	3.05	0.56	0.01	3.62	22.72	26.53	13.53	62.78	0.42	0.42	0.18	1.03	63.80	26.76
2014	4.12	0.76	0.01	4.90	11.73	13.70	6.99	32.42	0.51	0.51	0.23	1.25	33.67	17.14
2015	4.10	0.76	0.01	4.87	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.38
2016	4.08	0.76	0.01	4.85	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.36
2017	4.06	0.75	0.01	4.82	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.33
2018	4.04	0.75	0.01	4.80	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.31
2019	4.02	0.74	0.01	4.78	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.29
2020	4.00	0.74	0.01	4.75	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.26
2021	3.98	0.74	0.01	4.73	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.24
2022	3.96	0.73	0.01	4.70	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.22
2023	3.94	0.73	0.01	4.68	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.19
2024	3.92	0.73	0.01	4.66	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.17
2025	3.90	0.72	0.01	4.63	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.15
2026	3.88	0.72	0.01	4.61	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.12
2027	3.86	0.71	0.01	4.59	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.10
2028	3.84	0.71	0.01	4.56	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.08
2029	3.82	0.71	0.01	4.54	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.05
2030	3.81	0.70	0.01	4.52	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.03
2031	3.79	0.70	0.01	4.50	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.01
2032	3.77	0.70	0.01	4.47	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	4.99
2033	3.75	0.69	0.01	4.45	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	4.96
2034	3.73	0.69	0.01	4.43	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	4.94
2035	3.71	0.69	0.01	4.41	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	4.92
2036	3.69	0.68	0.01	4.38	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	4.90
2037	3.67	0.68	0.01	4.36	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	4.87
2038	3.64	0.67	0.01	4.32	0.00	0.00	0.00	0.00	0.51	0.51	0.22	1.24	1.24	4.83
2039	3.52	0.65	0.01	4.18	0.00	0.00	0.00	0.00	0.48	0.49	0.21	1.18	1.18	4.66
2040	3.30	0.61	0.01	3.92	0.00	0.00	0.00	0.00	0.45	0.45	0.20	1.09	1.09	4.37
2041	2.96	0.55	0.01	3.52	0.00	0.00	0.00	0.00	0.39	0.39	0.17	0.95	0.95	3.91
2042	2.21	0.41	0.01	2.63	0.00	0.00	0.00	0.00	0.27	0.27	0.12	0.66	0.66	2.90
2043	0.94	0.18	0.00	1.12	0.00	0.00	0.00	0.00	0.09	0.09	0.04	0.22	0.22	1.21
NPV:	**$ 44.39**	**$ 8.20**	**$ 0.12**	**$ 52.71**	**$ 49.26**	**$ 57.52**	**$ 29.33**	**$ 136.12**	**$ 5.86**	**$ 5.87**	**$ 2.58**	**$ 14.30**	**$ 150.42**	**$ 107.83**

APPENDIX A-6
BASELINE, SENSITIVITY 1, COST-BENEFIT RESULTS

	ESTIMATED DIRECT COSTS (BASELINE)														
	(a)	(b)	(c)	(d)	(e)	(f) = (c)+(d)+(e)	(g)	(h)	(i)	(j) = (g)+(h)+(i)	(k)	(l)	(m)	(n) = (k)+(l)+(m)	(o) = (a)+(b)+(f)+(j)+(n)
	Unrecovered Interconnection Costs	NEM Admin. Costs	Rate Impacts: NEM Payments				Rate Impacts: Lost Revenues				State Tax Incentives				Total NEM Program Costs
			Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	
	($)														
2008	$ 0.02	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.02	$ 0.00	$ 0.01	$ 0.03	$ 0.80	$ 0.49	$ 0.28	$ 1.57	$ 1.62
2009	0.08	0.02	0.02	0.00	0.01	0.04	0.11	0.00	0.10	0.21	6.26	3.79	2.19	12.24	12.60
2010	0.11	0.05	0.04	0.01	0.03	0.08	0.27	0.00	0.26	0.54	10.20	6.18	3.56	19.94	20.73
2011	0.14	0.09	0.16	0.04	0.09	0.29	0.52	0.01	0.48	1.01	13.82	8.38	4.84	27.04	28.57
2012	0.34	0.18	0.33	0.06	0.21	0.61	1.13	0.02	1.07	2.22	30.95	18.76	10.82	60.53	63.87
2013	0.81	0.41	0.50	0.08	0.33	0.92	2.28	0.04	2.17	4.49	46.54	28.21	16.27	91.02	97.64
2014	0.59	0.58	0.60	0.09	0.40	1.10	3.13	0.04	2.99	6.16	24.30	14.73	8.49	47.52	55.94
2015	0.00	0.58	0.59	0.09	0.40	1.09	3.11	0.04	2.97	6.13	0.00	0.00	0.00	0.00	7.80
2016	0.00	0.58	0.59	0.09	0.40	1.09	3.10	0.04	2.96	6.10	0.00	0.00	0.00	0.00	7.76
2017	0.00	0.58	0.59	0.09	0.40	1.08	3.08	0.04	2.94	6.07	0.00	0.00	0.00	0.00	7.72
2018	0.00	0.58	0.59	0.09	0.40	1.08	3.07	0.04	2.93	6.04	0.00	0.00	0.00	0.00	7.69
2019	0.00	0.58	0.58	0.09	0.39	1.07	3.05	0.04	2.91	6.00	0.00	0.00	0.00	0.00	7.65
2020	0.00	0.58	0.58	0.09	0.39	1.06	3.04	0.04	2.90	5.97	0.00	0.00	0.00	0.00	7.62
2021	0.00	0.58	0.58	0.09	0.39	1.06	3.02	0.04	2.89	5.95	0.00	0.00	0.00	0.00	7.58
2022	0.00	0.58	0.57	0.09	0.39	1.05	3.01	0.04	2.87	5.92	0.00	0.00	0.00	0.00	7.55
2023	0.00	0.58	0.57	0.09	0.39	1.05	2.99	0.04	2.86	5.89	0.00	0.00	0.00	0.00	7.51
2024	0.00	0.58	0.57	0.09	0.39	1.04	2.98	0.04	2.84	5.86	0.00	0.00	0.00	0.00	7.48
2025	0.00	0.58	0.57	0.09	0.38	1.04	2.96	0.04	2.83	5.83	0.00	0.00	0.00	0.00	7.44
2026	0.00	0.58	0.56	0.09	0.38	1.03	2.95	0.04	2.81	5.80	0.00	0.00	0.00	0.00	7.41
2027	0.00	0.58	0.56	0.09	0.38	1.03	2.93	0.04	2.80	5.77	0.00	0.00	0.00	0.00	7.37
2028	0.00	0.58	0.56	0.09	0.38	1.02	2.92	0.04	2.79	5.74	0.00	0.00	0.00	0.00	7.34
2029	0.00	0.58	0.55	0.09	0.38	1.02	2.90	0.04	2.77	5.71	0.00	0.00	0.00	0.00	7.31
2030	0.00	0.58	0.55	0.09	0.37	1.01	2.89	0.04	2.76	5.68	0.00	0.00	0.00	0.00	7.27
2031	0.00	0.58	0.55	0.09	0.37	1.01	2.87	0.04	2.74	5.65	0.00	0.00	0.00	0.00	7.24
2032	0.00	0.58	0.55	0.09	0.37	1.00	2.86	0.04	2.73	5.63	0.00	0.00	0.00	0.00	7.21
2033	0.00	0.58	0.54	0.09	0.37	1.00	2.85	0.04	2.72	5.60	0.00	0.00	0.00	0.00	7.17
2034	0.00	0.58	0.54	0.09	0.37	0.99	2.83	0.04	2.70	5.57	0.00	0.00	0.00	0.00	7.14
2035	0.00	0.58	0.54	0.09	0.36	0.99	2.82	0.04	2.69	5.54	0.00	0.00	0.00	0.00	7.11
2036	0.00	0.58	0.54	0.09	0.36	0.98	2.80	0.04	2.68	5.51	0.00	0.00	0.00	0.00	7.07
2037	0.00	0.58	0.53	0.08	0.36	0.98	2.79	0.04	2.66	5.49	0.00	0.00	0.00	0.00	7.04
2038	0.00	0.57	0.53	0.08	0.36	0.97	2.76	0.03	2.64	5.43	0.00	0.00	0.00	0.00	6.98
2039	0.00	0.55	0.51	0.08	0.35	0.93	2.67	0.03	2.55	5.25	0.00	0.00	0.00	0.00	6.74
2040	0.00	0.52	0.49	0.08	0.33	0.90	2.51	0.03	2.40	4.94	0.00	0.00	0.00	0.00	6.36
2041	0.00	0.49	0.38	0.05	0.28	0.71	2.29	0.02	2.19	4.51	0.00	0.00	0.00	0.00	5.70
2042	0.00	0.40	0.23	0.03	0.17	0.43	1.75	0.02	1.68	3.45	0.00	0.00	0.00	0.00	4.27
2043	0.00	0.17	0.08	0.01	0.07	0.16	0.74	0.00	0.72	1.47	0.00	0.00	0.00	0.00	1.79
NPV:	**$ 1.54**	**$ 6.46**	**$ 6.57**	**$ 1.06**	**$ 4.42**	**$ 12.04**	**$ 33.60**	**$ 0.44**	**$ 32.05**	**$ 66.09**	**$ 99.96**	**$ 60.59**	**$ 34.94**	**$ 195.50**	**$ 281.63**

APPENDIX A-6
BASELINE, SENSITIVITY 1, COST-BENEFIT RESULTS

	ESTIMATED DIRECT NET BENEFITS (BASELINE)				
	(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) - (d)
	Total Avoided Power Costs	Total Solar Benefits	Total Benefits	Total Costs	Net NEM Program Benefits
	($)				
2008	$ 0.02	$ 1.22	$ 1.24	$ 1.62	$ (0.38)
2009	0.17	8.50	8.67	12.60	(3.93)
2010	0.44	13.75	14.19	20.73	(6.54)
2011	0.88	20.35	21.22	28.57	(7.35)
2012	1.88	42.90	44.78	63.87	(19.08)
2013	3.62	63.80	67.42	97.64	(30.22)
2014	4.90	33.67	38.57	55.94	(17.37)
2015	4.87	1.25	6.12	7.80	(1.67)
2016	4.85	1.25	6.10	7.76	(1.66)
2017	4.82	1.25	6.07	7.72	(1.65)
2018	4.80	1.25	6.05	7.69	(1.64)
2019	4.78	1.25	6.02	7.65	(1.63)
2020	4.75	1.25	6.00	7.62	(1.62)
2021	4.73	1.25	5.98	7.58	(1.61)
2022	4.70	1.25	5.95	7.55	(1.59)
2023	4.68	1.25	5.93	7.51	(1.58)
2024	4.66	1.25	5.91	7.48	(1.57)
2025	4.63	1.25	5.88	7.44	(1.56)
2026	4.61	1.25	5.86	7.41	(1.55)
2027	4.59	1.25	5.84	7.37	(1.54)
2028	4.56	1.25	5.81	7.34	(1.53)
2029	4.54	1.25	5.79	7.31	(1.52)
2030	4.52	1.25	5.77	7.27	(1.50)
2031	4.50	1.25	5.75	7.24	(1.49)
2032	4.47	1.25	5.72	7.21	(1.48)
2033	4.45	1.25	5.70	7.17	(1.47)
2034	4.43	1.25	5.68	7.14	(1.46)
2035	4.41	1.25	5.66	7.11	(1.45)
2036	4.38	1.25	5.63	7.07	(1.44)
2037	4.36	1.25	5.61	7.04	(1.43)
2038	4.32	1.24	5.56	6.98	(1.42)
2039	4.18	1.18	5.36	6.74	(1.38)
2040	3.92	1.09	5.01	6.36	(1.35)
2041	3.52	0.95	4.47	5.70	(1.23)
2042	2.63	0.66	3.29	4.27	(0.98)
2043	1.12	0.22	1.34	1.79	(0.45)
NPV:	**$ 52.71**	**$ 150.42**	**$ 203.13**	**$ 281.63**	**$ (78.50)**

APPENDIX A-7
BASELINE, SENSITIVITY 2, COST-BENEFIT RESULTS

	ESTIMATED DIRECT BENEFITS (BASELINE)													
	(a)	(b)	(c)	(d) = (a)+(b)+(c)	(e)	(f)	(g)	(h) = (e)+(f)+(g)	(i)	(j)	(k)	(l) = (i)+(j)+(k)	(m) = (h)+(l)	(n) = (d)+ (e)+(i)
	Avoided Power Costs				Solar Installation Benefits				Solar O&M Benefits				Total Solar Benefits	Total Direct Benefits
	Energy	Capacity	T&D	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total		
	(million $)													
2008	$ 0.01	$ 0.00	$ 0.00	$ 0.02	$ 0.44	$ 0.51	$ 0.26	$ 1.21	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 1.22	$ 0.46
2009	0.11	0.03	0.00	0.13	3.05	3.56	1.82	8.43	0.03	0.03	0.01	0.07	8.50	3.21
2010	0.28	0.07	0.00	0.35	4.92	5.74	2.93	13.59	0.07	0.07	0.03	0.16	13.75	5.34
2011	0.57	0.13	0.00	0.70	7.26	8.47	4.32	20.05	0.12	0.12	0.05	0.30	20.35	8.08
2012	1.21	0.29	0.00	1.51	15.31	17.88	9.12	42.31	0.24	0.24	0.11	0.59	42.90	17.06
2013	2.33	0.56	0.01	2.90	22.72	26.53	13.53	62.78	0.42	0.42	0.18	1.03	63.80	26.04
2014	3.15	0.76	0.01	3.92	11.73	13.70	6.99	32.42	0.51	0.51	0.23	1.25	33.67	16.17
2015	3.13	1.33	0.01	4.47	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	4.99
2016	3.12	1.90	0.01	5.02	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.53
2017	3.10	2.46	0.01	5.57	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	6.08
2018	3.08	3.01	0.01	6.10	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	6.61
2019	3.07	3.56	0.01	6.63	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	7.15
2020	3.05	4.10	0.01	7.16	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	7.67
2021	3.04	4.08	0.01	7.13	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	7.64
2022	3.02	4.06	0.01	7.09	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	7.60
2023	3.01	3.88	0.01	6.90	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	7.41
2024	2.99	3.70	0.01	6.71	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	7.22
2025	2.98	3.53	0.01	6.52	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	7.03
2026	2.96	3.35	0.01	6.33	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	6.84
2027	2.95	3.18	0.01	6.14	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	6.65
2028	2.93	3.01	0.01	5.96	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	6.47
2029	2.92	2.85	0.01	5.78	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	6.29
2030	2.90	2.68	0.01	5.59	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	6.11
2031	2.89	2.52	0.01	5.42	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.93
2032	2.88	2.35	0.01	5.24	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.75
2033	2.86	2.19	0.01	5.06	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.57
2034	2.85	2.03	0.01	4.89	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.40
2035	2.83	1.87	0.01	4.71	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.23
2036	2.82	1.72	0.01	4.54	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.06
2037	2.80	1.56	0.01	4.37	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	4.89
2038	2.78	1.40	0.01	4.19	0.00	0.00	0.00	0.00	0.51	0.51	0.22	1.24	1.24	4.70
2039	2.68	1.21	0.01	3.91	0.00	0.00	0.00	0.00	0.48	0.49	0.21	1.18	1.18	4.39
2040	2.52	1.01	0.01	3.54	0.00	0.00	0.00	0.00	0.45	0.45	0.20	1.09	1.09	3.98
2041	2.26	0.79	0.01	3.06	0.00	0.00	0.00	0.00	0.39	0.39	0.17	0.95	0.95	3.45
2042	1.69	0.50	0.01	2.20	0.00	0.00	0.00	0.00	0.27	0.27	0.12	0.66	0.66	2.47
2043	0.72	0.18	0.00	0.90	0.00	0.00	0.00	0.00	0.09	0.09	0.04	0.22	0.22	0.99
NPV:	**$ 33.89**	**$ 27.53**	**$ 0.12**	**$ 61.53**	**$ 49.26**	**$ 57.52**	**$ 29.33**	**$ 136.12**	**$ 5.86**	**$ 5.87**	**$ 2.58**	**$ 14.30**	**$ 150.42**	**$ 116.65**

APPENDIX A-7
BASELINE, SENSITIVITY 2, COST-BENEFIT RESULTS

	ESTIMATED DIRECT COSTS (BASELINE)														
	(a)	(b)	(c)	(d)	(e)	(f) = (c)+(d)+(e)	(g)	(h)	(i)	(j) = (g)+(h)+(i)	(k)	(l)	(m)	(n) = (k)+(l)+(m)	(o) = (a)+(b)+ (f)+(j)+(n)
	Unrecovered Interconnection Costs	NEM Admin. Costs	Rate Impacts: NEM Payments				Rate Impacts: Lost Revenues				State Tax Incentives				Total NEM Program Costs
			Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	
			($)												
2008	$ 0.02	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.02	$ 0.00	$ 0.01	$ 0.03	$ 0.80	$ 0.49	$ 0.28	$ 1.57	$ 1.62
2009	0.08	0.02	0.02	0.00	0.01	0.04	0.11	0.00	0.10	0.21	6.26	3.79	2.19	12.24	12.59
2010	0.11	0.05	0.04	0.01	0.03	0.08	0.27	0.00	0.26	0.53	10.20	6.18	3.56	19.94	20.73
2011	0.14	0.09	0.17	0.04	0.10	0.30	0.51	0.01	0.48	1.00	13.82	8.38	4.84	27.04	28.57
2012	0.34	0.18	0.35	0.06	0.22	0.63	1.12	0.02	1.06	2.20	30.95	18.76	10.82	60.53	63.88
2013	0.81	0.41	0.52	0.08	0.35	0.96	2.28	0.04	2.16	4.47	46.54	28.21	16.27	91.02	97.67
2014	0.59	0.58	0.62	0.09	0.43	1.14	3.13	0.04	2.99	6.16	24.30	14.73	8.49	47.52	55.99
2015	0.00	0.58	0.89	0.13	0.62	1.63	4.34	0.05	4.15	8.54	0.00	0.00	0.00	0.00	10.75
2016	0.00	0.58	1.17	0.17	0.82	2.16	5.54	0.07	5.29	10.90	0.00	0.00	0.00	0.00	13.63
2017	0.00	0.58	1.46	0.21	1.04	2.71	6.73	0.08	6.42	13.24	0.00	0.00	0.00	0.00	16.52
2018	0.00	0.58	1.77	0.24	1.27	3.28	7.91	0.10	7.55	15.55	0.00	0.00	0.00	0.00	19.41
2019	0.00	0.58	2.09	0.28	1.51	3.88	9.07	0.11	8.66	17.85	0.00	0.00	0.00	0.00	22.31
2020	0.00	0.58	2.42	0.31	1.77	4.51	10.23	0.13	9.77	20.13	0.00	0.00	0.00	0.00	25.21
2021	0.00	0.58	2.42	0.31	1.77	4.51	10.18	0.13	9.72	20.03	0.00	0.00	0.00	0.00	25.11
2022	0.00	0.58	2.41	0.31	1.77	4.48	10.13	0.13	9.67	19.93	0.00	0.00	0.00	0.00	24.99
2023	0.00	0.58	2.30	0.30	1.68	4.28	9.74	0.12	9.30	19.16	0.00	0.00	0.00	0.00	24.02
2024	0.00	0.58	2.19	0.29	1.60	4.08	9.35	0.12	8.93	18.40	0.00	0.00	0.00	0.00	23.06
2025	0.00	0.58	2.09	0.28	1.52	3.88	8.97	0.11	8.57	17.65	0.00	0.00	0.00	0.00	22.11
2026	0.00	0.58	1.98	0.26	1.44	3.69	8.59	0.11	8.21	16.91	0.00	0.00	0.00	0.00	21.17
2027	0.00	0.58	1.88	0.25	1.36	3.50	8.22	0.10	7.85	16.17	0.00	0.00	0.00	0.00	20.24
2028	0.00	0.58	1.78	0.24	1.29	3.31	7.85	0.10	7.50	15.44	0.00	0.00	0.00	0.00	19.33
2029	0.00	0.58	1.68	0.23	1.21	3.13	7.48	0.09	7.14	14.72	0.00	0.00	0.00	0.00	18.42
2030	0.00	0.58	1.59	0.22	1.14	2.95	7.12	0.09	6.80	14.00	0.00	0.00	0.00	0.00	17.53
2031	0.00	0.58	1.50	0.21	1.07	2.78	6.76	0.08	6.45	13.30	0.00	0.00	0.00	0.00	16.65
2032	0.00	0.58	1.41	0.20	1.00	2.61	6.40	0.08	6.11	12.60	0.00	0.00	0.00	0.00	15.78
2033	0.00	0.58	1.32	0.19	0.94	2.44	6.05	0.08	5.78	11.90	0.00	0.00	0.00	0.00	14.92
2034	0.00	0.58	1.23	0.17	0.87	2.28	5.70	0.07	5.44	11.21	0.00	0.00	0.00	0.00	14.07
2035	0.00	0.58	1.15	0.16	0.81	2.12	5.35	0.07	5.11	10.53	0.00	0.00	0.00	0.00	13.23
2036	0.00	0.58	1.06	0.15	0.75	1.97	5.01	0.06	4.79	9.86	0.00	0.00	0.00	0.00	12.40
2037	0.00	0.58	0.98	0.14	0.69	1.82	4.67	0.06	4.46	9.19	0.00	0.00	0.00	0.00	11.59
2038	0.00	0.57	0.90	0.13	0.63	1.67	4.32	0.05	4.12	8.49	0.00	0.00	0.00	0.00	10.73
2039	0.00	0.55	0.80	0.12	0.56	1.47	3.87	0.05	3.70	7.62	0.00	0.00	0.00	0.00	9.65
2040	0.00	0.52	0.70	0.10	0.48	1.29	3.37	0.04	3.21	6.62	0.00	0.00	0.00	0.00	8.43
2041	0.00	0.49	0.50	0.06	0.37	0.92	2.81	0.03	2.70	5.54	0.00	0.00	0.00	0.00	6.95
2042	0.00	0.40	0.27	0.03	0.21	0.51	1.96	0.02	1.88	3.86	0.00	0.00	0.00	0.00	4.76
2043	0.00	0.17	0.09	0.01	0.07	0.17	0.75	0.00	0.73	1.48	0.00	0.00	0.00	0.00	1.82
NPV:	**$ 1.54**	**$ 6.46**	**$ 16.93**	**$ 2.34**	**$ 12.14**	**$ 31.41**	**$ 74.97**	**$ 0.94**	**$ 71.57**	**$ 147.48**	**$ 99.96**	**$ 60.59**	**$ 34.94**	**$ 195.50**	**$ 382.39**

APPENDIX A-7
BASELINE, SENSITIVITY 2, COST-BENEFIT RESULTS

	ESTIMATED DIRECT NET BENEFITS (BASELINE)				
	(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) - (d)
	Total Avoided Power Costs	Total Solar Benefits	Total Benefits	Total Costs	Net NEM Program Benefits
	($)				
2008	$ 0.02	$ 1.22	$ 1.24	$ 1.62	$ (0.39)
2009	0.13	8.50	8.63	12.59	(3.96)
2010	0.35	13.75	14.10	20.73	(6.62)
2011	0.70	20.35	21.05	28.57	(7.52)
2012	1.51	42.90	44.41	63.88	(19.47)
2013	2.90	63.80	66.70	97.67	(30.97)
2014	3.92	33.67	37.59	55.99	(18.40)
2015	4.47	1.25	5.72	10.75	(5.03)
2016	5.02	1.25	6.27	13.63	(7.36)
2017	5.57	1.25	6.82	16.52	(9.71)
2018	6.10	1.25	7.35	19.41	(12.06)
2019	6.63	1.25	7.88	22.31	(14.43)
2020	7.16	1.25	8.41	25.21	(16.80)
2021	7.13	1.25	8.37	25.11	(16.74)
2022	7.09	1.25	8.34	24.99	(16.65)
2023	6.90	1.25	8.15	24.02	(15.87)
2024	6.71	1.25	7.95	23.06	(15.10)
2025	6.52	1.25	7.77	22.11	(14.34)
2026	6.33	1.25	7.58	21.17	(13.59)
2027	6.14	1.25	7.39	20.24	(12.85)
2028	5.96	1.25	7.21	19.33	(12.12)
2029	5.78	1.25	7.02	18.42	(11.40)
2030	5.59	1.25	6.84	17.53	(10.69)
2031	5.42	1.25	6.66	16.65	(9.98)
2032	5.24	1.25	6.49	15.78	(9.29)
2033	5.06	1.25	6.31	14.92	(8.61)
2034	4.89	1.25	6.14	14.07	(7.93)
2035	4.71	1.25	5.96	13.23	(7.27)
2036	4.54	1.25	5.79	12.40	(6.61)
2037	4.37	1.25	5.62	11.59	(5.96)
2038	4.19	1.24	5.43	10.73	(5.30)
2039	3.91	1.18	5.09	9.65	(4.56)
2040	3.54	1.09	4.63	8.43	(3.81)
2041	3.06	0.95	4.01	6.95	(2.94)
2042	2.20	0.66	2.86	4.76	(1.90)
2043	0.90	0.22	1.12	1.82	(0.69)
NPV:	**$ 61.53**	**$ 150.42**	**$ 211.95**	**$ 382.39**	**$ (170.44)**

DRAFT - February 27, 2015

APPENDIX A-8
BASELINE, SENSITIVITY 3, COST-BENEFIT RESULTS

	ESTIMATED DIRECT BENEFITS (BASELINE)														
	(a)	(b)	(c)	(d)	(e) = (a)+ (b)+(c)+(d)	(f)	(g)	(h)	(i) = (f)+(g)+(h)	(j)	(k)	(l)	(m) = (j)+(k)+(l)	(n) = (i)+(m)	(o) = (e)+ (f)+(j)
	Avoided Power Costs					Solar Installation Benefits				Solar O&M Benefits				Total Solar Benefits	Total Direct Benefits
	Energy	Capacity	T&D	Environmental	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total		
	(million $)														
2008	$ 0.01	$ 0.00	$ 0.00	$ 0.01	$ 0.03	$ 0.44	$ 0.51	$ 0.26	$ 1.21	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 1.22	$ 0.47
2009	0.11	0.03	0.00	0.05	0.19	3.05	3.56	1.82	8.43	0.03	0.03	0.01	0.07	8.50	3.27
2010	0.28	0.07	0.00	0.14	0.49	4.92	5.74	2.93	13.59	0.07	0.07	0.03	0.16	13.75	5.47
2011	0.57	0.13	0.00	0.27	0.97	7.26	8.47	4.32	20.05	0.12	0.12	0.05	0.30	20.35	8.35
2012	1.21	0.29	0.00	0.58	2.09	15.31	17.88	9.12	42.31	0.24	0.24	0.11	0.59	42.90	17.65
2013	2.33	0.56	0.01	1.12	4.02	22.72	26.53	13.53	62.78	0.42	0.42	0.18	1.03	63.80	27.16
2014	3.15	0.76	0.01	1.51	5.43	11.73	13.70	6.99	32.42	0.51	0.51	0.23	1.25	33.67	17.68
2015	3.13	0.76	0.01	1.51	5.41	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.92
2016	3.12	0.76	0.01	1.50	5.38	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.89
2017	3.10	0.75	0.01	1.49	5.35	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.87
2018	3.08	0.75	0.01	1.48	5.33	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.84
2019	3.07	0.74	0.01	1.48	5.30	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.81
2020	3.05	0.74	0.01	1.47	5.27	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.79
2021	3.04	0.74	0.01	1.46	5.25	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.76
2022	3.02	0.73	0.01	1.45	5.22	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.73
2023	3.01	0.73	0.01	1.45	5.20	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.71
2024	2.99	0.73	0.01	1.44	5.17	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.68
2025	2.98	0.72	0.01	1.43	5.14	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.65
2026	2.96	0.72	0.01	1.43	5.12	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.63
2027	2.95	0.71	0.01	1.42	5.09	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.60
2028	2.93	0.71	0.01	1.41	5.07	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.58
2029	2.92	0.71	0.01	1.40	5.04	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.55
2030	2.90	0.70	0.01	1.40	5.02	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.53
2031	2.89	0.70	0.01	1.39	4.99	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.50
2032	2.88	0.70	0.01	1.38	4.97	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.48
2033	2.86	0.69	0.01	1.38	4.94	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.45
2034	2.85	0.69	0.01	1.37	4.92	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.43
2035	2.83	0.69	0.01	1.36	4.89	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.40
2036	2.82	0.68	0.01	1.36	4.87	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.38
2037	2.80	0.68	0.01	1.35	4.84	0.00	0.00	0.00	0.00	0.51	0.51	0.23	1.25	1.25	5.35
2038	2.78	0.67	0.01	1.34	4.80	0.00	0.00	0.00	0.00	0.51	0.51	0.22	1.24	1.24	5.31
2039	2.68	0.65	0.01	1.29	4.63	0.00	0.00	0.00	0.00	0.48	0.49	0.21	1.18	1.18	5.12
2040	2.52	0.61	0.01	1.21	4.35	0.00	0.00	0.00	0.00	0.45	0.45	0.20	1.09	1.09	4.80
2041	2.26	0.55	0.01	1.09	3.91	0.00	0.00	0.00	0.00	0.39	0.39	0.17	0.95	0.95	4.30
2042	1.69	0.41	0.01	0.81	2.92	0.00	0.00	0.00	0.00	0.27	0.27	0.12	0.66	0.66	3.19
2043	0.72	0.18	0.00	0.35	1.24	0.00	0.00	0.00	0.00	0.09	0.09	0.04	0.22	0.22	1.34
NPV:	**$ 33.89**	**$ 8.20**	**$ 0.12**	**$ 16.31**	**$ 58.51**	**$ 49.26**	**$ 57.52**	**$ 29.33**	**$ 136.12**	**$ 5.86**	**$ 5.87**	**$ 2.58**	**$ 14.30**	**$ 150.42**	**$ 113.63**

APPENDIX A-8
BASELINE, SENSITIVITY 3, COST-BENEFIT RESULTS

	ESTIMATED DIRECT COSTS (BASELINE)														
	(a)	(b)	(c)	(d)	(e)	(f) = (c)+(d)+(e)	(g)	(h)	(i)	(j) = (g)+(h)+(i)	(k)	(l)	(m)	(n) = (k)+(l)+(m)	(o) = (a)+(b)+ (f)+(j)+(n)
	Unrecovered Interconnection Costs	NEM Admin. Costs	Rate Impacts: NEM Payments				Rate Impacts: Lost Revenues				State Tax Incentives				Total NEM Program Costs
			Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	Direct	Indirect	Induced	Total	
	($)														
2008	$ 0.02	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.02	$ 0.00	$ 0.01	$ 0.03	$ 0.80	$ 0.49	$ 0.28	$ 1.57	$ 1.62
2009	0.08	0.02	0.02	0.00	0.01	0.04	0.11	0.00	0.10	0.21	6.26	3.79	2.19	12.24	12.60
2010	0.11	0.05	0.04	0.01	0.03	0.08	0.27	0.00	0.26	0.54	10.20	6.18	3.56	19.94	20.73
2011	0.14	0.09	0.16	0.04	0.09	0.29	0.52	0.01	0.48	1.01	13.82	8.38	4.84	27.04	28.57
2012	0.34	0.18	0.33	0.06	0.21	0.61	1.13	0.02	1.07	2.22	30.95	18.76	10.82	60.53	63.87
2013	0.81	0.41	0.50	0.08	0.33	0.92	2.28	0.04	2.17	4.49	46.54	28.21	16.27	91.02	97.64
2014	0.59	0.58	0.60	0.09	0.40	1.10	3.13	0.04	2.99	6.16	24.30	14.73	8.49	47.52	55.94
2015	-	0.58	0.59	0.09	0.40	1.09	3.11	0.04	2.97	6.13	-	-	-	-	7.80
2016	-	0.58	0.59	0.09	0.40	1.09	3.10	0.04	2.96	6.10	-	-	-	-	7.76
2017	-	0.58	0.59	0.09	0.40	1.08	3.08	0.04	2.94	6.07	-	-	-	-	7.72
2018	-	0.58	0.59	0.09	0.40	1.08	3.07	0.04	2.93	6.04	-	-	-	-	7.69
2019	-	0.58	0.58	0.09	0.39	1.07	3.05	0.04	2.91	6.00	-	-	-	-	7.65
2020	-	0.58	0.58	0.09	0.39	1.06	3.04	0.04	2.90	5.97	-	-	-	-	7.62
2021	-	0.58	0.58	0.09	0.39	1.06	3.02	0.04	2.89	5.95	-	-	-	-	7.58
2022	-	0.58	0.57	0.09	0.39	1.05	3.01	0.04	2.87	5.92	-	-	-	-	7.55
2023	-	0.58	0.57	0.09	0.39	1.05	2.99	0.04	2.86	5.89	-	-	-	-	7.51
2024	-	0.58	0.57	0.09	0.39	1.04	2.98	0.04	2.84	5.86	-	-	-	-	7.48
2025	-	0.58	0.57	0.09	0.38	1.04	2.96	0.04	2.83	5.83	-	-	-	-	7.44
2026	-	0.58	0.56	0.09	0.38	1.03	2.95	0.04	2.81	5.80	-	-	-	-	7.41
2027	-	0.58	0.56	0.09	0.38	1.03	2.93	0.04	2.80	5.77	-	-	-	-	7.37
2028	-	0.58	0.56	0.09	0.38	1.02	2.92	0.04	2.79	5.74	-	-	-	-	7.34
2029	-	0.58	0.55	0.09	0.38	1.02	2.90	0.04	2.77	5.71	-	-	-	-	7.31
2030	-	0.58	0.55	0.09	0.37	1.01	2.89	0.04	2.76	5.68	-	-	-	-	7.27
2031	-	0.58	0.55	0.09	0.37	1.01	2.87	0.04	2.74	5.65	-	-	-	-	7.24
2032	-	0.58	0.55	0.09	0.37	1.00	2.86	0.04	2.73	5.63	-	-	-	-	7.21
2033	-	0.58	0.54	0.09	0.37	1.00	2.85	0.04	2.72	5.60	-	-	-	-	7.17
2034	-	0.58	0.54	0.09	0.37	0.99	2.83	0.04	2.70	5.57	-	-	-	-	7.14
2035	-	0.58	0.54	0.09	0.36	0.99	2.82	0.04	2.69	5.54	-	-	-	-	7.11
2036	-	0.58	0.54	0.09	0.36	0.98	2.80	0.04	2.68	5.51	-	-	-	-	7.07
2037	-	0.58	0.53	0.08	0.36	0.98	2.79	0.04	2.66	5.49	-	-	-	-	7.04
2038	-	0.57	0.53	0.08	0.36	0.97	2.76	0.03	2.64	5.43	-	-	-	-	6.98
2039	-	0.55	0.51	0.08	0.35	0.93	2.67	0.03	2.55	5.25	-	-	-	-	6.74
2040	-	0.52	0.49	0.08	0.33	0.90	2.51	0.03	2.40	4.94	-	-	-	-	6.36
2041	-	0.49	0.38	0.05	0.28	0.71	2.29	0.02	2.19	4.51	-	-	-	-	5.70
2042	-	0.40	0.23	0.03	0.17	0.43	1.75	0.02	1.68	3.45	-	-	-	-	4.27
2043	-	0.17	0.08	0.01	0.07	0.16	0.74	0.00	0.72	1.47	-	-	-	-	1.79
NPV:	**$ 1.54**	**$ 6.46**	**$ 6.57**	**$ 1.06**	**$ 4.42**	**$ 12.04**	**$ 33.60**	**$ 0.44**	**$ 32.05**	**$ 66.09**	**$ 99.96**	**$ 60.59**	**$ 34.94**	**$ 195.50**	**$ 281.63**

APPENDIX A-8
BASELINE, SENSITIVITY 3, COST-BENEFIT RESULTS

	ESTIMATED DIRECT NET BENEFITS (BASELINE)				
	(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) - (d)
	Total Avoided Power Costs	Total Solar Benefits	Total Benefits	Total Costs	Net NEM Program Benefits
	($)				
2008	$ 0.03	$ 1.22	$ 1.24	$ 1.62	$ (0.38)
2009	0.19	8.50	8.68	12.60	(3.91)
2010	0.49	13.75	14.24	20.73	(6.49)
2011	0.97	20.35	21.32	28.57	(7.25)
2012	2.09	42.90	44.99	63.87	(18.88)
2013	4.02	63.80	67.82	97.64	(29.82)
2014	5.43	33.67	39.11	55.94	(16.83)
2015	5.41	1.25	6.66	7.80	(1.14)
2016	5.38	1.25	6.63	7.76	(1.13)
2017	5.35	1.25	6.60	7.72	(1.12)
2018	5.33	1.25	6.58	7.69	(1.11)
2019	5.30	1.25	6.55	7.65	(1.10)
2020	5.27	1.25	6.52	7.62	(1.09)
2021	5.25	1.25	6.50	7.58	(1.09)
2022	5.22	1.25	6.47	7.55	(1.08)
2023	5.20	1.25	6.44	7.51	(1.07)
2024	5.17	1.25	6.42	7.48	(1.06)
2025	5.14	1.25	6.39	7.44	(1.05)
2026	5.12	1.25	6.37	7.41	(1.04)
2027	5.09	1.25	6.34	7.37	(1.03)
2028	5.07	1.25	6.32	7.34	(1.02)
2029	5.04	1.25	6.29	7.31	(1.02)
2030	5.02	1.25	6.27	7.27	(1.01)
2031	4.99	1.25	6.24	7.24	(1.00)
2032	4.97	1.25	6.22	7.21	(0.99)
2033	4.94	1.25	6.19	7.17	(0.98)
2034	4.92	1.25	6.17	7.14	(0.97)
2035	4.89	1.25	6.14	7.11	(0.97)
2036	4.87	1.25	6.12	7.07	(0.96)
2037	4.84	1.25	6.09	7.04	(0.95)
2038	4.80	1.24	6.04	6.98	(0.94)
2039	4.63	1.18	5.82	6.74	(0.92)
2040	4.35	1.09	5.44	6.36	(0.92)
2041	3.91	0.95	4.86	5.70	(0.84)
2042	2.92	0.66	3.58	4.27	(0.69)
2043	1.24	0.22	1.47	1.79	(0.33)
NPV:	**$ 58.51**	**$ 150.42**	**$ 208.93**	**$ 281.63**	**$ (72.70)**

LPSC Net Metering Annual Report

Utility Name: ______________________

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential													
1 Number of Solar Unit Installations													
2 Solar Generation Capacity, kW (DC)													
3 Solar Inverter Capacity, kW (AC)													
4 Number of Wind Unit Installations													
5 Wind Generation Capacity, kW (DC)													
6 Wind Inverter Capacity, kW (AC)													
7 Number of Biomass Unit Installations													
8 Biomass Generation Capacity, kW (DC)													
9 Biomass Inverter Capacity, kW (AC)													
10 Number of Other Unit Installations (Microturbine, Fuel Cell)													
11 Other Generation Capacity, kW (DC)													
12 Other Inverter Capacity, kW (AC)													
13 Total Number of Installations													
14 Total Generation Capacity, kW (DC)													
15 Total Inverter Capacity, kW (AC)													
Commercial													
16 Number of Solar Unit Installations													
17 Solar Generation Capacity, kW (DC)													
18 Solar Inverter Capacity, kW (AC)													
19 Number of Wind Unit Installations													
20 Wind Generation Capacity, kW (DC)													
21 Wind Inverter Capacity, kW (AC)													
22 Number of Biomass Unit Installations													
23 Biomass Generation Capacity, kW (DC)													
24 Biomass Inverter Capacity, kW (AC)													
25 Number of Other Unit Installations (Microturbine, Fuel Cell)													
26 Other Generation Capacity, kW (DC)													
27 Other Inverter Capacity, kW (AC)													
28 Total Number of Installations													
29 Total Generation Capacity, kW (DC)													
30 Total Inverter Capacity, kW (AC)													
Total													
31 Number of Solar Unit Installations													
32 Solar Generation Capacity, kW (DC)													
33 Solar Inverter Capacity, kW (AC)													
34 Number of Wind Unit Installations													
35 Wind Generation Capacity, kW (DC)													
36 Wind Inverter Capacity, kW (AC)													
37 Number of Biomass Unit Installations													
38 Biomass Generation Capacity, kW (DC)													
39 Biomass Inverter Capacity, kW (AC)													
40 Number of Other Unit Installations (Microturbine, Fuel Cell)													
41 Other Generation Capacity, kW (DC)													
42 Other Inverter Capacity, kW (AC)													
43 Total Number of Installations													
44 Total Generation Capacity, kW (DC)													
45 Total Inverter Capacity, kW (AC)													

Utility Name: ____________________

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Utility													
46 Utility Peak Load (MW)													
47 Retail Portion													
48 Percent of System Peak ((line 44/1,000)/line 47)													
49 Energy Purchased from Net Metered Customers (kWh)													
50 Average Rate Paid for Energy Purchased from Net Metered Customers ($/kWh)													
51 Cost of Energy Purchased from Net Metered Customers ($)													
52 Utility Avoided Cost Rate ($/kWh)													
53 Utility Fuel Clause Rate ($/kWh)													